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Australian Energy Market Commission

FINAL REPORT

Transmission Frameworks Review

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two main functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Executive Summary

The Australian Energy Market Commission (AEMC) has finalised a comprehensive review of the transmission arrangements that underpin the National Electricity Market (NEM). The review tests whether the current frameworks are likely to drive the most efficient future investment in both transmission and generation to minimise the total long term costs of the energy system for end user consumers.

There may be significant changes in the types and location of electricity generation in the future, depending on policy settings, technology development and patterns of demand. Under current arrangements, investment decisions about generation and transmission are driven by different considerations and processes.

The Commission has developed an alternative transmission model for the NEM, called optional firm access. It has the potential to deliver better long term outcomes by introducing more commercial drivers into transmission development. It enables better trade-offs to be made between the cost of transmission and the cost of generation. It aligns more of the risk of investment decisions with those who make them, and away from consumers.

These trade-offs become of greater importance when established patterns of demand and generation are changing. The Commission considers it reasonable and prudent to progress the optional firm access model, against the possibility of a future that brings such change. However, the model is complex. Implementing it would represent a fundamental change to the market, and would not be without risk.

The Commission therefore recommends that governments commit time and resources to the detailed design and testing of the model, in consultation with industry, prior to making a final implementation decision.

This report also proposes solutions to address the cost, complexity and delays associated with connecting new generation to the transmission network. These arrangements seek to introduce additional transparency and competition to the process balanced against the need to maintain clear accountability for the safe and secure operation of the network.

The review

The review was instigated by the Ministerial Council on Energy (MCE), now the Standing Council on Energy and Resources (SCER), in April 2010 to recommend any changes required to the arrangements governing the provision and utilisation of electricity transmission services.

The review follows from the Commission's previous Review of Energy Market Frameworks in Light of Climate Change Policies. In the context of changing patterns of generation and demand, we were asked to assess whether current transmission frameworks are likely to lead to efficient outcomes.

The focus has been on the interface between transmission and generation including how generators connect to the transmission network, how they access the wholesale market via transmission, the way network congestion is managed, what charges generators should face for transmission, and how the network is planned.

Many of these issues have been the subject of ongoing debate since the establishment of the NEM in 1998 and there has been extensive consultation as part of this review. There are divergent views about the efficiency of the current arrangements, and their ability to accommodate any possible future changes in generation and demand.

While patterns of generation and demand in the early years of the NEM were relatively stable and predictable, the future is less certain and greater flexibility may be required to facilitate efficient coordination of generation and transmission investment.

Coordination of generation and transmission investment

Under the current framework, decisions about investment in electricity generation and transmission infrastructure occur through different processes:

- Investment in generation assets is market-driven and takes into account expectations of future demand, the location of the energy source, access to land and water and proximity to transmission.
- Investment in transmission is centrally planned according to a cost-benefit test. Transmission businesses are subject to an incentive-based economic regulatory regime.

These differences in generation and transmission investment processes have the potential to result in a development path that does not minimise the total system costs, faced by consumers. A key issue is the degree to which the allocation of risks between owners of the businesses and consumers are aligned in these processes.

Generators benefit from transmission investment where it allows them to be dispatched and so earn revenue. They may value the benefit of additional transmission more than the investment would cost. However, there is no means for them to fund additional investment and secure a right to the additional market access that is created.

The differences between generation and transmission decision-making processes can limit the ability of generators to transmit electricity, or lead to inefficient investment in transmission networks to alleviate capacity constraints:

- Scarce transmission capacity in a given region can limit the ability of some generators to sell their energy at the regional wholesale price. During times of congestion, generators have an incentive to offer their electricity in a non-cost reflective manner, which may lead to the dispatch of needlessly costly generation.
- Generation investment decisions are more risky due to volume uncertainty and price volatility, which may decrease generators' willingness to invest in new

generation or increase the price at which they are willing to contract with retailers.

- The current market arrangements mean it is less risky to contract within a region than between regions.

There is limited firm evidence that the current arrangements have caused significant coordination issues to date. They may, however, increase in significance in the event of changing patterns of demand, technological change, investment in smaller and more dispersed generation, and increased uncertainty concerning the development path that best satisfies the National Electricity Objective.

Optional firm access

With a view to the longer term, the Commission has developed an integrated package of market arrangements, termed optional firm access. It creates the ability for generators to “insure” against the risk of congestion. It would transform the way generators access the market during times of congestion and the way transmission investment decisions are made:

- Generators would have the option of buying firm access rights to transmission networks to manage congestion risk. These financial rights would take the form of compensation payments funded by generators without such rights, and would be underpinned by the provision of transmission capacity.

- Generators, rather than planners, would drive some part of the decision-making about future transmission development. In choosing to acquire firm access, generators would fund and guide the development of new transmission to underpin their access rights. The development of interconnectors between different regions would be predominantly driven by generators' and retailers' purchases of inter-regional access.

The arrangements represent an internally consistent and highly interlinked set of proposals. A key finding of this review has been that it is not possible to address any one element of the transmission frameworks in isolation. We therefore do not recommend implementation of parts of the model in a piecemeal manner.

Commercial drivers on transmission development and operation

The optional firm access model would introduce more commercial drivers on transmission businesses and more commercial financing of transmission infrastructure. The approach should result in a closer alignment of generation and transmission investment.

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

Generation and transmission location. If generators face the full cost of transmission, they will factor this into their location decision. They have incentives through competition to minimise the combined lifetime cost of generation and transmission, and of other energy networks - such as gas pipelines - where they use them.

Efficient levels of transmission development. In choosing whether to acquire firm access, generators would trade off the cost of transmission with the avoided cost of congestion. The result should be an efficient level of transmission development.

Risk for consumers from investment decisions. The owners of generation businesses would bear the costs of transmission development undertaken to support their access decision. Competition is likely to limit their ability to pass through the costs of inefficient decisions to consumers.

Operation of transmission networks. The arrangements would result in a measurable outcome from TNSPs' operations of their network. Incentives would be placed on them to maximise the availability of their network when it is most valuable to the market.

Ability of market participants to contract and trade

The optional firm access model also has the potential to improve the ability of market participants to contract and trade.

Support for inter-regional trade. The arrangements would support trade between generators and retailers in different regions of the NEM by providing a firmer hedge against inter-regional price differences than is currently available. Increased trade may enhance competition in both the wholesale and retail markets.

Financial certainty for generators. Giving generators the ability to secure firm access should create more revenue certainty. This may result in a lower risk-adjusted cost of capital, resulting in lower financing costs for power stations. Decreased risk may also increase the willingness of generators to contract with retailers at a given price.

Efficient dispatch. The current incentive for generators to offer their electricity in a non-cost reflective manner during times of congestion would be reduced.

Benefits increase with the degree of change

The optional firm access arrangements would provide a more robust set of transmission frameworks, whatever the future. We expect, however, that the associated benefits may be greater in a future that involves more change from current patterns of demand and generation.

The model enables better trade-offs to be made between the cost of transmission and the cost of generation, and these trade-offs become more important when there is more change from established fuel sources and transmission flowpaths, and where there are greater cost differences between different types of generation and energy transmission.

We commissioned modelling which finds that the improved co-optimisation of generation and transmission investment under optional firm access creates a positive but limited benefit in net present value terms. As with any modelling of the future, a number of simplifying assumptions are necessary, and the results should be treated with caution.

The modelling indicates that previous regulatory arrangements and historical investment decisions have led to spare capacity in the transmission system, the costs of which are met by consumers. Much of the review was undertaken against the background of reforms to the rules governing the economic regulation of network service providers, completed in November 2012. The new rules improve the strength and capacity of the regulator to determine network price increases so consumers do not pay any more than necessary for the reliable supply of electricity.

The modelled benefits become significant from the 2020s onwards, when existing spare transmission capacity is predicted to be insufficient to meet emerging demand. Although substantial, on a discounted basis they appear less so.

Other benefits of the revised arrangements are not easily estimated. These include decreased revenue volatility that generators may experience during times of congestion, with a possible reduction in the risk premium that is added to generators' prices (both spot and contract) and to their risk adjusted cost of capital. We have also not estimated the benefits that would result from enhanced support for inter-regional trade.

Connections

The cost, complexity and time delays associated with connecting new generation to the market are a concern which the Commission considers can be addressed in the shorter term. Transmission businesses could be encouraged to make efficient trade-offs between the specification of connections and their cost. Ambiguity in the current rules also contributes to the problem.

The Commission is recommending an approach to increase competition and transparency in the construction of the assets required for generator connection. It should promote faster and cheaper connections for generators. We consider that there is a need to balance increased competition with maintenance of clear accountability for outcomes on the shared network. Therefore, regional transmission businesses would always be accountable for the operation and control of any assets forming part of the shared network, once constructed.

Recommendations

The Commission is recommending both short-term reforms to facilitate more efficient connections between generators and transmission networks, and detailed design and testing of the longer-term model for optional firm access for generators.

We recommend that SCER propose a rule change to give effect to the proposed solution for connections, which would clarify existing rules and allow for assets to be constructed competitively.

We recommend that governments commit to the detailed design and testing of the optional firm access arrangements. The program should be directed by an industry panel, supported by a multi-disciplinary project team. This would ensure industry involvement and input to address the complex and technical issues involved.

The blueprint for optional firm access includes arrangements for transmission planning and investment decision making that would be implemented as part of the model. However, it would be possible to take more immediate action on some of the planning recommendations. We are of the view that there would be merit in doing so.

The implementation plan below sets out our recommendations in full, along with the actions to implement them.

This report is structured in two parts. Part 1 discusses optional firm access and planning. Part 2 discusses connections. Chapter 1 provides an overview of the review, and the rationale for our recommendations.

Transmission Frameworks Review Implementation Plan

Final recommendations	SCER action	Implementation
Driving efficient investment in, and use of, transmission networks		
Initiate detailed design and testing program for optional firm access. This will allow for the better assessment of the costs and benefits associated with the model.	Direct the AEMC to commence the detailed design and testing program for optional firm access. (Table 10.1 sets out the core and recommended elements of the optional firm access model.) Commit to provide funding to support this.	SCER decision at its end-2013 meeting. AEMC to establish, following SCER direction, the OFA Panel and project team.
TNSP planning and decision making should be enhanced through new arrangements to: • promote the identification and implementation of network investment options that cross regional boundaries; • allow TNSPs to provide greater input into the national planning process; and • improve the consistency of TNSP planning reports.	Submit a rule change request to give effect to these modifications (Appendix A details how these changes would be implemented in the rules by setting out draft specifications).	SCER decision at its end-2013 meeting.
TNSP regulatory resets should be aligned to further facilitate enhanced TNSP coordination and assist the effectiveness of the AER's revenue setting process.	Task the AER with developing a rule change request to facilitate this.	SCER decision at its end-2013 meeting. AER to submit rule change proposal to the AEMC no later than March 2014.
AEMO should produce "bottom up" demand forecasts at a transmission connection point level for use in a variety of processes. These forecasts could be used as an additional source of information by the AER to test demand forecasts by other parties	Consider our recommendations when developing its response to the related task assigned to AEMO (task 12.2 in the December 2012 COAG Energy Market Reform - Implementation Plan).	SCER decision in May 2013.

Final recommendations	**SCER action**	**Implementation**
Enhancing transparency, contestability and clarity in the connection frameworks		
Transmission connection frameworks should be enhanced to: • better facilitate contestable build of shared network assets required for connections; • require TNSPs to provide more transparent information for negotiated transmission services; and • provide greater clarity, particularly in regards of dedicated connection assets not forming part of the shared network.	Submit a rule change request to give effect to these modifications (Appendix C details how these changes would be implemented in the rules by setting out draft specifications).	SCER decision at its end-2013 meeting. AER to modify network exemption guidelines to reflect these recommendations following implementation of the rules.
Additional safeguards are required to maintain the separation of generation and transmission in the NEM. However, restrictions should not apply to: • dedicated connection assets; and • the ownership of assets, where these are controlled by the local TNSP.	Consider our recommendations when finalising its approach to the separation of generation and transmission.	SCER to progress.

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1 Overview

1.1 Background

Australia's National Electricity Market (NEM) is experiencing a period of significant change. In the transmission sector, the pattern of network flows is changing and forecasts of future needs are increasingly uncertain. Climate change policies and technological developments are affecting the use of the transmission system by generators. Factors such as retail price increases and global economic conditions and the resulting impacts on the structure of the Australian economy are resulting in changes to patterns of demand.

These factors will have significant impacts on transmission investment over the longer term, as well as on the management of network flows in operational timescales. They also make it increasingly difficult to be deterministic or forecast which particular combination of generation and transmission investments will minimise the total system costs faced by consumers.

Against this background, in April 2010 the Ministerial Council on Energy (MCE), now the Standing Council on Energy and Resources (SCER),[1] directed the Australian Energy Market Commission (AEMC or Commission) to 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".[2]

This review is to recommend any "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".[3]

Accordingly, the focus of the review has been on the arrangements that govern the interface between transmission and generation. These include how generators can 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.[4] These arrangements are highly inter-related and so cannot be considered in isolation, which has required the review to be progressed in a comprehensive and holistic manner.

1 SCER was established in late 2011 to replace the MCE.

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

3 MCE direction, p.3.

4 It should be noted that some of the review's recommendations, particularly those relating to connections, would also affect demand-side customers. In addition, other elements of the Commission's recent and current work focus on the use of networks by the demand-side, most relevantly the Review of the National Framework for Transmission Reliability but also the broader Power of Choice review.

As in every AEMC review, our recommendations have been developed with regard to the National Electricity Objective (NEO), which aims to promote efficiency for the long term interests of electricity consumers. In this context, the objective should be to minimise total system costs across transmission and generation, which are reflected in the level of consumer prices.

We have concluded that there is a case for reform of the NEM transmission arrangements. This chapter sets out, at a high-level, our rationale as to why the current arrangements are unlikely to promote efficient long term outcomes given uncertain future circumstances and why change may therefore be warranted. It outlines our recommendations to SCER, as well as providing a more general introduction to the review and this final report.

1.2 Linking transmission arrangements with the wholesale market

The NEM commenced operation on 13 December 1998.[5] The focus of the developers of the NEM was to facilitate competition between electricity generators across the interconnected system and trade with retailers. Importantly, this allowed future investment in generation to be determined by market participants on the basis of signals from the market: expectations of future spot prices and retailers' willingness to enter into contracts to hedge against future price risk.

A primary concern was therefore to promote liquidity in the contract market. To this end, the NEM was formed around a small number of regions (based on the meshed transmission networks and this broadly aligned with the states participating in the NEM). Retailers pay, and generators receive, a uniform wholesale price in each region. This allows all retailers and generators in that region to trade with each other on the same basis, and write contracts around a common "strike" price.

An issue with electricity market design is how scarcity of transmission capacity is managed and how transmission investment decisions are made. In the NEM, although all generators in a region receive the same energy price, if transmission capacity is limited some generators may not be able to receive that price. This is because constraints on the network lead to "congestion", preventing them from being able to generate as much as they would wish to at that price (as revealed through their dispatch offer price). This is described as being "constrained-off".

This issue is addressed in some markets employing uniform wholesale energy pricing (such as Western Australia and Alberta) by ensuring that all congestion is "built out": sufficient transmission capacity is provided to ensure that any realistic combination of generators can be dispatched to meet demand for electricity at any given time.

Such an approach results in its own inefficiency: the provision of transmission infrastructure is very costly, and the costs of the additional investment could exceed

5 Various wholesale market arrangements had been in place within jurisdictions and between New South Wales and Victoria before this.

the costs that result from the congestion. In other words, the most efficient level of congestion is not zero.

This need to efficiently balance transmission investment against the costs of congestion has long been recognised in the NEM. The current processes for doing this have relied upon regulatory and institutional arrangements, ie various forms of central planning as distinct from the market and commercial drivers of generation investment.

The central issue for this review then has therefore been to evaluate alternative means of coordinating market driven generation investment with transmission investment. As such, the recommendations we are making focus on linking the arrangements for investment in, and usage of, the transmission system with those governing the wholesale market.

1.2.1 Efficiency of investment in the transmission system

Following the introduction of the NEM, an approach evolved whereby investment in the transmission system is determined by Transmission Network Service Providers (TNSPs) using a cost benefit test. The most recent version of this test, the Regulatory Investment Test for Transmission (RIT-T), was implemented in August 2010.

Under the RIT-T, TNSPs are required to assess the efficiency of proposed investment options by estimating the benefits that would result for market participants and consumers, and comparing these to the associated costs. If a proposed investment passes the criteria governing the RIT-T, the TNSP will proceed with the investment, and this will be funded by market customers through Transmission Use of System (TUOS) charges.[6] While there are processes to review TNSPs' application of the RIT-T, to the extent that costs and benefits are forecast inaccurately then these risks are borne in full by consumers.

The benefits assessed under the RIT-T include some accruing to generators, such as differences between:

- capital costs;
- fuel consumption; and
- operational and maintenance costs.

TNSPs consult publicly under the RIT-T process, partly in order to test their identification of the likely costs and benefits. This provides the opportunity for generators to input information.

In practice, transmission investment within regions has been dominated by the need to meet jurisdictional demand-side reliability standards, with the estimation of generator

6 TUOS charges are levied on market customers directly connected to the distribution network, including Distribution Network Service Providers (DNSPs). DNSPs pass these charges through to their customers.

benefits being relatively minor in comparison. In most jurisdictions, investments may proceed, even with a net cost, if required to meet reliability standards. In addition, few investments in interconnectors between regions have occurred, largely due to the relatively small differences in fuel costs between the regions.

Historically, major load centres in the NEM have been served by generation clusters in relatively close proximity (such as Melbourne and the Latrobe Valley). Therefore, the process whereby TNSPs assess the benefits associated with transmission investments have not been tested to any great degree.

However, going forward, TNSPs are likely to have to assess much greater changes in the pattern of generation in the NEM. For example, ElectraNet has recently attempted to quantify the effects of additional wind generation on the Eyre Peninsula in South Australia displacing investment in wind generation that would have otherwise occurred in areas with lower quality wind resources (principally in New South Wales (NSW)).[7]

With the endorsement of the Council of Australian Governments (COAG), SCER has tasked the AEMC with developing a national framework for transmission reliability more explicitly based around the economic trade-off between the costs of investment and the value placed on reliable supply by consumers. While the details of this framework have yet to be finalised, it may result in fewer investments with a net cost proceeding than has been the case to date. All else being equal, this might tend to increase the scarcity of transmission within regions to be rationed amongst generators.

The costs associated with the continuation of the centrally planned approach to transmission investment might be small given a stable, predictable generation market with little divergence in fuel costs and generous demand-side reliability standards. However, changes currently underway, together with increasingly uncertain future circumstances, may affect this outcome. This has led us to consider whether efficiency could be enhanced by allowing the generation market to drive investment in transmission.

Although there has long been the ability in the NEM for generators to fund investment in the transmission system, these arrangements have been little used due to a free rider problem: other generators will also benefit from the network capacity without having contributed to the costs of the network investment, and may even prevent the funding generator from using it. A prerequisite for promoting market-driven transmission investment is therefore to provide generators with enforceable rights to the use of the transmission system.

1.2.2 Efficiency of usage of the transmission system

Under the current NEM arrangements, no defined service is provided to generators for use of the transmission system. A generator may be constrained-off in the dispatch

7 ElectraNet, *Lower Eyre Peninsula Reinforcement*, RIT-T Project Assessment Draft Report, January 2013.

process by another generator or as the result of insufficient transmission capacity being made available by the TNSP, without compensation. This means that generators have uncertain access to the market, in terms of their ability to be dispatched and receive the regional energy price.

In international terms, this is an unusual market design. Other liberalised electricity markets around the world with uniform prices either build-out congestion (as discussed previously) or make use of a system of "side-payments" to compensate generators for being constrained-off.

In the absence of constrained-off payments, generators have an incentive to adjust their offers into the market in order to maximise the amount of output they are dispatched for. Generally, this means that generators will make offers at levels lower than their costs. There is little risk that such a generator will receive a payment lower than its costs because the constraints on the network usually mean that the regional price (at which all generators are settled) will be set by a higher priced generator.

This behaviour, which has come to be known as "disorderly bidding", can ultimately see all generators behind a constraint making offers at the market floor price (currently -$1,000/MWh). Generators may also use other mechanisms, such as ramp rate constraints, in order to ensure that they are dispatched and continue to receive the regional energy price for a substantial part of their capacity.

Disorderly bidding can result in volatile spot market outcomes. The price at which generators are willing to contract, as well as the overall attractiveness of investing in the generation sector, is affected by the certainty with which generators can access the market.

Generators engaging in disorderly bidding within a region will be dispatched ahead of inter-regional generation provided via interconnectors. This is because interconnector capacity cannot bid in a disorderly fashion – the market operator's system dispatches generators, irrespective of their region, based on their offer price. Generators' offers in an adjoining region could affect the regional energy price prevailing in that region, and so they are unable to compete with the market floor price being offered by generators within the region.

This effect can ultimately result in "counter-price flows", where power flows from a high priced region to a lower priced region (it would normally be expected to be transferred from low priced regions to higher prices regions). In such circumstances, the market operator will pay out more money to generators in the high priced exporting region than it will receive from consumers in the lower priced importing region. The direct cost of this - the shortfall in settlement funds - is recovered from the TNSP's customers in the importing region. However, this will also affect the ability of market participants to trade between regions.

Inter-regional trade is facilitated by the auctioning of inter-regional settlement residues. These are 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. Obtaining these Settlement Residue

Auction (SRA) units aims to allow market participants to hedge the risk associated with trading between two differently priced regions.

However, the result of counter-price flows on an interconnector is to reduce the return to SRA unit holders to zero, despite the price differential between the two regional energy prices. This impedes inter-regional trade, potentially reducing competitive pressures on both generators and retailers in a given region.

Finally, disorderly bidding can also affect the efficiency of dispatch. In normal circumstances, generators' offers represent a proxy of their costs. When all generators are offering at the market floor price, the market operator has no way of differentiating between them, and so some more efficient generation capacity may be displaced by less efficient plant. While it is generally accepted that the direct costs of this form of productive inefficiency have been relatively small to date (given the similar fuel costs of generators in the NEM), the likely greater spread of fuel costs amongst generators in the NEM in the future (including relatively high cost open cycle gas generators) may affect this outcome over time.

Although a number of measures to mitigate the effects of disorderly bidding have been considered (and continue to be), to resolve the issue requires changes to be made to the market design. In particular, it is only by de-linking the right of generators to receive the regional energy price from their actual level of dispatch that the current incentive on them to maximise their dispatch will be removed. In other words, if a generator received compensation equal to the difference between the regional energy price and its costs, it would be indifferent to whether it generated or not. As previously noted, such financial access rights would also allow for market participants to provide signals regarding transmission investment, and so the major focus of this review has been on designing revised market arrangements to give effect to these.

1.2.3 An integrated package to promote efficiency

To respond to the challenges set out above, we have developed an integrated package of market arrangements for the provision and utilisation of the transmission system, which has been termed "Optional Firm Access".[8]

Under the optional firm access arrangements, generators would have the ability to purchase financial access rights. These would entitle the "firm" generator to receive the difference between the regional energy price and a price calculated at the generator's local connection point, irrespective of whether it was dispatched. This right would therefore enable a generator to manage its volume risk. It would only have value in the presence of network congestion: in normal circumstances, the local price would equal the regional price.

There would be no obligation on generators to purchase access rights. However, if a "non-firm" generator without rights was dispatched ahead of a firm generator such that the firm generator's local price diverged from the regional price, the non-firm

8 See chapters 2-7, and 9 for a more complete description of these arrangements.

generator would be required to fund the payment made under the firm generator's access right. The result would be that, while they would normally receive the regional price, in the presence of congestion non-firm generators may be settled at a price less than this. However, they would never receive less than their local price, which means that they would never make a loss from generating.

Access rights, although a financial product, would be underpinned by transmission capacity. Generators procuring access rights would pay a charge reflecting the costs associated with the resulting transmission investment. In the event that the unavailability of transmission capacity resulted in congestion, the TNSP would make a contribution towards the compensation paid to firm generators. This would also have the effect on incentivising TNSPs to maximise the availability of transmission capacity at the times it was most valuable.

As discussed in greater detail in chapter 8, these arrangements would result in changed outcomes as compared to the current arrangements, including:

- A defined service would be provided to generators (and generators would have the ability to indicate that they would value such a service being provided). This would allow generators to manage the risk associated with network congestion. This should decrease the risk premium included in the price of contracts sold by generators. There would be strong incentives on TNSPs to provide the access service, where requested.

- In deciding whether or not to procure this service, generators would be making the trade-off between the costs of transmission investment and transmission congestion. By purchasing access rights (which would be underpinned by transmission capacity), generators would be making decisions regarding the need for much transmission investment. Because generators are subject to competition, they have a natural incentive to make efficient decisions. Unlike TNSPs, generators would face the consequences resulting from a bad decision. (They also have more information regarding the generation market than TNSPs.) Efficient decisions minimise overall costs, and so risk would be transferred away from consumers to generators.

- All generators would face clear signals relating to their location on the transmission system. For firm generators, this would be the price associated with the provision of transmission capacity. For non-firm generators, it would be any costs associated with compensating firm generators (ie congestion costs). It is these price signals that would form the basis for the market-led co-optimisation of generation and transmission.

- The service provided by interconnectors would be significantly firmer, for two reasons. Firstly, the firm rights would mean that interconnector capacity could not be degraded by new generators, as at present – if a new generator requested firm access, additional transmission capacity would be provided, preserving the capacity of the interconnector. Secondly, if a non-firm generator was dispatched with the effect of constraining off the interconnector, it would pay compensation to the interconnector. This would have the effect of keeping interconnector users financially whole. A firmer interconnector service should promote inter-regional competition in generation and retail, putting downward pressure on costs to consumers.

- Finally, by removing the current incentive on generators to bid in a "disorderly" manner, efficient dispatch would be promoted.

These arrangements are complex, and would represent a substantial change to the status quo. However, they are not without precedent, in many ways drawing on features present in other international wholesale energy markets. Closer to home, a similar mechanism is a feature of the Short Term Trading Market (STTM) for gas. In the STTM arrangements, if a pipeline is constrained and an as-available (non-firm) gas shipper prevents a shipper with firm rights from shipping gas, the as-available shipper pays a capacity charge. The firm shipper who has been displaced receives a capacity payment reflecting the difference between the market price for that hub (similar to the regional energy price in optional firm access) and the maximum price offer scheduled on the relevant pipeline (equivalent to the local price).

Assessment

We commissioned modelling in order to quantify some of the benefits associated with the optional firm access arrangements.[9] This modelling undertaken for us (by ROAM Consulting[10]) estimated savings from an improved level of co-optimisation between generation and transmission investment, and in generator fuel costs. A key finding of the modelling was that there is currently significant over-capacity in the transmission network, when compared to the level of generator capacity. While the modelling does reveal significant changes as a result of the implementation of optional firm access, most of these occur in the later years of the modelling when existing spare transmission capacity is predicted to be insufficient to meet emerging demand. The benefits are therefore not fully reflected in the discounted value of the savings, which only captures a few years of the annualised repayments of the total capital cost.

More generally, modelling in this context should be treated with a degree of caution. Many of the potential benefits of optional firm access are not amenable to being estimated in this manner. For those benefits that do lend themselves more readily to quantification, it is still necessary to make many simplifying assumptions. Moreover, the modelling inherently favours central planning, with no way of capturing the benefits that would be offered by decentralised decision-making in an uncertain future.

Importantly, the modelling reflects a particular view of the future, which includes assumptions about the relative costs of different generation and transmission technologies and the rate and pattern of demand growth. If those cost differentials were greater, or demand growth higher, then the efficiency benefits would be larger. For instance, the modelling finds that optional firm access results in significant changes

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9 These results are discussed in more detail in chapter 8.

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

in the location of generation and transmission investment, but because of the relatively small cost differentials between electricity and gas transmission, those changes result in relatively small net savings.

Conversely, if cost differentials were smaller, and demand lower, then the modelled benefits would be smaller. In other words, the modelling suggests that the more change from current patterns of generation and demand that occur in the future, the more scope there is for optional firm access to deliver the efficiency benefits that result from enhanced co-optimisation.

Recommendation

For the reasons above, we consider that the optional firm access arrangements have the potential to deliver significant benefits to the NEM, in the long term interests of consumers. However, the complexity of the model and the consequent difficulty in quantifying the benefits that would result from it means that it is not possible to unequivocally recommend its implementation at this stage. Further detailed design and testing of the model would allow for a better understanding of the likely costs and benefits, and for further assessment to be undertaken. The next section of this chapter (1.3) introduces our recommended approach for progressing this.

1.2.4 Connections

The terms of reference for the review specifically directed us to "assess the effectiveness of the current arrangements for connection services for generators".[11] However, the level of stakeholder comment that this topic attracted has led to it assuming a greater prominence than perhaps had been anticipated. Of the areas we were tasked to review, it is also the only one that we found possible to consider on a largely separable basis. This area covered both shared network assets used to facilitate connections and dedicated assets used to link remote generation and load to the shared network.

Issues

The connection arrangements for generators have been problematic since the commencement of the NEM. An important contributing factor appears to have been the decision to levy TUOS charges only on load customers and not on generators. Whereas the costs of substations forming part of the shared transmission network required to connect loads have been recovered through TUOS charges, there has been no clear mechanism for such costs to be recovered from generators. While the cost recovery arrangements for dedicated connection assets for generators have been clearer, there has also been a lack of clarity as to the scope of these assets.

11 MCE direction, p.4.

The economic regulation of connection services for generators was fundamentally reformed by the Commission in 2006.[12] These rule changes, which established Chapter 6A of the rules, meant that the costs of connection services for generators and large (ie non-DNSP) loads were no longer directly regulated but were instead determined by negotiation between TNSPs and connecting parties. The Commission considered that parties connecting directly to the transmission system would typically be large and well resourced, providing a counterweight to the negotiating power possessed by TNSPs and making commercial negotiation a feasible proposition. This Negotiated Transmission Services regime would be less intrusive and less administratively costly than directly regulating connections as a Prescribed Transmission Service.[13]

In practice, a number of issues with this set of arrangements have emerged. The fact that connections typically form a small part of a TNSP's business (as compared to the provision of the shared transmission network) means that the countervailing market power of connecting parties has been limited. Whereas direct revenue regulation requires TNSPs to strike a balance between cost and service outcomes, the monopoly pricing power held by TNSPs in connection negotiations means that there is no check on the incentive on TNSPs to maximise the reliability and security - and therefore the cost - of the resulting investments.[14] Some TNSPs may also have more generally failed to be responsive to the needs of connecting generators, for instance in facilitating connections in a timely manner or being prepared to accept an appropriate liability for late delivery.

The focus of the 2006 changes was on defining the services to be provided by TNSPs. While the service provided is, ultimately, what is important for customers, the absence of any linkage between service classifications in the rules and the assets underpinning their provision has proved problematic. The majority of costs involved in providing a connection are driven by investment in assets. Without a clear understanding of which assets could reasonably be specified by a TNSP, connecting parties have not been able to participate in negotiations in an informed manner. In particular, there has remained considerable ambiguity in the rules regarding the provision of substations forming part of the shared network that are required to connect a generator.

Recommendations

In light of these issues, we are recommending a package of changes to the frameworks for connecting to the transmission system. These recommendations aim to enhance contestability, transparency and clarity in the connection arrangements, while ensuring that accountability for service outcomes on the shared network is maintained.

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12 See: AEMC, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, Sydney.

13 AEMC, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, Sydney, p.xvii.

14 While the reintroduction of direct revenue regulation would provide an incentive on TNSPs to minimise costs (as for the rest of the shared network), such an option attracted little to no support from generators.

A key recommendation seeks to promote competition in the construction of assets required to facilitate connections. Generators would have the option of appointing their own contractor to construct assets in accordance with a design agreed with the TNSP. Once constructed, accountability for operation and control of any assets forming part of the shared network would rest with the TNSP.[15]

This approach would allow generators greater control over both the cost and timing of the provision of the specified assets. It also contains a number of safeguards to reduce the risk of TNSPs over-specifying the assets required. Equally, the arrangements regarding the operation and control of all shared network elements would allow TNSPs to be fully accountable for shared network service outcomes. This would be consistent with the implementation of the optional firm access model, where the incentives placed on TNSPs to promote the efficient provision of the firm access service are dependent on TNSPs being able to manage the key determinants of the quality of this service. It would also ensure that there were no concerns regarding the subsequent use of shared network assets to facilitate further connections on a non-discriminatory basis.

Where generators chose not to take advantage of this contestable option, TNSPs would continue to have an obligation to provide all relevant shared network elements required to effect a connection, if requested. We are recommending that current negotiating frameworks be strengthened to provide better information to connecting parties. This would allow them to negotiate in a more informed manner.

We are also recommending that the current rules governing connections be substantially reworked to provide greater clarity. This would also strengthen the ability of connecting parties to negotiate effectively, reducing the current ambiguity.

In particular, we consider that additional clarity is required in the frameworks for dedicated connection assets outside of the shared network. These dedicated connection assets are fully contestable and are the responsibility of the connecting party. We recommend that it be put beyond doubt that all equipment operated at transmission voltages in participating jurisdictions and interconnected with the rest of the transmission system is subject to the National Electricity Law (NEL) and rules.

Although it would be possible to then provide exemptions for many dedicated connection assets, this approach would ensure that appropriate third party access arrangements could be put in place. It would also provide a mechanism for dedicated connection assets to subsequently be subsumed into the shared network, if this was required and represented the most efficient solution. In the context of the COAG/SCER initiative concerning the separation of transmission and generation, we recommend that while additional safeguards to maintain this separation are warranted, this should not apply to dedicated connection assets.

While our recommendations in this area are not as wide-ranging as the optional firm access model, it should be noted that clarifying and streamlining the connection

15 This would be from the outset, including during commissioning.

arrangements in the manner we envisage would still represent a very complex and detailed technical challenge. Although the recommendations in this report provide a sound basis for changes to be made to the rules, we consider that it may be possible to make further improvements during the implementation of such changes. The next section of this chapter briefly outlines how we consider that these changes should be progressed.

1.3 Way forward

1.3.1 Progressing the optional firm access model

Section 1.2 of this chapter set out the background to our recommendation that SCER should initiate a detailed design and testing program for optional firm access.

While the Commission considers that the optional firm access model is qualitatively superior to the current arrangements and to any alternatives that have been suggested, the complex and inter-related nature of the changes that would need to be made in order to implement it makes undertaking a comprehensive quantitative assessment very challenging.

Detailed design and testing of the model would allow for a better understanding of the likely costs associated with its implementation and the benefits that would flow from this. Additional modelling could also be undertaken, for example to understand the effects of the improved ability of market participants to compete inter-regionally.

These tasks would represent a material amount of work. We are therefore seeking SCER's agreement that it would be appropriate to allocate additional resources to undertake this. Following the conclusion of this work, a more developed model would be available to SCER to assess for implementation in the context of unfolding developments in the wider market.

We recommend that the detailed design and testing should be directed by an industry panel. Stakeholder reaction to the optional firm access model has been mixed. Although there has been significant support expressed by many parties, even some of those advocating adoption of the optional firm access model have suggested that various amendments be made to it. The panel would allow for industry involvement and input to guide the progression of the revisions to transmission arrangements.

The panel would be supported by a multi-disciplinary project team, coordinated by the AEMC but including staff and secondees from TNSPs, market participants and other market bodies. This would allow the complex and technical issues involved to be most effectively addressed.

We anticipate that, following SCER's approval, it would take around 12 months to undertake the further work set out above. We have estimated that approximately $5 million would be required to fund the panel and the project team.

We have also developed a process through which the optional firm access model could be implemented, assuming a positive outcome is reached following the completion of the further work described above. This would be likely to take around three years.

We are conscious that this represents a long-term approach to resolving the challenges identified with the current transmission frameworks, and would ultimately result in fundamental change to the NEM arrangements. However, one finding of the review is that it is not possible to address these issues in a piecemeal or incremental manner.

We are aware that some stakeholders have indicated their support for steps to be taken in the short-term to address issues associated with disorderly bidding. In particular, introducing the settlement arrangements from the optional firm access model would provide a mechanism to price congestion.

However, such an approach would substitute volume risk for generators with "basis risk" (at times of congestion, dispatched generators would not be settled at the regional energy price). We consider implementation of the full optional firm access model to be superior in this regard, as it would allow generators to manage both volume and basis risk. There may also be large wealth transfers associated with the introduction of a congestion pricing mechanism in isolation. We therefore do not favour, at this stage, implementing such a mechanism in advance of the full optional firm access arrangements.

Chapter 10 of the report sets out our proposals for progressing the optional firm access model in more detail. It also explains how three recommendations related to transmission planning frameworks could be implemented separately to this.

1.3.2 Implementing changes to the connection arrangements

The Commission is recommending that SCER submits a rule change request to the AEMC to give effect to the package of recommendations we have developed regarding the connection arrangements.

While there are a number of recommendations, covering a range of areas, the proposed amendments are interrelated. The Commission considers that it would be both possible and preferable to implement all of the changes required to give effect to the recommendations, and any further consequential amendments, in a single rule change. Assessment and implementation of all the changes together would also help to provide the enhanced clarity and certainty that many of the recommendations seek to achieve.

We have developed a detailed specification of our recommendations, which would form the basis for the drafting of changes to the rules. This is contained as appendix C of this report.

Our recommended amendments to the rules, if implemented, would lead to consequential changes being made to some subsidiary documents, for example the Australian Energy Regulator's (AER's) exemption guidelines and TNSPs' individual negotiating frameworks.

We do not anticipate that any changes to the NEL will be necessary to implement our recommendations. In a number of circumstances the NEL contains terms that would be no longer required as a result of the changes that we are proposing be made to the rules. However, in each case we consider that it will be possible to draft the required rule changes in a manner that precludes the need to remove or amend those definitions from the NEL.

1.4 The Commission's approach to the review

1.4.1 NEO assessment

As in every AEMC review, the overarching principle guiding our approach to the Transmission Frameworks Review has been 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."

In this report, we explain how the introduction of the optional firm access model would better allow for the NEO to be met, particularly with regards to the price of energy for the long term interests of consumers. Exposing generators to congestion costs and transmission investment costs would allow generators to make efficient trade-offs. Generators would have the ability to receive a defined service, allowing them to manage the volume risk they currently face, which would put downward pressure on contract prices. In these ways, investment in, and operation and use of, transmission and generation would be better co-optimised, reducing total system costs. The improved arrangements for inter-regional trade would also increase competitive pressure in regional wholesale and retail markets.

For connections, by allowing generators greater control over both the cost and timing of the provision of connection assets forming part of the shared network, our recommendations would put downward pressure on prices. However, this would not be at the expense of the quality or reliability of the supply of electricity – a key plank of our proposed approach is to provide clear accountability in this regard. Our recommended clarifications to the rules would also give greater certainty to promote efficient investment over the long term.

1.4.2 Consistency with COAG principles

In addition to the NEO, the MCE Terms of Reference specified that the AEMC, in reviewing the existing arrangements for transmission in the NEM and identifying any options for reform, should have regard to certain principles previously agreed by COAG in relation to earlier reforms.[16] These principles were:

- accountability for jurisdictional investment, operation and performance will remain with transmission network service providers;
- where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment; and
- the new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place.

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

As explained in chapter 4 of the report, under our proposals responsibility for jurisdictional investment, operation and performance would remain with TNSPs. Accountability on TNSPs would be strengthened with the introduction of a clearly defined and measurable service provided to generators. The new regime would also not be slower than the existing arrangements for the regulatory approval for transmission investment; indeed, it may be possible to reduce the current timescales. The need for clearly defined accountability has also informed our recommendations regarding connections.

Trading and contracting risks, and the need for investment certainty, have been the key issues considered in the review. Chapter 8 assesses our recommended approach against the current arrangements in these regards. Chapter 9 sets out the transitional arrangements that should apply.

1.4.3 Other processes relevant to the Commission's considerations

Over the course of the review, a number of other projects, both internal and external to the AEMC, have informed our considerations set out in this report.[17] The most relevant of these are summarised below.

Economic regulation of network service providers rule change

On 29 November 2012, the Commission made a final determination on new rules to regulate electricity network prices. The rules improve the strength and capacity of the regulator to determine network price increases so consumers don't pay any more than necessary for the reliable supply of electricity. The new rules better equip the Australian Energy Regulator (AER) to develop methods and processes to achieve efficient outcomes in setting revenues and prices in a number of areas. The rules were

16 MCE direction, p.2.

17 Documents relating to AEMC reviews and rule changes can be found at www.aemc.gov.au.

made in response to a request submitted by the AER and a group of large energy consumers in September and October 2011.

Power of choice review

Over the course of 2011-12, the Commission has developed a substantial reform package for the NEM through its Power of Choice review. The package provides households, businesses and industry with more opportunities to make informed choices about the way they use electricity and manage expenditure. The overall objective is to provide that the community's demand for energy services is met by the lowest cost combination of demand and supply side options. This objective is best met when consumers are using electricity at the times when the value to them is greater than the cost of supplying that electricity. The final report for the review was submitted to SCER in November 2012.

Review of the national framework for transmission reliability

On 8 February 2013, the AEMC received a request from SCER to develop a nationally consistent framework for expressing and setting transmission reliability standards, and for reporting reliability outcomes. This will explore a national framework to provide a transparent approach for NEM jurisdictions to set efficient reliability levels which take account of the costs required to deliver reliable electricity supplies and the value placed on reliability by consumers. An issues paper for the review was recently published.

Productivity Commission inquiry into electricity network regulation

The Productivity Commission has been commissioned by the Australian government to examine the use of benchmarking in the regulation of electricity networks and the delivery of interconnector investment in the NEM. A draft report for the inquiry was released on 18 October 2012. In addition to considering the issues it had been required to address, the Productivity Commission also commented on many other aspects of electricity network regulation. Its final report is due on 9 April 2013.[18]

1.5 Project dates and consultation

The Commission has taken a highly consultative approach in conducting the review, having undertaken four rounds of formal public consultation. Two public forums have been held, and the review's stakeholder consultative committee has met on six occasions. We have also held many more informal meetings with stakeholders, and have published ad hoc papers provided by stakeholders on a dedicated web forum.

Stakeholder participation has been extensive, with the divergent and detailed views presented being very valuable to the development of the recommendations set out in

18 See: www.pc.gov.au/project/inquiry/electricity.

this final report. We appreciate the advice and evidence provided, and the time and resources committed to the review. In particular, we would like to thank the members of our consultative committee for their contribution.

While a consensus has not emerged across all stakeholders as to the future development of the transmission arrangements, the high level of stakeholder engagement that has characterised the review has been invaluable in, we believe, significantly moving the debate forward.

Table 1.1 Review process

Document	Purpose	Date
Issues Paper	Presented the key issues identified by the Commission and set out the process for the review.	18 August 2010
Directions Paper	Explored the key issues raised in submissions to the Issues Paper and identified key themes to be taken forward and the approach for achieving this.	14 April 2011
First Interim Report[19]	Identified and discussed a short list of potential internally consistent policy packages, explained the framework for the assessment of these and continue to test the materiality of the problems identified.	17 November 2011
Public Forum	Held in Melbourne to discuss the issues and proposals contained in the First Interim Report.	12 December 2011
Second Interim Report[20]	Assessed the packages identified in the First Interim Report and narrowed these packages down to two options.	15 August 2012
Public forum	Held in Sydney to discuss the packages presented in the Second Interim Report.	17 September 2012
Final Report	**Sets out the Commission's policy conclusions and recommendations, including a proposed approach to further progression of the issues**.	**Submitted to SCER on 28 March 2013**

1.6 Structure of this report

The remainder of this report is composed of two main parts. Part 1 discusses the optional firm access model, and the changes that would need to be made to the transmission arrangements to implement this. This part covers all the issues that we have previously characterised as generator access (including congestion management and transmission pricing) and transmission planning. It is structured as follows:

19 AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011. All subsequent references to the First Interim Report mean this document.

20 AEMC, *Transmission Frameworks Review*, Second Interim Report, 15 August 2012. All subsequent references to the Second Interim Report mean this document.

- Chapter 2 sets out the objectives and summarises key features of the model;
- Chapter 3 describes the firm access products and the new access settlement payment that would underpin them;
- Chapter 4 sets out our recommended planning framework that would apply to TNSPs under the optional firm access arrangements, which includes an enhanced role for the national transmission planner;
- Chapter 5 describes the processes through which generators could procure new or additional access, and how the prices for firm access would be determined;
- Chapter 6 describes the inter-regional access product under optional firm access, including the recommended inter-regional expansion and allocation process;
- Chapter 7 sets out how revenue regulation would occur under the optional firm access regime, including potential incentive schemes that would apply to TNSPs;
- Chapter 8 assesses the optional firm access model against current and possible alternative sets of transmission arrangements;
- Chapter 9 describes the transition processes that would apply in the early years of the optional firm access model; and
- Chapter 10 sets out our recommended way forward.

The second part of the report discusses connections to the transmission system. It is structured in the following way:

- Chapter 11 introduces our recommendations for connections, as well as some of the key considerations and concepts;
- Chapter 12 explains our recommendations for facilitating connections where changes are required to the shared transmission network;
- Chapter 13 explains our recommendations regarding dedicated connection assets; and
- Chapter 14 sets out how these recommendations should implemented.

Finally, the report contains a number of appendices which provide additional information on issues relating to both the optional firm access model, planning and connections.

Note also that a separate paper has been prepared by AEMC staff which explains the optional firm access model, and the reasons for many of the design choices made, in a greater level of technical detail than contained in this report.[21]

21 AEMC, *Transmission Frameworks Review*, Technical Report: Optional Firm Access, 11 April 2013. All subsequent references to the Technical Report mean this document.

2 Introduction to optional firm access

2.1 Introduction

Part 1 of this report sets out a model for transmission access that provides generators with the option of obtaining financially firm access to their regional reference price.[22] It largely reflects the optional firm access model that was presented in the review's Second Interim Report. It also integrates our recommendations for how TNSPs should plan and operate their networks to meet the new requirements implied by the access model as well as existing reliability standards, while improving coordination between TNSPs.

Having assessed five different policy packages for managing congestion and providing a firmer level of service to generators, and having considered the large number of submissions received over the course of this review, the Commission believes this model to be the best alternative set of transmission arrangements to those that exist currently.

The following chapters give a high level overview of how optional firm access and planning would interact. In some places the account is necessarily simplified. A more detailed description of the model is provided in the Technical Report, which also provides the reasoning for the selection of particular design options.

2.2 Overview

2.2.1 Objectives

The optional firm access (OFA) model aims to address the most significant concerns with the interface between transmission and generation:

- the lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network;
- the resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion;
- the lack of clear and cost-reflective locational signals for generators, such that their locational decisions do not take into account the resulting transmission costs
- TNSPs estimating the benefits of transmission development, where those benefits are better known to generators, and the risk of inefficient decisions being borne by consumers rather than the decision-maker;

22 The concept of "financial", as opposed to physical, access is discussed in Box 3.1.

- the resulting planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission;
- the importance of TNSPs' operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given their lack of exposure to the financial costs of reductions in capacity; and
- the difficulty that market participants have in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions.

The scope of the optional firm access model makes it more complex than alternative models with a more limited scope (eg shared access congestion pricing, the second package of reforms considered in the review). However, an all-encompassing model such as this is in some sense simpler to implement than introducing a patchwork of changes, which might also risk creating unintended consequences.

In the event that no generator held firm access rights, the arrangements would operate in the same manner as the current regime, with the addition of a congestion management mechanism (similar to shared access congestion pricing).[23] However, we consider that introducing such a mechanism without giving generators the option of obtaining firm access could introduce undue risk to the market.

The optionality in the model creates complexity and requires careful and robust design to ensure dysfunctional behaviour is not encouraged. However, the Commission believes that this is preferable to an alternative of no optionality (ie generator reliability standards, the third package of reforms considered by the review).

In this context, the optional firm access model 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 (RRP). 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 would still be paid. The key features of the model are illustrated in Figure 2.1 and may be summarised as follows:

23 See access settlement and congestion management in section 3.3.2.

- *Access products and settlement*. Generators would have the option of agreeing a quantity of firm access with their TNSP, which may be for all or part of their output. Generators that did not procure firm access would receive non-firm access.[24] Where dispatch of non-firm generators contributed to congestion they would compensate firm generators for any loss of dispatch.[25] The aim would be to ensure that firm generators were in the financial position they would have enjoyed had they not been constrained off – that is, financial certainty would be enhanced. Access settlement would occur automatically through the market's settlement process. The processes for dispatch and regional pricing would not be changed.

- *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. 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. For-profit TNSPs would be responsible for investment decisions. The National Transmission Planner would have an enhanced role to provide contestability of views in planning and to promote national coordination.

- *Access pricing and procurement*. 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. 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 these incremental costs. The purpose of access pricing is to estimate what these costs are. Generators could obtain new or additional firm access from the TNSP through the procurement process. They could also obtain short-term firm access through an auction, or transfer firm access between power stations using secondary trading processes.

- *Inter-regional access*. Generators and retailers would be able to procure firm inter-regional access rights which would entitle them to the price difference between two regions on their access amount. Their purchase of firm inter-regional access would guide and fund the expansion of interconnectors.

- *TNSP regulation and incentives*. TNSPs would be monopoly providers of the firm access service, which would be treated as a prescribed service. TNSPs would be subject to regulation in four areas: access issuance, access pricing, revenue and access quality.

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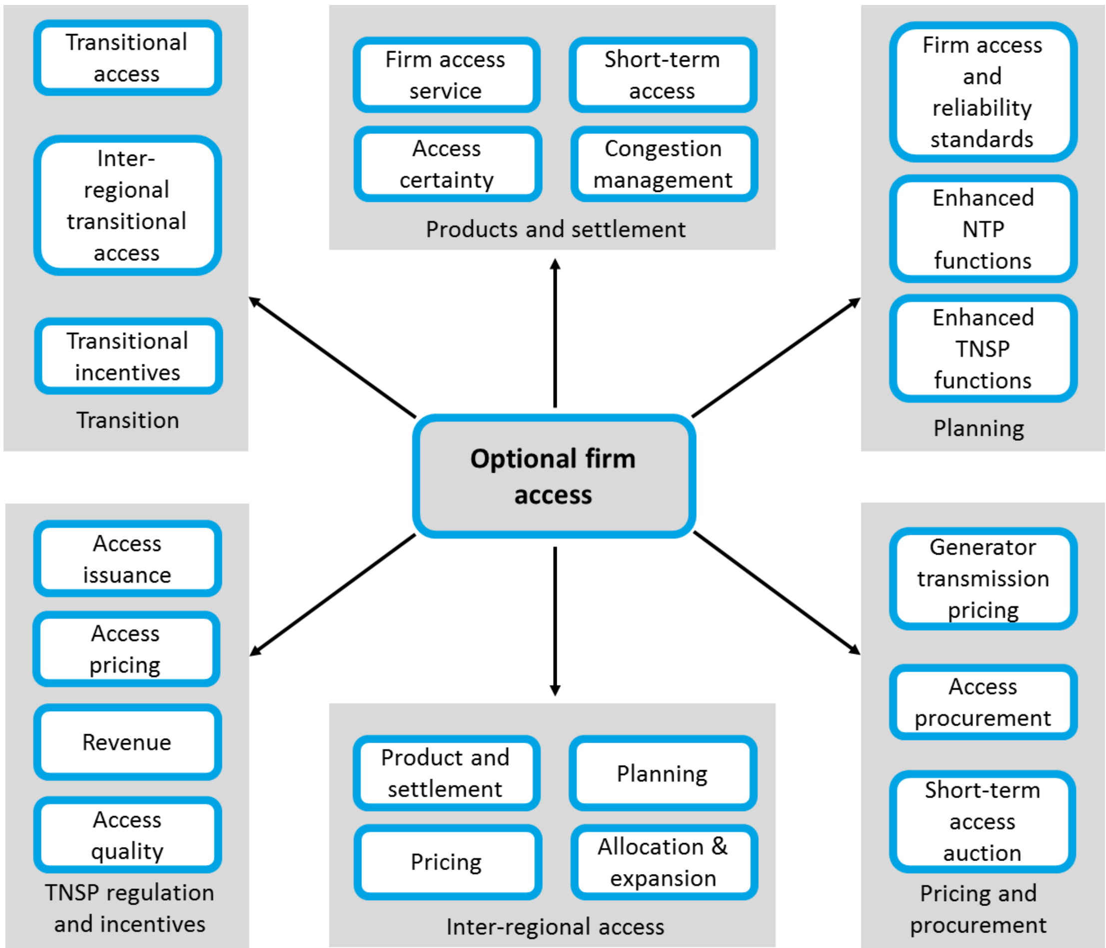
24 Generators could be part-firm – agreeing an access amount that is less than their generating capacity, and receiving non-firm access for any output in excess of the agreed access amount.

25 Although generators would have the option of being firm or non-firm, participation in the model would be mandatory, thereby addressing the issues with providing firm access where participation is optional (see Box 8.1).

- *Transition*. 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. 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. However, transitional firm access would be sculpted back over time and would then expire. No access charges would apply to transitional access.

Figure 2.1 Key features of the optional firm access model



Chapters 3-7, and 9, discuss these features in greater detail.

Chapter 8 provides our assessment of optional firm access against the current arrangements and our rationale for why optional firm access represents the best alternative set of transmission arrangements.

Chapter 10 recommends the way forward, should SCER accept the recommendation in chapter 1.

2.2.3 Changes from the Second Interim Report

We have made some modifications to the optional firm access model in response to stakeholders' suggestions, which for the most part seek to simplify the model without compromising its objectives. The main changes from the Second Interim Report are that:

- Firm access would be limited by rated capacity, rather than by availability, and should be more attractive to intermittent generators as a result.
- The firm access standard would only apply during the set of normal operating conditions, resulting in a single-tier standard. The scaling factors that previously applied under lower tiers of the standard would no longer apply.
- Access pricing would use different growth forecasts for the short, medium and long terms to avoid spurious accuracy and allay concerns about the sensitivity of prices to the underlying forecasts.

3 Optional firm access products and settlement

Summary of this chapter

This chapter describes the firm access service. It gives generators the option of obtaining firm access to their regional reference price. Even when they were not dispatched because of congestion, firm generators would still be paid an amount at least equal to the difference between their offer and the regional price.

The new payment would occur automatically through access settlement. Existing dispatch processes would be unchanged.

A new firm access standard would require TNSPs to plan and operate their networks to provide sufficient transmission capacity to support firm access.

The new access service would be firm not fixed: the firm access standard would define some circumstances (such as a level of forced transmission outages) in which firm generators would not receive their agreed access level.

