AEMC

REVIEW

Australian Energy Market Commission

**SUPPLEMENTARY INFORMATION PAPER**

# COGATI IMPLEMENTATION - ACCESS AND CHARGING

4 APRIL 2019

## INQUIRIES

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## ABOUT THE AEMC

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

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# 1 INTRODUCTION

## 1.1 Purpose of this paper

A consultation paper for this project was published on 1 March 2019. Based on preliminary feedback from stakeholders that the consultation period for the paper was insufficient, the Commission extended the timeframe for receipt of submissions for an extra four weeks. Submissions are now due on 26 April 2019.

This also allowed the Commission to provide additional information to provide further context for stakeholders.

This paper therefore supplements the *CoGaTI Implementation - Access and Charging* consultation paper that was published on 1 March 2019. The purpose of this supplementary information paper is to provide further information and context to stakeholders about the need for access and charging reforms for the CoGaTI framework. The paper also provides answers to frequently asked questions about the recommended CoGaTI access and charging reforms.

## 1.2 Scope and purpose of this review

The Commission's recommendations for the need for reform to the current access regime and a review of whether existing transmission use of system charging arrangements are fit for purpose are being progressed by the AEMC in 2019 as part of the *CoGaTI implementation - access and charging* work stream (i.e. this review).

This review builds on the initial work undertaken by the Commission over the course of 2018, which was undertaken pursuant to a standing terms of reference that we have received from the Council of Australian Governments (COAG) Energy Council.[1] The standing terms of reference asks the AEMC to undertake biennial reporting on when the transmission planing and investment decision-making frameworks will need to change, given the state of the power system, and what these changes may be.

The inaugural *Coordination of generation and transmission investment review* (CoGaTI) commenced in early 2017, and concluded with its final report being published in December 2018. In particular, that report set out:

- **Access** - a potential strawman for how access reform could be undertaken. This strawman included several options for how access reform could be given effect, including **dynamic regional pricing** and / or **firm transmission access.** These options are not necessarily mutually exclusive.
- **Charging** - a series of **drivers of change** that warrant reviewing the charging framework, in particular for inter-regional TUOS, the large amount of interconnection that is proposing to be built.

1 The standing terms of reference for this reporting was received from the COAG Energy Council in February 2016 under section 41 of the National Electricity Law (NEL). The terms of reference are available from the AEMC website. See: https://www.aemc.gov.au/sites/default/files/content/97164a7b-09bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

This review builds on the inaugural CoGaTI review and will seek to develop the necessary regulatory reforms to implement the recommended phased approach to access and charging reform. The review will involve extensive consultation at multiple stages throughout the year.

To commence the consultation process, a consultation paper was published on this review in March 2019 for stakeholder feedback. The purpose of the consultation paper was to:

- explore the issues raised in the Commission's final report, including seeking stakeholder feedback on the proposed high-level principles for reforming the current access and charging arrangements, including whether there are different ways the detailed elements of the proposal could be implemented
- seek input from stakeholders on the possible implications of the proposed access and charging reforms
- seek views from stakeholders as to what further details need to be developed on the proposed reforms
- see if there are any alternatives to the proposals, or any other jurisdictions that should be looked at in terms of seeking
- seek views from stakeholders on the proposed timing and sequencing, as well as how these interact with other reforms on foot.

It is the Commission's intent that it will provide the COAG Energy Council with a set of recommendations to implement reforms to the access and charging regimes at the end of 2019 that can then be submitted back to us to commence the rule change process.

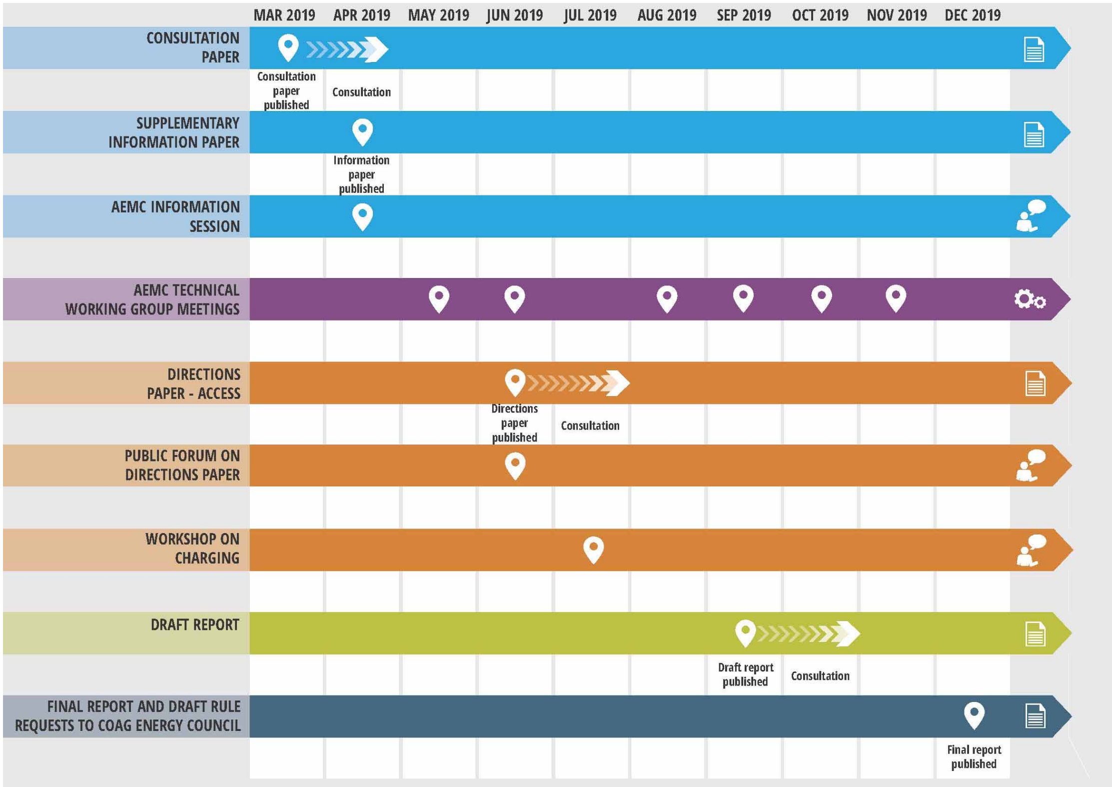
It is also worth noting that the Energy Security Board made a recommendation in its Integrated System Plan: Action Plan report to the COAG Energy Council in December 2018 that congestion and access issues be considered in 2019, and options developed for how to address them. The work being undertaken by the Commission as part of the *Coordination of generation and transmission investment implementation - access and charging* work stream feeds into this. The Commission will collaborate with the Energy Security Board, the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO) in progressing this recommendation.

