REVIEW

Australian Energy Market Commission

SUPPLEMENTARY REPORT: PRICING

Optional Firm Access, Design and Testing

31 October 2014

Submissions due 11 December 2014. Reference: EPR0039
Supplementary Report: Pricing

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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.

Executive Summary

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

The National Electricity Market (NEM) is currently experiencing a period of significant change and uncertainty. Changes being observed include in the areas of: policy settings to deliver Government's environmental objectives, growth of local generation, structural changes in the gas sector, new patterns of consumption, and technological change.

The AEMC considers that we need resilient and flexible market and regulatory arrangements. The market should be capable of adjusting to change efficiently with respect to price and reliability outcomes in response to whatever the future holds. A market that is able to adapt to changing conditions will deliver better outcomes for consumers.

The optional firm access model is intended to contribute to a market that is able to adapt to changing conditions, particularly demand and generation patterns, to deliver better outcomes for consumers. The optional firm access model is intended to introduce more commercial drivers on transmission businesses, and more commercial financing of transmission infrastructure. This could shift some transmission investment risk away from consumers.

At the same time, optional firm access would better enable generators to signal where they value transmission capacity. Better coordination of transmission and generation investment, could minimise the total system cost of building and operating both generation and transmission over time, and so potentially minimise prices for electricity consumers in the longer term.

The purpose of this report is to provide a progress update on the work the AEMC has done on the access pricing element of the optional firm access model. It builds on the AEMC's first progress update, provided in our First Interim Report.

Background to our pricing model

To achieve these aims, the optional firm access model needs to send efficient price signals to generators. Such signals promote more efficient use of the network by exposing generators to the long-term transmission costs associated with their locational decisions. This assists generators in making efficient decisions about where to locate new power stations, or retire existing ones.

We consider prices for firm access should be based on the long run incremental costs (LRIC) created by a generator's decision to locate in a particular part of the network. These are costs that are incremental to what network costs would have been had the generator not sought firm access. The LRIC approach is preferable to other approaches to pricing, including deep connection charging and long run marginal cost, on the basis that it values spare capacity most appropriately.

While prices for firm access should be reflective of incremental transmission costs, it is possible to apply a *stylised* methodology which does not capture every aspect of the network and involves some judgments about the future. We prefer a stylised approach because it assumes away some of the complexity inherent in transmission planning. Therefore, it is likely to produce more smooth and stable price outcomes than an approach that captured every aspect of the network. Such pricing outcomes contribute to providing financial certainty for firm generators.

The price signals produced by this stylised methodology should nevertheless represent an improvement on the current arrangements, where locational signals are minimal.

In addition to the locational signals, the quantum of the prices charged to generators for firm access is also important. If prices do not reflect incremental costs of providing access, generators may pay more or less than the costs their access actually imposes on transmission businesses. If they pay less, for example, consumers may indirectly bear some of the costs of providing the generators with access.

How our prototype works

We have developed a prototype pricing model which produces access prices for different amounts of access, at different locations, and for defined terms based on the LRIC pricing methodology. In developing it we have had input from transmission businesses and consultants.

At this stage, the prototype pricing model is a work in progress:

- it shows that a model can be developed to produce prices for the different parameters described above;
- the prices produced demonstrate the right relativities, with higher prices for access more remote from the regional reference node or for access in more congested areas;
- however, we are not yet confident that the model produces prices whose quantum reflects incremental transmission costs.

The quantum of prices generated by the prototype pricing model may not reflect incremental transmission costs due to the following factors:

- the model includes augmentation costs but not replacement costs;
- the model does not accommodate non-thermal constraints (such as stability);
- capacity is always provided by adding new lines, not incremental changes (for example, installation of a capacitor bank); and

- our cost inputs are limited.

We are working to overcome as many of these factors as possible, however some are a result of our inability to get access to data. **We are therefore publishing the model to seek stakeholder input on how the model currently works. It should NOT be used as a guide to what generators may pay if OFA was implemented.** It is also important to bear in mind that if OFA was implemented a more comprehensive model would be developed.

We seek the following input from stakeholders:

- Could it be possible to improve the model to produce prices that are reflective of incremental transmission costs?
- If not, why not?
- How does the model need to change?
- What inputs need to change?

Next steps

To request a copy of the prototype pricing model please contact Victoria Mollard on (02) 8296 7800, or victoria.mollard@aemc.gov.au.

Submissions on this Supplementary Pricing Report are requested by no later than **Thursday, 11 December 2014**. We will incorporate stakeholder feedback as we further develop the model. We intend to release an updated version of the prototype pricing model, which will address as many of the above limitations as we can, with our Draft Report in February 2015.

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

Contents

1 Introduction

1.1 Objective of Optional firm access

The optional firm access model aims to minimise the total system cost of building and operating both generation and transmission over time, and so potentially minimise prices for electricity consumers in the longer term. It does this by introducing more commercial drivers on transmission businesses, and provide for more commercial financing of transmission infrastructure.

The National Electricity Market (NEM) is currently experiencing a period of significant change and uncertainty. Changes being observed include in the areas of: policy settings to deliver Government's environmental objectives, growth of local generation, structural changes in the gas sector, new patterns of consumption, and technological change.

The AEMC considers that we need resilient and flexible market and regulatory arrangements. The market should be capable of adjusting to change efficiently with respect to price and reliability outcomes in response to what the future holds. A market that is able to adapt to changing conditions will deliver better outcomes for consumers.

The optional firm access model is intended to contribute to a market that is able to adapt to changing conditions, particularly demand and generation patterns, to deliver better outcomes for consumers. The optional firm access model is intended to introduce more commercial drivers on transmission businesses, and more commercial financing of transmission infrastructure. This would shift some transmission investment risk away from consumers.

At the same time, optional firm access would better enable generators to signal where they value transmission capacity. Better coordination of transmission and generation investment could minimise the total system cost of building and operating both generation and transmission over time, and so potentially minimise prices for electricity consumers in the longer term.

1.2 Purpose of this report

The purpose of this report is to provide a progress update on the work the Australian Energy Market Commission (AEMC or Commission) has done on the access pricing element of the optional firm access model.

This report builds on the AEMC's first progress update, provided in the First Interim Report, published in July 2014. In this report, the AEMC set out the proposed assessment framework for this review, and provided an update on all the elements (except access pricing) of the optional firm access model. The First Interim Report also included potential implementation pathways for optional firm access (OFA). The First Interim Report is available on our website.[1]

Therefore, this supplementary report on pricing should be read in conjunction with the First Interim Report. Also accompanying this report is a pricing prototype model, and user guide, which is designed to assist participants in understanding the proposed access pricing method.

1.3 Transmission Frameworks Review

In April 2013, the AEMC completed a comprehensive review of the transmission arrangements that underpin the National Electricity Market (NEM), known as the Transmission Frameworks Review. Amongst other things, this review developed an integrated package of market arrangements for the provision and utilisation of the transmission system, known as optional firm access.

1.4 Optional firm access

Under the optional firm access model, a generator would have the ability (but not an obligation) to purchase financial access to the transmission system. If, in the event of congestion, a generator without such access was dispatched ahead of a generator with access, the "non-firm" generator would pay the "firm" generator the difference between the local price[2] and the regional price.[3] The access would be underpinned by transmission capacity; that is, the transmission business would be required to provide this transmission capacity. It could do so by augmenting its network, undertaking operational actions, or entering into network support agreements to provide more capacity.[4]

The Commission considers that this model has the potential to deliver better long-term outcomes by:

- introducing more commercial drivers into transmission development;
- aligning more of the risk of transmission investment decisions with those who make them, and away from consumers; and
- enabling the cost of transmission to be taken into account in generator investment or retirement decisions (and vice versa).

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1 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Optional-Firm-Access,-Design-and-Testing.

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

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

4 Such investments could displace reliability expenditure - if the TNSP can meet reliability standards with the provision of access to firm generators they would not need to undertake augmentations for reliability purposes. Such an outcome would result in better outcomes for consumers.

Therefore, at the conclusion of the Transmission Frameworks Review the Commission considered it reasonable and prudent to progress the optional firm access model, but also noted that implementing it would be a fundamental change to the market and would not be without risk. Accordingly, the Commission recommended further work on the detailed design and testing of the optional firm access model. This would allow for a more detailed and comprehensive assessment of the costs and benefits associated with the model.

1.5 This review

On 25 February 2015 the AEMC received Terms of Reference from the COAG Energy Council to develop, test and assess the optional firm access model. The purposes of this project are to confirm (and potentially modify) the design of optional firm access, assess whether implementation would be beneficial, and if so, determine how it could be implemented.[5]

The Australian Energy Market Operator (AEMO) also received a Terms of Reference to undertake its own review, which complements that received by the AEMC. AEMO's work focuses on the "access settlements" element of optional firm access, and what variations to the access settlement mechanism would be necessary for a staged implementation of the optional firm access model.[6] AEMO has also assisted the AEMC by carrying out a number of tasks such as, testing an initial transitional access allocation method.

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

1.6 Submissions

Written submissions from interested stakeholders in response to this Supplementary Report on Pricing must be lodged with the AEMC **by no later than 5pm, Thursday 11 December 2014.**

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

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

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

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

1.7 Workshop

In order to assist stakeholders in understanding how the pricing model works, and the prices that it produces, the AEMC will hold two workshops on the model in November 2014. The AEMC invites all stakeholders to participate.

The workshops will be held in Sydney on Thursday 13 November, and Melbourne on Friday 14 November, both from 10am-12pm.

The workshop will discuss:

- an overview of the LRIC pricing method;
- an overview of how the prototype pricing model can be used; and
- an overview of results from the prototype pricing model.

Further details on the workshop, and information on how to register are available on our website.[7]

1.8 Content of this report

This report contains the following chapters:

- chapter 2 provides the background to access pricing, including some answers to frequently asked questions regarding access pricing;
- chapter 3 provides a high-level overview of the prototype pricing model;
- chapter 4 details some indicative access prices obtained from using the prototype access pricing tool, and provides information on how these indicative access prices are sensitive to changes in a number of key parameters;[8]
- appendix A discusses the process that we are undertaking to complete this review;
- appendix B discusses the value of spare capacity, and the Commission's reasoning for recommending an LRIC, as opposed to a long run marginal cost or deep connection charge;
- appendix C details the source of assumptions and inputs for the prototype pricing model; and

7 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Optional-Firm-Access,-Design-and-Testing.

8 The Commission notes that the indicative access prices produced by the prototype pricing model discussed in chapter 5, are provided by the AEMC for information and to seek feedback on the efficacy of the model. While the AEMC has endeavoured to ensure the content of the model is accurate, adequate or complete, it does not represent or warrant its accuracy, adequacy or completeness.

- appendix D provides further detail on indicative access prices, and their sensitivity.

Note also that the prototype pricing model, and accompanying user guide are available separately. These items supplement this report, and provide further detail and practical evidence on the method proposed for access pricing.

An issue we have yet to explore in detail is governance. Governance refers to the institutional arrangements for the administration of the optional firm access model. For example, an entity will be required to run the pricing model to produce the access price. Similarly, an entity or entities will be responsible for providing the inputs to the pricing model, and revising the model and its inputs over time.

There will be a range of considerations in identifying the most appropriate governance arrangements for optional firm access, including any interactions with existing governance arrangements in the NEM. Governance can only be finalised once the design of each element of the model is settled and it is clear what will be required from the entity that is responsible for it. Our work on governance will be included in the Draft Report to be published in February 2015.

2 Access pricing in the Transmission Frameworks Review and recent developments

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. This method gives more efficient pricing signals than other 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, or retire existing ones.

Access pricing determines the charges that generators would pay to TNSPs for firm access. This chapter discusses the following:

- the objectives of access pricing (section 2.1)
- the Commission's reasoning for using a long run incremental costing method (section 2.2);
- how long run incremental costing works (section 2.3);
- the sources of forecasts to be used in long run incremental costing (section 2.4);
- the core and recommended elements of access pricing as set out in the Transmission Frameworks Review (section 2.5);
- developments to access pricing since the Transmission Frameworks Review (section 2.6); and
- answers to some frequently asked questions about access pricing (section 2.7).

2.1 Access pricing objectives

The provision of firm access would likely result in the TNSP providing new network capacity under the firm access standard[9], 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 optional firm access model would require the firm generator to pay an amount to the TNSP in respect of these costs.

The purpose of access pricing is to estimate what these costs are. There are a number of objectives that apply to access pricing:

9 The First Interim Report set out that we have refined the firm access standard since the Transmission Frameworks Review. The proposed firm access standard would now have two components: a firm access planning standard and a firm access operating standard. Throughout this report we refer to the term "firm access standard", which can be considered to comprise both the planning and operating standards as discussed in the First Interim Report.

1. Access charges are calculated through the application of an access price model based on a specified access pricing methodology that likely would be set out in the Rules.

2. Access charges are fixed at the time of procurement of firm access by the generator.

3. Access charges are cost-reflective: a generator is charged for the estimated costs that a TNSP will incur to provide access.

2.2 Preference for long run incremental cost method for pricing

The Transmission Frameworks Review considered three different access pricing methodologies that could be used:

- long run marginal cost (LRMC), where the access price is a constant unit cost regardless of incremental usage, based on the average unit cost of capacity expansion;

- deep connection charging, where the access price is either zero (where 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; and

- long run incremental cost (LRIC), where the access price is the sum of all incremental costs (both present and future).[10]

The Commission recommended that LRIC should be used for access pricing since LRIC provides price signals to generators that are more cost reflective than the other two methodologies. Transmission planning is a long-term process and it would not be sufficient to simply calculate the immediate cost of the extra investment required prior to new access rights commencing. The new access may cause a future, already planned, investment 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. Long run incremental cost calculates all these incremental costs - present and future.

Charging based on LRMC or deep connection costs can result in access prices that diverge strongly from cost reflectivity. The reasons for this are discussed in further detail in appendix B.

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10 We understand that "FL-LRIC" is a defined term used in telecommunications pricing and regulation. It takes account of lumpy capital costs and assumes that a lump of additional service is to be costed. However, it takes no account of existing capacity and no account of demand growth. This therefore can be considered akin to a long-run *average* incremental cost. Such a method is not appropriate in a declining demand situation. These concerns (about not using FL_LRIC in a declining demand situation) do not arise here since a fundamental assumption of the LRIC to be used for access pricing is that it takes into account demand growth.

In summary, LRIC provides an efficient locational signal to generators. 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 characteristics of the LRIC pricing methodology are that, other things being equal:

- generators locating remotely from the regional reference node 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 network 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.

2.3 LRIC pricing method

2.3.1 Calculation of the LRIC price

When using the LRIC method for access pricing, the LRIC would estimate the incremental costs to a TNSP that arise from the TNSP providing a generator with firm access from a specified point on the transmission network to the regional reference node in the local NEM region.

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

- the baseline cost, which is the NPV of a baseline modelled network development scenario (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 network development scenario - that is, an amendment to the baseline scenario to accommodate the new access request.

The LRIC cost for a firm access request is therefore defined as follows:

$$LRIC = \textit{adjusted cost} - \textit{baseline cost}$$

In the Transmission Frameworks Review, we used the term "expansion plan". However, we have changed this terminology to "modelled network development scenario" to reflect that: a TNSP could *replace* assets as well as *invest in new* assets; and that the *modelled* scenario is a stylised approach rather than what the TNSP may actually *plan*.

The scenarios would be derived using a stylised methodology which, would not capture every aspect of the network and would involve some judgments about the future. The methodology would capture the major aspects of the network.

We consider that a stylised approach has a number of advantages. A stylised approach assumes away some of the complexity inherent in transmission planning. Therefore, it is likely to produce more smooth and stable price outcomes than an approach that captured every aspect of the network. Such pricing outcomes contribute to providing financial certainty for firm generators.

We consider that such an approach would provide a robust basis for determining access charges.

In order that the calculated long run incremental cost is as reflective as possible of actual 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 investment; 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 2.1 represents the baseline development scenario for a single element of the shared transmission network, such as a transmission line or network transformer. Its development has three drivers:

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

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”. This 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 2.1 Baseline development scenario for a network element

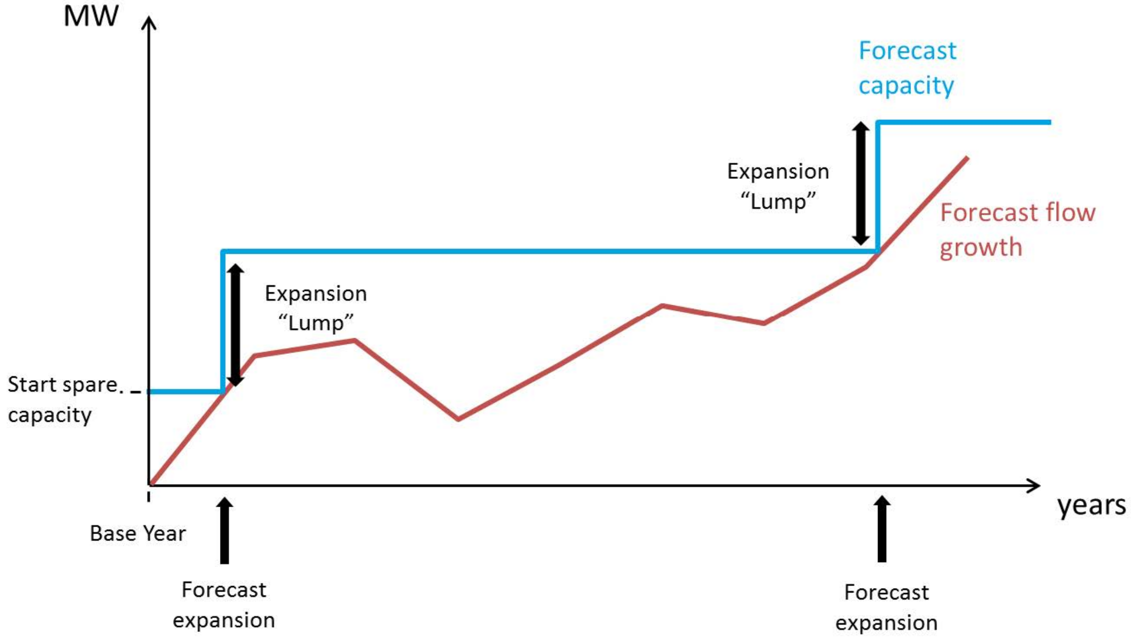
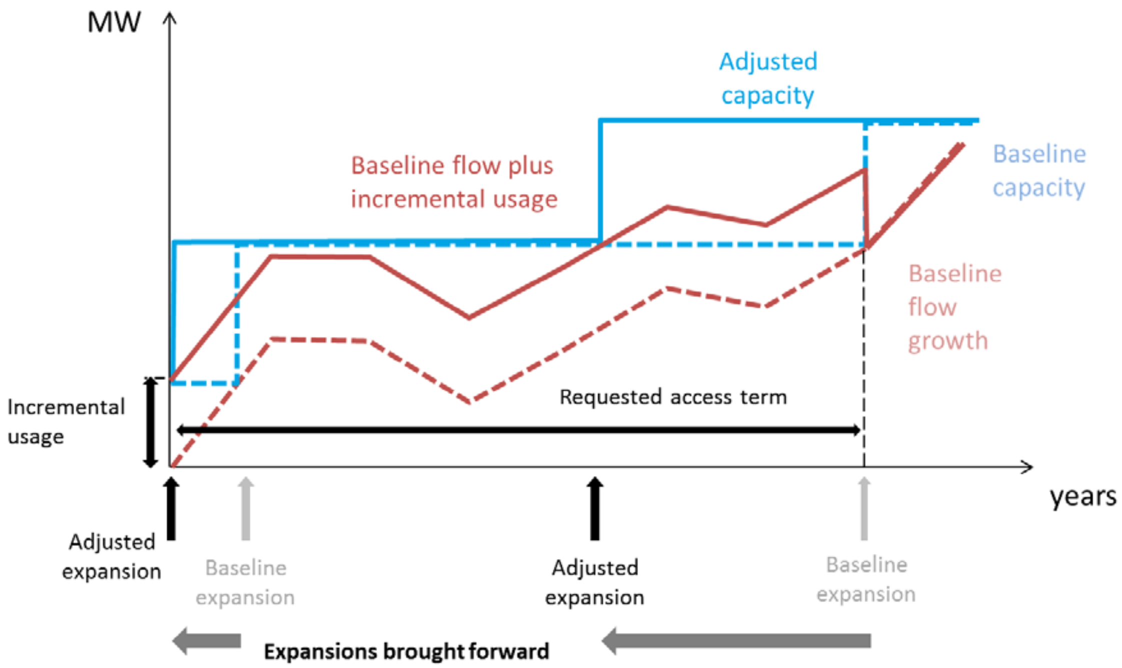


Figure 2.2 illustrates how the request for additional access would result in an adjusted development scenario for the network element. The effect of the access request is to increase the forecast flow on the network element, and therefore to bring forward the already planned developments by varying amounts. To model the adjusted development scenario, two things need to be represented:

- incremental usage: the extra flow induced on the element by the access request; and
- access term: the period of the access request and so the period for which the extra flow occurs.

Figure 2.2 Adjusted development scenario 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 development scenarios. The access price is the difference between these two costs, summed over all transmission elements in the network.

2.3.2 Treatment of replacement of assets in LRIC

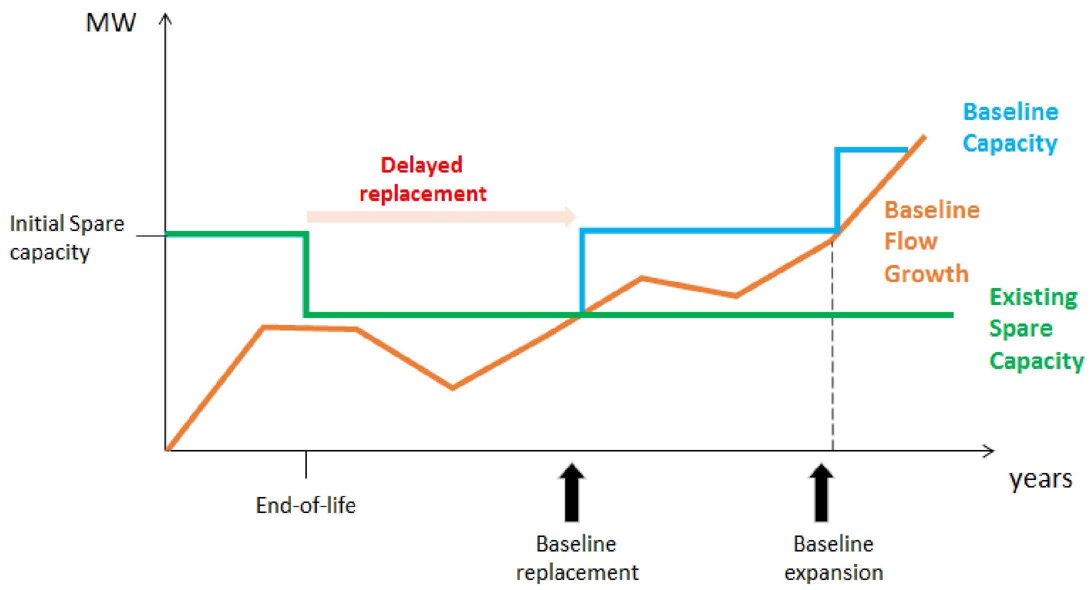
Since the Transmission Frameworks Review, we have considered how the LRIC pricing method could incorporate replacement expenditure, and what this may mean for access pricing.

The above graphs represent a simplistic depiction of the network, since they implicitly assume that transmission assets are treated as being everlasting.

In fact, assets have a finite life - although we recognise that predicting the end of asset life is not straightforward. When an asset is nearing the end of its life, a TNSP must decide whether or not to replace it. Under optional firm access that decision will depend, amongst other things, on that assets' current contribution to maintaining the firm access planning standard as well as its contribution to meeting the relevant regional transmission reliability requirements. In turn, this depends upon existing and forecast firm access, and existing and forecast customer demand. Accordingly, new firm access could cause an increase in replacement expenditure and/or an increase in expansion expenditure.

Figure 2.3 illustrates how finite asset-life and asset replacement could be modelled in the baseline development scenario in the LRIC pricing model. The green line represents existing spare capacity and the blue line planned capacity. Both step down when a network asset reaches its forecast end-of-life. As forecast usage grows, an expansion is eventually required, which can be considered to represent a delayed replacement of the old asset – although, in practice, this would be modelled with the same characteristics (size and cost) as any other expansion.

Figure 2.3 Replacement costs in the baseline scenario



The existence and extent of the delay in replacement is predicated on the forecast rate of flow growth. If growth is high, immediate replacement may be required. If growth is very low, replacement might be required only after a long delay, if at all.

Figure 2.4 uses a similar approach to develop the adjusted development scenario. The incremental usage from the access request means that the old asset must be replaced immediately that it expires, since the adjusted flow exceeds the baseline capacity at this point. Thus, compared to the baseline development scenario, the replacement has been advanced: there is no longer a delay in replacement. This creates an increase in the NPV of the overall cost (between the baseline and adjusted scenarios) and this increase could be included in the access price.

Figure 2.4 Replacement costs in the adjusted scenario

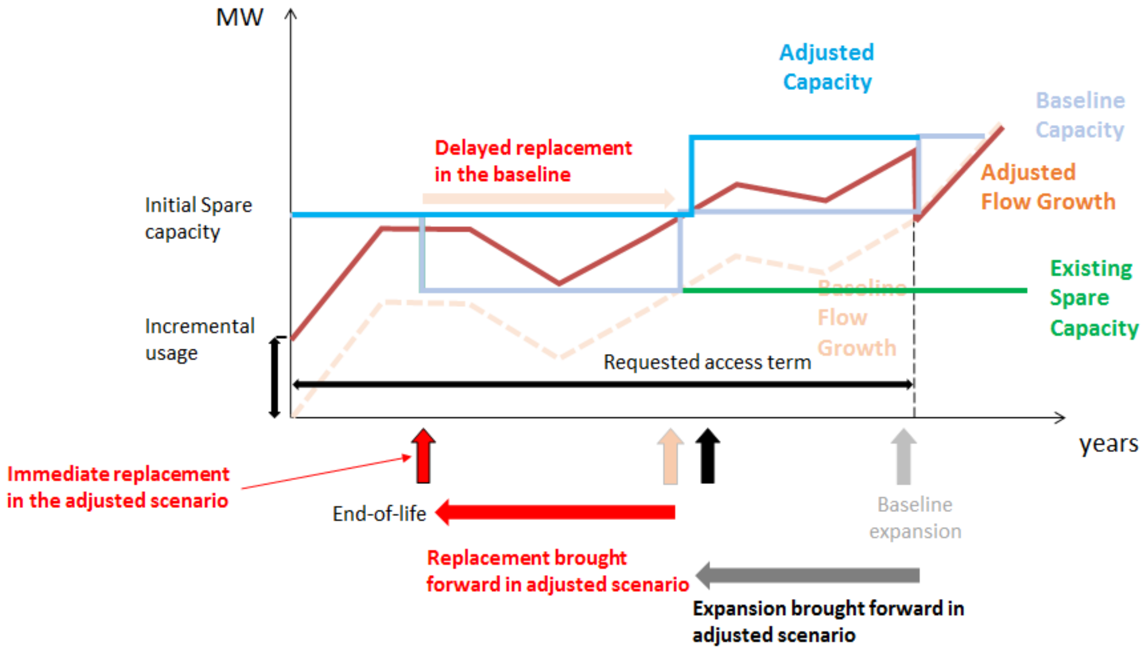


Figure 2.4 also shows that a subsequent expansion would be advanced. This is not related to asset replacement and so is unaffected by the changes considered here.