Generators that chose to be non-firm would face new costs: they may be liable to make payments to firm generators through access settlement in the event of congestion. They would be assured of receiving at least their offer price.

TNSPs would also be able to offer a short-term access product, backed by either additional capacity that resulted from their operational decisions or existing spare capacity.

3.1 Introduction

The optional firm access model introduces the following products:

- the firm access service;
- short-term firm access; and
- firm inter-regional access products - both short-term and long-term.

The *firm access service* gives generators the option of obtaining firm access to their regional reference price, and is described in section 3.2 below.

Firm access is given effect through a new *access settlement* payment, which is described in section 3.3.

Short-term firm access is backed by spare or additional capacity, which we expect to result primarily from TNSPs' operational decisions, and is described in section 3.4.

The *inter-regional access* product provides firm access between two regions. It is described in chapter 6.

3.2 Firm access service

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 firm access service gives generators more certain access to their regional reference price. Even when they were not dispatched because of congestion, firm generators would still be paid. See Box 3.1 for a further explanation of "firm access", including some circumstances in which it would not be fully firm.

Box 3.1: What is firm access?

A generator's primary concern is earning revenue. This is currently achieved by being dispatched, subject to constraints and the offers of other generators, and receiving the spot price in return. This provides backing for forward (derivative) contracts sold to retailers. When generators raise concerns that they are not getting "access" to the market, their fundamental concern is that they are not earning revenue.

Consequently, we can think of *access* as *being paid at the regional reference price*.[26] In the optional firm access model, a firm generator may be paid an amount at least equal to the difference between its offer and the regional price even if it is not dispatched because of network congestion. This is referred to as "financial access" and delinks (financial) access from (physical) dispatch. However, even financial access must be underpinned by physical network capability to provide sufficient revenue from non-firm generators to compensate firm generators where they are constrained off. Therefore, sufficient network capability must be provided to meet aggregate demand for firm access.

By decoupling access from physical dispatch, access can be reallocated on a different basis, with priority given to firm generators – those generators who pay for a firm access service from their local TNSP. Firm generators would enjoy greater financial certainty than they do now; non-firm generators would receive less certainty.

Although network capability may be planned to meet aggregate demand for firm access, there may be operating conditions under which the capacity of the transmission network is reduced and access for firm generators might correspondingly reduce.[27] Consequently, even "firm" generators will only ever achieve firm financial, and not fixed financial or physical, access.

26 Ignoring losses.

27 TNSPs might contribute to part of the shortfall though an incentive scheme – see section 7.3.1.

Each TNSP would offer the firm access service to generators in its region. Through the access procurement process a generator could procure new or additional firm access service by entering into an access agreement with the local TNSP.[28] 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.[29] Default firm access service terms and prices would be regulated.

There would be no obligation on generators to procure firm access. Generators who did not do so would receive, instead, a non-firm access service for which they would not pay the TNSP. They may, however, earn a lower price during times of congestion, in effect providing compensation to firm generators through access settlement.[30]

Where a generator entered into an access agreement, the agreement would specify:

- the power station(s) to which the agreement applies, which must be connected to the shared network at a common point;
- the access amount (in MW);
- the term of the agreement;
- the firm access charge; and
- other service parameters, such as whether the agreed amount would vary between peak and off-peak times.[31]

The agreement may also include some standard terms such as prudential requirements, termination and assignment.[32] However, most terms of service – such as service standard and liability – would lie outside the agreement, in the rules and associated regulatory instruments.

The access agreement would provide 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. The implied access right should be distinguished from those that operate in other energy markets:

1. It does not constitute a right to preferential dispatch on the network, as is the case, for example, for firm shippers on a gas pipeline. The physical side of providing access – ensuring that enough transmission capacity is there to

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28 See access procurement in section 5.3.

29 See access pricing in section 5.2.

30 Non-firm generators would never receive less than their offer price – see access settlement in section 3.3.

31 This would allow generators to match their access requirements to their forward energy contracts.

32 Prudential requirements would be significant, reflecting generators' financial commitments for the length of their access agreements. Further consideration would need to be given to how they would be structured.

underwrite firm access – is an obligation imposed on the TNSP through the firm access standard (described below).

2. A generator need only specify the node at which it requires access and not the physical network through which that access is provided: access settlement then automatically arranges for the generator to be appropriately compensated whenever congestion on the network affects access at that node.

In other words, after the generator has nominated its access amount, it need not concern itself with the means (either physical or financial) through which that access is provided.

3.2.1 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 agreements, into the level of transmission capacity that TNSPs are obliged to provide. It therefore drives TNSP network planning and operation.

The quality (ie the firmness) of the firm access service would depend on the capacity and reliability of the shared transmission network that underpins it. Two features of the model should provide firm generators with confidence that service quality will be maintained:

- a *service standard* that specifies the minimum service quality that must be provided to each firm generator; and
- a corresponding *network standard* that specifies the minimum level of transmission capacity that the TNSP must build and maintain to provide, concurrently, the minimum service quality to all firm generators in aggregate under a given set of operating conditions.

The *firm access standard* – in combination with the set of all access agreements – performs both of these roles. In planning and operating its network, a TNSP must ensure that it could provide the defined level of service to every firm generator concurrently.[33] It must also maintain existing demand-side reliability standards, which would still apply alongside the OFA model.

For access settlement to deliver adequate compensation to firm generators, it would be critical that the TNSP met the firm access standard. Measurement of its performance against the standard would therefore form the basis of new incentives to be placed on the TNSP.[34]

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33 A TNSP must ensure that it could provide the level of service defined by the firm access standard to every firm generator concurrently, since it is possible that every generator would require access at the same time.

34 See section 7.3.1 for a discussion of the proposed incentive regime..

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

Even for firm generators, access would be *firm* but not *fixed*. The firm access standard would allow firm generators' allocated access to be below target under specified circumstances, for example under a defined level of forced transmission outages. The firm access standard would therefore require TNSPs to provide the agreed access amount specified in each access agreement under normal operating conditions only. No minimum level of access would be required under abnormal operating conditions.[35]

The firm access standard would be defined during implementation of optional firm access.[36] The definition would include the set of normal operating conditions in which firm access must be provided, and an allowable level of transmission outage in which firm access may not be provided. We anticipate that the standard would become part of the rules.

In summary, the firm access standard provides the nexus between access agreements and other transmission processes such as network planning and operations, access pricing, and TNSP incentive regulation. A TNSP would have to ensure that, in real time, it always has sufficient available transmission capacity to provide at least the minimum level of access that the firm access standard specifies. That obligation drives operational decisions and also, through the TNSP forecasting future access demand, drives planning decisions.

3.2.2 Firm - not fixed - access

Because it applies only under normal operating conditions, the firm access standard supports an access service that is firm but not fixed. A fixed access standard would guarantee the agreed access level in all conditions. For settlement to balance, that means a fixed target network capacity. Achieving this is impractical: there is always the possibility of extreme conditions (multiple outages, extreme weather events etc) where a minimum level of transmission capacity cannot be maintained.

We acknowledge that the non-fixed nature of the firm access service may reduce its desirability to generators. Other energy markets provide fixed transmission rights by:

1. Smearing settlement payments across settlement periods. At times, transmission capacity will exceed what is necessary to provide total access, creating a settlements surplus. This can be used to make up the shortfalls in settlements

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35 This single-tier firm access standard, applying only in the set of normal operating conditions, is a change in design from the Second Interim Report. Many stakeholders were concerned that the multiple-tiered standard that we proposed would be extremely difficult to define, manage and enforce. Consequently it might not achieve its stated objectives - to provide generators with more certainty regarding their access outside normal operating conditions, and to provide them with more choice about their access level. The simplification is a response to these concerns and, more generally, is an opportunity to reduce the complexity of the model without compromising its objectives.

36 See section 4.2.1.

when transmission capacity falls short of what is needed to provide total access; and/or

2. Levying an uplift charge on consumers when there is a shortfall in settlements owed to the holders of the rights.

The first option might not be workable in the NEM. Overseas markets with fixed transmission rights tend to be more highly meshed, reducing the likelihood of extreme settlement deficits or surpluses. In the NEM, with its high price cap and less meshed networks, a fixed access approach could give rise to very large deficits that could not be recovered from surpluses in other periods.[37]

Similarly, a fixed access service could imply very large uplift charges on consumers under the second option. We do not consider that the benefits of providing a fixed service to generators would warrant exposing consumers to these costs.[38]

Consequently, the optional firm access model adopts the principle that settlement should balance in each settlement period, providing for firm - but not fixed - access. However, the model provides generators with the ability to secure a higher level of access even outside normal operating conditions (see below). Additionally, incentives should be designed to encourage TNSPs to provide an efficient level of access outside normal operating conditions.[39]

3.2.3 Effective service level

A single firm access standard would apply to all firm access on the shared network. It would not be feasible to have different standards for different access agreements. However, a generator could choose the effective firmness of access that it preferred by agreeing an access amount that was higher or lower than its generating capacity, and paying correspondingly higher or lower access charges:

- A generator would be *part-firm* if it agreed an access amount that was lower than its generating capacity.
- A generator would be *super-firm* if it agreed an access amount that was higher than its generating capacity.

A generator that procured super-firm access would enjoy a higher level of entitlements to access during abnormal operating conditions – see below.

37 Instead, settlements surpluses are allocated to part-firm and non-firm generators. This choice reflects the core principle of OFA: that non-firm generators should compensate firm generators when the former's dispatch causes the latter to be constrained off. Although not explicitly stated in this principle, penalties on non-firm generators should not exceed the amount needed to fund this compensation; we are not seeking to penalise non-firm generators, just to compensate firm generators.

38 This decision could be reviewed should the benefits of providing a firmer service - in terms of measurably lower final energy prices to consumers - outweigh the costs of the uplift charge.

39 See section 7.3 which discusses this further.

3.3 Access settlement

Access settlement is the process through which financial compensation would be provided to firm generators that were constrained off and so not dispatched.

The cost of providing the financial compensation would be recovered from the non-firm generators whose dispatch, by contributing to congestion, was causing the firm generators not to be 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). Typically, there are no more than a handful of congested flowgates in a region in any particular settlement period, so access settlement, whilst conceptually complex, should be straightforward to implement.

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 rated generating capacity,[40] and would also depend upon the prevailing network conditions.[41]

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.[42]

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 (for example, during transmission outages), this might not be possible. Consequently, entitlements might be scaled back, resulting in a shortfall in access settlements payments.[43] The scaling process would mean that super-firm generators were scaled back less than firm generators, while no entitlements would be provided to non-firm generators.

Figure 3.1 illustrates the scaling of entitlements under decreasing levels of flowgate capacity for the four generator access categories set out in Table 3.1. For simplicity, the

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40 Availability in the case of non-firm access amounts.

41 This is a design change from the Second Interim Report, which proposed that entitlements be based on availability, so an unavailable generator would receive no access. With this change, a firm generator that was subject to a power station outage would still receive access entitlements (although only during times of congestion). The change should make the firm access service more attractive to intermittent generators, whose availability is often lower than their rated capacity. See section 4.3.3 of the Technical Report.

42 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.

43 Although TNSPs might contribute to part of the shortfall though an incentive scheme – see section 7.3.1.

generators are assumed to have the same capacity, availability and participation in the flowgate.

Figure 3.1 Entitlement scaling for different access categories

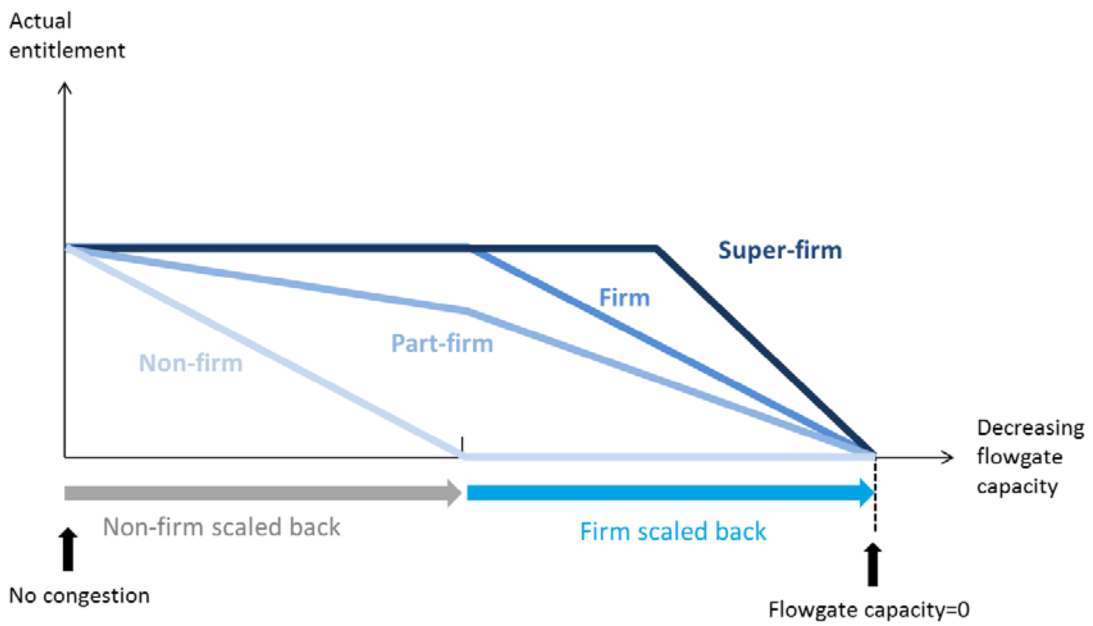


Table 3.1 Generator access categories

Generator type	Description
Super-firm	agreed access > capacity
Firm	agreed access = capacity
Part-firm	agreed access < capacity
Non-firm	agreed access = 0

It can be seen from the figure that:

- the scaling of firm entitlements only occurs once non-firm entitlements have been scaled to zero;
- up to that point the super-firm generator receives the same entitlements as the firm generator, but then is protected from scaling; and
- super-firm entitlements are only scaled back once the flowgate capacity is significantly degraded.

On the other hand, when flowgate capacity was high, it might be possible to give full entitlements to firm generators and also give some entitlements to part-firm generators in excess of their agreed access amount, and to non-firm generators. Allocation in this case would be based on availability (not capacity).[44]

Where a generator's actual usage exceeded its entitlement it would be required to pay compensation. Conversely, where a generator's entitlement exceeded its usage it would receive compensation. Typically, dispatched non-firm generators would compensate constrained-off firm generators. However, it is also possible for firm generators to pay into access settlement, and for non-firm generators to receive access settlement payments.[45] Aggregate compensation paid out would always equal aggregate compensation received.

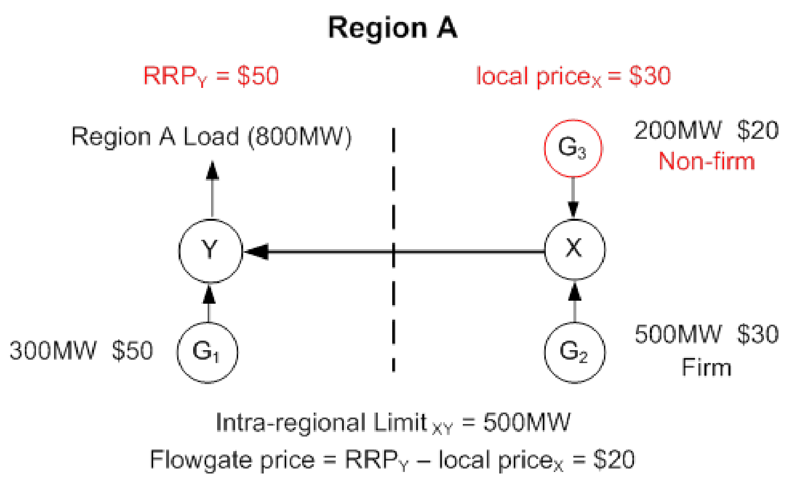
The amount of compensation paid or received would be the difference between a generator's usage and its entitlements, multiplied by the *flowgate price*. The flowgate price is a measure of the value that is gained by relaxing the underlying constraint by a small amount. It is measured by the reduction in the total cost of generation dispatch when 1MW additional energy is able to pass through the flowgate. Where a constraint prevents cheaper generation from being dispatched, such that demand must be met by more expensive generation from elsewhere in the region, then the flowgate price will be high.

Note that generators that were required to pay compensation would always earn at least their offer price on each unit of energy for which they were dispatched. Therefore a generator should never regret being dispatched. A simple numerical example of access settlement is illustrated in section 3.3.1.

3.3.1 Example of access settlement

Figure 3.2 illustrates a region with two nodes: X and Y. The regional demand of 800MW is located at node Y. The network limit between X and Y is 500MW. The dashed line indicates a flowgate.

Figure 3.2 Two-node network example



44 See section 3.3.2 for discussion of availability-based allocation.

There are three generators: G_1 and G_2 are located at node X and G_3 is located at node Y. G_2 has 500MW firm access. G_3 is non-firm. G_1 does not participate in the flowgate: it has no need for access to the flowgate capacity.

G_2 offers 500MW at $30. G_3 offers 200MW at $20. The combined dispatch of the two generators cannot be greater than 500MW. With offers totalling 700MW, the network would be constrained and access to the flowgate would be rationed. G_3, with the cheaper offer, would be dispatched for 200MW causing G_2 to be constrained off by this amount. G_3, however, would make payments to G_2 through access settlement. Settlement outcomes are illustrated in Table 3.2.

Table 3.2 Access settlement outcomes

Generator	Dispatch (MW)	Energy settlement	Flowgate entitlement (MW)	Flowgate usage (MW)	Entitlement - usage (MW)	Access settlement	Total revenue
G_1	300	$15,000	-	-	-	-	$15,000
G_2	300	$15,000	500	300	200	$4,000	$19,000
G_3	200	$10,000	0	200	-200	-$4,000	$6,000
Total	**800**	**$40,000**	**500**	**500**	**0**	**$0**	**$40,000**

Through energy settlement, G_2 receives the regional reference price of $50 for each unit for which it is dispatched. The payment G_2 receives through access settlement is equal to the difference between its entitlement to the flowgate and its usage of the flowgate, multiplied by the flowgate price of $20. Assuming that G_2's offer of $30 is reflective of its operating costs, it would earn a $20 margin on the 300MW for which it was dispatched. Through access settlement, G_2 also receives $20 for each unit of the 200MW by which it is constrained off (for which it incurs no operating costs).

The compensation is funded by G_3, as a non-firm generator contributing to congestion. G_3 receives the regional reference price of $50 on its dispatch, but after paying compensation through access settlement, receives net revenue equal to the local price of $30. Table 3.3 shows the resulting operating margin for each of the generators, and assumes that the generators' offers were equal to their unit operating costs.

45 See section 4.3.7 of the Technical Report.

Table 3.3 Operating margin with congestion

Generator	Total revenue	Generating costs	Operating margin	Margin/MW
G_1	\$15,000	-\$15,000	-	-
G_2	\$19,000	-\$9,000	\$10,000	\$20
G_3	\$6,000	-\$4,000	\$2,000	\$10
Total	**\$40,000**	**-\$28,000**	**\$12,000**	

For comparison, Table 3.4 repeats the above margin analysis as if there were no congestion, ie as if the flowgate capacity were increased to 700MW so both G_2 and G_3 could be fully dispatched (with dispatch of G1 decreasing to 100MW). In this case, no access settlement would apply, and each generator would simply earn the regional price on its dispatch quantity.

Table 3.4 Operating margin without congestion

Generator	Total revenue	Generating costs	Operating margin	Margin/MW
G_1	\$5,000	-\$5,000	-	-
G_2	\$25,000	-\$15,000	\$10,000	\$20
G_3	\$10,000	-\$4,000	\$6,000	\$30
Total	**\$40,000**	**-\$24,000**	**\$16,000**	

By comparing the outcomes in Table 3.3 and Table 3.4 it can be seen that:

1. Access settlement puts G_2 in the same financial position it would have enjoyed if it had been fully dispatched for 500MW: in both scenarios it earns \$10,000 margin, or \$20/MW.

2. G_3 earns a lower margin when there is congestion than when there is not. Even with access settlement G_3 still earns a positive margin - its net revenue of \$30/MW is higher than its offer of \$20/MW - so it should not regret being dispatched.

3.3.2 Access settlement and congestion management

Another feature of access settlement is that it functions as a congestion management tool, even when no generators have firm access. Entitlements to a flowgate used only by non-firm generators would be allocated on the basis of availability. Availability-based allocation is consistent with the shared access congestion pricing model, which has generally been considered the least contentious way of allocating access in the absence of explicit access rights.[46]

Access settlement would work in the same way it does with firm generators: a generator whose usage of the flowgate was less than its entitlement would receive an access payment; the payment would be funded by generators whose usage exceeded their entitlements.

At this stage, we do not advocate the introduction of this access settlement process as a congestion management tool without also giving generators the option of obtaining firm access. To do so would expose generators to their local prices without any means of hedging this risk, which we consider might impose undue risk.

3.3.3 Flowgate support generators

Access settlement excludes generators whose generation helps to relieve congestion.[47] These are referred to as *flowgate support* generators, and would always earn the regional price regardless of whether they were firm or non-firm. Often such generators are dispatched even though their offer price is higher than the regional price - they are *constrained on* - and respond by bidding unavailable. The current mechanisms for addressing constrained-on situations would continue:

- the Australian Energy Market Operator (AEMO) may direct a constrained-on generator to run, which is then paid direction compensation.
- A TNSP could enter into a network support agreement with the generator, paying it to run where that is cheaper than augmenting the network to meet its firm access and reliability obligations.

It would also be possible to extend the optional firm access model to address constrained-on situations. However, the model would be complex to design and its implementation cost would likely be disproportionate to the problem. We therefore do not propose the extension at this stage; it could potentially be developed and introduced at a later date.[48]

3.3.4 Summary

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 financial compensation to generators dispatched below their (scaled) access levels and recovers the cost of this from generators dispatched above their (scaled) access levels.

46 Chapter 7 of the First Interim Report describes a version of the model.

47 These are generators with a negative participation in a binding constraint; their generation adds to the effective flowgate capacity.

48 See section 2.3.9 of the Technical Report for further discussion.

Access settlement is conceptually complex, but it would be practically straightforward for two reasons. Firstly, all of the information required to calculate settlement amounts is either already present in the existing dispatch process (eg the flowgate formulations and prices) or would be specified in the access agreements (eg agreed access amounts). Secondly, the nature of transmission congestion is that only a handful of flowgates are likely to be congested at a time in each region. Therefore, the settlement algorithm would never be computationally onerous, and the verification and analysis of settlement statements by generators would be relatively straightforward.[49]

3.4 Short-term firm access

In addition to the *long-term* firm access service that would be provided through generators entering into access agreements with the local TNSP, a *short-term* firm access product would be available to generators. This product would be useful to generators for backing their forward contracts - it would enable generators to better manage their contract positions, and so risk.

The short-term firm access product would differ from the firm access service in a number of ways, specifically:

- short-term firm access would only be offered for a quarterly period (as opposed to the firm access service that could be purchased for any term) - this would be most useful to generators to back their forward contracts;[50]
- short-term firm access would be issued through an open auction (as opposed to bilateral negotiations between the generator and the TNSP).[51]

TNSPs would engage in activities to release additional capacity on the network, and would have incentives to maximise the amount of short-term access that they offer. TNSPs would offer short-term access provided that the costs of doing so were less than the revenue they would receive from selling the firm access.

TNSPs could undertake either capital or operational activities (eg re-rating lines or spending money on a non-network solution) to back short-term firm access. However, none of the expenditure associated with this would be regulated – or rolled into the Regulatory Asset Base (RAB). Therefore, if a TNSP did wish to undertake capital expenditure, the assets associated with this should be clearly separable from the assets used to provide regulated services (including the long-term firm access service). It is unlikely that a TNSP could sell sufficient short-term access on an ongoing basis to cover the cost of long-lived assets (which could never earn a regulated return). We

49 Generator traders should typically be aware of transmission constraints and their impacts on dispatch.

50 We note that this does not preclude the offering of short-term access on a longer or shorter timeframe if so desired by generators. However, we consider that a quarterly product will be most desirable since generators contract on a quarterly basis. We also note that an off-peak and peak short-term access products may be desirable. Again, these should be offered if there is sufficient demand from generators.

51 See section 5.3.2.

therefore consider it unlikely that in practice a TNSP would undertake capital expenditure to provide short-term access. The release of short-term access would most likely be underpinned by a TNSP's operational decisions.

We also note that there may be some *existing* spare capacity on the network - that already exists without the TNSP undertaking operational activities. Specifically, network capacity might be significantly higher in some parts of the network due to:

- 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; and
- reliability standards requiring that some network access be provided to non-firm generators.

To the extent that any spare capacity on the network exists, TNSPs would be able to use this to back short-term access. However, given that this has been previously paid for by consumers and/or generators, further consideration would need to be given to how much of the revenue associated with this product the TNSP would be able to retain.

4 Transmission planning under optional firm access

Summary of this chapter

This chapter sets out the integrated planning framework that would form part of the optional firm access model, providing a holistic set of transmission planning arrangements to further promote efficient investment in, and use of, the transmission network across the NEM over the long term.

Key aspects of the planning process would be the same as currently, with TNSPs being required to produce both APR and RIT-T planning documents. 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.

The framework is based around an institutional framework where TNSPs are responsible for investment decisions and are exposed to financial incentives through settlement shortfalls. The NTP has a role in providing additional planning information and perspectives, and in promoting national coordination, specifically:

- reviewing draft TNSP planning and investment test reports;
- providing an expert independent advisory role; and
- providing demand forecasts.

Further, the role of TNSPs is enhanced in order to drive coordination between businesses:

- supporting increased consultation between TNSPs to identify and implement cross-regional network investment options;
- providing greater input into the NTP's annual strategic planning report to ensure that both local and national perspectives are captured and reflected in the longer term planning process;
- providing consistency across TNSP planning reports; and
- aligning the regulatory control periods for TNSPs.

This aims to provide more efficient arrangements for supporting investment across regional boundaries, lowering prices to consumers over the long term. Increased transparency and coordination should also provide greater certainty to market participants, supporting their own investment and operational decisions.

4.1 Introduction

Under the OFA model a TNSP would be responsible for meeting two standards – the firm access standard and the relevant jurisdictional network reliability standard. Previously in this review, we presented proposals for transmission planning, which were considered separately to the OFA model. However, given the inter-linkages between these two standards, and so planning, the Commission has sought to integrate its planning recommendations with the OFA model. These standards and the linkages between the standards are discussed in section 4.2.

TNSPs would be required to plan to meet both of these standards. The planning *process* would be largely the same as currently – TNSPs would produce planning documentation. However, there would be changes to the RIT-T *analysis* resulting from the implementation of OFA. This is discussed in section 4.3.

The institutions that are responsible for planning form an important part of this framework. Our recommendations are therefore based around an institutional foundation where TNSPs that are subject to financial incentives are responsible for investment decisions – discussed in section 4.4. The national transmission planner has a role which facilitates contestability of views in planning and to promote national coordination. The proposed framework is based around two key concepts:

- enhancing the role of AEMO as National Transmission Planner (discussed in section 4.5); and
- enhancing the role of TNSPs in driving coordination (discussed in section 4.6).

4.2 Planning standards

Under the OFA model, TNSPs would be responsible for meeting two standards:

- the firm access standard (section 4.2.1); and
- the existing reliability standards (section 4.2.2).

Section 4.2.3 discusses the interaction between these two standards.

4.2.1 Firm access standard

The firm access standard would be a real-time standard: in every settlement period the TNSP must ensure that congested parts of the network provide enough capacity for firm generators to be dispatched to earn the regional energy price, and so underwrite firm access. It is therefore both a planning and an operating standard: 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). By implication, the TNSP must take account of local demand which can both add to network capacity (by absorbing generation that would otherwise contribute to congestion) or subtract from it (by absorbing generation that would otherwise alleviate congestion).[52]

The firm access standard defines the set of normal operating conditions during which firm generators are provided with their agreed access amount. We anticipate that these should include:

- system normal, when transmission elements are in service;[53] and
- planned outages, when some transmission elements are out of service due to planned maintenance.

Planned outages are included within normal operating conditions to ensure that TNSP outage schedules allow access levels to be maintained. This is likely to mean scheduling outages when congestion is not expected. However, it is recognised that defining and monitoring planned outages – and appropriately distinguishing them from unplanned outages - may be difficult. This matter would need to be considered during optional firm access implementation.

During optional firm access implementation the set of normal operating conditions would be defined exactly and explicitly, and this would involve TNSPs, AEMO and generators. In defining the set of normal operating conditions it is important that:

- it is *clearly defined*, such that normal and abnormal operating conditions can be unambiguously distinguished within settlement timescales;[54]
- it does not encourage *perverse* TNSP behaviour: for example, taking a line out so that its firm access standard obligation is removed; and
- it is *relevant* to generators: for example, if generators are most concerned about congestion during planned outages, these should ideally be covered.

The TNSP would be responsible for meeting the firm access standard. We anticipate that the standard would become part of the rules – and so would be enforceable under the rules. If TNSPs did not meet the firm access standard, they would be liable to pay some of the settlement shortfall: through access settlement, payments by the TNSP would be allocated directly to the generators affected. This is discussed more fully in section 7.3.1.

4.2.2 Reliability standards

Reliability standards ensure that there is enough transmission capacity to transport sufficient generation to meet demand. In the current transmission planning framework,

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52 Demand not located at the regional reference node.

53 The system as a whole need not be in a normal condition, only those elements that affect access settlement at a particular moment in time. See Technical Report section 5.2.4.

54 This is to allow TNSP incentive payments to be cleared through AEMO settlement - see TNSP regulation in section 7.3.1.

reliability standards are found in a variety of instruments, and are set by different bodies in each NEM jurisdiction. There are three broad approaches to reliability standards:

- redundancy (or deterministic) standards – applying in NSW,[55] Queensland,[56] and Tasmania[57];
- economic redundancy (or hybrid) standards - applying in South Australia;[58] and
- economic (or probabilistic) standards - applying in Victoria.[59]

Previously in this review, the Commission emphasised the importance of a national framework for reliability standards. This was supported by stakeholders.[60] Recently, the AEMC has received a Terms of Reference for a review of the national framework for transmission reliability. This will consider and address reliability related issues, and so we are not making recommendations in this regard in this report.

4.2.3 Interaction between standards

Under OFA, TNSPs will be required to meet both the standards as set out above. While there are two standards, neither dominates the other, ie maintaining the firm access standard is neither *sufficient* nor *necessary* for maintaining reliability standards (and vice versa). The firm access standard does not replace reliability standards, and so the latter must be retained if existing reliability of supply is to be maintained.

TNSPs are responsible for meeting *both* of these standards:

- firm access – a TNSP must meet the standard under normal operating conditions or be liable for some of the settlement shortfalls that may occur (discussed in chapter 3); and

55 These are contained in the Transmission Network Design and Reliability Standard, which serves as a direction from the NSW government.

56 These are contained in the Transmission authority (licence) issued under s 34 of the Electricity Act (Queensland) 1994.

57 These are contained in the Electricity Supply Industry (Network Performance Requirements) Regulations 2008 enforced through licence conditions.

58 These are contained in the Electricity Transmission Code of South Australia.

59 The obligation to plan in this manner is contained in the National Electricity Law.

60 See: EnergyAustralia, Second Interim Report submission, p.10; Transmission Operations (Australia), Second Interim Report submission, p.4; AER, First Interim Report, p.9; Grid Australia, First Interim Report submission, p.24; InterGen, First Interim Report submission, p.3; Hydro Tasmania, First Interim Report submission, p.2; MEU, First Interim Report submission, p.31; Government of South Australia, First Interim Report submission, p.3; Infigen, First Interim Report submission, p.4; Alinta Energy, First Interim Report submission, p.17; and TRUenergy, First Interim Report submission, p.5.

- reliability standards – failure to comply with these potentially results in civil penalties.[61]

4.3 Regulatory Investment Test for Transmission

As discussed above, TNSPs will be required to undertake planning in order for the network to meet both of the standards. The general structure of the planning *process* would not be changed under optional firm access. TNSPs would still be obliged to produce the following planning documents:

- Annual Planning Reports (APRs) – which are detailed short-term plans for a particular region in the NEM, developed by the jurisdictional TNSP. These set out the current capacity and emerging limitations of the network under a range of different scenarios; and

- RIT-T – this is a separate and distinct process for individual investment decisions, which examines the costs and benefits of various options and establishes the one that maximises net market benefits. This must be applied to all augmentation investments with a value of over five million dollars.[62]

Despite not changing the *form* of the planning process, there would be changes to the *analysis* undertaken by TNSPs in these documents. First, APRs would set out the current capacity and emerging limitations of the network reflecting the need to meet both the firm access standard and reliability standards.

Second, the RIT-T would be undertaken where investments were made to meet either the reliability or firm access standard. There would be some changes to what benefits are estimated in a RIT-T analysis. The current focus of the RIT-T is on the "net market benefits" to those who produce, consume and transport electricity. The RIT-T is very prescriptive about what market benefits must be estimated. These are contained in Table 4.1 below.

TNSPs estimate changes in fuel consumption, and costs to parties other than the TNSP (eg generators). Therefore, *TNSPs* make decisions based on *their* perceptions about which generators would be better off, and worse off, following an upgrade to the transmission network.

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61 In Victoria, Queensland, South Australia and Tasmania, compliance with the instrument noted above is a condition of the TNSP's licence. Failure to comply with a licence condition may result in civil penalties and, ultimately, suspension or revocation of the licence with the Government or the regulator having the power to take over the licensee's operations. In NSW, TransGrid may be subject to an order of the Director-General if it is not in compliance with any aspect of the Network Management Plan, and failure to comply with an order will attract a civil penalty.

62 The RIT-T came into effect on the 1 August 2010 and represented a change to the previous Regulatory Test. As defined in NER clause 5.16.1(b) the purpose of the RIT-T is to "identify the credible option that maximises the net present value of net economic benefit to all those who produce, consumer and transport electricity in the market."

However, OFA represents a shift to market-driven pricing and investment where *generators* have incentives to invest in new capacity. *Generators* decide on the economic benefits associated with expansions. They have incentives to make a request for access if the cost for the augmentation (as calculated in accordance with the regulated pricing methodology as set out in section 5.2) is expected to be less than the continuing costs of the constraints that would otherwise be incurred. This purchase of firm access by generators (in conjunction with reliability standards), funds and guides network expansion by TNSPs.

This has various implications for the benefits and costs to be considered in a RIT-T assessment. Any costs and benefits that accrue to generators would be internalised to *generators* under the OFA model. Since generators decide where investments occur in the network, they are incentivised to reveal their preferences through seeking firm access. Consequently, *TNSPs* should not assume that certain generators benefit or not, unless this is revealed by the generator seeking firm access.[63]

The commercial incentives on generators should place a discipline on them to only seek an optimal amount of access. This therefore removes the need to require TNSPs to consider, and make assumptions about where generators would locate in the network.

Consequently, the benefits calculated under the RIT-T should only take into account those accruing to parties *other* than generators.[64] This is consistent with the fundamental principle of optional firm access. Table 4.1 illustrates that the current benefits associated with generators (changes in fuel consumption, and changes in costs for parties other than TNSPs) would not be estimated in a RIT-T under optional firm access. We also consider that competition benefits should no longer be required to be calculated. The rationale for this is discussed in section 8.3.9 of the Technical Report.

63 The core principle of the OFA model is that non-firm generators should compensate firm generators when the former's dispatch causes the latter to be constrained off. This implies that these parties should not be considered in the RIT-T analysis since non-firm generators do not value the access service (which is illustrated by these generators not procuring access).

64 This is different to the standard approach in US FTR/LMP markets. In these markets the independent system operators, when assessing the need for investment, take into account not only project upgrades that may be needed for reliability, but also evaluate whether those planned reliability upgrades would also bring economic benefits to the system in terms of savings in congestion costs. This is the case of PJM, for example, where the transmission upgrades for economic reasons (savings in congestion costs) may be included in the transmission planning even if no reliability-based need has yet been identified. See: NERA Economic Consulting, *Review of Financial Transmission Rights and Comparison with the Proposed OFA Model*, March 2013.

Table 4.1 Benefits to be considered in the RIT-T analysis

Benefit	Currently considered	Considered under OFA
Changes in fuel consumption arising through different patterns of generation dispatch	✓	×
Changes in voluntary load curtailment	✓	✓
Changes in involuntary load shedding (unserved energy)	✓	✓
Changes in costs for parties, other than the RIT-T proponent, due to: • differences in the timing of new plant; • differences in capital costs; and • differences in the operating and maintenance costs	✓	×[65]
Differences in the timing of expenditure ie unrelated transmission investment	✓	✓
Changes in network losses	✓	✓
Changes in ancillary services costs	✓	✓
Competition benefits	✓	×

Consistent with the current RIT-T framework, the above benefits should only be considered if:

- they are material; and
- the calculation of benefits is not disproportionate to the analysis, which should now include that this does not cause delays to access being obtained.

We consider that in practice, most intra-regional investments would have no additional benefits aside from network losses – the same as the majority of RIT-Ts currently undertaken for reliability purposes.

Theoretically, investments may still be able to be justified as creating net market benefits (in the absence of a reliability driver) – this provision should not be removed from the rules. However, because all the benefits to generators have been reassigned under optional firm access, in practice few - if any - investments will be able to be

65 We note that where the changes in costs for parties are for *other* TNSPs (eg due to the investment having a material inter-network impact) these would still be included.

justified on a net market benefit basis alone.[66] The main drivers for intra-regional investments will be to meet either reliability or firm access standards. This is more consistent with the economic regulatory framework which places strong incentives on TNSPs to minimise costs for a defined set of outputs.

The RIT-T process requirements would still occur as currently:[67]

- the requirements surrounding the preparation of three reports; and
- the requirements relating to considering non-network options.

The timeliness associated with publication, and consultation, on the three RIT-T reports may need to be revised. Market modelling would likely be no longer be required (which is used to estimate changes in fuel costs, and capital/operating costs for generators). The removal of the need to undertake this complex process would speed up the RIT-T analysis. This is discussed further in section B.1.3.

We also note that it is important to ensure that transparency of the RIT-T is not reduced as a result of these changes.

4.4 Institutions and incentives

The above discussion sets out the various planning processes, and associated analysis, that would be undertaken under the recommended model. These roles and responsibilities would be undertaken by institutions within the planning framework. There are a number of matters that need to be taken into consideration when determining the appropriate institutions to undertake these functions. Specifically, this includes the incentives that these institutions face.

In order for effective planning and investment decisions to occur, the institutions or bodies who are responsible for these tasks must face appropriate incentives. We consider that financial incentives are likely to provide the most robust and transparent driver for efficient decision making. Efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers.

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. While all entities are subject to various forms of incentives, financial incentives provide an understandable and transparent approach to influencing behaviour.

TNSPs are best placed to make investment decisions since they face financial incentives. These investment decisions are bounded by incentives and regulation, which are developed and overseen by the AER. The recent Economic Regulation of Network Service Providers rule change has made improvements to the NEM

66 This is since a substantial component of the net market benefit for these investments is made up of those benefits associated with changes in fuel costs, and capital/operating costs for generators.

67 We note that there may be a need to consider further the specified timeframes in the Rules, in order to better fit within the access procurement process.

frameworks to better align TNSP incentives with the interests of consumers. As the effects of these rule changes are applied over the forthcoming years, we expect that this will be reflected in practice and further improve incentives.

Box 4.1: Role of the National Transmission Planner

AEMO would have an important role in planning under the OFA framework through an enhanced national transmission planning role. The National Transmission Planner is responsible for long-term strategic planning, with this informing TNSPs who undertake more detailed planning of the network ("project specific planning"). Project specific planning relates to a particular investment need, with this culminating in a particular investment decision being undertaken by the TNSP: planning functions are separate to investment decision making. In its enhanced NTP role, AEMO would have an increased role in *planning*.

AEMO currently has a role determining augmentation investments in Victoria, ie making investment decisions. AEMO has proposed that this independent transmission planner-decision making role should apply across the NEM.[68] However, we do not support such an approach, since we consider TNSPs are best placed to make investment decisions.

AEMO has questioned the use of financial incentives in transmission investment decision making, suggesting that a body not subject to such incentives might make more efficient decisions. However, we note that all bodies face incentives: financial incentives provide an understandable and transparent approach to influence behaviour. In the Commission's view efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers. Decisions made by an independent transmission planner would be subject to its own perspectives, including those resulting from any other roles it performed. These drivers of behaviour would be less transparent and robust than direct financial incentives.

We note that the Victorian DPI has proposed an alternative Victorian planning model if OFA was implemented, where generation-led augmentation would be undertaken within a single entity (ie SP AusNet), linking service accountability, risk management and reward.[69] However, planning for all for reliability augmentations would remain with AEMO.

We do not consider that this is a very feasible institutional structure. The two standards must be met concurrently. Given the large overlap and interactions we do not consider that having separate planners would result in the lowest overall cost outcome. Having separate planners would not allow TNSPs to make trade-offs and examine linkages between projects to meet firm access and reliability standards. Often, projects would help TNSPs to meet both of these.

68 AEMO, Second Interim Report submission, p.5.

69 DPI, Second Interim Report submission, pp.3-4.

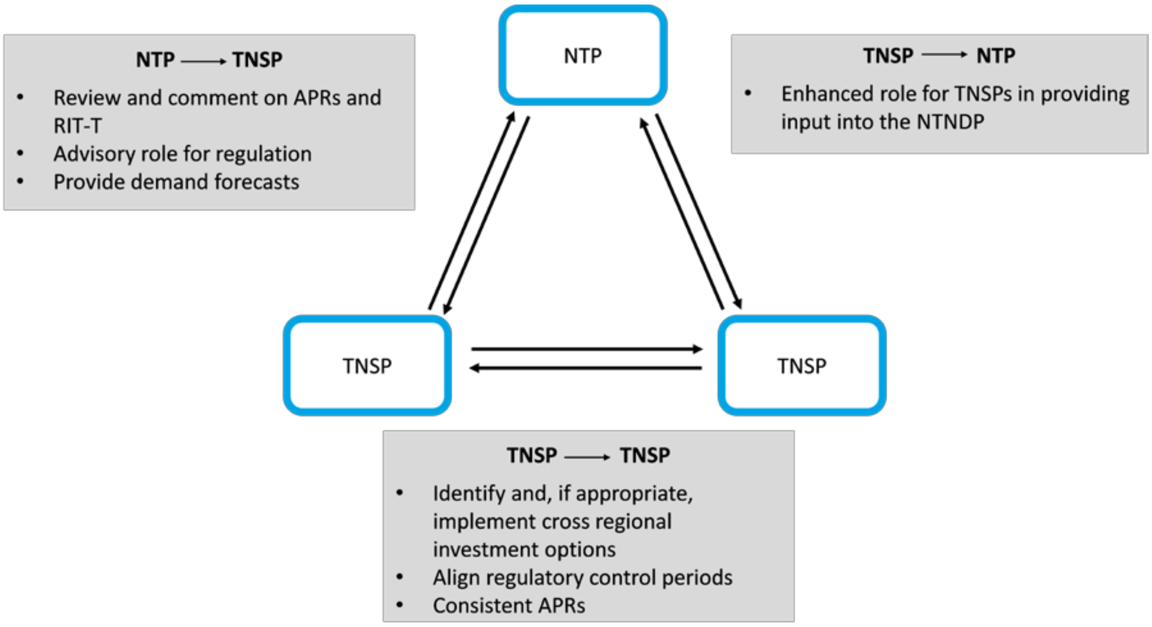
We have developed a series of incentive schemes in the OFA framework that aim to incentivise TNSPs to make decisions about how to most efficiently meet both the firm access and reliability standards. These are discussed in greater detail in chapter 7.

These would place the appropriate incentives on TNSPs to enter into OFA agreements with generators, and to provide for efficient investment and operation in response to the market signals generated by OFA.

The figure below provides an overview of the key components of the recommended framework for transmission planning in terms of the relationships between the National Transmission Planner (NTP) and TNSPs, and between TNSPs. These recommendations include:

- an enhanced role for AEMO as National Transmission Planner, both in promoting coordination between TNSPs at high level and providing strategic input to TNSP planning processes; and
- an enhanced role for TNSPs, both in improving coordination between TNSPs and providing input into the National Transmission Planner's national planning process.

Figure 4.1 Overview of recommended planning framework



4.5 An enhanced role for the national transmission planner

AEMO would have an enhanced role as NTP in order to facilitate increased coordination in transmission planning across the NEM. Currently, the national planner has a long-term, strategic focus. While this is important, the Commission also sees a useful role for the national planner in the planning process to help drive consistency and coordination between TNSPs over the short to medium term.

AEMO would gain several functions:

- reviewing planning documents prepared by TNSPs (section 4.5.1);
- providing specialist advice to the AER (section 4.5.2); and
- preparing demand forecasts (section 4.5.3).

We previously proposed that AEMO might assume responsibility for the Last Resort Planning Power (LRPP). However, we do not consider that this role would exist or would be necessary in an OFA framework. This is discussed in section 4.5.4.

4.5.1 Reviewing TNSP planning documentation

AEMO in its role as NTP would be given a formal role to review TNSPs' draft APRs and draft RIT-T documentation. In undertaking this task, the NTP would review:

- whether all constraints in a region have been identified, and are being assessed;
- whether the options identified to meet the need actually address the need;
- whether an identified need could potentially be met by other investment options including network options in a neighbouring region and non-network options; and
- whether the options identified to meet needs are consistent with those contained in the National Transmission Network Development Plan (NTDNP), and meet firm access and reliability standards in that jurisdiction.

The NTP would aim to identify areas where coordination between regions is likely to be beneficial. This role would act as a check on the new cross-regional requirements in the rules (discussed below), and would provide a further avenue for TNSPs to become aware of what others are planning.

This would become more important under OFA (and in some cases, necessary), since it is likely that more intra-regional investments will have material inter-network effects requiring upgrades in other TNSP networks.[70] This is because inter-regional (or interconnector) terms are included in constraints.

The NTP would highlight with a TNSP that it should be consulting on a particular investment with neighbouring TNSPs. Since all APRs must be published by 30 June each year, the NTP would be able to review all APRs at the same time and provide

70 The RIT-T currently requires that the relevant TNSP should consider whether the credible option is reasonably likely to have a material inter-regional impact. Material inter-regional impact is not a defined term within the NER, but it has been generally assumed to be synonymous with material inter-network impact, which is a defined term. A material impact on another TNSP's network is defined in Chapter 10 of the NER: it includes (a) the imposition of power transfer constraints within another TNSP's network; or (b) an adverse impact on the quality of supply in another TNSP's network.

consistent comments across all jurisdictions. TNSPs should consider any additional options suggested by AEMO at the later, more detailed planning stage of the RIT-T.

TNSPs would not be compelled to action and incorporate the NTP's comments. However, if they did not adopt the NTP's suggestions they would be required to explain in their APR the reasons for not doing so.[71]

This role is consistent with the "additional advisory functions" that AEMO currently performs in South Australia. In particular, we understand that, although not explicitly specified in the NEL or NER, AEMO does comment on draft RIT-T documentation. This proposal would formalise that role across the NEM.

4.5.2 Provision of advice

AEMO in its role as NTP would also provide specialist advice to the AER. Advice to the AER prior to the final determination for a particular regulatory period would be provided in the form of an independent report.[72] It would focus on augmentation expenditure[73] and involve assessing:

- whether the identified need exists;
- whether the proposed project's timing is appropriate;
- whether the option being proposed appears reasonable;
- whether a different network option or non-network option may be more appropriate (with the expectation that the TNSP would investigate these options more fully during the RIT-T stage);
- the appropriateness of the contingent projects proposed; and
- the consistency of the proposed projects with the NTNDP and the reliability standards.

This advice would assist the AER, by giving it access to a different view from the TNSP's – one which reflects AEMO's specialist knowledge on these matters.

We also note that AEMO should be available to provide advice to the AER in an ad hoc manner if required, eg in relation to the development of incentive schemes. Further, while the exact framework for transmission reliability standards is yet to be finalised – and will be determined during the review of the national framework for transmission

71 This requirement would be contained in NER clause 5.12.2(c).

72 In relation to the recent revenue reset for South Australia, the South Australian government requested AEMO to review ElectraNet's load-driven investments in their regulatory period. The process described here would be similar.

73 There is limited assistance that AEMO could provide in reviewing replacement expenditure, since these projects would have to be undertaken regardless.

reliability – it is likely that AEMO would also play a role in providing advice on reliability standards.

4.5.3 Provision of demand forecasts

As part of its enhanced functions, AEMO would produce a standardised set of "bottom up" demand forecasts (ie at a transmission connection point level) for each region of the NEM. These demand forecasts could be used by:

- TNSPs - in the various regulatory tasks to be undertaken, eg production of APRs;
- the AER - as independent demand forecasts to help assess TNSP expenditure forecasts in regulatory determinations; and
- AEMO - in its market and system operator role, eg calculating loss factors.

The Commission is of the view that there are advantages from having AEMO producing "bottom up" forecasts. Most importantly, it provides contestability of views – AEMO connection point forecasts can be compared to TNSP-prepared connection point forecasts.

The AER's ability to provide effective incentive regulation would be enhanced since AEMO demand forecasts could potentially be used as a "cross check" against TNSP demand forecasts submitted as part of a revenue determination.[74] This cross check becomes even more important under optional firm access, since demand forecasts will likely be used in the pricing model.

In order to produce "bottom up" forecasts AEMO would need access to connection point forecasts generally prepared by DNSPs. There are two main ways AEMO could be given required rights to access this information – either through a rule change request, or a NEL change. We outline these options in more detail in appendix A.1.

AEMO would still be required to produce "top down" demand forecasts as part of its NTP role – as it does currently. It would be required to reconcile the differences between these two approaches, setting out reasons why there may be differences. AEMO should not force these two demand forecasts to be equivalent.

We acknowledge that regardless of the other sources of demand forecasts available, TNSPs would still use their own "bottom up" forecasts – because TNSPs are responsible for investment planning and investment decision making. As discussed above we consider it appropriate for financially incentivised network providers to make these decisions. Such bodies should not be compelled to use other sources of information if they are liable for the consequences of their decisions. Given that TNSPs are financially accountable for investment decisions, the AER should take this into

74 Currently, the AER engages independent consultants to prepare econometrically derived "top down" forecasts. "Bottom up" forecasts cannot be developed since consultants do not have the relevant information.

account when considering the demand forecasts and associated advice provided by AEMO.[75]

4.5.4 Last Resort Planning Power

During this review, we canvassed the possibility that responsibility for the LRPP should be reassigned to AEMO as the NTP. The LRPP is currently held by the AEMC, and allows the Commission to direct registered participants to apply the RIT-T to potential transmission projects if they are likely to relieve forecast constraints in respect of national transmission flow paths connecting NEM regions.

The Commission reports annually on the LRPP and, to date, we have not identified any gaps in relation to inter-regional transmission planning that would require a direction to a TNSP to undertake a RIT-T.[76]

However, under an OFA model there would be no need for a LRPP. For intra-regional investments for reliability purposes, TNSPs are required to undertake investments in order for the standards to be met. The same is true for firm access: TNSPs would be required to meet the firm access standard, and so these investments should occur. As discussed above, while it is theoretically possible for investments to be justified on a net market benefit basis, we do not consider this would occur in practice. Accordingly, investments to meet the firm access and reliability standards would comprise all intra-regional investments. Efficient decisions on what investments would be needed to meet these standards should be made by TNSPs, given the incentives faced.

Inter-regional investments would occur following an expansion and allocation process - the first stage of which is an auction that is designed to facilitate demand for inter-regional capacity.[77] AEMO would "filter" auction results, and if it considered that a potential inter-regional upgrade looked possible, then it would pass this information through to the relevant TNSPs – in order for them to undertake a RIT-T on the expansion. This process is discussed in section 6.7. This replaces the need for AEMO to have responsibility for the LRPP as it exists currently. However, this new role can be considered akin to a LRPP for inter-regional investments (although in a different form).[78]

Under the Commission's preferred institutional structure, a national entity would provide oversight and advice on the analysis and conclusions of jurisdictional TNSPs that is independent of those state-based planning processes. The different institutions

75 For example, if AEMO considered that demand was likely to be substantially lower than had been predicted by the TNSP, then the AER should allow the TNSP to explain why it considers it would be higher. This is appropriate since the TNSP is ultimately financially accountable.

76 The AER suggested that, if this power were held by AEMO, it should have a more determinative role in approving or rejecting RIT-T assessments. See: AER, Second Interim Report submission, p.3.

77 Inter-regional investments could still occur to meet reliability standards.

78 We consider that this increased review role may address the AER's proposal to have AEMO review RIT-Ts and approve or reject RIT-T assessments. See: AER, Second Interim Report submission, p.3.

involved in planning ensure that there is an appropriate tension and check on the planning role within the market.

In the absence of the full implementation of the model set out in this chapter, the Commission considers that AEMO assuming the LRPP would be inconsistent with its current jurisdictional planning function in Victoria; AEMO would essentially be providing a check and balance on its own work. Therefore, in the absence of any broader planning changes in the NEM, the LRPP should remain with the AEMC.

4.6 Enhancing TNSP decision making

The role of TNSPs would also be enhanced in order to facilitate increased coordination in network investment and to provide consistency across the NEM:

- arrangements should be introduced that promote the identification and implementation of network investment options that cross regional boundaries (section 4.6.1);
- TNSPs should provide greater input into the NTNDP to ensure that coordination between national and local issues occurs at the outset of the planning process (section 4.6.2);
- the structure of APRs should be consistent across the various TNSPs (section 4.6.3); and
- regulatory control periods should be aligned (section 4.6.4).

4.6.1 Cross-regional investment

TNSPs should investigate investment options in other regions that may help them to meet either of their planning standards (firm access or reliability standards). For example, a reliability standard in NSW could potentially be met by an option undertaken in Queensland. A nationally coordinated planning approach ensures that both intra-regional and cross-regional options would be considered in determining the optimal investment.

TNSPs would be required to consider whether there were options located either wholly or partly in other regions that could address an identified need. These options would be identified and developed through consultation with neighbouring TNSPs.

Where a TNSP did not consider that options in other regions would meet an identified need, it would be required to explain the reasons for this. TNSPs would be required to make transparent any consultation that had taken place with other TNSPs. This process would be followed in developing APRs and in undertaking both RIT-T and non-RIT-T assessments.[79]

To assist in this process, the NTP would be required to develop guidelines on assessing whether an investment need could be met by an investment in another region.