## 1.3 Process for this review

### 1.3.1 Timeline

We have set out a timeline that sets out the next steps for the review, the consultation proposed and how stakeholders can be involved. It also shows how the Commission will be developing draft rule changes on the proposed reforms in 2019, to be submitted back to the Commission in 2020 for full assessment through the rule change request process.

**Figure 1.1: CoGaTI - access and implementation indicative timeline**




### 1.3.2 Technical working group

The Commission will shortly form a technical working group of experts from the market bodies, networks, generators and consumer groups to provide input into the proposed reforms and to help develop rule change requests needed to support the reforms. The notes from these meetings will be published on the project page for this review.

The first technical working group will be held in May 2019, and will occur approximately monthly after that. We expect that the first several technical working group meetings will cover the following topics:

- high level design options for firm transmission access
- high level design options for how non-thermal (system security) constraints can be incorporated into dynamic regional pricing and firm transmission access
- high level design options to address how new market participants categories such as storage could be incorporated into dynamic regional pricing and firm transmission access.

## 1.4 Structure of the paper

The remainder of the paper is structured as follows:

- Chapter 2 sets out the rationale for why access and charging reform is needed
- Chapter 3 sets out frequently asked questions about the recommended access and charging reforms and provides answers to these questions.

# 2 FURTHER CONTEXT FOR RECOMMENDATIONS

This chapter provides further information and context to stakeholders about:

- the need for access reform
- the interaction between access reform and other market reforms that are expected or under way.

It should be read in conjunction with Chapter 2 of the CoGaTI 2019 consultation paper[2], as well as Chapters 6 and 7 of the CoGaTI 2018 final report.[3]

## 2.1 Need for access reform

There is currently a significant amount of generation capacity that is seeking to gain access to the network. Private sector investors are planning generation where the transmission network has limited or no capacity to accommodate it. The scale of investment in the sector also means that projected revenues from a particular project can change rapidly as investment patterns vary and new generators connect to the grid. This uncertainty and lack of coordination is increasing costs in the sector and affecting investment decisions.[4]

Under the current framework, transmission businesses have obligations to meet jurisdictionally-set reliability standards for their networks. As a result, they are focussed on making transmission investments to reliably supply *consumers*. While more generation can help to reduce costs in the wholesale market, it can also increase system costs if the generator is located in a congested part of the network. Under the current framework, transmission businesses do not plan their networks to provide a particular generator with a specific amount of transmission capacity.

In the 2017-18 CoGaTI review, the Commission concluded that the current access regime needs to evolve to allow the risk and cost of generation investment to complement planning and investment in transmission.[5] This involves changing the access regime so that transmission can be built to reliably connect *generators.* Such reform would represent an evolution of the current arrangements where the network is built to reliably supply consumers.

How generators access the transmission network, and how the congestion of the transmission network is managed, underpins the transmission framework as well as outcomes in the wholesale market. The way that transmission and generation investment decision-making processes interact has been the subject of on-going discussion before the establishment of the national electricity market (NEM) in 1998, and has continued since that time. Since the start of the NEM, there have been at least thirteen major reports and reviews

2 The 2019 consultation paper can be found here: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

3 The 2018 final report can be found here: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

4 As well as other factors, such as the lack of an integrated emissions reduction mechanism within the NEM.

5 AEMC, *Coordination of generation and transmission investment, Final report,* 21 December 2018.

dealing with various aspects of congestion management and generation access; at least half of which have been undertaken by the Commission.

The last transmission framework review that was undertaken by the Commission set out a model, called optional firm access, that the Commission thought would best meet the national electricity objective.[6] In 2015, the Commission developed a standalone report outlining a detailed design of optional firm access. This report concluded that the benefits did not outweigh the costs to the national electricity market at that time.[7]

The strawman that the Commission put forward in the 2018 CoGaTI final report, and which is currently being consulted on, has some similarities with optional firm access, but there is substantial scope to alter that model in light of differences in the NEM now compared to 2015. We have a much higher penetration of renewables. In addition, there is a significant number of new generator connections every year, which is putting strain on TNSPs and AEMO. System security issues have also become a significant feature of the market since that time.

In chapter 2 of the consultation paper for this review, we set out a range of issues that are currently being experienced by investors.[8] All of these issues could be considered to be symptomatic of how generators access the network and how congestion on the transmission network is managed. The Commission considers that reforming the access and charging regime is a more holistic and efficient solution to these issues; particularly given the fact that the existing transmission framework comprises a set of elements that are internally consistent and highly interlinked. Addressing one element in isolation is likely to either result in the need for changes to other elements, or, if only a single element is changed it can result in unintended consequences.

The Commission has had feedback that it is not necessarily clear to stakeholders how access reform could address some of these issues. In some cases, stakeholders consider that there are other reforms under way that could address these issues. The remainder of this section provides more context and detail as to how the Commission considers that access reform can address the following issues in the NEM.

### 2.1.1 Long term investment signals and congestion

#### Nature of the issue

Due to the current lack of locational signals in the transmission framework, as well as the speed and scale of connections, private sector investors are planning to place their generation assets where the network has limited or no capacity for the additional generation capacity to be dispatched.

These decisions ultimately undermine the broader system benefits that will result from the additional generation investment. Under the current framework, a generator can connect

6 AEMC, *Transmission Frameworks Review Final Report,* 11 April 2013.

7 AEMC, *Optional Firm Access, Design and Testing, Final Report - Volume 1*, 9 July 2015.

8 AEMC, CoGaTI implementation - access and charging, Consultation paper, 1 March 2019, pp. 9-11.

where there is relatively good access to the transmission network and little current congestion. However, there is nothing to stop another generator connecting beside it and effectively constraining off that first generator, undermining its business case.