2.4 Forecasting of flow growth

As noted above, in order to develop efficient LRIC prices there needs to be accurate, objective and transparent forecasts of new generation, and so flow growth on the network. Below we set out where such forecasts would come from. We expect that the inputs into the pricing model should be consistent with assumptions made in TNSPs' regulatory determinations.

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

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 National Transmission Network Development Plan (NTNDP), which is the product of an open and transparent process, or other similar information developed and published by AEMO.

To simplify the access pricing model, forecast flows would be stylised rather than precise beyond a certain point (say 10 years out). 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. Therefore, there is a point where including detailed forecasts does not substantially improve accuracy of the modelling.

Long-term forecasts should therefore assume a fixed rate of growth, rather than being calculated on explicit demand and generation forecasts.

2.5 Core and recommended elements

The key features of the pricing method as set out in Table 10.1 of the Transmission Frameworks Review's final report are extracted below.

Table 2.1 Table 10.1: Access pricing

Core elements	Recommended elements	Optional elements
• Access charge based on Long Run Incremental Cost (LRIC), defined as difference in NPV between baseline expansion costs and adjusted expansion cost • LRIC estimated based on stylised model rather than actual TNSP expansion plans • Access charge must take account of cross-regional impacts and provide for appropriate cross-regional payments between TNSPs • Access charge is payable through annualised payments over the access term • Non-firm generators do not pay an access charge	• Access charge excludes the effects of reliability standards and reliability access • LRIC calculated separately for each transmission branch element • Element LRIC based on initial spare capacity, flow growth, lumpiness, incremental usage and access term • Element parameters based on a combination of detailed forecasts for shorter-term and stylised estimates for longer-term • Forecasts based on NTNDP or other information provided by National Transmission Planner (NTP) • Super-firm access charged the same way as firm access: i.e. generator capacity not taken into account • No negative access charge on elements where a negative LRIC is calculated (i.e. expansion can be deferred as the result of the new access) • Annual payment profiling specified in access charge methodology	• Meshedness factor used to adjust the lumpiness of parallel lines (other alternative approaches may be possible) • Discount rate for NPV calculations based on TNSP regulated cost of capital (alternative discount rates are possible) • Pricing is undertaken by TNSP, using a copy of the model provided by the NTP (alternative is that NTP or another central agency undertakes pricing)

Core elements	Recommended elements	Optional elements
	• Access pricing model and input parameters are maintained by NTP • Pending access requests included in forecasts	

2.6 Developments since the Transmission Frameworks Review

The Transmission Frameworks Review set out the theoretical construct of the LRIC pricing method. This was described above in section 2.3.

Since the conclusion of the Transmission Frameworks Review we have undertaken further work on the design of the access pricing method. These developments relate to considering how such a model could be practically implemented into the NEM and the likely outcomes. Accordingly, we have developed a prototype of the pricing model in order to better assist stakeholders in understanding the pricing method. Such a model would also assist the Commission in understanding the strengths and weaknesses of the LRIC pricing methodology.

The prototype pricing model is discussed in the following chapters, and is consistent with the core and recommended elements of Table 10.1 that were set out in section 2.5 above.

2.7 Frequently asked questions

The Commission, over the course of the Transmission Frameworks Review, and also through more recent stakeholder interactions as part of this project, has identified a number of frequently asked questions about the LRIC pricing method. These are answered, and discussed, below.

Table 2.2 Frequently asked questions

Question	Answer
1 .How does the access price from the pricing model interact with, and influence, the planning that a TNSP would undertake in order to meet its firm access requests?	The stylised development scenarios 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 investment project: • TNSPs would always plan to meet the total 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. • More significantly, the LRIC model is stylised, considering only independent duplication of existing network elements, whereas real planning considers a range of possible solutions: new transmission paths, voltage changes, network control equipment, generation network support and load management etc. • TNSPs would be obliged (as they are now) to undertake a Regulatory Investment Test for Transmission (RIT-T) investment to respond to particular investment needs. The TNSP would plan, and then apply a RIT-T to identify and select an augmentation option with the highest net benefit to resolve any potential firm access planning standard breaches. The RIT-T focuses on identifying what exact augmentation would be undertaken, and the project costs associated with this. • Access prices would be fixed for the term of the firm access. Network plans (appropriately) change over time, as information - such as demand forecasts - changes. Nevertheless, in principle, the LRIC pricing method could deliver robust, transparent and efficient prices that deliver broadly the revenue to cover TNSPs' costs in meeting firm access requests. Further, planning and pricing forecasts should be aligned.

Question	Answer
2. What if the LRIC model gets the pricing wrong?	If access prices do not reflect the LRIC of access provision, then signals to generators would be distorted: pricing too low may encourage generators to enter at an expensive location and prompt inefficient transmission investment. On the other hand, pricing too high might discourage generators from entering at a cheap location and leave existing network capacity underutilised. If access prices consistently underestimate the cost of transmission investment, then these costs would not be recovered through access charges (over the long-run) and would be paid for by customers instead (see answer to question 3). However, while prices would always be inefficient if they are biased in one direction, in principle, the LRIC pricing method should not produce prices that are biased in one direction. Our work on the prototype is designed to help test this proposition. Further, access prices do not need to be perfectly accurate in order to provide an efficient price signal. LRIC provides a signal of the costs of network elements (taking into account distance on the transmission network, and the level of spare capacity), ie, it is the relative difference in price between different locations that is important (rather than the absolute values).[11]
3. Do firm access arrangements need to be forecast in the revenue reset process, and what happens if these forecasts are wrong?	This relates to the arrangements for revenue regulation, which are set out in chapter 7 of the Final Report of the Transmission Frameworks Review.[12] In summary: • Future firm access arrangements would need to be forecast, in the same way as customer demand is to be forecast currently. Given the lead time associated with access procurement, the TNSP would be aware of most pending access requests at the time of the revenue reset. However, it is possible that new access requests would arise, or some anticipated access requests would not eventuate.

11 Although we do recognise that prices that are too high across the board will not affect locational decisions, but may affect entry timing and firmness decisions.

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

Question	Answer
	• Any forecast errors about future firm access would affect both TNSP revenue and TNSP costs. For example, if an unexpected access request occurs, this would bring in some additional access revenue, but may also create some unexpected costs in relation to transmission investment to provide that access. • Since the access charge is based on incremental costs, the additional revenue should match the incremental costs over the life of the new access. Of course, there may be pricing errors (as discussed above) and this will cause some variances. • Even in the absence of pricing errors, there may be timing differences between the incurring of the incremental costs and the receipt of the access revenue. If this causes a difference within the current regulatory period, this difference would be borne by the TNSP. Transmission use of system (TUOS) prices would not be adjusted. In the second and later regulatory periods, consumers would bear the financial risk that the TNSP's costs to provide the firm access are greater than the price paid by the firm access generator with any such costs being added to TUOS payments. Conversely, consumers would benefit from reduced TUOS charges in subsequent regulatory periods if the price paid by a firm access generator in that regulatory period is higher than the TNSP's costs to provide the firm access. Prices should not be systematically biased in one direction of costs, so consumers should be left largely whole on average.
4. What happens if there is TNSP investment that increases transmission capacity by more than the firm access service requested by a generator due to the lumpiness of investment? For example, if a generator buys 100MW of access, but this triggers a (efficient) 500MW of transmission capacity.	The LRIC pricing model is based on scale-efficient expansions, based on the forecast growth in the baseline scenario. The TNSP would actually plan and build scale-efficient expansions based on its planning forecasts. Since planning and pricing forecasts would be aligned, the pricing model should reflect the true lumpiness of network expansion (see answer to question 1). The LRIC model only charges a generator for the cost of bringing forward an investment and not its full cost (this is the essential difference between LRIC and deep connection charging). The timing of investment in the baseline scenario depends upon current spare capacity and on the forecast growth rate.

Question	Answer
	For example, if spare capacity is high and/or the forecast growth is low, any baseline investment is far into the future, and so the LRIC model would charge the new generator the vast majority of the cost. On the other hand, if spare capacity is low and/or forecast growth is high, the baseline investment is not so distant, and the LRIC model would charge the new generator only a proportion of the cost. In the latter case, the access charge will not cover the majority of the investment costs and the remainder will be borne by the TNSP and/or customers (depending upon revenue regulation). However, these revenue shortfalls will be offset by other access requests in which no immediate investment is required and so the access revenue exceeds the TNSP's costs (being zero) and so a revenue surplus arises. In the absence of consistent mispricing, the shortfalls and surpluses will average out.
5. Would a model that relies on fewer assumptions (for example, a deep connection charge which makes no assumptions about the future, and instead allocates all of today's costs to the party who is causing the costs) be more accurate?	We accept that the outcomes under the LRIC pricing method do depend on the assumptions that feed into it. However, we consider that any method of pricing relies on assumptions. The deep connection charge only reflects the long-run incremental cost of access provision in a situation where there is zero growth for the foreseeable future. This is explored in more detail in appendix B. In addition, the assumptions under LRIC are, in part, informed assumptions. Therefore, a model that is based on somewhat accurate assumptions is likely to produce more reasonable prices than a model that are known to be incorrect. Further, the pricing model should converge to producing more accurate prices over time. The parties responsible for providing inputs to the model should over time become more familiar with what these inputs should be. Therefore, learning about the pricing model should improve its accuracy.

Question	Answer
6. How does the access charge depend upon the term of the access?	The LRIC price paid by the generator would depend on the period of time the firm access is requested for. A request for firm access for a period of 10 years may trigger or bring forward network investment that a request for the same MW of firm access for 5 years may not. In the pricing model, timings would only be affected within the access term. For example, if the term is ten years, the request may cause investments to be brought forward and scheduled within this period and so be factored into the access charge. However, investment scheduled beyond the 10 year term would not be affected and so would not affect the access charge. Thus, the longer the term, the more advancements are captured within the pricing model and so the higher the access charge. This means that it is not possible that lengthening the term of the access request would lead to a reduced access charge.
7. Is a centralised pricing model inconsistent with the objective of decentralising transmission planning?	Ideally, access prices would be set by the market, like wholesale energy prices, rather than determined administratively. Of course, this is not possible, since TNSPs are monopolies and so there can be no competitive market for access provision. It is acknowledged that forecasts are part of the pricing model proposed. However, this does not make it central planning – generators are still responsible for making decisions that influence where the transmission network will be built.
8. Does the model contain 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, the impact of higher load flow growth on an element is to flatten the long run incremental cost curve. 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 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.

Question	Answer
	With a mix of elements, with varying degrees of spare capacity necessary to fulfil an access request, it is unlikely that prices will be systematically biased in one direction or not. We have tested the sensitivity of the LRIC to such forecasts. This is discussed further in section 4.4.

3 Prototype pricing model

Summary of chapter

We have developed a prototype pricing model in order to better understand how the LRIC pricing method could be implemented in practice, and the strengths and weaknesses of using the LRIC method to calculate access prices. The model implements the logic of the LRIC pricing method, and so produces prices based on the difference in net present value terms between two modelled network development scenarios:

- a baseline modelled network development scenario, that is, the modelled network development scenario of the transmission network that is in place before a particular access request is received; and
- an adjusted modelled network development scenario, that is, the adjusted modelled network development scenario of the transmission network to accommodate a firm access request made at a specified location, for a specified MW amount of access, for a specified amount of time.

This prototype pricing model, and accompanying user guide, is available for stakeholders to use.

We note that the prototype pricing model is a work in progress. There are still some elements that can be refined, and improved, including:

- cost inputs may not always be realistic;
- the model includes augmentation costs, but not replacement costs; and
- the model does not accommodate non-thermal constraints (such as stability).

We are currently considering ways of refining the model to address such limitations.

It is also important to bear in mind that if OFA was implemented a more comprehensive model would be developed.

3.1 Introduction

It is important to understand:

- how the LRIC pricing method may be implemented in practice;
- the strengths and weaknesses, and practicality, of using the LRIC method to calculate access prices; and

- potential access prices, and the extent to which those calculated access prices are sensitive to input data and other assumptions.

Accordingly, the Commission has developed a prototype pricing model, which stakeholders can apply. The prototype, and its inputs and outputs, will also feed into the Commission's assessment of the costs and benefits of implementing optional firm access.

This chapter discusses in detail:

- the development of the pricing model (section 3.2);
- how the pricing model works at a high level (section 3.3);
- limitations with the pricing model (section 3.4)
- how interested stakeholders can access the pricing model (section 3.5); and
- areas on which we seek stakeholder feedback (section 3.6).

We note that the prototype pricing model will also be explained at the pricing workshop referred to in section 1.7.

3.2 Overview of the prototype pricing model

3.2.1 Development of the prototype pricing model

The Commission has engaged a software consultant to develop the program for the prototype pricing model. The program implements the logic of the LRIC pricing method as specified in the Transmission Frameworks Review (and as described in chapter 2), and so is consistent with the core and recommended elements of Table 10.1 of the Transmission Frameworks Review Final Report.

The prototype pricing model comprises three main elements:

- a model of the NEM transmission network;
- other input data (such as demand growth); and
- the program itself, which calculates the LRIC prices.

The prototype pricing model allows the user to select a location that it wants access from, a length of time that it wants access for, and an amount of access that it wants. The model then uses this information, and the input data, in order to calculate an LRIC price for these characteristics. We note that the network model and input data can be varied by the user.[13] Further information on how stakeholders can access this prototype is available below in section 3.5.

If the optional firm access model was to be implemented, the prototype would not be the pricing model that would apply. A complete, more comprehensive version of the model would be developed at that time by the relevant body responsible for the LRIC model.[14] This model would be fully tested and auditable.

3.2.2 Key inputs and assumptions in the model

Table 3.1 sets out the key inputs and assumptions that are used in the pricing model. The model does not include any data that may be considered confidential, eg, demand associated with large industrial loads. Further information on these inputs and assumptions used in the prototype pricing model is given in appendix C.

Information relating to the model of the transmission network was sourced from AEMO and public information. We note that some of this input data obtained from AEMO has been modified following feedback from TNSPs and EMCa. All other input data were obtained from public sources.

Commercial-in-confidence data (eg, the demand of large industrial loads) was excluded from the model.

Table 3.1 Key inputs and assumptions to the pricing model

Input	Source
Existing access	Results of the transitional access allocation test undertaken by AEMO, which are set out in appendix A of the First Interim Report.[15] For the purpose of the prototype pricing model, transitional access was not sculpted.
Forecast access	Generator entry is sourced from data from the 2013 National Transmission Network Development Plan (NTNDP). We have made assumptions about the preferred firmness of new generators, and existing generators going forward.
Peak local demand	10 year forecasts of peak local demand are from the TNSPs' 2013 Annual Planning Reports. We note that these reports do not include commercial-in-confidence data (ie, forecasts of large, transmission-connected industrial loads).

13 Further information on how to do this is contained in the user guide that accompanies the model. Details on how to access the model are set out in section 3.5.

14 As noted in chapter 1, we will consider governance arrangements in our Draft Report, to be published in February.

15 We note that where access exceeded a generator's registered capacity, we set the access level equal to the registered capacity. This is discussed in further detail in appendix C.

Input	Source
Long-term peak line flow growth	The model assumes a generic annual increase in line flows for flows that are more than 10 years away.
Existing transmission network, including nodes, edge topology, admittance, ratings, size of lines, length of lines[16]	AEMO.[17]
Expansion - costs of expansion lumps	We have made assumptions around indicative costs, with these sourced from publically available data.[18] These costs are expressed in $/MW/km for lines and $/MW for transformer. That is, small, medium and large lines and transformers have different costs.
WACC	We have assumed a 6.4 per cent real pre-tax WACC in our model.[19]

3.3 How does the prototype model work

The prototype pricing model produces LRIC prices. It also produces access prices based on deep connection and long run marginal costs for comparison. The differences between these different methodologies for access prices are discussed further in appendix B.

In accordance with the LRIC pricing method specified in the Transmission Framework Review (and as described in chapter 2), the prototype model produces prices based on the difference in net present value terms, between two modelled network development scenarios:[20]

- a baseline modelled network development scenario, that is, the forecast scenario of the transmission network that is in place before a particular access request is received; and
- an adjusted modelled network development scenario, that is, the adjusted forecast scenario of the transmission network to accommodate a firm access request made at a specified location, for a specified MW amount of access, for a specified length of time.

16 The prototype pricing model currently only includes thermal constraints. This is discussed further in appendix C.

17 We note that some line length data has been estimated by the AEMC.

18 See: AEMO, 100 per cent renewables study - electricity transmission cost assumptions, 18 September 2012.

19 This is based on the AER's recent WACC parameters as set out in the final determination for AusNet. See: AER, *SP AusNet Transmission determination, 2014-15 to 2016-17*, January 2014.

20 To be clear, these are modelled network development scenarios - that is, these are not what would actually occur in the network. Instead, these scenarios are stylised.

An overview of the calculation of the cost of the baseline scenario and adjusted scenario, and so the LRIC price, is given below.

3.3.1 Calculating the cost of the baseline network development scenario

The cost of the baseline network development scenario is calculated in six simplified steps:

1. Calculation of forecast peak line flows

The prototype pricing model includes a model of the NEM transmission network in its current form. Each node[21], line[22] (or location)[23] and transformer[24] in the NEM is represented in the model. Each line and transformer has a number of physical and electrical characteristics (such as location, length, voltage and reactance) which are defined in the model. These are defined based on how these elements currently exist in the network.

With regard to calculating the flow of electricity, lines and transformers are treated identically within the model. In this report, references to lines should be taken to refer to both lines and transformers.

The model calculates the annual peak line flows (in MW) for each line in the region[25] using two different methods. The first method applies in a short-term time horizon, the second, a long-term time horizon until the end point in the model.[26]

In the short term, input assumptions to the prototype pricing model define the annual peak load being withdrawn from, and the annual level of firm access[27] injected at, each node.[28] From these, and based on the physical and electrical characteristics of the lines, the peak flow on each line in the region is calculated on an annual basis. These calculations are based on DC (direct current) lossless load flow equations (which

21 There is a node for each transmission substation.

22 Each line connects two nodes. A lien may be an overhead line, an underground cable or a transformer.

23 The terms location and node are used interchangeably in this report. Where there are multiple circuits (eg, a double-circuit overhead line) these are represented as a single, equivalent line.

24 Transformers connect nodes of different voltages at the same location.

25 The transmission model has been divided into NEM regions, to increase the speed at which the model produces output prices.

26 Both the timing of the delineation of the short term/long term, and the end point in the model, can be set as variables in the model.

27 What is relevant for the calculation of LRIC prices is the level of firm access, rather than the level of generation, at each node of the network. This is because the TNSP is obliged to provide capacity to the level of firm access. Firm access is therefore equivalent to the maximum generation that the TNSP is obliged to provide for. As such, the level of firm access is used as a proxy for maximum generation, and is treated equivalent to generation in the line flow calculations.

28 In circumstances where peak load exceeds firm access, additional access (known as reliability access) is calculated by the model and added to the node. The rationale and calculation of reliability access is explained in detail in the Prototype Pricing Model User Guide.

model the flow analogously to the flow of water through pipes), which provide a good approximation of the actual load flow on an AC (alternating current) network.

In the long term, the peak flow on each line is assumed to grow by a fixed MW amount. This amount is based on a percentage of the peak line flow calculated in the final year that the short term method was applied.[29]

The distinction between the short-term and long-term method for calculating peak line flow is based on pragmatic considerations. Peak load and firm access can be more easily forecast in the short term, and information to inform these forecasts currently exist (ie, the NTNDP and the TNSPs' Annual Planning Reports). In the longer term, peak load and firm access cannot be as easily forecast, and so the long-term forecast for peak line flow is based directly on a short term forecast peak line flow (itself based on forecast short term demand and access growth at each node).

2. Prompting an expansion

For each year, the forecast peak line flow in MW for each line in the region is compared to the capacity of that line in MW.[30]

If peak line flow is forecast to exceed the line capacity for any individual line, then an expansion to the line will be prompted within the model, with this occurring at the time at which the capacity is forecast to be exceeded by the peak flow. That is, the model predicts when expansions would occur within the model, and reflects this in the modelled scenarios.

3. The nature and size of the forecast expansion

As set out in the Transmission Frameworks Review, the LRIC pricing method would be stylised. This means that in order to expand the network, the model replicates the route of the existing line.

The size of the expansion in MW is based on an assumed, pre-defined economic lumpiness of expansion (in MW of capacity), divided by the "meshedness" of the line.

Lumpiness is the amount of capacity that would be added through the efficient expansion of that element.[31]

Meshedness is a measure of the extent to which electricity will flow along alternative paths in the network between the two ends of the line. A highly meshed line means that a large proportion of the flow of electricity between the two ends of the line flows along a route other than along the line. Proportionally, therefore, the size of the

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29 This percentage can be varied as an input assumption into the model.

30 The capacity of the lines are defined as an input into the model.

31 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.

required expansion is lower per line for a highly meshed line than would be required for a line with low meshedness.[32]

4. The forecast cost of the expansion

For lines, the forecast cost of the expansion is calculated based on assumed cost per MW per km of expansion for that type of line, multiplied by the line length and the expansion size. For transformers, the cost of the expansion is based on assumed cost per MW for that transformer type multiplied by the expansion size.

5. Updating the capacity of the line based on the expansion

The capacity of the line is increased in those years after the forecast expansion, to reflect the fact that the modelled expansion has increased the capacity of the line. Further forecast expansions to the line are not required until the forecast peak line flow exceeds the new, higher capacity.

6. Calculating the cost of the baseline development scenario

The total cost of the baseline development scenario is the sum of the net present cost of all the expansions on all of the lines which are forecast to occur until the end time of the requested access, based on an assumed discount rate.[33]

Box 3.1: Worked example: Baseline network development scenario cost

Assume a simple, radial part of the network, with a line connecting two nodes. The line has a flow capacity of 500MW.

In the base case, generator 1 has 450MW of firm access at node 1. The firm access level at node 1 is forecast to increase by 10MW per year.[34] The load at node 2 is assumed to be equal to the firm access across the line at any given time (and hence there is no requirement for reliability access).

The economic lump of expansion for the line is 100MW, and the meshedness of the line is 1 (as there is only one route by which electricity passes between the nodes). The length of the line is 10km and the cost per km per MW is $0.1m.

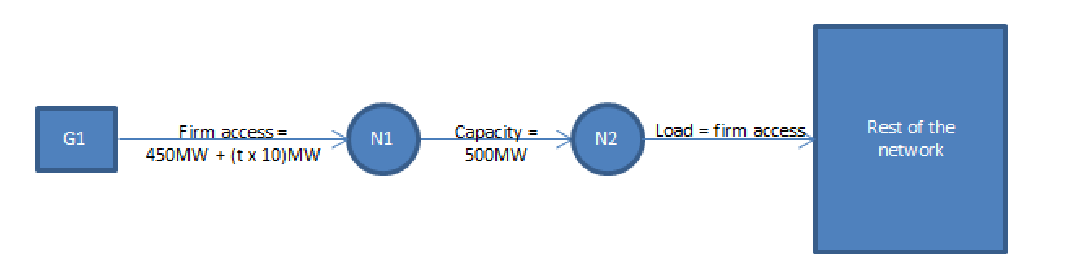
The discount rate is assumed to be 10 per cent.

The model's end point is 20 years in the future.

32 The concept of meshedness is explored in greater detail in the prototype pricing model's user guide.

33 The model actually calculates the sum of the net present cost of all the expansions on all of the lines which are forecast to occur until the defined end time of the model. However, expansions that occur after the access term has concluded do not matter to the calculation of the access price, and so we can consider these two timeframes to be consistent with each other.

34 This could occur through generator 1 purchasing more access, or other generators locating at node 1 purchasing access.



The cost of the baseline development scenario is calculated as follows:

- The flow on the line is equal to the firm access amount in any given year.
- The forecast firm access exceeds line capacity after 5 years (450MW + 5 years ×10MW per year = 500MW).
- The expansion on the line is for 100MW (lumpiness of 100MW ÷meshedness of 1).
- The expansion on the line costs $100m (expansion of 100MW ×10km ×$0.1/km/MW). This occurs in year 5.
- The capacity of the line beyond year 5 is 600MW.
- The forecast firm access exceeds line capacity after a further 10 years (15 years from the start: 450MW + 15 years ×10MW per year = 600MW).
- A further 100MW, $100m expansion will be prompted in year 15.
- The capacity of the line beyond year 15 is 700MW.
- The forecast firm access will not exceed line capacity before the model's end point (450MW + 20 years ×10MW = 650MW, which is less than 700MW).
- The baseline development scenario cost is calculated as the net present cost of $100m in year 5 + the net present cost of $100m in year 15 = $86m.

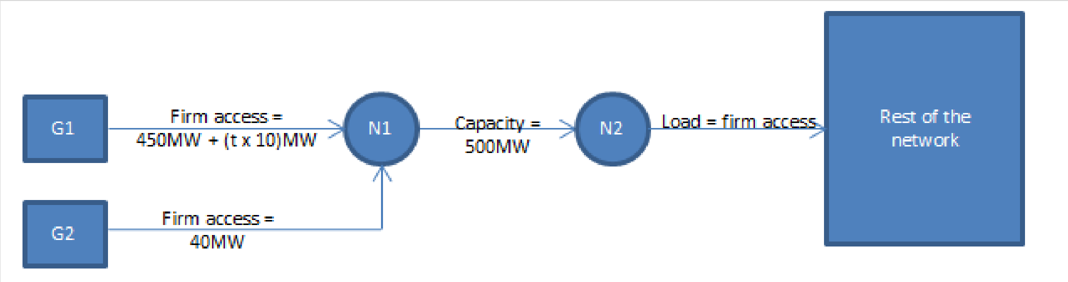
3.3.2 The cost of the adjusted network development scenario

The cost of the adjusted network development scenario is calculated using an identical method to that of the baseline network development scenario. The difference in the costs between the baseline and adjusted scenarios is therefore solely the result of different inputs with regard to the amount, timing and location of firm access.

Firm access requested in the adjusted network scenario would prompt lines to reach capacity more quickly than they were forecast to do in the baseline network scenario. This, in turn, would result in higher and/or earlier costs, which will result in higher net present costs.