If an option in another region was identified as being the preferred option, the TNSP in that region would need to agree to be the proponent of the investment. Without a proponent, the option could not be chosen as the preferred option under the RIT-T.[80]

We expect that the transparent process by which the preferred investment options are identified would provide an incentive for neighbouring TNSPs to agree to be proponents where appropriate. Where investments were to meet the firm access standard, there would be an obligation on the neighbouring TNSP to be a proponent – although this would be subject to negotiation between the TNSPs as to arrangements relating to project scope, associated liability and cost.

The economic regulatory regime would also provide incentives (or at least not provide disincentives) for TNSPs in neighbouring regions to agree to be a proponent for cross-regional investments. The current framework for economic regulation does not explicitly allow for TNSPs funding investments to meet an identified need in a *different* jurisdiction, eg TransGrid may undertake an investment project to help Powerlink to meet its reliability standards. The framework should be clarified to ensure that cross regional investments are treated as regulated investments under Chapter 6A of the NER. This is because these may be substantial investments, whose use may change over time. For example, such an investment (while initially for the purpose of meeting an identified need in a different jurisdiction) could later be augmented to meet investment needs within its own jurisdiction.

Under optional firm access some intra-regional investments would have material inter-network effects requiring upgrades in other TNSP's networks. TNSPs are currently required to consider whether this may occur in their RIT-T analysis.[81] If there is a material inter-network effect on another TNSP's network, then the other TNSP must be informed. This requirement would remain.

4.6.2 Input into the National Transmission Network Development Plan

TNSPs would also provide input into the NTNDP. The NTNDP is a long-term strategic plan which is designed to provide an overarching, strategic view of the network over the next 20 years.

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79 We understand that it is common practice within TNSPs to conduct cost-benefit assessments for those projects that are not covered by the RIT-T. This is consistent with NER clause 5.16.3(d) that states that the investment must be planned at "least cost" over the life of the investment.

80 This is consistent with current NER clause 5.16.4(l).

81 NER clause 5.16.4(b)(6)(ii).

Just as it is important for the NTP to have a codified role reviewing and commenting on jurisdictional investment planning processes, it is also appropriate for TNSPs to formally comment on the NTNDP. The different perspectives of the different parties involved in planning would be appropriately captured and reflected throughout the process. Coordination between national and local issues should occur right at the outset of the planning process.

A working group, comprising TNSP representatives from all jurisdictions, would comment on, and provide input to, the NTP's development and preparation of the NTNDP. This complements the NTP's role in commenting on aspects of the TNSP's own planning and investment decision making process.

We understand that such a working group already exists, and that this recommendation would therefore largely represent a formalisation of existing practice.[82]

4.6.3 Consistency of Annual Planning Reports

Improving the consistency of the structure of APRs is desirable since increasing the uniformity would make it easier to examine plans and so facilitate comparative analysis. This would be useful for the purposes of economic regulation, as well as increasing predictability in the investment planning process for market participants.

We note that the following would further facilitate comparison between APRs:

- commonality of project labels and constraint labels between TNSPs, to the extent possible; and
- a distinction of projects addressing intra- and inter-regional issues, to the extent possible.

Grid Australia is supportive of this approach, and noted that this could be developed further into a formalised collegiate approach between the organisations with transmission planning in the NEM.[83] The Commission is welcoming of this suggestion; however, we consider that improvements in coordination of APRs should be underpinned by a requirement in the rules to facilitate this.

Reporting on the consistency of APRs could also be facilitated by the NTP in its role in commenting on planning documentation. For example, discussing consistency of APRs could become a feature of the NTNDP. AEMO is well placed to comment on the consistency of APRs, given its enhanced role in reviewing planning documentation.

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82 We understand that the NTNDP TNSP Reference Group meets three to four times a year. It is described by AEMO as a "working group of planning managers to coordinate the exchange of information for the NTNDP and keep AEMO and TNSPs informed on the progress of the NTNDP and APRs. See: AEMO, Industry Working Groups, Committees and Forums, p.8.

83 Grid Australia, First Interim Report submission, p.26.

4.6.4 Alignment of revenue resets

We are recommending that TNSP regulatory resets should be aligned. Amongst other things, this would further facilitate enhanced TNSP coordination. It should:

- assist the AER to compare TNSP augmentation plans on a holistic basis across the NEM, facilitating implementation of cross-regional planning recommendations; and

- allow consistent regulatory arrangements between TNSPs, through the use of consistent assumptions and assisting with benchmarking.

The AER agrees that it would allow it to assess TNSP proposals on a holistic manner, reflecting investment options that are most efficient on a NEM-wide basis.[84]

The introduction of optional firm access would further emphasise the need for alignment of revenue resets. Optional firm access would change a number of features of revenue determinations, eg revenue proposals would reflect the obligation to meet both the firm access and reliability standards and so it is advantageous to align revenue resets as part of optional firm access.

We have therefore sought to develop a timetable for achieving alignment of TNSP regulatory periods. We note that similar issues were considered in the transitional section of the Economic Regulation for Network Service Providers rule change. This ultimately resulted in a number of transitional arrangements being adopted in order to smooth transition to coverage by the new rules.

Table 4.2 sets out the current TNSP regulatory periods, including the transitional arrangements.

Table 4.2 Transitional arrangements and regulatory periods

TNSP	Form of transitional arrangements	Next regulatory period	
		Length	Dates
SP AusNet (Vic)	Old rules for 3 years	3 years	1 April 2014 - 31 March 2017
	New rules	5 years	1 April 2017 - 31 March 2022
TransGrid, Transend (NSW, Tas)	Placeholder with true-up	1 year	1 July 2014 - 30 June 2015
		4 years	1 July 2015 - 30 June 2019
Powerlink (Qld)	No transitional arrangements	5 years	1 July 2017 - 30 June 2022
ElectraNet (SA)		5 years	1 July 2018 - 30 June 2023

84 AER, Second Interim Report submission, p.4.

Although there are a number of ways to align, we recommend that all TNSPs be aligned with Powerlink's existing regulatory cycle (ie from 1 July 2017 to 30 June 2022 and so on). Alignment would occur in a staged process, with TNSPs not completely aligned until 2022. In developing this recommendation we have consulted with the AER.

This alignment does not change any of the transitional arrangements that are already in place (to transition to the new rules), but it does change some of the upcoming regulatory periods once the new rules are in place.

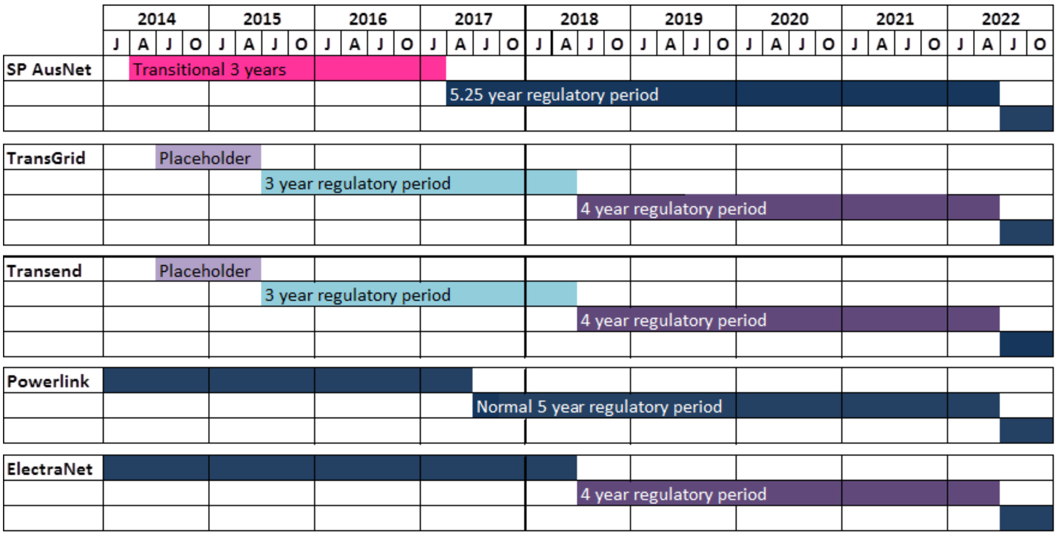
Appendix A.3 sets out in detailed steps out how TNSP reset alignment would occur, in summary:[85]

- Powerlink is currently on a 2017 to 2022 cycle, and so no changes are proposed.
- SP AusNet's determination will conclude on 30 March 2017, we propose that the following determination should be 5.25 years in length (1 April 2017 to 30 June 2022), so alignment is achieved from 2022.
- ElectraNet would have a four-year regulatory period from 1 July 2018 to 30 June 2022, with alignment from 2022.
- TransGrid and Transend would propose a three-year regulatory period (1 July 2015 to 30 June 2018), followed by a four-year regulatory period (1 July 2018 to 30 June 2022). Alignment would occur from 2022.

This is illustrated in Figure 4.2. NER clause 11.48.4(1)(2) currently allows TransGrid and Transend to propose a three-year regulatory period from 2015 to 2018, and so this could easily be facilitated. However, a rule change would be required to facilitate the later four-year determinations.

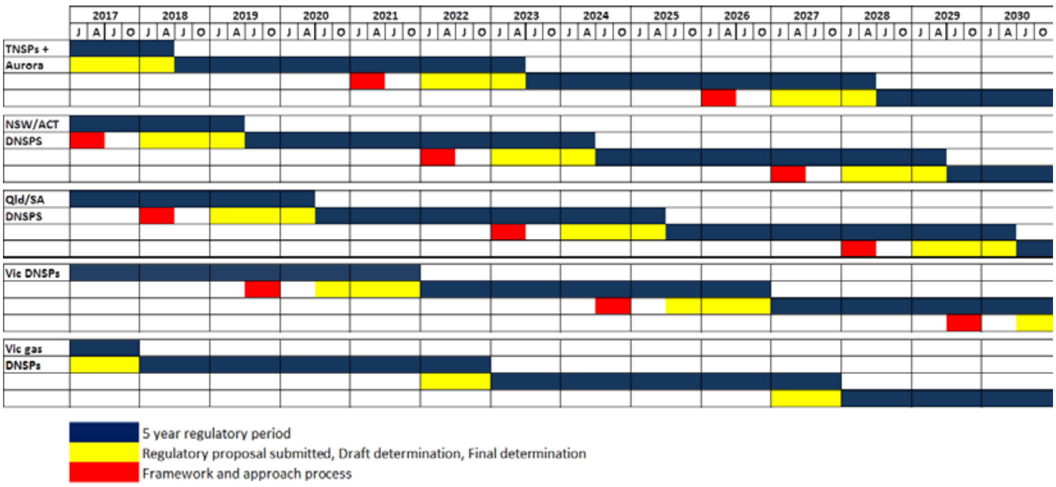
85 We note that Appendix A.3 sets out two alternative ways that alignment could be achieved. However, the above represents our preferred option.

Figure 4.2 Revenue reset alignment



This alignment process would not see the TNSP reset processes overlap with processes in other sectors: no consequential changes would be required. This is depicted in Figure 4.3. This is an advantage since it will not result in the need for transitional arrangements in other sectors, eg electricity distribution or gas distribution. It also minimises resourcing constraints for both the AER, and interested parties who wish to contribute throughout the regulatory determination process, eg consumer groups.[86] Consequently, this pattern is a sensible arrangement for the long-term revenue regulation of Network Service Providers (NSPs) by the AER.

Figure 4.3 Regulatory periods for all sectors



86 The limited ability of consumers to respond to five transmission determinations concurrently was raised by the MEU. See MEU, Second Interim Report submission, p.14.

5 Pricing and procurement under optional firm access

Summary of this chapter

Determining the charges that generators would pay for access is an important part of the optional firm access model. Access prices would be calculated using a long run incremental costing method. Although complex, we are of the view that it is the best of the available options.

There are challenges associated with the method, particularly the use of long term forecasts of network usage. However, it gives more efficient price signals than the alternative pricing methods. It sends better signals about the value of spare network capacity and would therefore assist generators in making efficient decisions about where to locate new power stations.

The alternative pricing methods deliver efficient prices (ones that appropriately value spare capacity) only in the special cases that there is no expectation of growth (deep connection charge) or an expectation of very high growth (LRMC). Any access price *implicitly* contains a forecast – and will give inefficient signals when that forecast differs significantly from actual growth. Better price signals will be achieved by *explicitly* taking a view of the future and using the best information available – forecasts that recognise that growth varies over different parts of the network and over time.

We suggest a possible access procurement process in which TNSPs would assist generators by providing information on how access charges would vary with different locations and access quantities.

We describe secondary trading mechanisms through which generators could transfer firm access from one power station to another.

5.1 Introduction

Access pricing determines the charges that generators would pay to TNSPs for the firm access service. Access prices would be based on a long run incremental costing methodology, which is described in section 5.2.

Generators would use the procurement process, described in section 5.3, to agree new or additional firm access.

They could also procure short-term firm access through the auction described in section 5.3.2, or transfer firm access between power stations using the secondary trading mechanisms described in section 5.3.3.

5.2 Access pricing

Providing new or additional firm access is likely to increase the network capacity that the TNSP would be required to provide under the firm access standard, either immediately or at some point in the future (where existing spare capacity could be utilised in the interim), thus imposing new costs on the TNSP. The OFA model would require the firm generator to pay an amount to the TNSP that covered these incremental costs. The purpose of *access pricing* is to estimate what these costs are. To provide financial certainty for firm generators, the charge to be paid by the firm generator would be calculated and agreed during the access procurement process, and fixed for the life of the agreement.[87]

Access pricing would provide a locational signal to generators that is not part of the current arrangements. The access charges paid by firm generators would be *cost reflective* – capturing the incremental transmission costs that are created by their decision to locate in a particular part of the network (or to request additional firm access in the case of an existing generator). The intended outcomes of the pricing methodology that is described below are that, other things being equal:

- generators locating remotely from the Regional Reference Node (RRN) and from other major demand centres would pay a higher price than generators locating closer to the regional reference node or demand centre; and
- generators locating where there is limited spare transmission capacity and where expansion would be required immediately would pay a higher price than generators locating where there is plenty of spare transmission capacity and where no expansion would be needed for some time.

These signals should promote more efficient use of the existing network and, by exposing generators to the long-term transmission costs associated with their locational decision, help to co-optimise generation and transmission investment.[88]

A consistent pricing methodology, to be applied across the NEM, would be developed in detail during implementation of the OFA model.

5.2.1 Long run incremental costing methodology

Transmission planning is a long-term process and it would not be sufficient to simply calculate the *immediate* cost of the extra expansion required prior to new access rights commencing. The new access may cause a *future*, already planned, expansion to be brought forward. The capital cost would remain the same, but the advancement means that, after applying a discounting rate, there would be an incremental cost in net present value (NPV) terms. A methodology in which *all* incremental costs are calculated – present *and* future – is referred to as long run incremental costing

[87] Except for some defined indexation.

[88] For further discussion, please see chapter 8.

(LRIC).[89] Long run incremental costing forms the basis for the access pricing approach.

Long run incremental cost is the difference between two costs:

- the baseline cost, which is the NPV 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 NPV of the adjusted expansion plan - that is, an amendment to the baseline expansion plan to accommodate the new access request.

LRIC = adjusted cost – baseline cost

The expansion plans would be derived using a *stylised* methodology which, by assuming away some of the complexity inherent in transmission planning, should provide stable and smooth expansion outcomes. The methodology is unlikely to capture every aspect of the network and would involve some judgements about future outcomes, but within these limitations it would be a robust basis for determining access charges.

To ensure that the calculated long run incremental cost was nevertheless realistic and representative of actual expansion costs, critical features that determine long run incremental cost characteristics would be reflected in the methodology. These features include: the measurement of *existing spare capacity*; the *lumpiness* of transmission expansion; the *topology* of the existing transmission system; and the *background growth* of demand and firm generation.

A stylised example of how the long run incremental cost would be calculated is provided in the following two figures. Figure 5.1 represents the baseline expansion plan for a single element of the shared transmission network, such as a transmission line or network transformer. Its expansion plan has three drivers:

1. initial spare capacity – the amount of spare capacity on the element in the base year;
2. annual flow growth – the amount by which maximum flows on the element increase each year; and
3. lumpiness – the amount of capacity that would be added through the efficient expansion of that element.[90]

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89 See section 6.3.1 of the Technical Report for a discussion of the alternative charging methodologies, long run marginal cost (LRMC) and deep connection charging, and why long run incremental costing has been preferred.

90 With electricity transmission, it is not practical to add capacity in very small increments. Economies of scale mean that it is efficient for capacity to be added in "lumps", reflecting the "off-the-shelf" nature of transmission assets. This often results in a transmission upgrade providing a greater increase in capacity than is, initially, required.

The initial spare capacity would be eroded as the forecast flow increased on the element, typically through an increase in the demand for electricity over time. As soon as the spare capacity was forecast to be exhausted, the element would be expanded in a scale efficient "lump". That expansion would provide new spare capacity, which would be progressively eroded through subsequent flow growth until, eventually, a second expansion was required, and so on.

Figure 5.1 Baseline expansion plan for a network element

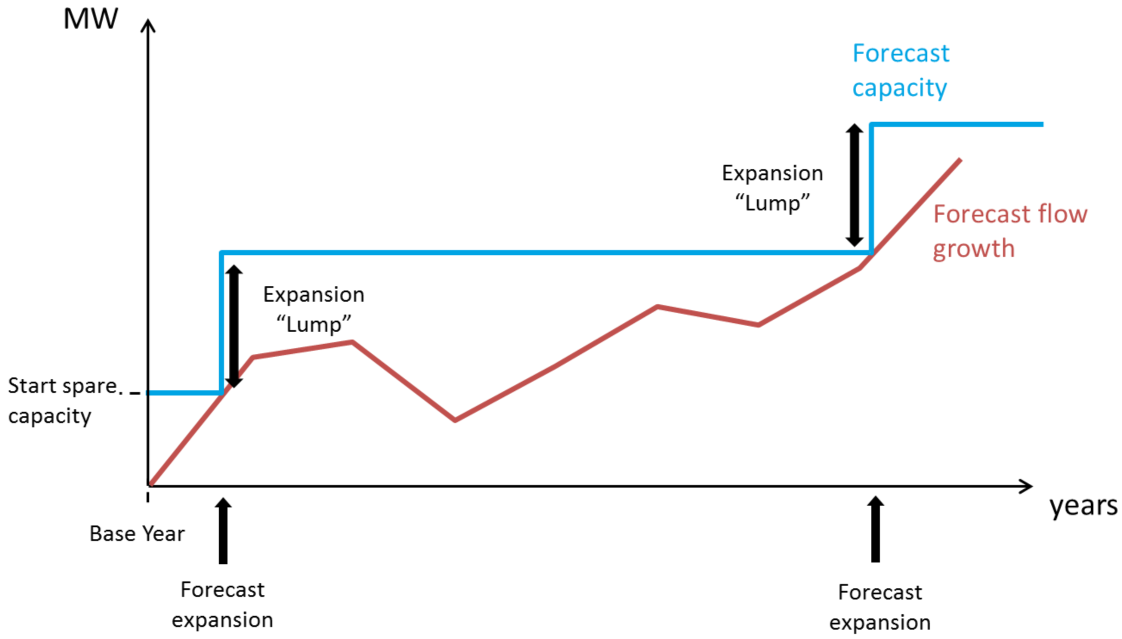
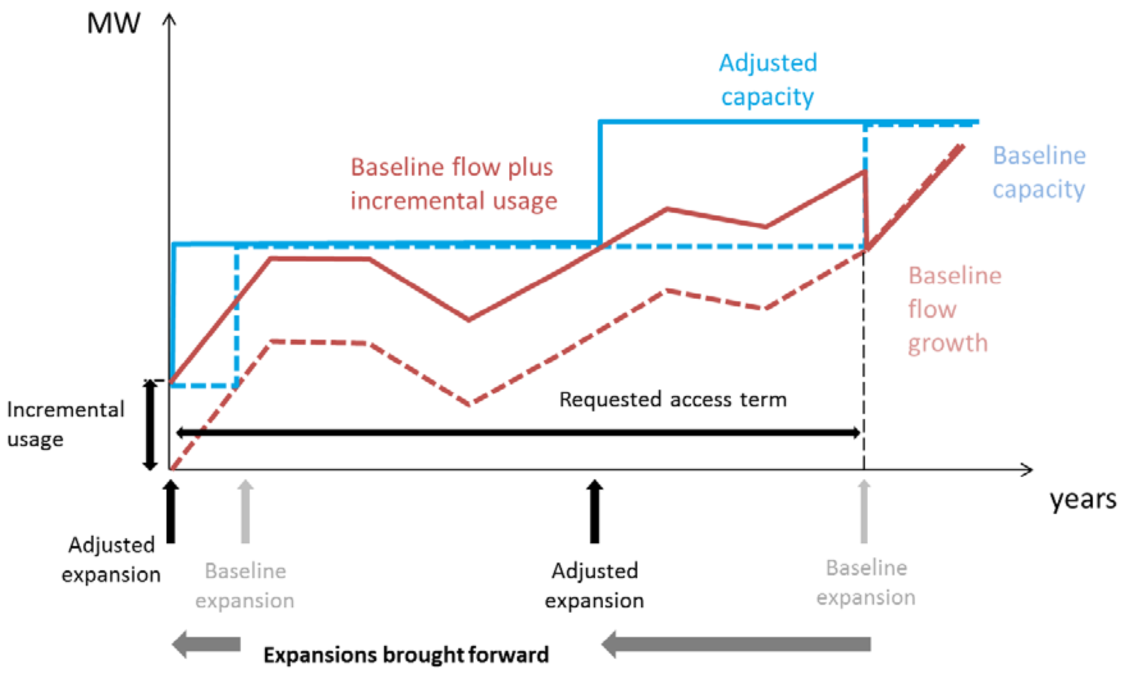


Figure 5.2 illustrates how the request for additional access would result in an adjusted expansion plan for the network element. The effect of the access request is to increase the forecast flow on the network element, and therefore to bring forward the already planned expansions by varying amounts. To model the adjusted expansion plan, two things need to be represented:

1. incremental usage: the extra flow induced on the element by the access request; and

2. access term: the period of the access request and so the period for which the extra flow occurs.

Figure 5.2 Adjusted expansion plan for a network element



The baseline cost and adjusted cost are then calculated by applying an appropriate discount rate to the capital costs implied by the corresponding expansion plans. The access price is the difference between these two costs, summed over all transmission elements in the network.[91]

The access pricing methodology is based on a highly stylised model of transmission expansion which, nevertheless, is expected to broadly reflect the characteristics and levels of a true long run incremental cost forecast. It is designed to provide smooth, transparent and robust prices which would guide efficient generator behaviour whilst covering the cost to TNSPs of providing firm access services.

5.2.2 Medium-term and long-term forecasting

The access pricing model and the background forecasts that drive it would be managed and maintained by the National Transmission Planner. TNSPs or a central pricing agency would use the model – or a faithful copy of the model – to calculate access prices.[92]

Efficient prices would require accurate, objective and transparent forecasts.

Short-term firm generation forecasts would be based on current access agreements and requests.

91 In practice, incremental usage will only be material on a subset of elements, and so the long run incremental cost on only these elements needs to be calculated and summed.

92 The appropriate body to calculate access prices would be determined during optional firm access implementation.

Medium-term forecasts of flow growth would be based on forecasts of end-user demand and firm generation. These forecasts would be based on the NTNDP, which is the product of an open and transparent process, or other similar information developed and published by AEMO.[93]

To simplify the access pricing model, and to avoid spurious accuracy, forecast flows would be *stylised* rather than *precise* beyond a certain point (say 10 years out).[94] The pricing model must cover many years into the future, given the long-lived nature of transmission assets and the relatively low discount rate applicable to network businesses. On the other hand, forecast flows become increasingly uncertain into the future, and discounting diminishes the influence of longer-term forecasts. There comes a point at which the inclusion of detailed forecasts creates the appearance but not the substance of improved accuracy.

Long-term forecasts should therefore assume a fixed rate of growth, rather than being calculated on explicit demand and generation forecasts. The assumed rate could be standardised for different types of elements, eg a higher rate for core elements - those located on major flowpaths - and a lower rate for local elements.

The point of delineation between explicit medium-term forecasting and stylised longer-term forecasting should be defined during the implementation process.

5.2.3 The value of spare capacity

One important property of the long run incremental costing method is that it appropriately values spare transmission capacity. It ensures that generators pay for the capacity they use, whether that capacity is developed especially for the generator (where its access triggers an immediate expansion) or was provided by an earlier lumpy expansion.

Any new access will change the amount of spare network capacity. If the new access prompts immediate lumpy expansion, the amount of spare capacity is likely to increase, as the lumpy addition will typically exceed the new access requirement. Alternatively, if no immediate expansion is required, the amount of spare capacity must decrease, as some of it is now being used to provide access.

Although spare capacity is, by definition, currently unused, it is likely to have some value due to the possibility of it being used to provide some future access. Because of discounting, this (net present) value depends upon how quickly that future use occurs which, in turn, depends upon the current amount of spare capacity and the anticipated rate of flow growth. If spare capacity is high and/or flow growth low, future use will be distant and so net present value low.

93 Section 4.5.3 recommends that AEMO produce "bottom up" demand forecasts. These could potentially be used in the model.

94 This change also responds to stakeholder concerns that access prices could be subject to manipulation through the forecasts that underpin the baseline expansion plan. See: AER, Second Interim Report submission, p.8.

The long run incremental costing method *charges* the access-seeking generator the value associated with any *reduction* in spare capacity: when there is no immediate expansion, the access charge reflects the opportunity cost (in present value terms) of using the spare capacity to provide access to that generator rather than to a future access seeker. It *credits* the generator with the value of any *increase* in spare capacity in the form a discount to the access price: when there is an immediate expansion, the access charge reflects the cost of the expansion minus the (present) value of the additional spare capacity providing future access.

As a special case, the long run incremental cost will give a zero charge where existing spare capacity is sufficient to meet the access request, and that capacity is estimated to have zero value - because it is not expected to be used for future access.[95]

Figure 5.3 illustrates how the incremental access price (incremental cost divided by the incremental usage) varies with forecast growth for a single network element. The *LRIC local* curve represents the access price on a local network element, where forecast growth is lower. The *LRIC core* curve represents the access price on a core network element, where forecast growth is higher.

On the left hand side of the figure, spare capacity is plentiful: incremental usage is less than initial spare capacity. No immediate expansion is triggered, and the price reflects the value of existing spare capacity. On the right hand side of the figure, spare capacity is insufficient: incremental usage is greater than initial spare capacity. An expansion "lump" is triggered, and the price reflects the value of the new spare capacity that is created.

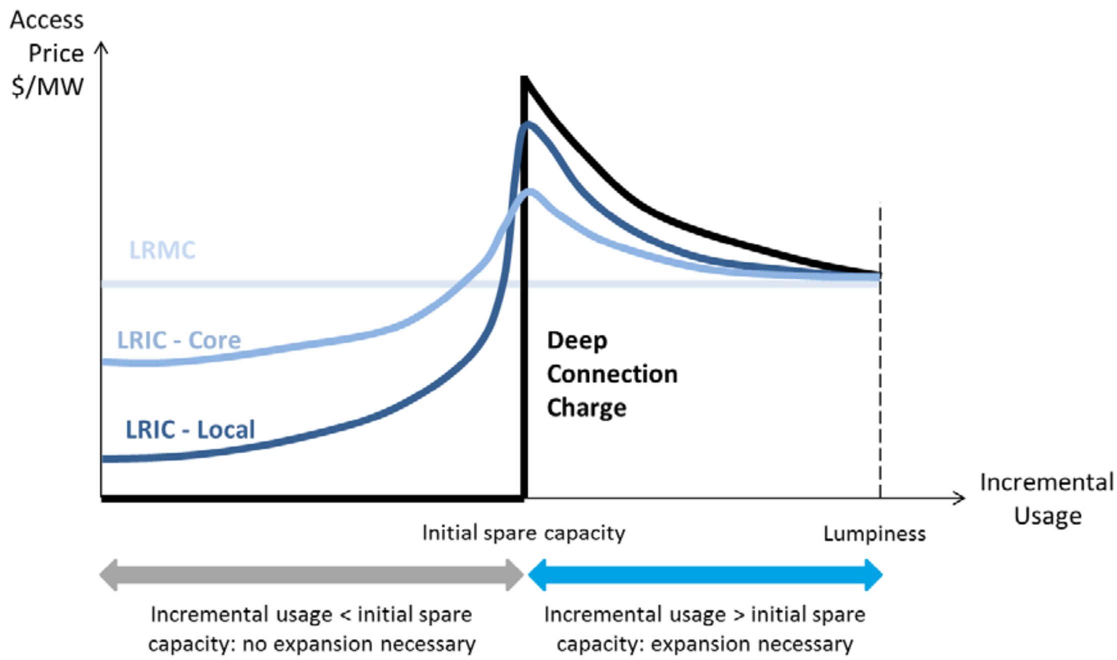
For comparison, two other charges are illustrated:

- A deep connection charge, where the access price is either zero (incremental usage is less than initial spare capacity) or the full expansion cost (incremental usage exceeds initial spare capacity), which decreases on a per unit basis as incremental usage increases.

- A long run marginal cost (LRMC), which ignores spare capacity and charges a constant unit cost regardless of incremental usage, based on the average unit cost of capacity expansion.

95 This will also be the outcome where a generator seeks firm access in a part of a network where a generator previously held firm access, that access has expired (or the generator has closed down) and no future firm access is forecast in that location.

Figure 5.3 Comparison of access prices with different growth forecasts



It can be seen from the figure that:

- Where spare capacity is plentiful (incremental usage is less than initial spare capacity), a higher forecast growth assumption *increases* access prices. On the left hand side of the figure, the *LRIC core* curve (representing higher forecast growth) is *higher* than the *LRIC local* curve (representing lower forecast growth). There is a greater opportunity cost in using spare capacity when future use is near because flow growth is high.

- As spare capacity becomes scarce (incremental usage approaches initial spare capacity), the access prices delivered by the long run incremental costing method increase.

- Where incremental usage triggers an expansion (incremental usage exceeds initial spare capacity), a higher forecast growth assumption *decreases* access prices. On the right hand side of the figure, the *LRIC core* curve is *lower* than the *LRIC local* curve. There is greater value in the spare capacity that is created when future use is near, and so a greater discount to the current access seeker.

- In the special case that there is zero forecast growth on an element, then the long run incremental costing access price would be the same as the *Deep connection charge* curve.

- In the special case that there is very high forecast growth on an element, then the long run incremental costing access price would approach the *LRMC* curve.

- In the special case that incremental usage equals the expansion size then all three pricing methods deliver the same charge. In this case, the amount of spare capacity is unchanged and so the value of the *change* in spare capacity is zero. Therefore the access charge simply reflects the expansion cost.

In conclusion, except in the special cases listed above, only the long run incremental costing method appropriately values spare capacity. The alternative pricing methods deliver efficient prices (ones that appropriately value spare capacity) only in the special cases that there is no expectation of growth (deep connection charge) or an expectation of very high growth (LRMC). In other words, any access price *implicitly* contains a forecast – and will give inefficient signals when that forecast differs significantly from actual growth. Better price signals will be achieved by *explicitly* taking a view of the future and using the best information available – forecasts that recognise that growth varies over different parts of the network and over time.

5.2.4 Central pricing is not central planning

Ideally, access prices would be set by the market, like wholesale energy prices, rather than determined administratively. Of course, this is not possible, as TNSPs are monopolies and so there can be no competitive market for access provision. Thus, access pricing must be highly regulated, just as demand-side transmission charging is currently.

The fact of regulated prices, together with the way they are predicated on a central forecast of demand and generation, has led to concerns from some stakeholders that access pricing amounts to central (transmission) planning by stealth, contrary to the objective of the optional firm access model that transmission planning should, on the generation side, be more market driven.[96]

It is acknowledged that prices will affect generator decisions and so centralised pricing necessarily establishes a central influence on generation. However, this does not make it central planning, which usually refers to a command and control approach to generation investment.

A more specific concern is that generation outcomes will reflect the forecasts embedded in the pricing method, making these forecasts a self-fulfilling prophecy: whatever scenario is used in the pricing model will eventually come about, because the prices guide generators to follow it. This concern reflects a misunderstanding of the characteristics of prices with long run incremental costing and the influence of forecasts on these.

For access forecasts to be self-fulfilling, higher levels of forecast firm generation at a location must lead to lower access prices, thus encouraging more generators to locate there. However, Figure 5.3 shows that the impact of higher load flow growth on an element is to flatten the long run incremental cost curve (eg moving from *LRIC local* to *LRIC core*). The flattening may result in either higher or lower access prices, depending on the access request and the level of spare capacity. In particular, on elements with

96 See: NGF, Second Interim Report submission, p.2.

high levels of spare capacity, higher flow growth leads to *higher* prices. Thus, the forecasts in this situation become self-denying rather than self-fulfilling.

5.2.5 Access prices are not project plans

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

- TNSPs would always plan to meet the sum of all their obligations - under both the firm access and reliability standards. The most efficient way of meeting the combined set of obligations may be quite different from the plan to meet a single access request.
- The pricing model is a stylised network representation which would not include every network connection and element. It is not intended to be an actual network planning model.
- Access prices would be fixed for the life of the access agreement. Network plans (appropriately) change over time, as information - such as demand forecasts - changes.[97]

Nevertheless, the pricing model should deliver robust, transparent and efficient prices that deliver broadly the revenue to cover TNSPs expansion costs in meeting firm access requests. Furthermore, for the reasons given in section 5.2.3 it is better than the alternatives that do not explicitly take a view about future network use.

5.2.6 Access prices and reliability access

Where total firm generation fell short of peak demand, TNSPs would be required to provide some access to non-firm generators in order to meet reliability standards. We term this *reliability access*. The more firm access there was, the less reliability access TNSPs would generally have to provide. Firm access therefore creates an indirect saving to the TNSP.

The pricing method does not attempt to estimate and include the saving to the TNSP in the access price. In fact, care is taken to exclude it.[98] Some stakeholders have questioned whether this is appropriate, and whether access prices would be too high as a result.[99] At the extreme, if no generators procured firm access, TNSPs might provide generators with the same amount of access they would have paid 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

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97 See section 7.2.2 for discussion of discrepancies between access charges and TNSP costs.

98 See section 6.2.4 of the Technical Report.

99 See: NGF, Second Interim Report submission - Frontier Economics attachment, p.20.

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 consider that the least distortionary outcome should be sought.

We have therefore rejected the option of generators only paying for the access that is incremental to what would have otherwise been provided to meet reliability standards (ie receiving an explicit discount for providing reliability access).

Instead, two mechanisms are likely to deliver cheaper access to generators as a result of reliability access:[100]

1. The first mechanism takes place automatically in the long run incremental costing method, since the presence of the reliability standards – and the extra transmission capacity associated with them – will automatically lead to higher levels of spare capacity and so lower access prices.

2. 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 through the auction process described in section 5.3.2.[101] These auctions are likely to clear at prices less than the long run incremental cost. So, the short-term auction process is a way of converting reliability access into discounted firm access, for those generators prepared to pay the auction prices.

5.2.7 Demand-side transmission charging

Over the course of the review, we have also considered some related issues with transmission pricing for load. In particular, in the same way that our proposals aim to provide robust arrangements to promote efficient investment in the network across regional boundaries, the transmission frameworks should also promote the efficient use of the network across regions.

To date, the costs of all network augmentations in a particular jurisdiction have been paid for by consumers in that jurisdiction. Any consumers in a neighbouring region that may benefit from such an augmentation have not been exposed to any of the costs associated with it.

This issue has recently been addressed by a rule change made in response to a request made by the MCE. This implements a system of inter-regional transmission charging

100 A third possible mechanism could be considered at a later stage to extend the philosophy of market-led development to the reliability side of the network. This is the reliability access safety net, where TNSPs would be responsible for "topping up" reliability access over and above that demanded by generators. This is described in section 6.3.8 of the Technical Report.

101 Although we expect that most short-term access issuance would arise from TNSPs' operational decisions.

referred to as “load export charging”.[102] While this significantly mitigates the issues considered in the review, the scope of the rule change was necessarily limited. In particular, under load export charging:

- inter-regional charges would be uniformly recovered from all consumers within an importing region, as opposed to being targeted at beneficiaries;
- consumers would not contribute to the costs of assets from which they benefit in non-adjoining regions; and
- inconsistencies in charges between regions, and between intra- and inter-regional charges, would be maintained, distorting the cost reflectivity of transmission prices.

Given the broader remit of the Transmission Frameworks Review, we canvassed the views of stakeholders with regards to the introduction of a national pricing approach, which would address these issues.

A crucial part of this scheme would be the identification and appointment of a single central agency to administer it. We consider that AEMO would be uniquely qualified to take on this role, being familiar with the transmission system across the NEM through its role as NTP. Its core competencies include calculating and settling financial transactions as market operator. It also uses Tprice (the software used by TNSPs to calculate TUOS charges) to set loss factors. However, discharging this function would be inconsistent with AEMO’s current role in Victoria, as AEMO would be both determining and receiving charges for that jurisdiction.

This issue would be addressed under the optional firm access model, since a key feature of the model is for-profit TNSPs having responsibility for investment in all jurisdictions. AEMO’s overarching role to facilitate and drive coordination under the optional firm access arrangements would then be consistent with it adopting responsibility for the calculation of transmission prices on a national basis.

We therefore recommend that, during the optional firm access implementation process, the approach to transmission pricing for load be reviewed:

- in light of the experience that will have been gained in relation to the practical application of load export charging; and
- to ensure consistency with the long run incremental costing methodology.

5.3 Access procurement

Through the procurement process, a generator could procure new or additional firm access service, by entering into an access agreement with the TNSP in its region (the local TNSP). The generator would seek the combination of firm access amount, location

102 AEMC, *National Electricity Amendment (Inter-regional transmission charging) Rule 2013*, Rule Determination, 28 February 2013.

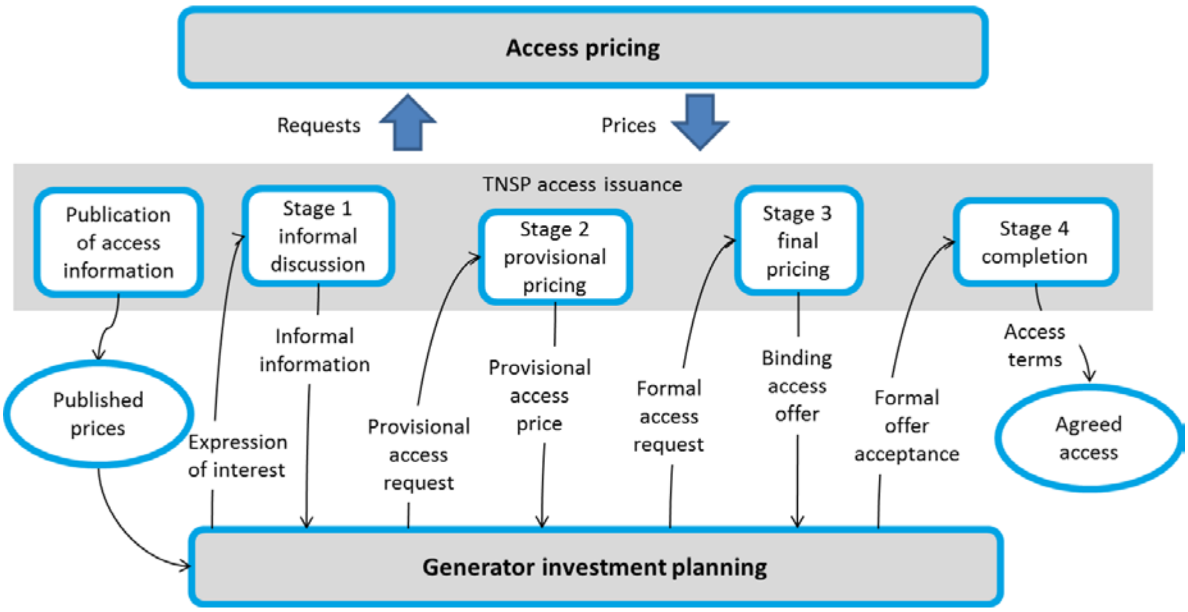
and duration that best met its needs and for which it was prepared to pay the associated firm access charge.[103] Primarily, the procurement process would involve information exchange rather than commercial negotiation.[104]

TNSPs would be able to specify the earliest date that the access term could commence, to give time for necessary network expansion.

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 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.

Access pricing and procurement interact, since prices depend upon existing and prospective access agreements. Therefore, each access request or agreement may affect the pricing of other, concurrent requests. The procurement process would need to be structured to manage these interactions so as to avoid placing undue risk and uncertainty on generators or TNSPs. A possible process is illustrated in Figure 5.4.

Figure 5.4 Possible access procurement process



Generators would be able to withdraw from the procurement process at any stage until the agreement was finalised. They would be liable for the costs incurred by the TNSP

103 Determined through the access pricing process described above in section 5.2.

104 In principle, it may be desirable that service parameters could be customised by mutual agreement, to the extent that this did not adversely affect other transmission users (other than non-firm generators). For further discussion see section 7.3.5 of the Technical Report. However, customisation would create complexity; the degree of customisation permitted would need to be determined in later stages of the project.

in providing information and prices. TNSPs would be required to provide information in a timely fashion, and in good faith.

It may be possible to make the pricing model described in section 5.2 available for prospective firm generators to use independently, albeit informally, to help in deciding on their location and access level. That might reduce reliance on TNSP input: substantially in stage 1, above, and partly in stage 2. However, the ordering of access requests and the formal making and acceptance of an access offer would still rely on TNSP involvement.

Stage 1 access requests would be confidential. Progress in later stages would be published to ensure transparency of the ordering and pricing processes. Once agreed, service parameters would be published. Whether details of access charges, payment arrangements and any customisations of service parameters were published would need to be considered further.

5.3.1 Grouped access procurement

Generators could be permitted to procure access in a group rather than individually. Access would be awarded to each group member in the same way as if they had applied individually. However, the TNSP would calculate a single access charge, based on the cost of the group's aggregate access. The group members would need to reach agreement on how to divide up this charge between themselves and then agree – in their access agreements – to make their respective payments to the TNSP.[105]

The major benefit of grouping to a generator would be to share the cost of a lumpy expansion, where the access price calculation attributes most of this charge to a new generator.[106] In that situation, the first generator may be the instigator of the grouping. The benefit to a TNSP of grouping would be avoiding the difficulty of managing concurrent and inter-related access applications.

5.3.2 Short-term access auction

As outlined in section 3.4, TNSPs could offer short-term access. This would only be offered for a quarterly period, and would be issued through an open auction process. TNSPs could undertake either capital or operational activities to release short-term firm access. Additionally, existing spare capacity on the network - that already exists without the TNSP undertaking operational activities - could be used to back short-term access.

105 If a group were large, involving several major generating companies, such an agreement might require Australian Competition and Consumer Commission (ACCC) exemption or authorisation in order to avoid breaching competition law.

106 For example, because additional use of the asset by future generation is not anticipated in the access pricing forecasts.

The auction would run by the relevant TNSP. It would be advantageous if a common approach could be taken across the NEM, with simultaneous regional auctions.[107]

We consider that an auction for access can be considered analogous to a dispatch process in which:

- access allocated to each generator is analogous to its dispatched output;
- the TNSP "restriction" is analogous to the flowgate constraints placed on dispatch; and
- dispatch offers reflect bids and offers made in the auction.

Each TNSP would decide the amount offered in the auction and any reserve price associated with it. The TNSP would develop "restrictions" determining the amount offered themselves – which would be different to those constraints used by AEMO in NEMDE. For example, if the TNSP considered that it could re-rate a line to create additional capacity that could be used for short-term access, then this would be reflected in the restrictions contained in the auction. These restrictions would also reflect any existing spare capacity in the network that TNSPs decide to back short-term access.

The TNSP would also decide any associated reserve prices. Continuing on the above example, the TNSP would set a reserve price that reflected the costs of re-rating the line to create additional capacity for short-term access. Reserve prices associated with existing spare capacity would necessarily be lower – since less TNSP expenditure would be required.

In the auction, participants would submit bids and offers, representing maximum quantities they wish to buy (or sell), and maximum or minimum prices at which they wish to buy (or sell). These would be converted into equivalent dispatch offers.[108] An economic dispatch would be calculated, using these dispatch offers together with the necessary flowgate "restrictions".

5.3.3 Secondary trading

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. There would be two alternatives for such secondary trading:

- a bilateral agreement, subject to relevant approval by the relevant TNSP - for permanent or short-term trades; or
- the short-term auction described above – solely for short-term trades.

107 Another option would be to combine this with the auction of short-term inter-regional access. This would potentially better facilitate the issuance of short-term access.

108 See section 12.6.3 of the Technical Report.

Any trade would need to be notified to the relevant TNSP, which would be entitled to levy fees to recover reasonable costs incurred.

Bilateral transfers

If a bilateral transfer was to a different generating company, that company would acquire the obligation to make any future access payments specified in the access agreement, together with any prudential obligations. If only part of the access was transferred, payments would be shared pro rata between the two generating companies. The TNSP would need to establish prudential arrangements to ensure that these payments were made, which may differ from those applying previously.

Transfers between power stations connected at the same node would be relatively straightforward and would not require TNSP approval. The stations would require the same access to constrained parts of the network, so could be substituted for one another in access settlement, and should not impose any additional obligations on the TNSP under the firm access standard. The exception would be transfers from a super-firm generator to a non-firm or part-firm generator, which could trigger an immediate increase in the TNSP's obligations.[109] Nonetheless, TNSPs would be expected to manage their networks to permit such transfers, and would not be permitted to prevent or delay them.

A bilateral transfer to a power station at a different node would be more complex: because the power stations require different access to constrained parts of the network, the transfer may increase the capacity the TNSP was required to provide on some flowgates, and reduce it on others. Mechanisms would need to be designed to protect the TNSP from an increase in its obligations without corresponding compensation.[110] If the access transfer led to a requirement on the TNSP to change its transmission expansion plans, the transfer could be delayed by the TNSP to give reasonable time for this to occur.

Auction-based transfers

Firm generators would be permitted to participate - as sellers - in the short-term access auction that is run by the TNSP. They would offer some or all of their access amount on a short-term basis (ie one quarter in advance), alongside the TNSP offers. Generators would be able to offer any amount up to their pre-auction agreed access level for the specified term and node.

Generators bidding for short-term access might then either buy from the TNSP or from a firm generator, depending upon which offered the desired access at the better price. Given that all auction sales would be settled through the TNSP, it would be transparent to the buyer whether the source of their access is the TNSP or another generator.

109 See section 5.3.3 of the Technical Report.

110 A possible mechanism is explored in section 7.2.5 of the Technical Report.

For the auction, flowgate constraints would be placed on the auction clearing process to ensure that any transfers between nodes - in aggregate - did not create any additional requirements on the TNSP. This mechanism is discussed in section 5.3.2.

Following the auction, payments between buyer and seller would be made immediately - settled through the TNSP - so there would be no ongoing prudential implications. Auction bidders would need to satisfy some form of credit requirements before participating in the auction.[111] Notwithstanding that a firm generator may have sold some of its firm access into the auction, it would still be required to make the same contractual payments to its TNSP.

111 Similar to current requirements for participants in SRA auctions.

6 Inter-regional access

Summary of this chapter

This chapter describes inter-regional access. In the OFA model 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 SRA units that are available for purchase, and so the OFA product would give generators and retailers greater confidence to trade across regional boundaries.

In order to facilitate the allocation of inter-regional access we have developed a process that draws heavily on the current approach to obtaining SRA units – an AEMO-run auction. However, unlike the current process, as well as allocating existing capacity, this would also determine the future expansion of inter-regional capacity. We have developed a two-stage process to achieve this:

- the first stage of the allocation and expansion process involves AEMO running an auction for inter-regional access on interconnectors, offering access in quarterly blocks; and
- where a potential expansion signal has been received, the second stage involves the relevant TNSPs undertaking a joint investment test on the upgrade of the interconnector in question.

6.1 Introduction

One of the key problems with the current transmission arrangements is the lack of firmness of the existing inter-regional product, which can be used to hedge some price differences between two regions. Generators risk not being able to get paid the price difference, particularly at those times when this would be most important. This impedes inter-regional trade, potentially reducing competitive pressures on both generators and retailers in a given region. An overview of how this problem can be resolved under OFA through the offering of a *firm* inter-regional access product is provided in section 6.2.

This chapter then sets out how the inter-regional access product would operate, including:

- what the inter-regional access product is (section 6.3);
- the inter-regional settlement process (section 6.4);
- how the firm access standard would operate (section 6.5);
- inter-regional pricing (section 6.6); and
- the inter-regional expansion and allocation process (section 6.7).

6.2 Overview of inter-regional access

Generators face "basis" risk when trading between regions, which have different prices as set at their regional reference nodes.[112]

Currently, one way that generators can partially hedge against this risk is to purchase the right to a share of the inter-regional settlements residue (IRSR) that accrues when prices between regions separate – see Box 6.1. Such rights are known as settlement residue auction (SRA) units, after the auction that AEMO holds every quarter. SRA units do not, however, provide a perfect hedge for inter-regional basis risk – this is discussed more fully in section 8.2.

Box 6.1: Inter-regional settlement residues

Inter-regional settlement residues occur when the prices between regions separate. Generators are paid at their regional spot price while retailers pay the spot price in their region. The difference between the price paid in the importing region (by retailers) and the price received in the exporting region (by generators), multiplied by the amount of flow across the interconnector is called a settlement residue.

That is:

inter-regional settlement residue = $(price_{\text{importing region}} - price_{\text{exporting region}}) \times$ *flow across the interconnector*

As can be seen from the equation above, the residues that accrue are directly dependent on interconnector flow. Therefore, anything that reduces the flow will reduce the payment to the holders of SRA units.

The optional firm access model introduces a firmer inter-regional access product, with provides efficiency benefits. There are also potential efficiency benefits from allowing interconnector parties to decide their levels of inter-regional access (just as there are efficiency benefits in allowing generators to decide their levels of intra-regional access).

Since the benefits of inter-regional access are potentially dispersed across a number of sectors (generators, retailers), representatives of all of these sectors should - to the extent possible - be allowed to gain access.

Further, inter-regional access must be included in the optional firm access model for reasons of design. Many transmission elements provide a combination of intra- and

112 Flow between two different regional reference nodes occurs on interconnectors. In dispatch and settlement, they represent the net flow between two regions. Interconnectors are, however, a conceptual representation of connection between two regions. In practice, the physical assets which provide the interconnection between two different regional reference nodes may also support flows within a region, apart from those transmission lines which actually across regional boundaries. There may also be several transmission pathways between two regions, which are represented as a single aggregate interconnector (apart from DC interconnectors, which are separately controllable and separately dispatched).

inter-regional access, which are represented in the model as hybrid flowgates.[113] To ensure that access settlement balances on hybrid flowgates, interconnector usage and entitlements must be defined, and interconnector access payments made by or received from the interconnector parties. So long as there are hybrid flowgates, it is necessary to include arrangements for inter-regional access as part of the OFA model.

The following sections provide a more detailed description of the inter-regional access product, and how it operates in practice.

6.3 Inter-regional access product

We have 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 (ie similar to current SRA units).[114]

Firm interconnector rights have the following features:

- they are issued through an open auction;
- they are offered on a quarterly basis;
- they are open for any market participants (eg generators or retailers) to purchase, enabling the demand for these access rights to be linked with the supply of inter-regional capacity;[115]
- the product offers firm inter-regional access from one regional reference node to another regional reference node;[116] and
- the product is available on both a short-term and a long-term basis.[117]

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113 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.

114 This would be the case where that price difference was positive. Note that access amounts would be scaled to determine entitlements using the same scaling process described in section 3.3.

115 Compared with intra-regional access, where only generators may purchase access rights.

116 Compared with intra-regional access, where access rights are from a particular node to the regional reference node.

117 This is the same as intra-regional access, where both a short-term and a long-term service is offered. However, for intra-regional access, short-term access is only available for the upcoming quarter. Inter-regional access is available in quarterly blocks, with the possibility of short-term access being made available over the upcoming three year period. This timescale is consistent with the current SRA auctions.

6.4 Inter-regional access settlement

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 under normal operating conditions (in accordance with the operational incentive scheme as discussed in section 7.3.1).

It is a notable effect of the model that this pool would always be positive, even where there are counter-price flows. Counter-price flows on interconnectors may still arise, where generators in the exporting region were in merit relative to the importing regional reference price, despite the exporting region having a higher regional reference price. Through the access settlement process, interconnectors would be compensated for any counterprice flows, preventing any negative settlements residue from arising.[118] The inter-regional access right would therefore be firmer than existing SRA units.

We note that the model used for inter-regional settlement would be the same as that used for intra-regional settlement. This is easily facilitated since intra-regional settlement needs to recognise inter-regional entitlements on flowgates where the underlying constraint has an interconnector term, as discussed above.

6.5 Inter-regional firm access standard

TNSPs would be required to maintain capacity on hybrid flowgates in accordance with the firm access standard, ie to meet the total of firm access requirements under normal operating conditions. Hybrid flowgates include interconnector entitlements. The issuance of inter-regional 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.

Although inter-regional expansion would typically be a joint project between two TNSPs, firm access standard obligations would nevertheless fall solely on the TNSP in whose region the congested flowgate was located.[119] As discussed, TNSPs would

118 This would therefore remove the current obligation on AEMO to intervene when there are counter-price flows and "clamp" interconnectors to prevent negative inter-regional settlements from exceeding $100,000.

119 Where the location was unclear - for example in the case of stability constraints - the firm access standard obligation would need to be allocated and managed through some agreement between the two TNSPs.

contribute to shortfalls of transmission capacity that resulted in entitlements being scaled back beyond what should be delivered under the firm access standard. Through access settlement, payments by the TNSP would be allocated directly to the generators affected. The TNSP payment would be equal to a proportion of the costs to firm generators resulting from the breach – this is discussed in section 7.3.1.

6.6 Inter-regional pricing

Prices for inter-regional access would be produced based on the standard pricing methodology that is used in intra-regional access, and that was described in chapter 4. This standard pricing methodology is based on a long run incremental cost, which calculates both present and future incremental costs associated with expansion.

We note that this is different to the recommendation presented previously in this review, which contemplated that there would be no standard pricing methodology to determine inter-regional access charges.[120] However, we consider that there are significant benefits with using the same standard pricing methodology.

The methodology 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 be *cost reflective* and so capture 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 more efficient use of the existing network. This also helps generators to better understand the inter-regional access product, since it is based on the same pricing methodology as for the intra-regional access service.