In addition, interconnectors have large capacity and are dispatched after generators in the current framework. This creates an incentive for generators to locate on the interconnector flowpath and so degrade the value and capacity of the interconnector. This means that interconnectors are becoming increasingly constrained, meaning that consumers cannot always access lower cost energy from generation in neighbouring states. This creates further congestion within the transmission system and increases costs for consumers.

Current 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. This is particularly true of marginal loss factors - while we understand that historically investors have sought to forecast marginal loss factors, this is becoming harder given the current scale of investment and topography of the network.

#### How access reform will address this issue

Firm transmission rights 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 generators by providing them with a price that reflects an estimate of the incremental cost that the generator would impose on the transmission system.

Generators would then trade off different locations, taking into account the relative costs of transmission, as well as the other factors such as fuel costs. While there are a number of other factors generators consider when making locational decisions, these signals may make a difference in some cases, and would result in more efficient locational decisions being made.

A firm access model should achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated approach to transmission planning. In particular, the option to purchase firm access rights makes the cost of transmission part of a generator's investment decision. The investor should seek a location for a power station which minimises the combination of its operating and establishment costs and the cost of transmission.

Under a firm transmission access regime, 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.

### 2.1.2 Disorderly bidding and storage

#### Nature of the issue

The absence of intra-regional price signals can give rise to disorderly bidding. Disorderly bidding results when generators know that the offers they make will, in all likelihood, not affect the settlement price they receive as a result of congestion between them and the rest of the market. Disorderly bidding can involve a generator behind a constraint bidding at the market floor price to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

Disorderly bidding may become particularly prevalent and result in inefficiencies if grid scale storage devices become commonplace in the NEM. Storage devices behind a constraint have an incentive to disorderly bid (as a seller of electricity) in order to receive the region wide market price. Not only might this be more inefficient than were the storage not there (when the storage device has a higher resource cost than a generator which it displaces in dispatch), it is even more inefficient compared to a scenario where the storage device was charging instead of dispatching. By charging, the storage device would alleviate the constraint. Local, cheaper generation behind the constraint would be dispatched to meet local load. In turn, disorderly bidding of storage has an impact on the locational decisions of storage devices connecting to the transmission network.

#### How access reform will address this issue

Dynamic regional pricing should resolve this issue. Exposing generators[9] to the dynamic regional price removes the incentives to disorderly bid when transmission constraints arise.

This is because doing so would expose the higher cost generator to a low dynamic regional price instead of the higher regional reference price. Under these circumstances, the higher cost generator may lose further revenue if it places a disorderly bid, as it likely will not be able to cover the operating costs of dispatching electricity.

At times of transmission congestion, dynamic regional pricing should therefore disincentivise disorderly bidding to ensure that the lowest cost combination of generation is dispatched.

### 2.1.3 Outages

#### Nature of the issue

TNSPs are required to maintain and upgrade their equipment in order to provide services in line with relevant network performance requirements. This occasionally requires outages to be planned on the power system to facilitate the safe maintenance and upgrade of network infrastructure. TNSPs provide information on the timing of planned outages through AEMO's network outage scheduling tool and in 13 month plans.

For generators connected to network assets undergoing maintenance, there may be a period where there is a need to curtail output or disconnect to manage system security for the next contingency, or where network equipment is de-energised to allow safe work. Where

9 And possibly storage, when either drawing from or exporting to the grid.

unplanned outages are extended or prolific, this can cause significant effects on a generator's revenue, with no compensation available.

#### How access reform will address this issue

Under a firm transmission access regime, TNSPs would be obliged and financially incentivised to provide a level of access consistent with the firm transmission rights collectively held by generators. This collective level of firm access would drive TNSP network planning and operation decisions.

It is inefficient for a TNSP to operate and plan its network to provide full capacity at all times. There may be circumstances that affect capacity on the network that are caused by events outside the TNSP's control, such as a bushfire. Further, TNSPs need to reduce capacity at times when it is not valued (for example, during off-peak times) for actions such as maintenance. It would not be possible to require full capacity under these conditions.

To account for this reality, the access model would need to **encourage** rather than **mandate** TNSPs to operate their network efficiently in order to provide firm access. Depending on the final design of how access reforms are given effect, this could occur through an incentive scheme targeted so that TNSPs efficiently manage their network with regard to congestion at all times.

The incentive scheme could include rewards or penalties for TNSPs depending on the amount of 'shortfall costs' that accrue to firm generators over a particular period. These shortfall costs would account for the shortfalls of transmission capacity that result in firm access entitlements, and so compensation for firm generators, being scaled back. Through the incentive scheme, the TNSP would be incentivised to manage the level of shortfall costs, and so the costs to firm generators, of network constraints.

Such a scheme would encourage TNSPs to minimise outages, and conduct them at times that would have minimal impact on generators. For example, if there were solar generators connected to a particular network element, an outage of this element would occur at night when the sun was not shining.

### 2.1.4 Marginal loss factors

#### Nature of the issue

To investors, marginal loss factors represent a "multiplier" of revenue - they calculate the difference between how much is produced by a generator, which is measured at its meter, and how much is estimated to be delivered to customers at the regional reference node. This then affects how much is paid by AEMO to the generators, which impacts its revenue stream and therefore the generator's commerciality.

Marginal loss factors are set annually by AEMO, and are set using a forward-looking modelling approach. They are based on the expectation of what will happen in the year ahead, in terms of demand and dispatch patterns, and hence network flows and losses. This means there is not a perfect match between the loss factors and what actually happens in a given financial year.

Given the large number of generators connecting at the moment, and the fact that marginal loss factors inherently change after a new generator connects to the network, this is resulting in significant year-on-year fluctuations in the marginal loss factors.

#### How access reform will address this issue

There are a number of ways in which access reform can help address this issue. For example, dynamic regional pricing would create a price at each node where there is congestion. One possibility under this reform is that marginal loss factors could be incorporated into this price, with the costs of losses and congestion simply showing up as differences between energy prices at the different nodes of the network.