Box 3.2: Worked example: Adjusted network development scenario cost

Continuing on the example from above, generator 2 makes a 40MW firm access request at node 1 for 20 years, starting immediately.



This brings forward the timing of the two expansions forecast in the baseline by four years each. Capacity is now reached in year 1 (450MW + 40MW + 1 year ×10MW per year = 500MW) and year 11 (450MW + 40MW + 11 years ×10MW per year = 600MW).

The adjusted development scenario cost is calculated as the net present cost of $100m in year 1 + the net present cost of $100m in year 11 = $126m.

3.3.3 Calculating the LRIC price

The LRIC price is then calculated as the difference between the net present cost of the baseline and adjusted network scenarios. That is, the access price is the difference between these two costs, summed over all transmission elements in the network.[35]

Box 3.3: Worked example: LRIC price

Continuing on the example from above, the LRIC price is calculated as the difference between the net present cost of the two scenarios: $126m - $86m = $40m.

3.4 Limitations with the prototype pricing model

In developing this prototype, the Commission circulated an earlier version of the model to the TNSPs in the NEM for their review.[36]

TNSPs identified some errors in the coding of the model, which were rectified by our software consultant. They also noticed several errors or inaccurate assumptions in the input data, which we have corrected. Further, they noted that the model produces a

35 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.

36 That is, Powerlink, TransGrid, AusNet Services, AEMO (as Victorian TNSP), Tas Networks and ElectraNet.

stylised development scenario based on replicating existing transmission lines, whereas actual TNSP expansion plans reflecting the most economic development can be significantly different. This is particularly so in the short term, where there is a better understanding of likely transmission limitations and expansions than in the long term. However, despite the above, the TNSPs generally consider that the model is producing prices with the intended relativities; ie, prices are high in areas that are far away or congested, and low in areas that are closer or have lots of spare capacity. How cost reflective the prices generated by the model would be is likely to be heavily influenced by forecast demand assumptions.

We have also had the model reviewed at a high-level by an independent consultant (EMCa).[37] The consultant's report has been published alongside this supplementary report. In summary the consultant concluded that while the model produces prices with the intended relativities, the quantum of the prices may not reflect incremental transmission costs. It said some enhancements could be made - with the most important enhancement to have more realistic cost assumptions.

Therefore, the prototype version that is available to stakeholders incorporates some feedback we have received from these parties. Despite this review by other parties, we consider that stakeholder feedback on the prototype may identify any remaining errors in the coding, as well as identify further improvements or refinements that could be made.

The Commission considers that there are four main limitations with the prototype pricing model in its current form. We discuss these below, and set out how we are planning to address these limitations, and areas where stakeholder feedback would be valuable.

3.4.1 Improved cost inputs

Currently, the model only categorises assets based on the following criteria:

- asset type (line or transformer);
- size (low, medium or high); and
- voltage.

Therefore, there is only a high-level disaggregation of costing inputs. This may impact on the accuracy of the LRIC prices produced. However, we do not have sufficient information as to say whether the prices would be higher or lower as a result of this limitation.

We appreciate that cost assumptions currently in the prototype can be improved in order to become more granular. The Commission is considering engaging a consultant

37 We asked EMCa to understand a limited scope review focussing on priority aspects of the model, and to suggest improvements to the model which could be made in order to improve the accuracy of outputs and also the useability of the model.

to provide us with more accurate costing information to update the prototype pricing model. For example, the model could reflect more categories of asset based on more characteristics (eg, more types of assets, or whether a line is underground or overhead). This would provide more granular costing of assets, and so more accurate costing of the incremental costs of associated with transmission cost expansions.

Related to this, we are also investigating whether the model could be adapted to include some of the TNSPs' short-term planning. This may result in the LRIC pricing model being more accurate in the short term. However, we note that this would require substantial changes to the stylised nature of the prototype pricing model. Indeed, including these short-term plans would only be appropriate if the TNSP plans were also driven by the same assumptions (eg, demand forecasts) as those used in the LRIC model. If the same assumptions were not used, then it is likely that including the TNSP plans would not add to the accuracy of LRIC.

3.4.2 Inclusion of replacement expenditure

As noted in chapter 2 when planning their network, TNSPs would consider (amongst other things): augmenting the network, replacing an asset, replacing an asset with something smaller, or not replacing the asset at all. Therefore, we consider it is important that replacement costs should be considered in LRIC, and so generators can signal through their access decision which parts of the network are valued.

Replacement costs have not yet been included in the prototype pricing model that has been published alongside this report.

In a low growth scenario, replacement might be deferred for a long period in the baseline (indeed, in a declining growth scenario, assets might never be replaced). On the other hand, there may be only a limited need for expansions not related to replacement. The NPV of advancing replacement in the adjusted scenario is therefore likely to be higher, both in absolute terms and also relative to the incremental NPV expansions unrelated to replacement. Therefore, modelling of finite asset life may be important to send appropriate pricing signals to generators considering procuring firm access.[38]

Currently in the NEM, actual and planned replacement costs presented in TNSP planning reports are high relative to expansion costs, reflecting low forecast demand growth. This would suggest that replacement costs, if modelled, might contribute materially to LRIC.

38 It is worth noting that in a high growth scenario, replacement would be deferred for only a short period, if at all, in the baseline. Thus, the NPV of advancing replacement in the adjusted scenario is likely to be low. In such a scenario, incorporating finite asset life into the pricing model might not materially affect pricing outcomes.

Impact on pricing prototype model

We propose that stylised asset replacement could be included in the pricing prototype model, if it was modelled as follows:[39]

- Expected end-of-life for every network asset is determined by TNSPs, where end-of-life is within the pricing model's forecasting horizon.
- This data is incorporated as an input to the model.
- At the end-of-life of a network asset, the corresponding transmission capacity steps down, as presented in Figure 2.3 above.
- The usual logic for modelled transmission expansion is then applied: ie expansion occurs as soon as forecast flow exceeds forecast capacity. The model would not distinguish between expansion prompted by end of asset life and expansion prompted by flow growth.

We anticipate that provided the AEMC can obtain end-of-life values for every network asset, it would be relatively easy to modify the pricing prototype model to incorporate this proposal. As noted above, we consider that including replacement costs would likely increase LRIC prices.

We are particularly interested in hearing stakeholders' views on:

- whether the inclusion of replacement expenditure into the LRIC pricing method is considered appropriate;
- how asset lives can be modelled; and
- what confidentiality, if any, concerns arise in the upfront, or ongoing, provision of end-of-life values.

3.4.3 Inclusion of stability constraints

The model only includes thermal constraints. Other constraints (eg, stability constraints) have not been included.

While limiting the model to thermal constraints (and excluding other constraints) may not affect the relativities of prices, it may lead to incorrect price signalling on those corridors that are dominated by stability constraints. For example, on the generation corridor between the Latrobe Valley and Melbourne the LRIC is shown to be low since

39 Clearly replacement costs must be predicated on asset life. In practice, asset life may be neither well-defined nor accurately predicted. Asset life depends upon many factors, such as asset design, operating regime, environmental conditions and maintenance activity. Assets approaching their end of life may in some cases be reconditioned to extend life. These real-world complexities and uncertainties are also present in expansion, as well as, replacement planning. The pricing model aims for a stylised representation of these factors, since an approximate estimation of these costs is better than no estimation at all.

there is significant spare thermal capacity. However, in fact, we understand the corridor to be constrained by stability limits. If these were included, the LRIC would likely be higher, and more cost reflective of what a TNSP would actually plan to do in this area of the network.

We are currently investigating ways in which the LRIC model could reasonably overcome this issue, and we welcome stakeholder feedback on this issue.

3.4.4 Tasmanian prices not reported

Due to the way it is currently specified, the prototype pricing model is not producing representative prices for Tasmania.[40]

As noted in section 3.2.2, one input into calculating access prices is the transitional access allocation. In our First Interim Report we set out our proposed method for the initial allocation of transitional access to generators, and provided an overview of the results on our first tests of doing so. These results are assumed to apply in our prototype model.

In modelling transitional access for Tasmania, large variances in transitional access are observed across the individual generators. This is due to a number of unique characteristics of the Tasmanian power system, and further work is required to determine initial access allocations for Tasmania. The average initial Tasmanian access amount was 63 per cent of installed capacity. The prototype pricing model was found to not produce representative access prices when initial access amounts are substantially below forecast load.[41]

Accordingly, we do not report prices for Tasmania in this section. We are investigating potential ways that the prototype model could be adapted to produce prices for Tasmania.

3.5 Dissemination of the prototype model and user guide

As stated above, one of our aims in developing a pricing prototype is to allow stakeholders to better understand the impacts of access pricing on their business. Accordingly, the prototype pricing model is available to any interested stakeholders. There is also a user guide available to stakeholders, which accompanies the prototype model.

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40 We also received feedback on this aspect from TasNetworks. It noted that there are a number of limitations with the model when it is applied to Tasmania. These are largely driven by a number of unique aspects of the Tasmanian power system: the frequent use of special protection schemes to allow the network to be loaded beyond "N-1" ratings; Tasmania's peak demand occurs in winter whilst network thermal constraints generally occur during summer; and the uncertainties regarding initial access allocation.

41 Further details are available in our First Interim Report. See: AEMC, *First Interim Report*, July 2014, p. 151.

To obtain a copy of the prototype model, please contact Victoria Mollard at victoria.mollard@aemc.gov.au, or on (02) 8296 7800.

3.6 Consultation questions

The AEMC would be interested in receiving feedback on the prototype pricing model discussed in this chapter. We are particularly interested in hearing stakeholders' views on:

- the ease of usability of the model, and whether there are additional features that could make the model easier to use;
- the inputs, and assumptions that have been used in the model;
- the outputs of the model, including whether it could be possible to improve the model to produces prices that are reflective of incremental transmission costs;
- should this model be progressed, how much transparency on the inputs and assumptions is required to understand the numbers; and
- how frequently should the inputs and assumptions into the model be reviewed.

4 Results from the pricing prototype

Summary of chapter

We have used the prototype pricing model to produce indicative LRIC prices for access at different locations across the network. The results produced by the LRIC pricing prototype model display LRIC prices that have characteristics that are consistent with cost reflectivity:

- the total price paid for firm access always increases as the access amount increases; but
- the rate of increase in this cost varies, depending on the level of spare capacity between the location and the regional reference node.

Therefore, the prices produced demonstrate the right relativities, with higher prices for access more remote from the regional reference node or for access in more congested areas. However, we are not yet confident that the model produces prices whose quantum reflects incremental transmission costs. We are publishing the model to seek stakeholder input on how the model currently works. It should not be used as a guide as to what generators may pay if optional firm access was implemented.

We have also undertaken sensitivity analysis on a number of variables in the model. This has shown that the indicative LRIC prices are not particularly sensitive to assumptions around the long-term line flow growth rates, or the discount rate used to calculate the net present value. However, the LRIC prices are somewhat sensitive to assumptions about changes to firm access and load growth in the short-term.

4.1 Introduction

Chapter 3 discussed the development of the prototype pricing model. This model can be used to calculate an indicative LRIC price for access from a particular location, for a particular length of time, and a particular amount of access.

This chapter presents and discusses access prices produced by the prototype pricing model.

First, it sets out the key inputs that are used throughout this chapter (section 4.2). It then sets out:

- access prices, and how these vary by the three key variants of the access price (location, length of access arrangement, and amount of firm access requested) (section 4.3); and
- sensitivity analysis on a number of key variables within the prototype pricing model (section 4.4).

Appendix B.2 provides a comparison of prices produced under the LRIC method with the other two pricing methods discussed in the Transmission Frameworks Review, namely deep connection charges and long run marginal cost; while appendix D provides further analysis of the access prices produced by the prototype model and sensitivity analysis.

4.2 Parameters used throughout this chapter

In calculating the access prices presented in the rest of this chapter, the following parameters were used:[42]

- a 400 MW firm access request;
- a firm access request of 20 years (2014-2033); and
- all other inputs and assumptions as stated in Table 3.1.

These inputs are pre-loaded into the version of the prototype pricing model available for stakeholders. However, all these inputs can be changed by users when using the model.

4.3 Access prices produced by the prototype

4.3.1 Indicative access prices by location

Locational LRIC prices

Figures 4.1 to 4.4 sets out prices by location when the pricing model is run using the above inputs.[43]

The expected characteristics of the LRIC pricing method include that, all other things being equal:

- generators locating remotely from the regional reference node and from other major load centres would pay a higher price than generators locating closer to the regional reference node or load centre, due to the higher cost of longer transmission lines to provide access; 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 otherwise be needed for some time.

42 Where a parameter is varied in order to establish the relationship between that parameter and price, all other parameters were fixed at the above values.

43 The maps below plot all generator nodes in the network, but only high-voltage lines.

These trends are evident in the figures below, specifically:

- generators that seek access at a location remote from the regional reference node (such as far North Queensland, and on the Eyre Peninsula) would face higher access prices than those generators locating closer to the regional reference node, (such as at Sydney and Melbourne), all else being equal; and
- generators that seek access at a location where there is limited spare transmission capacity (such as around the Snowy Mountains), would pay a higher price than generators locating where there is plenty of spare transmission capacity (such as on the Central Coast of NSW).

However, since both of these characteristics (distance from regional reference node, and level of spare capacity) affect the level of the LRIC it can be difficult to discern which characteristic most significantly influences the LRIC at a particular location.

Figure 4.1 Map of indicative LRIC for Queensland

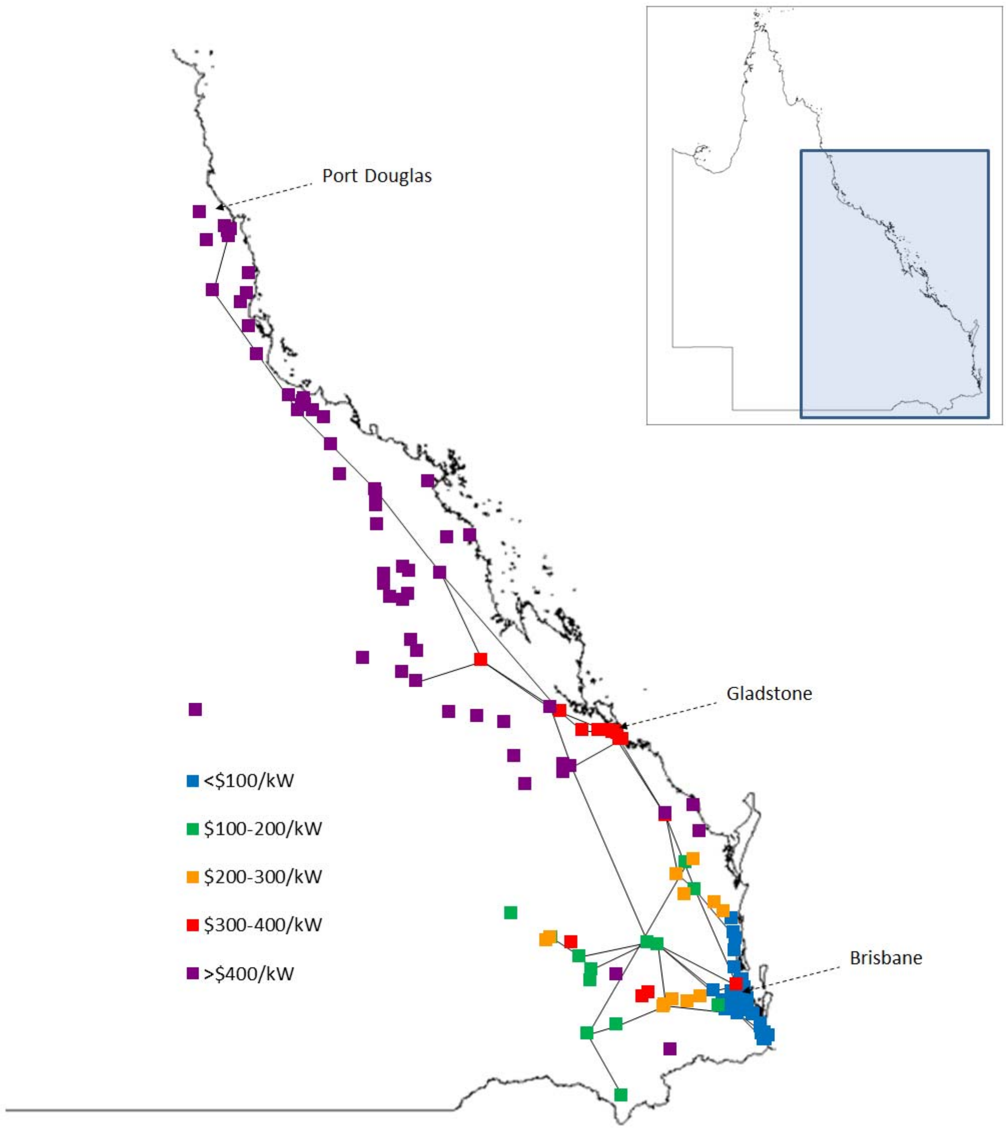


Figure 4.2 Map of indicative LRIC for NSW

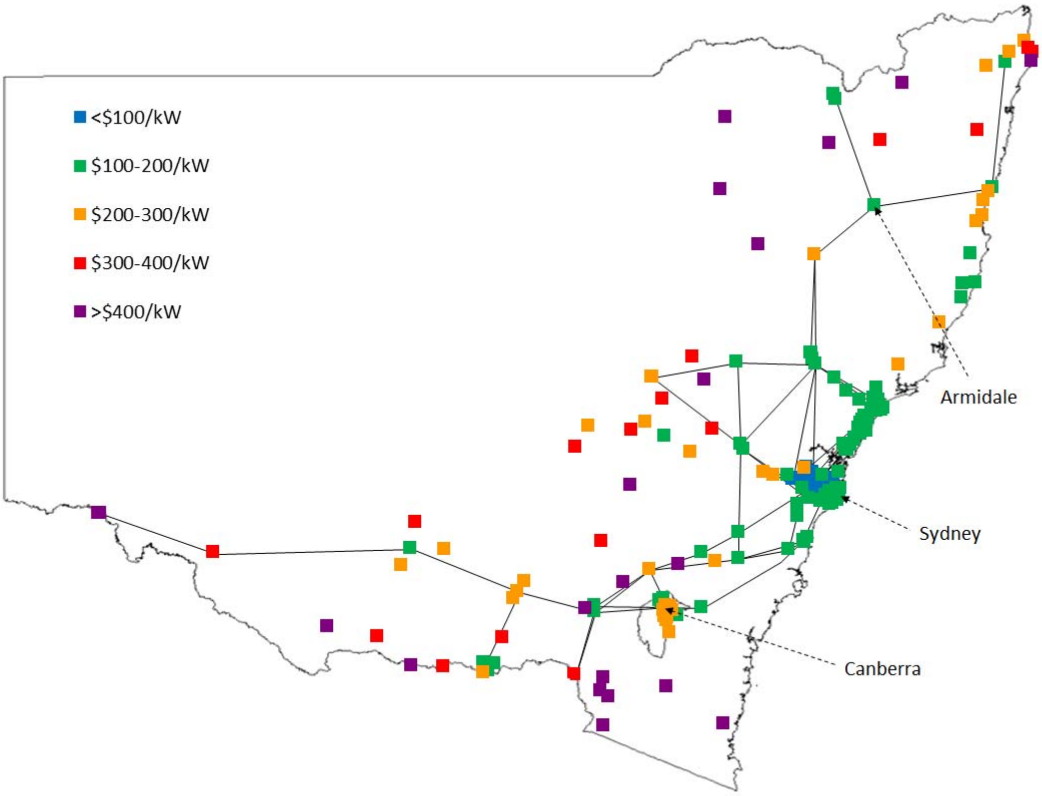


Figure 4.3 Map of indicative LRIC prices for Victoria

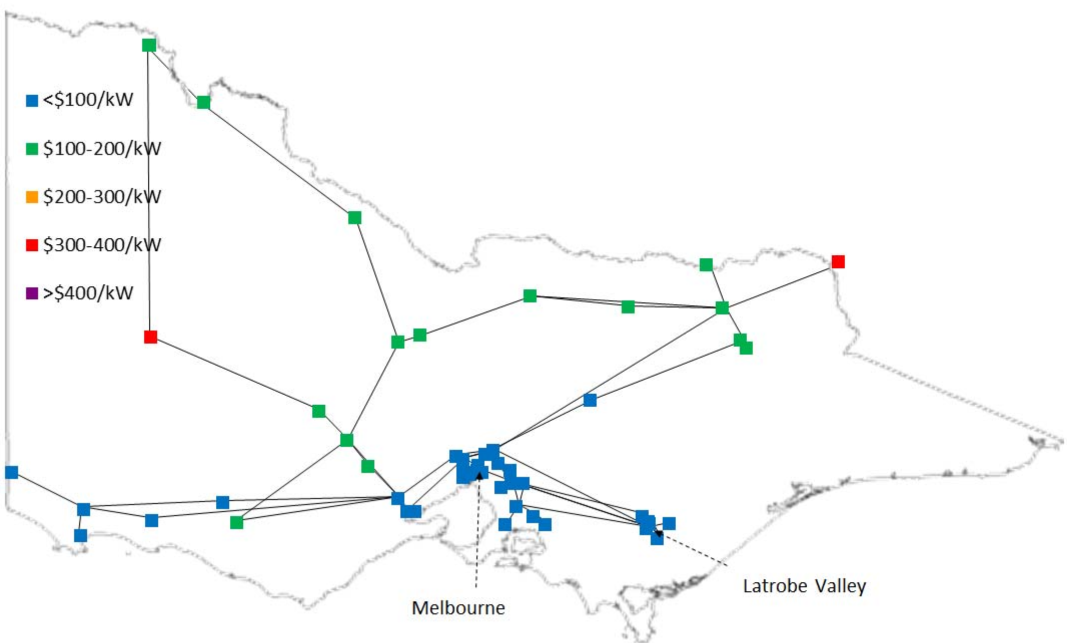
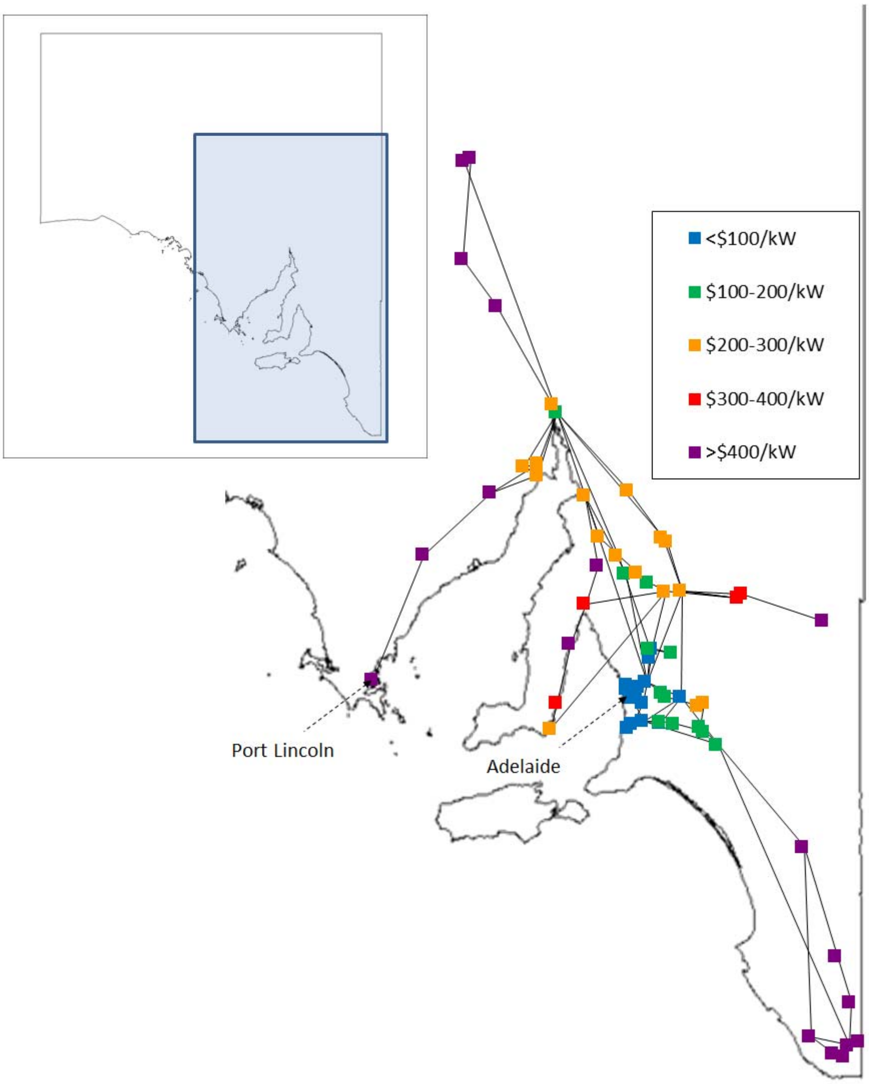


Figure 4.4 Map of indicative LRIC for South Australia



LRIC/LRMC value

One way we can more clearly understand these results is by considering the relationship between the LRIC and the LRMC. Unlike LRIC, the LRMC pricing method does not take account of spare capacity on the network: LRMC charges a constant unit cost regardless of incremental usage, based on the average unit cost of capacity expansion.[44] Therefore, under the LRMC method, those generators at locations remote from the regional reference node would pay higher prices than those generators locating closer, regardless of the level of spare capacity.

44 It is this failure to take account of spare capacity that makes LRMC less suited to optional firm access than LRIC. This is discussed more in appendix B.

Figures 4.5 to 4.8 present a map of different locations around the network, showing the ratio between the LRIC and LRMC. This ratio represents a measure of the spare capacity of the network (after transitional access has been serviced),[45] and so is useful in that it disaggregates this characteristic from distance, and so we can see what influences LRIC price more in particular locations. A low ratio implies that LRIC and LRMC are similar, ie, that distance, not scarce capacity is the primary driver of LRIC in that location. Conversely, a high ratio implies that scarce capacity is the primary driver on LRIC in that location.

For example, in Northern Queensland, the LRIC is high. However, the LRIC/LRMC is relatively low. This reflects that the total cost of an upgrade is high, due to the location's distance from the regional reference node, as opposed to having low spare capacity on the network. Conversely, the LRIC/LRMC around the Southern NSW Snowy region is relatively high. This reflects that there is relatively little spare capacity on the network in this location, leading to a higher LRIC/LRMC value (despite being relatively close to the regional reference node).

Overall we consider that the model is likely to be producing LRIC values that are consistent with the degree of spare capacity. We are undertaking further analysis on these conclusions.

45 Since we have used the transitional access values as an input into the prototype pricing model, this "spare capacity" is the residual after the transitional access has been serviced.