We also consider that the intra-regional pricing model could be easily adapted to be used for this purpose. This is because it needs to recognise inter-regional entitlements on flowgates where the underlying constraint has an interconnector term. However, we note that using the model to price firm interconnector rights may cause some complications for the expansion and allocation process.[121]

6.7 Inter-regional allocation and expansion process

There is a distinct planning process under optional firm access for inter-regional access products, which is described in this section. Here, planning is undertaken by both AEMO and TNSPs through the firm interconnector rights allocation and expansion process. This is different to the process for intra-regional planning that was set out in chapter 4.

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120 The Second Interim Report proposed that prices would be based on the actual project cost.

121 For example, since the long run incremental cost does not necessarily produce a monotonically increasing price schedule.

AEMO currently sells SRA units through a quarterly auction process covering a three-year period as outlined above. However, the auction does not link demand with supply. We have therefore sought to develop a clearly defined auction process to allocate firm interconnector rights that links demand and supply for existing and future inter-regional capacity and access. We have also sought to develop a process (and associated procedures) that is consistent with the procurement of and planning for the intra-regional access service. An auction is used since there are likely to be multiple generators seeking to procure inter-regional access concurrently – it is preferable to manage these collectively.

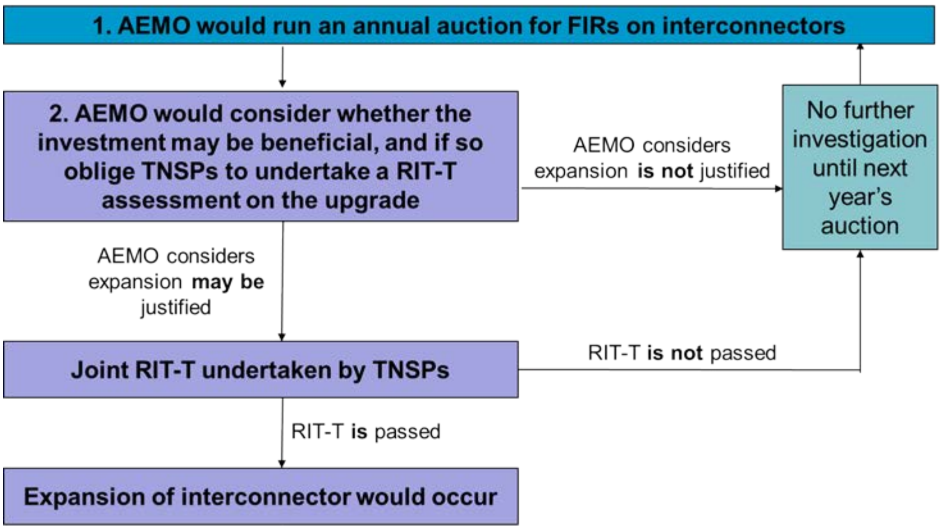
The allocation and expansion process occurs in two stages, which are illustrated in Figure 6.1 below:

- the first stage of the allocation and expansion process involves AEMO running an auction for inter-regional access on interconnectors, offering access in quarterly blocks; and

- where a potential expansion signal has been received, the second stage involves the relevant TNSPs undertaking a joint investment test on the upgrade of the interconnector in question.

These stages are briefly discussed below, with appendix B providing further detail on this process.

Figure 6.1 Inter-regional allocation and expansion process



6.7.1 Annual auction by AEMO

The first stage of the allocation and expansion process involves AEMO running an auction for inter-regional access on interconnectors, offering access in quarterly blocks. The auction would be designed to both allocate *existing* capacity, as well as signal interest in *expansions* of capacity. The auctions would therefore sell:

- existing spare capacity on the network ("baseline long-term inter-regional access") - this would be defined as any spare capacity up to a "baseline" level of capacity;[122]
- any spare capacity *above* the baseline that can be created through the TNSP making operational decisions ("short-term inter-regional access"); and
- potential future capacity ("incremental long-term inter-regional access") - this is defined as any additional capacity that can be created through *expanding* the interconnector, ie undertaking capital expenditure.[123]

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. However, the proportion of benefits accruing to parties other than these participants is likely to be higher for inter-regional investments than for intra-regional investments. Therefore, it is likely that benefits would exceed the bids from these – potentially justifying higher cost projects.

Accordingly, we propose that there would be a "filtering" process to identify those projects warranting further assessment. Those upgrades that can clearly not be justified (eg, if no bids demanding additional capacity are received) would be discarded. Where there was a reasonable chance that benefits would exceed costs, further investigation would be undertaken. This filtering and coordination role would be played by AEMO – consistent with its enhanced NTP functions and its role in running the auction. Where warranted, AEMO would direct the respective TNSPs to undertake a RIT-T assessment on the upgrade.

6.7.2 Assessment by TNSPs

The second stage involves the relevant TNSPs undertaking a joint investment test on the upgrade of the interconnector in question, where a potential expansion signal has been received. This is necessary since the auction is designed to elicit *demand* for *inter-regional* access, whereas the RIT-T focuses on the benefits associated with a *particular project*. This would consider the potential options available to the TNSPs that would result in the requested capacity being released.

This RIT-T would be conducted through a similar process as set out for the intra-regional RIT-T. As discussed in section 4.3 generator benefits (ie fuel costs, operating and capital costs) would not be included in the RIT-T, since this would result in double counting. If included, TNSPs would count private benefits that market participants had already accounted for in their bids.

122 The initial baseline capacity would be allocated in the transition process and so initial baseline capacity can be considered equivalent to transitional inter-regional access. See section 9.3.

123 This incremental long-term inter-regional access would become part of the baseline capacity following construction.

Following the passing of the RIT-T (ie benefits are greater than costs), TNSPs would be obliged to release the increased capacity. Inter-regional access rights would be allocated only to the successful market participant bidders, with total rights limited to the amount of inter-regional capacity provided by the expansion.

7 Revenue regulation and incentives under optional firm access

Summary of this chapter

This chapter discusses the regulation that would apply to TNSPs under optional firm access - both in terms of revenue and also quality incentive regulation.

Revenue regulation would aim to ensure that the combined revenue from load and firm access services was just sufficient to cover the efficient cost of delivering these services.

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

Quality incentive regulation is an important component of the optional firm access model since it influences the uptake of firm access by generators. There would be incentive schemes under optional firm access that would apply at the start of, or very soon after, the introduction of the optional firm access model - relating to the provision of all of types of access.

Generally, these would be low-powered incentive schemes, since we consider that low-powered schemes can result in large changes to TNSP behaviour. The schemes focus around exposing TNSPs to a share of any settlement shortfalls that may occur - incentivising TNSPs to provide an efficient amount of firm access.

7.1 Introduction

Firm access rights would be underpinned by transmission capacity on the shared network, the provision of which is a regulated monopoly. Since the shared network would be providing firm access as well as meeting customer load, the firm access service would be treated as a prescribed service, consistent with the current regulation of shared network services for customers.

As a result, there is a need to put in place appropriate regulation around the service. In addition to regulation around pricing and issuance (described in chapter 5), regulation for firm access would cover the following areas:

- revenue regulation (section 7.2); and
- quality incentive regulation (section 7.3).

7.2 Revenue regulation

Revenue regulation would aim to ensure that the combined revenue from load and firm access services was just sufficient to cover the efficient cost of delivering these services. Ensuring effective revenue regulation under optional firm access requires consideration of a number of areas, which are discussed in turn below:

- revenue allowances (section 7.2.1);
- recovery of revenue allowances (section 7.2.2); and
- uncertainty mechanisms (section 7.2.3).

7.2.1 Revenue allowances

The AER would determine an ex ante allowed revenue requirement for the TNSP, based on the efficient cost of building, owning and operating a shared network capable of providing current and forecast levels of load and firm access services to meet the relevant firm access and reliability standards.[124] This comprises setting both capital and operational expenditure allowances. The capital and operating expenditure associated with investments to meet reliability standards would be set as it is currently. Reliability investment expenditure is not considered any further.

Ex ante revenue allowances provide a strong incentive for TNSPs to minimise their costs over the regulatory period since TNSPs are able to profit by spending less than their allowed revenue allowance. Ex ante revenue allowances also provide incentives for TNSPs to reduce their overall costs by making trade-offs across their network and prioritising projects.

The allowance would take into account committed firm access. Most expenditure associated with meeting the firm access standard would be included in the allowance: existing access agreements (the majority of access) will have been entered into prior to the regulatory period.

In addition to the incentives provided by the ex ante allowance, investments would be subject to an ex post efficiency review. An efficiency review of past capital expenditure was established in the Economic Regulation of Network Service Providers rule change, including the ability for the AER to preclude inefficient expenditure from going into the regulated asset base (RAB) up to an amount that is equal to the amount of expenditure above the allowance.[125] Under our proposed incentive scheme (section 7.3.1) TNSPs face strong incentives, which should result in efficient decisions being made. Therefore, we consider that the efficiency review would be a last resort, and unlikely to be regularly used.

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124 Section 4.2 discusses the standards that TNSPs are required to meet.

125 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, Rule Determination, 29 November 2012.

In the next regulatory period the *actual* project cost of the investment would form part of the RAB (as opposed to an amount based on the access charges). If an operational decision is reached (or network support agreement entered into) then the economic regulation arrangements would ensure that the TNSP will have continuing access to a separately set operating expenditure allowance.

7.2.2 Recovery of revenue allowances

TNSPs recover their costs (as set in the revenue allowance) incurred in building and operating its transmission system from customers within its region. This occurs through recovering transmission use of system (TUOS) charges from customers. 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 estimated access revenue from the allowed annual revenue requirement, a cap on the TUOS revenue to users of load services would be derived. Aggregate revenue from firm access sales would not be capped; instead, firm access *prices* would be regulated, as discussed in section 5.2.

If the actual volume of firm access sales within a regulatory control period was less than forecast at the time of the revenue determination, the TNSP would recover less revenue: the TUOS cap would prevent the TNSP from recovering the revenue shortfall from demand-side users. This would be appropriate since the TNSP's costs would be correspondingly lower.

Similarly, the additional access charges received through the sale of higher than forecast levels of firm access would provide TNSPs with a broadly appropriate amount of revenue to cover the additional costs.

In relation to new access agreements entered into during the regulatory period, access pricing would be designed to ensure that incremental access revenue and costs were broadly matched, but they would not *exactly* match. The accuracy of the access charges as compared to TNSP costs will need to be considered further in OFA implementation.

There could be circumstances of revenue uncertainty to the TNSP during a regulatory control period where additional costs to the TNSP were either substantially higher or lower than the extra revenue: for example, where a particularly large expansion was required. There may also be a misalignment between when revenue is received and when costs would be incurred by the TNSP.

Given this, a mechanism would need to be developed in order to release revenue (and for the TUOS revenue cap to be adjusted upwards or downwards) in the current regulatory period to the TNSP associated with this uncertainty. Potential mechanisms are discussed in section 7.2.3 below. In the absence of such a mechanism this uncertainty would be borne by the TNSP - increasing its risk. However, this risk is removed in the following regulatory period since the actual project would be rolled into the TNSP's RAB.

7.2.3 Uncertainty mechanisms

There are two possible mechanisms for addressing this uncertainty discussed above:

- the existing contingent project mechanism (as contained in clause 6A.8 of the rules); or
- a revenue driver mechanism, such as that used in the UK (discussed below).

The contingent project mechanism is currently used when there is a degree of uncertainty if an investment is needed or not. A contingent project is a project which is considered by the AER as being reasonably required to be undertaken, but is excluded from the capital expenditure allowance since the requirement, timing or cost of the project is uncertain.

TNSPs propose expenditure for contingent projects in their regulatory proposals and the trigger events that would necessitate the project needing to be undertaken. Where a proposal for a contingent project has been accepted by the AER and a trigger event occurs during the regulatory control period, a TNSP may apply to the AER to amend the determination to include the forecast capital expenditure and operating expenditure for the project for the remainder of the regulatory control period.

The contingent project mechanism can only be applied to projects where the proposed capital expenditure for the project exceeds the larger of either $30 million or five per cent of the value of the maximum allowed revenue for the relevant TNSP for the first year of the relevant regulatory period.

This mechanism could be adapted to be used for access requests – the expenditure could be proposed in the regulatory proposal, with the trigger being an access agreement being entered into. There may need to be further consideration of the threshold values for contingent projects – potentially some projects to meet an access request may be smaller than the current thresholds.

The alternative would be to use revenue drivers - Ofgem in the UK uses revenue drivers as a mechanism to adjust revenue for a regulated business during a regulatory period. Revenue drivers are a means of linking revenue allowances to specific measurable events considered to influence costs, and are typically set on a dollar per unit of capacity basis.

For example, National Grid Gas has revenue drivers set that allow additional revenue to be released in response to demand for additional capacity backed by user commitment (which can be considered analogous to projects undertaken to meet firm access service requests). National Grid Gas earns the additional revenue driver amount for a fixed five year period. At the next regulatory determination, Ofgem reviews the expenditure to ensure that National Grid is appropriately remunerated going forward.

Both of these mechanisms have their advantages and disadvantages - therefore which specific mechanism should be used would need to be considered further in OFA implementation. However, we note the following:

- contingent projects are a well-established and understood mechanism in Australia, while revenue drivers may require more development in the Australian context;

- contingent projects require a project-by-project approval, whereas revenue drivers can be structured to apply more generally and so may be more useful in releasing additional revenue in response to uncertainty;

- contingent projects, as used currently, are only to adjust revenue *upwards*, ie not downwards – it is difficult to see how an equivalent mechanism to adjust revenue downwards would work in practice; and

- any conclusions reached in the review of the national framework for transmission reliability in relation to revenue regulation and contingent projects would need to be considered.[126]

7.3 Quality incentive regulation

Multiple submissions to the review have emphasised the importance of incentives to the optional firm access model. In particular:

- the AER strongly supported enhanced incentives that increased TNSP exposure to the consequences of their operational and investment decisions while avoiding creating excessive risks;[127] and

- the Victorian DPI commented that the TNSP incentives to operate and invest to meet the needs of the market and load are central to the effective operation of the OFA model.[128]

Incentive schemes address both of these concerns. In particular, high-powered incentive schemes would be seen by generators to *decrease* the risk of curtailment, and *increase* the likelihood of compensation.

Therefore, the transmission owner should be incentivised to perform multiple tasks, specifically:

- to plan, operate and invest in the network efficiently to meet both the firm access and reliability standards: facing appropriate incentives to build the efficient amount of infrastructure – including not to over or underbuild;

- to efficiently manage the trade-offs between operational and expansion of capacity considerations; and

- to maintain the transmission infrastructure and maximise the availability of capacity.

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126 AEMC, *Review of the national framework for transmission reliability*, Issues Paper, March 2013.

127 AER, Second Interim Report submission, p.7.

128 DPI, Second Interim Report submission, p.3.

The structure of the incentive schemes is an important component of the OFA model. In deciding whether or not to seek firm access, generators will consider the likelihood of the following occurring (when within the firm access standard):

- access curtailment; and
- receipt of compensation (both from other generators, and also the TNSP) if curtailment did occur.

As discussed by FTI Consulting[129] different incentive frameworks correspond to lower or higher-powered incentives. Emerging evidence in Australia suggests that TNSPs respond effectively to relatively low-powered incentives (eg the Service Target Performance Incentive Scheme (STPIS) under which TNSPs are exposed to a very small amount of their maximum allowed revenue[130]), ie low-powered incentives create large changes in TNSP behaviour. In general we consider that – in the first instance at least - incentive schemes should be relatively low-powered since this might significantly affect their behaviour, while still minimising risks on TNSPs.

However, in some limited cases there may be justification in exposing TNSPs to the full consequences of their decisions (ie face more high-powered schemes). The presence of high-powered incentives also requires appropriate indicators and incentives to be in place to ensure that TNSPs do not sacrifice service quality in their drive to reduce costs.

We recognise that the development of incentive schemes is a complex, and sometimes lengthy, process.[131] However, the Commission also considers that having effective incentives on TNSPs to maintain access service quality at or above the minimum standard specified in the firm access standard is an important feature of the model. Therefore, some incentives should be in place immediately or very soon after the introduction of the OFA model.

7.3.1 Proposed incentive schemes

Given the importance of incentives under the optional firm access model, we have developed a set of “strawman” proposals for potential low-powered incentive schemes that may apply. These schemes would be developed further in optional firm access implementation (in conjunction with the AER), but these proposals articulate a set of principles that would influence future development of schemes.

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129 FTI Consulting, *Critical Assessment of Transmission Investment Decision-Making Frameworks in the National Electricity Market,* April 2013.

130 The STPIS consists of three components. First, the service component, which has an incentive of +/- one per cent of maximum allowed revenue. Second, the market impact component, which has an incentive of zero to two per cent of maximum allowed revenue. Third, the network capability component, which provides an incentive of 1.5 per cent of maximum allowed revenue subject to completion of projects that improve the capability of the transmission network at times most needed.

131 For example, the STPIS was first introduced in 2007. It has been refined over time, with version four being published in December 2012.

In developing these proposals we have considered that there is a balance between providing a sufficiently clear framework that helps to provide investment certainty, but also sufficient flexibility for the AER to appropriately calibrate incentive schemes over time.

The two proposed incentive schemes that we have suggested are:

- an operational incentive scheme; and
- a short-term access incentive scheme.

Each of these incentive schemes applies to both intra- and inter-regional access products. We consider that these incentive schemes should be introduced soon after implementation of the OFA regime – ideally on day one.

Operational incentive scheme

The incentive would be 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. Through access settlement, payments by the TNSP would be allocated directly to the generators affected.

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) × shortfall value

The AER would set a sharing factor, ie “X” between zero and 100 per cent - based on an appropriate process as set out in the rules. “X” would likely start off low, and increase over time: sharpening incentives on TNSPs as they become more familiar with providing access. This is consistent with the Commission’s conclusions that relatively low-powered incentive schemes can have large effects on TNSP behaviour as stated above. A series of principles to be followed in setting "X" would be developed. They would be contained in the rules in order to guide the AER when setting this sharing factor.[132]

This 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 would be appropriate.[133]

132 The principles would be similar in nature to those principles specified in NER clause 6A.7.4(b) relating to the service target performance incentive scheme. This includes setting boundaries on the range of possible values that "X" could be.

133 A longer time period may result in too high an overall risk exposure, or mean that in any one year the cap may be set at a lower level than would be desirable from an incentive perspective. It may

A cap is necessary due to the large market price cap in the NEM. The market price cap is the maximum price at which generators can offer into the market, and is currently $12,900/MWh. It would only take several shortfall periods at the market price cap for a TNSP to be facing, and responsible for, a large settlement shortfall.

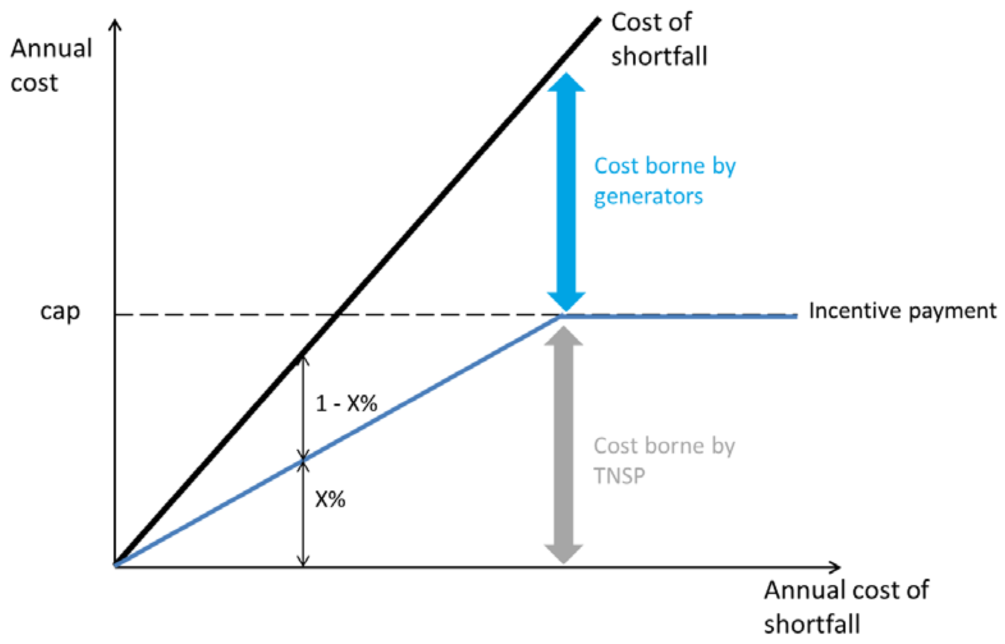
There are a number of principles that should be used by the AER in setting the cap. Specifically the cap should be set having regard to:

- the financial position of a benchmark-efficient TNSP;
- the impact of the risk on a benchmark-efficient TNSP, and its required rate of return to compensate for that risk; and
- creating sufficiently strong incentives for the TNSP to deliver firm access as efficiently as possible.

These principles would be included in the rules in order to guide the AER. We note that consideration would also need to be given to the interaction of caps set here, with the liability caps on TNSPs that exist through immunities in favour of NSPs under the NEL.

Figure 7.1 illustrates the operational incentive scheme. The cost of shortfall would be shared between TNSPs (X per cent) and generators through the scaling back of entitlements (1-X per cent) up until the cap was reached. Once the cap has been reached, the full cost of the shortfall is borne by generators (ie 100 per cent) – with the TNSP not liable for any shortfall anymore.

Figure 7.1 Operational incentive scheme



also be useful to define a cap by location or node to ensure that one breach does not exhaust the cap. See section 8.2.5 of the Technical Report for a more detailed discussion.

Lastly, we note that the above incentive scheme is asymmetric (there is downside risk without any associated upside); however, TNSPs would be able to earn additional revenue through sales of short-term firm access. As discussed in section 3.4 a TNSP could release short-term access where it could create additional capacity on the network. The associated incentive scheme is discussed below.

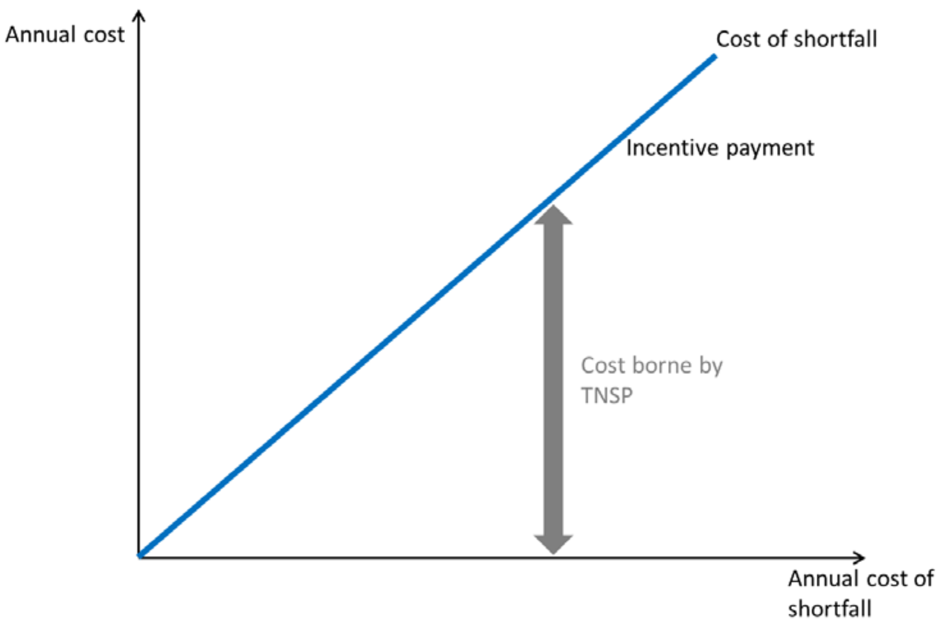
Short-term access incentive scheme

The aim of offering short-term access is to encourage TNSPs to undertake operational actions to promote the most efficient use of the network. In order to incentivise TNSPs to take steps to maximise the available capacity, they would retain 100 per cent of the revenue associated with the sale of short-term access.

However, in order to balance the upside that exists through this scheme - TNSPs would be 100 per cent exposed to any shortfalls that result from not providing short-term access that has been released. This exposure would not be subject to any cap.[134]

The short-term access incentive scheme is illustrated in Figure 7.2.

Figure 7.2 Short-term access incentive scheme



Another important driver for making TNSPs responsible for 100 per cent of their costs is in order to ensure that long-term firm access rights are unaffected (and so ensuring that long-term access service is still an attractive product to generators).

134 There is a possibility that this may be perceived as being inconsistent with the first revenue and pricing principle (TNSPs must be given reasonable opportunities to recover at least the efficient costs it occurs) as set out in the NEL; however, this is arguably addressed by the second revenue and pricing principle (a regulated network service provider should be provided with effective incentives in order to promote economic efficiency).

We recognise that TNSPs would likely be risk averse in offering short-term access rights. Short-term access would therefore only be likely to be offered when the chances of transmission capacity falling short of what is needed to provide access are small.

As discussed in section 3.4 there may be some existing spare capacity on the network – which already exists without the TNSP undertaking operational activities. TNSPs would be able to use this to back short-term access.

However, given that this has been previously paid for by consumers and/or generators, further consideration would need to be given to how much of the revenue associated with this product the TNSP would be able to retain. This would also require the identification of any *existing* spare capacity on the network in the auction process. Further consideration of this issue would occur during OFA implementation.

Changed risk profile for TNSPs

The above incentive schemes would provide strong signals to TNSPs to manage the network consistently with the way in which capacity is valued by the market at any point in time. Exposing TNSPs to even *part* of the costs of network unavailability may have a large effect on TNSP behaviour.

However, this would be likely to result in a change in the risk profile of TNSP businesses:

- Since settlement shortfalls would be based on the spot market price, TNSPs would be exposed to spot market price movement – prices may range from -$1,000 to $12,900 per megawatt hour in the space of a day.

- In addition, to the extent that actual project costs differ from regulated access charges in the *current* regulatory period, TNSPs would be required to bear the difference in costs. Access charges could exceed or fall short of project costs; that is, the TNSP would be exposed to both upside and downside risk.

Given the potential change in the risk profile for TNSPs, it may be appropriate to allow TNSPs to recover some form of related compensation. How this compensation would be allowed for would be considered further in the development stage.

Allowing compensation for changed risk as part of the regulated rate of return may be problematic: the change in risk only relates to the expenditure that is related to the firm access standard, ie not that associated with meeting reliability standards.[135] A more appropriate compensation might be allowing TNSPs to recover some level of "insurance" relating to the risks associated with firm access. If an insurance allowance was deemed appropriate to be included in a TNSP's allowed revenue, then an associated cost could also be included in the access charge, paid by firm generators.

135 Which could include "part" of an investment, where the investment enables the TNSP to meet both reliability and firm access standards.

7.3.2 Potential additional incentive schemes

We have also identified that there may be other *additional* incentive schemes, which could potentially form part of the OFA model. These might not form part of the initial model – rather, these may be "add-ons" at a later stage. We briefly discuss two of these incentive schemes below:

- long-term incremental access incentive scheme; and
- abnormal operating conditions incentive scheme

Long-term incremental access incentive scheme

There are some instances where more high-powered incentives might be appropriate. In particular, one such instance would be when a new access request is received. This would be for *incremental* access, ie in addition to current access agreements. This would occur when a new generator wishes to become firm, or an existing generator desired a higher firm access service. Here, it would be important to incentivise TNSPs to make efficient trade-offs and so decisions about the best way to provide this additional access.

Under such a scheme, TNSPs would be exposed to 100 per cent of settlement shortfalls for some period of time following when the new access starts – perhaps five years.[136] We consider that five years is long enough to provide adequate incentives.

Following the conclusion of the five year period, the assets would be rolled into the asset base and subject to the operational incentive scheme as discussed above in 7.3.1.[137]

Similar to the above operational incentive scheme, the aggregate amount of shortfall would be subject to caps. We consider here the cap would be set both on a short-term (eg monthly or quarterly basis) as well as on a long-term (annual) basis. The caps would be set based on a similar set of principles to those articulated above.

It is important to note that, if such a high-powered incentive scheme was warranted, it would only apply to a very small portion of the firm access provided.

Figure 7.3 illustrates the long-term incremental access incentive scheme. If firm access was not available to the generator, then the TNSP would be responsible for paying 100 per cent of the compensation to the generator - up to a cap.

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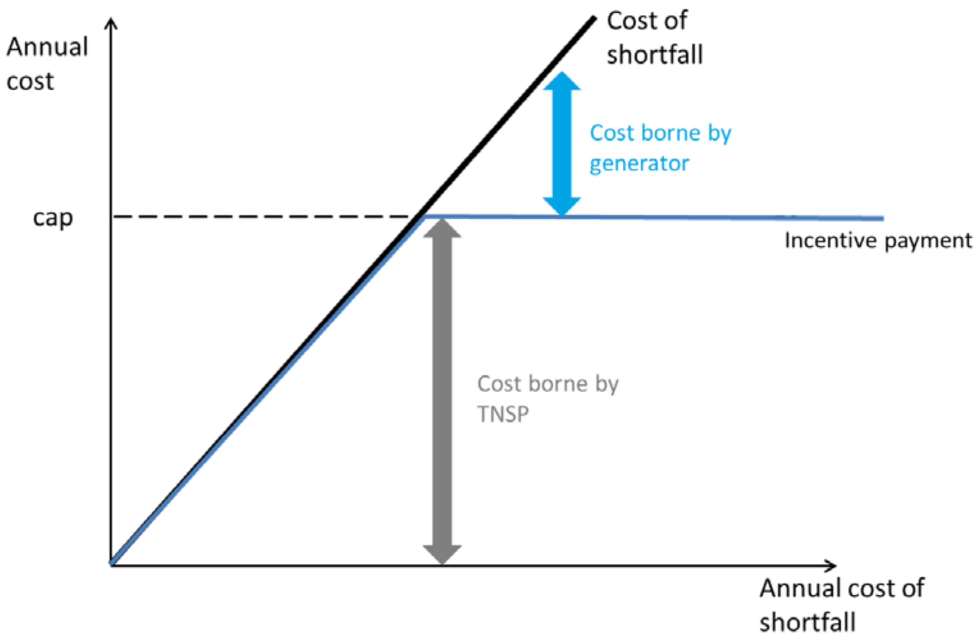
136 The five year period could cover two regulatory periods, eg if access was released in year three of the first regulatory period, then five years would take it to year two of the second regulatory period.

137 To the extent that revenue received from access charges differed from the actual project costs that were rolled into the regulated asset base, then revenue from consumers would be used to offset the difference – that is, if access charges were less than the actual project costs consumers would fund this difference, whereas if access charges were greater than the actual project costs consumers would receive a "refund".

Figure 7.3 Long-term incremental access incentive scheme



The higher-powered incentives would more strongly incentivise the TNSP into making the right decision in how to provide the firm access service, choosing between:

- building new capacity now;
- making operational savings now, and building new capacity later;
- making operational savings forever;
- entering into network support agreements; or
- paying compensation.

We consider that the above decision is very important and so it is worth placing higher-powered incentives on TNSPs in order to encourage them to make the most efficient decision.

Furthermore, combined with this scheme, TNSPs could be subject to a regime to promote more timely release of access. A standard time would be set, in which most projects would be expected to be completed – although the times may differ for different projects, eg depending on estimated cost.

TNSPs could delay providing access within this time – provided they gained approval from the AER. If a TNSP considered there may be a delay in providing access (eg from delays in obtaining planning permissions) then it must obtain approval from the AER. It would have to justify why there is a delay through a written application. These would be circumstances where delay or failure to provide firm access is beyond the TNSP's control.

The AER would then approve (or not approve) this delay. If approval was not obtained, then the TNSP would be exposed to any settlement shortfalls.

An alternative to the TNSP gaining approvals from the AER each and every time there is a delay, which may result in large administrative burdens for the AER, would be to use a permit scheme. This is similar to a scheme used in the UK – described in Box 7.1.

Box 7.1: Permit scheme in the UK

National Grid Gas owns and operates the gas National Transmission System (NTS) in Great Britain. The UK system allocates capacity in the NTS between a small number of entry nodes and a national balancing point. Under this system National Grid Gas is obliged to release "incremental obligated entry capacity" for use by system participants, subject to a default investment lead time of 42 months.

National Grid Gas is given a number of opportunities or permits that can be used to extend the 42 month default lead time – these are defined in the license. This sets a limit on the number of months of allowed delay that can occur, subject to a total cap. These increases may be caused by the length of time required to obtain consents or construction challenges. The permits can be used without any justification to Ofgem (the regulator). The cap can also be increased by National Grid releasing incremental obligated entry capacity early.

When all of National Grid's permits have been exhausted, National Grid may only extend the 42 month default lead time for the release of capacity with the consent of Ofgem. This requires written application to, and approval from Ofgem.

Incentives outside firm access standard

There is also likely a need to have incentives applying to TNSPs for performance *outside* the firm access standard, both:

- providing incentives to encourage TNSPs to *provide an efficient level of access* even outside normal operating conditions – wherever the cost of providing additional access is less than the benefit of doing so, eg by reducing the duration of planned outages when in abnormal operating conditions (and so forced outages apply); and
- providing incentives for TNSPs to move back *within* normal operating conditions, when there are abnormal conditions, eg by reducing forced outage rates and/or undertaking appropriate maintenance.

However, we consider that TNSPs should face fairly low exposure under these schemes. Furthermore, any risk and reward balance for TNSPs in these circumstances should interact effectively with the other incentive schemes that exist.

8 Assessment

Summary of this chapter

This chapter assesses the optional firm access model and the current arrangements for transmission against the objectives of this review. The overarching aim of this review is 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.

Optional firm access would have impacts in the following areas of the current arrangements for transmission:

- *Support for a deep and liquid contract market* – by providing:
  - a mechanism for generators to obtain firm financial access that is not affected by congestion; and
  - a mechanism for market participants to obtain inter-regional access, which should encourage contracting between generators and retailers in different regions.
- *Efficient investment in generation and transmission* – by establishing:
  - clear and cost-reflective locational signals for new generation investment through access pricing, encouraging the co-optimisation of transmission and generation investment;
  - more market-led development of the transmission network, where generators' procurement of firm access would fund and guide network expansion; and
  - a new mechanism for the efficient expansion of inter-regional transmission capacity which would allow financially interested parties to internalise the costs and benefits of interconnector capacity.
- *Efficient dispatch of generators* – by reducing the current incentives on generators to engage in disorderly bidding.
- *Efficient operation of transmission networks* – by exposing TNSPs to some part of the market impact of transmission constraints.

The chapter also presents our arguments for why optional firm access represents the best alternative set of transmission arrangements that we have been able to identify of other plausible models considered.

8.1 Introduction

Consistent with promoting the NEO, the objective of this review is to provide arrangements that are likely to optimise investment and operational decisions across generation and transmission to minimise the expected total system costs borne by electricity consumers.[138] This will occur where:

- TNSPs have incentives to efficiently invest in and operate their networks to meet consumer requirements at least cost and support a competitive generation sector. They should ensure that existing capacity is used efficiently and that the network is expanded in an efficient and timely manner.

- Generators have incentives to offer their energy at an efficient price and to invest in new plant where and when it is efficient to do so. They should have access to deep and liquid contract markets.

- The policies, incentives and signals that govern transmission and generation decisions are coordinated to promote consistent decision making between the regulated and competitive sectors of the NEM. Transmission and generation investment should be co-optimised.

- The safety, reliability and security of the transmission system is maintained.

These objectives form the basis for the following comparison of the optional firm access model to the current transmission arrangements, which do not provide generators with firm access – see section 8.1.1 below.

The assessment undertaken in the remainder of this chapter is largely qualitative, although informed by stakeholder submissions. Where possible, we provide quantitative assessment of the efficiency benefits that would arise from implementing optional firm access, drawing on the modelling of alternative transmission frameworks that we commissioned ROAM Consulting to undertake.

As with all modelling, results are sensitive to the assumptions used. Some potential benefits, such as those relating to impacts on contract markets and on investment decisions at a granular level, have proven hard to quantify. Others, such as the decreased risk for consumers of inefficient investment where transmission investment is market-led, are not quantified. Nevertheless, the modelling finds a positive benefit from implementing optional firm access, largely in minimising the combined total costs of generation and transmission by changing the pattern of investment over time.

8.1.1 Current transmission access arrangements

The transmission service that generators currently receive is not well defined – both in the first instance, and over time. We characterise it as *non-firm access.*

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138 The Terms of Reference for this review specify that we should have regard to the NEO and other principles agreed by COAG, as specified in section 1.4.2 of this report.

The NEM operates under an open access regime. Generators have a right to connect to the transmission network,[139] but this right does not extend to a firm right of access across the network to the regional reference price. When there is congestion within a region, a generator may effectively be denied access through being constrained off: that is, not being dispatched by AEMO despite offering to run at a price less than regional reference price. Since there is no right of access, there is correspondingly no compensation provided when constrained off.

Although congestion may be mitigated through network expansion, generators have no say on where or when such expansion might take place.[140]

We note that several generators disagree with this interpretation of the rules, and consider that they have a right of access across the network, even if it is implicit.[141] They consider that NER clause 5.4A enables them to negotiate with TNSPs to obtain firm access. However, we consider that the rules as written cannot work in practice with an open access regime – see Box 8.1.

Box 8.1: Giving effect to clause 5.4A

The rules contemplate generators being able to negotiate firm transmission network access with TNSPs. The rules provide for a generator to negotiate compensation from a TNSP in the event that it is constrained off or on, in return for an access charge.[142] In practice, this provision is unworkable because the scheme is not mandatory and all generators have open access to the network.

If a generator currently negotiated firm access, the TNSP would have two options:

1. Augment the network to provide sufficient capacity for that generator to always be dispatched; or

2. Pay compensation to the generator in the event that it was constrained off.

Under an open access regime, the first option is not practical. The TNSP could not prevent other generators from connecting to the network and using capacity. If new generators did not opt into the scheme, the TNSP would have no funding to further augment the network.[143]

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

140 While generators have the ability to fund investments in the transmission system, there is no mechanism to prevent other generators from making use of this additional capacity, or to require them to fund further augmentations to maintain the original generator's access.

141 AGL, Issues Paper submission, p.2; International Power GDF Suez Australia, Issues Paper submission, p.27; LYMMCo, Directions Paper submission, p.4.

142 NER clauses 5.4A(b), (f) and (h)(1).

143 Assuming that further augmentation did not pass the RIT-T.

The second option is also not workable. The rules do not provide a source of funding for the compensation payable to the constrained-off firm generator. The rules appear to contemplate the TNSP recovering charges from other generators whose dispatch constrains off the firm generator. However, there are no rules to compel other generators to pay such charges, or to compel them to opt in to such a scheme. Generators that cause congestion are unlikely to have incentives to join voluntarily.[144]

In summary, the firm access provisions contemplated in the rules cannot work in practice and, as far as we are aware, have not been applied to date. The optional firm access model represents what we believe to be the best integrated set of reforms to put in place such a regime while retaining the NEM's regional pricing structure.

8.2 Impact on financial certainty

The decision to invest in generation is influenced by, among other things, the ability of generators to enter into contracts to manage the trading risks that they face.[145] Where generators rely on contracting to manage trading risk, a deep and liquid contract market is required to support generation investment. Investors might rely on a long-term contract, or if they are confident that the contract market is sufficiently deep and liquid, can rely instead 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. 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 difference payments where the spot price is lower (or higher) than the contract price. 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 as 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. Ultimately, this should 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

144 Generators that cause congestion are, by definition, being dispatched themselves. They would have no incentive to join a scheme that required them to: (a) pay charges for access that they already have; and (b) pay compensation to the generators that they constrain off.

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

willingness of generators to offer contracts, would be expected to improve retail competition. In particular, it should 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.

8.2.1 Financial certainty with non-firm access

Currently, dispatch risk may affect the ability of generators to sell forward contracts against their output.[146] Congestion may prevent generators from selling all 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.[147] Potentially, the cost is very high. Generators' uncertainty as to whether they will be able to generate and receive the regional energy 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, albeit that was not 100 per cent of their generating capacity. However, congestion tends to be volatile and unpredictable, 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. The options available to manage the risk appear to be:

- To contract for a lesser volume, with corresponding impacts on investment certainty and therefore financing costs;
- To contract at a higher price, or seek to recover losses on contracts from other products, resulting in higher priced products and possible upward pressure on prices for consumers;
- To buy a cap contract from another generator, covering times when the regional reference price is high. It would unnecessarily cover the generator when it was not constrained off, so would be an expensive way to hedge; or

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

147 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 the offsetting of risk which is achieved by hedging, ie contracting up to expected dispatch volume.

- To acquire a large portfolio of generating assets that enables the effects of congestion on generation in one part of the network to be offset by generation in another. If a viable strategy, this may reduce the relative competitiveness of smaller participants, driving industry concentration, with corresponding upward pressure on electricity prices.

Materiality

Over the course of this review, there has been much comment on the materiality of congestion. Some generators argue that the risk of power station outage is greater than the risk of congestion. For instance, a generating company may only contract for 75 per cent of the capacity of a power station with four generating units to protect against the risk of one unit being out of service.[148] If the effects of congestion on dispatch are not as great as this 25 per cent reduction, then the effects on contracting should not be material.

Other generators, however, report congestion effects that are greater than the risk of plant outage; that is, congestion causes them to be constrained to a dispatch level that is less than an n-1 level (where n is the number of generating units). Times of network congestion tend to be associated with high wholesale electricity prices (because higher priced generators are dispatched in place of generators who are constrained off). Therefore, the generator’s exposure, even if contracted only up to an n-1 level, could be significant. For instance, generators have reported instances of being constrained below their contracted level for several hours while prices were at the market price cap, at a cost of several millions of dollars.

This is an area that is particularly difficult to quantify. Generating companies have not provided us with the risk premiums, associated with congestion, that may be added to their cost of capital or product prices. Further, congestion can cause both winners and losers. While some generators suffer financial losses due to congestion, others realise gains from the associated high prices. Such "wealth transfers" may not appear in an aggregation of costs and benefits. However, the effects of financial uncertainty on individual participants will not be in the long run interests of consumers if they result in higher product prices or a higher risk-adjusted cost of capital.

8.2.2 Financial certainty with optional firm access

By decoupling access from dispatch, the optional firm access model would create the ability for generators to hedge against the risk of congestion. Under normal operating conditions, 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.[149] Firm access may therefore provide greater financial certainty for generators to offer forward contracts on a

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148 Generating companies that control a portfolio of power stations may employ a different contracting strategy.

149 The local price is the price of supplying a marginal unit of electricity at a point in the network.

volume reflective of their access amount. Generators might be expected to contract for a volume somewhat less than their nominal access amount to reflect the probabilities of less than optimal network operating conditions, where access is correspondingly scaled back.

The higher expected level of hedging or lower contract prices that may result,[150] as compared to under a non-firm access model, 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.

Conversely, non-firm generators would face a higher degree of basis risk – of 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).

Providing investment certainty for generators has guided the design of the optional firm access pricing methodology. The access charge would be fixed for the life of an access agreement, similar to connection charges currently.

8.2.3 Inter-regional trade with non-firm access

Under current arrangements, generators face some price (or basis) risk when trading inter-regionally. 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. It must sell its power at one regional price and buy it at another, exposing it to possible price differences.

One way that generators can partially hedge against this risk is to purchase 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 do not, however, provide a firm hedge against inter-regional basis risk. The IRSR is directly dependent on interconnector flow, so anything that reduces the flow will reduce the payment to the holders of SRA units:

- 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.

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

- 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.[151]

- 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. New generators may, however, 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.

In any of these events, generators will continue to be exposed to a level of basis risk, even if they hold a volume of SRA units equal to that which they are trading inter-regionally.

8.2.4 Inter-regional trade with optional firm access

The optional firm access model introduces a firmer inter-regional access product. A number of generators and the AER expressed support for this product in submissions – particularly since it would address many of the limitations outlined above with the current arrangements.[152]

The firmness of the new inter-regional access product would be (largely) independent of interconnector flow. Access settlement payments would be provided by generators that caused the interconnector to be constrained off, so in normal operating conditions the payout on the inter-regional access product would not be reduced. While counter-price flows may still arise, access settlement would again ensure that the holders of the product were not affected.

Although access settlement payments would be scaled back if transmission capacity was reduced, if the outage occurred during normal operating conditions then the responsible TNSP would be liable to pay a proportion of the shortfall in funds.[153] Moreover, such incentives, even low-powered ones, should lead to changes in TNSP behaviour, decreasing the frequency and impact of planned outages.

New generators locating on interconnector flowpaths would not degrade the firmness of inter-regional access – see section 8.3.4 below.

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151 Negative settlements residues are, in effect, borne by consumers in the importing region; they reduce the proceeds from the settlements residue auction that would otherwise offset TUOS charges.

152 EnergyAustralia, Second Interim Report submission, p.8; Alinta Energy, Second Interim Report submission, p.6; AGL, Second Interim Report submission, p.4; and AER, Second Interim Report submission, p.6.

153 See section 7.3.1.

The inter-regional access product should therefore give generators and retailers greater confidence to trade across regional boundaries. It should also give vertically integrated participants greater confidence to meet their retail load using remotely located generation.

The result should be to better enable generators in lower priced regions 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.

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.[154]

8.3 Impact on investment

8.3.1 Non-firm access – regulated planning approach

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. 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.

Ability of TNSP to predict least-cost development path

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.[155] 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.

154 Existing interconnector capacity will in effect be the residual capacity after the allocation of transitional access to generators – see section 9.3.

155 The RIT-T guidelines also allow for the use of market-driven modelling – see clause 21 of AER, *Regulatory Investment Test for Transmission*, June 2010.

Generally markets are more efficient than central planners in coordinating allocation decisions.

Locational signals for generators

Irrespective of the development path predicted by a TNSP, generators will not necessarily align with this path. Efficient generator location requires a price signal of the impact of their locational decisions on transmission network costs.

Certain locational signals such as transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator location. However, these signals are incomplete, as they do not signal the long term costs of transmission. Moreover, current congestion costs are not necessarily a meaningful indicator of future congestion costs. A generator may not be able to predict TNSP behaviour, and therefore congestion costs, over the life of its investment.

The absence of a generator transmission charge in the NEM may therefore result in inefficient locational decisions that increase the overall cost of transmission and generation. For instance, proximity to a gas pipeline is likely to be important to a gas-fired generator, but it would not be exposed to the full cost of electricity transmission investment that may be required to support its locational decision. The potential cost is not only imperfect co-optimisation between electricity generation and transmission, but also between electricity and other energy networks.

Efficiency implications

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 have only limited influence on these investment decisions. This does not represent an ideal alignment of risk and decision making.

ROAM applies a theoretical model that rebuilds the NEM over time to meet actual demand, as if with perfect hindsight. ROAM's modelling finds a substantial amount of transmission overcapacity at present in most parts of the NEM, compared to what would be required under such an approach. A relatively small amount of new transmission capacity would be required by 2021, with this increasing over the period to 2030.[156] With perfect hindsight this may not be surprising. Decisions that were appropriate at the time, in light of the available information and prevailing reliability standards, may appear inefficient in retrospect with different information available, for example if forecast and actual patterns of demand differ. At best, this illustrates the immense difficulties associated with central planning; at worst, it suggests that the current arrangements do not promote efficient decision making.

8.3.2 Optional firm access – market-led development

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). Our recommendations would allow this trade-off to be made by generators, rather than TNSPs, so can be thought of as completing the market arrangements for the NEM – the market would signal the need for new transmission investment, just as it does for generation. Moreover, our recommendations 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.

The optional firm access model would create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM. Locational signals would 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 methodology aims to be cost reflective. It should 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.

Non-firm generators would be encouraged to locate in parts of the network where they are less likely to contribute to congestion, where the expected cost of compensation through access settlement is correspondingly lower.

156 ROAM Consulting, *Modelling Transmission Frameworks Review*, Appendix E, February 2013.

The optional firm access model should achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated planning approach. Optional firm access makes the cost of transmission part of a generator's investment decision. The investor should seek the location for a power station which minimises the combination of its operating and establishment costs and the cost of transmission. In making a locational decision a generator would therefore account for both its private costs and also the costs to the transmission network. Better co-optimisation of investment in other energy networks, where they are used as fuel sources, should also result.

In an appropriate alignment of decision-making and risk, 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. This represents an improvement over the current planning arrangements, where consumers bear the risk of inefficient transmission decisions.

The optional firm access arrangements would give firm generators the ability to trade access rights, allowing for efficient re-use of network assets. If, instead, access procurement created an access right for the life of the asset that could not be traded, the result would be inefficient duplication of assets where a new party sought access and the original access holder no longer valued its access right.

Modelling of efficiency benefits

ROAM's modelling finds that the improved co-optimisation of generation and transmission investment under optional firm access would save $85 million over the period 2013-30 in net present value terms, when compared to the modelled outcomes under the current RIT-T process.[157] Total savings in generator and transmission investment and operating costs over this period are $1.2 billion (in 2012/13 dollars).[158] Many of the changes occur in the later years of the modelling when existing spare transmission capacity is predicted to be insufficient to meet emerging demand. The benefits are therefore not fully reflected in the discounted value, which only captures a few years of the annualised repayments of the total capital cost.

The modelling results should be treated with a degree of caution. Modelling of dynamic benefits is very challenging, and requires a number of simplifying assumptions. Moreover, the modelling inherently favours central planning. Perfect co-optimisation is achieved where the model decides the location of both transmission

157 In full, this number represents the NPV of the annualised transmission and generation investment (ie the annual repayments of total capital cost), plus operating costs, over the period 2012/13 to 2029/30.

158 In full, this number represents the total (undiscounted) value of all transmission and generation investment, plus operating costs, over the period 2012/13 to 2029/30. That is, for transmission projects that are undertaken in the final years of the period, the gross figure captures the total value of the project; the discounted value (referred to in the previous footnote) only captures the capital repayments during those years.

and generation, with perfect knowledge of the future.[159] In the context of an uncertain future, decentralised planning offers benefits that are not captured by the modelling. Decentralised planning:

- removes agency risk (generators spend their own money);
- removes information asymmetry (generators do their own analysis); and
- improves diversity (generators can experiment and fail).

The modelling reflects a particular view of the future, which includes assumptions about the relative costs of different generation and transmission technologies and the rate and pattern of demand growth. If those cost differentials were greater, or demand growth higher, then the efficiency benefits would be larger. For instance, the modelling finds that optional firm access results in significant changes in the location of generation and transmission investment, but because of the relatively small cost differentials between electricity and gas transmission, those changes result in relatively small net savings.

Conversely, if cost differentials were smaller, and demand lower, then the modelled benefits would be smaller. In other words, the modelling suggests that the more change from current patterns of generation and demand that occur in the future, the more scope there is for optional firm access to deliver the efficiency benefits that result from enhanced co-optimisation.

8.3.3 Interconnector investment with regulated planning

Currently, interconnector investment may occur on the basis of net market benefits.[160] The cost is borne by users of load services and passed through to consumers. The subsequent location of new generation on or near the interconnector may decrease its benefits to consumers. Those generators would benefit from a relative lack of congestion, but would not compensate consumers for the loss of benefits.

Moreover, the supply (or expansion of) inter-regional capacity is not linked to the demand for inter-regional hedges, provided by SRA units. There may be some participants who are willing to pay for a higher level of SRA units. Under the current framework, there are no signals to develop increased capacity in response.

8.3.4 Interconnector investment with optional firm access

The creation of inter-regional access rights protects against the erosion of interconnector benefits by subsequent generator entry. The firm access standard would

159 See ROAM Consulting, *Modelling Transmission Frameworks Review*, Figure 6.13, February 2013, p.66.

160 The RIT-T requires TNSPs when considering a transmission investment to examine the costs and benefits of credible options to establish the one which maximises net market benefits. The benefits provided by an interconnector may include changes in generator fuel consumption and investment costs, and reduced network losses and unserved energy.

require TNSPs to maintain inter-regional access, so they could not degrade interconnector capacity by using it to meet intra-regional firm access. Where generators located on or near the interconnector and chose to be non-firm, they would compensate holders of inter-regional access through access settlement for any congestion they caused. The ability of inter-regional access holders to trade those rights also allows for efficient re-use of interconnector capacity.[161]

The optional firm access model would allow interested parties to internalise the costs and benefits of interconnector capacity, through the inter-regional allocation and expansion process described in chapter 6. The result should be an efficient level of interconnector investment: inter-regional investment will occur when the benefits exceed the costs, where the majority of benefits are estimated by market participants.

8.4 Impact on generator bidding behaviour

8.4.1 Non-firm access and disorderly bidding

Currently, financial access to the regional reference price is linked to a generator's dispatch level. Generators located in a congested part of the network are likely to submit identical offer prices of -$1,000 – a process known as disorderly bidding. Congestion means that their bidding is unlikely to affect the regional reference price. AEMO is unable to identify and preferentially dispatch the cheaper generation.

Productive efficiency

Disorderly bidding may result in productive inefficiency, with more expensive generation (in terms of operating costs) dispatched ahead of cheaper generation.

Further, because the 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. This can exacerbate the cost of congestion and the level of the regional reference price associated with it.

Financial certainty

Disorderly bidding can result in very unpredictable and volatile market outcomes. Because offer prices are identical, dispatch priority is based on secondary factors such as ramp rate limits, prior period output and constraint coefficients. This makes dispatch levels highly uncertain for generators.

As already noted, times of congestion are associated with high prices, because constraints on the network usually mean that the regional price will be set by a higher priced generator. The sudden unbinding of constraints (for example where the

161 Trading of inter-regional access rights could potentially allow for the use of assets that were created as part of an interconnector expansion to be used instead for intra-regional purposes.

underlying constraint relates to a dynamic line rating) can cause the regional price to collapse, due to the amount of generation being offered at -$1,000.

Disorderly bidding may therefore contribute to the lack of financial certainty described in section 8.2, where a generator's revenue stream is dependent on the level of congestion and the offer prices and availability of generators nearby.

Inter-regional trade

Disorderly bidding affects the firmness of the current SRA instrument, diminishing the ability of generators and retailers to trade across regional boundaries, as noted in section 8.2.3. In most system normal constraint equations in the NEM, interconnectors can be redispatched to help manage congestion.[162] The smaller the interconnector's participation in a particular binding constraint, the greater the change in its dispatch that AEMO will require in order to manage the constraint. That is, the interconnector need not be strongly implicated in a particular instance of congestion in order to be greatly affected by the disorderly bidding that results. Often, reduced dispatch of the interconnector creates enough capacity for the generators behind the constraint to be dispatched for their offered availability.

Where it does not, counter-price flows on the interconnector often result. Although AEMO intervenes to limit exports from a higher to a lower priced region, technical limitations of the power system (including the ramp rates at which generators can be redispatched) may affect the speed at which the interconnector can be wound back, during which time negative IRSRs accumulate. The cost is borne by consumers in the importing lower-priced region, by reducing the proceeds of the settlements residue auctions that would otherwise offset TUOS payments.