Where there is firm transmission access, it may also be possible for generators to purchase firm rights to a pre-determined loss factor, which hedges the risk of changes to marginal loss factors over time, in the same way that generators might be able to purchase firm access rights to hedge the risk of transmission congestion over time. This idea needs careful consideration.

### 2.1.5 System strength

#### Nature of the issue

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

In 2017, the Commission made a rule that, amongst other things, requires new connecting generators to 'do no harm' to the security of the power system. This is defined in relation to any adverse impact on the ability to maintain system stability, or on a nearby generating system to maintain stable operation. The rule would allow for remediation to be provided by building for it.

The high volumes of connections we are seeing can mean a lot of little synchronous condensers being built for the purposes of system strength remediation. Multiple synchronous condensers are being built by multiple connecting generators, resulting in a potential degree of overbuild or cost inefficiency; that is, it may be more efficient for one larger synchronous generator to be built and its fault current to be "shared" between generators.

#### How access reform will address this issue

Access reform will improve coordination between generators and the transmission networks. This could extend to system strength. For example, one possible way that access reform could assist is that access rights could include a product which meets the generator's obligation in relation to system strength.

This is a key area of policy development that the Commission will be focussed on over the coming months, and will be looking to discuss in detail at one of the first technical working group meetings.

### 2.1.6 Connection enquiries

#### Nature of the issue

AEMO, TNSPs and DNSPs are receiving an unprecedented volume of connection enquiries, which has created some resourcing issues at these organisations. As a result developers are experiencing increased uncertainty, costs and delays. This is exacerbated by the current framework where parties have no right to be dispatched across the network.

As more and more parties connect, a party's particular connection arrangements may change before it is signed, undermining financing that has been previously agreed. This is a necessary consequence of the current open access framework, given that generators typically do not want confidential information to be shared with others, given they are competing for access to the transmission network.

#### How access reform will address this issue

A firm transmission access regime involves generators purchasing firm access to the transmission network. This will allow generators more certainty over how the revenue that their generator may earn from the wholesale market. If another generator connects in beside it, it will have access to the market price regardless of whether it is physically dispatched; and, depending on what changes are made to marginal loss factors, its marginal loss factor would be maintained.

Generators would also be more willing to have confidential information being shared, given that they are no longer competing for access to the transmission network, which will further help with coordination.

### 2.1.7 Generators sharing the costs of transmission infrastructure or renewable energy zones (REZs)

#### Nature of the issue

Currently, connecting parties are directly responsible for the payment of costs associated with any new apparatus, equipment, plants and buildings, or upgrades to these, to enable their connection to the transmission network and to meet their performance standards. These are "connection assets", and are paid for by the connecting party or parties. There are existing mechanisms in place to facilitate the coordination of connection assets, including from prospective REZs in the shared network, such as the arrangements for scale efficient network extensions.

Given the large amount of generators seeking to connect, there is a lot of potential to develop shared connection assets to reduce overall system costs. The existing scale efficient network extension framework has been unused since it was established in 2013 due to generator commercial tensions and disparate generator project timing.

In the inaugural CoGaTI review, the Commission considered that part of the reason why this framework has not been used is because generators will not contribute to the costs of a connection asset that is shared by others unless the generator receives some form of firmer access right than is currently available. At the moment, generators have an incentive to free-ride on investments contributed to by other generators, enjoying the benefits of access without having contributed to the costs.

#### How access reform will address this issue

As detailed in the final report for the 2018 CoGaTI review, the Commission has not been able to identify any options that facilitate the development of REZs which do not also involve a change to the access regime and which also represent an improvement on the status quo.[10]

A key consideration for the Commission is who bears the risk associated with REZs. Some party will need to bear the risk that if the decision to build a REZ is based on an expectation that new generation will locate in a particular area of the NEM, but this expectation is wrong and the assets become stranded. In this case some party will be left with the costs associated with the assets. In the absence of changes to the access regime, it is difficult to see any risk allocation would facilitate the development of REZs consistent with the long-term interests of consumers. This is because any option which involves:

- generators contributing to the cost of shared transmission assets (or otherwise taking some of the risk of developing shared transmission assets) requires that the generator receive some form of firmer access right than currently available under the open access regime. Otherwise, generators will have an incentive to free-ride on investments contributed to by other generators, enjoying the benefits of access without having contributed to the costs. Given that each generator will have an incentive to free-ride, each individual generator will be reluctant to contribute to the cost of the shared transmission assets.
- TNSPs undertaking speculative investment in either shared network infrastructure or connection infrastructure either requires:
  - consumers to bear the risk of this investment, which the Commission does not consider to be appropriate or in their long-term interests or for
  - TNSPs themselves to bear the risk, and be compensated accordingly. However, establishing how to appropriately compensate TNSPs is both practically and legally challenging.

Therefore, the Commission considers that changes to the access regime will facilitate REZs as a consequence of generators and prospective generators' commercial locational investment decisions (which will be better informed due to the locational signals provided, and which were discussed above). For example, if there is an area that has a good fuel source (a REZ should have high quality wind and solar resources), and there is a locational price signal that reflects the transmission costs associated with connecting in that location, then generators should all pick that area. As discussed above, access reform creates efficient incentives for

10 AEMC, *Coordination of generation and transmission investment, Final report*, 21 December2018, p. 73.

locational decisions by generators. If a particular location is popular, and so a significant number of generators are seeking to locate at this good fuel source, pay for the TNSP to build transmission infrastructure in this location, and are no longer competing for access to the network, then there is effectively de facto coordination by the TNSP who will builds for, and provide access to, all of the generators connecting in this location. In this way, REZs would be facilitated.

## 2.2 Interaction with other reforms

### 2.2.1 Five-minute settlement

Some stakeholders have suggested that concerns about disorderly bidding will be resolved by the introduction of five minute settlement.

It is important to note that there are several types of disorderly bidding behaviour that can occur in the NEM. These disorderly bidding behaviours have arisen in response to different incentives resulting from market design, and therefore require tailored solutions to address the varying incentives they represent.