Figure 4.5 Ratio of indicative LRIC:LRMC for Queensland

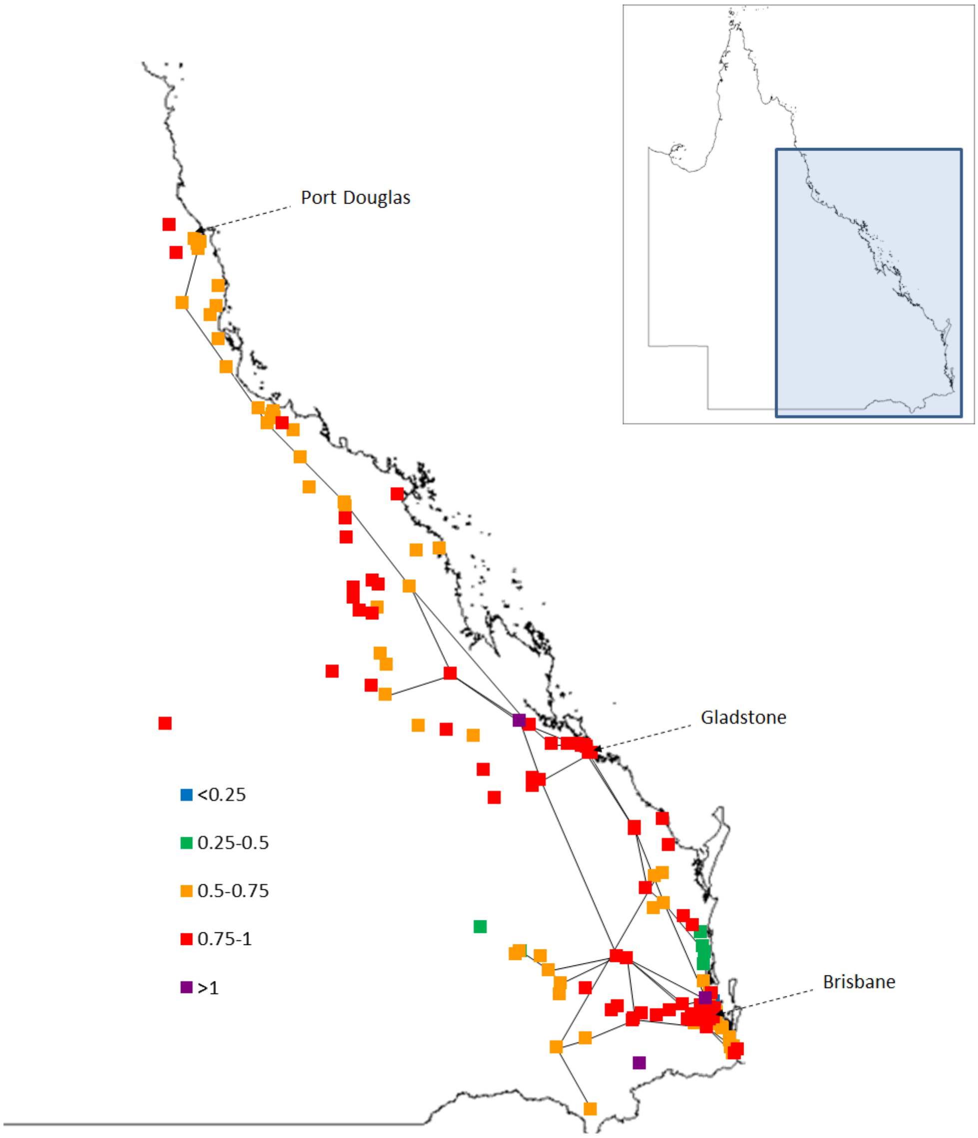


Figure 4.6 Ratio of indicative LRIC:LRMC for NSW

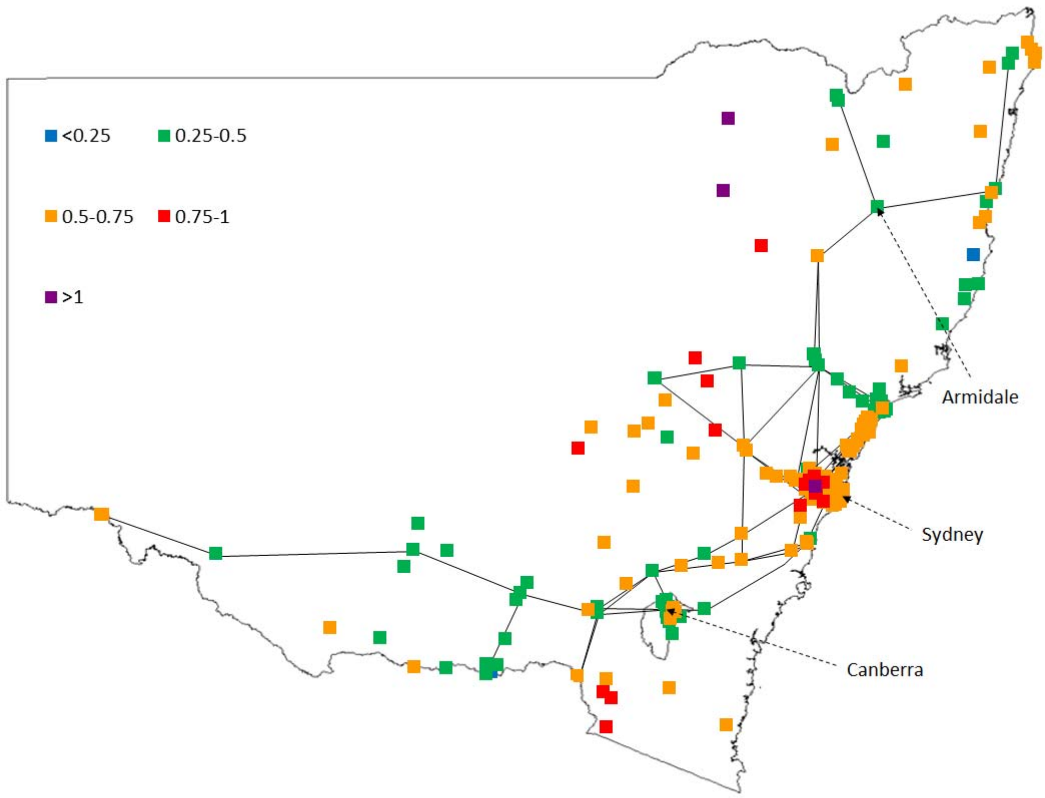


Figure 4.7 Ratio of indicative LRIC:LRMC for Victoria

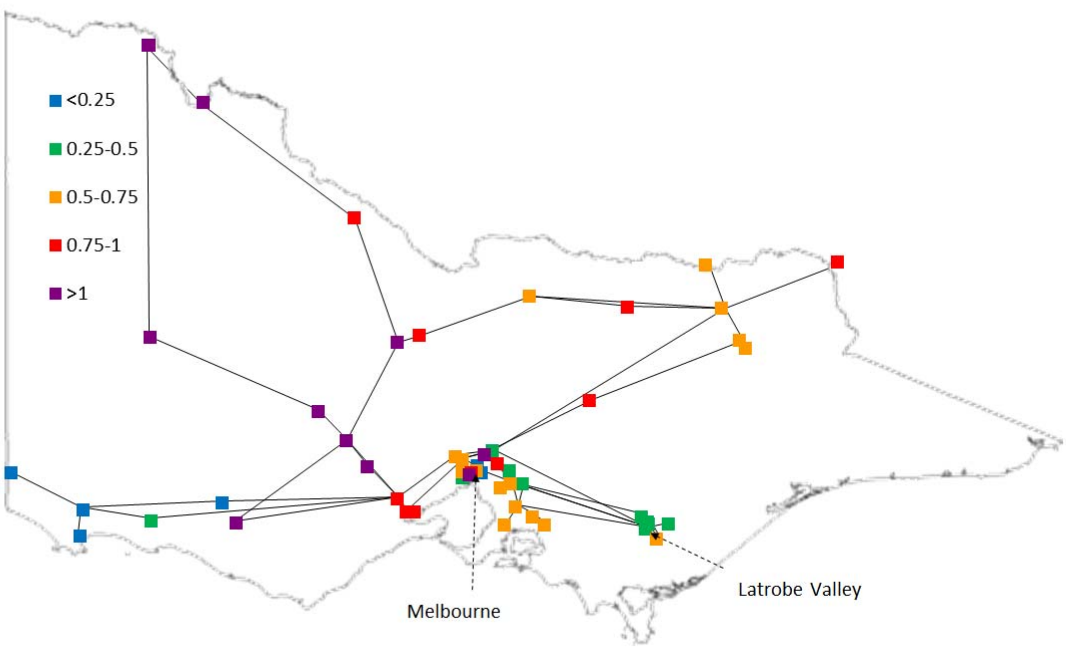
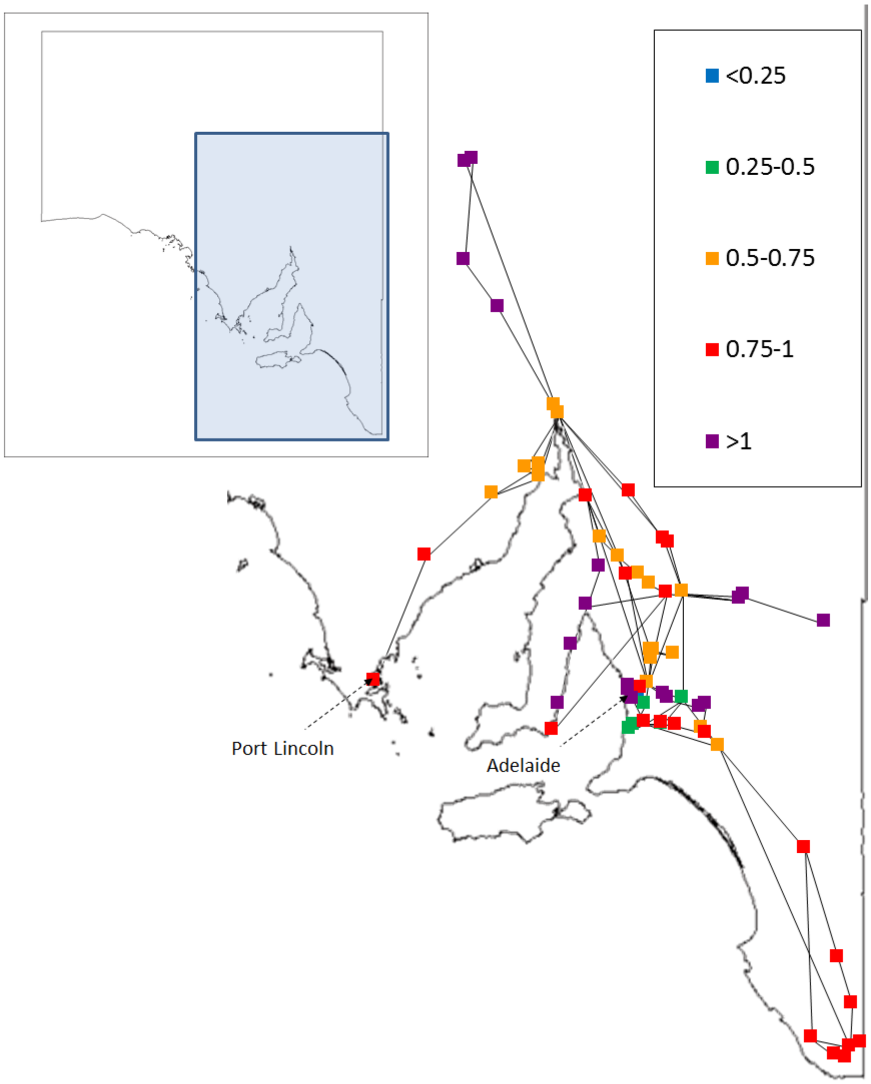


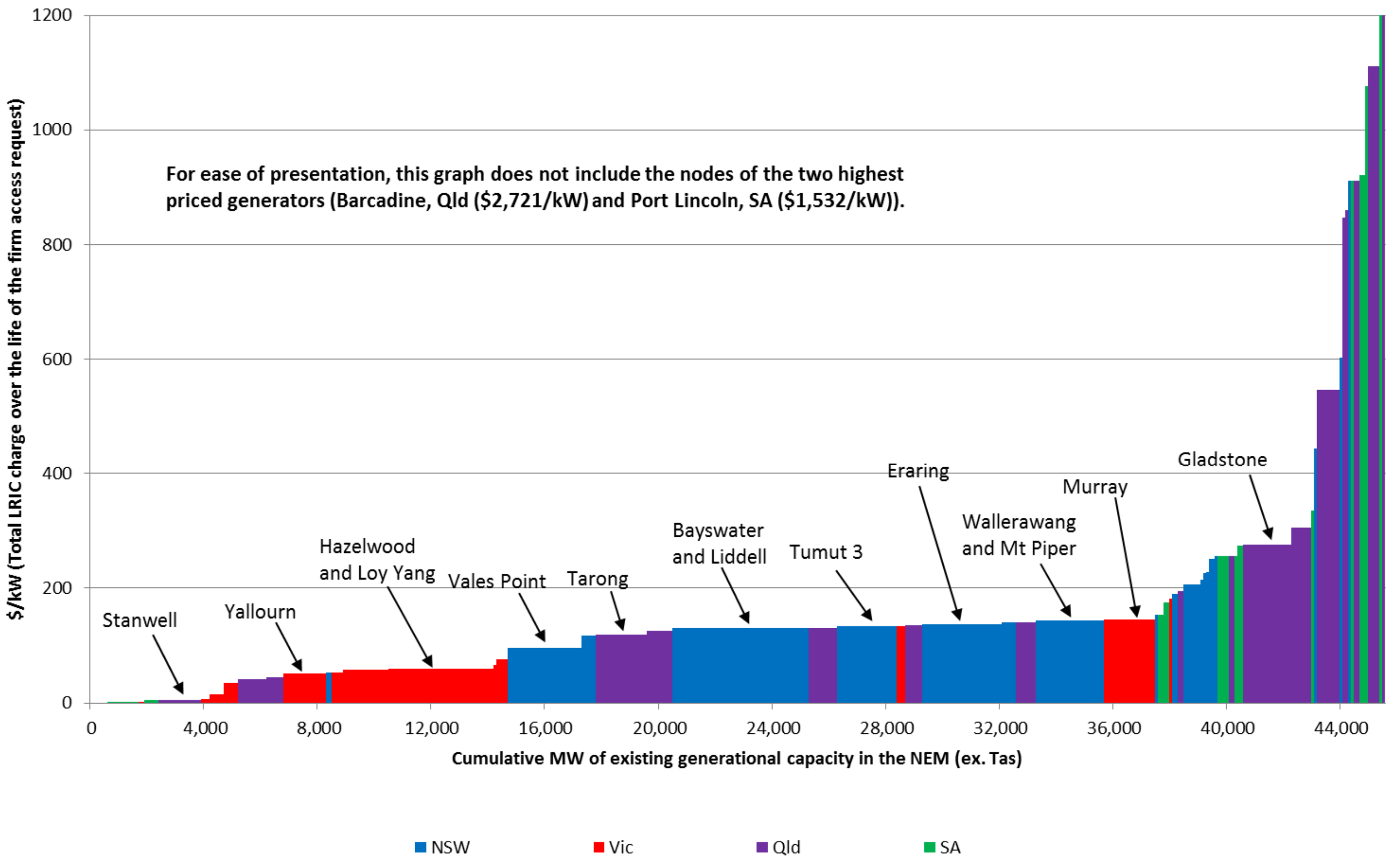
Figure 4.8 Ratio of indicative LRIC:LRMC for South Australia



Distribution of access prices

The above maps also demonstrate a large variety in price across locations. This is further illustrated by Figure 4.9, which sets out the indicative price of firm access at each node in the NEM where there is currently a generator. The horizontal axis represents the amount of cumulative generation capacity in the NEM (excluding Tasmania).

Figure 4.9 Distribution of access prices in the NEM for a 400MW access request for 20 years, by cumulative generator capacity and region (excluding Tasmania)



This demonstrates the large variety in access prices across locations, from \$0/kW (for generators connected at the regional reference node) to \$2,721/kW for Barcaldine in Central Queensland, which is very remote from the regional reference node and has a relatively low amount of spare capacity. Further, these prices vary substantially even within regions of the NEM.

Locations comprising half of the generation capacity (22,500MW) have an indicative firm access price of less than \$130/kW, about a twentieth of the maximum LRIC price at Barcaldine. Approximately eighty per cent of current generation locations have LRIC prices of less than \$150/kW. It is worth noting that an indicative cost of a new wind generator is approximately \$2,500/kW (with an expected life of 20 years).[46] Therefore, for an median access price of \$130/kW, access is expected to cost around five per cent of the capital cost of a wind farm.[47]

In summary, the prototype pricing model is producing LRIC prices that are reflective of LRIC's intended characteristics with respect to location. It produces locational signals reflecting both distance and spare capacity on the network, and so the cost of providing firm access. By exposing generators to the long-term transmission costs associated with their locational decision, it would help to co-optimise generation and transmission investment, by promoting the efficient utilisation of the existing spare capacity on the network.[48]

4.3.2 Indicative access prices by access amount

Given the above analysis which demonstrates the wide variability in price across locations, we consider that analysis of *average* prices is of limited value. Indeed, a key intended feature of the LRIC methodology is that it creates locational signals for generators, which averages do not take into account.

As a result, we have not undertaken analysis on average prices, either across the NEM or on a regional basis. Instead, we have selected a number of nodes that we consider may be of interest to current or future generators and assessed how the prices at these nodes vary by access amount.

In this chapter we present this analysis only for locations in Victoria. Victorian was chosen since the trends observed are consistent with those observed in the other regions. Appendix D presents the results for the other regions. These Victorian locations are chosen because they appear to be likely places in the network where future generators may locate (eg, Terang in Central Victoria since it is a good location for wind).

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46 See: AEMO's planning assumptions available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

47 If the windfarm chooses to be fully firm, which we consider may be unlikely. We also note that analysis of average prices is of limited value.

48 We note that a deep connection charging method also provides signals that reflect both distance and spare capacity on the network. However, a deep connection charging method does not reflect the *value* of spare capacity. This is discussed further in appendix B.

The nodes we have selected for analysis are:

Table 4.1 Nodes selected for analysis

Node reference	Name	Region	Zone (as specified in the NTNDP)
3TER220	Terang	Victoria	Central Victoria
3MRT500	Mortlake	Victoria	Melbourne
3MUR330	Murray	Victoria	Northern Victoria
3BAL220	Ballarat	Victoria	Central Victoria
3LYB500	Loy Yang	Victoria	Latrobe Valley

Indicative prices are presented below, by region, on a $/kW basis.

Figure 4.10 Access prices, by access amount, selected Victorian locations

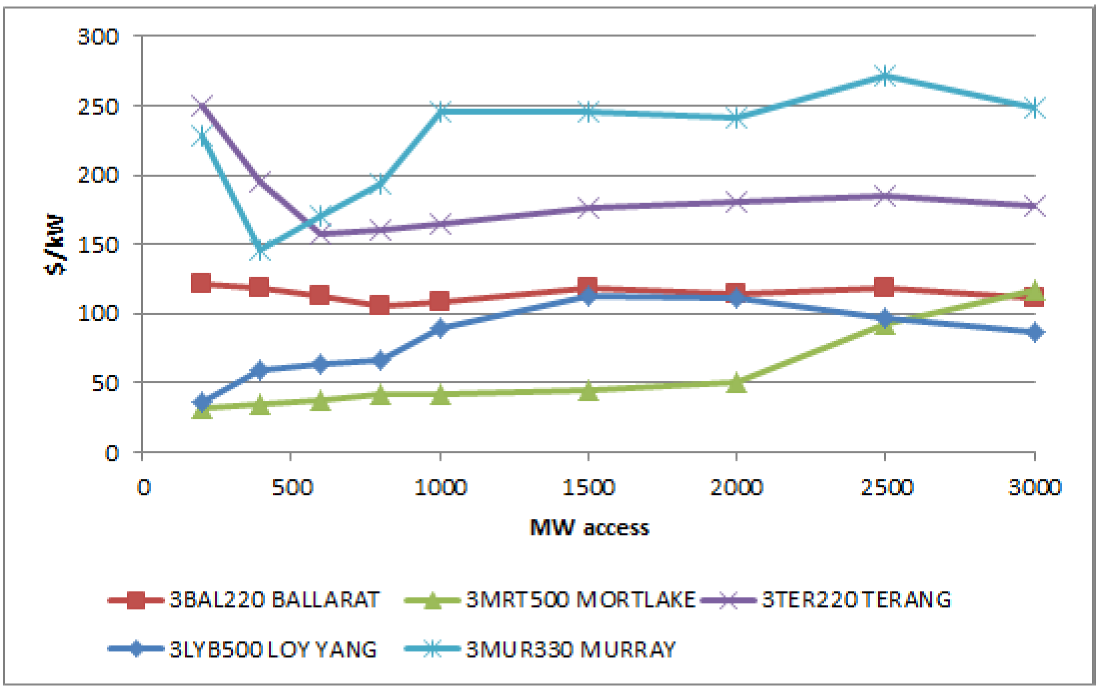
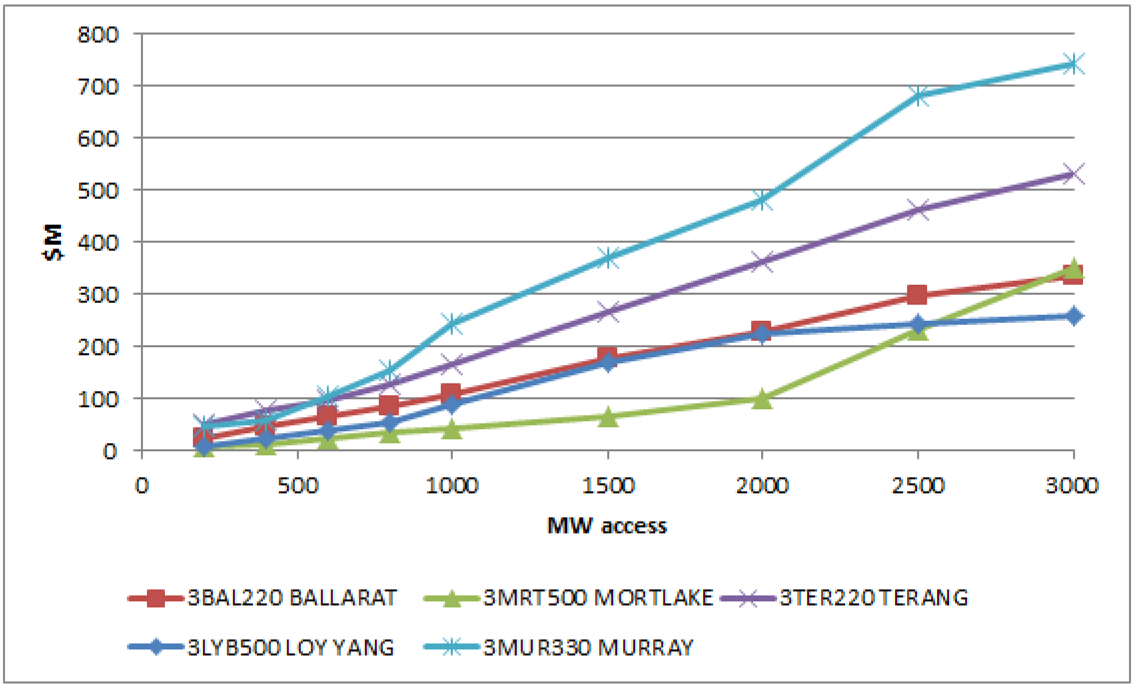


Figure 4.10 demonstrates that there is sometimes an upwards trend in price per MW of access. This trend is since larger amounts of firm access are more likely than smaller amounts to trigger expansions. This is because more spare capacity would be "used up" by the access request.

However, there are also sometimes downward movements in price as access amounts increase, most notably for the Murray node in Victoria between 200MW and 400MW of access. We consider that this is since where an expansion on a line occurs, the line would have higher total capacity than before the expansion (ie, spare capacity is created). This reduces the cost, per kW, of subsequent access requests. An expansion has been triggered by the access request at the Murray node.

While there may be variability in how prices differ by the amount of access requested, the total amount paid for access always increases as more access is requested. This is demonstrated in Figure 4.11 below. It is never cheaper, overall, for a generator to request a greater amount of firm access. This is appropriate.

Figure 4.11 Total access payment, selected Victorian locations



Note that although the total cost for Murray does not always increase at the same rate as the access request increases, it does always increase.

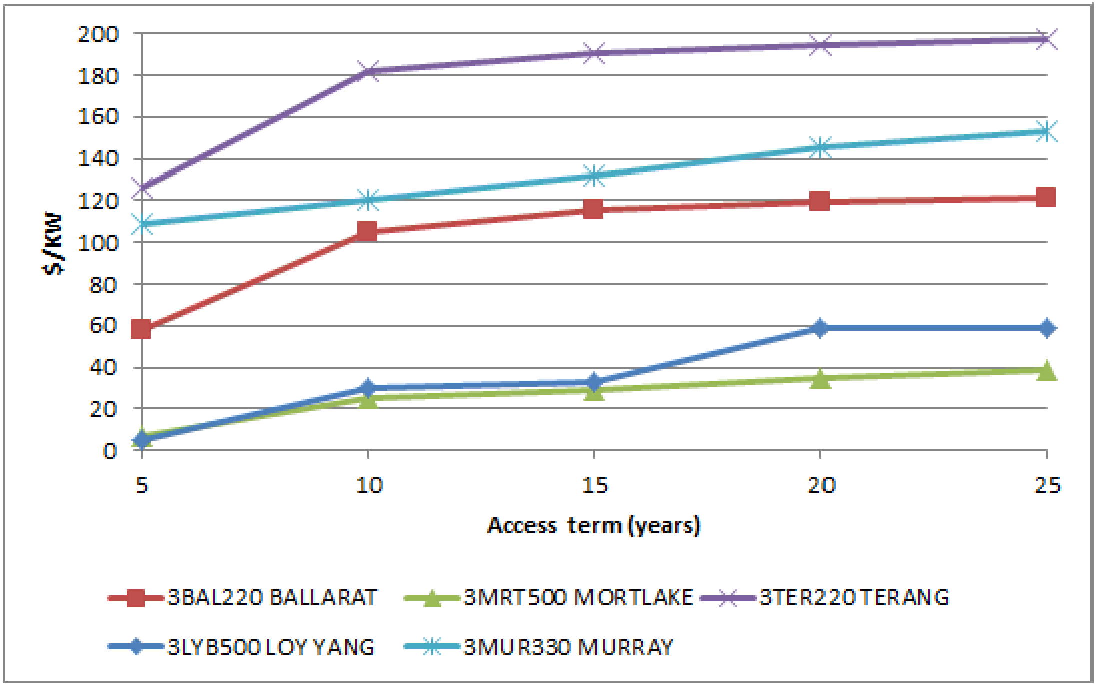
In summary, the results produced by the LRIC pricing prototype model displays LRIC prices that have characteristics that are consistent with cost reflectivity:

- since the total price paid for firm access always increases as the access amount increases; but
- the rate of increase in this cost varies, likely depending on the level of spare capacity between the location and the regional reference node (as demonstrated by the consistently upward but non-linear trends in Figure 4.11).