Materiality

Some aspects of the materiality of the inefficiency created by disorderly bidding currently are discussed in section 8.4.2 below.

8.4.2 Optional firm access and disorderly bidding

The optional firm access model would reduce the incentives for disorderly bidding. 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 exposes generators to their local price, for any output above their access level. This should give generators the incentive to offer their energy in a cost reflective manner – ie to reduce incentives for disorderly bidding. If a generator offers

162 Interconnectors (like generators) are excluded from the left hand side of constraint equations where their coefficient is less than 0.07.

electricity at a price less than its short run marginal cost, it risks being dispatched at a loss when the local price is below its cost.

Modelling of efficiency benefits

The ROAM modelling finds that the cost of disorderly bidding in terms of productive efficiency has not been material: for the past three years, it ranges from $3 million to $15 million. Removing disorderly bidding through the implementation of optional firm access is predicted to save $8.8 million, in net present value, over the 18 years to 2030. The benefit is predicted to increase over time, resulting in an annual saving of $3-6 million for the last five years of the period.

The modelling does not, however, attempt to estimate other benefits that would result from removing the incentives for disorderly bidding:

- 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.

- 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 counter-price flows, and therefore the accumulation of negative IRSRs. Significant counter-price flow events have cost about $45m in the last three years.[163]

These further benefits would be expected to result from the implementation of optional firm access.

8.4.3 Strategic behaviour with optional firm access

The Commission interprets efficiency as having both short and long-term components. Both static and dynamic efficiency are important. Sometimes, however, trade-offs between these forms of efficiency need to be made. The ability of generators to establish power station portfolios and enter into forward contracts (and, under the optional firm access model, firm access agreements) is critical to establishing an environment conducive to generation investment and so to promoting dynamic efficiency. But these same features may provide generators with incentives to maximise profit in the short term by bidding away from their direct operating costs, potentially degrading static efficiency.

This trade-off exists currently. Generators do not always bid at their notional short-run marginal cost, consistent with a theoretical model of perfect competition. The most profitable bidding strategy for a generator at any point in time will depend on factors

163 As noted in chapter 1 of this report.

such as its costs, demand, forward contracts and availability of other generators. However, if the wholesale market is workably competitive then we would expect that bidding behaviour will in general lead to the least cost generators being dispatched first and so on, which is consistent with productive efficiency.

We expect optional firm access to promote dynamic efficiency: the availability of firm access products gives generators greater assurance of dispatch, which may affect their willingness to enter into forward contracts. Consideration should be given to whether this gain in dynamic efficiency could be at the expense of productive efficiency, ie whether the optional firm access model would change the trade-off between dynamic and static efficiency, compared to the status quo. Therefore, this section compares the potential for generator bidding incentives to lead to static inefficiency under the current arrangements and under the optional firm access model, recognising that there is likely to be some degree of such inefficiency under both regimes.

A comparison of generators' incentives under the optional firm access model with those under the current market design suggests that:

- Generators may have incentives to move dispatch away from the level associated with static efficiency and towards their access level. The behaviour is analogous to behaviour under the current arrangements, in the absence of congestion, where generators have some incentive to move output away from the level associated with static efficiency and towards their forward contract level.

- The impacts on dispatch efficiency under optional firm access are likely to be low, as the incentives will be strongest under minor constraints involving only a few generators. Under major constraints, involving many generators, the competitive pressure to offer close to direct operating costs will be stronger. This is in contrast to the current situation, under major constraints with disorderly bidding, where many generators with a range of costs all offer the same price, leading to more substantial dispatch inefficiency.

- Bidding under optional firm access is not likely to lead to large moves in offer prices away from cost, so is not likely to affect interconnectors to the same extent as disorderly bidding does currently.

We have not assessed whether the optional firm access model lessens or heightens the ability of portfolio generators to optimise their output across power stations that are located on either side of a constraint.

Incentives to offer away from direct operating costs

As noted in section 8.4.2, during congestion generators would be paid their local price at the margin under the optional firm access model. This should encourage more cost-reflective bidding. However, it is not expected that generators would offer exactly at their direct operating costs.

Under the current arrangements, when a region is uncongested, generators have some incentive to offer away from their direct operating costs, depending upon their hedging level and the degree of influence that they have on the regional reference price. To the extent that it has pricing influence, a short generator (whose output is less than its contract level) may offer somewhat below cost in order to reduce the regional price. On the other hand, a long generator (whose output is greater than its contract level) may offer somewhat above cost to increase the regional price. In both cases, a generator seeks to move its output closer to its forward position.

Similar strategic behaviour may be seen under the optional firm access model during congestion. In this context, though, it is the access level rather than the forward level which is most relevant, and the influence on the local price rather than the regional price becomes important. Where non-firm generators exert local pricing influence, they may give up some level of dispatch in order to increase the local price and decrease access settlement payments. Where firm generators exert local pricing influence, incentives would operate in the opposite direction. Firm generators may gain some level of dispatch, but only up to their access level. In combination, these individual generator incentives may tend to drive dispatch of firm generators towards their firm access level and dispatch of non-firm generators towards whatever transmission capacity is left.

Impact on dispatch efficiency

When 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. That creates some dispatch inefficiency, just as may occur at present where a short generator displaces a lower-cost long generator. However, this effect is likely to be strongest under minor constraints - where only a few generators are involved - so the materiality of the impact on overall dispatch efficiency is likely to be low.

Under major constraints where there are more generators and thus less pricing influence, the competitive discipline on generators to offer close to cost - irrespective of their access position - is stronger. This is in contrast to the current situation, where disorderly bidding under major constraints - which involves many generators, with a range of costs, all offering at the same price - may lead to more substantial dispatch inefficiency.

Under the optional firm access model, constrained generators would remain responsive to changes in the regional reference price through its impact on local prices.[164] This is likely to reduce the regional pricing influence of those generators who continue to be paid the regional price: that is to say, unconstrained generators and flowgate support generators.[165] This strengthens the incentive on those generators to offer closer to their direct operating costs and may encourage support generators to

164 With the exception of radial constraints, where changes in the regional reference price do not affect local prices behind the constraint.

165 See section 3.3.3 for a description of flowgate support generators.

increase their output level and so help to relieve congestion. These effects are likely to help mitigate the impact that congestion can currently have on regional prices.

Effect on interconnectors

Under the optional firm access model, although generators may offer somewhat away from their direct operating costs, distortions as extreme as those seen under disorderly bidding are highly unlikely. Thus the dispatch inefficiency for interconnectors associated with non-cost reflective bidding would be substantially reduced.[166]

8.5 Impact on transmission operational decisions

The current incentives on TNSPs to operate transmission networks efficiently do not fully capture the value of network capacity to market participants.[167]

The firm access standard introduced by optional firm access would place an obligation on TNSPs to both plan and *operate* the transmission network such that sufficient transmission capacity is available to meet all firm access. 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 maximise network availability when it is most valuable.

This approach would provide a strong signal to TNSPs to manage the network consistently with the way in which capacity is valued by the market at any point in time. Exposing TNSPs to even some part of the cost to the market of network unavailability may have a large effect on TNSP behaviour. However, it would expose TNSPs to movements in the spot market price, which might represent a significant change in the risk profile of their businesses.[168]

The ability of TNSPs to sell short term access and earn additional revenue above their annual revenue cap would create a further incentive to maximise network availability.

Possible changes in the risk/reward balance for network businesses, and whether it may be appropriate to allow TNSPs to recover some form of related compensation, are discussed in section 7.3.1.

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166 There may still be counter-price flows under the OFA model. Indeed, these may be consistent with efficient dispatch. However, this would not create negative settlement residues and would not require AEMO intervention as currently.

167 Although we note that recent changes to the STPIS have introduced a network capability component, which is designed to influence a TNSP's operation and management of its network assets to develop one-off projects that can be delivered through low cost operational and capital expenditure. See: AER, *Electricity Transmission Network Service Providers: Service Target Performance Incentive Scheme*, Final Decision, December 2012.

168 Although incentives would only apply during the set of normal operating conditions, which would lessen TNSP risk.

8.6 Choice of optional firm access over plausible alternatives

In the First Interim Report for this review, we proposed four alternative reform packages as alternatives to the current arrangements for transmission. We are recommending optional firm access as the best alternative because it has the best potential to achieve the objectives of the review. We describe the shortcomings of the other packages relative to optional firm access below.

We also explain how optional firm access differs from other transmission models that use financial transmission rights, and what has guided the particular design of this model.

8.6.1 Why not shared access congestion pricing

The purpose of this model was to introduce a market-wide mechanism to better maintain incentives for generators to bid in a cost-reflective manner when the network is constrained.[169] This mechanism, termed the shared access congestion pricing (SACP) mechanism, would effectively put a value or price on congestion so that generators would take account of it in constructing their offers. Access to the transmission network would continue to be based on generator bids and network availability, as occurs in practice under the status quo.

The shared access congestion pricing mechanism would not be sufficient on its own to achieve the objectives of the review. While it would address concerns relating to disorderly bidding, it would not create the basis for market-led development of the transmission network or provide signals for efficient generator location. It would therefore not achieve the benefits that relate to improved co-optimisation of generation and transmission investment.

Although reducing incentives for disorderly bidding would improve the firmness of the current inter-regional hedging instrument, it would not achieve the full benefits for inter-regional trade that would be achieved with optional firm access (where access settlement payments result in a still firmer product).

As previously noted, at this stage we consider that to introduce a congestion pricing mechanism without giving generators the option of obtaining firm access may impose undue risk.

8.6.2 Why not generator reliability standards

The purpose of this model was to introduce a transmission reliability standard for generators, which would increase certainty for generators by defining a level of access to the transmission network that TNSPs would be mandated to provide.[170] Generators

169 For a full discussion of this model refer to chapter 7 of the First Interim Report.

170 For a full discussion of this model refer to chapter 8 of the First Interim Report.

would face a transmission use of system charge to reflect the costs to TNSPs of maintaining the generator reliability standard.

The generator reliability standards model lacks flexibility: it would mandate firm access for all generators. In contrast, the optional firm access model would allow generators to select the option that most closely meets their requirements. This should better allow for co-optimised outcomes between generation and transmission, promoting overall efficiency in the market.

We are also concerned that mandating firm access might lead to generators “queuing”: being unable to connect to the network for a number of years while waiting for deeper network reinforcements to be completed. Such an outcome – which has been observed in other markets with mandatory firm access – might negatively impact on competition in the wholesale market. Under the optional firm access model, even if firm access is not available for a period of time, generators would still be able to connect on a non-firm basis and participate in the market.

8.6.3 Why not national locational marginal pricing

The purpose of this model was to promote a deeper and more liquid market in energy trading by providing generators with compensation for being constrained off or on and a hedge against (market-wide) basis risk.[171] Under this model, fully firm financial transmission rights to a single national hub would be auctioned. Generators that purchased firm access rights would be settled at a single "system marginal price". Load would also be settled at this single price. Non-firm generators - those that did not purchase rights - would be settled at their locational marginal price (LMP).

An uplift charge would be levied on consumers to ensure that the residues available through settlement were equal to the compensation payments necessary to provide fully firm access.

The model would introduce a single NEM-wide TNSP and a single set of planning standards for generation and load. This set of standards would determine when new transmission investment was required to accommodate the release of incremental long term firm access rights. The TNSP would be exposed to a portion of the uplift charge to incentivise it to ensure that sufficient network capacity was made available on an operational basis.

The Commission considers that attempting to create the single NEM-wide TNSP proposed in the model would not be a proportionate response. Combined with efficiency concerns regarding the pricing of load on a national basis, we conclude that it is appropriate to retain a regional approach, but to take steps to promote nationally coordinated transmission planning.

We also consider that it would not be appropriate to expose consumers to the uplift charge that the model proposes to ensure that access rights would be fully firm.

171 For a full discussion of this model refer to chapter 10 of the First Interim Report.

Instead, we consider that exposing TNSPs to a portion of these costs would be likely to have a significant effect on the ultimate firmness of the access rights under optional firm access.

8.6.4 Why not nodal pricing with financial transmission rights

In some respects, optional firm access can be viewed as similar to nodal pricing with Financial Transmission Rights (FTRs), raising the question: why not implement a more standard system such as is commonly used in the US.[172]

Optional firm access differs from the more usual model in the following three respects.

Long term access rights

Optional firm access would give generators the option of acquiring long term access rights – for the expected life of their investment, if that is what they desire. In US markets, FTRs are more commonly of shorter duration.

Real-time settlement balancing

Under optional firm access, settlement would be balanced in every trading interval:

- Even during congestion, more transmission capacity may be available than is necessary to provide the firm access purchased by generators. During such settlement periods, non-firm generators would be allocated the settlement surplus, moving the price they receive towards the regional price.
- In other periods, where transmission capacity fell short of what was necessary to provide the firm access purchased by generators, access payments would be scaled back as needed to ensure that settlement balanced.
- The scaling of access payments would be on a flowgate basis.

In the more general nodal model:

- Generators without FTRs receive only the nodal price. Any settlement surpluses are typically used in other periods to preserve the firmness of FTRs where there is shortfall in funds (as a result of insufficient transmission capacity).
- FTRs are typically paid out in full, as far as possible, with settlement surpluses from one period used to fund deficits in subsequent periods. However, a

172 For instance in the PJM, New York, New England, MISO, California and Texas-ERCOT markets. See: NERA, *Review of Financial Transmission Rights and Comparison with the Proposed OFA Model in Australia*, March 2013.

long-run settlement surplus is not guaranteed, and so FTR payouts may still be scaled back from time to time or a source of additional revenues found.[173]

- To the extent that FTR payments are scaled back, this is done using a simple global scaling factor. This reflects the scaling back being a result of a cumulative settlement shortfall over an extended period, rather than a real-time shortfall.

Real-time settlement balancing is our preferred basis for optional firm access. Cumulative settlement balancing is likely to work less well in the NEM than in overseas markets. Our less meshed networks and much higher price cap create the likelihood of large settlement deficits in one period that could not be recovered from surpluses in other periods. An approach which allows risk to be managed on a per flowgate basis is likely to be more attractive to generators than one where risk is shared by all generators.

Real-time settlement balancing allows the quality of the firm access service to be measured - via settlements shortfalls - and therefore operational incentives to be placed on TNSPs. These should reduce the incidence of shortfalls and partly offset them when they do arise.

Treatment of flowgate support generators

Under optional firm access, generators at points where the local price exceeds the regional price would only be paid the regional price. In the more conventional model, such generators are paid the nodal price, subject to some "market power mitigation" mechanisms, which may limit the generator payment or bids.

We have not found the problems associated with constrained-on generation to be as significant as with constrained-off generation. Extending the model to resolve constrained-on issues by paying nodal prices in these instances might also raise market power problems (especially given the much higher market price cap in the NEM, as compared to most nodal markets). However, in principle, there is no reason why the optional firm access model could not subsequently be extended in this manner if it was felt to be important and these concerns could be addressed.

173 In some US markets, where there are extreme deficits uplift charges may be collected from FTR holders or transmission owners. See: NERA Economic Consulting, *Review of Financial Transmission Rights and Comparison with the Proposed OFA Model*, March 2013.

9 Transition

Summary of this chapter

Transition processes would be necessary to ensure that the introduction of the optional firm access model did not create sudden changes in the market, and to provide for a learning period.

The main mechanism would be the allocation of transitional access that would function in the same way as the firm access service, but for which generators would pay no charges. Exposing generation investors to significant, unforeseeable regulatory risk would be likely to deter - or increase the costs of - future investment. Transitional access would therefore aim to act as a proxy for the access that generators could expect now and in the future under the current arrangements.

Equally, however, we do not favour arrangements that would grandfather access rights in perpetuity. This would risk overcompensating generators, and may affect competitive neutrality between new and existing generators. Further, given that the current regulatory framework does not guarantee anything in terms of generator access, and that some regulatory change is an accepted feature of the NEM, it may be justifiable for transitional access to expire prior to some reasonable expectation of a power station's life.

We recommend an approach to the allocation of transitional access based on these considerations. The details, including a number of key parameters, would need to be determined during implementation of the model.

9.1 Introduction

Transition processes would apply in the early years following implementation of the optional firm access model. The objectives of these processes would be:

- to mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the optional firm access regime;
- to encourage and permit generators – existing and new – to acquire and hold the levels of firm access that they would choose to pay for;
- 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
- to prevent abrupt changes in aggregate levels of agreed access that could create dysfunctional behaviour or outcomes in access procurement or pricing.

Importantly, the transition process should not delay or dilute the efficiency benefits that the optional firm access model is designed to promote.

9.2 Transitional access

The main transition mechanism would be the allocation of transitional access to existing generators. Transitional access would act identically to 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.

It is in the long run interests of consumers that investors in the electricity sector do not suffer large, unforeseeable risks resulting from regulatory change. Optional firm access represents a significant change to the market framework on the basis of which previous generation investment has occurred. Implementation of optional firm access without some kind of transitional access for incumbent generators could create an expectation of future regulatory change without compensation. The result could be to increase the cost of capital for future investors to cover the additional perceived risk, putting upward pressure on electricity prices, or to deter future investment altogether.

On the other hand, to grandfather access rights in perpetuity would risk compensating existing generators by more than is necessary to address any regulatory risk. Even after its power station had been closed, a generator would be able to financially benefit from transitional access through secondary trading - at the expense of consumers (because the access would otherwise need to be purchased, and revenue from firm access offsets the charges that market customers pay through TUOS.)

We therefore recommend a transitional access allocation process that aims 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.

There are strong arguments that access, as with any property right, should be allocated to the party that values it most, as quickly as possible. We therefore recommend a one-off auction to allow generators to buy and sell transitional access from each other. This would seek to ensure that existing transmission capacity was efficiently allocated.

However, there are equally arguments to suggest that holders of property rights often systematically overvalue those rights, holding on to them when they would be better off selling them. This is due to what has been dubbed the "endowment effect".[174] In this case, purchase prices are more efficient than selling prices; that is, forcing generators to relinquish their access rights over time will lead to more efficient access prices than would be achieved by relying on secondary trading alone. Efficient access prices are particularly important in terms of facilitating efficient entry into the market.

A further consideration is that the optional firm access model should start somewhere close to a steady-state situation, where most of the network is covered by firm access. An alternative to allocating transitional access to protect against regulatory risk would be simply to compensate existing generators. However, there would then be an "empty" network and potentially a large number of generators seeking access on optional firm access commencement, which the procurement and access pricing processes would not be designed to manage.

Taking these considerations into account, we recommend a transitional access allocation that follows the four-stage process described below. The values that are ascribed to the various parameters, such as the degree to which transitional access is sculpted back and over what time period, would need to be determined during the implementation of optional firm access.

In ascribing those values, difficult judgements would need to be made as to how to best serve the long run interests of consumers, trading off the need to *sufficiently* protect existing investors without *unnecessarily* compensating them (at the expense of consumers). Given that the current market framework for transmission does not guarantee anything in terms of generator access, we do not favour grandfathered rights in perpetuity. Further, given discounting effects over the very long term, and the fact that some regulatory change is an accepted feature of the NEM, it may be justifiable for transitional access to expire prior to some reasonable expectation of a power station's life.

9.2.1 Stage 1: Access requirements

Generators' access requirements – the level of firm access they would need to have unfettered access to the RRN – would be calculated, based on historical generation patterns.[175]

9.2.2 Stage 2: Access scaling

These access requirements would 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 efficient (small changes in access for one generator should not cause large changes in access for others).

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174 See D Kahneman, JL Knetsch, and RH Thaler, 'Experimental Tests of the Endowment Effect and the Coase Theorem', *Journal of Political Economy*, vol 98, no 6, 1990, pp.1325-1348.

175 MNSPs would be treated as generators for the purpose of allocating transitional firm access.

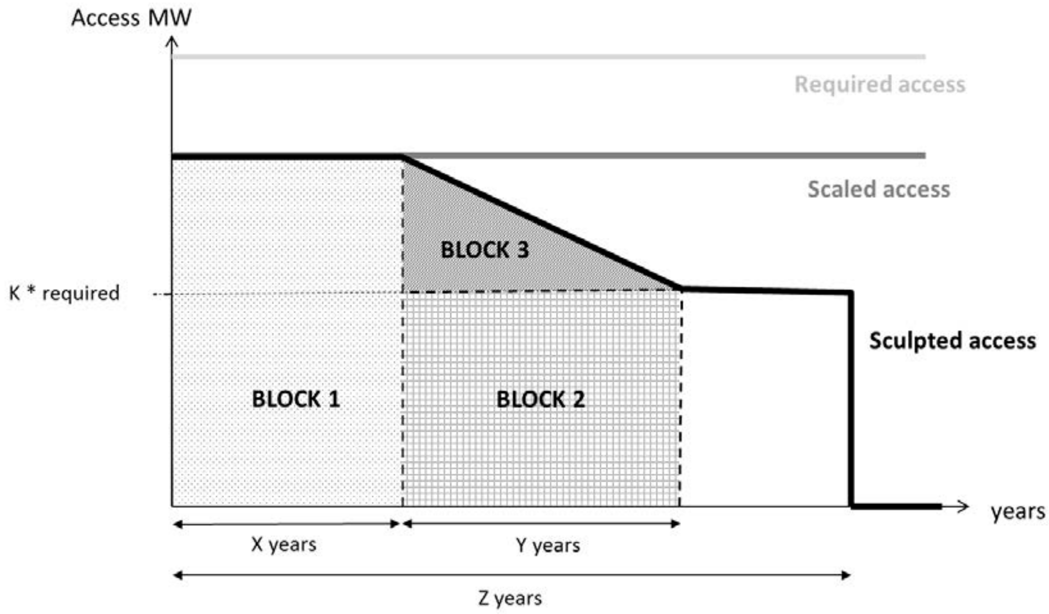
9.2.3 Stage 3: Access sculpting

Each power station's scaled access level would 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 below.

All power stations could be provided with a minimum X+Y years of access. X would represent a learning period; Y the period needed to ensure a gradual transition. Younger power stations could be provided with longer terms, Z years, where Z is a proxy for residual power station life.[176]

The values of X, Y, Z and K (the access sculpting factor) would be determined during optional firm access implementation.

Figure 9.1 Sculpting of transitional access for a power station



9.2.4 Stage 4: Access auction

A one-off auction would be established to allow generators to sell some of their transitional access or buy additional transitional access from other generators.[177] It would allow for more efficient reallocation of access than could be achieved through a series of bilateral trades. The auction would be similar to the short-term access auction described in section 5.3.2, although auction clearing and settlement would be conducted by AEMO, not TNSPs.

176 Although for generators for whom the likelihood of optional firm access is a *foreseeable* regulatory change, ie those that have invested since our last report was published or who do so subsequent to this report, a shorter transitional period might be justified.

177 Generators would also be allowed to bilaterally trade access outside the one-off auction.

The auctioned products would be based on the three blocks illustrated in Figure 9.1. Constraints would 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.

9.2.5 Summary

In summary, the transition process would help to ensure that, from the commencement of the optional firm access regime, existing generators would hold access amounts that provided them with firmness of access to the RRN 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 a number of years, transmission capacity would be freed up to support new access issuance, charged for in accordance with access pricing, to existing or new entrant generators.

9.3 Inter-regional transitional access

Inter-regional transitional access would be allocated in the transition process, but only to the extent that it could be without causing any additional scaling back of generators' transitional access.[178] The priority allocation of access to generators reflects their priority over interconnectors in the current dispatch arrangements.[179]

Unlike generator transitional access, inter-regional transitional access would not be scaled back over time. It would remain at its initial level indefinitely, forming the initial baseline inter-regional capacity.

Many of the drivers for sculpting back generator transitional access do not apply to interconnectors. For example, unlike generators, interconnectors will not ultimately close. There would also be no risk associated with inefficient endowment effects, since providing inter-regional transitional access would be a regulatory obligation for TNSPs.

AEMO, on behalf of TNSPs, would auction inter-regional access regularly to market participants, through an auction process similar to the existing settlements residue auction.[180] The proceeds from auctioning inter-regional transitional access would be used to cover the costs incurred by TNSPs in providing this capacity, offsetting charges that would otherwise have been recovered from consumers.[181] Thus, generators, retailers or other parties could potentially acquire inter-regional access through the

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178 MNSPs would be treated as generators for this purpose.

179 Currently, when there is congestion on hybrid constraints, affected generators can bid -$1,000. Inter-connectors are unable to bid in this way, so generators are dispatched at their expense.

180 See section 6.7.

181 This is the same as the current arrangements for inter-regional settlements residue and settlements residue auctions. However, it might no longer be appropriate to use these to adjust *locational* TUOS charges.

auction. Successful bidders would receive the payments through access settlement described in section 6.4.

9.4 Transitional incentives

The operational incentive scheme for TNSPs should be in place from the start of the optional firm access arrangements. However, it should be sufficiently low-powered that network businesses do not face undue risk. That is, the proportion of settlement shortfalls that TNSPs are liable for should be relatively low. The AER would progressively strengthen incentives over time as the businesses' understanding and internal capabilities increased.[182]

182 As discussed in chapter 7.

10 Way forward for the Optional Firm Access model

Summary of this chapter

This chapter sets out our recommendations as to how the optional firm access model and associated planning arrangements should be progressed.

Based on the analysis that has been carried out, we consider that while optional firm access has the potential to deliver long term benefits to the NEM, there are likely to be costs and risks associated with its introduction. The complex and multi-faceted nature of the changes required to implement the model make it difficult to quantify the benefits that might result. Further, the value of these would be significantly affected by the extent to which broader changes in the market eventuate. We are not therefore, at this stage, in a position to recommend to SCER that optional firm access should be implemented.

Instead, we recommend that SCER should commission a detailed design and testing program for the optional firm access model, allowing for the better assessment of the costs and benefits associated with the model, before making a final decision on whether or not to implement it.

If SCER endorses this recommendation, the Commission would seek to involve key stakeholders by establishing:

- a new independently chaired specialist panel (the OFA Panel), comprising senior representatives from the generation, transmission and end-user segments of the NEM, AEMO, the AER and the AEMC, to direct the detailed design and testing program; and
- a multi-disciplinary project team led by the AEMC, comprising staff and secondees from AEMO, the AER and industry, to carry out the work.

While the Commission would retain overall responsibility for reporting and making recommendations to SCER, the OFA Panel and project team would play an integral role in the detailed design and testing program. We anticipate it could take 12 months to complete this, at a cost of around $5 million.

If SCER subsequently decided to proceed with implementation of optional firm access, further work would need to be carried out on the remaining elements of the model and the legal architecture required to give effect to optional firm access and related planning arrangements. At this point in time, we expect that it could take around three years for this work to be completed.

We are conscious that this proposed approach represents a long-term commitment to resolving the issues associated with identified with the current transmission frameworks. However, we do not consider that it is possible to address these issues in a piecemeal or incremental manner.

10.1 Introduction

Based on the preceding chapters, it is apparent that while we consider optional firm access has the potential to deliver long term benefits of the NEM, we recognise that a decision to implement the model is likely to give rise to some significant costs and risks.

Although work has been undertaken to understand the costs and benefits associated with optional firm access, it has not been 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 are therefore not in a position, at this point in time, to recommend to SCER that the optional firm access model should be implemented. However, we consider that further detailed design and testing should be undertaken now in order to further develop it. A more detailed design of the model would therefore be available to SCER to assess for implementation in the context of unfolding developments in the wider market.

The Commission therefore recommends that SCER:

- endorse the optional firm access concept as a means of addressing a number of the identified shortcomings with the current arrangements; and
- commission further work (the "detailed design and testing program") to develop the optional firm access model in more detail and, as far as possible, to better assess the costs and benefits, before making a final decision on whether or not to implement it.

To this end, we have given further consideration to:

- the work to be carried out in the detailed design and testing program, the resources that are likely to be required to support this and the level of involvement that key stakeholders, such as AEMO, the AER, generators, TNSPs and end-users, should have; and
- the implementation plan that could be followed if, at the completion of the detailed design and testing program, SCER decides to proceed with the introduction of the optional firm access model.

Our proposed approach to each of these issues is set out in the remainder of this chapter, namely:

- section 10.2 defines the parameters of the optional firm access model, including those features we view as core and those that are likely to require further consideration;

- section 10.3 outlines the further work on the optional firm access model that would need to be carried out in the detailed design and testing program;

- section 10.4 provides an overview of the Commission's views on the level of involvement that stakeholders should have in the detailed design and testing program and the measures that could be put in place to facilitate that involvement;

- section 10.5 sets out the resources that are likely to be required to carry out the work during the detailed design and testing program;

- section 10.6 provides an overview of the key elements of the implementation plan that could be employed if SCER decides to proceed with the introduction of the optional firm access model and related transmission planning and investment decision making arrangements; and

- section 10.7 outlines the more immediate actions that can be taken on a number of the planning related recommendations set out in chapter 4.

10.2 Scope of future work on the design of the optional firm access model

Although the optional firm access model has been designed in some detail over the course of this review, further work would need to be carried out if SCER decides to progress development. To ensure that this future development does not unnecessarily duplicate the work that has already been undertaken, we have given careful consideration to those elements of the model that should be 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 and should *not* therefore be revisited when developing the final design of the model or further assessing it;

- recommended – the term "recommended element" is used to describe those elements of the model that, in our opinion, should form part of the final design of the model, but which would require further work to establish whether or not they are workable and so 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 and should form part of the final or future design of the model.

The categorisation of the model's elements as core, recommended or optional element is set out in Table 10.1. The references in brackets after each element refer to the relevant section in the Technical Report where the element is discussed.

Table 10.1 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 (2.2.3) • Access entitlements are independent of dispatch (2.2.3) • Access settlement balances in each settlement period (2.2.4) • Access settlement occurs at congested flowgates (2.2.5) • The amount of compensation paid or received would be the difference between a generator's usage and its entitlements, multiplied by the flowgate price (2.2.5) • The sum of the entitlements must equal the flowgate capacity (2.2.5) • TNSPs must maintain the firm access standard (2.2.7) • The firm access standard is based on level of flowgate capacity required to provide access to firm generators (2.2.7) • Access is firm but not fixed (2.2.8)	• Access charge is fixed - apart from specified indexation - for life of access agreement (2.2.8) • Flowgate support generators paid regional reference price (2.2.9)	

	Core Elements	Recommended Elements	Optional Elements
	• Access charges paid to TNSPs (2.2.8)		
Access settlement	• Flowgates created on every transmission constraint (4.2.2) • Flowgate parameters (participation factor and capacity) taken from NEMDE (4.2.2) • Target entitlements based on access amount multiplied by participation factor (4.2.3) • Non-firm entitlements not provided unless firm target entitlements are met (4.2.4)	• Transmission constraint defined as "any NEMDE constraint arising from a limitation on a TNSP network for which a constrained generator is not currently compensated" (4.2.2) • Firm access amount limited by capacity (4.3.4) • Non-firm access amount is the shortfall between availability and firm access (4.2.3) • Super-firm entitlements provided, subject to firm entitlement scaling factor and as needed to top-up firm entitlements (4.2.3) • Flowgate support generators provided with negative entitlements (to ensure paid regional reference price) which adds to effective flowgate capacity (4.2.5) • The settlement period for access settlement is a trading interval (30 minutes) (4.2.7)	
Firm access standard	• Firm access standard is an operational standard that applies in real-time dispatch, as opposed to a planning standard (5.2.2)	• 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)) (5.3.2)	• Firm access standard target flowgate capacity should include target super-firm entitlements. (The alternative is that it does not include super-firm entitlements) (5.3.3)

	Core Elements	Recommended Elements	Optional Elements
	• Target capacity on each flowgate based on access and participation of firm generators only (5.2.2) • Firm access standard does not place any obligation on TNSPs in relation to non-firm generators (5.2.2) • Normal operating conditions includes system normal (5.2.2) • Target flowgate capacity not required to be provided on uncongested flowgates (5.2.2) • RIT-T assessments no longer include benefits and costs that accrue to generators (8.3.9)	• Firm access standard is uniform across the NEM (alternative is for it to vary between regions) (5.3.6) • Normal operating conditions includes planned outages (5.2.2) • Normal operating conditions criteria are flowgate specific (5.2.4) • Firm access standard does not place any obligation on TNSPs outside normal operating conditions (5.3.1) • No change in reliability standards for OFA implementation (but a parallel change to reliability standards is not ruled out by this) (5.3.7)	
Access pricing	• Access charge based on Long Run Incremental Cost (LRIC), defined as difference in NPV between baseline expansion costs and adjusted expansion cost (6.1) • LRIC estimated based on stylised model rather than actual TNSP expansion plans (6.2.2) • Access charge must take account of cross-regional impacts and provide for appropriate cross-regional payments between TNSPs (6.2.4)	• Access charge excludes the effects of reliability standards and reliability access (6.2.3) • LRIC calculated separately for each transmission branch element (6.2.1) • Element LRIC based on initial spare capacity, flow growth, lumpiness, incremental usage and access term (6.2.1) • Element parameters based on a combination of detailed forecasts for	• Meshedness factor use to adjust the lumpiness of parallel lines (other alternative approaches may be possible) (6.2.3) • Discount rate for NPV calculation based on TNSP regulated cost of capital (alternative discount rates are possible) (6.2.3) • 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) (6.3.6)

	Core Elements	Recommended Elements	Optional Elements
	• Access charge is payable through annualised payments over the access term (6.2.5) • Non-firm generators do not pay an access charge (6.1)	shorter-term and stylised estimates for longer-term (6.2.2) • Forecasts based on NTNDP or other information provided by NTP (6.2.2) • Super-firm access charged the same way as firm access: ie generator capacity not taken into account (6.2.3) • No negative access charge on elements where a negative LRIC is calculated (ie expansion can be deferred as the result of the new access) (6.2.4) • Annual payment profiling specified in access charge methodology (6.2.5) • Access pricing model and input parameters are maintained by NTP (6.3.6) • Pending access requests included in forecasts (6.3.7)	
Access procurement	• Access agreement defined by: amount, power station, node, term, profile, payments (7.2.1) • Access firmness standard and incentives not specified in access agreement, but through rules or regulations (7.3.2)	• 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 (7.3.4) • Access customisation permitted, subject to no adverse impact on other users (7.3.5)	• Procurement will follow a process described in the technical report (alternative processes are possible) (7.2.2) • Pricing model may be available for generators to use (7.2.2) • Access profiled by peak/off-peak

	Core Elements	Recommended Elements	Optional Elements
		• Generator details will be confidential at early stage of procurement process, but will be published at a later stage (7.2.3) • Access term not restricted (7.2.1) • TNSP can offer short-term access through auction process (7.2.4) • Generators can secondary trade access bilaterally with TNSP permission (7.2.5) • Generators can sell short-term access through the TNSP auction (7.2.5) • Prudential arrangements to ensure access payments made are specified in access agreement (7.3.2) • TNSPs may delay access commencement where expansion required (7.3.6) • Grouped procurement permitted (7.3.9)	following forward market conventions (other profiles are possible and even option structures) (7.2.1) • TNSP approves bilateral secondary transfer, subject to no increase in net LRIC (other criteria are possible) (7.2.5) • Short-term access has equal firmness to long-term access in access settlement (alternative is that short-term access is treated as mezzanine) (7.3.8)
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 (9.2.2) • Access settlement for inter-regional access is the same as for intra-regional access (9.2.4)	• Inter-regional access is sold in quarterly blocks (9.2.5) • Auction sales are subject to TNSP verification that any associated capacity expansion is economic (9.2.5) • Auction prices would be based on the LRIC pricing methodology (9.3.3)	• 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) (9.2.5)

	Core Elements	Recommended Elements	Optional Elements
	• Firm access standard for inter-regional access is the same as for intra-regional access (9.2.3) • 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) (9.2.5) • Inter-regional access is sold in a AEMO-run auction (cf intra-regional access, which is sold bilaterally by TNSP) (9.2.5)		
Revenue regulation and incentives	• TNSPs have an ex ante allowed revenue allowance based on the efficient costs of providing current levels of load and firm access services (8.2.4) • 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 (8.2.4) • A cap on the TUOS revenue – which would restrict charges that users of load services face – would apply (8.2.4) • TNSPs would face an incentive scheme and pay a penalty equal to some proportion of the settlement shortfall due	• An uncertainty mechanism would be introduced allowing the TUOS revenue cap to be adjusted upwards or downwards (8.3.2) • Short-term access incentive scheme – TNSPs would be subject to 100% of any settlement shortfalls (8.2.5) • TNSPs face incentives outside the firm access standard to move back within normal operating conditions (8.3.10)	• 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) (8.3.10) • TNSPs face incentives outside the firm access standard to encourage TNSPs to provide an efficient level of access (8.3.10)

	Core Elements	Recommended Elements	Optional Elements
	to firm access standard breach (8.2.5) • TNSP penalties paid into access settlement to offset settlement shortfall and mitigate the scaling back of firm access (8.2.5)		
Transition	• Existing generators are allocated some transitional access, at no charge (10.2.2) • Transitional access allocation is firm access compliant on existing network (10.2.2) • Transitional access is sculpted back over time (10.2.2)	• Transitional access auction established for one-off reallocation of transitional access (10.2.2) • Transitional access allocation based on generator capacity and pre-OFA operating regime (10.2.2) • Inter-regional transitional access would only be allocated to the extent that it would not cause any additional scaling back of generators' transitional access (10.2.2)	• Sculpting profile based on 3 parameters X, Y, Z and K to be determined in implementation (other profiles are possible) (10.2.2)

10.3 Detailed design and testing program

To enable SCER to make an informed decision about whether or not optional firm access should be implemented, further work would need to be carried out on the design of some of the more critical elements of the model. In particular, the focus of this work would be on better defining some of the core and recommended elements of the model. This would concentrate on:

- the firm access standard to apply to both intra- and inter-regional access products;
- the access settlement model that would underpin both the intra- and inter-regional access products; and
- the access pricing methodology and pricing model that would apply to both the intra- and inter-regional access products.

This detailed design and testing program would allow for a more informed assessment of the costs and benefits to be carried out. However, based on our experience in this review it is unlikely that all of these would be capable of being quantified. Some form of qualitative assessment is therefore likely to be required for particular categories of costs and benefits.

It is also important to emphasise that the level of the benefits derived from the implementation of optional firm access would depend on the extent to which wider changes in the market eventuate. Benefits associated with implementing the model would likely be more substantial the greater the changes in future generation and demand patterns. While it may be possible to model various potential scenarios, this would ultimately require a view of the likely future change in the market to be taken.

10.3.1 Additional quantitative assessment

While it may not be possible to quantify all the costs and benefits associated with it, the more developed specification of the model would allow for a better understanding of these. In particular, it would be possible to estimate many of the costs that would eventuate including:

- implementation costs;
- any enduring additional costs faced by AEMO, the AER, TNSPs or market participants; and
- potential changes to the risk profile of TNSPs.

In addition to the work undertaken for us by ROAM Consulting regarding savings from the improved co-optimisation of generation and transmission investment, further work could be undertaken to assess the potential benefits associated with:

- increased financial certainty for generators and a reduction in price volatility in the wholesale market; and

- the firmer inter-regional hedging product, which would increase competitive pressures in regional wholesale and retail markets. This work could draw on existing approaches to estimating competition benefits when assessing interconnector expansions.

It may be possible to identify other approaches to assess benefits associated with the model, as the understanding of it increases. This may be aided by obtaining additional expertise and different perspectives, as discussed in the following section.

10.4 Stakeholder involvement in the detailed design and testing program

Developing the optional firm access model will require a number of complex issues to be considered from a range of different perspectives. The complex and multi-faceted nature of this task, coupled with the fact that optional firm access would represent such a fundamental change to the current arrangements and has received a mixed reaction from market participants, has prompted the Commission to give further consideration to the level of involvement that stakeholders should have in the detailed design and testing program.

The Commission is of the view that there would be value in having key stakeholders involved in both:

- the project team that would be responsible for carrying out the work outlined in sections 10.2 and 10.3; and

- directing the detailed design and testing program and providing advice to both the project team and the Commission.

We therefore recommend that, if SCER directs the AEMC to further develop the model, there would be significant merit in establishing both:

- a multi-disciplinary project team led by the AEMC and consisting of staff and secondees from AEMO, the AER, TNSPs and other market participants, to carry out the work outlined in sections 10.2 and 10.3; and

- an independently chaired specialist panel (akin to the Reliability Panel), consisting of senior representatives from the generation, transmission and end-user segments of the NEM, AEMO, the AER and the AEMC, to direct the development stage (the "OFA Panel").

We recognise that these measures are likely to require a significant degree of commitment and cooperation from key stakeholders. However, in our opinion, this is appropriate given the nature of the task and the need to ensure that the project team and OFA Panel have the appropriate skills set to carry out the development and testing.

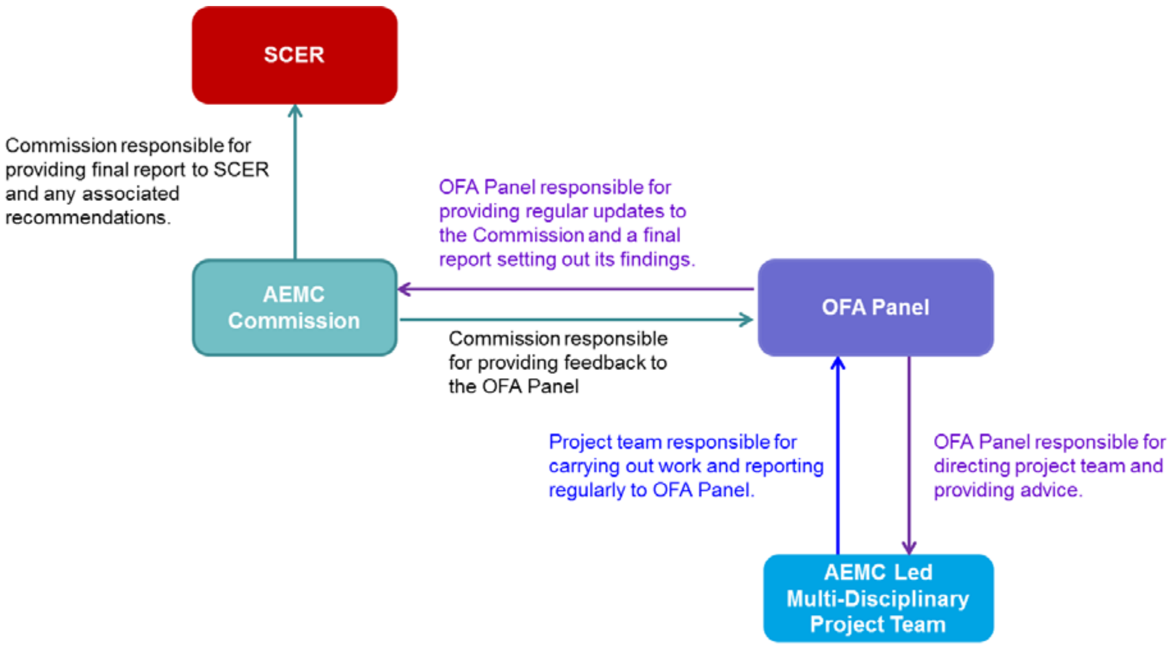
The remainder of this section provides further detail on:

- the roles that the project team, the OFA Panel and the Commission would be expected to play during the detailed design and testing program; and
- the other measures that would be put in place to encourage stakeholder involvement in the detailed design and testing program.

10.4.1 Roles to be played by the project team, OFA Panel and the Commission

Figure 10.1 depicts the roles we propose should be played by the project team, the OFA Panel and the Commission in the detailed design and testing program.

Figure 10.1 Roles to be played by the project team, OFA Panel and Commission



As Figure 10.1 shows, the Commission would retain overall responsibility for the work. The OFA Panel would be responsible for the detailed direction of the work and would therefore be directly involved in:

- designing key elements of the optional firm access model, such as the firm access standard, the access settlement model, the access pricing methodology and the pricing model;
- testing key elements of the optional firm access model; and
- assessing the costs and benefits, to the extent possible, of implementing the model.

Operating in this capacity, the OFA Panel would be responsible for:

- directing the project team and providing it with advice on any issues arising during the development process;
- providing the Commission with regular updates on the status of the work being carried out on the design of the model and any assessment of the costs and benefits; and
- presenting a report to the Commission at the completion of the work that sets out the Panel's findings.

The Commission would be responsible for the providing the final report to SCER, and making any associated recommendations.

Further detail on how the OFA Panel and project team would be established and how they would be expected to operate is provided in Box 10.1.

Box 10.1: OFA Panel and multi-disciplinary project team

OFA Panel

Under the proposed structure set out in Figure 10.1, the OFA Panel would be responsible for directing the detailed design and testing program. To formalise the role to be played by the OFA Panel in this process, the panel would be established under section 39 of the NEL. This section of the NEL allows the AEMC to establish a panel to provide advice on specific aspects of its functions, or to undertake any other activity in relation to its functions as specified by the AEMC.

At this stage it is envisaged that the OFA Panel would be led by an independent chairperson, with Panel members nominated and appointed by the AEMC. To ensure appropriate representation of all key stakeholders, five panel members would be senior representatives from AEMO, the AER, the generation, transmission and end-user segments of the NEM. AEMC Commissioners would sit on the panel in an ex officio capacity.

Given the significance of the task, the OFA Panel would be expected to meet at least once a month and provide regular updates to the Commission on the status of the work. Any secretariat services required by the OFA Panel would be provided by the AEMC.

Project team

To carry out the work set out in sections 10.2 and 10.3, the project team would require a range of different skills. The project team would therefore ideally consist of staff and secondees from the AEMC, AEMO, the AER, TNSPs and other market participants, and, where necessary, would draw on the services of expert advisers.

To ensure the skills of the team are appropriately utilised, it is expected that the project team would be divided into a number of work streams.[183] Each work stream would report into an AEMC nominated project leader, who would be responsible for coordinating the work program.

Setting up this type of project team would require a significant degree of cooperation between the employers of the project team members. However, the process is likely to be facilitated by both:

- the Memoranda of Understanding between the AEMC, the AER and AEMO; and
- the OFA Panel, which will consist of senior representatives from the employers of the project team.

Under the proposed structure, the project team would report directly to the OFA Panel and to provide it with regular updates on the status of the work program. While not shown in Figure 10.1, the AEMC would be responsible for the day-to-day management of the team.

10.4.2 Other measures to facilitate stakeholder involvement

In addition to having key stakeholders involved in both the project team and the OFA Panel, the following measures would be put in place to encourage other stakeholders to participate in the detailed design and testing program:

- an issues paper would be published shortly after the commencement of work and interested parties would be given the opportunity to respond to the matters raised in this paper;
- stakeholder workshops would be conducted at various points throughout the process; and
- industry-based working groups may also be convened on an ad hoc basis during the detailed design and testing program, to provide advice to the project team and the OFA Panel on particular elements of the optional firm access model.

10.5 Resource requirements in the development stage

At this point in time, we expect that it would take around 12 months for the project team to complete the detailed design and testing program, and for the OFA Panel to report its findings to the Commission. Expert advice is also likely to be required during this process on a range of issues, including:

183 For example, the work to be carried out on the access settlement model would ideally be carried out by the AEMO team members while the work to be carried out on the firm access standard might be carried out by the AEMC team members and a TNSP secondee.

- the firm access standard;
- the access pricing methodology;
- the pricing model; and
- the quantification of particular costs and benefits, to the extent this is possible.

Based on our current expectations of the work that would need to be carried out, the expert advice that is likely to be required and the costs of establishing both the OFA Panel and the multi-disciplinary project team, we have estimated that it would cost around $5 million to complete this further work program.

Given the significance of this piece of work, the funds required to carry out this assessment would need to be in addition to the AEMC's general funding requirement. Work on the detailed design and testing program could not therefore commence until the AEMC received an appropriate direction from SCER and funding arrangements were established.

10.6 Implementation process

If, following the process outlined above, SCER decides that the optional firm access model should be implemented, then a significant amount of further work would need to be carried out on both:

- the design of the remaining elements of the optional firm access model; and
- the legislative, regulatory and institutional arrangements that would be required to give effect to the optional firm access model and the related planning arrangements.

We have therefore developed a high-level implementation plan that could be employed if SCER decides to proceed with the introduction of the model. In short, this consists of the following steps:

Step 1: Finalise the complete detailed design of the optional firm access model and identify all the changes to be made to the rules and the NEL to give effect to the model and the transmission planning and investment decision making arrangements;

Step 2: Enact the required changes to the NEL, institutional arrangements and the rules; and

Step 3: Implement the optional firm access model and the related planning arrangements.

Ideally, the work to be carried out in Step 1 of this implementation plan would be subject to the same arrangements as those established for the detailed design and testing program (see section 10.4) while the responsibility for enacting changes to the legislative, regulatory and institutional architecture in Step 2, would be divided between:

- SCER, who would be responsible for progressing any revisions to the NEL and institutional arrangements (including their passage through the South Australian parliament); and
- the AEMC, which would be responsible for assessing any rule change request that is made in response to the recommendations contained in its report to SCER at the end of Step 1.

The remainder of this section provides further detail on the three steps of the proposed implementation plan.

10.6.1 Step 1: Develop complete detailed design of model and identify changes to the rules

Under the proposed implementation plan, the multi-disciplinary project team, the OFA Panel and the Commission would play a similar role to that outlined in section 10.4.1 in Step 1. The OFA Panel and the project team would therefore be responsible for completing the detailed design of the model, identifying all of the changes to be made to the rules to give effect to the model and the related transmission planning and investment decision making arrangements, and reporting these findings to the Commission. The Commission would then be responsible for making final recommendations to SCER.

We anticipate that the following work would need to be carried out during this step:

- make any refinements that may be required to the firm access standard, the access settlement model, the access pricing methodology and the pricing model developed during the earlier development stage;
- specify the basic terms and conditions to be included in a firm access agreement;
- identify all of the changes to be made to the economic regulatory framework applying to TNSPs. These changes would be required to, amongst other things, account for the revenue derived by TNSPs through firm access sales and to give effect to the new access procurement process, the access pricing methodology, an incentive sharing regime and the new RIT-T process;
- define the scope and term of any transitional arrangements that would be required and develop an auction process to facilitate the trade of transitional firm access rights amongst generators;
- design an inter-regional auction process and the functional specification of IT infrastructure to support this process;
- develop an inter-regional project cost-benefit assessment framework;

- carry out detailed testing of all the elements of the optional firm access model (including the settlement and access pricing models) and run market simulations;
- identify the changes to be made to the network planning arrangements to give effect to the recommendations set out in chapter 4; and
- identify all of the changes to be made to Chapters 2, 3, 5, 6A, 10 and 11 of the rules to give effect to the optional firm access model and the related planning arrangements.

The key deliverable at the end of this step would be a report from the Commission to SCER setting out the recommended design of the optional firm access model and identifying all of the changes to the rules that would be required to implement the model and the related planning arrangements.

At this point in time, we expect that it would take a project team of around 15, consisting of staff from the AEMC, AEMO, the AER and industry, approximately three years to complete this work. A significant amount of expert advice would be required on a wide range of issues, such as the design of an inter-regional auction process, the development of an incentive regime and the design of an inter-regional cost-benefit assessment framework. We estimate that it would cost around $15 million to complete this.[184]

Finally, it is worth noting that we would expect extensive stakeholder consultation to be carried out throughout the process and that similar measures to those set out in section 10.4.2 would be employed to facilitate the consultation process.

10.6.2 Step 2: Enact legislative, regulatory and institutional changes

Before implementation of the optional firm access model and the transmission planning and investment decision making arrangements could occur, significant revisions would need to be made to the legislative, regulatory and institutional architecture currently underpinning the NEM.

Changes to the NEL and institutional arrangements

Any revisions that need to be made to the NEL or institutional arrangements to give effect to the optional firm access model or the related planning arrangements would need to be made before the rule change process commences. These revisions would therefore ideally be made at the same time the work in Step 1 is being carried out. To enable this to occur, the report presented to SCER at the end of the development stage should aim to identify all the revisions to be made to the NEL and institutional arrangements if SCER decides to proceed with the implementation of the optional firm access model.

184 Again, this funding requirement would need to be in addition to the AEMC's general funding requirement.

Rule changes

To implement the optional firm access model and planning related changes, extensive revisions to Chapters 2, 3, 5, 6A, 10 and 11 of the rules would be required. To avoid any unnecessary duplication of work and consultation, any optional firm access related rule change request that is made following the completion of Step 1 would ideally be assessed using the "fast track" rule change process set out in section 96A of the NEL. This section of the NEL allows the AEMC to proceed straight to a draft determination if certain conditions are satisfied. The conditions of particular relevance in the current context are set out below:

- the rule change request must be made on the basis of a recommendation for the making of a rule in a MCE directed review or an AEMC rule review; and
- the AEMC must be of the opinion that:
  - the rule change request reflects, or is consistent with, the relevant recommendation contained in the MCE directed review or relevant conclusion in the AEMC rule review (as the case requires); and
  - there was adequate consultation with the public by the AEMC on the content of the relevant recommendation during the MCE directed review or relevant conclusion in the AEMC rule review (as the case requires).

If, these conditions are not satisfied, then the rule change request would be subject to the standard rule change process.

If the fast track provisions were able to be utilised, the rule change assessment process might be completed within six months (reflecting the significant amount of development work and consultation that would already have been undertaken). If, on the other hand, the standard rule change process was employed, it would take 12-18 months to complete the assessment process.

10.6.3 Step 3: Implement the optional firm access model and related planning arrangements

Once the legislative, regulatory and institutional architecture is in place and any other conditions are satisfied,[185] the optional firm access model and related planning arrangements could be implemented. This implementation could occur by either:

- phasing in particular elements of the model over time; or
- implementing all of the elements of the model at once.

185 An example of another condition that may need to be satisfied is the potential requirement for the AER to develop a guideline on how it will apply an incentive sharing regime. This guideline could only be developed on the rules are in place.

Box 10.2: Interaction with the regulatory determination process

In the absence of any other measures, the regulatory determination processes could delay the introduction of the Chapter 6A elements of the optional firm access model. While a decision on how this issue should be dealt with does not need to be made at this time, we have given some preliminary thought to the options that could be employed. These options include:

1. delaying the regulatory determination processes until the revised Chapter 6A rules are in place and any other conditions precedent are satisfied, which could involve using a similar type of placeholder approach to that employed in the AEMC's recent Economic Regulation of Network Service Providers Rule Determination; and

2. incorporating a narrowly defined prospectively operating mandatory re-opener provision in Chapter 11 of the rules that would be triggered once the revised Chapter 6A rules are in place and any other conditions precedent are satisfied. To limit the issues that would need to be considered at this time, the re-opener would only allow those elements of the regulatory determination that are directly affected by the operation of the optional firm access model could be re-opened (eg the capex forecasts, the calculation of TNSP's revenue requirement and the operation of the quality based incentive regime).