Five minute settlement will help to remove the anomaly that currently exists between the five-minute dispatch and 30-minute settlement periods, which has been identified as a contributing factor to disorderly bidding. Under the current market arrangements, generators which observe a high five-minute price at the start of a settlement period may attempt to disorderly bid in subsequent five-minute dispatch intervals periods within the 30-minute settlement period. They may do this in order to take advantage of the settlement price, in the knowledge that the average of the six five-minute dispatch intervals is likely to be high. Five minute settlement should resolve this incentive, by aligning the dispatch and settlement periods.

However, disorderly bidding can also arise when generators know that the offers they make will not affect the settlement price they receive because there is transmission congestion between them and the rest of the market. When a transmission constraint binds, the NEM dispatch engine (NEMDE) dispatches constrained generators out of merit order, which results in an elevated regional reference price. AEMO publishes information in pre-dispatch systems that enable generators to identify the likely impact of transmission constraints on their generation assets.

If a generator forecasts that they are likely to be constrained off due to congestion, it may have an incentive to rebid in at the market floor price to maximise its dispatch quantity - remembering that currently, physical dispatch and financial access are linked.[11] This can result in inefficient dispatch; that is, higher cost generation resources behind the constraint being dispatched instead of lower cost resources that are available. This occurs because NEMDE does not know the underlying costs of the two generators, and so pro rates the dispatch.

11 If a generator is not dispatched, it may risk losing significant revenue due to the position it has taken under hedge market contractual obligations. If it is dispatched, it is likely to receive a higher regional reference price for its dispatched quantity than it would have received in the absence of congestion.

Five minute settlement will not solve this particular type of disorderly bidding. However, dynamic regional pricing should. Exposing generators to the dynamic regional price removes the incentives to disorderly bid when transmission constraints arise. This is because doing so would expose the higher cost generator to a low dynamic regional price instead of the higher regional reference price. Under these circumstances, the higher cost generator may lose further revenue if it places a disorderly bid, as it likely will not be able to cover the operating costs of dispatching electricity. In addition, a disorderly bid is likely to further depress the local price, resulting in a poor outcome for generators behind the transmission constraint.

At times of transmission congestion, dynamic regional pricing should therefore disincentivise disorderly bidding caused by transmission constraints, in order to improve the prospect of the lowest cost combination of generation being dispatched.

### 2.2.2 Marginal loss factors

As noted above, there is currently a lot of concern within the industry about marginal loss factors. This is driven by the significant changes that have been observed in marginal loss factors between years recently.

The Commission has received two rule change requests from Adani Renewables regarding the MLF framework.[12]

One of these is a request for changes to the way that Intra-Regional Settlement Residue (IRSR) reallocation is accommodated in the National Electricity Rules, a process which is impacted by MLFs. Adani Renewables has proposed that the allocation of IRSRs should apply equally to both generators and certain categories of network users. It has expressed the view that this change would lead to fewer losses for generators as well as more competitive generation bidding, resulting in lower prices to market customers.

In a separate rule change request, Adani Renewables is seeking to have the marginal loss factors methodology that is currently used replaced by an average loss factor methodology. Adani Renewables expressed the view that this change would lead to fewer losses for generators and customers, as well as a more accurate reflection of the cost of generation.

These rule changes are being considered in the context of the changes to access proposed by the 2019 CoGaTI access and charging review.

### 2.2.3 ESB's post-2025 work

The COAG Energy Council has tasked the Energy Security Board with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. By the end of 2020, the ESB needs to:

- recommend any changes to the existing market design, or
- recommend an alternative market design.

12 See the following project pages: https://www.aemc.gov.au/rule-changes/loss-factor-frameworks and https://www.aemc.gov.au/rule-changes/intra-regional-settlement-residue-reallocation.

These recommendations will be made in order to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least-cost. Any changes to the existing design or recommendation to adopt a new market design would need to satisfy the National Electricity Objective. This forward work plan was approved by the COAG Energy Council at its December 2018 meeting.

As a member organisation of the ESB, the AEMC is contributing to and assisting with this work.

The ESB notes that significant changes to the electricity market design would need to be well-considered, including substantial input from stakeholders and detailed consideration of alternative market designs, and telegraphed well in advance of any change to ensure there is minimal disruption to the forward contract markets for electricity.

The ESB also notes that if changes are required to deliver a long-term, fit-for-purpose market framework by the mid-2020s, then consideration of any required changes should be concluded by the end of 2020 to enable sufficient time for the market to transition to the new market framework.

The Commission is aware that there is a overlap between the ESB's post-2025 work and the access reform proposed in CoGaTI. The Commission notes that in its *Integrated System Plan; Action Plan* report,[13] the ESB identified the importance of access reform and noted it will report back to the COAG Energy Council by December 2019 on its views on congestion and access. The Commission is working closely with the ESB on these issues in order to make sure that a coordinated, cohesive, plan is being developed.

13 See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

# 3 FREQUENTLY ASKED QUESTIONS ABOUT THE ACCESS MODEL

This chapter provides answers to some frequently asked questions about the proposed access model that have been raised by stakeholders during the consultation process. It organises the questions according to whether they relate to:

- the proposed access models as a whole
- dynamic regional pricing
- firm transmission access.

## 3.1 Questions about the proposed access models

This section answers the following questions about the proposed access model:

1. Why does the proposed access reform preserve the regional reference price as 'king'?
2. What is the likely impact on contract liquidity of the access reform?
3. Would access reform apply to distribution networks as well as transmission?
4. Are there any competition concerns with the proposed access regime?

### 3.1.1 Why does the proposed access reform preserve the regional reference price as 'king'?

Under the proposed access regime, regional reference prices are retained as the wholesale market price:

- that generators are settled at in the absence of transmission constraints
- the load is settled at, regardless of whether there are constraints or not.[14]

We consider that it is important to retain the regional reference price (rather than, for example, moving to nodal electricity pricing) in order to promote a liquid contract market in the NEM.

The decision to invest in generation is influenced by, amongst other things, the ability of generators to enter into contracts to manage the trading risks that they face.[15] Where generators rely on contracting to manage trading risk, a deep and liquid contract market is required to support generation investment.