4.3.3 Indicative access prices by access term

This section provides an analysis of the relationship of access term (in years) to price. Indicative prices are presented below on a $/kW basis. As with section 4.3.2, we have only presented the analysis for the selected Victorian nodes, with other analysis included in appendix D.

Figure 4.12 Access price for 400MW of access, by access term, selected Victorian locations



In Figure 4.12, access price per kW always increases as the access term increases.[49]

However, the rate of increase is not the same across locations. For example, at Terang, there is a significant decrease in rate of increase in price where the access term is greater than ten years.

We consider that these results reflect the situations where:

- if the access term ends immediately prior to a required baseline expansion, then the access request does not affect the timing of the expansion and so there are no cost in LRIC associated with advancing that expansion; while
- if an access term ends immediately after a required expansion, then the access request would affect the timing of the expansion, and so there would be costs in LRIC associated with advancing that expansion.

Generators may seek to vary the length of their access to receive lower prices, eg, by requesting an access term that ends just prior to a planned expansion occurring. However, access prices are calculated as the difference in net present costs between the baseline and adjusted development scenarios across the *whole network*, as opposed to just on an *individual* line. For those access requests which increase flows across multiple lines (eg, where locations are some distance away from the regional reference node), it is likely (in most situations) to be difficult to significantly influence the price by

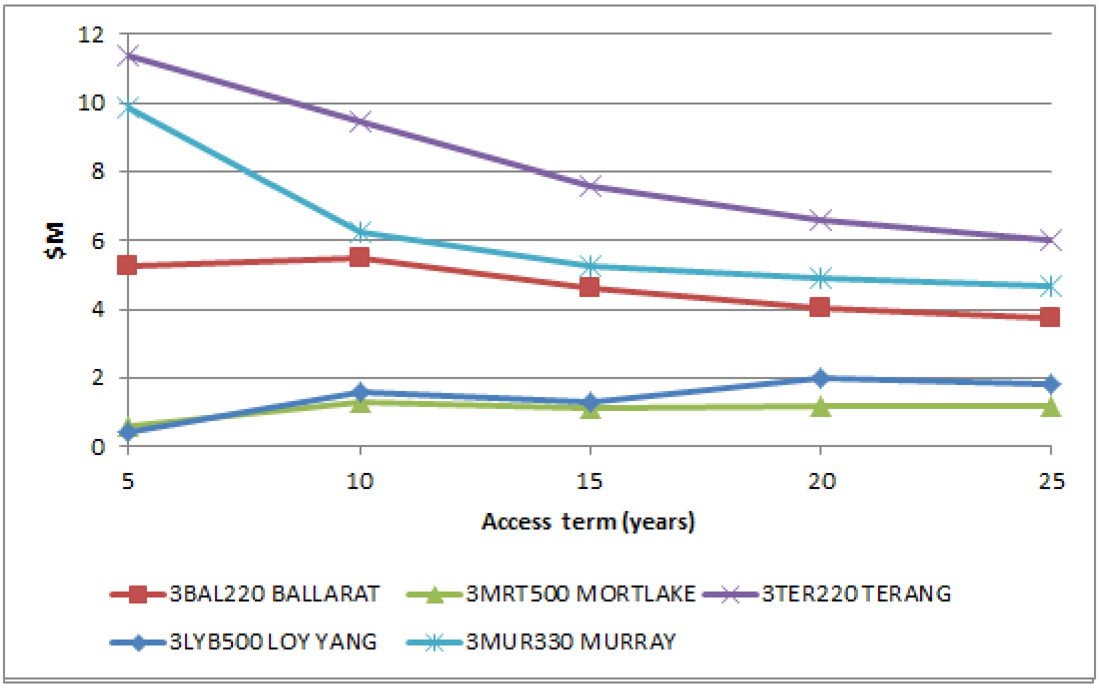
49 The total access charge (or total access price) also increases given that the access amount is fixed in this analysis at 400MW.

varying the access term. A marginal change in access term would likely only avoid the cost associated with one particular line.

Figure 4.13 shows the indicative annual payment that a generator would make for a given access request length (assuming a fixed annual payment that, in net present value, is equal to the calculated access charge).

This demonstrates that in most cases, the annual payment decreases with an increasing length of the firm access request, even as the total payment made over the life of the firm access request increases, due to the length of time over which the annual payments are being made. However, in some cases, such as Loy Yang, the cost of access per year increases as access term increases. This is because the cost per kW of access has increased by a significant proportion as the access term has increased (refer to Figure 4.12), meaning that the generator would pay more on an annual basis (and, as the access request is longer, also for more time).

Figure 4.13 Total annual access payment, varying by access term, Victoria



4.4 Sensitivity testing

We undertook sensitivity analysis on a number of variables in the model:

- assumed annual growth in line flow, in the long term;
- assumed annual growth of firm access and load, in the short term; and
- the discount rate used in the NPV calculation (ie, the weighted average cost of capital (WACC)).

The trend in average prices against these variables is demonstrated and explained below in respect of each of the regions in the NEM (excluding Tasmania) and also the average of the NEM (excluding Tasmania).

4.4.1 Sensitivity to change in line flow, in the long term

As described in section 3.2.2 beyond the forecasting horizon[50] in the model (ten years) a fixed MW annual line growth is applied to each line in the model. Our sensitivity testing shows that the impact of long-term flow growth on price is not strong.

As explained in Appendix D line flow growth has two competing effects on price:

- Higher long-term line flow growth would attribute a higher value to any spare capacity that exists on the network currently, since this spare capacity is expected to be soaked up rapidly rather than not being used. So, if an access request causes a reduction in spare capacity (ie, if no expansion is prompted), then the higher value of that spare capacity - under a high growth assumption - would lead to a higher access price.

- Conversely, if the request causes an increase in spare capacity causes an increase in spare capacity (because a lumpy expansion is prompted) then the value of that spare capacity is credited against the cost of expansion. So, a higher growth assumption would lead to a lower access price.

We have used the prototype to assess the overall impact from these two competing effects.

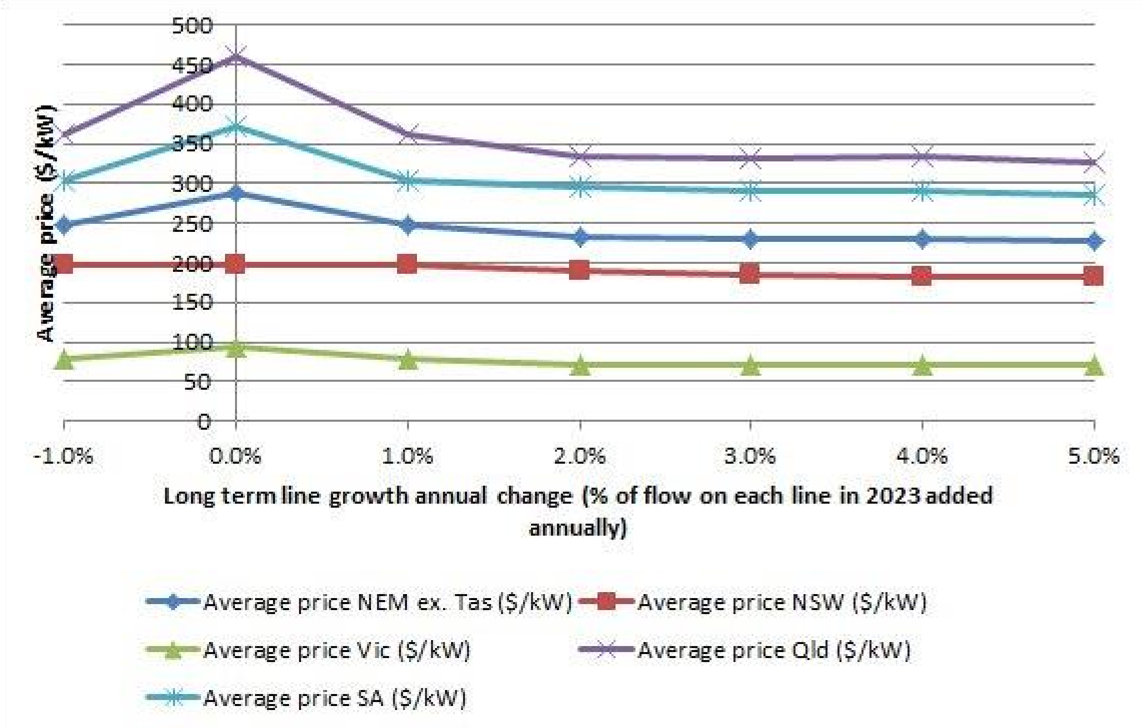
Figure 4.14 illustrates the relationship between the long-term line flow growth and price. It expresses the relationship beyond the short-term horizon, expressed as a percentage of the line flow growth on each line post 2023. It shows that there is generally a slight negative relationship between price and line flow growth, but with some exceptions (eg, for low positive line flow growth rates in NSW, an increase in line growth results in an increase in price). This demonstrates the potential net impacts of the two competing effects described above.

However, the graph indicates that the sensitivity of the access price to long-term flow growth is not strong. On average across the NEM (excluding Tasmania) for each percentage point increase in line growth prices decrease by 1.1 per cent. Although we note that the sensitivity appears greatest around the zero per cent growth change.

This is partly because the long-term flow growth variable only alters development scenarios beyond 2023 (ie, ten years into the future), when discounting is likely to reduce the materiality of the impact of the variable on price. Therefore, the LRIC prices are not particularly sensitive to this particular input assumption.

50 We note that the forecasting horizon in the pricing model (of ten years) is different to the timeframe for the definition of the short-term access product (which was discussed in the First Interim Report. Here, when we refer to the short-term horizon, we refer to this in the context of the pricing model, which is assumed to be ten years.

Figure 4.14 Sensitivity of access prices to long-term line flow growth



4.4.2 Sensitivity to changes in firm access, and load in the short-term

As described in section 3.2.2, two inputs to the model are, for each year up to the defined short-term horizon, the assumed amount of:

- baseline firm access at each node; and
- peak load at each node in the network.

Our analysis shows that access prices are sensitive to these inputs.

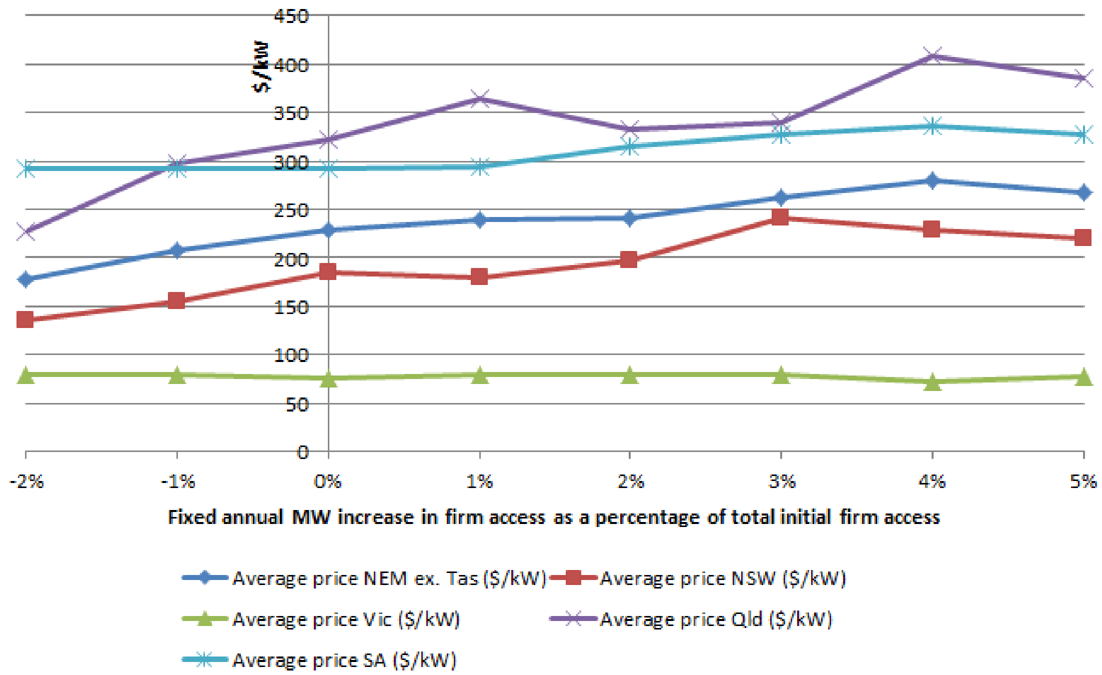
As discussed in the previous section, faster line flow growth can, theoretically, lead to high or lower access prices, due to two competing effects. However, practically, it generally leads to higher access prices.

In the short-term, line flow growth is not set directly, but rather reflects the assumed demand and access growth, driving changes in load flows on the network. Generally, higher access (or lower demand) would lead to higher line flows, although there are exceptions, due to loop-flow effects. Therefore, one would expect that higher growth in access (or lower growth in demand) would generally lead to higher access prices.

Our analysis confirms this expectation.

Figure 4.15 plots price as a function of the annual change in baseline firm access at each location in the network.[51]

Figure 4.15 Sensitivity of access prices to short-term firm access growth



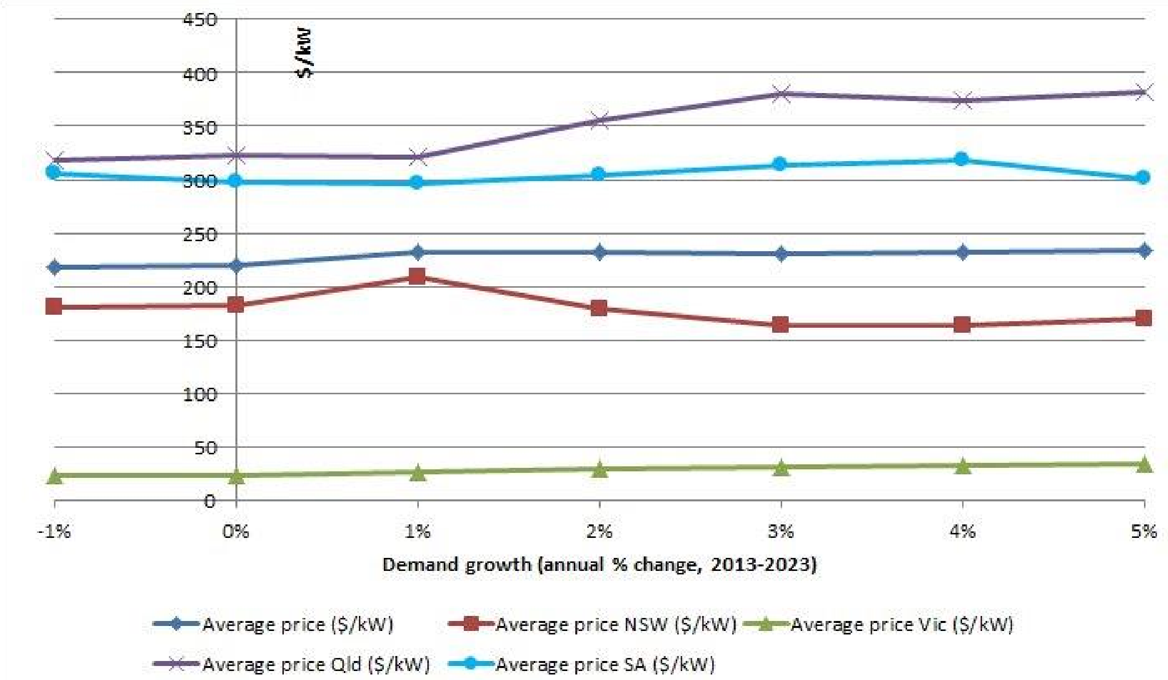
This demonstrates a general upwards trend in price relative to the annual change in firm access within the baseline. This suggests that the access requests does not prompt substantial immediate expansion. However, the relationship is neither smooth nor one-directional, reflecting the complexity in the relationship as discussed above. On average across the NEM (excluding Tasmania) for each percentage point increase in the growth of access, prices increase by six per cent.

Figure 4.16 plots price as a function of the annual change in demand at each location in the network.[52]

51 Within the current design of the model, the annual change in firm access at each node in the network up to the short-term horizon is a fixed MW amount. Figure 4.15 illustrates the sensitivity of price to this fixed MW amount of annual change in firm access. The x-axis represents the annual MW change in access across the region as a percentage of the initial allocation of access across the region. The annual MW change in access across the region is distributed across the nodes in that region in proportion to the current (2013) level of generation capacity in the zone

52 Within the current design of the model, the annual amount of demand at each node is a separate input in the model up to the short-term horizon. Figure 4.16 illustrates the sensitivity of price to an exponential growth in demand at each location. The x-axis represents the annual, year-on-year percentage increase in demand at each location.

Figure 4.16 Sensitivity of access prices to short-term demand growth



Again, the relationship of peak load growth to price is neither smooth nor one-directional. On average across the NEM (excluding Tasmania) for each percentage point increase in demand growth, prices increase by 1.1 per cent.

Results from the prototype have demonstrated that prices are likely to be reasonably sensitive to assumptions for both firm access growth and demand growth. Particularly care would therefore need to be applied to the forecasting of these two variables.

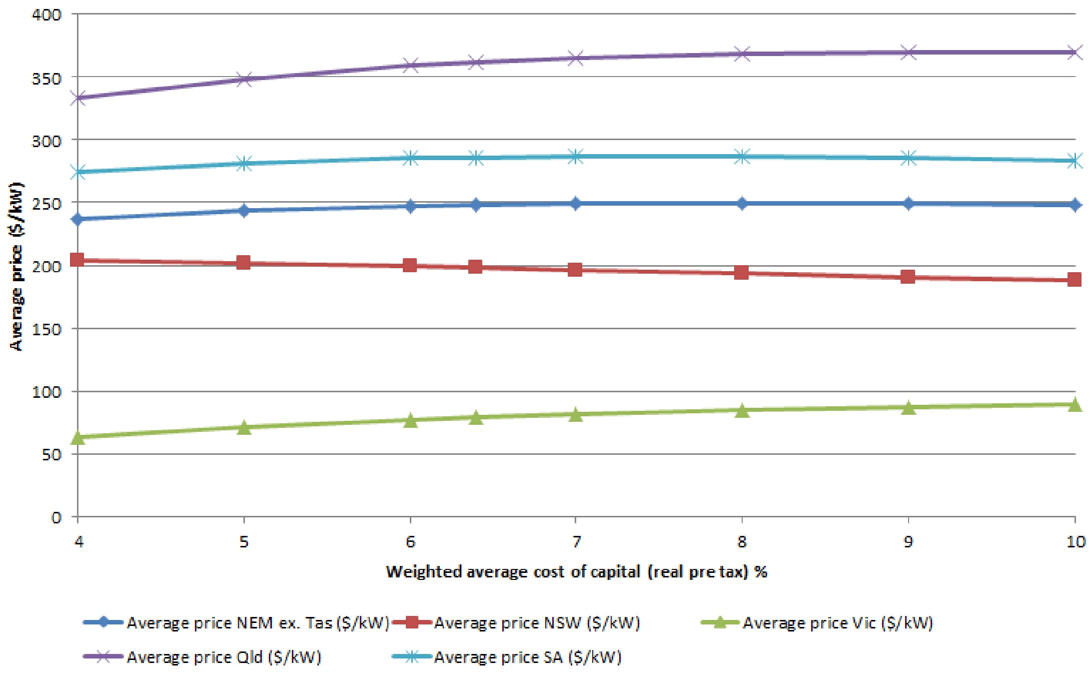
However, we note that firm access growth and load growth are likely to be correlated, ie, higher demand growth is liable to prompt more generation entry and so more growth in access. Holding one assumption constant while altering the other is not necessarily realistic. This correlation, if reflected in the model inputs, may dampen the impact on price (as an identical increase in firm access and load at a node will have no impact on line flows, and hence no impact on price).

4.4.3 Sensitivity to change in the WACC

We tested the sensitivity of the LRIC price to changes to the WACC, with the results outlined in Figure 4.17 below. The results show that, for the input assumptions used, WACC is not strongly correlated to LRIC price.

The LRIC, which represents the cost difference between two development scenarios, is the discounted cost of advancing an expansion. The impact of WACC on price for any individual line therefore depends on both how far in advance the original expansion on that line was, and by how much the expansion is being advanced. The LRIC is then the summation of bring forward costs across all the affected lines. There is therefore no simple relationship of WACC to LRIC.

Figure 4.17 Sensitivity of access prices to WACC



A Our process

A.1 Updating the COAG Energy Council

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

We also update the Energy Market Reform Working Group regularly.[53]

A.2 Reports to be published

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

Table A.1 Review process

Document	Purpose	Date
First Interim Report	To present the assessment framework, and provide a progress update on our work.	Published 24 July 2014
Supplementary Report: Pricing	To provide a progress update on the work we have done to date on pricing[54] since the Transmission Frameworks Review. We will also publish a pricing model prototype for participants to consider.	31 October 2014
Draft Report	To set out: • a detailed design of the optional firm access model; • our draft assessment of the benefits and costs of optional firm access; and • our draft recommendation as to whether or not optional firm access should be implemented.	February 2015
Final Report	To set out: • a detailed design of the optional firm access model; • our final assessment of the benefits and costs of optional firm access; • our final recommendation as to whether or not optional firm access should be implemented, and if so, in what form; and • draft implementation plans (if required) for optional firm access should it be introduced.	By Mid-2015

53 The Energy Market Reform Working Group is a committee of state, territory and Commonwealth officials who manages the COAG Energy Council's overall energy market reform program.

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

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

A.3 Stakeholder engagement

We have been engaging with jurisdictions and key stakeholders - which include market participants, Transmission Network Service Providers (TNSPs), the Australian Energy Regulator (AER), consumer representatives and the COAG Energy Council - in collaboration with AEMO. This engagement has been through our Advisory Panel and Working Group, as well as bilateral meetings.[55]

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

While this is a critical component of the stakeholder engagement we will undertake on this project, there are other opportunities for stakeholders to engage with us. We held a public forum on 14 August 2014 on our First Interim Report.

We will hold two workshops on this supplementary report. The workshops will be held in Sydney on Thursday 13 November, and Melbourne on Friday 14 November, both from 10am-12pm.[56]

Further public forums or workshops may be held later in this project.

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

56 Further details on this are available on our website.

B Value of spare capacity

B.1 Value of spare capacity - theory

One important property of the long run incremental costing method is that it appropriately values spare transmission capacity. It allows generators to 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.

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.

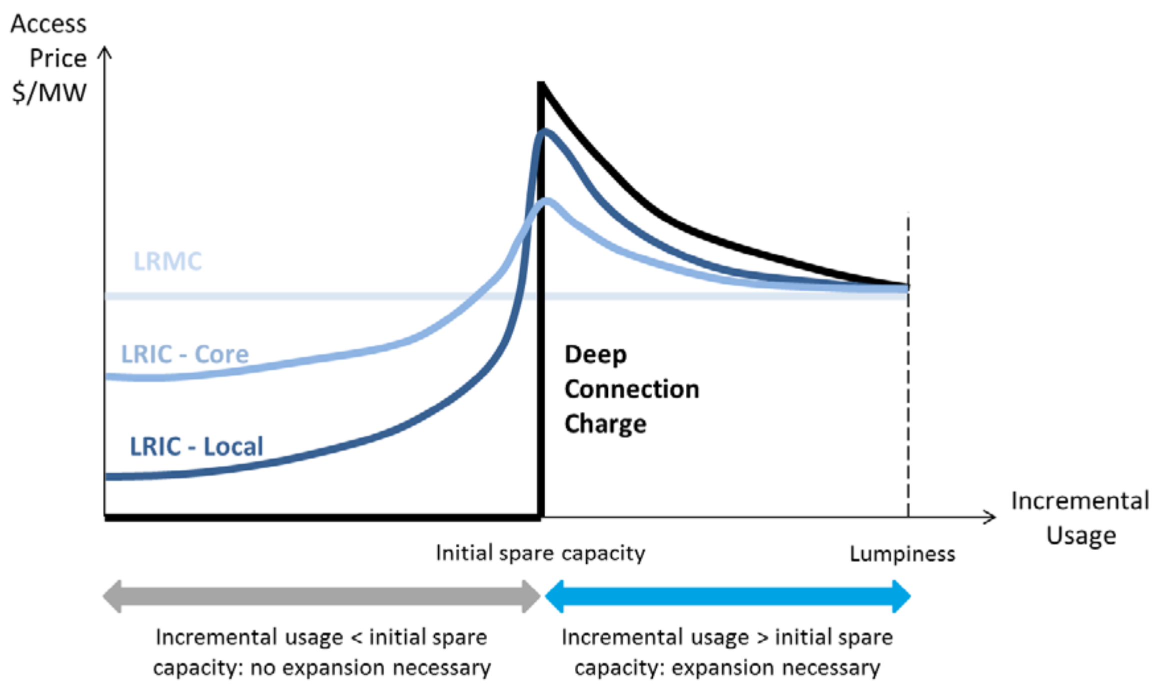
Figure B.1 illustrates how the incremental access price (incremental cost divided by the incremental usage) varies with forecast growth for a single network element. The LRIC local curve represents the access price on a local network element, where forecast growth is lower. The LRIC core curve represents 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.

Figure B.1 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.

B.2 Value of spare capacity - prototype results

B.2.1 LRIC versus LRMC

LRMC is a blunter methodology than LRIC, because there is no need to take account of existing spare capacity or future planned expansions: capacity is expanded only as needed and so tracks the flow growth rather than occurring in steps. However, this simpler method is also its flaw. Other things being equal, the access price at a location where there is lots of spare capacity would be the same as the price where there is no spare capacity, despite the incremental cost of transmission being much higher at the latter location. Generators will choose locations that are best for them (considering a number of factors, including land and fuel availability), rather than those where access can be provided more cheaply by the TNSP, due to existing spare capacity.

In the Transmission Framework Review technical report, we noted that the materiality of this pricing inaccuracy is unclear and it may be that LRMC could be quite a good proxy for LRIC.[57]

57 TFR Technical Report p56

We have now undertaken an empirical assessment of the suitability of using LRMC as a proxy for LRIC. The results of this assessment are provided illustratively in the figures below:

The figures indicate that for LRMC prices are proportional to distance from the regional reference node. Areas remote from their respective regional reference nodes, for example Northern Queensland[58], demonstrate high LRMC prices. Locations near the respective regional reference nodes (eg, those near the capital cities) show low LRMC prices.

Section B.1 discussed that the results of the LRIC and LRMC methodologies approach one another when there is very high forecast line flow growth. Here, the lumpiness of the network is close to zero, and so the LRMC method, which ignores lumpiness, approaches the LRIC method.