Of the two options listed above, the narrowly defined mandatory re-opener option is likely to be the most appropriate, because:

- it would avoid the need for complex transitional arrangements to deal with a delay in the regulatory determination process;
- it would be flexible enough to deal with any delays in the enactment of the new Chapter 6A rules or any other conditions precedent that need to be satisfied before these elements of the model are implemented; and
- it would operate in a prospective manner only and leave those parts of a TNSP's regulatory determination that are unaffected by optional firm access untouched and, in so doing:
  - reduce the risks that may otherwise be posed by a full reopening of the regulatory determination and, in so doing, provide TNSPs with a greater degree of certainty about how the non-optional firm access related elements of their determination will be treated over the regulatory control period; and
  - minimise the amount of work to be carried out by the AER and TNSPs.

It is not necessary now to conclude which of these two alternatives would be more appropriate. However, it is worth noting that unless additional measures are put in place during Step 2, the regulatory determination process could act as an impediment to the latter alternative, because any changes to the Chapter 6A rules could only take effect through a new regulatory determination. Our preliminary thoughts on the measures that could be used to deal with this issue are outlined in Box 10.2.

10.7 More immediate actions that could be taken on planning

As previously noted, due to the degree of overlap between them, full implementation of the Commission's preferred approach to transmission planning and investment decision-making would be combined with implementation of the optional firm access model. However, it would be possible to take more immediate action on some of the planning recommendations outlined in chapter 4, and we are of the view that there would be merit in doing so.

The relevant recommendations are:

- provision of "bottom up" demand forecasts by AEMO (section 4.5.3);
- enhancing TNSP planning and decision making:
  - arrangements that promote the identification and implementation of network investment options that cross regional boundaries (section 4.6.1);
  - TNSPs providing greater input into the NTNDP to ensure that coordination between national and local issues occurs at the outset of the planning process (section 4.6.2);
  - consistency of APRs across the various TNSPs (section 4.6.3); and
- alignment of regulatory control periods (section 4.6.4).

The below sections discuss how each of these recommendations should be progressed.

10.7.1 Provision of "bottom up" demand forecasting

AEMO's functions should be modified to reflect its new role in providing "bottom up" demand forecasts. AEMO could then use its current information gathering powers[186] to gain access to the necessary information needed to produce the forecasts. Given that AEMO's functions are specified in both the NEL and the rules, the modification of AEMO's functions could through either a NEL or a rule change. Section A.1 sets out in detail how this could occur.

Since the publication of the Second Interim Report a number of other recent reviews have made recommendations regarding the production of demand forecasts by

186 Section 53(1), Part 5, Division 5 of the NEL.

AEMO. Most notably, the December 2012 COAG communique requested that AEMO should provide independent demand forecasts to the AER in a manner that would "enhance the AER's ability to analyse demand forecasts submitted by network businesses".[187] AEMO has committed to developing a consistent methodology for connection point forecasting across the NEM (at a transmission level), with the target delivery date at the end of June 2013.[188]

Given this development, the Commission recommends that SCER should consider our recommendation on demand forecasting when developing its response to the related task assigned to AEMO, as set out in the December 2012 communique.

10.7.2 Enhancing TNSP planning and decision making

The recommendations associated with enhancing TNSP planning decision making (ie the second recommendation identified above) would be implemented through a rule change request. In summary, rule modifications would be required around the sections of the rules that relate to the preparation of the NTNDP, APRs and RIT-T documents as set out in NER clauses 5.20, 5.12 and 5.16 respectively. Accompanying changes would also be required to Chapter 6A, allowing TNSPs to be able to recover revenue for constructing an asset that is required to meet regulatory obligations in another region.

We recommend that SCER should make a rule change request to give effect to these modifications. Appendix A.2 sets out the draft specifications for this rule change request, which would form the basis for draft rules.

These changes aim to allow for the identification and implementation of network investment options that cross regional boundaries and, as set out in chapter 4, this could be further facilitated by enhancing the role of AEMO as NTP. However, we consider that, while it continues to have a role in investment decision making in Victoria, it would be inconsistent to assign AEMO responsibility for independently reviewing the identification of cross-regional investments by jurisdictional planners (particularly those involving Victoria).

10.7.3 Alignment of revenue resets

The Commission also recommends aligning TNSP regulatory resets. This would begin to align regulatory control periods in 2017, with full alignment achieved from 2022. We have developed two alternative pathways for how this could be achieved – as set out in section A.3. While no enduring framework changes are required to support this, a transitional rule change would be necessary to achieve alignment. This would provide, on a one-off basis, for four-year regulatory control periods for a number of TNSPs. The rule change would need to be made before the AER began to consult on its approach for these revenue determinations (likely to be in 2015).

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187 COAG, *COAG Energy Market Reform - Implementation Plan*, 7 December 2012, p.11.

188 AEMO, *Planning Studies - 2013: Information and Consultation Paper*, 30 January 2013, p.6.

We recommend that SCER should task the AER with developing a rule change request to facilitate this revenue reset alignment, in accordance with this proposed approach (as set out in section A.3). If the AER chooses to pursue an alternative approach to achieve alignment, it should explain why in the rule change request.

11 Introduction to Connections

11.1 Introduction

Part 2 of this report presents a comprehensive package of recommendations for changes to the frameworks for connecting to the transmission system. In developing the changes, we have sought to strike a balance between the interests of connecting parties and those of electricity consumers more broadly.

This is an area that attracted significant stakeholder comment over the course of the review, and we gave careful consideration to this. While our recommendations build on the proposals we presented in the review's Second Interim Report, these were further developed in some areas in light of the stakeholder responses received and the further debate these triggered.

When considering connection issues, a key distinction can be made between services provided by assets that form part of the shared network and those provided by assets used exclusively by the connecting party (or parties). Our recommended framework can consequently be most easily understood when broken down into these two elements. The following chapters therefore set out and explain our recommendations in this way.

11.2 Overview

11.2.1 Objectives

Our package of recommendations seeks to address two main issues related to transmission connections:

- the complexity, ambiguity and lack of clarity in the rules and frameworks in this area; and
- the asymmetric power held by TNSPs in negotiating with connecting parties.

These issues have led to generators and other parties encountering difficulties in connecting to the network, which they consider have resulted in unsatisfactory outcomes in terms of cost and timeliness.

To an extent, improving the first issue will help in mitigating the second issue. That is, making the rules clearer and simpler should make it easier for generators to know exactly what assets and services they are negotiating for, and enhance their ability to negotiate on more equal terms with TNSPs.

However, we consider that further changes can be made to help address the issue of asymmetric power in negotiating, as follows:

- current negotiating frameworks can be strengthened to require TNSPs to provide better information to connecting parties, allowing them to negotiate in a more informed manner; and
- competition in the construction of assets required to facilitate connections can be promoted. This should give connecting parties a greater ability to manage costs and timings, and place competitive pressure on TNSPs to improve performance.

11.2.2 Key policy principles

A key theme of the review was debate regarding the extent to which competition should play a role in the provision of transmission services.

The Commission's view is that, where it is workable, competition in the provision of services will produce the most efficient outcomes. However, there are aspects of electricity markets, in particular electricity transmission, which are natural monopolies. For these services, an effectively regulated monopoly provider should produce more efficient outcomes than competition. This is particularly relevant to the provision of the shared transmission network, where trade-offs between costs and system security/reliability will affect all network users.

Our recommendations therefore seek to ensure that an appropriate balance is struck between maintaining secure and reliable operation of the network and enabling generators and loads to connect at efficient cost. We consider that TNSPs should remain centrally accountable for operation, control and maintenance of the shared transmission network in their licensed (or "local") area.[189] This includes assets required to facilitate connections, but which form part of the shared transmission network. This focussed accountability for operation on a single body represents the best framework for a secure and reliable electricity system, with TNSPs clearly required to maintain:

- reliability standards;
- technical standards such as voltage and frequency stability; and
- service and availability standards.

Accountability for the operation of all shared network assets by the local TNSP means that TNSPs are fully responsible for shared network service outcomes.[190] This approach would also be consistent with the implementation of the optional firm access model, where the incentives placed on TNSPs to promote the efficient provision of the firm access service are dependent on TNSPs being able to manage all the determinants of the quality of this service.

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189 As explained in Box 12.1, the transmission arrangements in Victoria are different to those in the rest of the NEM. Consequently, implementation of the Commission's recommendations would need to take account of this.

190 TNSPs should not be precluded from sub-contracting elements of network operation as AEMO does.

For assets used only by the connecting party, the risks of inadequate design, construction and operation of the assets falls on that user. Action can be taken to protect the shared network, such as isolating the connection. Consequently, for such assets, the balance of considerations falls more clearly in favour of full contestability, subject to appropriate provisions to facilitate access to the assets by third parties.

11.2.3 Features

Given these principles, the Commission is recommending an approach whereby construction (and potentially ownership) of shared network assets that are used to connect a generator would be contestable. Furthermore, connection assets which do not form part of the shared network would be open to construction, ownership and operation by any qualified party, including connecting generators.

However, TNSPs would remain as monopoly providers of some elements of a connection service. These would include the high level design, operation and work to cut in to the existing shared network, since they directly affect the operation and performance of the shared network. Consequently, in order to mitigate the TNSP's monopoly power in the negotiating process, we are recommending measures to: increase the transparency of information (particularly with regard to costs), allow an independent check of the appropriateness of TNSPs' technical requirements, and clarify the process for disputes if agreement cannot be reached.

A final, but crucial, part of our recommendations is to improve the clarity of the rules. In particular, this helps facilitate all the other measures by defining the boundaries between contestable services, negotiated services and prescribed services.

11.3 Boundaries and definitions

It is important that the rules recognise that connecting to the network requires the provision of a connection service, and not just assets. However, the absence of a clear linkage between service classifications in the NER and the assets underpinning their provision has been a source of confusion, and has hampered effective negotiations.

In order to negotiate the terms of a transmission service, the service needs to be specified in a way that can be priced. The majority of costs involved in providing a connection are driven by investment in assets. Without a clear understanding of which assets could be reasonably specified by a TNSP, connecting parties have not been able to participate in negotiations in an informed manner.

It is therefore important that the clarity of the connection frameworks is improved, and we are recommending significant changes in this regard, particularly around boundaries and definitions. Appendix C sets out draft specifications that should be applied in drafting rule changes, both to effect this and to implement the other changes recommended in part 2 of this report. In this section we summarise some of the most significant changes that should be made in order to provide a framework and key terminology for the recommendations in the chapters that follow.

11.3.1 High level principles

As a starting point to clarifying the frameworks, we recommend that it be put beyond doubt that all equipment operated at transmission voltages in participating jurisdictions and interconnected with the rest of the transmission system is subject to the NEL and, by default, the rules.

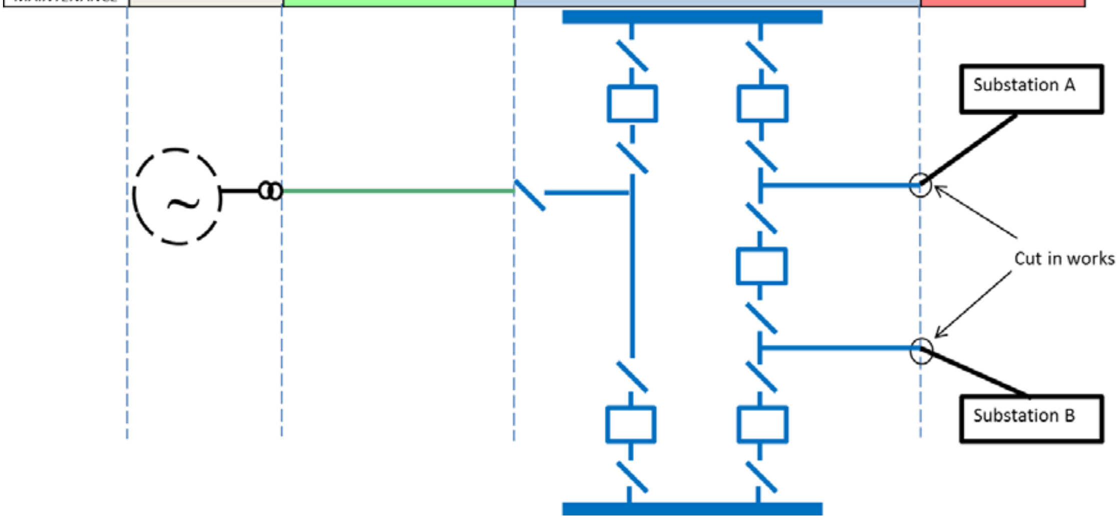
This approach would ensure that appropriate third party access arrangements could be put in place. It would also provide a mechanism for connection assets to subsequently be subsumed into the shared network, if this was required and represented the most efficient solution. As described in chapter 13, this could be achieved while still exempting many parties from registering as a TNSP (and therefore being subject to the rules).

Accordingly, an asset should be a "transmission asset" for the purposes of the rules if it meets specified physical and technical criteria - primarily related to the voltage of electricity transfer. Transmission assets would then be divided into "transmission connection assets" (referred to in this report as dedicated connection assets)[191] and "shared transmission network assets" (shared assets)[192].

These concepts are illustrated in Figure 11.1, which provides a stylised example of a layout of the assets used to connect a generator.

Figure 11.1 Illustrative transmission asset classification

TITLE	Generator Assets	Dedicated Connection Assets	Identified User Shared Assets (part of shared transmission network)	Shared Transmission Network
CONSTRUCTION AND OWNERSHIP	Generator	Contestable (as a non-regulated service)	Contestable (as a non-regulated service) OR Local TNSP (as a negotiated service)	Local TNSP (as a prescribed service)
DESIGN, OPERATION, CONTROL, MAINTENANCE			Local TNSP (as a negotiated service)	



191 The rules would define these assets as "transmission connection assets". However, we refer to these throughout this report as dedicated connection assets.

192 The rules would define these assets as "shared transmission network assets". However, we refer to these throughout this report as shared assets.

11.3.2 Dedicated connection assets

Dedicated connection assets would broadly comprise the transmission equipment between a substation and a generator's plant or large customer's site. More precisely, dedicated connection assets are transmission assets:

- developed and constructed for the purpose of connecting an identified user group to an existing transmission network (the "purpose limb");
- used exclusively by the relevant identified user group (the "use limb"); and
- for which the costs of developing, constructing, operating and maintaining are not recoverable from the broader customer base as charges for prescribed transmission services (the "payment limb").

An "identified user group" is a group of one or more specifically identified generators or large loads that are connected to transmission assets that are, in turn, connected to the shared transmission network at the same point.

Previously in the review, we have referred to lines between a substation and a user's plant or site as an "extension". The term is replaced under the above definition of dedicated connection assets, although it should be noted that this would additionally refer to some assets located within the substation.[193]

The boundary between dedicated connection assets and shared assets should be defined as the first point at which the power flow from the generator can be isolated from the shared network. In most cases this will be an identifiable isolator or disconnector.

We recommend that dedicated connection assets should be capable of being constructed, owned, operated, controlled and maintained by any party.

11.3.3 Shared assets

The majority of shared assets would be those forming part of the wider shared network, providing TUOS services to consumers. However, for the purposes of connections, it is important that a particular sub-category of shared assets is defined. In this report, we term these **identified user shared assets**.[194]

Identified user shared assets are those parts of a substation which, while forming part of the shared network, are required solely for the connection of an identified user group. More precisely, identified user shared assets are shared assets developed and constructed for the purpose of connecting an identified user group to an existing

193 The term "extension" is defined in the NEL as well as in the rules. Following implementation of our recommendations, it could therefore be deleted from the NEL. However, it is not necessary to do so in order to make the relevant changes to the rules.

194 The rules would define these assets as "identified user shared network assets". However, we refer to these throughout the report as identified user shared assets.

transmission network, but not used exclusively by the relevant identified user group (ie transmission assets that meet the purpose limb, but not the use limb).

We recommend that identified user shared assets should broadly be capable of being constructed by any party, but that the local TNSP should be responsible for operating, controlling and maintaining them either directly or under contract. However, in practice, it will be necessary for construction of some identified user shared assets to be undertaken by the TNSP (ie works to "cut into" the broader shared network).

It should also be noted that the rules do not currently treat generator, large load and DNSP connection consistently. In particular, identified user shared assets would not currently exist for large load or DNSP connections: these assets would instead be classed as providing TUOS services. We consider that it would be appropriate for large loads to benefit from the contestability that we are recommending for identified user shared assets, and further consideration should therefore be given to service classifications in this regard.

11.3.4 Summary

The definitions and principles set out in this chapter lead to three types of transmission asset (in addition to interconnectors, which are not of direct relevance in this context).

Table 11.1 Categories of transmission assets

Asset type	Description	Paid for by	Contestability
Shared assets	Used by the broad base of consumers.	All market customers (through TUOS).	Built, owned and operated by TNSP.
Identified user shared assets	Required for connecting generator or load but not used exclusively by it.	Connecting generator for generator connections. All market customers, through TUOS, for load connections.	TNSP accountable for operation, control and maintenance. Construction and ownership contestable.
Dedicated connection assets	Required and used exclusively by connecting generator or load.	Connecting generator or connecting load.	Construction, ownership and operation contestable.

The remainder of this part of the report refers to the last two categories set out in the table above.

Chapter 12 sets out our recommendations for the treatment of identified user shared assets, in particular the arrangements for contestability in the construction of these and the measures for increasing transparency. Appendix D presents a detailed description of the process for gaining a connection to the shared network under this approach.

Chapter 13 explains our recommendations for the treatment of dedicated connection assets, notably provisions for third party access. Appendix E provides more information on the potential applicability of Part IIIA of the Competition and Consumer Act in this regard.

Finally, while there is a degree of interaction with the arrangements for optional firm access put forward in this report, we consider our connections recommendations to be largely separable and capable of implementation independent of the recommendations in part 1 of this report. Chapter 14 therefore presents a summary of the approach we recommend for implementing the changes to the connections frameworks. Detailed draft specifications that should be applied in drafting rule changes are set out in appendix C.

12 Connecting to the shared network

Summary of this chapter

Identified user shared assets and services are fully funded by connecting generators. Consequently, there are currently limited checks on the incentive on TNSPs to maximise the reliability and security - and therefore the cost - of those investments. The Commission recommends greater contestability for aspects of the service where it will not compromise the ongoing security and reliability of the system, greater transparency for the other aspects, and an improved overall connection process.

In particular, greater contestability should be introduced in construction of identified user shared assets. A connecting party should be able to select its own contractor to construct the assets, construct them itself, or alternatively require the TNSP to carry out the construction as a negotiated service. It should also be able to negotiate whether it owns the assets, or the TNSP or a third party owns them. Other aspects of the connection service should be provided by the TNSP, and will therefore require negotiation between the two parties.

In order to increase the transparency of the information available to connecting parties to inform their negotiations, TNSPs should be required to publish information on standard designs, costs and processes for negotiated services. They should also be required to provide more detailed cost information to connecting parties in relation to specific connection applications.

The rights of the parties to seek resolution of disputes when the parties are not able to agree on one or more aspects of a negotiated service should be clarified in the rules. Parties should also have access to an independent expert review of any technical aspects of the negotiations.

The Commission considers the local TNSP should in all cases have accountability for operation, control and maintenance of all identified user shared assets within its licensed area, even if assets are constructed by a third party under the contestability regime. This means the TNSP should also necessarily have responsibility for the high level design of these assets.

Together with the clarified definitions set out in chapter 11 and appendix C of this report, the Commission considers that these recommendations would facilitate more timely and cost-effective connections to the shared network.

12.1 Introduction

This chapter sets out our recommendations for connecting to the shared network, in particular the treatment of identified user shared assets - those which are required to enable a generator to connect to the transmission network, but once built and operational, form part of the shared network.[195] This chapter is structured as follows:

- section 12.2 sets out a summary of our recommendations;
- section 12.3 presents the overarching rationale for these;
- section 12.4 explains the recommendations in more detail; and
- section 12.5 sets out how connection process would be altered.

12.2 Commission's recommendations

The connections frameworks should be amended to better facilitate contestable build and ownership of identified user shared assets. The local TNSP should always be accountable for the operation, control and maintenance of these assets, and should provide the high level design of the assets required.

All aspects of the service provided by a TNSP in respect of identified user shared assets should be provided as a negotiated transmission service. The principles in the rules underlying negotiations should be bolstered and applied directly to all TNSPs, rather than through individual negotiated service criteria and negotiating frameworks.

The transparency requirements on TNSPs when providing negotiated services should be enhanced. TNSPs should publish standard connection contracts, design standards and philosophies and pro forma preliminary programmes. When providing a quote for negotiated services, TNSPs should be required to provide a range of options for connection and a reasonable breakdown of costs.

Where agreement cannot be reached on the reasonableness of any technical requirements in the connection process, either party should have the option to appoint an independent engineering expert to provide their opinion. The choice of engineer is to be agreed between the TNSP and the connecting party, and the cost of the engineer's services should be shared equally between the two parties.

It should be clarified that the price, terms and conditions of all negotiated services are subject to commercial arbitration processes.

12.3 Rationale for Commission's recommendations

Connecting generators fund all the costs associated with connecting to the shared transmission network, and these are determined by negotiation between the TNSP and

195 As noted in the previous chapter, the rules do not currently treat generator, large load and DNSP connection consistently. In particular, identified user shared assets would not currently exist for large load or DNSP connections: these assets would instead be classed as providing TUOS services. We consider that it would be appropriate for large loads to benefit from the contestability that we are recommending for identified user shared assets, and further consideration should therefore be given to service classifications in this regard.

the connecting generator. This Negotiated Transmission Services regime was introduced in 2006 on the premise that parties connecting directly to the transmission system would typically be large and well resourced, providing a counterweight to the market power possessed by TNSPs and making commercial negotiation a feasible proposition.[196]

However, the fact that connections typically form a small part of a TNSP's business (as compared to the provision of the wider shared network) means that the countervailing market power of connecting parties has, in practice, been limited. The monopoly power held by TNSPs in connection negotiations means that there are limited checks on the incentive on TNSPs to maximise the reliability and security - and therefore the cost - of the resulting investments. Concerns have also been raised regarding the timeliness of connections.

The Commission recommends the introduction of greater contestability in construction and ownership of identified user shared assets where it will not compromise clear accountability for the ongoing security and reliability of the system. Facilitating contestability in construction gives the connecting parties the opportunity to seek lower cost providers and greater control over timing, as well as increased countervailing power in negotiations with the TNSP.

The Commission considers that contestability is not desirable for all aspects of a connection service. As explained in chapter 11, since the local TNSP has responsibility for the security and reliability of the system, the TNSP should have operational control of all shared network assets within its licensed area, even if assets are constructed by a third party under the contestability regime. This means the TNSP should also necessarily have responsibility for the high level design of identified user shared assets before detailed design and construction of the assets by a connecting or third party. This would not prevent TNSPs from sub-contracting elements of the operation or design if they choose, potentially including to connecting generators. However, accountability for those services should in all cases remain clearly and solely with the local TNSP.

Consequently, connecting to the shared network will always require negotiation with a monopoly TNSP for the provision of at least some aspects of the connection service. While it is not possible to replicate perfectly competitive outcomes under these circumstances, facilitating greater access to, and transparency of, information can make the playing field for negotiation more even and maximise the efficiency of outcomes. Our recommendations also seek to clarify the rights of the parties to seek resolution, and the principles to be followed by an arbitrator in determining a dispute, when the parties are not able to agree on one or more aspects of the connection service. This includes the ability to obtain an independent review of TNSPs' technical requirements.

The following section explains our recommendations and reasoning in more detail.

196 AEMC, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, Sydney, p.xvii.

Box 12.1: Applying the Commission's connections recommendations in Victoria

In Victoria, the functions undertaken by TNSPs elsewhere are split between AEMO and Declared Transmission System Operators (DTSOs). AEMO is accountable for the provision of the shared network, procuring services from DTSOs (such as SP AusNet), which own and operate the shared assets. This impacts on the process for connecting to the shared network.

Where a connection requires additional investment in shared assets (ie new identified user shared assets) the connecting party must apply to AEMO. Where such an augmentation is “separable” from the existing network, a DTSO would then be appointed to make this investment. Where the augmentation was not separable, the work would be undertaken by the incumbent DTSO (this would usually be SP AusNet).

Implementation of the Commission’s recommendations in Victoria would need to take account of this. It would need to be clear that, as the party responsible for shared transmission services, AEMO would be accountable for the operation, control and maintenance of the shared network. However, many of these responsibilities would be discharged by DTSOs.[197] The connections process would therefore need to include the user, AEMO, the DTSO providing the existing shared network and the DTSO providing the additional shared assets required for the connection.

12.4 Explanation of the Commission's recommendations

12.4.1 Contestability

Recommendation 1

The connections frameworks should be amended to better facilitate contestable build and ownership of identified user shared assets.

The local TNSP should always be accountable for the operation, control and maintenance of these assets, and should provide the high level design of the assets required.

The Commission recommends that connecting parties should be able to choose who constructs the identified user shared assets used to enable their connection to the network. This would give the connecting party the opportunity to seek a contractor which best suits its needs in terms of cost, timing or other terms, rather than having to accept the TNSP's choice of contractor. The ability to use alternative contractors should also give the connecting party countervailing power in negotiations with the TNSP.

197 We understand that, in practice, operation of the entire shared network (such as directing switching) is undertaken by SP AusNet, irrespective of ownership.

The Commission recommends that during the application to connect process, the applicant should be able to seek quotes and negotiate prices with a range of parties. However, before signing a connection agreement the connection applicant will need to choose which party will construct and own the identified user shared assets.

The rules should allow a connecting party (or another party) to retain ownership of identified user shared assets if it can agree terms with the local TNSP to allow the TNSP full operation, control and maintenance rights, including the ability for the TNSP to facilitate future connections and network expansion where necessary. The terms of the lease, transfer or any other arrangement should be negotiated as part of the connection application, and the protections and regulations which apply to TNSP provision of negotiated services would apply.[198,199]

The rules should contain principles to be applied by both parties in negotiating the terms of the lease, transfer or other arrangement for the operation of identified user shared assets. These principles should be designed to protect both parties to the negotiation. For example, they should require the terms of a lease to reflect the reasonable costs of operating and maintaining the assets, and should protect a TNSP from incurring costs, such as tax liabilities, that it would not have incurred had it constructed the assets itself.

In a practical sense, these recommendations mean there could be contestability in construction and ownership in one of the following ways:

- a TNSP "build, own, operate" service, where the connection applicant would require the local TNSP to provide all identified user shared assets as a negotiated transmission service;
- a TNSP " own, operate" service, where the connection applicant's contractor would build the assets, and the TNSP would own, operate, control and maintain the assets as part of its network as a negotiated transmission service;
- a TNSP "operate only" service where the connecting party would appoint its own contractor to construct the assets or construct them itself. The connection applicant or another party could choose to retain ownership of the assets, but arrangements would need to be made for the TNSP to operate, control and maintain the assets as part of its network after commissioning.

In addition to being accountable for operating, controlling and maintaining the identified user shared assets as part of its network, the local TNSP should:

- be the party responsible for designing the primary and secondary requirements of the identified user shared assets. Where the connection applicant elects for contestable build, the TNSP's design should be at a level that will enable the

198 Our recommendations for improving these protections and regulations are set out later in this chapter.

199 In Victoria, lease or transfer of assets would need to be to a third party from whom AEMO procures operational services.

chosen contractor to undertake detailed design and construction of the assets in accordance with the TNSP's primary and secondary requirements; and

- have responsibility for commissioning of the assets.

In addition, even where the connection applicant engages a contractor for construction, some works will always have to be carried out by the TNSP as a negotiated service. The TNSP will have to perform "cut-in works", ie works to modify its existing assets and interface with protection and control equipment, to enable the assets constructed by the connection applicant (or its contractor) to safely interface with the TNSP's existing shared network.[200]

We consider that this service must be treated separately to the main construction works because it directly affects the performance of the shared network. While construction of the identified user shared assets can take place without the need for a planned outage of the existing network, the "cut-in" work will be that work which requires existing transmission assets on the shared network to be temporarily taken out of service. Managing outages is a part of the operation of the shared network, a role which the TNSP must perform.

12.4.2 Provision of negotiated services

Recommendation 2

All aspects of the service provided by a TNSP in respect of identified user shared assets (including build, ownership and operation) should be provided as a negotiated service.

The principles in the rules underlying negotiations should be bolstered and applied directly to all TNSPs, rather than through individual negotiated service criteria and negotiating frameworks.

While the construction and ownership of identified user shared assets should be contestable, the local TNSP should be the only party that can provide related services, such as high level design, commissioning and operation.

The rules currently provide for "light-handed" regulation of monopoly connection services, designed to promote a fair and even negotiating process, and efficient

200 The actual cut-in work involved would depend on the nature and layout of both existing and new assets. For example, if the identified user shared assets comprise a new substation, the TNSP's cut-in works could be as simple as connecting a dropper from the new assets to an existing transmission tower during a planned outage of the relevant existing network assets. Alternatively, the cut-in works could be more extensive, such as connecting conductors from existing transmission towers to new transmission towers provided as identified user shared assets. Interfacing would occur when the assets constructed by the connection applicant's contractor are ready for first energisation and commissioning. This would be at a time agreed by the TNSP and the connection applicant.

outcomes from that process.[201] However, there is evidence that connecting parties are not currently sufficiently protected from TNSPs' negotiating power, which is leading to inefficient outcomes in terms of costs and time taken to connect.[202] The Commission recommends that the protections in the rules for connecting parties should be bolstered.

The existing rules requirements attempt to set out some "ground rules" for negotiation. The effectiveness of the existing principles contained in Chapter 6A of the rules has not been fully tested as no formal disputes over the terms and conditions of connection agreements have to date been raised. However, the existing principles are focussed on cost and price issues and do not adequately cover a number of the issues which are the sources of disagreement in connections negotiations in practice, such as perceived over-specification, timeliness and risk allocation.

We recommend that the negotiating principles should be updated and extended to ensure they cover all aspects of the service provided by a TNSP in respect of identified user shared assets. Box 12.2 (overleaf) sets out examples of requirements that should be incorporated into the negotiating principles in the rules.

The Commission also recommends that the requirements in the rules relating to negotiated services should be rationalised. Chapter 6A of the rules sets out the framework for negotiated transmission services. In particular:

- Clause 6A.9.1 sets out principles relating to access to negotiated transmission services;
- Clause 6A.9.4 requires those principles to be given effect in each TNSP's negotiated transmission service criteria, which are determined by the AER as a part of that TNSP's five-yearly transmission determination; and
- Clause 6A.9.5 sets out the requirements that a TNSP must incorporate within its individual "negotiating framework" document (and that this document must be approved by the AER).[203]

The Commission recommends that the three separate clauses should be amalgamated into a single set of negotiating principles, contained in the rules, that apply directly to all TNSPs. This would provide a simpler set of rules which reduce both the administrative burden on the AER and the potential for a divergence in arrangements across the NEM.

These amalgamated negotiating principles should replace the individual negotiating frameworks developed by each TNSP and approved by the AER.[204] Many of the

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201 NER, Chapter 6A.

202 Citipower and Powercor, First Interim Report submission, p.5; Government of South Australia, First Interim Report submission, p.4; Private Generators Group, First Interim Report submission, p.5; TRUenergy, First Interim Report submission, p.9; Victoria DPI, First Interim Report submission, p.13; Major Energy Users Inc, Second Interim Report submission, p.18.

203 NER, clause 6A.9.5.

provisions of the negotiating frameworks would be required under the Commission's recommendations for increased transparency, detailed in section 12.4.3 below. Where they are not, they should be incorporated in the amalgamated negotiating principles in the rules.

The negotiating principles should be applied by a commercial arbitrator in resolving any dispute between the TNSP and the connection applicant in relation to the connection process or the terms and conditions of access to a negotiated service.

Box 12.2: Examples of requirements to be incorporated into negotiating principles

Design and future expansion

Identified user shared assets should be designed so as not to inhibit future expansion. At the same time, the connection applicant should not be required to bear undue costs in relation to capability for future expansion.

Design and appropriate specification

Subject to ensuring the safe and reliable operation by the TNSP of the transmission network, the design of identified user shared assets should minimise the costs to the connecting party.

Terms and conditions of access – Risk allocation in contracts

The terms and conditions of any contract entered into by a TNSP with a connection applicant or its contractor should represent a fair and reasonable allocation of risk between parties.

This means that price must reflect, and be commensurate with, risk. This also means that the party who bears the risk should be the party who is best able to manage the risk.

(Examples of terms and conditions that should be highlighted in this context include: exclusions of liability; limitations of liability; indemnities; events of force majeure; and bank guarantees/credit risk mitigations.)

Terms and conditions of access – Timing obligations

A TNSP should use its reasonable endeavours to complete its part of the construction and commissioning in a timeframe that accommodates the reasonable timing requirements of the connection applicant.

204 As an alternative, if AER involvement was considered to be beneficial, a single negotiating framework could be applied across the NEM, with a modified approval process.

12.4.3 Increasing transparency

Recommendation 3

The transparency requirements on TNSPs when providing negotiated services should be enhanced. TNSPs should publish:

- **design standards and philosophies;**
- **standard form connection contracts; and**
- **pro-forma preliminary programmes, including relevant milestones and indicative timeframes.**

When providing a quote for negotiated services, TNSPs should be required to provide to the connection applicant:

- **a range of options (eg in terms of location and configuration); and**
- **a reasonable cost breakdown for identified user shared assets.**

While contestability of construction provides additional bargaining power to connecting parties, transparency remains of key importance in enabling fair and equal negotiations. In order to make a decision on whether to request the TNSP to build the identified user shared assets as a negotiated service, or to engage another party for the construction, the connecting party needs to be able to accurately compare the costs and other terms of the two options. It also needs to be able to understand the costs and terms of negotiated services in order to negotiate on an informed and even basis.

This section explains each of the recommended enhanced transparency requirements summarised in the box.

Design standards and philosophies

Publication of design standards and philosophies will help eliminate misunderstanding about how and why a TNSP has designed identified user shared assets in a particular way. It will also help connecting parties to assess whether a cost quoted is justified.

This measure will also assist connection applicants to compare and contrast design philosophies and standards used by different TNSPs.

Ideally, the standards and philosophies should address two main issues:

- Substation configurations: The types of configurations for substations (both new and modified) which the TNSP expects to use, and the circumstances in which those augmentations/configurations would be used.[205] Indicative costs for such arrangements at relevant voltage levels, should also be published by the TNSP;

- Design components: TNSPs should provide an understanding of the standards the TNSP uses to specify the main components of a identified user shared assets such as primary and secondary equipment, non-current carrying items of plant and equipment such as earthgrid, rack structures, footings etc.

"Network standards" documents published by Ausgrid, an electricity distribution NSP in New South Wales, provide good examples of the kind of document that is required for this purpose.[206]

Standard form contracts

The availability of pro-forma connection contracts required to establish a connection would give intending connection applicants a better understanding of what they need to prepare for in their negotiations with a TNSP. These should cover the various services provided by the TNSP to effect a connection to the shared network, including for example:

- construction of identified user shared assets;
- operation and maintenance of the assets;
- lease/transfer agreement options (if the connecting party manages the construction); and
- preparation/cut-in/interface works.

The standard forms could be used as a starting point for negotiations. In combination with the publication of design standards and philosophies recommended above, this should enable connection applicants to form a relatively accurate estimate of the type of connection service they require and the likely cost and other terms of the agreement. Where TNSPs' offers vary substantially from these estimates, the connection applicant would have a basis for challenging the offer and requesting explanation.

Clearer cost breakdowns

When negotiating for a connection, connecting parties often receive little information from TNSPs about costs and how they have been determined.

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205 For example: hard-T, soft-T, breaker-and-a-half, double breaker and construction of a new circuit, as well as options for connecting to existing substations. We note that information of this type has been published by AEMO and Grid Australia on their websites.

206 See: http://www.ausgrid.com.au/Common/Our-network/Standards-and-Guidelines/Network-standards.aspx.

The Commission considers that TNSPs should be required to provide a breakdown of the assets required and the work a TNSP expects to undertake in providing a identified user shared assets. The level of information should be sufficient to enable the connection applicant to seek a second opinion of costs from the independent engineer or other consultant, if they choose.[207] It should also inform the applicant's view (and, if necessary, the commercial arbitrator's view) as to whether the costs are fair and reasonable. The breakdown could be cross-referenced by the TNSP to its design specifications and philosophies which the TNSP, under these measures, will be required to publish.

The Commission recommends that TNSP quotes for service should, as a minimum, break down the following items:

- items of large primary plant (transformers, circuit breakers, etc);
- other items of primary plant;
- secondary equipment (communication equipment);
- land costs (lease/purchase/easements);
- internal services / overheads;
- planning & environmental approvals;
- project management costs;
- site investigation costs;
- design costs;
- civil works;
- installation costs, for both primary and secondary equipment;
- commissioning costs;
- operation & maintenance for the life of the plant/duration of the service;
- finance costs;
- insurance;
- "contingency" allowance (if required), and what the allowance has been made for; and
- legal fees.

207 Section 12.4.4 below sets out our recommendation for the role of an independent engineer.

The break down should allow the connection applicant to assess separately the costs for contestable services and non-contestable services.

Preliminary program

We understand that connection applicants are often unable to establish how long the connection negotiation and construction processes will take. The current rules oblige a TNSP to prepare a "preliminary program" containing “proposed milestones” in relation to the connection activities.[208] However, on the basis of submissions from and discussions with generators, it appears that connection applicants do not generally receive the clarity from preliminary programs which they should, because TNSPs often include little meaningful detail about milestones, or their associated timeframes, in the programme.[209]

To assist in making timeframes and milestones more transparent to connection applicants, the Commission recommends that TNSPs should be obliged to publish a pro-forma preliminary program on their websites.

In providing a preliminary program for a specific connection application, the rules should also oblige a TNSP to include in the program more specific detail about each aspect of the negotiation and construction processes. This should include, for example, what key decisions need to be made, and when; when detailed design begins and how long it should take; when long lead items should be procured; when civil works should commence and when commissioning should occur. This should also include an obligation to update the program if timings or milestones change during the process.

Connection options

NER clause 5.3.6(e) entitles a TNSP to include in its offer options for connection which can be considered by the connection applicant. However, this provision is not a binding commitment on the TNSP and, we understand, is therefore rarely included.

In addition, receiving information about options at the offer to connect stage (ie close to the end of negotiations) is too late in a connection applicant's project development phase. A connection applicant should be given an idea of the realistic options for connection as early as possible, and by no later than the end of the connection enquiry stage.

The rules should require a TNSP to set out a full range of options and an analysis as to which are preferred and which are not. This information may help the connection applicant to formulate its business case, and to prepare its application to connect. It

208 NER clause 5.3.3(b)(6).

209 AGL, Second Interim Report submission, p.4; Major Energy Users Inc, First Interim Report submission, p.39 and Second Interim Report submission, p.18; TRUenergy, First Interim Report submission, p.7.

may also help to identify any connection options which the TNSP may have overlooked.[210]

This process for examining options should start as early as possible in the connection process. See section 12.5.2 below for further discussion of this.

12.4.4 Independent engineer

> **Recommendation 4**
>
> **Where agreement cannot be reached between a TNSP and a connecting party on the reasonableness of any technical requirements in the connection process, either party should have the option to call for the appointment of an independent engineering expert to provide its opinion. The choice of engineer is to be agreed between the TNSP and the connecting party, and the cost of the engineer's services should be shared equally between the two parties.**

The Commission recommends that, where a dispute arises in relation to the design of assets, or any other matter which has a technical focus, an independent engineering expert could be engaged to provide their opinion.[211] The engineer's opinion would not be binding on the parties, but would assist the parties to come to a view on whether the requirement to be fair and reasonable was being observed. This could help to resolve any dispute between the parties. If not, the opinion should help to inform an arbitrator's view in any subsequent arbitral proceedings (see section 12.4.5 below).

Whilst there is nothing in the rules currently to prevent either party employing an engineering consultant to provide their opinion, making an explicit provision would drive the independence of the engineer's opinion. This would give it greater weight in negotiations, and ultimately in any arbitration process.

Either party could elect to request that an opinion be sought from an independent engineer, but the independent engineer's costs would be borne equally. This has two advantages. First, it provides an incentive on both parties to reach agreement without the engineer in order to avoid costs. Second, the engineer's independence is clear as it would not be working for any one business. Preferably, both parties should agree on the choice of independent engineer. Where agreement cannot be reached within a certain period of time, the party wishing to appoint the engineer can ask the AER to appoint an appropriately qualified, and independent, engineer.

The engineer can be engaged at any stage in the connection process. One area where an independent opinion is likely to be valued, particularly by generators, is in assessing the appropriateness of a TNSP's design for identified user shared assets. The

210 We understand that there are examples of connection applicants being informed by a TNSP that only a double breaker or a break-and-a-half configuration will be acceptable. However, after discussion, more economically viable alternatives have been found.

211 In practice this is likely to be an engineering firm, but could be an individual as long as both parties agree.

requirement for TNSPs to operate, control and maintain identified user shared assets requires them to also have a close role in designing those assets. In order to protect against TNSPs over-specifying the design of these assets, generators should have access to an independent expert review of the design.

Examples of other issues on which the parties may wish to seek the engineer's opinion include:

- the nature of any constraint arising in relation to the connection of the generator (as identified by the TNSP);
- the options for solving any constraint (ie the connection options);
- whether assets have been built according to the TNSP's design; and
- timeframes for the connection process.

12.4.5 Disputes process

> **Recommendation 5**
>
> **It should be clarified that the price, terms and conditions of all negotiated services are subject to commercial arbitration processes.**

The rules presently provide two overlapping, inconsistent processes for dispute resolution for connections:

- NER Chapter 6A, Part K provides commercial arbitration for “transmission services access disputes" (meaning disputes about provision of a negotiated service and related access arrangements as part of the connections process); and
- NER Chapter 8, Part B applies its comparatively lengthy and involved dispute resolution procedure to "the proposed access arrangements or connection agreements of an Intending Participant or a Connection Applicant".[212]

Given the interrelated nature of connection agreements and the provision of associated services – where both should be negotiated contemporaneously – the Commission considers this existing confusing approach to dispute resolution should be clarified.

In the context of commercial and technical negotiations, where a relatively swift mechanism to resolve deadlocks is preferable, the rules should be amended to confirm that the commercial arbitration process should apply to all disputes during negotiation of a connection service. The AER's role should be limited to investigating any allegations of rule breaches.

The arbitrator's role should be to determine whether the price or other terms of any element of a negotiated connection service, are fair and reasonable, as required by the

212 NER clause 8.2.1(a)(4).

rules. Where the arbitrator determines that the terms of a negotiated connection service are not fair and reasonable, it may issue instructions to either party which, in the arbitrator's view, make the terms of the service fair and reasonable.

As set out in section 12.4.2 above, the Commission recommends that changes should be made to the principles and negotiating framework requirements in Chapter 6A of the rules, and that both parties should be required to observe those principles when negotiating for a connection. If a dispute is raised, the arbitrator should apply these principles in determining whether the issue in dispute is fair and reasonable.

The arbitrator could be engaged by either party, at any stage of the connection process. For example, parties could ask the arbitrator to determine whether the cost of negotiated services, or timeframes for delivery of services, are fair and reasonable. The parties could also ask the arbitrator to rule on any of the issues where the independent engineer could be engaged to provide their view. Where the engineer has previously provided an opinion, that independent opinion should be taken into account by the arbitrator.

The rules should clarify that any decision reached through commercial arbitration is binding on the parties, including, for example, any instruction to amend the terms of the connection agreement to make them fair and reasonable.

12.5 The connection process under the Commission's recommendations

12.5.1 Summary of existing process and modified process under Commission's recommendations

Overview of Existing process

The connections process as currently set out in NER clause 5.3 is predicated on the following staged process:

1. Making of a connection enquiry and TNSP's response;
2. Connection applicant lodges an application to connect;
3. Preparation of Offer to Connect:
   (a) Negotiation of Access Standards;
   (b) Negotiation of price & other terms of access – under Chapter 6A & the TNSP’s negotiating framework;
4. Finalisation of the Connection Agreement (NER clause 5.3.7);
5. Construction;

6. Commissioning; and
7. Operation.

Overview of modified process

Our recommendations would amend the connection process as follows:

1. Making of a connection enquiry and TNSP's response, including:
    (a) Analysis of the potential locations, connection options and configurations;
    (b) Provision of indicative cost estimates for the options;
2. Connection Applicant lodges the application to connect;
3. Negotiation of access standards (can incur in parallel with the following);
4. TNSP to design the primary and secondary requirements of the identified user shared assets;
5. Seeking quotes:
    (a) Connection applicant can seek quotes from potential contractors; and
    (b) TNSP to prepare an offer in relation to the cut-in works; and/or
    (c) Connection Applicant can request TNSP to provide negotiated services offer for the whole identified user shared asset works.
6. Connection applicant to select approach (all services provided by TNSP or tender for construction/ownership);
7. Negotiations on commercial, technical, construction and agreements relating to the service, including the connection agreement;
8. Construction;
9. Commissioning; and
10. Operation.

Appendix D sets out a more detailed description of the connection process under our recommendations.

12.5.2 Description of recommended changes

Connection enquiry

Consistent with our recommendations on transparency, the enquiry process should oblige a TNSP to provide more information on options for connection (both location and configuration), as well as indicative costs for each type of configuration.[213] Grid Australia has indicated that this investigation should occur early in the connection process, but is presently outside the scope of the rules and the fees are determined on a contestable basis.[214] The Commission considers this is a necessary step in formulating an appropriate connection solution and should be mandated by the rules. To the extent that only the TNSP can do the investigation work (ie where no other party has the necessary models and data), the fees charged by the TNSP are not genuinely contestable, and should be subject to a fair and reasonable requirement, consistent with the requirements for all negotiated services.

This information may help the connection applicant to formulate its business case and to prepare its application to connect; it may also help to identify any other connection options which the TNSP may have overlooked.

Aside from the transparency measures and minor drafting fixes, the Commission considers that no significant changes are needed to the connection enquiry process.[215]

Application to connect

When the connection applicant submits an application to connect, the rules require the TNSP, amongst other things, to prepare an offer to connect. This offer to connect then becomes the basis for negotiation and finalisation of the connection agreement.

To facilitate the introduction of contestability, the processes underpinning the preparation of the offer to connect and finalisation of the connection agreement will need to be modified. We set out below how those processes should change.

The TNSP's design role

In assessing an application to connect, a TNSP will identify whether new identified user shared assets are required. Under the transparency measures, the TNSP will need to set out the various options for connection for the connection applicant's consideration, and an agreement will need to be reached by the TNSP and the connection applicant about the chosen configuration for the identified user shared assets from cost and network security perspectives.

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213 The current version of the rules anticipates that connection options can be contained within the offer to connect (NER clause 5.3.6(e)). It would be more practical for options to be discussed by the TNSP with the connection applicant right at the beginning of the connections process.

214 Grid Australia, *Transmission Network Connection Guidelines, Version 1*, July 2009, p.4.

215 For example, NER clause 5.3.3(c)(4) contains an outdated reference to rules 6.6 and 6.7

Under the contestability measures, if a need for new identified user shared assets is identified, they will need to be designed by the TNSP. This is because the TNSP will ultimately be responsible for the operation, control and maintenance of the assets as part of its network. Hence, the TNSP has an interest in being satisfied that the assets are designed in a way that is consistent with the safe and reliable operation of their network.

Accordingly, the TNSP will need to design the identified user shared assets at a high level in a way which addresses the needs of both parties.[216] The TNSP will also want to be satisfied that the detailed design of the assets occurs in such a way that is consistent with the TNSP's existing design standards and philosophies and operational practices, so that it meshes with its existing network and does not unnecessarily cause risk to the network. This can be assisted by publishing or providing its minimum building and design standards.[217]

The outcome of this level of design undertaken by the TNSP should be to enable the connection applicant's contractor to take responsibility for detailed design. In other words, there needs to be a "dividing line" in responsibility between the design that the TNSP performs, and the contractor's design responsibilities. The TNSP’s design will need to provide sufficient guidance to the contractor to perform detailed design in a way that will ensure security, reliability and other relevant standards are maintained; but the TNSPs design must not substitute the entirety of the detailed design process.

The parties can agree where the "dividing line" is drawn; however, in the absence of agreement, the Commission recommends that the rules provide guiding principles. The principles should seek to achieve an appropriate balance between:

- allowing the connecting party flexibility in its choice of contractor, materials and other detailed design decisions; and
- providing sufficient detail that the TNSP is satisfied that assets built to its design would be capable of being operated by the TNSP without compromising the TNSP's obligations in relation to security, reliability and other relevant standards.

The TNSP's design should be capable of review by the independent engineer. If the parties are unable to agree on a design, it could be referred to a commercial arbitrator, who should apply these principles in determining whether the specified design is fair and reasonable.

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216 At this level of design, the TNSP will need to specify, for example, the appropriate configuration of primary assets, thermal ratings of primary equipment, fault level withstand & interrupting capability etc, as well as the necessary schema for protection and control schemes and communication requirements. The TNSP may specify the minimum requirements to the size of land, and other issues that relate specifically to the particular augmentation.

217 For example, Ausgrid has published its "*NS 185 Major Substations Building Design Standard*, April 2008" and "*NS 178 Secondary System Requirements for Major Substations*, April 2008" at http://www.ausgrid.com.au/Common/Our-network/Standards-and-Guidelines/Network-standards.aspx.

Committing to the approach and selection of contractor

After the high level design of the identified user shared assets has been scoped by the TNSP, the connection applicant would have the opportunity to seek quotes for construction from potential contractors, and to ask the TNSP to prepare an offer to provide the cut-in works as a negotiated transmission service. The connection applicant could also seek an offer from the TNSP for an offer to provide a service for the whole identified user shared asset works, including construction and ownership as well as operation and cut-in works (etc), as a negotiated transmission service.

If the connection applicant wishes to proceed with the connection, it will need to commit to its chosen approach before signing a connection agreement. The approach could be one of the following:

- engaging the TNSP to provide all aspects of the service as a negotiated transmission service;
- constructing the identified user shared assets itself;
- appointing its own contractor to construct the identified user shared assets; or
- conducting a tender.

The rules should require the connection applicant to inform the TNSP of its decision.

Negotiation – Key commercial arrangements & connection agreement

Once the constructing party has been selected, commercial and technical negotiations will need to be pursued by all parties in relation to the provision of the service and finalisation of the connection agreement.

To facilitate a negotiations process that yields fair and reasonable outcomes, and also ensures the safe and reliable operation of the power system in accordance with rules, the parties should be bound by the negotiating principles in the rules. These can be used to facilitate the resolution of any dispute in the negotiation by referral to the independent engineer and/or commercial arbitration.

Section 12.4.2 above sets out our recommendation that these principles be updated to cover the issues that are commonly the source of disagreement and complaint in negotiations.

Construction

Since the connecting party is reliant on the TNSP agreeing that the construction meets its high-level design, it may be prudent for the connecting party to communicate regularly with the TNSP throughout the detailed design and construction process.

Before commissioning the new identified user shared assets and taking on the operation, the TNSP should have the right to inspect the construction, to verify that the assets have been built to meet the design it provided. The TNSP should be able to refuse connection if the TNSP considers, on reasonable grounds, that the proposed connection and augmentation arrangements are not consistent with the safe and reliable operation of the power system in accordance with the rules. If a TNSP refuses to connect new identified user shared assets to the network, the process should require the TNSP to justify, in writing, why it considers a connection should be refused, and set out what changes are required for the assets to be connected.

The generator would have two options in these circumstances (in addition to engaging the independent engineer): make the specified changes, or refer the matter to arbitration.

The arbitrator would then determine whether the TNSP's refusal to connect was fair and reasonable (and therefore whether it had complied with the rules). The rules should clarify that any decision reached through commercial arbitration is binding on the parties, including, for example, any instruction to amend the terms of the connection agreement to make them fair and reasonable.

13 Dedicated connection assets

Summary of this chapter

Increases in generation and large load located remotely from the existing shared transmission network may require the construction of new dedicated connection assets of significant length. In order to minimise costs to consumers, the regulatory framework should allow these dedicated connection assets to be developed as efficiently as possible. In particular, greater clarity in the rules is required on who can provide and own them, and how and to what extent they are regulated. In particular it should be clarified that all transmission voltage equipment interconnected with the rest of the transmission system should be subject to the NEL, and by default, the rules.

Such dedicated connection assets do not form part of the shared network, and TNSPs can isolate them at the connection point to the shared network if necessary. Since the connecting party therefore bears all the risk associated with the quality of the dedicated connection assets, it should be able to make its own choices on cost, design, etc. However, to ensure ongoing connection to the network, the dedicated connection assets will need to meet minimum technical standards. The provision of dedicated connection assets should be fully contestable, so that a connecting party can choose any appropriately qualified party to design, build, own, operate, control and maintain them.

To facilitate the efficient development of the national transmission grid, all transmission assets should be subject to third party access provisions. Any party owning transmission voltage plant and equipment should be required to either register as a TNSP or gain exemption from the AER from the requirement to register. In the former case, third party access requirements in the rules would apply. In the case of exemptions, a condition of exemption should be a requirement to negotiate third party access on reasonable terms, where a generator or large load wishes to connect to the assets covered by the exemption.

In some circumstances it may be appropriate for assets developed as dedicated connection assets to transition to shared network assets. The circumstances in which this should occur, and the process for giving effect to it, should be clearly set out in the rules.

The Commission supports SCER in progressing provisions to maintain the separation of generation and transmission in the NEM. However, we consider that such restrictions need not apply to dedicated connection assets.

13.1 Introduction

This chapter sets out our recommendations for the treatment of dedicated connection assets - those transmission assets provided for and used by a connecting party (or group of connecting parties) exclusively. This chapter is structured as follows:

- section 13.2 sets out a summary of our recommendations;
- section 13.3 presents the background to these; and
- section 13.4 explains the recommendations in detail.

13.2 Commission's recommendations

All transmission voltage equipment interconnected with the rest of the transmission system should be subject to the NEL, and by default, the rules.

The provision of dedicated connection assets (as defined by this report) should be fully contestable, so that a connecting party can choose any appropriately qualified party to design, build, own, operate, control and maintain them.

Any party owning transmission voltage equipment should be required to either register as a TNSP, or gain exemption from the AER from the requirement to register. Dedicated connections of less than 2km in length would be entitled to a deemed (automatic) exemption, although conditions would apply to the exemption.

One condition of an AER exemption should be a requirement to negotiate third party access on reasonable terms, where a generator or large load wishes to connect to the exempt connection.