The original designers of the NEM were cognisant of the need to promote liquidity in electricity contract markets. To this end, the NEM was formed around a small number of discrete regions[16], with each region settling at a regional reference price.[17] This design allows all retailers and generators in that region to trade with each other on the same basis, and

14 It is still an open question as to the price that storage, when acting as load, should pay.

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

16 These regions were based on the meshed transmission networks that existed and the nature of transmission constraints between. This resulted in the regions being broadly aligned with the state boundaries. It is worth noting that a legal framework was set up to change the regions over time, with the intent to move to a higher number of regions. The only time this process has been followed was to remove the Snowy region in 2008.

17 The regional reference price being the local price at a pre-determined reference node in each region.

makes it easier for them to write financial contracts around a common "strike" price at which all load and generation is settled.

We consider that it is important to retain this design feature so that market participants continue to face common prices in the absence of transmission constraints. The ability of generators to sell forward contracts against their output allows them to hedge against the risk of spot price volatility, which increases financial certainty to investors. Ultimately, this should result in lower prices for consumers, with generators able to offer electricity (in both spot and contract markets) at lower prices than they otherwise would.[18] The alternative - nodal pricing - risks splitting liquidity in the contract market, with contracts struck against many different nodal prices.

### 3.1.2 What is the likely impact on contract liquidity of the access reform?

More analysis needs to be done to assess the impact that the proposed access regime may have on the electricity contracts market, including its potential impact on market liquidity. We are particularly interested in stakeholder views on this point, including any particular issues that we should investigate further.

However, preliminary analysis suggests that the impact may ultimately be positive. This is because the current dispatch process, which includes the prospect of transmission constraints that are largely outside of the control of generators, negatively affects the ability of generators to sell forward contracts against their output.[19] With firm transmission access, this dispatch risk would be largely removed for generators who have purchased firm access rights.

Transmission congestion prevents some 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 it does not earn revenue by selling into the spot market to back those contracts. This cost could potentially be very high, depending on the nature of congestion, the contract made and the prevailing spot price.

Generators' uncertainty as to whether they will be able to generate and receive the regional reference price - at exactly those times when prices are likely to be particularly high - can decrease their willingness to contract with retailers or increase the price at which they are willing to do so.[20] Where congestion is stable and predictable, generators may contract forward for the quantity of output for which they could be confident of being dispatched.[21] However, as congestion tends to be volatile and unpredictable, the willingness of a generator to contract at a given price is likely to be correspondingly lower.

18 Increased financial certainty should be reflected in a lower risk-adjusted cost of capital, i.e. in lower financing costs for investors. The higher level of certainty should also make investment in the electricity sector more attractive than it otherwise would be.

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

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

21 This may not be 100 per cent of their output, given other types of risk such as unplanned outages and fuel constraints.

Furthermore, the nature of congestion in the NEM is a function of the output of other generators throughout the network. New generation in some areas of the network can cause constraints that were otherwise unlikely, with impacts on the output of incumbent generators.

By decoupling financial access to the market price from physical dispatch of generation, firm transmission access would create the ability for generators to hedge against the risk of congestion. It would allow a firm generator that had been constrained off to earn the difference between the 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.

Firm access may therefore provide greater financial certainty for generators to offer forward contracts on a volume reflective of their access amount. This may increase general liquidity in the electricity contracts market and/or reduce the contract prices that result. However, further analysis will need to be conducted in order to assess the materiality of this improvement, in addition to any effects that may result from the proposed reform.

### 3.1.3 Would access reform apply to distribution networks as well as transmission?

Access reform is targeted at the transmission level because this is where the majority of generation capacity is currently located. However, we recognise that the distinction between transmission and distribution networks is not always clear.

For example, in some cases, a distribution line can run in parallel with a transmission line with the result that a constraint on one will limit flows on the other. Such distribution lines are referred to in the rules as dual function assets and it may be appropriate for them to be included within any new transmission access regime.

In addition, we understand that the electricity industry is experiencing significant growth in the connection of large-scale generation to distribution networks. Distribution networks are having to create system limitations around these plants, with these being incorporated into AEMO’s dispatch system.

We do not want to create a market design that creates incentives for generators to locate on distribution networks rather than within the transmission network. Therefore, this aspect requires further consideration as to how to create consistency between the two regimes.

We will also need to consider what types of generators should be included within the final access regime. Regardless of where the asset is located, it may not be appropriate for certain types of market participants to be able to buy firm access; for example, unscheduled generators or generators below a certain capacity.

### 3.1.4 Are there any competition concerns with the proposed access regime?

Careful attention will need to be paid to the impact of the final market design on competition, in order to ensure that there are no unintended consequences for market structure or individual participants.

For example, one important consideration will be the design of any transitional regime. A successful transitional regime should, where possible, attempt to mitigate the commercial and financial impacts of the new access model on existing participants’ balance sheets.

Where there are significant regulatory changes in the electricity sector, it is in the long-term interests of consumers that there should be an orderly and transparent transition for investors in the sector.

Likewise, it will be important to consider whether the final market design is likely to be the subject of 'gaming' by savvy market participants. For example, it will be important to ensure that the firm access procurement process, if designed as a queue, does not allow generators to stonewall their competitors or place multiple tactical requests in the same queue. The type of governance arrangements that are chosen, as well as the incentives that are likely to result, will be fundamental to the ultimate success or failure of the reform.

### 3.1.5 Are dynamic regional pricing and firm transmission access alternatives?

While dynamic regional pricing and firm transmission access are presented as stages on a path to reform in the consultation paper published on 1 March 2019, this is not necessarily the case.

Dynamic regional pricing (being just a different way to settle the market when transmission congestion arises) would likely be relatively quicker & cheaper to implement than full firm transmission access, and would deliver some of the same outcomes. In this way, we could consider these as alternatives, although, we would note that these are not mutually exclusive given that you could still have both reforms together. We are interested in stakeholder view on this point.

## 3.2 Questions about dynamic regional pricing

This section answers the following question about dynamic regional pricing:

1. How does inter-regional access work under dynamic regional pricing?

### 3.2.1 How does inter-regional access work under dynamic regional pricing?

Dynamic regional pricing will not change the ability of generators to sell in regions other than the one they are located in. Likewise, it will likely not change the existing process of inter-regional settlement, with settlement residues continuing to be allocated via auction.