The maps illustrate a significant disparity in price between the LRIC and LRMC methods. Since we are in a climate of slowing demand growth, the level of line flow growth assumed, which is based on forecasts within the NTNDP and TNSPs' Annual Planning Reports, is not high enough for the LRMC method to reasonably approximate the LRIC method. By not taking into account lumpiness, and hence the relative congestion of different parts of the network, the LRMC method's results diverge significantly from those of LRIC, and so diverge significantly from being cost reflective. Given this, the Commission considers that LRMC is unlikely to be a suitable proxy for LRIC.

58 Also see Northern South Australia, the Eyre Peninsula, Southern South Australia and South West New South Wales.

Figure B.2 Queensland - LRIC

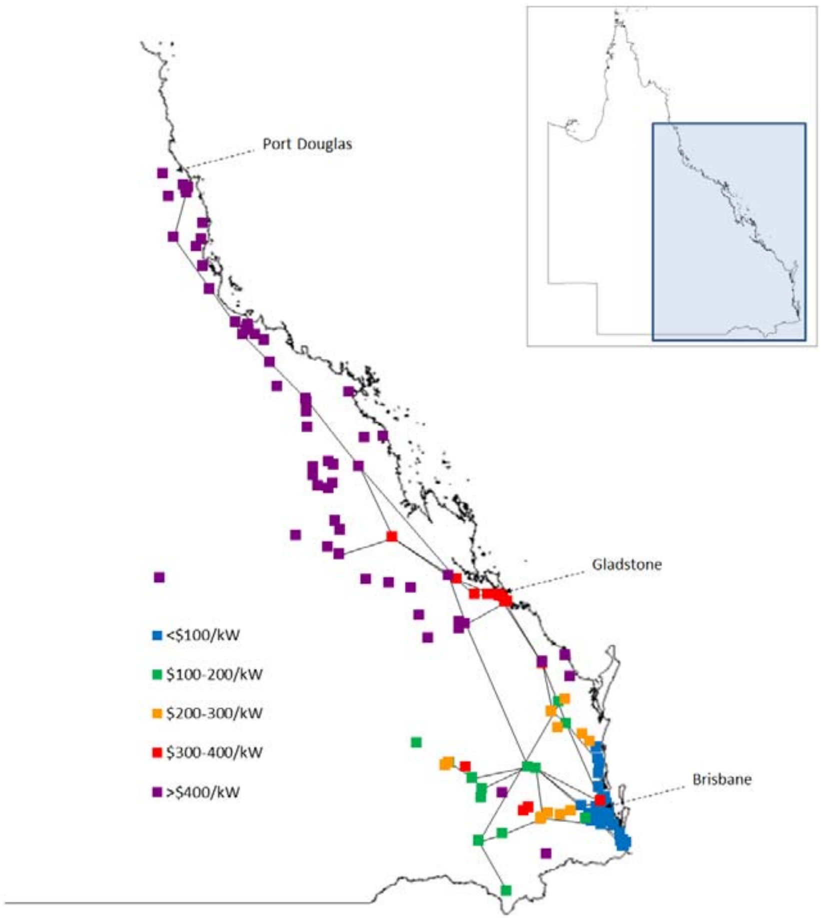


Figure B.3 Queensland - LRMC

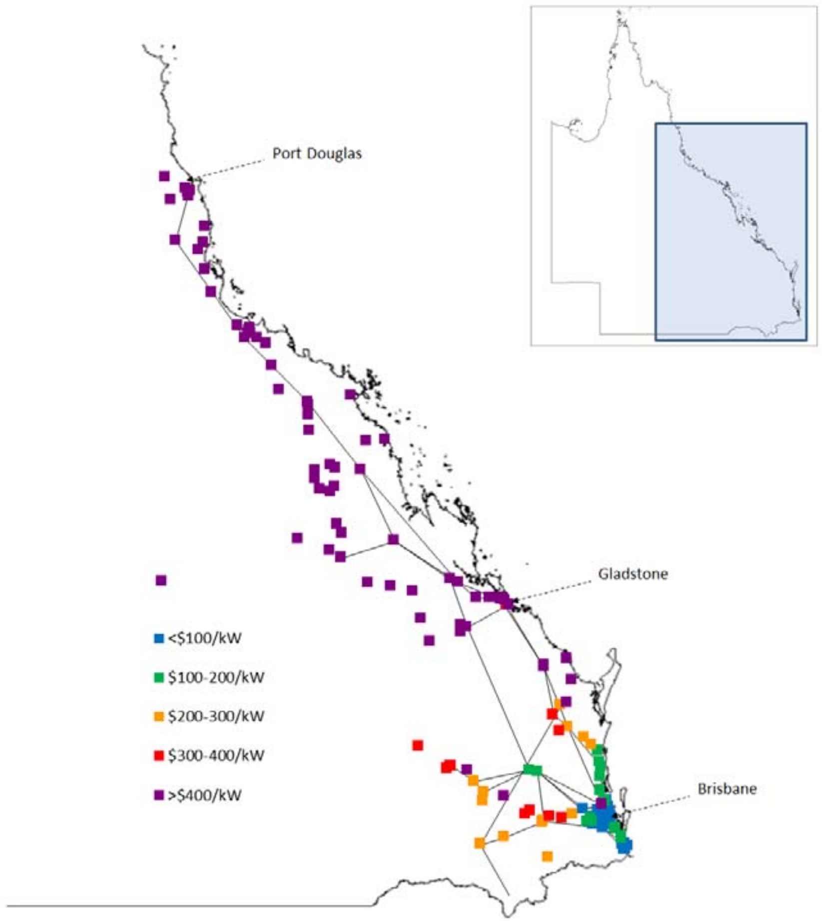


Figure B.4 NSW - LRIC

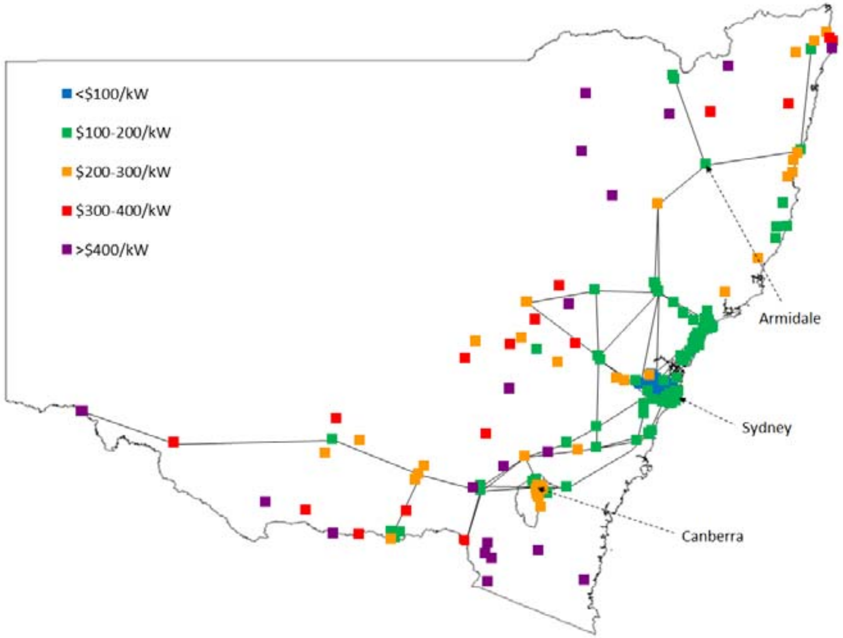


Figure B.5 NSW - LRMC

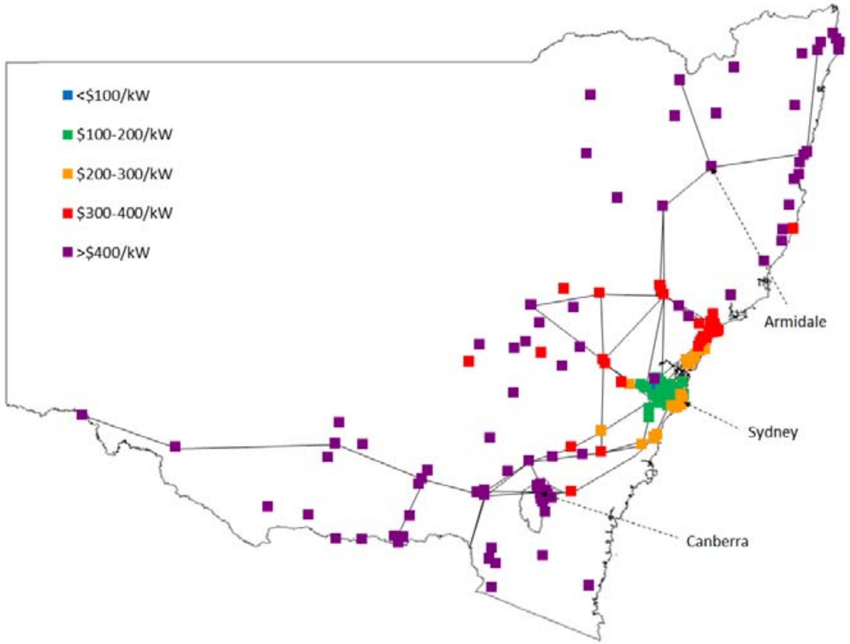


Figure B.6 Victoria - LRIC

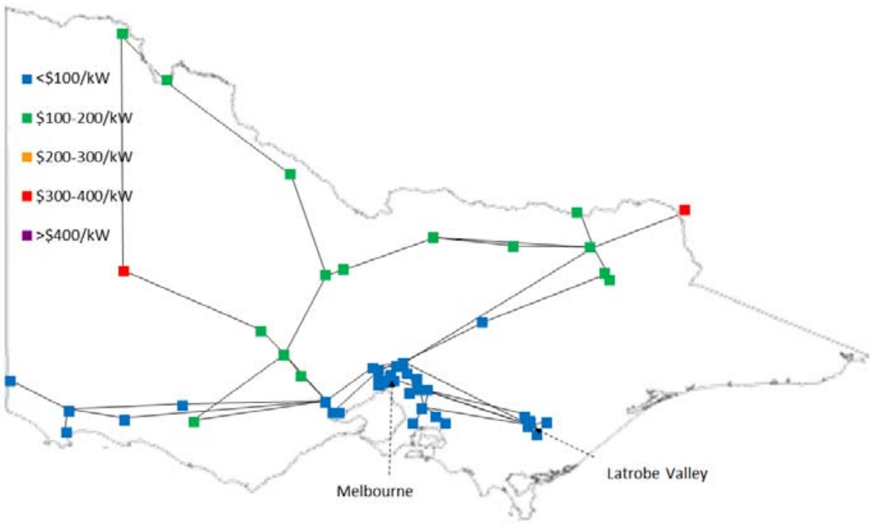


Figure B.7 Victoria - LRMC

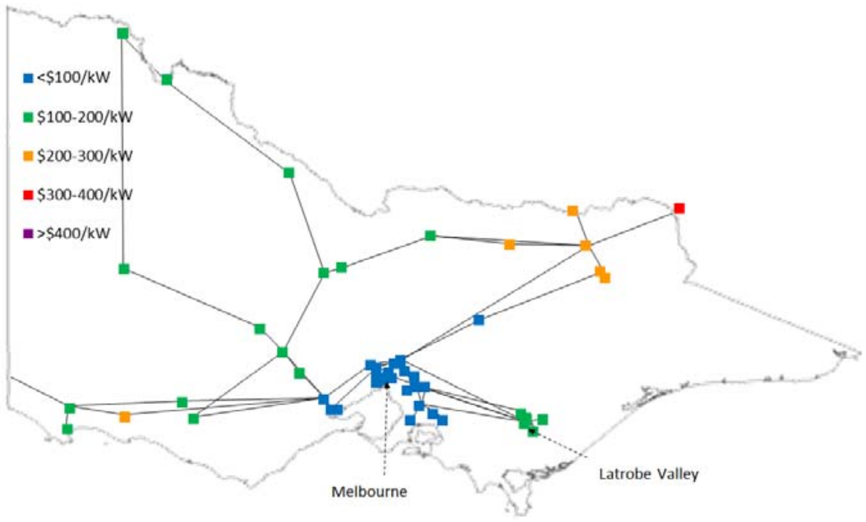


Figure B.8 South Australia - LRIC

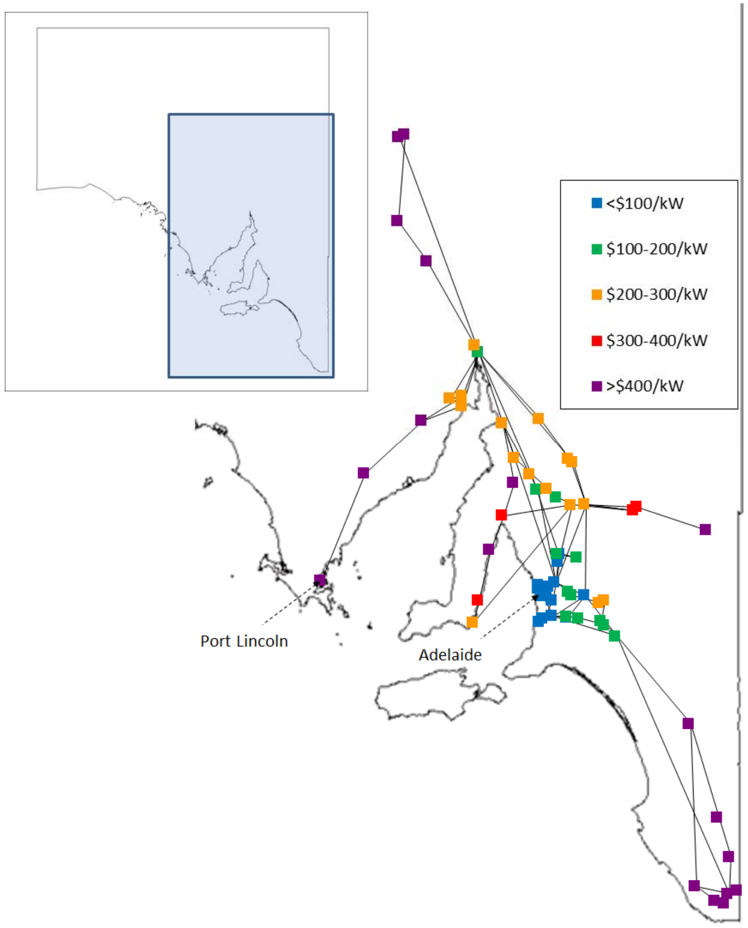
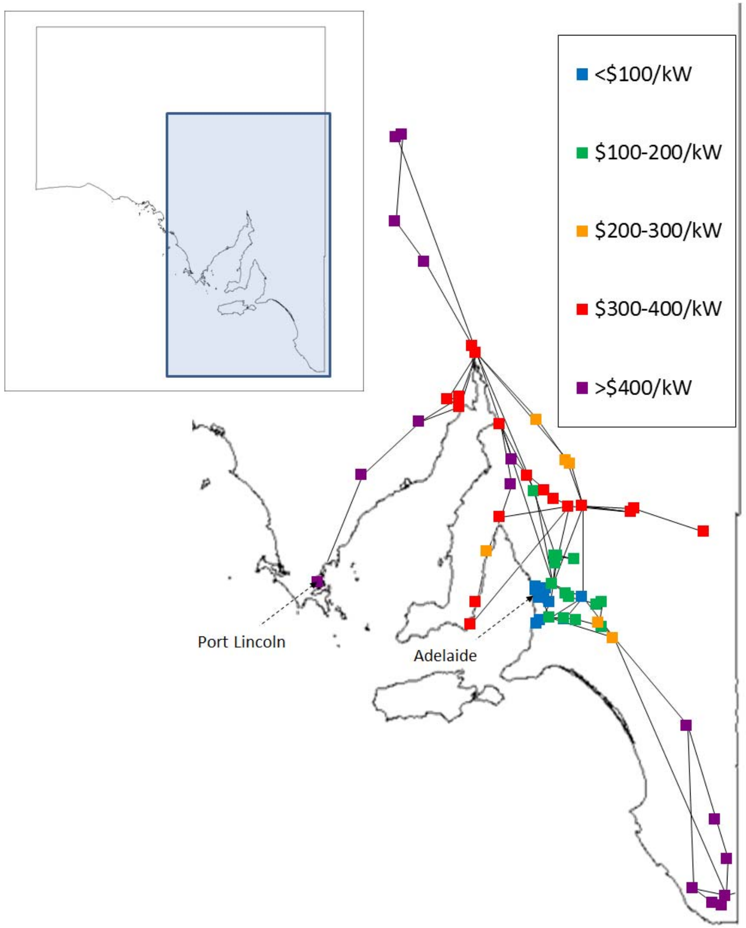


Figure B.9 South Australia - LRMC



B.2.2 LRIC versus deep connection charges

We have also compared the LRIC pricing method with the deep connection charging method. These results are shown in the figures below.