The rules should specify two circumstances in which a dedicated connection asset would become part of the shared network:

- where a DNSP connects to the dedicated connection assets; or
- where a TNSP is augmenting the existing shared network to facilitate additional capacity, and the most efficient option would be to utilise the dedicated connection assets.

In these circumstances operational control of the dedicated connection assets should transfer to the local TNSP. The owner of the assets could choose to retain ownership and enter an agreement for the operation of them, or sell them to the local TNSP.

13.3 Background to the Commission's recommendations

The development of new sources of generation, driven by policy decisions and technology development, may lead to a requirement to connect generators in remote locations. Equally, developments such as the extraction of coal seam gas may lead to an increased amount of remotely located large loads. These factors are therefore likely to drive the construction of new dedicated connection assets of significant length.

However, there is currently ambiguity in the frameworks regarding the provision of the various assets and services required to connect such remotely located generation or load to the transmission network. It is not clear who can provide and own the dedicated connection assets involved, or how or to what extent they are regulated.

In some cases the most efficient route for a new generator or load to access the shared network may be via existing connection assets. The owner of these may have little incentive to negotiate access with another party (particularly if the owner was a competing generator), and may therefore refuse access to its assets, which could result in inefficient duplication of assets and a higher cost outcome.

Similarly, in some (relatively rare) cases, efficient network development may involve the transition of dedicated connection assets to shared network assets. The owner of the dedicated connection assets may have little incentive to change the nature of its assets, potentially resulting in higher cost overall outcomes.

13.4 Explanation of the Commission's recommendations

13.4.1 Coverage by the national frameworks

Recommendation 1

All transmission voltage equipment interconnected with the rest of the transmission system should be subject to the NEL, and by default, the rules.

The Commission considers that all equipment operated at transmission voltages in participating jurisdictions and interconnected with the rest of the transmission system should be subject to the provisions of the NEL and rules. To the extent that there is any ambiguity, this should be removed.

Grid Australia interprets the current rules to mean that assets between the substation fence and the generator's plant are "extensions" which fall outside the scope of the rules.[218] We understand that Grid Australia considers that these assets and the service they provide are covered by jurisdictional legislation, but are not economically regulated and are not subject to the NEL or rules. We do not consider this to be appropriate; all transmission assets should be subject to rules which provide for the efficient development and use of the network, such as third party access provisions. Differences in economic regulation can be handled within the rules.

Similarly, where dedicated connection assets are owned by parties other than TNSPs such as connecting parties, this equipment should be subject to the national frameworks. As explained later in this chapter, in most cases it would then be possible to exempt such parties from the rules, while still facilitating the efficient development and use of the network through the conditions of exemption.

218 Grid Australia, *Categorisation of Transmission Services Guideline*, 4 August 2010, p.7.

13.4.2 Contestability of provision of dedicated connection assets

Recommendation 2

The provision of dedicated connection assets (as defined by this report) should be fully contestable, so that a connecting party can choose any appropriately qualified party to design, build, own, operate, control and maintain them.

The Commission considers that connecting parties should have the flexibility to engage any qualified party (or parties) to provide dedicated connection assets. The Commission considers that there are sufficient providers, and that barriers to entry are low enough, such that in the majority of cases a connecting party will have an alternative to the TNSP for the provision of these assets. Since dedicated connection assets are not part of the shared network, there are no material benefits to consumers in a TNSP operating and maintaining these assets that are not internalised by the connecting party.

TNSPs should be free to compete to provide dedicated connection assets in all parts of the NEM.

In the Second Interim Report we proposed to allow contestable provision of dedicated connection assets (referred to in that report as extensions), but to require the local TNSP to provide these as a negotiated service where the generator requests them to do so. Although there was evidence of some contestability in the provision of dedicated connections, TNSPs appeared to have a significant competitive advantage in many cases. However, in responses to the Second Interim Report, both TNSPs and generators expressed the view that workable competition exists in the provision of these services.[219] Many suggested that the majority of dedicated connections are currently provided by the connecting generator, or a contractor on its behalf.[220] While some respondents were in favour of having the backstop obligation on TNSPs in place, they still considered that the provision of dedicated connections is workably competitive.

A key advantage we identified for TNSPs was that they hold compulsory land acquisition powers, potentially allowing them to construct dedicated connection lines along more direct routes than other parties. Respondents have provided evidence that other parties are also able to obtain compulsory acquisition powers.[221] In light of this, there does not therefore appear to be a significant barrier to non-TNSP parties providing dedicated connection assets.[222]

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219 AGL, Second Interim Report submission, p.5; Grid Australia, Second Interim Report submission, p.12; International Power GDF Suez, Second Interim Report submission, p.27; Transmission Operations (Australia) Pty Ltd, Second Interim Report submission, p.3.

220 AGL, Second Interim Report submission, p.32; International Power GDF Suez, Second Interim Report submission, p.27.

221 Grid Australia, Second Interim Report submission, p.13; TransGrid, Second Interim Report submission, pp.3-4.

222 Appendix E sets out a summary of the legal and licensing arrangements for operating transmission in each NEM jurisdiction.

Box 13.1: Rationale for recommending a different treatment of dedicated connection assets and identified user shared assets

Submissions to the Second Interim Report revealed a strong view among stakeholders that workable competition exists in the provision of dedicated connection assets and is feasible and developing in the provision of identified user shared assets. This has caused the Commission to amend its proposals, with the effect of reducing the level of regulation involved in the process of providing those services.

The Commission considers that, where it is able to work effectively, competition produces more efficient outcomes than regulation. Regulation should only be applied where competition is not possible, or where it is not sufficiently developed. Competition appears sufficiently developed in the provision of dedicated connection assets that the costs of imposing obligations on TNSPs would outweigh the benefits.

Unlike for identified user shared assets, dedicated connection assets can be provided with minimal involvement from the local TNSP. Subject to meeting minimum technical standards at the connection point, the design and quality of the dedicated connection only affects the ability of the connecting party (or parties) to export or import power to the network; there are no impacts on other users. Since the connecting party therefore bears all the risk associated with the quality of dedicated connection assets, it should be able to make its own choices on cost, design etc with minimal involvement from the TNSP.[223]

Conversely, we have presented a clear policy that local TNSPs be accountable for the operation, control and maintenance of all aspects of the shared network (including identified user shared assets), since they have responsibility for system security and reliability across the shared network. We are concerned about the potential consequences of a division and dilution of responsibilities and liabilities which would result from multiple parties operating different parts of the shared network. Since TNSPs will always be accountable for operating and maintaining identified user shared assets, we also consider that the TNSP must be primarily responsible for the design of those assets.

Grid Australia raised a concern that the backstop obligation would create an unlimited liability for TNSPs which placed them at greater risk from counterparty default.[224] However, it seems likely that TNSPs would largely be able to shield themselves from such risks through bank guarantees and other commercial tools. Nonetheless, the uncertainty around the potential scale of connections they could be required to provide may create difficulties in planning, obtaining and allocating resources.

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223 The TNSP will need to be involved in the provision of communications equipment.

224 Grid Australia, Second Interim Report submission, p.10.

The Commission has not seen evidence that a backstop obligation on TNSPs to provide dedicated connections as a negotiated service would result in better price outcomes for generators or consumers. As a result, dedicated connection assets should be provided on an entirely contestable basis. A connecting party should be able to choose any appropriately qualified party to design, build, own, operate, control and maintain these assets.

13.4.3 Third party access

Recommendation 3

Any party owning transmission voltage equipment should be required to either register as a TNSP, or gain exemption from the AER from the requirement to register.

One condition of an AER exemption should be a requirement to negotiate third party access to the exempt connection on reasonable terms.

In order to facilitate efficient use of the transmission system, we consider that a requirement should be placed on any party owning dedicated connection assets to negotiate access with third parties on reasonable terms.

Ownership by a TNSP

TNSPs are currently subject to third party access requirements under Chapter 5 of the rules. The Commission recommends that those requirements should continue. Where a party owning transmission voltage equipment registers as a TNSP (or is already a registered TNSP), these requirements would apply.

We also recommend that the rules should be clarified to specify that if dedicated connection assets are owned by a TNSP, the existing generator or customer should not have to accept terms that disadvantage it as a result of the TNSP providing access to a third party. If a third party wishes to connect to the line, access should only be offered if there is sufficient spare capacity on the line, or the party that wishes to connect funds any upgrade that is required to ensure that it can be operated to an unconstrained level up to the point of connection to the shared network (unless the foundation user agrees to the contrary).

Ownership by the connecting party or a third party

NER clause 2.5.1(a) requires that only a licensed Network Service Provider (NSP) own, control or operate a transmission or a distribution system unless exempted under clause 2.5.1(d).[225] However, it would not be proportionate to require a generator or other party owning dedicated connection assets to register as a TNSP and be subject to all of the obligations of the rules. Exemptions can be gained from the requirement to

225 This is also contained in the NEL, Part 2, Division 1, s11(2).

register as a TNSP (and therefore to comply with the rules), or from the operation of Chapter 5 of the rules (which sets out the technical requirements on NSPs). We understand that all exemptions granted to date have been from the requirement to register as a TNSP. The AER may also impose conditions on an exemption, including conditions relating to standards and regulatory controls in place for the network, access and charging.

Therefore, if the connecting party or a third party owns dedicated connection assets it should either be registered as a TNSP, or gain an exemption from the AER.

The Commission recommends that generators and other parties owning and/or operating transmission lines longer than 2km should be required to register their assets in order to gain exemptions from the AER to own and operate these assets (registrable exemptions). Standard conditions relating to metering, dispute resolution, access and charging, for example, apply to all exemptions. A party can apply to vary the conditions by applying for an individual exemption. However, the AER has not granted any individual exemptions to date.[226]

We recommend that the AER guidelines are clarified in order to make a number of explicit provisions related to access clearer.[227] The conditions applying to registrable exemptions should include:

- requiring a mechanism to enable third party access to dedicated connections, including that this should occur through a negotiate/arbitrate framework; and
- requiring an appropriate and binding dispute mechanism process, including a set of third party access principles that should be considered by an arbitrator.[228]

Threshold for automatic exemption

It would be disproportionate and unnecessary to require parties to register as a TNSP (or seek exemption) in respect of a very short connection with little prospect of being subject to a request for access. We therefore recommend there should be a minimum threshold length of 2km, below which all lines qualify for deemed (ie automatic) exemption.[229] This means that exemption is automatic if dedicated connection assets fall within this category, although conditions still apply to the exemption. Penalties may apply to any party who wrongly claims to be eligible for a deemed exemption.

226 Appendix B of the Second Interim Report contains a description of the AER's exemption process (http://www.aemc.gov.au/Media/docs/Second-Interim-Report-1d093f1d-2bdf-42c5-b0e3-d041ad36a28f-0.pdf).

227 Minor changes to NER clause 2.5.1 may be advantageous to give these conditions greater legal force.

228 This is consistent with the principles contained in the Competition Principles Agreement, which include that a dispute mechanism is to be embodied in the access regime.

229 This recommendation could be implemented either through AER creating a new category of deemed exemptions, or through a provision in the rules.

We have based our recommendation of a 2km threshold on our review of the current "contestable" extensions in the NEM. Of the twelve examples of non-TNSP owned extensions submitted by Grid Australia, two are 20km or above; all others are 2km or less.[230]

We recommend that the size of the threshold be contained in the rules, so that it can be subject to rule change requests if future developments suggest a different value is more appropriate.

13.4.4 Transition to the shared network

> **Recommendation 4**
>
> **The rules should specify two circumstances in which a dedicated connection asset would become part of the shared network:**
>
> - **where a DNSP connects to the dedicated connection assets; or**
> - **where a TNSP is augmenting the existing shared network to facilitate additional capacity, and the most efficient option would be to utilise the dedicated connection assets.**
>
> **In these circumstances operational control of the dedicated connection assets should transfer to the local TNSP. The owner of the assets could choose to retain ownership and enter an agreement for the operation of them, or sell them to the local TNSP.**

In some circumstances it may be more appropriate to treat an asset built as a dedicated connection asset as part of the shared network, providing prescribed transmission services, rather than a dedicated connection providing services to identifiable users.

The circumstances under which dedicated connection assets must transition to the shared network should be clearly specified in the rules in order to provide certainty to owners of dedicated connections. The recommended triggers are set out in the box above.

The incumbent TNSP would identify when these triggers were met, by undertaking a RIT-T to assess meeting a particular identified need. The RIT-T process is open and transparent, involving extensive consultation and industry input. We recommend that the rules should state that if a RIT-T finds that upgrading the network through utilising dedicated connection assets is the most efficient option, they would become part of the shared network.[231]

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230 Grid Australia, First Interim Report submission, pp. 39-40.

231 This should also be incorporated into the AER's NSP Registration Exemption Guidelines, in order to make it clear that if one of the two triggers occurs, then the extension will transition to providing prescribed transmission services.

Ownership and operation

Chapter 11 of this paper explains the Commission's policy that the local TNSP should be responsible for the operation, control and maintenance of the entire shared network within its jurisdiction for reasons of accountability and system security. Consistent with that policy, if one of these triggers occurs for a dedicated connection that is not owned by the local TNSP, operational control should transfer to the TNSP. The Commission recommends that, unless the local TNSP explicitly consents to an alternative arrangement, the owner should be required to either sell the dedicated connection to the TNSP, or enter arrangements that allow the TNSP to operate and maintain the connection as part of the shared network.[232]

If a service is defined as being provided by part of the shared network, it would be provided as a prescribed transmission service and so funded by transmission users through Transmission Use of System (TUOS) charges. Necessarily, the assets associated with these services would be subject to a revenue determination by the AER. Where ownership of the assets is transferred to the TNSP, the TNSP would therefore receive a revenue allowance for the ownership and operation of those assets.

Where the generator (or third party) retains ownership of the assets and only transfers operational control, it would be up to the AER to determine the appropriate treatment in terms of revenue allowances.[233] This may depend on the nature of the agreement between the owner and the operator (TNSP).[234]

The terms of a transfer or sale of assets to the TNSP would be a matter for negotiation between the parties (with a right to commercial arbitration[235]), but are likely to be based on the expected revenue allowance the TNSP would receive from the AER for the operation (and possibly ownership) of the assets.

The Commission recognises that the recommendations in this section may, to some extent, change the risks for businesses owning and/or operating dedicated connection assets, compared with the status quo. The potential for dedicated connection assets to be transitioned to a shared network asset is not currently explicitly contained in the NER. The Commission considers that its recommendations are consistent with the least cost development of the network, and would produce the most efficient outcomes for

232 This policy is a development of the proposals in the Second Interim Report, which included allowing the owner of the connection to continue operating and maintaining the connection (if it registered as a TNSP and was subject to an AER revenue determination).

233 If a generator/third party chose to retain ownership and register as a TNSP, it would need to be subject to a revenue determination by the AER. The rules currently only specify a single process for revenue determinations. This is a long, resource-intensive process which it would be disproportionate to undergo for a single asset. We recommend that a simplified revenue determination process should be developed to apply in these circumstances.

234 The ability of a generator to register as a TNSP may be subject to the outcomes of the COAG/SCER process looking at issues of co-ownership of generation and transmission - discussed in Box 13.2.

235 Chapter 12 explains the Commission's recommendations for the role of commercial arbitration in relation to negotiated services. Notwithstanding those recommendations, commercial arbitration can be enacted for any commercial dispute.

consumers. In order to minimise any uncertainty and allow parties to assess the level of risk, we have recommended that this transition would happen only if one of two triggers is met. Those triggers should be clearly set out in the rules, and can only be met if identified through a RIT-T process.

We also recommend that, since accountability rests with the TNSP, it should have discretion to allow other parties to continue operating (and owning) assets that have been transitioned to the shared network. While the NEM may see an increase in the number of generator- or third party-owned dedicated connection assets in coming years, we consider that the triggers for transfer to the shared network would rarely be met.

Ownership of generation and transmission

Many of the recommendations set out above concern situations where transmission assets would be owned by generators, and developing these recommendations has required us to consider the appropriateness of this. The need to clarify the frameworks in light of the anticipated increase in the number of generator owned dedicated connection assets provides a driver to resolve the issue of generation and transmission cross-ownership.

Concerns with a single company owning, operating and controlling both transmission and generation assets are well documented and recognised in energy markets around the world.[236] In 2007, the MCE recommended specific provisions to maintain the separation of generation and transmission in the NEM, at the request of COAG. These were consulted on but not finalised, with the MCE's Standing Committee of Officials (SCO) undertaking a second consultation in 2011.[237] We note that a number of respondents to that consultation suggested that the MCE should take account of the findings of the Transmission Frameworks Review, before finalising its position.[238]

As set out in Box 13.2, we agree that there are concerns with a single party having control over the operation of both generation and shared transmission assets (as opposed to dedicated connection assets), and we support SCER in progressing the resolution of this issue, in line with COAG's request. However, as a result of the findings of this review, we make two important qualifications.

236 See, for example: Hilmer, *National Competition Policy*, 1993, p.219; MCE SCO, *Separation of generation and transmission*, Consultation Regulation Impact Statement, 11 August 2011, p.4.

237 MCE SCO, *Separation of generation and transmission*, Consultation Regulation Impact Statement, 11 August 2011.

238 Alinta Energy, *Separation of generation and transmission – consultation regulatory impact statement submission*, 23 September 2011, p.2; NGF, *Separation of generation and transmission – consultation regulatory impact statement submission*, 21 September 2011, p.3; Origin, *Separation of generation and transmission – consultation regulatory impact statement submission*, 22 September 2011, p.1.

Box 13.2: Concerns with co-ownership of generation and transmission

Vertical unbundling is a key measure in implementing liberalised electricity markets. Potentially competitive sectors, such as generation, are disaggregated from monopoly elements, such as transmission. Where a transmission owner also participated in the competitive generation market, it would have the power and the incentive to discriminate in favour of its downstream generation business and/or against its generation business's competitors.

In its 2011 consultation, MCE SCO analysed a number of possible anti-competitive behaviours that might be adopted by an integrated entity.[239] These included:

- a reduction in transmission service quality and connection for competing generators;
- investment and maintenance decisions (such as planned and unplanned outages) made in favour of the co-owned generator;
- the TNSP changing short-term current ratings to advantage a co-owned generator; and
- sharing of commercially sensitive information in order to improve the affiliate generator's bidding or re-bidding strategies.

The current arrangements rely on the provisions of the Competition and Consumer Act 2010 (CCA) to prevent a merger or acquisition. However, this cannot prevent co-ownership if it results from a greenfield investment (such as the building of a generator by a TNSP). MCE SCO also noted concerns that the ACCC would not be able to convince a court of the market power risks associated with a merger or acquisition transaction involving a TNSP and a generator.[240] We agree that the risks are real, but may be difficult to prove unambiguously, and therefore that additional safeguards are warranted.

There is currently a low level of generation and transmission cross-ownership in the NEM (aside from state governments), and it has been suggested that this points to no further protections being required.[241] In contrast, we consider that this represents an opportunity to put in place appropriate measures without being constrained by legacy or transitional considerations. We note that in other jurisdictions (particularly the EU), regulators and legislators have expressed a clear intent to restrict cross-ownership, but have been frustrated by the continued existence of vertically integrated companies.

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239 MCE SCO, *Separation of generation and transmission*, Consultation Regulation Impact Statement, 11 August 2011, pp.21-30.

240 Ibid, p.45.

241 Alinta Energy, *Separation of generation and transmission – consultation regulatory impact statement submission*, 23 September 2011, p.1; LYMMCo, *Separation of generation and transmission – consultation regulatory impact statement submission*, 6 October 2011, p.1.

The first qualification is that restrictions should apply only to the operation of the *shared* transmission network. In line with the views of some respondents to the MCE SCO consultation,[242] we consider that it would be disproportionate to apply the prohibition to dedicated connection assets. In most cases these will be used only by the developer of these assets, and there are clear benefits from the synergies involved in developing the generating plant and connection together, and from the additional competition that this allows for the provision of dedicated connection assets.

In instances where third party access is provided to dedicated connection assets, it will be considerably easier to identify any instances of discriminatory behaviour than it would be for the shared network, which is much more complex and is used by many more parties.

The second qualification is that restrictions should apply to the control, rather than to the ownership, of assets. Co-ownership itself is unlikely to create competition concerns if the party owning generation has no decision-making power or operational control over the transmission assets. Our policy on transition of dedicated connections to the shared network would allow a generator to continue ownership of shared transmission assets, but the owner would be required to allow the local TNSP to operate and maintain those assets (including to modify the assets to connect third parties). Similarly, our recommendations on shared connections could result in generators owning - but not controlling - assets forming part of the shared network, and we do not consider that this would be inappropriate.

242 Alinta Energy, *Separation of generation and transmission – consultation regulatory impact statement submission*, 23 September 2011, p.1; Origin, *Separation of generation and transmission – consultation regulatory impact statement submission*, 22 September 2011, p.1.

Box 13.3: Differences between distribution and transmission

In the final report for the Power of Choice review published in November 2012, we recommended that:

> "the AER should give consideration to the benefits of allowing distribution businesses to own and operate distributed generation assets when developing the national ring fencing guidelines for these businesses.
>
> We consider that distribution businesses should be allowed to own DG assets, where the primary purpose is to provide network support. Secondly, we also consider that there are likely to be substantial benefits associated with allowing distribution businesses to export power from these assets to the wholesale market.
>
> We acknowledge that both of these outcomes must be considered in the context of their impacts on competition in non-regulated markets."

Underpinning our recommendation was a recognition that co-ownership of network and generation has costs and benefits. For the shared transmission network the benefits of co-ownership are likely to be less, and the potential incidence and costs of discrimination greater. For example, issues associated with constraints on the transmission network are quite different to distribution: the efficient level of congestion on the transmission network is not zero, and so transmission capacity will often have to be rationed. In distribution, many of the benefits in a NSP being able to operate generation arise because of the ability to manage network disturbances etc caused by reverse flows from distributed generation.

Consequently, we consider that the differences between transmission and distribution network - just as for the differences between transmission dedicated connection assets and shared assets - mean that it is appropriate to strike a different balance. It should also be noted that we consider that the AER should give careful consideration to any impacts on competition in progressing this issue for distribution.

14 Way forward for connections recommendations

Summary of this chapter

This chapter sets out how our recommendations to enhance the frameworks for transmission connections should be implemented.

The primary means would be through SCER requesting the AEMC to make changes to the rules. The interrelated nature of the concepts and terminology means that all our recommendations regarding connections should be implemented as part of a single rule change package.

No changes to the NEL would be required, although changes to remove redundant terminology might subsequently be made.

14.1 Introduction

Part 2 of this report sets out the Commission's recommendations for improving the transmission connection process and clarifying the rules relating to transmission connections. This chapter sets out the Commission's recommendation to SCER for progressing those recommendations. It also sets out at a high level the areas of the rules that we consider would need to be changed in order to give effect to the recommendations.

Appendix C sets out a more detailed specification of our recommendations, which would form the basis for the drafting of changes to the rules.

14.2 Recommendation to SCER

The Commission recommends that SCER submits a rule change request to the AEMC to give effect to all of the recommendations in part 2 of this report.

While there are a number of recommendations, covering a range of areas, the proposed amendments are interrelated. The Commission considers that it would be both possible and preferable to implement all of the changes required to give effect to the recommendations, and any further consequential amendments, in a single rule change. Assessment and implementation of all the changes together would also help to provide the enhanced clarity and certainty that many of the recommendations seek to achieve.

14.3 National Electricity Rule changes

Numerous amendments to the rules would be required to give effect to the Commission's recommendations for additional contestability and greater transparency in the connection process. The existing rules are in several respects inconsistent and confusing in their treatment of various assets and services. Properly clarifying these arrangements would also inevitably result in a number of amendments. These amendments would in turn require extensive consequential amendments (although these consequential amendments are generally in relation to terminology rather than to any substantive elements of the rules).

We anticipate that, at a minimum, the following amendments to the rules would be required:

1. amendments to Chapter 2 to implement the proposals in relation to registration and exemptions, and third party access conditions to be placed on exemptions;

2. amendments to Chapter 5 to accommodate recommendations regarding ownership and operation, and the connection enquiry and connection application processes. This includes amendments to:

   - better facilitate contestable build and ownership of identified user shared assets;

   - make clear that the local TNSP should always be the party accountable for operating, controlling and maintaining shared assets required to effect connections, and for providing the high level design of the assets required;

   - set out the triggers and processes for connection assets being reclassified as part of the shared network;

3. amendments to Chapter 6A to implement:

   (a) the enhanced transparency provisions;

   (b) the rationalisation of the existing negotiating framework requirements and addition of updated negotiating principles;

   (c) consolidation of the existing service definition;

4. amendments to Chapter 8 to accommodate the independent engineer review of transmission connections design and specifications and clarify the process for dispute resolution; and

5. substantial changes to the definition section of Chapter 10. Changes would include amendment to existing definitions, insertion of new definitions and deletion of definitions made redundant by the new/amended definitions. Consequential amendments would also be required to distribution system provisions if they are to remain consistent with the proposed transmission system amendments.

14.4 National Electricity Law changes

We do not anticipate that any changes to the NEL will be necessary to implement our recommendations. In a number of circumstances the NEL contains terms that would be no longer required as a result of the changes that we are proposing be made to the rules. However, in each case we consider that it will be possible to draft the required rule changes in a manner that precludes the need to remove or amend those definitions from the NEL. Future NEL amendments to remove redundant terminology might subsequently be made.

In chapter 13 we noted the ongoing process by SCER to maintain the separation of transmission and generation in the NEM. To the extent that SCER progresses NEL changes in this regard, we recommend that our conclusions on this matter be taken into account.

14.5 Other changes

Our recommended amendments to the rules, if implemented, would lead to consequential changes being made to some subsidiary documents. For example:

- amendments would be required to AER's exemption guidelines to clarify the third party access conditions applying to exempt transmission assets, and to introduce an associated dispute resolution mechanism. We anticipate that these would be significantly more prescriptive than at present, and that a consultative development process would likely be required; and
- TNSPs' individual negotiating frameworks would not be required under our recommendations, as they would be replaced by either new requirements related to enhancing transparency, or principles in the rules that apply directly. We expect that this would be best achieved through a transition process where each TNSP continues to be bound by its existing negotiating framework until its next revenue reset, when the new national principles would take effect.

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
COAG	Council of Australian Governments
DNSPs	Distribution Network Service Providers
FTR	Financial Transmission Right
IRSR	inter-regional settlements residue
LMP	locational marginal price
LRIC	long run incremental cost
LRMC	long run marginal cost
LRPP	last resort planning power
MCE	Ministerial Council on Energy
MNSP	market network service provider
NCC	National Competition Council
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NPV	net present value
NSP	Network Service Provider
NTDNP	National Transmission Network Development Plan

NTP	National Transmission Planner
OFA	optional firm access
RAB	Regulatory Asset Base
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
RRP	regional reference price
SACP	shared access congestion pricing
SCER	Standing Council on Energy and Resources
SRA	Settlement Residue Auction
STPIS	Service Target Performance Incentive Scheme
STTM	Short Term Trading Market
TNSPs	Transmission Network Service Providers

A Implementation of planning recommendations

A number of our planning recommendations are separable from the OFA model and we consider that there would be merit in progressing these. This appendix sets out how this would be achieved. Specifically:

- section A.1 discusses how our demand forecasting recommendations can be achieved;
- section A.2 sets out how TNSP functions can be enhanced; and
- section A.3 discusses how revenue reset alignment can occur.

A.1 Demand forecasting

A.1.1 Background

Section 4.5.3 set out our recommendations on demand forecasts, in summary:

- AEMO (as NTP) should produce a standardised set of "bottom up" demand forecasts for each region of the NEM; and
- AEMO would be required to reconcile its "top down" demand forecasts produced as part of the NTNDP, with its "bottom up" forecasts.

The Commission is of the view that there are advantages from having AEMO producing "bottom up" forecasts. Most importantly, it facilitates contestability of views – AEMO connection point forecasts can be compared to TNSP-prepared connection point forecasts.

A.1.2 Information required

In order to produce these "bottom up" forecasts, AEMO would need access to a variety of information, specifically:

1. connection point forecasts from DNSPs and directly connecting customers;
2. information on embedded generation such as location, size and output;
3. forecasts for new and decommissioned loads; and
4. metering configuration data.

The first information requirement is an essential input that AEMO would need in order to develop the "bottom up" forecasts. The remaining information would be used to supplement this in order to provide more detailed and accurate forecasts. In the absence of the last three components, AEMO would likely need to make a number of assumptions in order to modify the connection point forecasts.

The information originates from a mixture of DNSPs, TNSPs and large load customers. AEMO could receive separate information from each of these parties; or TNSPs could simply pass through all of this information to AEMO. In practice, the information provided should be the same – no matter which party provided it.

A.1.3 Modification of AEMO's functions

The NEL currently sets out AEMO's information gathering powers. AEMO (if it considers it reasonably necessary to do so) for the exercise of a relevant function, may:[243]

- make a general market information order requiring information from persons of a class specified in the order; and
- serve a market information notice requiring information from the person to whom the notice is addressed.

The NEL also defines AEMO's relevant functions, and these include its NTP functions.[244] These NTP functions include certain specified planning and review functions conferred on AEMO (including by the rules) in its capacity as National Transmission Planner.

AEMO can issue general information orders in relation to one of its functions. Therefore, if producing demand forecasts at a transmission connection point level is defined as one of AEMO's NTP functions – either in s.49(2) of the NEL or in the rules – then AEMO could use these *current* powers to collect information associated with this. Given the significance of this new function, and the need to use information gathering powers that are set out in the NEL, we consider that it would be preferable to specify this function in the NEL. However, this would require changes to be made by the South Australian parliament.

A.1.4 Recommendation

Since the publication of the Second Interim Report a number of other recent reviews have made recommendations regarding the production of demand forecasts by AEMO. Most notably, the December 2012 COAG communique requested that AEMO should provide independent demand forecasts to the AER in a manner that would "enhance the AER's ability to analyse demand forecasts submitted by network businesses".[245] AEMO has committed to developing a consistent methodology for connection point forecasting across the NEM (at a transmission level), with the target delivery date at the end of June 2013.[246]

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243 S.53(1), Part 5, Division 5 of the NEL.

244 S.49(2), Part 5, Division 5 of the NEL.

245 COAG, *COAG Energy Market Reform - Implementation Plan*, 7 December 2012, p.11.

246 AEMO, *Planning Studies - 2013: Information and Consultation Paper*, 30 January 2013, p.6.

The Commission is of the view that AEMO's functions should be modified to reflect its new role in demand forecasting. It could then use its current information gathering powers to gain access to the necessary information needed to produce the forecasts. The Commission recommends that SCER should consider our recommendation on demand forecasting in conjunction with the information received from AEMO in response to the related task as set out in the December 2012 COAG communique.

A.2 Enhanced TNSP functions

A.2.1 Background

Section 4.6 set out a number of recommendations relating to enhancing TNSP functions:

- arrangements that promote the identification and implementation of network investment options that cross-regional boundaries (section 4.6.1);
- TNSPs providing greater input into the NTNDP to ensure that coordination between national and local issues occurs at the outset of the planning process (section 4.6.2); and
- consistency of the structure of APRs across the various TNSPs (section 4.6.3).

These would all contribute to increased coordination in network investment and consistency across the NEM.

A.2.2 Draft Specifications

This section sets out how these enhanced TNSP functions would be implemented by setting out draft specifications. The purpose of these is to explain in detail the regulatory requirements to bring effect the planning recommendations that require a rule change. These provide the framework for developing draft rules.

Cross-regional investment options

To promote and encourage nationally coordinated decision making, TNSPs would be required to identify and consider investment options that may involve assets in other regions as part of the TNSP's planning activities.

To give effect to this proposal we have considered what amendments to the rules may need to occur. Below we set out the key changes that we have identified at this stage:

- clause 5.12.1(b) would be amended to require TNSPs to consider whether an option in another jurisdiction may also meet their investment needs, when preparing their APRs;
- clause 5.12.2(c) would be amended to require TNSPs to include in their APRs:

- whether an option in another jurisdiction may meet an investment need;[247] and
- a section summarising the consultation (relating to cross-regional investment options) that it has undertaken with TNSPs;

- clause 5.12.2(b) would be amended to specifically recognise investments in other regions as a credible option when undertaking the RIT-T;
- clause 5.16.4 would be amended to require TNSPs to set out in their Project Specification Consultation Report (clause 5.16.4(b)), and Project Assessment Draft Report (clause 5.16.4(k)) for each investment need:
  - whether an option in another region may meet that need, or, if not, the reasons why not; and
  - the consultation (relating to cross-regional investment options) it has undertaken with TNSPs in neighbouring regions;
- a new clause would be inserted in clause 5.21 requiring the NTP to produce guidelines to assist TNSPs in considering whether or not investments may be met by an investment option in another region;[248]
  - new clauses would be inserted under 5.12.1 and 5.16.4 requiring TNSPs to have regard to these guidelines when preparing their APRs and RIT-T documents respectively.

We also consider that there would need to be changes to the economic regulation arrangements since the current framework does not explicitly allow for TNSP funding investments to meet an identified need in a different jurisdiction. This would need to be considered further, and developed in the rule change request. However, we have developed a number of high-level principles that we consider should be reflected in these arrangements. Specifically:

- economic regulation for cross-regional investments should reflect the economic regulation arrangements for within region investments to the greatest extent possible;

247 We note that NER clause 5.12.2(c)(5)(vi) already defines "other reasonable network and non-network options" as including, but not limited to "options involving other transmission and distribution networks". The same terminology is contained in NER clause 5.12.2(c)(7)(vi) relating to replacement projects. The rule change should consider whether this definition would also cover cross-regional investments.

248 This could be similar to existing NER clause 5.21(b) setting out how AEMO must develop and publish guidelines assessing whether a transmission augmentation will have a material inter-network impact. We note that the RIT-T requires the relevant TNSP to consider whether the credible option is reasonably likely to have a material inter-regional impact. "Material inter-regional impact" is not a defined term within the NER, but it has been generally assumed to be synonymous with "material inter-network impact", which is a defined term.

- economic regulation for cross-regional investments should promote transmission system investment decision making on a coordinated basis across the NEM;
- the arrangements for economic regulation for cross-regional investments should promote efficient investment in transmission networks;
- the arrangements for economic regulation for cross-regional investments should not impose an undue level of regulatory burden on the AER;
- there should be no double recovery of costs associated with cross-regional investments; and
- the arrangements for economic regulation for cross-regional investments should be clear and transparent in approach.

There are a number of ways through which these principles could be given effect. These options are discussed more fully in the report prepared by NERA Economic Consulting and Allens prior to the Second Interim Report.[249] In brief, there are two potential routes: the contingent project route or the capital expenditure allowance route. These would need to be considered further in the rule change request.

Lastly, these cross-regional investments should be treated as prescribed transmission services under Chapter 6A of the rules. This is because these are substantial investments, whose use may change over time. For example, such an investment (while initially for the purpose of meeting an identified need in a different jurisdiction) could later be augmented to meet investment needs within its own jurisdiction.

TNSP input into the NTNDP

To ensure that the different perspectives of the different parties involved in planning are appropriately captured and reflected through the process it is appropriate for TNSPs to formally comment on the NTNDP. Coordination between national and local issues should therefore occur right at the outset of the planning process.

Clause 5.20 relates to the preparation of the NTNDP. TNSP input into the NTNDP would be effected through amendment to this provision, requiring the establishment of a TNSP working group and setting out the process for that working group to review and provide comments on the NTP during its development.

Consistency of APRs

Promoting the consistency of APRs would allow interested stakeholders to both:

249 NERA Economic Consulting and Allens, *Alternative transmission planning arrangements: ensuring nationally coordinated decision-making*, May 2012.

- more easily reconcile a TNSP's APR with the NTNDP (eg compare constraints identified in the APR and their solutions with the constraints identified in the NTNDP); and
- more easily recognise where cross-regional investments are identified, that these are included in both the relevant TNSP APRs (eg check where an identified need in one region is identified by one TNSP as being met by an investment in another region, that this investment is identified in the other TNSP's APR).

Clause 5.12.2 relates to the preparation of the APR. This should be amended to require TNSPs to consider the consistency of their APR documents with the NTNDP and other APRs.

A.2.3 Recommendation

The details provided in this drafting specification are intended to form the basis for a detailed design specification for SCER so that it can be returned to the AEMC as a rule change for considered implementation in the rules.

A.3 Alignment of regulatory resets

A.3.1 Background

The Commission considers that alignment of TNSP regulatory resets would be advantageous, as discussed in section 4.6.4. This would increase efficiency in transmission investment by:

- assisting the AER to compare TNSP augmentation plans on a holistic basis across the NEM, facilitating implementation of cross-regional planning recommendations; and
- allowing consistent regulatory arrangements between TNSPs, through the use of consistent assumptions and assisting with benchmarking.

In the recent Economic Regulation of Network Service Providers rule change, transitional arrangements were developed relating to regulatory periods. These rules were considered necessary in order to:

- enable the new rules and guidelines to be applied in the next round of determinations; and
- minimise the resourcing burden that the guidelines development process and transitional arrangements could otherwise place on stakeholders, while also allowing consultation with stakeholders.

The upcoming regulatory periods, and associated transitional arrangements for TNSPs are summarised in Table A.1.

Table A.1 Transitional arrangements and regulatory periods

TNSP	Form of transitional arrangements	Next regulatory period	
		Length	Dates
SP AusNet (Vic)	Old rules for 3 years	3 years	1 April 2014 - 31 March 2017
	New rules	5 years	1 April 2017 - 31 March 2022
TransGrid, Transend (NSW, Tas)	Placeholder with true-up	1 year	1 July 2014 - 30 June 2015
		4 years	1 July 2015 - 30 June 2019
Powerlink (Qld)	No transitional arrangements	5 years	1 July 2017 - 30 June 2022
ElectraNet (SA)		5 years	1 July 2018 - 30 June 2023

A.3.2 Aligning regulatory resets

As discussed in section 4.6.4, alignment with Powerlink's existing regulatory cycle is preferable.

This does not change any of the transitional arrangements that are already in place (to transition to the new rules), but it does change some of the upcoming regulatory periods once the new rules are in place.

This would occur through the following sequence of events. First, SP AusNet has a transitional three-year period from April 2014 to April 2017.[250] The next regulatory period starting on 1 April 2017 would be 5.25 years in length, which would align SP AusNet with Powerlink from 1 July 2022.

Second, ElectraNet currently has a regulatory period that ends on 30 June 2018. In order to align ElectraNet its following regulatory period (ie that starting on 1 July 2018) would be for a four-year term (ie ending on 30 June 2022). ElectraNet would be aligned with Powerlink from 1 July 2022.

Third, there are two potential options as to how TransGrid and Transend could be aligned.

Currently, TransGrid and Transend subject to a placeholder year (2014/15) followed by a four-year full determination process, concluding in 30 June 2019. However, both TransGrid and Transend have a transitional rule (NER clause 11.58.4(l)(2)), which allows them to propose a *three*-year regulatory period (instead of the current four-year period).

250 Since SP AusNet is due to commence its next regulatory period on 1 April 2014, the Commission decided that it would be subject to the old Chapter 6A rules for three years before moving to the new rules on 1 April 2017.

Option 1 involves TransGrid and Transend making use of this clause. This would result in the full determination covering 1 July 2015 to 30 June 2018. In order for this to occur, TransGrid and Transend would have to propose this in their revenue proposals – due to be submitted to the AER in June 2014. However, it would be beneficial for the AER to know if this was the TNSP's intention prior to the setting of the placeholder year, ie during the development of the framework and approach documentation.

Following this three-year regulatory period, TransGrid and Transend would have a four-year regulatory period covering from 1 July 2018 to 30 June 2022: alignment with Powerlink would be achieved in 2022.

Option 2 involves TransGrid and Transend having a two-year regulatory period from 1 July 2015 to 30 June 2017: alignment with Powerlink would be achieved in 2017. These businesses would face full five year determinations from 2017 onwards.

These two alternative options are set out in Figure A.1 and Figure A.2 below.

Figure A.1 Revenue reset alignment: Option 1

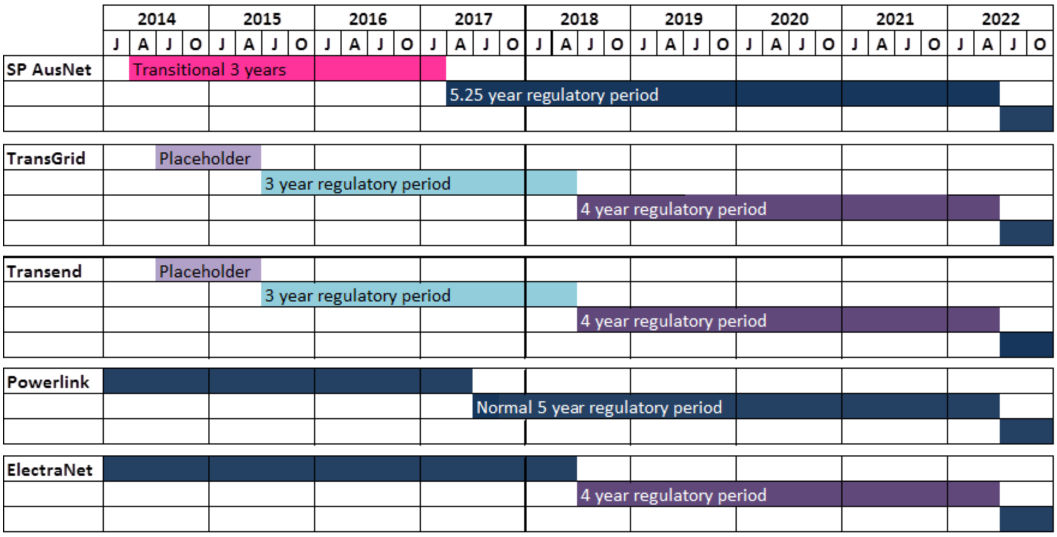
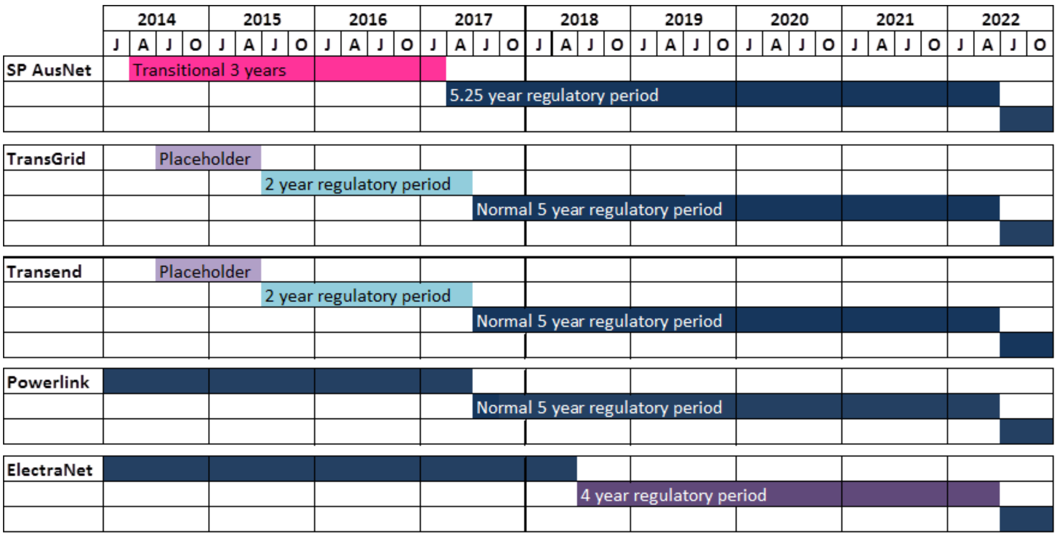


Figure A.2 Revenue reset alignment: Option 2



There are a number of advantages and disadvantages associated with each option.

Option 1 would require a rule change (to accommodate four-year regulatory periods for ElectraNet, TransGrid and Transend – NER clause 6A.4.2(c) states that a regulatory control period must be "not less than 5 years"). However, the three-year regulatory period for TransGrid and Transend can be accommodated under existing transitional arrangements.

Any step changes in price that result from the placeholder year for TransGrid and Transend would be able to be smoothed over a longer period of time, ie three years: consistent with the principles considered in the transitional arrangements for the Economic Regulation of Network Service Providers rule change.[251] However, only two TNSPs would be (partially) aligned in 2017: SP AusNet (April) and Powerlink (June). The remainder would be aligned in 2022.

Option 2 would also require a rule change: both to accommodate a four-year regulatory period (for ElectraNet), and the two-year regulatory periods (for TransGrid and Transend). The rule change for the two-year regulatory period would need to be submitted in the near term, in order for this to be made prior to TransGrid and Transend are submitting their revenue proposals (which is expected to be June 2014).

Any step changes in price that result in the placeholder year for TransGrid and Transend would be able to only be smoothed over two years. However, four businesses would be (partially) aligned in 2017: SP AusNet (April), and Powerlink, Transend and TransGrid (June). ElectraNet and SP AusNet would be fully aligned in 2022.

Therefore, our preferred option is Option 1.

A.3.3 Tasmania

We understand that following the Tasmanian government's merger of Transend and Aurora (scheduled to occur by 1 July 2014), these businesses would also seek to align their regulatory periods.

Aurora's next revenue period is scheduled from 1 July 2017 to 30 June 2022. Therefore, aligning Transend on to the same regulatory cycle as Powerlink would also have the effect of aligning it with Aurora. However, the AER may wish to consider its workload with undertaking regulatory determinations for all five TNSPs, plus one DNSP (Aurora).

We note there is less of a driver for aligning Transend with the mainland TNSPs (since there is little prospect of cross-border augmentation). There may be more benefits from aligning Transend and Aurora, irrespective of whether they were aligned with the remaining four TNSPs or not.

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251 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p.216.

A.3.4 Recommendation

The Commission has developed an approach that would achieve TNSP regulatory reset alignment. This involves rule changes being proposed, and made, that result in TNSPs aligning with Powerlink's existing regulatory cycle.

We recommend that SCER should task the AER with developing a rule change request to facilitate this revenue reset alignment, in accordance with the above specified approach. If the AER chooses not to pursue the proposed steps in order to achieve alignment, it should explain in the rule change request why an alternative approach (and potentially different alignment period) was chosen.

B Further detail on inter-regional access

Chapter 6 discussed the inter-regional access product, and set out how settlement, firm access standard and pricing would occur. The chapter also set out at a high-level how the inter-regional expansion and allocation process would occur. Section B.1 of this appendix discusses these concepts in greater detail.

The current framework provides an alternative to regulated interconnectors in the form of market network service providers. The impact of the optional firm access model on these is discussed in section B.2.

B.1 Inter-regional expansion and allocation

Section 6.7 set out at a high-level how the expansion and allocation process for inter-regional access would occur:

- the first stage of the allocation and expansion process involves AEMO running an auction for inter-regional access on interconnectors, offering access in quarterly blocks; and
- where a potential expansion signal has been received, the second stage involves the relevant TNSPs undertaking a joint investment test on the upgrade of the interconnector in question.

This is discussed more fully below, specifically:

- timetabling of inter-regional auctions (section B.1.1);
- the annual auction of firm interconnector rights by AEMO (section B.1.2);
- assessment by TNSPs (section B.1.3);
- timing for interconnector investments (section B.1.4); and
- the interaction between inter-regional and intra-regional investments (section B.1.5).

B.1.1 Timetabling of inter-regional auctions

The first stage of the allocation and expansion process involves AEMO running an auction for inter-regional access on interconnectors, offering access in quarterly blocks. The auction would be designed to both allocate *existing* capacity, as well as signal interest in *expansions* of capacity. The auctions would therefore sell:

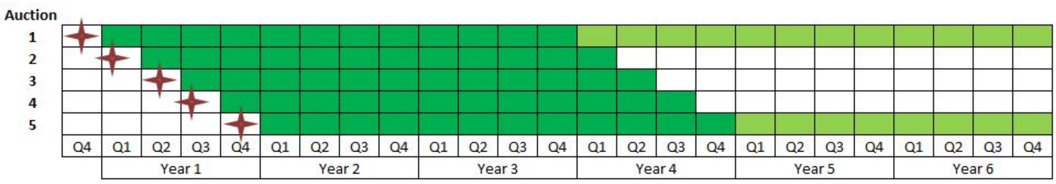
- existing spare capacity on the network ("baseline long-term inter-regional access") - this would be defined as any spare capacity up to a "baseline" level of capacity;[252]

- any spare capacity *above* the baseline that can be created through the TNSP making operational decisions ("short-term inter-regional access"); and

- potential future capacity ("incremental long-term inter-regional access") - this is defined as any additional capacity that can be created through *expanding* the interconnector, ie undertaking capital expenditure.[253]

Given that the expansion of the interconnector (ie access offered under potential future capacity) is complex, we propose that the process relating to this only occurs annually. This is illustrated in Figure B.1

Figure B.1 Example auction timetable



Auctions 1 and 5 would auction off all three types of capacity identified above – baseline long-term inter-regional access, short-term inter-regional access and incremental long-term inter-regional access - over a long-term period.[254] We suggest that this should be for a 10 to 20 year period. The auction would be held in Quarter 4 of the year preceding when access is first offered. The dark green represents the quarters where existing capacity that is available on the interconnector are auctioned, while the light green represents the quarters where potential increased capacity are auctioned.

The auctions in between these full auctions (ie Auctions 2, 3 and 4) will auction off the first two types of capacity over the upcoming three year period - baseline long-term inter-regional access and short-term inter-regional access. These auctions can be considered analogous to the current SRA auctions.

B.1.2 Auction of firm interconnector rights

AEMO would run an auction for quarterly firm interconnector rights. While the particular details of the auction design would be developed at a later stage, we have developed a preliminary auction process to illustrate how we consider that this may

252 The initial baseline capacity would be allocated in the transition process and so initial baseline capacity can be considered equivalent to transitional inter-regional access. See section 9.3.

253 This incremental long-term inter-regional access would become part of the baseline capacity following construction.

254 This process contemplates both short-term *inter*-regional and long-term *inter*-regional access being sold at the *same* auction. An alternative would be to have both *inter*-regional and *intra*-regional short-term access sold at the same auction.

occur. Importantly, the auction should create the right signals but also avoids creating opportunities for gaming by participants. The auction would be designed to both allocate *existing* capacity, as well as signal interest in *expansions* of capacity. This auction to gauge interests in expansion of capacity would occur annually.

Interested market participants would register with AEMO in order to participate in the auction. This registration process would include assessment of any prudential or credit requirements.

At a high level the process would occur as follows:

- Step 1: AEMO would circulate a price schedule to these registered participants;
- Step 2: Market participants would then bid in the quantity of access they want at each quarter, at each price step; and
- Step 3: AEMO would then assess the level of demand, and the amount of access that can be offered (supply). This would involve considering whether investment in additional capacity may be beneficial.

These steps are discussed in greater detail below. Figure B.2 sets out an example auction schedule and bids received. This will be used to assist the discussion below.

Figure B.2 Example Auction Schedule

Supply			*Demand (MW)*															
			Year 1				Year 2				Year 3				Year 4			
Capacity (MW)	Price Label	Price ($/MW)	J	O	J	A	J	O	J	A	J	O	J	A	J	O	J	A
540	P_4	0.9	495	495	495	500	500	501	503	510	520	510	503	501	500	500	500	500
530	P_3	0.8	495	495	495	501	501	502	504	510	520	510	504	502	501	501	501	501
520	P_2	0.5	495	495	500	502	502	502	505	510	520	510	505	502	502	502	502	502
510	P_1	0.3	495	495	500	503	503	504	506	510	520	510	506	504	503	503	503	503
500	P_0	0.1	390	390	500	500	505	506	507	510	520	510	507	506	505	505	505	504

In Step 1 AEMO would circulate a price schedule to registered participants, setting out reserve prices. This would look like the "supply" side in Figure B.2. It would set out the various amounts of capacity potentially available on the interconnector each quarter. The initial capacity increment would likely reflect existing capacity (eg 500MW). It would also include increments that represented an *expansion* in capacity (eg 510MW).

These capacity increases would also have corresponding step prices, which are based on the standard pricing methodology as set out in section 5.2.[255] The price associated with the existing capacity (500MW) will be low ($0.10/MW) since it would only reflect

255 The price associated with the "baseline" capacity will reflect the underlying operating and maintenance costs associated with the existing interconnector. We note that some changes to the pricing methodology may have to occur in order to "force" a monotonically increasing price function. For example, if the LRIC is non-monotonic, tranches could be defined so that the price of each *tranche* increases monotonically.

the underlying operating and maintenance costs associated with maintaining this level of capacity. Prices associated with additional capacity would be higher, reflecting the costs associated with expanding the capacity of the interconnector.

In Step 2, market participants would bid in the quantity of access (or firm interconnector rights) they want, at each price step. This is reflected in the “demand” side from Figure B.2. We expect that demand would increase over time, before tapering off at the end of the period.

Lastly, Step 3 would involve AEMO assessing the outcome of the auction. If demand for access is less than, or equal to the existing capacity then AEMO will simply allocate firm interconnector rights. For example, for the first three quarters of Year 1 the level of access demanded (390MW, 390MW and 500MW respectively) is less than the existing capacity (500MW). Participants will simply be allocated these firm interconnector rights.

However, following this period there is demand for more access than is currently provided (bids are greater than 510MW). AEMO would then look to see if there was any quarter where the bids for a given quantity of access were equal to the offered supply of access. Here, this occurs in the August quarter of Year 2. Participants' demand (510MW) equates to the offered supply (510MW), and so additional capacity and release of firm interconnector rights may be beneficial.

In order for AEMO to consider whether the increased capacity would be beneficial or not, it would compare the results of the auction (ie bids received) to an estimate of the costs necessary to upgrade the relevant interconnector.[256]

Inter-regional investments are likely to have a higher proportion of benefits accruing to parties other than generators, than intra-regional investments. Therefore, it is likely that benefits would exceed the bids from market participants justifying higher cost projects. For example, TNSPs could more readily meet their reliability and firm access standards by making use of a cross-regional option (ie a planning option in a neighbouring region), which is facilitated through undertaking inter-regional investments.

It is therefore necessary to assess whether or not these total benefits would outweigh the costs. We propose that there should be a "filtering" process to discard those upgrades that can clearly not be justified, eg if no bids demanding additional capacity are received. Where there was a reasonable chance that benefits would exceed costs, further investigation would be undertaken. This filtering and coordination role would be played by AEMO - consistent with its enhanced NTP functions and its role in running the auction. AEMO would direct the respective TNSPs to undertake a RIT-T assessment on the upgrade, where this was warranted.