Rather, dynamic regional pricing will bring intra-regional trade closer in line with how electricity is currently traded across regions. Where congestion arises, intra-regional pricing regions will be dynamically created through existing dispatch processes. This process is not unlike what happens when congestion currently occurs on an interconnector; that is, regional reference prices in two separate regions diverge to reflect the transmission constraints that are occurring at a particular time.

A key difference between intra-regional and inter-regional trade under dynamic regional pricing is the process by which settlement residue arising from congestion is allocated to market participants. Currently, market participants can bid to access a share of the inter-regional revenue through an auction process. In contrast, the intra-regional settlement residue created under dynamic regional pricing will be allocated to generators located behind a constraint in proportion to their capacity.

Dynamic regional pricing should better align incentives for generators with those that currently exist inter-regionally. The idea is to put a price on congestion and introduce a signal to generators that reflects the short-run costs of using the network. In turn, this should provide better information to generators regarding the costs of congestion.

## 3.3 Questions about firm transmission access

This section answers the following questions about firm transmission access:

1. How could firm access be priced?
2. How will firm transmission access take account of system security?
3. Will firm transmission access result in higher cost transmission investment?
4. What will be the impact of firm transmission access on wholesale electricity prices?
5. Will there be grandfathering of access rights for existing generators under firm transmission access?

### 3.3.1 How could firm access be priced?

With firm transmission access, generators would be able to acquire firm access rights in order to manage the risk of congestion within the transmission system. TNSPs would be obliged and financially incentivised to provide a level of access consistent with the firm transmission rights collectively held by generators.

The aim is to introduce more commercial drivers into transmission investment, in order to shift investment risk away from everyday consumers. Better coordination of transmission and generation investment should also minimise the total cost of building and operating the electricity system over time, lowering prices for consumers in the longer term.

To achieve these aims, the final access regime should send efficient price signals to generators regarding the transmission costs associated with their investment decisions. The best way to send these pricing signals may differ depending on the type of access that the generator is seeking to obtain.

For example, a generator may be seeking firm access rights to the transmission system for a short or longer length of time. Alternatively, it could be seeking to obtain firm access rights within the region it is located or inter-regionally.

It is likely that firm transmission access would introduce a number of products that reflect the different types of firm access rights generators may require. These products may be priced differently so that they can accurately reflect the incremental cost to the transmission system of the access they provide.

For example, it may be appropriate for generators to purchase longer term firm access rights directly from the relevant TNSP at a price that reflects the long run incremental costs (LRIC) created by the decision to build a certain size and type of generation asset in a particular part of the network. This pricing method would account for costs that are incremental to what transmission costs would have existed had the generator not sought firm access.

This procurement method may be best suited to an environment where there is a low frequency of competing access requests lodged with a particular TNSP at any given time. This is because the long-run incremental costs to the transmission network would fluctuate depending on the aggregate demand for generation investment and order in which procurement requests were processed.

If instead there were likely to be high demand for long term access from multiple prospective generators within a region, or between regions, an auction process may be more efficient. This is because an auction process allows multiple parties to reveal their demand for firm access at the same time. It also allows for a limited amount of access rights to be allocated to those parties who would value it most highly.

For **short-term** access, it may be appropriate for generators to purchase firm access products from a TNSP through an auction process or from other generators through a secondary trading platform. These short-term products could reflect spare capacity on the transmission network, and would only need to be priced to reflect the demand at a given time (as no network augmentation would be required to fulfil the access request - meaning that the cost to the TNSP would be zero).

Further consideration is needed as to what access products would be most desirable by generators. The Commission is interested in stakeholder views on these matters.

### 3.3.2 How will firm transmission access take account of system security?

We will need to consider further whether firm transmission access should be limited to thermal constraints or whether it should relate to all forms of transmission constraints, including non-thermal, security constraints. We are particularly interested in stakeholder on views on this point, including any particular issues that we should investigate further.

Thermal constraints are caused by the heating of transmission assets as more power is sent across them. Non-thermal, security constraints include when the power system is not operating within its design tolerance for voltage. Both forms of constraint can impact on the proper functioning of transmission assets, with implications for power system security and safety.

Under firm transmission access, generators will be able to acquire firm access products that entitle them to receive compensation payments when transmission constraints bind. It will be important to factor both thermal and non-thermal constraints, where possible, into the design of these firm access products in order to ensure that generators have firm access regardless of what transmission constraints may occur.

Thermal and non-thermal constraints have different characteristics, and therefore may need to be priced and modelled differently. For example, there is a simple correspondence between the capacity of transmission assets and the amount of thermal constraints that may arise at a given level of generation and demand. This makes it relatively straightforward to model the required system expansion when thermal constraints start to bind.

In contrast, the type of transmission investment that is required to alleviate a security constraint is more likely to be highly customised to a particular circumstance. This is because stability constraints tend to vary with the location and quantity of generation and demand, including factors such as the amount of inertia in the system and amount and type of capacitors that are installed.

More analysis will need to be completed in order to assess the appropriate firm access procurement and pricing method for each type of transmission constraint. In addition, it will be important to consider whether TNSPs should remain obliged and financially incentivised to provide access to firm generators despite whether congestion occurs due to the presence of security constraints or thermal constraints within the system.

The Commission has also made a number of reforms in relation to system security over the past few years. It will be important that these changes can be incorporated in, and be consistent with, access reform.

### 3.3.3 Will firm transmission access result in higher cost transmission investment ?

It is important to recognise that transmission investment can be characterised by economies of scale and scope, whereby the unit costs of building the transmission network decrease as the volume or variety of assets that are built increase. For example, it may be cheaper per MW of capacity to build a 1000MW transmission line now than a single 500MW line followed by a 500MW expansion at a later date.

Some stakeholders have expressed a concern that the proposed access reform would create incentives for TNSPs to build only the incremental amount of capacity that they need at a given time to meet a request from a generator for firm access. If this were the case, then it is likely that either:

- the total transmission system costs over time will be more expensive as economies of scale and scope are lost, or
- there will be less transmission assets built than are efficient, as generators may decide not to purchase firm access if the cost is too high.