Figure B.10 Queensland - LRIC

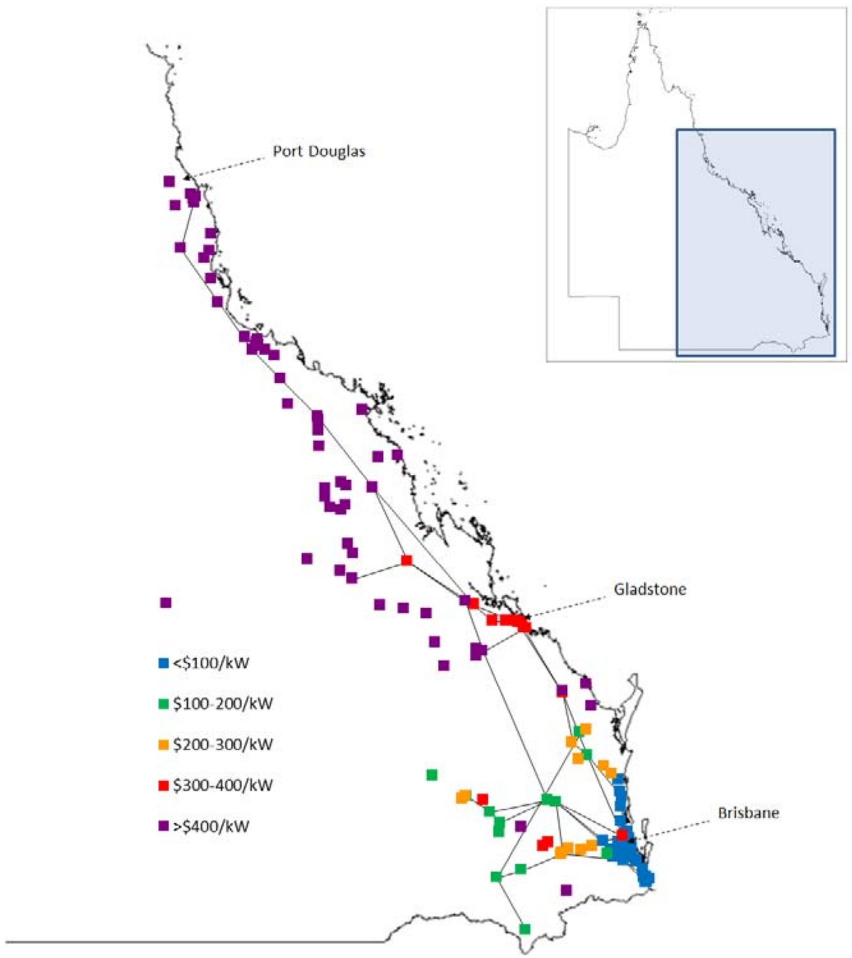


Figure B.11 Queensland - Deep connection

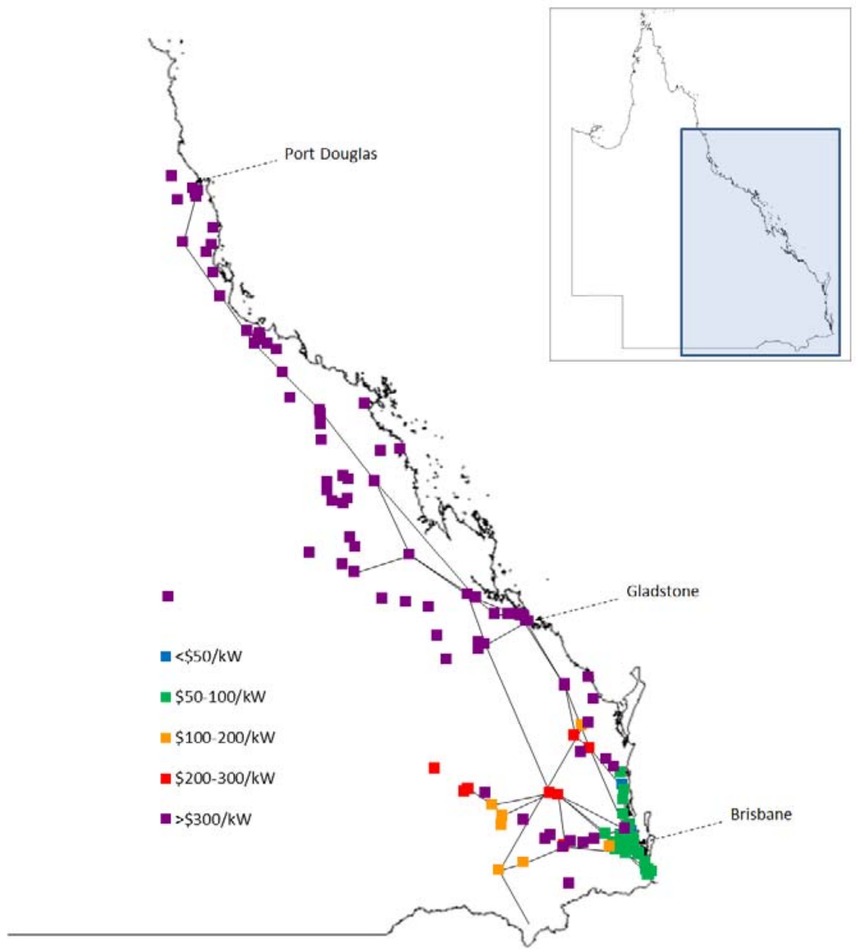


Figure B.12 NSW - LRIC

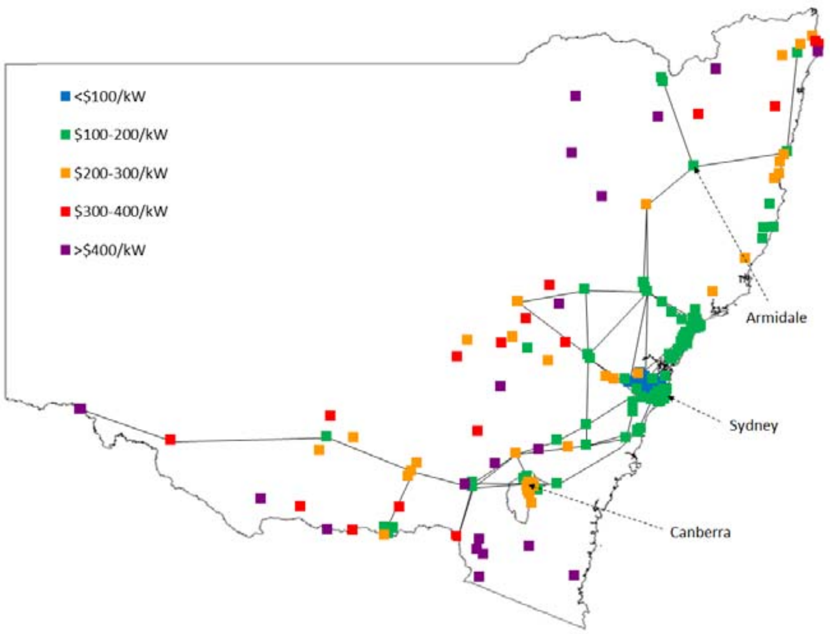


Figure B.13 NSW - Deep connection

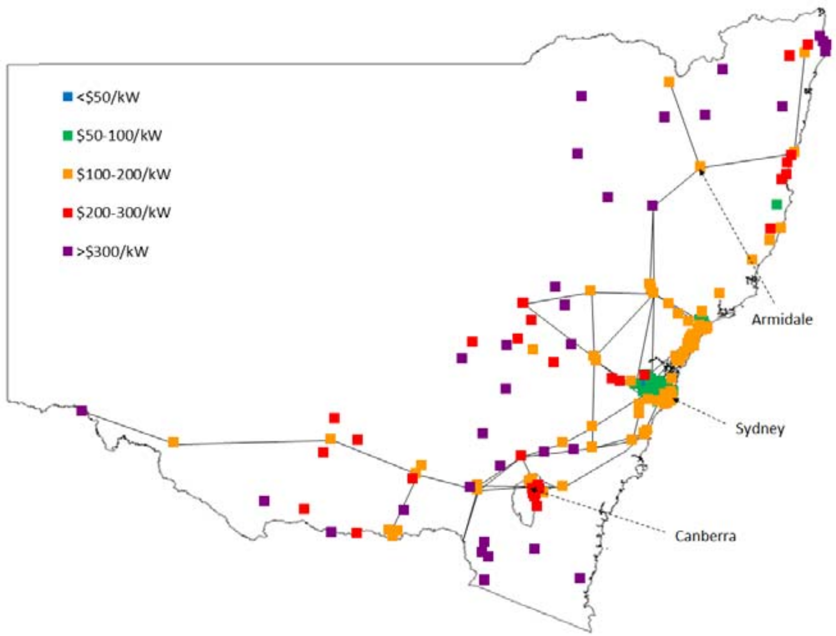


Figure B.14 Victoria - LRIC

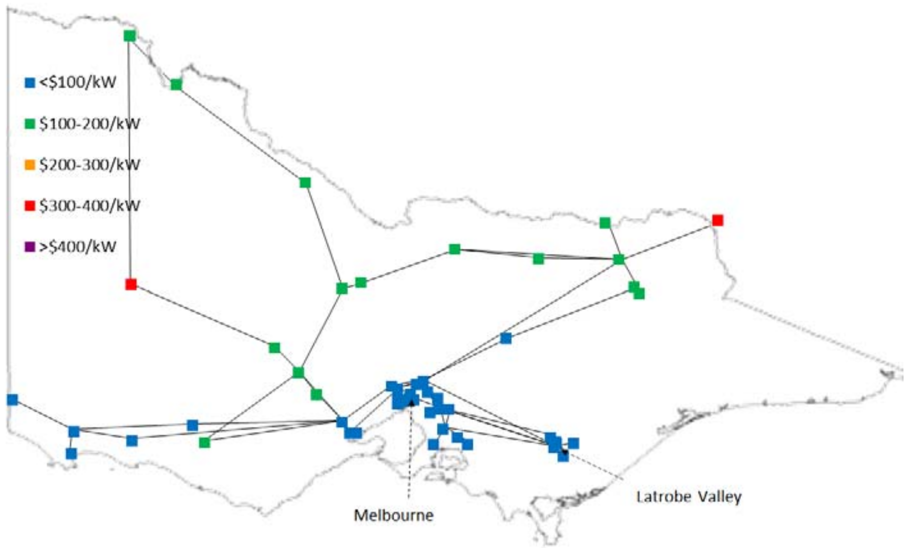


Figure B.15 Victoria - Deep connection

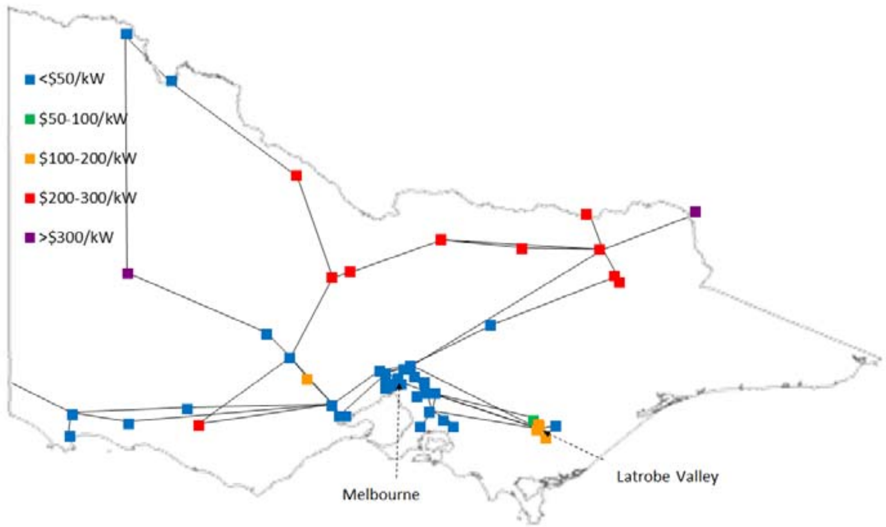


Figure B.16 South Australia - LRIC

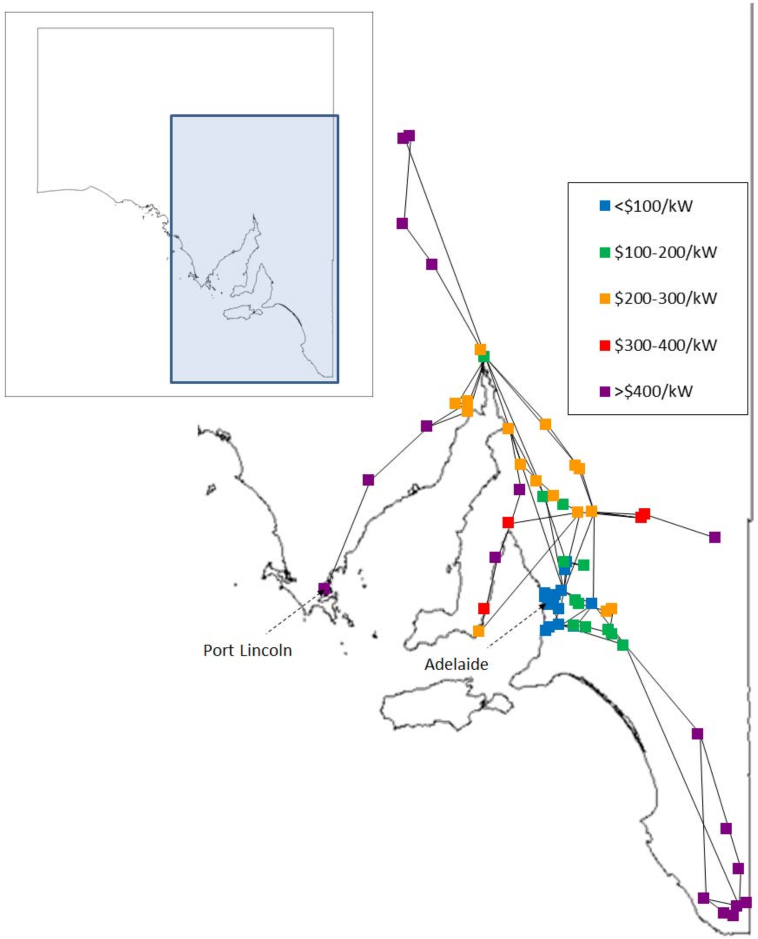
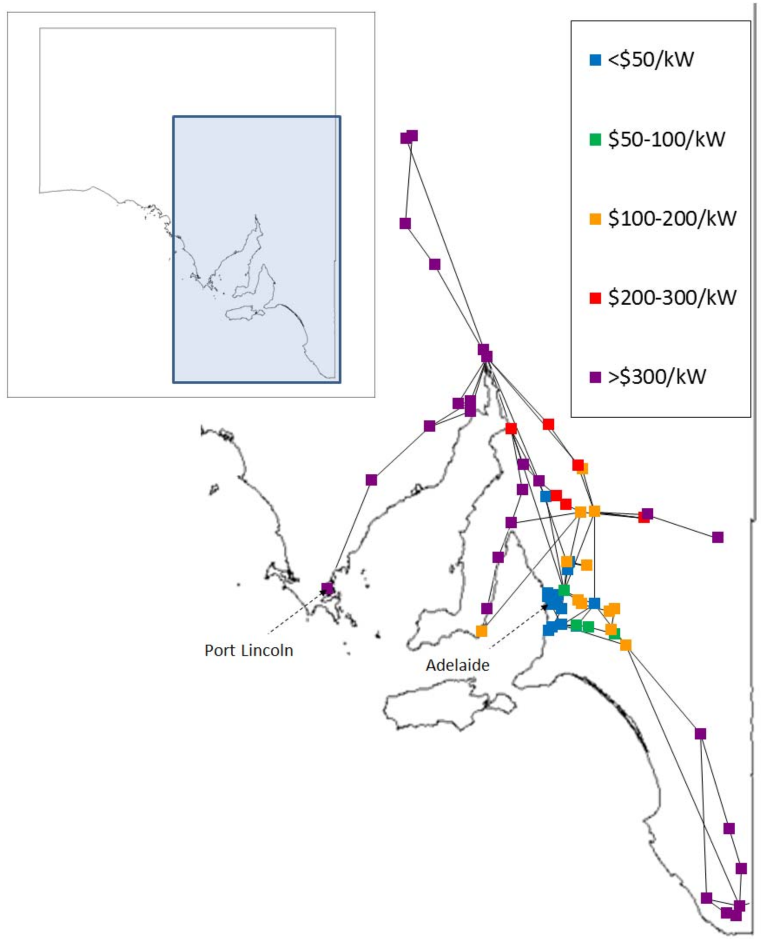


Figure B.17 South Australia - Deep connection



Initial comparison of these maps shows that the deep connection charges method is a relatively good approximation of the LRIC method (with similar relativities of prices between locations). This may be because, as set out above, a deep connection charge is the same as the LRIC price in circumstances of zero forecast growth. These are the approximate circumstances that currently exist in the NEM, and low growth inputs were used to generate these results.

We note that deep connection charges are likely to inaccurately represent LRIC for any given line[59], since an access request typically prompts immediate expansion on some lines but not on others. Therefore, there is an averaging effect across all lines.

However, caution should be applied when analysing these results. The prototype pricing model uses a stylised method to produce the deep connection charges, eg, it relies on stylised development scenarios that reflect a simplified version of the network. In reality, the deep connection approach would rely on the TNSP (or other entity) determining and charging exactly what needs to be built immediately to provide the new access. These different approaches may result in significantly different results.

Notwithstanding the limitations with the pricing prototype model, there may be other limitations with using a deep connection method:

- What constitutes an 'immediate expansion' will be subject to debate. Any definition of 'immediate expansion' is arbitrary. For example, the stylised method employed in the prototype pricing method defines an 'immediate expansion' as one which occurs in the first year after an access request.
- Regardless of where the line is drawn with regard to defining 'immediate expansions', the deep connection charge approach may result in perverse first and second mover incentives. A first mover generator will seek to buy just enough access so that it does not prompt an immediate expansion on a particular line, and hence avoids any costs associated with bringing forward the expansion of that line. Generators may then be strongly dis-incentivised from prompting an expansion and incurring the full associated expenditure, in the knowledge that were their competitors (or the TNSP on the basis of reliability standards) to do so, the subsequent cost of access on that line would be zero. In contrast, since LRIC takes into account the value of spare capacity, while there will still be first and second mover incentives, these may not be as extreme.
- To avoid this gaming, the generator paying the deep connection cost is likely to demand the smallest possible (and hence cheapest in absolute terms) expansion, despite this not necessarily being the most efficient lump of expansion.

59 The deep connection charge method either charges zero or the full cost of the expansion, depending on whether the expansion is required immediately.

C Input assumptions for the prototype pricing model

We acknowledge that the current version of the prototype pricing model is a work in progress:

- the input data that feeds into the model may not be fully accurate (section C.1); and
- there are a number of methodological assumptions that we have made (section C.2).

In this section we set out the various sources of our input data, and the methodological assumptions we have made. We also set out where these inputs and assumptions could potentially be improved.

C.1 Input data

Table C.1 Input data

	Input data	Possible improvement(s) to the model (where appropriate)
Peak demand forecasts	Peak demand forecasts based on peak demand at each node as provided in the TNSP's 2013 Annual Planning Reports (which provide forecasts up to 2023).	
	The TNSP Annual Planning Reports do not include major industrial load in their peak demand forecasts (as this data is commercial-in-confidence). In order for the line flow calculations within the model to operate, we have added an amount that represents the major industrial load to the regional reference node. This is discussed further below in methological limitations.	There may be an impact on the LRIC prices due to an inaccurate representation of demand forecasts due to some data not being included. The effect of this is that all major industrial load is represented at the regional reference node. Representing the major industrial load at the regional reference node may also have an impact on the location of congestion that is observed in the prototype model around the region. The amount of additional demand added at the regional reference

	Input data	Possible improvement(s) to the model (where appropriate)
		node varies by state, depending on the input supply and demand data. In Victoria, no additional demand was added at the regional reference node because the input demand exceeds the input access in the model. In Queensland, over 50 per cent of additional demand is entered into the model. This additional demand can be explained by the large amount of industrial demand in Queensland which is not represented at individual nodes within the model. This may impact the line flows around the regional reference node, and prompt expansions within the model. We are unlikely to resolve this issue in our prototype model. However, if optional firm access was to be implemented, then the entity responsible for developing the pricing model at that time could require that the commercial-in-confidence major industrial load data is provided to it. The entity could take necessary steps to protect the confidentiality of that data.
	The peak demand forecasts in the TNSP Annual Planning Reports are net of embedded generation (ie, connected to the distribution network). They do not include non-scheduled generation connected to the transmission network. It is appropriate for non-scheduled generation to be included in the model, otherwise the load flows may not adequately reflect local generation conditions. Therefore, we added all *current* non-scheduled generation greater than 25MW capacity (excluding wind) into the demand forecasts in each year until 2023 (since beyond 2023 the model assumes a stylised line growth), as sourced from the generation registration list available on AEMO's website. We assumed that this non-scheduled generation would operate at its full capacity at times of peak demand.	While we have incorporated some of the non-scheduled generation into the model, we could incorporate a forecast of *all* non-scheduled generation at each node into the model, and make appropriate assumptions regarding the output by each non-scheduled generation at times of peak demand.

	Input data	Possible improvement(s) to the model (where appropriate)
	In the shorter term (until 2023), line growth is based on a DC lossless load flow equations, given the net access or demand at each node and physical and electrical characteristics of the lines, as provided by the National Transmission Planner (as described in section 4.3.1 of this report).	Load flows only approximate actual load flows in an AC load flow with losses included. We are considering whether we can include loss factors in the load flow equations.
	In the long term (beyond 2023), the peak flow on each line is assumed to grow by a fixed MW amount.	Sensitivity analysis (Figure 4.14 of this report) indicates that LRIC prices are not particularly sensitive to long term peak line flow.
Access allocations	Existing access allocations are based on the results of the transitional access allocation test undertaken by AEMO, which are set out in appendix A of the First Interim Report. An input to AEMO's test used was each generating unit's five minute peak generation in the last two years. For some generating unit, five minute peak generation exceeded the registered capacity of the generating unit. In cases where this resulted in an allocation of access in excess of the registered capacity of the generator, capacity was scaled back (specifically and only for the purpose of the prototype pricing model) to the registered capacity, to protect the confidentiality of actual five minute peak generation. For the purpose of the prototype pricing model, transitional access was assumed to not be sculpted, ie, all existing access is assumed to remain in place indefinitely.	If optional firm access was to be implemented, the transitional access allocation would be rerun. The transitional access allocation would change at that time to reflect any changes in the transitional access allocation methodology; and changes in network conditions. The transitional access numbers would also reflect sculpting of access. Therefore, when we publish an updated version of the prototype with our Draft Report it will reflect the most up-to-date numbers for transitional access at that time. However, we note that these numbers would be different if optional firm access was to be implemented. We note that stakeholders can change the existing access input into the prototype model.
	Generator entry is sourced from data from the 2013 National Transmission Network Development Plan (NTNDP). This is provided at a zonal level. We have assumed that generator entry will occur across nodes within a zone in proportion to the existing generator capacity at nodes within a zone.	We are unlikely to resolve this issue in our prototype model. However, if optional firm access was to be implemented, then the entity responsible for developing the pricing model at that time could reasonably forecast at a nodal level based on assumptions about committed access.

	Input data	Possible improvement(s) to the model (where appropriate)
	The exception to this is in the Northern Victoria zone. In this case, there is currently only one node with generator capacity, meaning that all additional access within that zone would be connected at this single node. We have therefore assumed generator access is added over time at three nodes in Northern Victoria. We have implicitly assumed that all generator entry forecast in the NTNDP will procure access to become fully firm.	We welcome feedback on the alternative approaches to the assumed level of generator entry.
Transmission network	We have obtained data detailing the physical and electrical characteristics of the lines used to model the peak line flows from both AEMO and TNSPs. We acknowledge the considerable effort to date of AEMO and TNSPs in assisting the Commission in compiling this data set. However, some issues may remain, including, but not necessarily limited to: • inaccuracies in the line/transformer ratings; • inaccuracies in lines length; and • misrepresentations of the network topography.	There is a possibility that the line flow is inaccurately modelled due to inaccurate input data. Further, lines with modelled line ratings of zero (95 of the 756 (13 per cent[60]) lines have a zero rating. However, all but one of these are low voltage lines, which should have a less significant impact on prices than high voltage lines) will require immediate expansion, in both the baseline and adjusted scenarios, altering the relative cost between these plans (and so the LRIC price). We welcome further feedback on the network data contained in the aemc-lines.cvs files. If further feedback is obtained then we can incorporate this more accurate network data into the model.
Costs	The model assumes assets categorised on the following criteria: • asset type (line of transformer); • size (low, medium or high); and • voltage.	Inaccurate costing of assets will result in inaccurately costed expansion plans, and ultimately inaccurate LRIC prices. We appreciate that costs assumptions currently in the prototype can be improved. The TNSPs have been unable to provide us with actual costing information due to reasons of confidentiality, which has restricted our ability to accurately cost transmission assets.

60 We intend to replace these line ratings of zero, with values by the time our revised prototype is published along with our Draft Report in February 2015.

	Input data	Possible improvement(s) to the model (where appropriate)
	Therefore, the forecast expansions do not take into account other potential transmission assets, such as substation bays. The cost of each of the categories of assets is based on a 2012 AEMO study.[61]	The Commission is considering engaging a consultant to provide us with more accurate costing information to update the prototype pricing model. The model could also be updated to reflect more categories of assets based on more characteristics (e.g. more types of assets, or whether a line is underground or overhead). This would provide more granular costing of assets, and hence more accurate costing of expansions.
	The size of expansions in MW is an assumed economic lumpiness of expansion (in MW of capacity), divided by the "meshedness" of the line. The lumpiness of a line is the assumed amount of capacity that would be added through the efficient expansion of that element. We made assumptions regarding the efficient lumpiness of assets based on a 2012 AEMO study.[62] Meshedness is a measure of the extent to which electricity will flow along alternative paths in the network between the two ends of the line.	To the extent that the assumed efficient lumpiness of assets is inaccurate, the modelled expansion will not accurately reflect actual expansion. The division of efficient lumpiness by meshedness means that individual lines will not be modelled to expand in as large a lump as would be the case in reality. However, the model stylises that multiple lines will expand, so that the total expansion across all the lines is representative of actual efficient lumpiness of expansion. While the expansion plans may diverge from what a TNSP would actually build, the cost impact (and hence the impact on LRIC) should not be significantly unchanged. We are considering engaging a consultant to provide us with more accurate costing information - including more accurate lumpiness data to update the prototype pricing model.
	Only capital costs of expansions are modelled	Costs will be less than the total life-time cost of an expansion, due to ignored operating and maintenance costs.

61 AEMO, 100 per cent renewables study – electricity transmission cost assumptions, September 2012.

62 AEMO, 100 per cent renewables study – electricity transmission cost assumptions, September 2012.

	Input data	Possible improvement(s) to the model (where appropriate)
		We will consider whether it is straightforward to include an estimation of the net present value of operating and maintenance costs in the costing assumptions.

C.2 Methodology assumptions

Table C.2 Methodological assumption issues

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Replacement expenditure	The model assumes that all assets have infinite life.	We will incorporate replacement of assets into the LRIC pricing model.
Non-thermal constraints	Only thermal constraints of the lines have been modelled. Other constraints, (eg, stability constraints) have not been included.	Only thermal constraints have been modelled. Given that non-thermal constraints are not included, there may be expansions at times different from what the model predicts. Grid Australia noted that this may not result in a LRIC relativity issue in many circumstances, but it appears to lead to incorrect price signaling at least on Victoria's main generation corridor, between the Latrobe Valley and Melbourne. Grid Australia considered that the LRIC is shown to be low on this corridor since there is significant spare thermal capacity. However, the corridor is constrained by stability limits. If these were included, the LRIC would likely be higher, and more cost reflective of what a TNSP would actually plan to do in this area of the network. We are investigating ways in which the LRIC model could reasonably overcome this issue, and welcome stakeholder feedback on this issue.

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Dynamic aspects of the transmission network	System protection schemes, run back schemes and other dynamic line ratings are not included in the model.	The model may not accurately represent physical and electrical characteristics of the lines. We are investigating whether it is appropriate for these schemes to be included; and if so, how these could be included in the LRIC model.
Electrical characteristics of the lines	Electrical characteristics of the lines are fixed at the start of the model, and not subsequently updated to reflect changes in load flows and network topology (eg, admittance of lines is assumed to be fixed for the life of the line).	The model does not dynamically update these assumptions over the life of the access request. This means that modelled line flows may over time diverge from actual line flows. We are considering possible ways that this would be addressed, for example, depending on the governance arrangements, some organisation(s) could be responsible for updating these inputs. Alternatively, the model could potentially recalculate the relevant characteristics of the lines each year.
Reliability access	Where aggregate firm access is less than aggregate demand, reliability access is included in addition to firm access so that total access (reliability plus firm) equals demand. This mimics a situation where a TNSP provides additional reliability access so that demands-side reliability standards are met. In effect, the model adjusts the assumed rates of access growth per zone (as per the NTNDP) so that aggregate firm access meets aggregate demand. This additional reliability access is then distributed across the nodes within a zone in proportion to existing generator capacity at the nodes in the zone, in the same manner as firm access (as described above).	We note that the addition of reliability access above existing generation capacity does not imply that any individual existing generators are purchasing firm access, or generating, above their current capacity. Instead, the model is recognising that in instances where aggregate demand exceeds aggregate access, the TNSP would be required to provide access to meet demands-side reliability standards. The assumed distribution of reliability access may result in modelled access (reliability and firm) per node that is different from actual access (reliability and firm) per node. Given the level of transitional access, and the level and growth of demand, there is unlikely to be any reliability access added under current circumstances. However, we welcome feedback on alternative approaches to distributing reliability access across nodes.

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Additional demand added to the regional reference node	For the line flow calculations within the model to operate, the total firm access amount in a region must be equal to the total demand in a region, ie, demand and access must balance. For example, access allocations may be in total *higher* than demand. Therefore, some "virtual" demand is required to balance the system. The model treats the regional reference node as the "slack node" which means that demand is added at the regional reference node to balance the system.	We consider this assumption to be appropriate, since the firm access product provides generators with access to the regional reference node. Further, the additional load that is added in our method is not to represent network topology, but rather to allow the system to balance in the model and this is best located at the regional reference node. One potential amendment would be to simulate an increase in demand across the network, rather than just at the regional reference node, to get the system to balance. For example, if a local load represents a quarter of the regional demand in the original NEMDE file, it would represent a quarter of the increased demand level used so that all generation is dispatched. This change would result in simulated remote load (ie regional towns and transmission connected industrial plants) consuming more generation, and thus potentially relieving constraints that may appear between generators and the regional reference node. However, we consider that there are issues with such an approach. In reality, the remote load may not be present. However, the LRIC price would estimate that it would be present - and so, it would estimate a "lower" LRIC price since by assuming there is remote load, the model would predict that less transmission capacity has to be provided by the TNSP in order for the firm access request to be met. In reality, the TNSP could not rely on the remote load being there, and so would have to provide capacity through to the regional reference node. This would result in a higher project cost by the TNSP than the access charge that was predicted by the LRIC model. Therefore, balancing the system by adding demand to other nodes is not an accurate reflection of the firm access product.

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Security adjustments	Network capacity is adjusted by an adjustment factor that reflects the need to enable there to be sufficient network capacity to have system security. This is an approximation of the actual security adjustment that the TNSP would make so that it planned its network to meet the firm access planning standard. This security adjustment is calculated once (at the start of the model) and applied for all years of the model, rather than adjusting dynamically.	Security adjustments may differ from those actually made by the TNSPs in planning their networks, meaning that network capacity is not accurately represented. We welcome feedback as to how security adjustments within the model could more accurately represent TNSP's likely actual behaviour.
Inter-regional elements	The transmission network has been split into regional elements to increase the speed at which the prototype produces LRIC prices.	We will aim to reintegrate the model. This will also allow inter-regional access prices to be produced.
Expansion scenarios	Expansions on a line are prompted once the flow on the line exceeds its capacity. The modelled expansion scenario is therefore not based on the current forecast expansion plans of the TNSPs, but instead on the modelled flow across the network. The model also makes a simplifying assumption that the expansion of the line occurs by replicating the same line (eg, voltage) and route of the existing line.	Modelled expansion scenarios may vary from TNSPs' forecast expansion plans. We are currently investigating how the model could be adapted to include such assumptions. For example, up to the TNSPs' short-term planning horizon, the modelled expansion scenario could be based around the TNSPs' forecast plans. However, this would require substantial changes to the stylised nature of the prototype pricing model. Indeed, these plans would only be appropriate if driven by identical assumptions as those used in the LRIC model.

D Indicative access prices

D.1 Input assumptions

As noted in section 4.3.1, analysis of average prices across the NEM or across regions is of limited value. Indeed, a key intended feature of the LRIC methodology is that it creates locational signals for generators, which averages do not take into account.

As a result, we have not undertaken analysis on average prices, either across the NEM or on a regional basis. Instead, we have selected a number of locations that we consider may be of interest to current or future generators and assessed how the prices at these locations vary by access amount.

The Victorian locations were presented and discussed in chapter 4. Here, we present the results for locations in other regions (other than Tasmania). The results and trends are similar to those discussed in chapter 4.

These locations are chosen to be indicative of places in the network where future generators may locate (eg, Braemar in Queensland since it is located close to the LNG fields, and Snuggery in South Australia since it is a good location for wind).

The locations we have selected for analysis are:

Table D.1 Locations selected for analysis

Node reference	Name	Region	Zone (as specified in the NTNDP)
4GSN132	Gladstone South	Queensland	Central Queensland
4MTS132	Mount Stuart	Queensland	Northern Queensland
4MTE275	Mt. England	Queensland	South East Queensland
4BRQ330	Braemar	Queensland	South West Queensland
2BAY330	Bayswater PS	NSW	Central NSW
2IPT330	Lower Tumut	NSW	South West NSW
2GPS132	Guthega	NSW	Canberra
2BAN330	Bannaby	NSW	Central NSW
5PTL132	Port Lincoln	South Australia	Northern South Australia
5DAV275	Davenport	South Australia	Northern South Australia
5SNU132	Snuggery	South Australia	South East South Australia
5ROB275	Robertstown	South Australia	Northern South Australia

D.2 Indicative access prices by access amount

Indicative access prices by access amount are presented on a $/kW basis below, by region, in Figure D.1 to Figure D.3. These results also confirm that the results produced by the LRIC pricing prototype model demonstrate that the LRIC method is cost reflective: since the total price paid for firm access always increases as the access amount increases, but the rate of increase in this cost varies, depending on the level of spare capacity between the location and the regional reference node.

Please note that the scale of the vertical axis varies between graphs.