256 Note that this is different to the price estimated through the standard pricing methodology.

B.1.3 Assessment by TNSPs

Following the direction from AEMO, the relevant TNSPs would undertake a joint RIT-T on the upgrade of the interconnector in question. This is necessary since the auction is designed to elicit *demand* for *inter-regional* access, whereas the RIT-T focuses on the benefits associated with a *particular project*. This would consider the potential options available to the TNSPs that would result in the requested capacity being released. The RIT-T would reveal both:

- the least cost solution (whether capital, operational or non-network); and
- other benefits associated with those options.

The RIT-T must be passed (ie benefits greater than costs[257]) for the additional capacity to be released, and firm interconnector rights created.

This RIT-T would be conducted through the same process as set out for the intra-regional RIT-T. As discussed in section 4.3 generator benefits (ie fuel costs, operating and capital costs) would not be included in the RIT-T, since this would result in double counting. If included, TNSPs would count private benefits that market participants had already accounted for in their bids.

We also do not consider that competition benefits should be considered. While in theory there may be competition benefits that would not be captured by generator firm access requests, in practice they are unlikely to be of sufficient magnitude to make a difference to the benefits associated with an inter-regional investment.[258] This is explored in greater detail in section 8.3.9 of the Technical Report.

Following the passing of the RIT-T (ie benefits are greater than costs), TNSPs would be obliged to release the increased capacity. Inter-regional access rights would be allocated only to the successful market participant bidders, with total rights limited to the amount of inter-regional capacity provided by the expansion.

Requiring TNSPs to conduct a RIT-T ensures that the auction bids, plus any other additional benefits would cover 100 per cent of the project cost. We consider that this is consistent with current practice of the RIT-T, and also provides incentives to TNSPs not to overbuild.

B.1.4 Timing for interconnector upgrades

As described in the process above, market participants bid for inter-regional access products in the auction, with these bids being binding. However, when an increase in capacity is required there would necessarily be a time delay between the time the bid is

257 The TNSPs would undertake detailed expansion planning in order to derive a set of costs to be included in the analysis.

258 For intra-regional investments we conclude that competition benefits should not be included since the inclusion of this category would not affect the investment outcome. We also recognise that is even more unlikely that competition benefits would occur for intra-regional investments.

entered, and when the capacity becomes available. This is since investments take time to be constructed, including obtaining planning permissions. This means that increased capacity must be auctioned off a number of years in advance - we have assumed a lead time of three years in the examples in this chapter.[259]

Therefore, bids should be valid for some amount of time (but not indefinitely) in order to allow the TNSPs to conduct the RIT-T and so consider the best project to provide the capacity – and then to build the investment.

However, this implies that the joint TNSP RIT-T would need to occur within a certain time period from the auction, ensuring bids received in the auction are binding for a discrete period of time. We consider that setting a time limit on when bids are valid is important in order to provide commercial certainty to businesses. Currently, the RIT-T process as set out in the rules takes approximately 18 to 24 months. We consider that this may need to be re-considered under OFA.

We consider that the RIT-T process could be undertaken in less time, while still allowing for full consultation. We understand that the majority of time associated with preparing a RIT-T currently is through the use of complex market modelling, used to assess changes in generator fuel costs and location patterns. Since these benefits would be privately valued by generators, who would then bid in the auction, it is less likely that this process would be required.

Further, NTNDP results could be used to assess (or at least guide the TNSPs) in whether the upgrade was likely to be requested. If this indication was given, then the TNSPs could begin work on the RIT-T prior to the auction being held.

We note that the main drivers for the move to the RIT-T was to better allow for stakeholder consultation, and also to better facilitate interest in non-network options. In some aspects, moving to a more market driven approach is consistent with both of these objectives. It also reduces the need for stakeholder consultation since generators would signal interests and their needs through the auction. Moreover, for non-network options interest could be sought at the same time as the auction.

B.1.5 Interaction with intra-regional investments

The increased focus on cross-regional investments as described in section 4.6, means that some intra-regional investments *may* also create inter-regional capacity, eg where intra-regional access requests are from generators located near borders. Under OFA, there may also be the case where, for a TNSP in a particular region to provide firm access to a generator, it *must* upgrade the network in another jurisdiction. In this situation, the network in the other region is *integral* to ensuring that the generator has

259 We consider that this is consistent with current practice. For example, ElectraNet and AEMO are assuming a three-year lead time for obtaining planning approvals, and constructing the relevant assets necessary to upgrade the interconnector.

firm access. That is, firm access cannot be provided unless *both* TNSP networks are upgraded.[260]

If the TNSP thought that firm interconnector rights would be created from an intra-regional expansion, then it would be allowed to build this increased capacity only if the costs would be *offset* by corresponding bids, ie benefits are greater than costs.

The use of annual auctions would provide the TNSP with a reasonably good idea of the likely market interest. Results from previous years' auctions could be used as proxies in the analysis to see if costs would be offset by bids. Informal discussions could then be held in order to see if parties were still interested. Alternatively, the TNSP could wait for the next annual auction, and test the interest then. Either way, there should not be any substantial delays to any intra-regional projects.

The Commission also considers that the NTP could look at the interaction between these inter-regional expansions and intra-regional expansions as part of its expanded NTP role. This could form part of the information it is required to assess when evaluating cross-regional investment planning.

B.2 Market Network Service Providers

The NEM currently allows for merchant investment in transmission links between regions. These market network service providers (MNSPs) are a category of market participant that must register with AEMO to operate in the NEM. Currently, the sole MNSP is Basslink, which connects Tasmania with the rest of the NEM at the Latrobe Valley in Victoria.[261]

MNSPs are entitled to the IRSR that accrue across the interconnector. MNSPs are required to submit a schedule of offers that sets out how much energy they are willing to transport in up to ten different price bands, similar to generators.

There are two potential ways a MNSP may seek to construct a business case in the NEM:

- if a certain level of price differential between two regions is maintained after the MNSP has entered service - revenue is earned by exploiting the price differences; or
- selling off long-term inter-regional hedges to market participants, with these used to cover the costs of the interconnector, and provide revenue.

Neither of these options is very attractive to MNSPs currently. This is because TNSPs are compelled to estimate all market benefits associated with expanding inter-regional capacity through conducting a RIT-T. Substantial inter-regional price differences are

260 As discussed in section 4.6 there would likely be an obligation on TNSPs to agree to be a proponent for a project in another region, if this project was required to meet the firm access standard.

261 Murraylink and Directlink were commissioned as MNSPs but were subsequently converted to regulated interconnectors.

unlikely to endure. TNSPs would undertake a RIT-T, find a positive net market benefit and so undertake interconnector expansion. Consequently, inter-regional price differences in the NEM are unlikely to be sufficient on their own to support MNSPs. This is evidenced since there is only one MNSP currently in the NEM, and this operates between regions where there is no regulated interconnector (ie Tasmania and Victoria).

Further, there is little incentive for participants to make a long-term commitment to fund an MNSP, when they know that the inter-regional capacity will be provided by regulated TNSPs even if there is no MNSP investment.[262] Therefore, proceeds from inter-regional hedges are unlikely to be sufficient to support MNSPs.

MNSPs may become more attractive propositions under the OFA model. MNSPs could offer a firm inter-regional access product as an alternative to firm interconnector rights, which may also be attractive to generators.[263] Importantly, the benefits accruing to the generator would no longer also be estimated by a TNSP to drive investment in a regulated interconnector. For an MNSP to be economic under OFA, its costs must be less than the revenue obtained from selling an inter-regional access product to hedge the price differential that would otherwise have occurred if the interconnector had not been built.

Given this, we have considered whether there need to be any changes to the NER under the OFA framework. MNSPs would be accommodated in the OFA model as follows:[264]

- MNSPs should be required to be controllable – in order to be accommodated in the OFA settlement and pricing model, as well as to clearly allocate liabilities;[265]
- any MNSPs would be treated as “generators” for the purposes of OFA - including transition, eg Basslink would be treated as a generator in the Latrobe Valley;
- any MNSPs would also be treated as "generators" for buying intra-regional access for injection into the system. However, further consideration would need to be given to the arrangements relating to buying intra-regional access for off-take (including how this would be priced); and
- consideration should be given as to whether access provisions for MNSPs are set out in the Rules.

262 Clearly this is less likely to be the case for Victoria and Tasmania.

263 Although note that in order to offer an equivalent product, MNSPs would also need to buy intra-regional access to connect to the RRN in each region.

264 We note that further consideration would need to be given to existing rules on MNSPs in relating to bidding. The AEMC is currently considering a rule change relating to this. AEMC, *National Electricity Amendment (Negative offers from scheduled network service providers) Rule 2012*, Consultation Paper, 29 March 2012.

265 This is already a requirement as set out in NER clause 2.5.2(a)(5)(B).

In relation to the last point, we note that the regulated process may be more costly than an existing MNSP due to the existence of economies of scale (discussed below). MNSPs should have incentives to offer an equivalent product if this is situation occurs since they would be able to competitively offer firm interconnector rights - undercutting the AEMO auction. However, if the MNSP was controlled by a single participant, then there may be a need for third party access provisions in the rules.

Despite the improved prospects for MNSPs under OFA, there are likely to be a number of challenges for MNSPs to overcome compared to regulated interconnectors with firm interconnector rights in offering an inter-regional access product, namely:

- coordination – it would be difficult for an individual MNSP to coordinate individuals together to buy inter-regional access. Regulated TNSPs have the advantage of AEMO running one, consolidated auction for firm interconnector rights under a well-understood process; and
- economies of scale – it would be cheaper for an existing interconnector to be upgraded to provide inter-regional capacity rather than for a new interconnector to be built.

C Implementation of connections recommendations

Chapters 11 to 14 discussed our recommended changes to the connections frameworks. This appendix sets out how these changes would be implemented in the rules by setting out draft specifications. These provide the framework for developing draft rules.

These specifications cover the recommendations by dividing them into five issues, as follows:

- asset definitions and boundaries (section C.1);
- transmission asset ownership and registration (section C.2);
- the connection process (section C.3);
- third party access (section C.4); and
- service definitions (section C.5).

C.1 Asset definitions and boundaries

We suggest that transmission asset definitions and boundaries in the NEL and rules should be specified as set out in the remainder of this section.[266]

C.1.1 Asset definitions and categories

An asset would be a "transmission asset" if it meets specified physical and technical criteria - primarily related to the voltage of electricity transfer (these are "primary transmission assets").

There are also assets, such as communications and other ancillary equipment, that do not meet the specified physical and technical criteria but are nevertheless directly related to the operation of primary transmission assets. These assets are currently defined in the rules as *transmission plant*.

"Transmission assets" therefore comprise primary transmission assets and *transmission plant*.

Transmission assets may also be separated into "transmission connection assets" (***connection assets***[267]) and "shared transmission network assets" (***shared assets***). This separate identification is necessary only for:

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266 The approach to asset definitions and boundaries has been developed with generator connections primarily in mind. While the principles set out might be equally applicable to the connection of loads (particularly large loads), we note that generators large load and DNSP connections to transmission networks are not currently treated consistently under the rules, or in practice.

- identifying the TNSP's obligations to develop the relevant asset and to negotiate with a connecting party;
- identifying who may operate the relevant asset; and
- determining who is required to fund the development and operation of the relevant asset.

Dedicated connection assets are transmission assets:

- developed and constructed for the purpose of connecting an identified user group to an existing transmission system (the "purpose limb");
- used exclusively by the relevant identified user group (the "use limb"); and
- where the costs of developing, constructing, operating and maintaining those transmission assets are not recoverable from *customers* as charges for *prescribed transmission services* (the "payment limb").[268]

An identified user group is a group of one or more specifically identified generators or industrial loads that are connected to transmission assets that are, in turn, connected to the shared network at the same point.

Shared assets are all transmission assets other than dedicated connection assets. However, there are two specific *sub*categories of shared assets that must be differentiated from the generality of shared assets. These are "identified user shared network assets"[269] and *interconnectors*.

Identified user shared network assets[270] are shared assets developed and constructed for the purpose of connecting an identified user group to an existing transmission system, but not used exclusively by the relevant identified user group (ie transmission assets that meet the purpose limb, but not the use limb). These assets will include substations "cut-into" the shared network for the purposes of facilitating a connection,

267 The rules would define these assets as "transmission connection assets". However, we refer to these throughout this report as dedicated connection assets.

268 It may not be necessary in addition to the purpose limb and use limb - the "who pays" issue could equally also be characterised as a consequence of the classification between connection assets and shared assets (other than identified user shared network assets) rather than a driver of that classification.

269 Identified user shared network assets have features in common with both connection assets and shared assets. Rather than classifying them as a third category of transmission asset we believe that they are best categorised as a subcategory of shared assets because: (1) their construction involves augmentation of the shared transmission network and they should be treated as much as possible in the same manner as other augmentations; (2) like the shared transmission network, the local TNSP must always be responsible for their operation; (3) they are "used" by all users of a shared transmission network in the sense that their operation impacts the flows of the shared transmission network; and (4) this categorisation will result in less drafting amendments to the rules.

270 The rules would define these assets as "identified user shared network assets". However, we refer to these throughout this report as identified user shared assets.

together with other augmentations required to the shared network to accommodate the connection.

Identified user shared assets must be funded by the relevant connecting party(ies).

Interconnectors are transmission assets used to connect transmission systems in adjacent regions.

C.1.2 Reclassification

Where a **DNSP** connects to dedicated connection assets or an identified user shared asset, all dedicated connection assets and identified user shared assets from the point at which the DNSP connects to those assets are automatically reclassified as shared assets.

C.1.3 Transmission Systems

A group of interconnected[271] dedicated connection assets and Shared assets owned and/or operated by a single participant is referred to as a "transmission system".[272] A transmission system may include only dedicated connection assets, ie shared assets are not necessary to constitute a transmission system.

The collection of all *interconnected* transmission systems across *participating jurisdictions* is the *national transmission grid*.

The *national transmission grid* and all *connected distribution systems* comprise the *national grid*.[273]

It will be important that the boundary between the different categories of transmission assets is clearly defined. It is also important that the *connection point* in each case is identified.

271 The requirement that transmission assets must be interconnected to constitute a transmission system has been included to reflect section 11(2) of the NEL, which requires that a party must be registered as a TNSP only if they operate an interconnected transmission system. Maintaining this approach avoids the need for amendment to the NEL, but does mean that non-interconnected transmission systems are not subject to a TNSP registration obligation (and therefore the exemption/access proposals).

272 We note that there are inconsistencies in the rules between the use of the terms "transmission system" and "transmission network"(eg the rules refer to connecting to a "network", when in almost all cases they will connect to a connection asset - part of a transmission system. Note also the use of the term "transmission network service providers"). We have continued to use the term "transmission system" to avoid amendments to the NEL.

273 We propose that the rules contain a new definition of the term "interconnected". Presently the rules collectively define "interconnection, interconnector, interconnect and interconnected" as "a transmission line or group of transmission lines that connects the transmission networks in adjacent regions". While appropriate for the nouns "interconnection and interconnector", this definition is inappropriate for the verbs "interconnect and interconnected". Similar amendments to the definition of "connect, connected, connection" should also be made.

Generally, the *connection point* should be where the connecting party's assets are physically connected to the dedicated connection assets of the relevant TNSP. In most cases this will be an identifiable isolator or circuit breaker at a switchyard, substation or other point. The definition of connection point could usefully provide more detail about the exact point of connection by referencing a physical element such as the relevant isolator or circuit breaker. This analysis is complicated by dedicated connection assets and identified user shared assets potentially being owned by the connecting party rather than the TNSP. Accordingly, we consider that the relevant connection point should be located at the point generator-operated assets connect to TNSP-operated assets. The TNSP-operated assets may comprise assets owned by the generator, but controlled and operated by the TNSP (see below).

To provide some clarity to the specific boundary between: (a) generator and industrial load connection assets and dedicated connection assets; and (b) dedicated connection assets and shared assets, we suggest that the rules provide examples of asset categorisation, asset boundaries and connection point locations for all common connection scenarios.

C.1.4 Ownership and operation

Our recommendations would permit identified user shared assets to be owned by the connecting party, but require that they be operated by the *local* TNSP.[274,275] Similarly, there is nothing to prevent a connecting party and TNSP from agreeing that dedicated connection assets will be owned by the connecting party but operated by the TNSP. In situations where identified user shared asset ownership and operation are separated, there may be a need to formalise the use of the relevant assets so that the TNSP may, in all relevant respects, treat the asset as if it were the owner (eg the TNSP can modify, augment, repair and decommission the relevant assets without the consent of the connecting party).

A connecting party may alternatively own identified user shared assets for the purposes of development and construction, but then elect to transfer ownership of the resulting assets to the TNSP on commissioning. The terms of this transfer would need to be agreed with the TNSP (as part of negotiating the connection agreement).

Similarly, a connecting party may own dedicated connection assets for the purposes of development and construction, but then transfer ownership of the resulting assets to the TNSP on commissioning. A TNSP would not be required to accept a transfer of dedicated connection assets and the terms of this transfer would need to be agreed with the TNSP.

274 The concept of a "local" TNSP requires further definition given the existence of more than one TNSP in certain regions (eg Ausgrid and TransGrid in NSW). Note also that this may result in an obligation enter into an arrangement for that asset to be operated by the local TNSP where a transmission asset is subsequently "converted" to a Shared Asset (eg by DNSP connection).

275 This would not preclude the TNSP from sub-contracting the operation, or elements of it. The TNSP would remain accountable for operation.

C.2 Transmission asset ownership and registration

We suggest the following approach to transmission asset ownership and registration in the NEL and rules, as set out below.

C.2.1 Registration and exemptions

An owner, operator or controller of a transmission system (which may only be dedicated connection assets in some cases) is required to register as a TNSP under the rules, unless it has a current exemption from the AER.

The AER should have the ability to grant exemptions from the requirement to register as a TNSP to owners, operators or controllers of transmission systems. This may include the use of exemptions for specific categories of transmission systems, such as:

- transmission systems comprising only dedicated connection assets less than 2km in length;[276]
- transmission systems comprising only dedicated connection assets longer than 2km but operated and controlled by another registered TNSP (and provided that the owner agrees, as a condition to obtaining that exemption, to provide third party access on reasonable terms); and
- transmission systems that are not *interconnected*.

The AER presently lacks an appropriate framework for enforcing conditions imposed upon an exempt party. We recommend that a framework for the enforcement of exemptions is included in the rules.

C.2.2 Ownership, operation and control of transmission assets

Shared assets, including identified user shared assets, may be owned by either a registered TNSP or a person who has the benefit of an exemption (we refer to this as "private ownership").[277]

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276 This exemption would include most generator-owned transmission assets (eg on the power station side of network connection points). The presence of Shared Assets would mean that the standing exemption is not available (but the participant could apply for an individual exemption). We note that instead of classifying transmission assets of less than 2km in length as being eligible for an AER exemption, the exemption could be "hard-wired" into the rules as a de-minimus level for the purposes of qualifying as a transmission asset (but this would leave such assets unregulated by the NEL and rules).

277 Private ownership of shared network assets gives rise to a number of issues including: (1) the need to develop a regime under which the owners of the assets are compelled to allow the TNSP to operate the assets; (2) the need to ensure that the TNSP has all the rights it will require in relation to the assets including rights to use, augment and replace the assets where necessary; and (3) the need to develop a mechanism by which the TNSP can recover the costs involved in leasing the asset under prescribed charges.

Private ownership of shared assets is most likely to occur in the following circumstances:[278]

- where a connecting party elects to construct and own the identified user shared asset required to connect them to the shared assets of an existing transmission system; and
- where a connecting party owns dedicated connection assets which are subsequently reclassified as shared assets.

Our recommendations require that responsibility for the operation and control of all new shared assets, including identified user shared network assets, must rest with the *local* TNSP. This may require the implementation of grandfathering provisions for existing shared assets that are not operated and controlled by the local TNSP.

Accordingly, the *local* registered TNSP must be responsible for the operation of privately owned shared assets. The terms of such operation would need to involve a grant to the TNSP of rights akin to ownership of the relevant assets (including the rights to grant third party access to the asset and augment, replace and maintain the asset).

Dedicated connection assets may be built, owned, operated or controlled by either a registered TNSP or a connecting party(ies).

C.3 Connection process

Our recommendations include the following principles which need to be highlighted:

- the development of shared assets (including identified user shared assets) is a *negotiated transmission* service provided by TNSPs.[279] However, TNSPs do not have any obligation to develop dedicated connection assets and the development of dedicated connection assets is **not** a negotiated service; and
- much of the connection process in Chapter 5 therefore applies only to the development of shared assets. However, Chapter 5 must still recognise that as part of the connection process, the connecting party and the relevant TNSP may agree that the TNSP may develop and own dedicated connection assets (eg any resulting connection agreement will need to accommodate all assets developed as part of the connection process).

The following process description separates the connection process into the existing connection enquiry and connection application stages. In reality, this process could be

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278 Although separation of ownership and operation/control exists in a number of current situations, including the Victorian arrangements and in circumstances where transmission assets are subject to finance and other lease arrangements.

279 In the current rules these services would be subject to the TNSP's negotiating framework. We recommend that the TNSP negotiating frameworks should be replaced. Negotiated charges will be required to comply with the replacement regulatory framework.

separated into additional stages and the end of the enquiry stage and beginning of the application stage could occur as several different points.

C.3.1 Step 1: the Connection Enquiry Stage

Potential connecting parties (***Connection Proponents***) may make an enquiry to the relevant TNSP about a potential connection (as per the existing connection enquiry process in Chapter 5 of the rules).

The connection enquiry stage is necessarily high level and the TNSP's response to a connection enquiry would be to identify the range of potential plausible technical solutions to achieve the connection proposal. These technical solutions should include an initial assessment of the potential costs of developing each potential solution.

C.3.2 Step 2: the Connection Application Stage

Once the TNSP has provided the Connection Proponent with the range of potential plausible technical solutions to achieve the connection proposal, and an initial indication of cost, the Connection Proponent may lodge a connection application to the TNSP.

On lodgement of a connection application, the TNSP would be required to develop a design and specification (**Specification**) for one or more of the potential plausible technical solutions (as selected by the Connection Proponent). The Specification would:

- set out a high-level technical design for the relevant transmission assets;[280]
- separately identify the relevant transmission assets into their component parts of:
  - dedicated connection assets;[281]
  - identified user shared assets - "non cut-in works"; and
- set out the terms (including indicative charges) on which the TNSP is prepared to:
  - build, own and/or operate dedicated connection assets, if at all;
  - build, own and/or operate identified user shared assets - "non cut-in works"; and

280 Note that this assumes that the Specification may only address the requirements of the Connection Proponent. The TNSP does not have any scope to identify economies of scale and use the proposed development to also augment the shared network. If this was contemplated, then a cost sharing basis would be required and the binary approach to classification of these assets would need to be reviewed.

281 Given TNSPs are not required to develop connection assets the inclusion of connection assets in the Specification would need the agreement of the TNSP.

— build, own and operate identified user shared assets - "cut-in works".

Criteria for the form and content of Specifications will need to be set out in the rules or AER guidelines (***Guidelines***).

The TNSP will be required to use its best endeavours to develop a Specification within a reasonable period.

The Connection Proponent will be entitled to refer the Specification to an independent engineering expert (***Engineer***). The identity of the Engineer will be agreed between the TNSP and the Connection Proponent. If the parties are not able to agree on the identity of the Engineer within a reasonable period either party may request the AER to make a binding recommendation. The Engineer will assess the Specification to ensure that:

- it efficiently meets the requirements of the Connection Proponent without over specification or redundancy;
- does not prevent future connections;
- meets all relevant technical and other standards; and
- otherwise meets the Guidelines.

The Engineer will need to have access to sensitive commercial information held by the TNSP and will need to be made subject to appropriate confidentiality obligations.

A determination of the Engineer will not be binding, but can then be produced by a party in any subsequent binding arbitration process initiated under Chapter 8 of the rules.

The costs of the Engineer will be met equally by the TNSP and the Connection Proponent, unless the Engineer determines that a different allocation of costs would be more reasonable in the circumstances. The Connection Proponent will otherwise meet the reasonable costs of the TNSP in responding to the connection enquiry and connection application.

Once the Specification has been finalised,[282] the TNSP must provide a quotation for developing and constructing the relevant transmission assets if requested by the Connection Proponent. The Connection Proponent may elect to itself develop and construct any dedicated Connection Assets and identified user shared network assets – "non cut-in works". The TNSP will still need to provide a quotation for any identified user shared network assets – "cut-in works".

If the Connection Proponent elects to itself build the dedicated connection assets and identified user shared assets -"non cut-in works", it must:

- cooperate with the TNSP for the identified user shared assets -"cut-in works";

282 A TNSP will not be committed to a Specification and may at any stage amend a Specification for any change in circumstances.

- make an election on whether it will continue to own the resulting transmission assets after the commissioning. If the Connection Proponent elects:
  - to own dedicated connection assets: the parties **may** agree the terms on which the TNSP will control the assets (so that the TNSP may commission and operate them);
  - not to own dedicated connection assets: the parties **may** agree the terms on which those assets will be transferred to the TNSP on commissioning;
  - to own identified user shared assets - non cut-in work: the parties **must** agree the terms on which the TNSP will control the assets (so that the TNSP may commission and operate them); and
  - not to own identified user shared assets - non cut-in work: the parties **must** agree the terms on which those assets will be transferred to the TNSP on commissioning.

The parties will need to negotiate the terms of all relevant documentation:

- the connection agreement. The connection agreement will include a commitment to fund the operation and maintenance by the TNSP of any developed transmission assets;
- a new investment agreement/recoverable works agreement for assets to be developed and constructed by the TNSP (this will include any identified user shared assets -"cut-in works" at a minimum);
- an agreement for privately owned transmission assets to be operated by the TNSP; and/or
- a transfer agreement for privately owned transmission assets that will be transferred to the TNSP on commissioning.

Once the above arrangements have been concluded, the TNSP must make the Connection Proponent a formal offer to connect on the agreed basis. TNSPs will also be under general obligations to:

- act reasonably in dealing with Connection Proponents;
- provide all information reasonably required by a Connection Proponent to evaluate and understand any TNSP proposals; and
- ensure that its obligations under the Chapter 5 processes are performed in a reasonable timeframe.

To assist the above process, each TNSP will be required to publish:

- a pro forma connection agreement;

- a pro forma new investment agreement/recoverable works agreement;
- the terms of operation for participant-owned shared network assets;
- the terms of transfer of participant-owned transmission assets (dedicated connection assets or identified user shared assets);
- design standards and philosophies for transmission asset development;
- a pro forma preliminary program;
- a list of accredited contractors; and
- costing principles for works undertaken by the TNSP.

C.4 Third party access

C.4.1 Current Proposals

We are recommending that a generator owning dedicated connection assets greater than 2 km in length would need to register as a TNSP or gain an exemption from that requirement from the AER, with such exemption to be conditional on allowing third party access on reasonable terms. The conditions in the exemption should include:

- requiring third party access to dedicated connection assets to be explicitly contemplated, including that this should occur through a negotiate/arbitrate framework;
- requiring a more fully developed description of an appropriate dispute mechanism process, including a set of third party access principles that should be considered by an arbitrator; and
- clarifying that if a dedicated connection asset (or any part of it) becomes part of the shared network then the dedicated connection asset must be operated by a registered TNSP.

The aim is to ensure that there are arrangements in place setting out a process for both gaining third party access, and dealing with disputes that may arise in this context.

Part IIIA of the *Competition and Consumer Act 2010* (CCA) contains a statutory regime for third party access to infrastructure. Under this regime a third party can obtain access through a declaration process.

We have set out below an overview of relevant aspects of the Part IIIA of the CCA which provide guidance as to the appropriate framework and principles for third party access regimes, including some of the considerations that arise in the context of developing effective access regimes under Part IIIA.

C.4.2 Negotiate/arbitrate framework

As set out above, an obligation to provide third party access within a negotiate/arbitrate framework is recommended. This approach overcomes the difficulties of the declaration process under Part IIIA which sets a high threshold for declaration (such that it is unlikely that dedicated connection assets would meet the criteria) and has proved to be time consuming, complex and expensive in its operation.

In its submission to the current Productivity Commission inquiry into the National Access Regime, the ACCC has reported that, with the exception of telecommunications, a negotiate/arbitrate regime to determine the terms and conditions of access has been successful and that the threat of arbitration has facilitated commercial settlements in access disputes.[283]

In order to ensure that access disputes are dealt with in a timely manner the CCA includes a six month time limit (subject to an ability to extend) on the ACCC to determine an access dispute.

A negotiate/arbitrate framework for access is also appropriate for dedicated connection assets given that for many dedicated connection assets third party access may not in fact be sought. A negotiate/arbitrate framework (as opposed to a framework requiring the provision of an access undertaking as a condition of the exemption) ensures that the costs of developing a specific access regime for the dedicated connection asset are only incurred when a third party seeks access.

C.4.3 Access principles

Part IIIA sets out a number of express protections for the provider of access and the infrastructure owner. Specifically, under section 44W the ACCC must not make an access determination in an arbitration that would:

- prevent an existing user obtaining sufficient capacity to meet its reasonably anticipated requirements;
- result in a third party becoming the owner of any part of the facility without the consent of the owner; or
- require the provider to bear some or all of the costs of extending the facility (or maintaining extensions) or the costs of interconnections to the facility (or maintaining interconnections to the facility).[284]

Section 44X of the CCA sets out various matters that the ACCC must take into account in determining an access dispute through the arbitration process. Relevantly, these include:

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283 ACCC, Submission to the Productivity Commission Review of the National Access Regime, February 2013 (***ACCC PC Submission***), pp.37-38.

- the legitimate business interests of the provider, and the provider's investment in the facility;
- the direct costs of providing access to the service;
- the value to the provider of extensions whose cost is borne by someone else;
- the value to the provider of interconnections to the facility whose cost is borne by someone else;
- the operational and technical requirements necessary for the safe and reliable operation of the facility;
- the economically efficient operation of the facility; and
- the pricing principles specified in section 44ZZCA (see further below).

Similar protections and principles would be appropriate for third party access to dedicated connection assets.

C.4.4 Pricing principles

Section 44ZC of the CCA sets out the following pricing principles for access disputes and access undertakings:

(a) that regulated access prices should:

    (i) be set as to generate expected revenue for a regulated service or services that is at least sufficient to meet the efficient costs of providing access to the regulated service or services; and

    (ii) include a return on investment commensurate with the regulatory and commercial risks involved; and

(b) that the access price structures should:

    (i) allow multi-party pricing and price discrimination when it aids efficiency; and

    (ii) not allow a vertically integrated access provider to set terms and conditions that discriminate in favour of its downstream operations, except to the extent that the cost of providing access to other operators is higher; and

(c) that access pricing regimes should provide incentives to reduce costs or otherwise improve productivity.

284 We note that the section 44W and 44X of the CCA uses the terms "extension" and "interconnections" in a general sense, not in the sense in which they are defined in the rules.

These pricing principles provide significant flexibility and allow the pricing methodology to be tailored to take into account industry-specific circumstances and other factors. This flexibility is reflected in the different approaches that have been taken to date in pricing under Part IIIA.[285] Access agreements and undertakings can set out specific prices or a methodology for determining prices or, as was the case in wheat port access undertakings, a prohibition on discriminatory conduct and a publish-negotiate-arbitrate model for determining actual prices.

C.4.5 Dedicated connection assets and capacity upgrades

We consider there is general support for the access proposals and agreement that third party access on reasonable terms "*should include the third party incurring the cost of any upgrade necessary to maintain the original party's access*". This is consistent with the protections set out above under section 44W of Part IIIA of the CCA.

The Australian Rail Track Corporation Ltd (ARTC) Access Undertaking is an example of an access undertaking dealing with this issue. This undertaking includes provision for requests for additional capacity and provides that the ARTC will consent to a request for additional capacity if:

- the ARTC considers that this is commercially viable to ARTC; or
- the applicant agrees to meet the cost of the additional capacity; and
- the additional capacity "*is, in the opinion of ARTC, technically and economically feasible, consistent with the safe and reliable operation of the network, will not impact on the safety of any user of the network, does not reduce capacity, meets ARTC's engineering and operational standards and does not compromise ARTC's legitimate business interests*".

This final requirement ensures that appropriate technical and safety issues are taken into account in relation to requests for dedicated connection assets and capacity upgrades.

Consistent with section 44W, under the ARTC Access Undertaking, any additional capacity is owned and managed by ARTC.

C.4.6 Access to information

Ensuring that access seekers have access to information can be an important factor in the success or otherwise of access negotiations. The lack of access to information is one of the reasons given by the ACCC for the lack of success of negotiations for third party access in telecommunications.[286] To address this issue, access undertakings accepted by the ACCC in recent times have included clauses dealing with the provision of information in order to facilitate negotiations.

285 For example, see ACCC PC Submission, p.44.

286 ACCC PC Submission, p.39.

C.4.7 Terms of access agreements and undertakings

Access undertakings typically include terms covering the following matters:

- the scope of the access being provided;
- the duration of the access arrangements;
- any pre-conditions of access;
- pricing, either specific prices or a methodology for determining access prices;
- capacity allocation procedure (if there are capacity constraints);
- performance indicators/KPIs;
- interconnection;
- measures to deal with the scope for discrimination arising from vertical integration (eg non-discrimination provisions, ring-fencing); and
- dispute resolution procedures.

In relation to the dispute resolution procedures, by way of example rail and wheat port access undertakings have set out a regime providing for notification of a dispute and good faith negotiations to attempt to resolve the dispute, followed by mediation and then, if mediation is not successful, a referral of the dispute to arbitration (which may or may not be by the ACCC).

C.5 Service definitions and charging

The various service definitions in the rules would benefit from changes being made with a view to consolidating and clarifying their use. This is a complex area that would benefit from further development during the implementation of our recommendations; however, we suggest a potential high-level approach to service definitions and charging as set out in the remainder of this section.

C.5.1 Services

The NEL currently defines and uses the terms of a "connection service" and "shared transmission service" which are defined by reference to the rules. This therefore provides the flexibility to follow a different approach in the rules, if this was warranted. One such approach is outlined below.

"Transmission services" should comprise all services provided by a TNSP in relation to the construction and operation of transmission system assets.

Transmission services would then be separated into generator transmission services (***Generator Services***) and transmission customer services. This classification by user type is required because of the convention that only customers pay for shared assets (other than identified user shared network assets).

Generator Services would consist of generator transmission connection services (***Generator Connection Services***) and *prescribed entry services* (a service category only provided by TNSP's in accordance with grandfathering arrangements).

Customer transmission system services would be made up of customer transmission connection services and customer transmission network services.

Customer transmission connection services would consist of non-DNSP transmission connection services and *prescribed exit services* (provided to DNSPs).

Customer transmission network services would be *prescribed services* provided to Transmission Customers for the use of the shared network. Customer transmission network services are provided to both DNSP loads and industrial loads.

C.5.2 Charges

The rules currently divide transmission services into two general categories: "prescribed" and "negotiated". Prescribed charges are charges in respect of *prescribed services* and are subject to regulatory oversight (via TNSP revenue caps) under Chapter 6A. Negotiated charges are charges in respect of all other services. Currently negotiated charges are not subject to any regulatory oversight other than compliance with the TNSP's *negotiating framework*.[287]

The potential services defined above would be categorised as either a prescribed service or negotiated service. The structure and categories of charges in the rules would then follow the amended service definitions. The amendments to the asset and services definitions are not intended to result in any change to the charges paid by *users*.

Charges relating to the design and construction of dedicated connection assets do not fall within the scope of charges set out in the rules as they are commercially negotiated charges agreed between the parties and are not subject to the *negotiating framework*.[288]

287 We recommend that the TNSP negotiating frameworks should be replaced. Negotiated charges will be required to comply with the replacement regulatory framework.

288 Charges relating to the design and construction of connection assets will not be subject to any regulatory framework that may replace TNSP negotiating frameworks.

D Process for facilitating generator connections

The following table seeks to provide some guidance as to the steps that may be taken by parties during the revised connections process discussed in chapter 12. The table is a guide only; it is not meant to be exhaustive or determinative of the precise steps and processes that may be undertaken.

Table D.1 Process for facilitating generator connections

STEP	PROCESS
CONNECTION ENQUIRY	**COMMENCEMENT**: *Connection Applicant lodges Connection Enquiry*. Connection Applicant: • Lodges enquiry, providing details including: — power transfer and reliability requirements; — technical requirements of plant (preliminary system planning data); — preferred and alternative locations; — preferred connection configuration for each location; — preferred connection date. • Payment terms for studies and services provided by the TNSP during the entire connection application process should be agreed. The fees and terms on which services are provided should be fair and reasonable. Commercial arbitration should be available where agreement is not reached. TNSP: • Performs preliminary technical studies to investigate the suitability of the Connection Applicant's preferred locations and options; • Consults with other TNSPs; • Provides connection options and its reasons for preferred and rejected options. Also provides indicative costs for identified user shared asset options;

STEP	PROCESS
	• Lists information which the Connection Applicant will be required to provide as part of the Application to Connect, regarding performance standards and system planning data; • Provides a preliminary program, setting out relevant milestones[289] and indicative timeframes for activities; • Provides advice on land requirements: size, geotech requirements, zoning, planning permit requirements. <u>Independent Engineer and Commercial Arbitrator:</u> will have access to relevant models and data to verify TNSP's design independently to assist resolving disputes that may arise at this early stage. **OUTCOME:** TNSP has provided the Connection Application with sufficient information to prepare a connection application.
APPLICATION TO CONNECT	**COMMENCEMENT:** *Connection Applicant lodges Application to Connect*. <u>Connection Applicant:</u> • Lodges application, including: — power transfer and reliability requirements; — proposed performance standards; — detailed system planning data; — project program / preferred connection date; — relevant commercial information.

289 Such as commencement and completion of: technical studies; negotiation and determination of access standards; confirmation of location and configuration; high level design; negotiation; detailed design and construction; commissioning; operation.

STEP	PROCESS
	TNSP: • Notifies AEMO about application to connect; • Consults with other TNSPs; • Accepts, rejects or nominates revised performance standards; • Updates the project program in discussion with the Connection Applicant (this will need to occur progressively throughout the process). AEMO, TNSP and Connection Applicant: Negotiation of performance standards. TNSP and Connection Applicant: An iterative discussion and negotiation process about: • Location, configuration and cost; • Timing; • To what degree the works can be contestable. Independent Engineer and Commercial Arbitrator: Will have access to relevant models and data to verify TNSP's design independently to assist resolving disputes. **OUTCOME**: • Agreement on configuration sufficient for TNSP to commence high level design; • Indicative cost - cut in works.

STEP	PROCESS
HIGH LEVEL DESIGN	**COMMENCEMENT:** *After lodgement of the Application to Connect; occurs in parallel with the negotiation of access standards process.* TNSP to prepare "high level" design of the entire identified user shared assets: • This design will be more than just a "functional specification" of the asset configuration, but at a level that the TNSP will have confidence that it will be capable of being operated, maintained and controlled by the TNSP as part of its entire network; • It will be specified in a way that will enable detailed design to be undertaken in the construction phase; • The high level design will be an iterative process depending on factors such as: — applicant's power transfer capability and reliability requirements; — access standards for the applicant's plant, and network requirements; — location and agreed configuration of the identified user shared assets; — physical size of the available land/bay, orientation towards transmission lines/buses/other physical limitations; — access during construction and during operation, and to accommodate the TNSP's reasonable requirements for future expansion;[290]; — municipal planning and zoning requirements, environmental regulatory requirements; — community engagement strategies; — landowner requirements (with regard to: acquisition of freehold; leasehold and easements; options to acquire land etc;

290 The Connection Applicant need not acquire the land. For example: facilitate the option of the TNSP acquiring additional land from a landowner if a trigger for future requirements.

STEP	PROCESS
	cost and timing); — underwriting of long lead items; • Primary and secondary asset boundaries identified. This high level design should then be broken down into the separate high-level requirements for: • Cut-in / interfacing works; and • Contestable works. These design steps should occur within a time frame that accommodates the applicant's project delivery program. Such as commencement and completion of: technical studies; negotiation and determination of access standards; confirmation of location and configuration; high-level design; negotiation; detailed design and construction; commissioning and operation. **OUTCOME:** A high-level design of the cut-in works and the contestable work is finalised
QUOTES	**COMMENCEMENT:** *A high-level design of the cut-in works and the contestable work is finalised*. TNSP to provide quotes for: • Performing the cut-in / interfacing works; • Operating, maintaining and controlling the entire identified user shared assets for an agreed service period (usually expected to be between 20-40 years). In relation to construction of the contestable works, the Connection Applicant can: • Seek quotes from third party contractors; or • Conduct a tender; or

STEP	PROCESS
	• Elect to construct itself; or • Ask the TNSP to provide a quote for the whole augmentation (cut-in/interfacing and contestable works) and subsequent operation, maintenance and control of the identified user shared assets as part of its network. The Connection Applicant can also consider asset ownership options, such as whether the Connection Applicant itself, a third party, or the TNSP should own the assets. Because of potential changes on the network, there will need to be a time limit on the Connection Applicant's exploration of options. **OUTCOME:** The Connection Applicant makes a decision on how it wishes to proceed with regard to contestability of construction and ownership, such that contract negotiations for construction, operation and connection[291] can commence.[292]
CONTRACT NEGOTIATION	**COMMENCEMENT:** *Connection Applicant decides how it wishes to proceed regarding construction and ownership*. Negotiation to occur between TNSP and Connection Applicant (and, if parties other than the TNSP will construct the contestable works and/or to own the assets, those parties where relevant) on issues which may include: • Agreement on contractual structure; • Terms and conditions to be fair and reasonable, consistent with the commercial principles; • Negotiation of access standards relating to the Connection Applicant's generating units or other plant to be progressed, for inclusion in the connection agreement; • Who will undertake detailed design: — if the TNSP, the level of transparency; and

291 Connection of the Connection Applicant's plant to the shared network.

292 Until the contracts are actually signed, the Connection Applicant can change its approach.

STEP	PROCESS
	— if not by the TNSP, the TNSP level of input. • Technical requirements for all aspects of the identified user shared assets, the practical completion criteria and the connection to be agreed; • Payment for the construction works – cut-in and contestable works; • Liquidated damages for delays; • Accommodation of Security of Payment Act requirements; • Amount of O&M charge payable to the TNSP; • Access to land before and after commissioning by relevant parties (including right of TNSP to inspect progress of construction); • Rights for TNSP to witness factory acceptance tests and progress of construction; • Agreement on commissioning testing program; • Process for handover of responsibility prior to energisiation and commissioning of the augmentation; • Contractual process / quality assurance program for TNSP to be able to verify that the assets are constructed in accordance with the design / capable of being operated by the TNSP as part of its network; • Allocation of risk and liability for negligence in design (high level and detailed), construction, interfacing, commissioning and subsequent operation, and liability for asset defects; • Provision for management of delays, variations, project timeframes and other project management; • Termination rights, force majeure and consequences; • Agreement on the dispute resolution process to apply under the contracts themselves;

STEP	PROCESS
	• Obligations to comply with permits; • Community engagement plan; • Interfacing. Commercial arbitration can be used for deadlocks in negotiation. The commercial principles are to be taken into account. **OUTCOME:** Agreements for all aspects of construction and connection, and also subsequent TNSP operation, maintenance and control are signed.
CONSTRUCTION	**COMMENCEMENT:** *Agreements are signed*. *Note: the terms on which construction occurs should have been agreed by the parties during the negotiation phase.* If the contestable works are being designed and constructed by a party other than the TNSP, the following will ordinarily occur (note, this is far from an exhaustive list): • Detailed Design to be progressed in accordance with the TNSP's high level design, with transparency for TNSP and a right for the TNSP to raise issues. If the detailed design process raises significant implications for the high level design, there should be processes for the parties to review the issues and agree variations where necessary; • There should be effective project management and coordination between the parties; • The parties will need to coordinate outages; • Variations, Delays, Disputes – attributing liability for these events – should be dealt with in accordance with the contractual dispute resolution mechanism (not the rules mechanism); • The TNSP should ideally have the right to witness progress of construction, so that any issues that may cause problems during commissioning, or may inhibit the TNSP's operation of the assets after commissioning, are identified early; • The parties should collaboratively prepare a commissioning plan, noting the TNSP should have responsibility for carrying

STEP	PROCESS
	out commissioning: — what plant needs to be tested; — criteria for success / failure; — process for dealing with failures and rectifying defects; • The parties should seek to interface the cut-in works and the contestable works at a time agreed in advance. **OUTCOME:** Assets are constructed, ready for interfacing, energisation and commissioning. The TNSP takes responsibility for the entire identified user shared assets.
ENERGISATION, COMMISSIONING AND REGISTRATION	**COMMENCEMENT:** *The TNSP takes responsibility for the entire identified user shared assets.* The TNSP will be responsible for: • Interfacing the cut-in works and the contestable works; • Energisation of primary assets; • Commissioning; • Completion of minor defects. Issues arising during the commissioning should be handled by the processes agreed in the contracts. **OUTCOME:** Commissioning completed and assets ready for operation by the TNSP. The Connection Applicant should also be able to connect its plant and energise from / synchronise with the shared network, provided that plant has been commissioned and registered with AEMO.

STEP	PROCESS
OPERATION, MAINTENANCE AND CONTROL	**COMMENCEMENT:** *Commissioning completed and assets ready for operation by the TNSP*. • TNSP has complete responsibility and accountability for operation, control and maintenance of the identified user shared assets; and • Connection Applicant has power transfer capability and other services.

E Further detail on proposals for dedicated connection assets

This appendix provides further detail on two elements of our proposals for the provision of dedicated connection assets, as set out in chapter 13:

- a summary of the transmission licensing regime and powers of land acquisition in each of the NEM jurisdictions; and
- the potential applicability of Part IIIA of the *Competition and Consumer Act 2010* to dedicated connection assets.

E.1 Transmission licensing regime and powers of land acquisition within the NEM

Table E.1 summaries the transmission licensing regime and powers of land acquisition in each of the NEM jurisdictions. In summary, the arrangements for acquiring land differ depending on the jurisdiction, specifically:

- in NSW any transmission owner can gain compulsory land acquisition powers to acquire land. For parties other than TransGrid, however, this requires additional Ministerial approval;
- in Queensland any licensed transmission entity can acquire land. For parties other than Powerlink, however, this requires additional Ministerial approval; and
- in Victoria, South Australia and Tasmania all licensed electricity entities (whether for transmission, distribution or generation) can compulsorily acquire land for the purpose of carrying out their operations (albeit this may be subject to some form of Ministerial approval).

Table E.1 Powers of land acquisition within the NEM

	Queensland	NSW	Victoria	South Australia	Tasmania
State-based licensing requirements to operate part of a transmission network	• parties can gain "special approval" from the Queensland Electricity Regulator under Electricity Act 1994 • these are granted where electricity network is "incidental" to the core business	• no licence provisions for transmission • the Energy Services Corporations Act[293]	• under the Electricity Industry Act 2000, a licence is required to engage in transmission unless that person is exempt • ESC can grant generation, distribution and transmission licenses • currently only SPI Powernet has a transmission licence	• Electricity Act 1996 requires a licence to operate a transmission network, with this being operated in accordance with safety, reliability etc • ESCOSA grants transmission licences – currently ElectraNet has the system control & transmission licence, while BHP Billiton and OZ Minerals have off-grid transmission licences	• under Electricity Supply Industry Act section 17, Part 3- a licence is required for transmission of electricity • OTTER can issue licenses • currently only Transend & Basslink have licence

293 This does not apply to any other participants in, or new entrants to, the electricity sector in NSW. Any companies wishing to build, own or operate transmission infrastructure only needs to obtain environmental and planning approvals, and NER registration or exemption.

	Queensland	NSW	Victoria	South Australia	Tasmania
Desirability of possessing land acquisition powers to obtain the necessary easements for the land over which the extension will be constructed	• any licensed transmission entity can acquire land • Powerlink is a “constructing authority” under the Electricity Act and so can acquire land • other transmission authorities who wish to compulsorily acquire land/easements can gain “constructing authority” under the Electricity Act with Ministerial approval • if works are for infrastructure facility of significance, then the Government has powers to acquire land • any other individuals would have to acquire land as with any other person, ie voluntary agreements will need to be negotiated	• any party can apply under s.93 of the Electricity Supply Act (NSW) 1995 to have infrastructure declared as a "transmission system". These parties would then have powers to compulsorily acquire land • any company can apply to the Minister to be empowered to acquire an "easement in gross" under the Conveyancing Act (NSW) 1919 - if the third party land is not adjacent to the land on which the facilities are located • any other parties would have to acquire land as with any other person ie voluntary agreements will need to be negotiated	• the statutory powers to acquire land are the same for any person that holds a generation, transmission or distribution licence issued by ESC, but the acquisition must be approved by the Governor in Council • if the relevant project is of State or regional significance then the Government has powers to compulsorily acquire land for the purposes of that project • if an individual is not a licensee under the Electricity Act and does not have government support, then acquisition of land would occur as with any other person, ie voluntary agreements will need to be negotiated	• electricity entities (licensed parties) have the power to compulsorily acquire land, with Ministerial approval[294] • • any other individuals have to acquire land as with any other person, ie voluntary agreements need to be negotiated	• electricity entities (licensed parties) have the power to compulsorily acquire land with Ministerial approval • if another entity had government support, then the Minister could acquire land for it to use • any other individuals have to acquire land as with any other person, ie voluntary agreements need to be negotiated

294 Additionally, the Planning Minister has the power to acquire land where he or she considers that the acquisition is reasonably necessary for the operation or implementation of a Development Plan.

E.2 Potential application of Part IIIA to dedicated connection assets

In a number of submissions to the review, stakeholders have suggested that access to dedicated connection assets could be gained under Part IIIA of the *Competition and Consumer Act 2010* (CCA).[295] Part IIIA of the CCA sets out provisions for access to services. We do not consider that this is a feasible prospect for reasons we set out below.

E.2.1 Pathways for access

There are three potential "pathways" to obtaining access under Part IIIA, specifically:

- **Declaration –** if an asset is not already subject to an effective access regime, a prospective user may apply to the National Competition Council (NCC) to have the service declared. Declaration gives the access seeker the right to negotiate with the service provider, with provision for legally binding arbitration if negotiations are unsuccessful;

- **Access undertaking** – under Part IIIA an asset owner can submit a voluntary access undertaking to the Australian Competition and Consumer Commission (ACCC) for approval. Amongst other things, the access undertaking must set out the terms and conditions upon which access will be provided, and the manner in which any accompanying negotiate-arbitrate model will operate; and

- **Certification of a state or territory access regime** – a state or territory can apply to the NCC for certification of a particular regime. The regime must comply with certain principles contained in the Competition Principles Agreement and the objectives of Part IIIA of the CCA.

The most pertinent "pathway" in this situation is for a third party seeking access to a dedicated connection asset to apply to the NCC to have the service declared, ie the first pathway above. We discuss this further below.

E.2.2 Declaration of a service

In seeking to have a service declared under Part IIIA, a prospective user of dedicated connection asset infrastructure would apply to the NCC. The NCC would then consider the application, before forwarding a recommendation to the designated Minister.[296] The Minister would then decide whether or not to declare the service.

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295 TRUenergy, First Interim Report submission, p.10; Grid Australia, First Interim Report submission, p.42; Energy Australia, Second Interim Report submission, p.13.

296 The State Premier or the Chief Minister of the Territory is the designated Minister where the service provider is a state or territory body and the state or territory concerned is a party to the Competition Principles Agreement. If this does not apply, the designated Minister is the Commonwealth Minister (see s.44D(1) of the CCA).

The NCC cannot recommend that a service is declared unless it is satisfied that the following five criteria are all met:[297]

- Criterion (a) – access (or increased access) to the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service;
- Criterion (b) – that it would be uneconomical to develop another facility to provide the service;
- Criterion (c) - that the facility is of national significance having regard to: the size of the facility, or the importance of the facility to constitutional trade or commerce, or the importance of the facility to the national economy;
- Criterion (e) - that access to the service is not already the subject of a declared access regime under Division 6 of Part IIIA; and
- Criterion (f) – that access (or increased access) to the service would not be contrary to the public interest.[298]

We consider that there would be considerable difficulties in convincing the NCC that these criteria are met for dedicated connection assets, for example:

- If the related markets are defined relatively broadly (which they may well be), then access would not promote a material increase in competition in any of those markets, in which case criterion (a) would not be met;
- In the case of load, if the price of the relevant raw material being mined (iron ore, coking coal etc) in the downstream market is forecast to be "high", then it will be privately profitable to duplicate the line, in which case criterion (b) would not be met;[299]
- A transmission line is unlikely to be considered of national significance (determined having regard to the criteria above)[300], in which case criterion (c) will not be met; and

297 ss 44G(2) of the CCA.

298 Criterion (d) was removed by an amendment to the CCA in 2010.

299 This definition of "uneconomic to duplicate" as being based on a "privately profitable" test was a consequence of the Full Federal Court's (and subsequently the High Court's) decision in Fortescue's application to gain access to Rio Tinto's assets in the Pilbara. That is, whether the NCC is satisfied that there is not anyone for whom it would be profitable to develop another facility. Previously, a "social benefit" test had been applied where it assessed whether the infrastructure was capable of meeting demand for the relevant service (including third party demand) at lower cost than two or more facilities. All costs (including production, social and consequential costs) were used in this social benefit assessment.

300 Some stakeholders have commented that transmission lines may meet this criterion. However, we consider that this is unlikely even in instances of long and/or large capacity transmission lines. For example, in relation to the Herbert River cane railway the NCC acknowledged that while the railway network was big in terms of overall track length (approximately 500km), since it was a

- The issues involved in considering the declaration criteria are interrelated. For example: if criterion (a) is not met, it is likely that access would be contrary to the public interest, and so criterion (f) would not be met. This is because the benefits of public interest principally arise from the promotion of competition considered under criterion (a), and the resultant positive effects on economic efficiency.

Lastly, we note that obtaining declaration is not as simple as the NCC recommending declaration of the service. The actual declaration must be made by the Federal Treasurer (who could ultimately choose not to declare the service). The decision is also subject to numerous appeals, and so may be a lengthy and contentious process.[301]

The Commission therefore considers it would be difficult for prospective users of dedicated connection asset infrastructure to prove that the criteria for declaration would be met.

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radial network the actual maximum haulage distance was less than 60km. Further the NCC noted that it serviced an area of approximately 55,000 hectares, was used by 575 growers, and lay within a population of 12,513. Ultimately the NCC concluded that the cane railway was *not* nationally significant. See: National Competition Council, *Declaration of services: a guide to declaration under Part IIIA of the Competition and Consumer Act 2010 (Cth),* February 2013, p.43.

301 For example, the final decision on the Pilbara third party access applications was handed down in February 2013 – after being submitted to the NCC in 2004. This process took approximately nine years to decide whether or not the networks were declared (or not).