To avoid this issue, the final access regime will need to send efficient price signals to TNSPs and generators regarding the long-term system costs associated with their investment decisions. This can be achieved through careful consideration and design of the firm access procurement process and its associated pricing methodology.

For example, it may not be efficient to have a procurement process whereby generators purchase firm access rights directly from a TNSP using a pricing methodology based on deep connection charging (DCC). DCC would calculate a price based on the full cost of the immediate transmission expansion that is required for the particular firm access request to be granted. The firm access price for each request would therefore either be zero[22] or the full expansion cost.[23]

This market design may lead to less transmission assets being built than are efficient. This is because TNSPs would have an incentive to plan their transmission expansion to build only

22 Where incremental usage is less than initial spare capacity and so there is no immediate expansion.

23 Where incremental usage exceeds initial spare capacity and so expansion is prompted.

the incremental expansion needed for each firm access request, in order to keep the costs of firm access reasonably attractive for generators. If TNSPs were to adopt an efficient approach to transmission development which was to take advantage of economies of scale and scope, generators may be dissuaded from paying for firm access rights entirely.[24]

Alternatively, it may be better to have a procurement process that is based off an auction model, where the auction reserve price is set at the estimated access cost.[25] This is because an auction process allows multiple generators to reveal their collective demand for firm access at the same time. TNSPs would be required to build enough capacity to satisfy the aggregate amount of firm access bought at a particular auction, which is likely to be larger than the capacity provided in a single access request. This should allow them to take advantage of economies of scale and scope in their transmission investment planning process.

However, it is also important to recognise that no process is perfect. The auction process would only account for current collective demand, not demand that may arise at a future date. Similarly, inefficient transmission investment can occur under the status quo, where central parties forecast the need for expansion based on a number of assumptions about how the future may look. The benefit of moving towards firm transmission access is that it would introduce more commercial drivers into transmission investment. This would shift investment risk away from everyday consumers, so that they no longer need to wear the full cost of an inefficient decision if and when it is made.

### 3.3.4 What will be the impact of firm transmission rights on wholesale electricity prices?

Access reform should lead to lower electricity bills for consumers. It is possible that the wholesale component of electricity bills may rise under firm transmission access. However, these costs should be more than offset by a reduction in the transmission use of system (TUOS) charges that are levied on consumers.

A primary aim of access reform is to introduce more commercial drivers into transmission investment, in order to shift investment risk away from everyday consumers. Currently, consumers bear the primary cost of transmission network investment and maintenance by paying transmission use of system (TUOS) charges through the retail component of their bill.[26]

This means that everyday consumers are burdened with transmission investment risk. If too much transmission infrastructure is built, they will pay for the costs of stranded assets through TUOS charges. If not enough transmission infrastructure is built, they are likely to face higher wholesale electricity prices as well as suffer from lower levels of reliability.

24 This is because of a free rider problem. If the transmission capacity that is created is larger than the exact capacity the generator has requested, then the generator would be subsidising subsequent access requests from its competitors (who would face a firm access price of zero).

25 The access cost would include the estimated cost of expansions required to overcome thermal and security constraints in the transmission system under a particular set of conditions.

26 The Australian Energy Regulator sets the maximum allowable revenue that TNSPs can earn from TUOS charges in each regulatory period, which is set to cover an efficient level of transmission investment and operating costs.

Under the final access regime, transmission investment costs would no longer be recovered solely from consumers through TUOS charges. The majority of these costs would instead be collected from generators.[27] This means that the TUOS component of a customer's bill will decrease substantially.

Generators would collectively underwrite the transmission investment that is required to provide them with the level of access they want to the transmission network. Wholesale costs of electricity may go up as a result, because all generators will factor in the cost of purchasing firm access rights or remaining non-firm (and facing a financial penalty when congestion arises) into their bottom line. In other words, they will face the investment risk that consumers face under the current arrangements.

While wholesale prices may go up, the total electricity bill faced by consumers should go down. This is because transmission and generation investment would be better coordinated. In addition, some generators will choose to remain non-firm, which will defer transmission investment that may have otherwise been undertaken under the current arrangements.

These decisions would reflect an efficient outcome of market design. The price of firm access would be set to reflect the costs of alleviating congestion that generators create by choosing to locate a certain type of generation asset in a certain part of the transmission network. If a generator does not value firm access enough to pay the efficient price, then it is ultimately preferable that they choose to remain non-firm rather than to impose the cost of alleviating congestion onto consumers.

### 3.3.5 Will there be grandfathering of access rights for existing generators under firm transmission access?

Yes, it is likely that existing generators would receive a level of 'transitional access'. Where there are significant regulatory changes in the electricity sector, it is in the long-term interests of consumers that there should be an appropriate transition for investors in the sector.

Currently, generators have some expectation of access to the regional reference price, though this implicit access can be degraded through changes to network conditions or the entry of new participants. The generators have made investment decisions based on the prevailing market conditions, including the assumption that there are no firm access rights for their competitors.

The implementation of a firm access regime would represent a substantial alteration to the current operation of the NEM. Transitional arrangements, including the provision of access rights to existing generators, would help to mitigate the commercial and financial impacts of the new access model on generator balance sheets.

The final design and length of any transitional arrangements will vary depending on the type of firm access regime that is implemented and the preferences of market participants. For example, free access rights could be allocated for a number of years to existing generators using a method based on either their historical level of access, or current transmission

27 Consumers would only need to pay the residual investment and maintenance costs that are required to deliver them with reliable electricity services.

capacity and regional peak demand. Alternatively, access rights could be auctioned off or a hybrid approach could be taken.

Regardless of the final form of transitional arrangements, it is likely that there will need to be gradually lessening of 'transitional access' over a number of years as the new regime commences. This gradual process will encourage generators to acquire and hold the levels of firm access rights that they value over time, thereby increasing the efficiency of transmission investment.

# ABBREVIATIONS

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| Commission | See AEMC |
| COAG | Council of Australian Governments |
| CoGaTI | Coordination of Generation and Transmission Investment |
| TUOS | Inter-regional transmission use of system |
| NEL | National Electricity Law |
| NEO | National electricity objective |
| TUOS | TUOS |