Figure D.1 Access prices, varying by access amount, Queensland

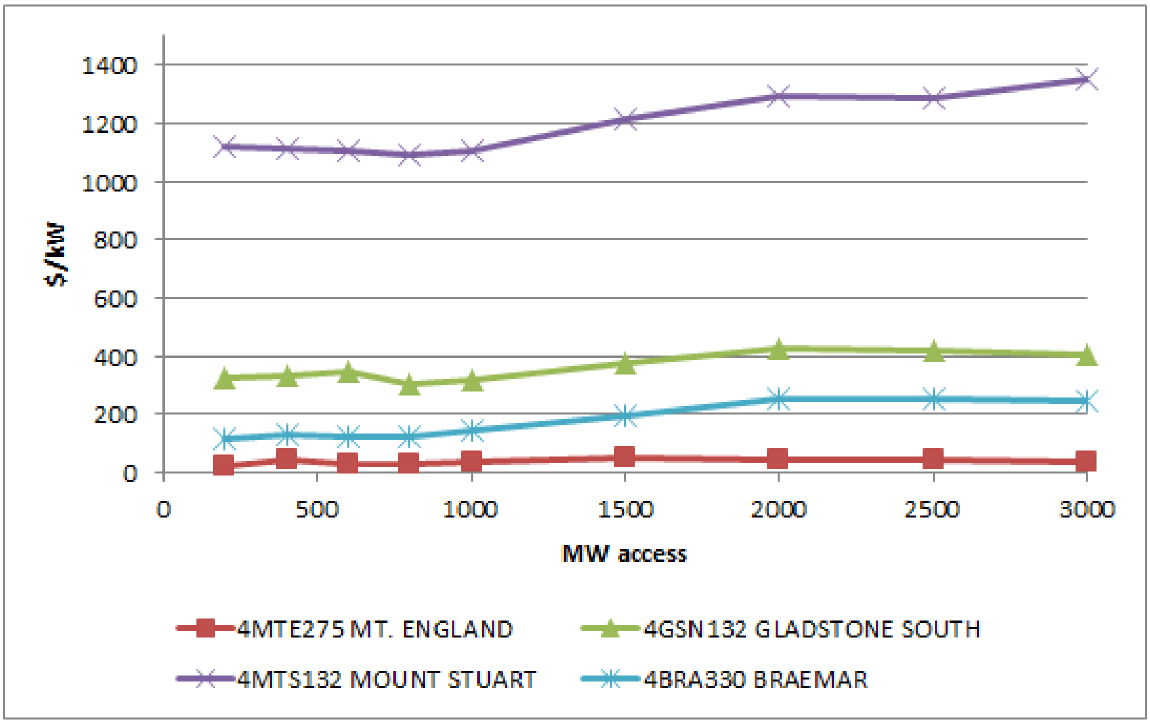


Figure D.2 Access prices, varying by access amount, NSW

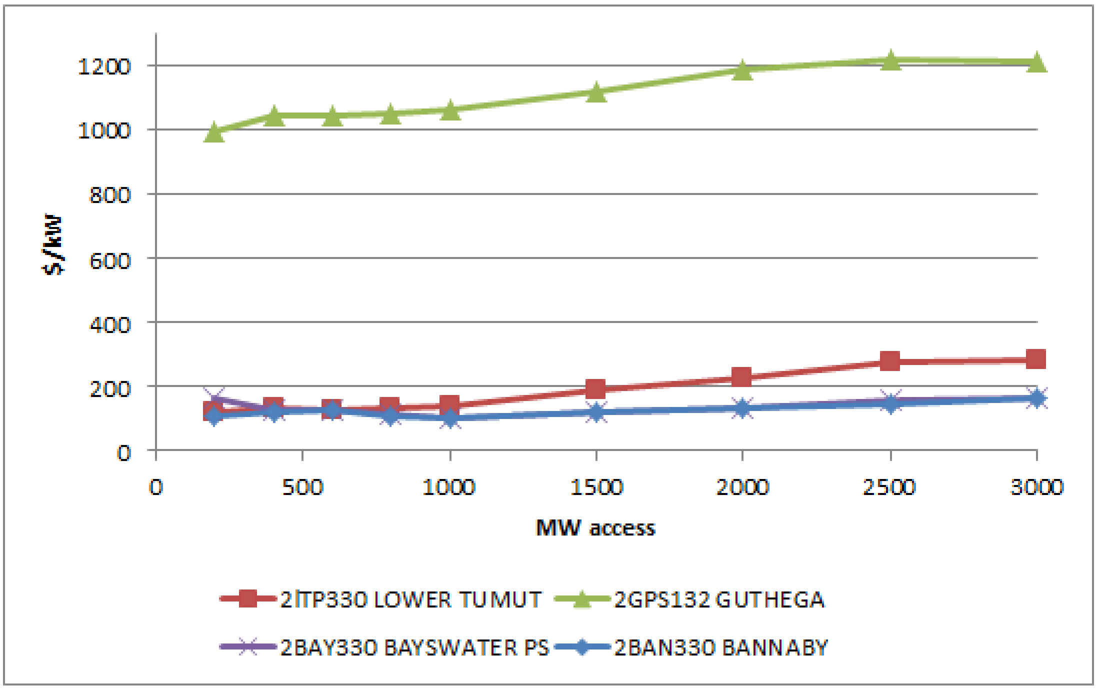


Figure D.3 Access prices, varying by access amount, South Australia

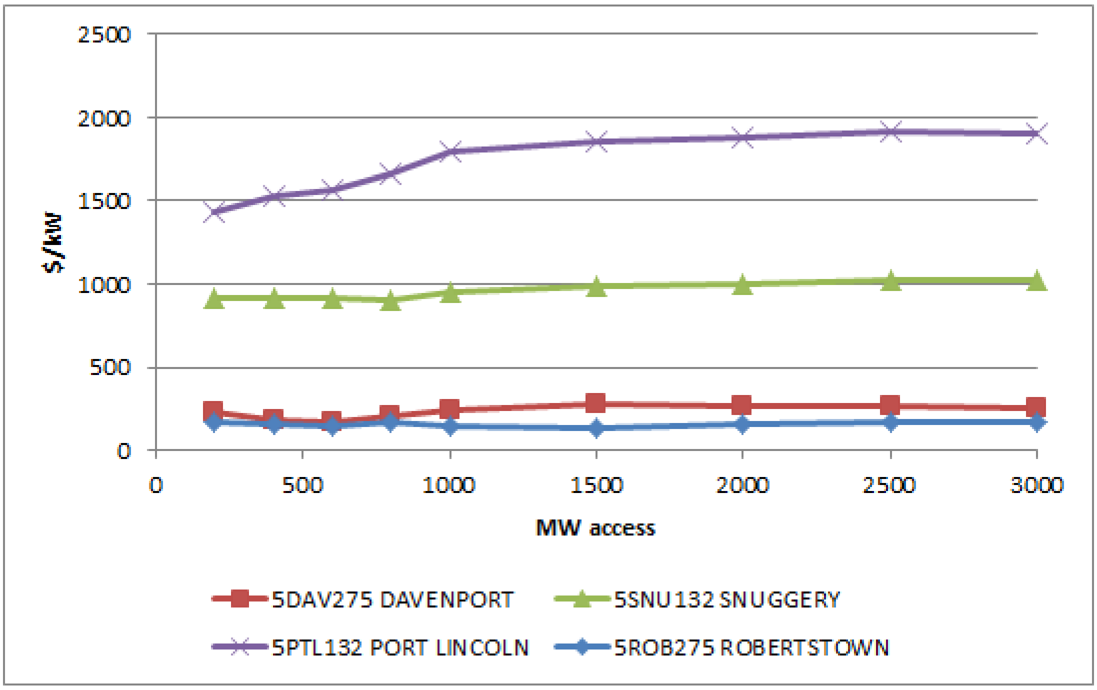


Figure D.4 to Figure D.6 show the total amount paid for access, differing by the amount of access requested. The total payment always increases as more access is requested.

Figure D.4 Total access payment, selected Queensland locations

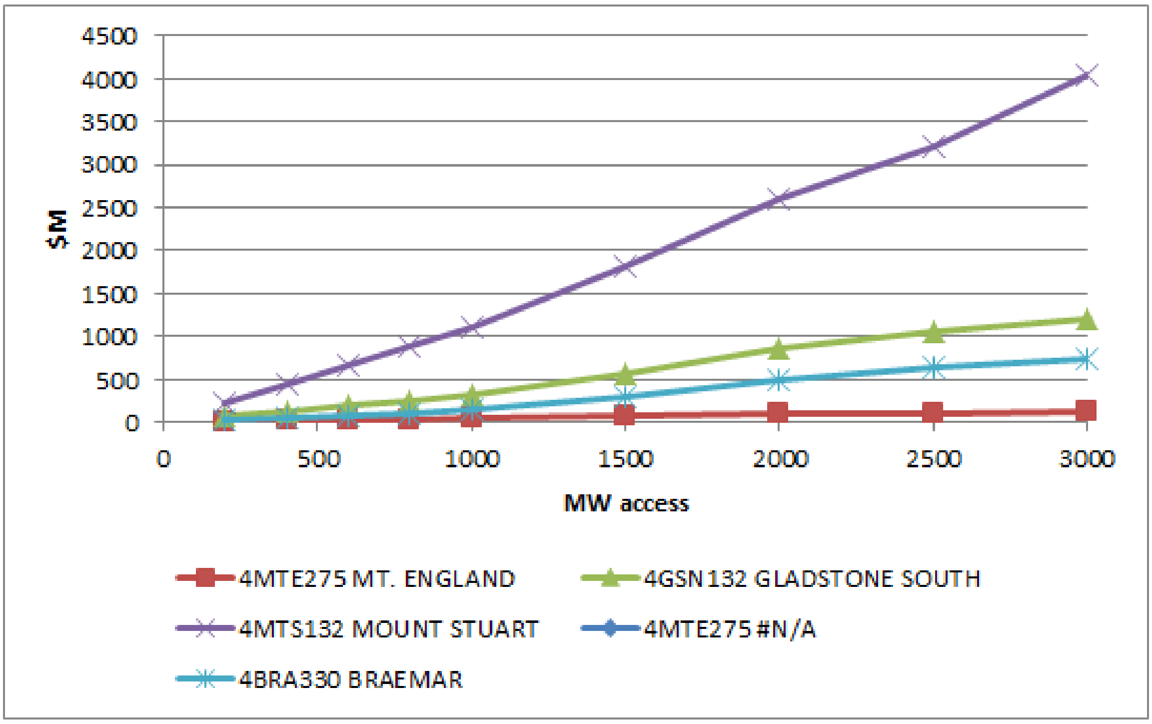


Figure D.5 Total access payment, selected NSW locations

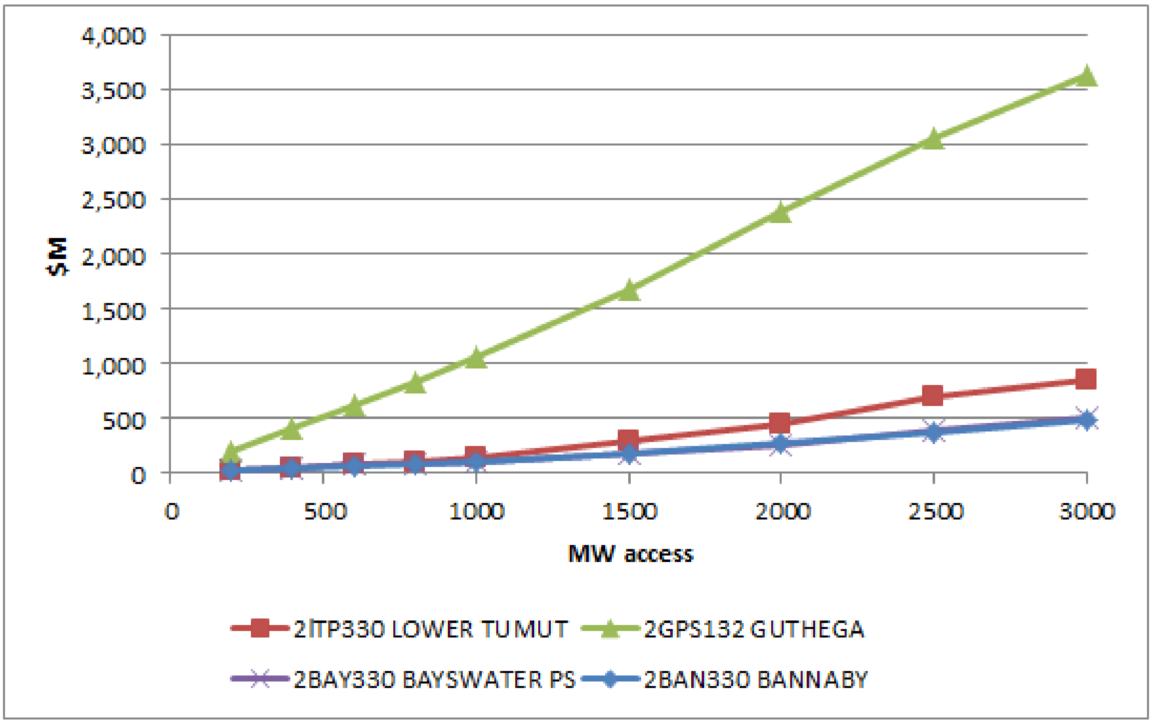
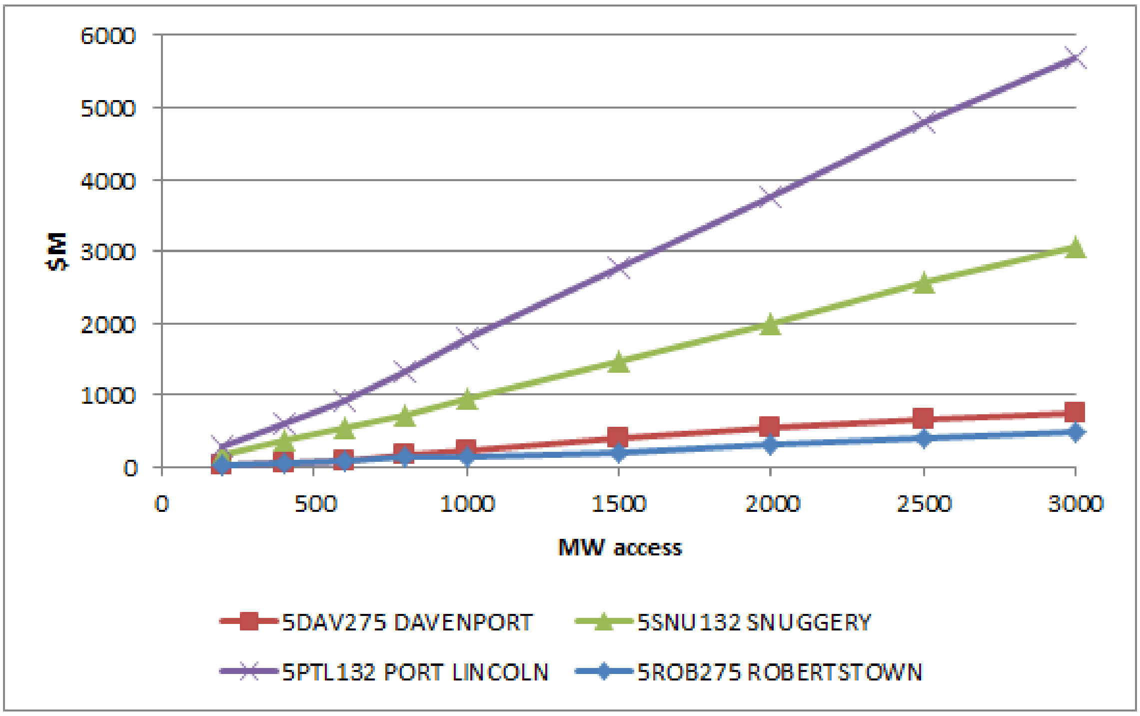


Figure D.6 Total access payment, selected South Australia locations



D.3 Indicative access prices by access term

Indicative access prices by access term prices on a $/kW basis are presented below, by region, in Figure D.7 to Figure D.9. These results also show that access price per kW always increases as the access term increases, but that the rate of increase is not the same across locations. This is to be expected. If an access term ends immediately prior to a required expansion, then the expansion would not be forecast to occur, and so the cost of the expansion would not be included in the adjusted development scenario. Conversely, if an access term ends immediately after a required expansion, the cost associated with the expansion would be included in the cost of the adjusted development scenario, raising the LRIC price.

Figure D.7 Access prices, varying by access term, Queensland

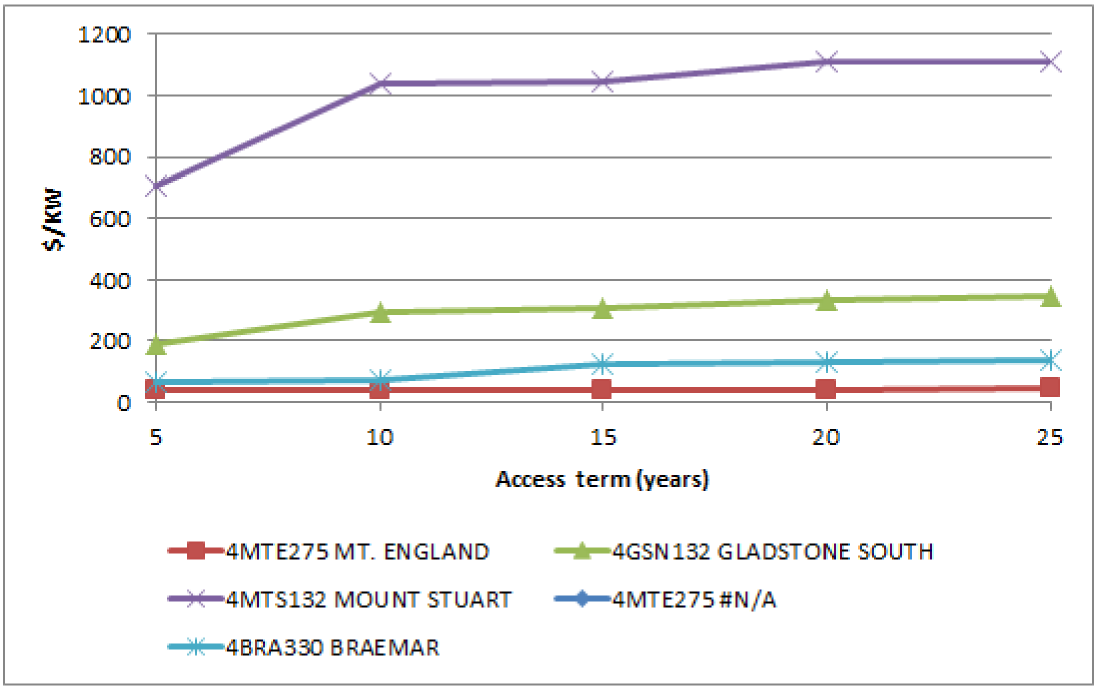


Figure D.8 Access prices, varying by access term, NSW

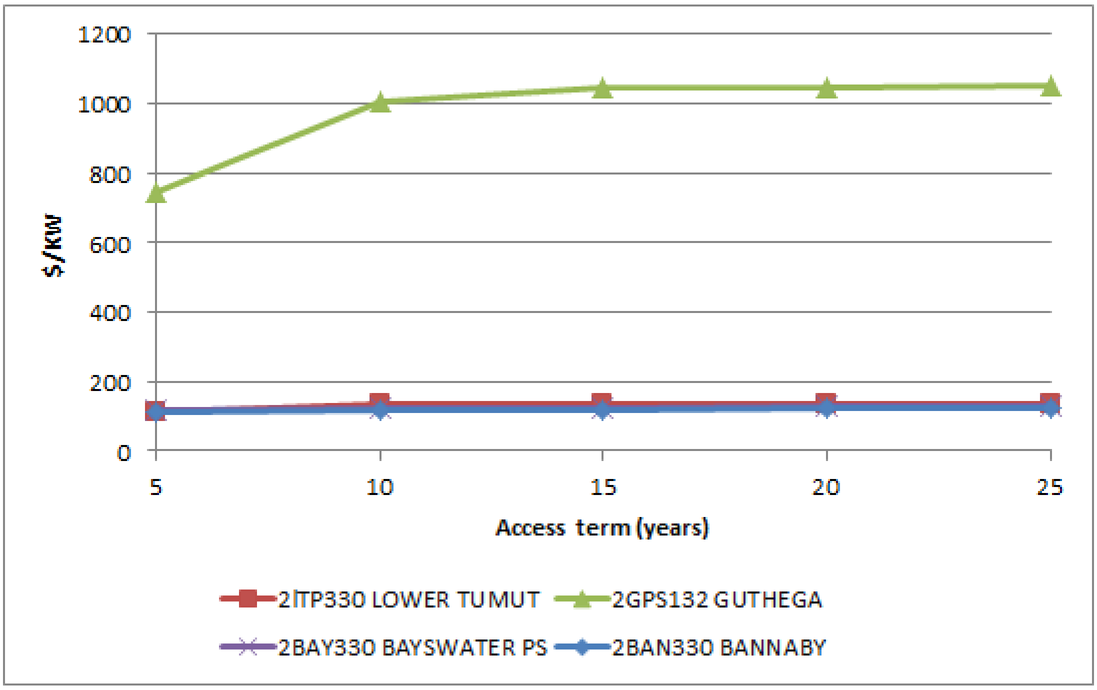


Figure D.9 Access prices, varying by access term, South Australia

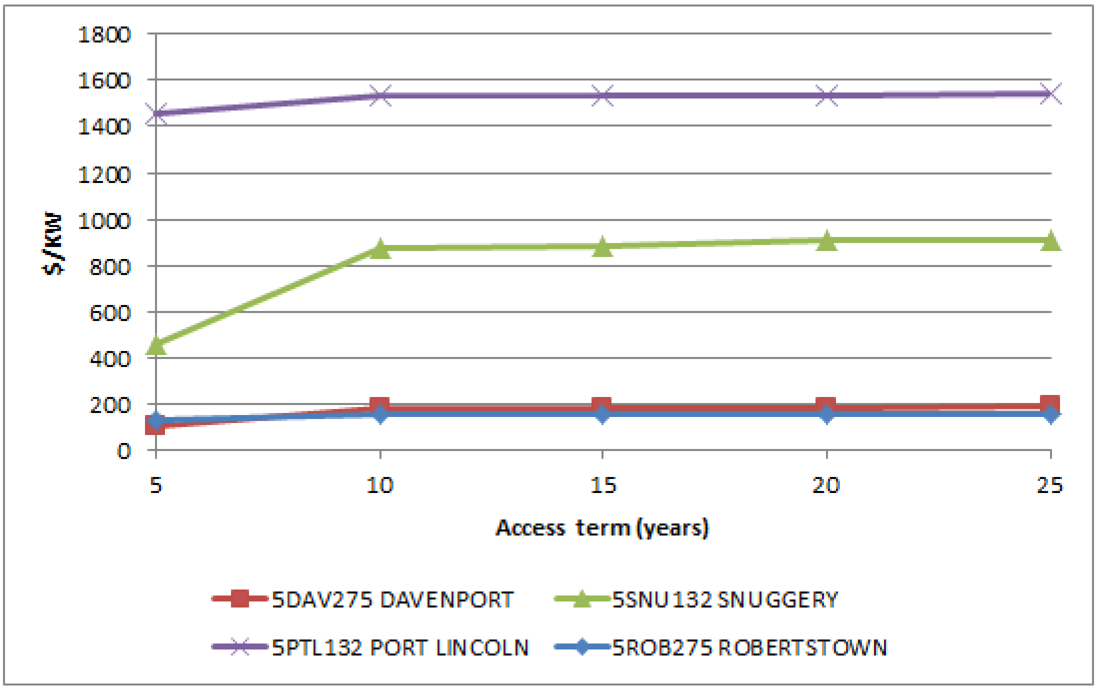


Figure D.10 to Figure D.12 show, for each region, the indicative annual payment that a generator would make for a given access request length (assuming a fixed annual payment in net present value terms over the life of the access request).

Figure D.10 Annual access prices by access term, Queensland

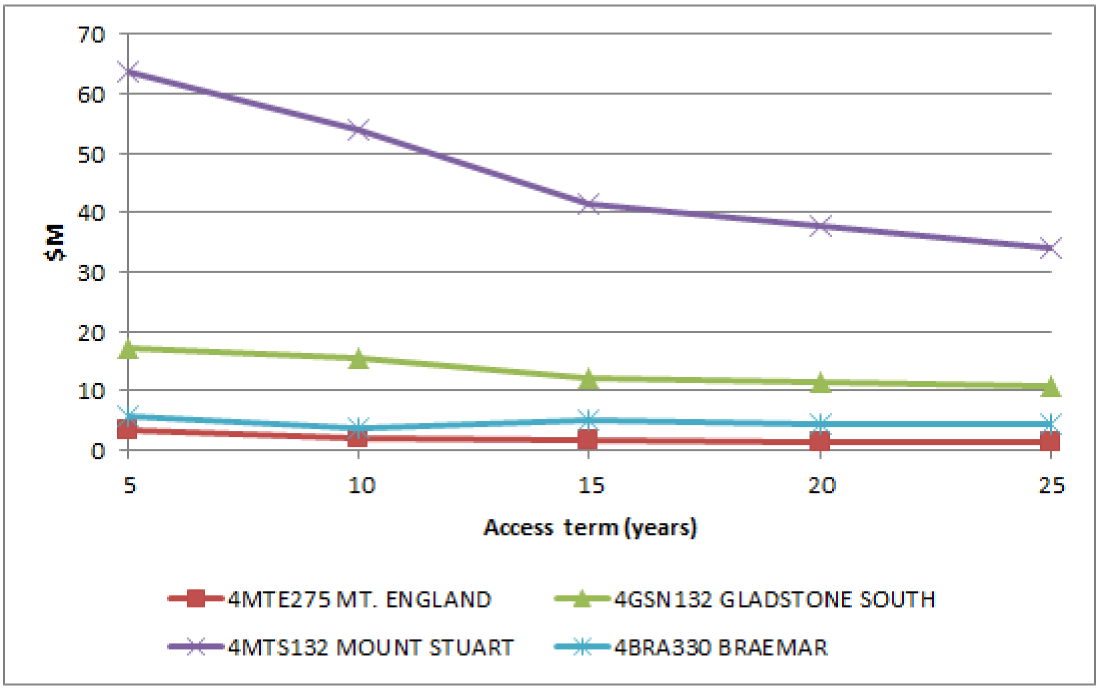


Figure D.11 Annual access prices by access term, NSW

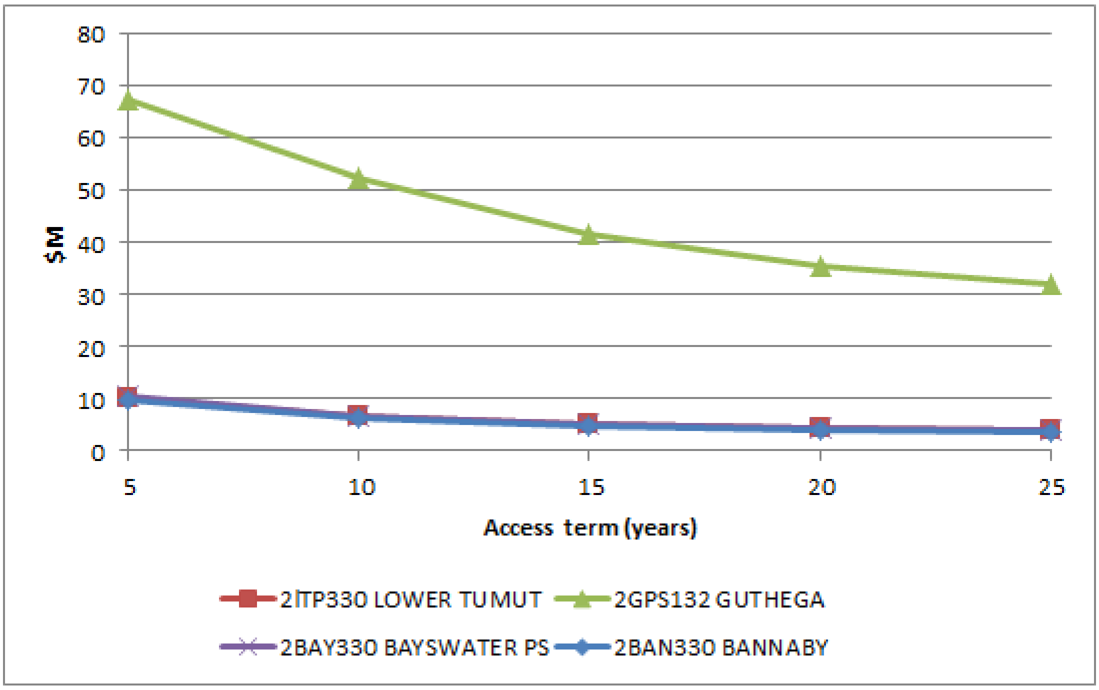


Figure D.12 Annual access prices by access term, South Australia