OFA design and testing – response to AEMC First Interim Report

A REPORT PREPARED FOR AGL, ORIGIN, SNOWY HYDRO, HYDRO TASMANIA AND STANWELL

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Executive summary

Frontier Economics has prepared this report for a broad coalition of NEM participants on the AEMC's Optional Firm Access (OFA) proposal. In our view, OFA can be characterised as 'a solution looking for a problem'. The AEMC has failed to demonstrate clear shortcomings in the existing NEM transmission arrangements that warrant such a radical change. Further, OFA is far from a benign intervention. Apart from having ambiguous effects on dispatch, OFA raises generators' risks and costs creating barriers to entry, centralises investment decision-making across the NEM and magnifies market complexity.

Bidding and dispatch effects

OFA is designed in part to improve the economic efficiency of generation dispatch. Generators in the current market can have incentives to bid in a non-cost-reflective or 'disorderly' manner. By settling generators at a price that reflects their local demand-supply conditions, OFA seeks to discourage disorderly bidding. However, our report shows that:

- The economic costs associated with disorderly bidding are extremely small, especially when put into perspective to total dispatch costs in the NEM. Moreover, OFA would increase incentives to engage in other forms of non-cost-reflective bidding, such as 'headroom bidding' and 'bidding-to-bind', both of which would reduce economic efficiency. The ultimate result is that OFA's impact on economic efficiency is ambiguous and minimal at best. In the Base Case, the *maximum* reduction in annual dispatch cost for the NEM is approximately 0.2%.
- Against this immaterial gross cost saving for consumers, OFA will have a large detrimental impact on existing generators. To the extent existing generators are not granted firm access rights, they will be compelled to acquire access, adding to their costs. These extra costs will ultimately be passed on to end-use customers, with the timing of the pass-through depending on whether generators:
  - raise their prices quickly, in which case consumers will quickly face the costs of generator access rights plus the other costs associated with OFA, including the costs of dealing with a significantly more complex market
  - do not quickly raise their prices, in which case our analysis shows that a significant amount of additional capacity will become loss making and eventually exit the market, thereby driving up wholesale and retail prices

Participant risks and implications for end-use customers

For those generators who are regularly constrained-off under current arrangements, moving to OFA with a high level of firm access may slightly reduce generator risk profiles and facilitate a small increase in optimal hedging levels. However, the benefits of increased firmness are outweighed by even small access costs. Additionally, acquiring firm access rights does not ensure a generator has firm access in the traditional meaning of the term as access is scaled back even for firm generators in the event of significant congestion. If the same generator chooses to remain non-firm whilst other generators are predominantly firm, then generator risk greatly increases and optimal hedging levels are significantly lower. These outcomes belie both the 'optional' and 'firm' description of OFA.

In the long term, the need for generators to recover access costs in addition to asset financing costs under OFA will require higher average wholesale market prices and final retail bills for end customers. This could occur via some combination of early generation retirement, delayed entry/investment or a reduction in maintenance spending which reduces the reliability of generation. The extra generator costs and heightened complexity of the NEM associated with OFA will raise barriers to entry for new generators and reduce competition.

In a best case, reallocation of transmission costs to generators would result in an indifferent outcome for consumers (any reductions in network costs are offset by corresponding increases in wholesale costs). In the more likely case, OFA will raise prices for consumers and create a demand for additional regulation such as has occurred in European and North American markets. In particular, policy-makers sensitive to the price rises resulting from the exit of generators due to OFA could respond through the adoption of capacity mechanisms that are directly funded by consumers.

Investment coordination

Another of the AEMC's key motivations for proposing OFA is to improve the coordination between generation and transmission investment. The AEMC suggested that OFA would improve investment coordination by:

- Promoting more 'market-led' transmission investment decision-making and
- Creating a cost-reflective locational signal for new generation investment that is currently missing in the NEM.

In our view, this assessment overlooks three key points:

- Existing transmission regulatory arrangements in the NEM help promote efficient coordination of transmission and generation investment.
- There is no evidence that the existing arrangements have caused or are likely in future to result in materially sub-optimal coordination of transmission and generation investment. For example, generation investments at Millmerran, Uranquinty and Mortlake were not locationally distorted by existing transmission planning arrangements.
- OFA reflects a more rather than less centralised approach to the coordination of generation and transmission investment compared to existing NEM

arrangements. This is because under OFA, the prices applicable to a particular access rights request would be highly dependent on the modeller's views regarding future generation and transmission investments and power flows in different locations into the distant future. OFA therefore represents a serious backward step to the failed centrally planned power system model.

In addition, the proposed approach to reliability planning under OFA is inherently flawed and likely to undermine the efficiency of transmission planning.

Indicative access prices

Our analysis of the AEMC's prototype access rights pricing model reveals that the model produces anomalous and inconsistent results. This may be indicative of fundamental issues with the model and is deeply concerning for stakeholders as there seems to be no recognition by the AEMC that these are problems that need to be addressed.

Complexity

The introduction of OFA represents the most significant change to the wholesale energy market since the inception of the NEM and is a step towards greater complexity and centralisation. Forecasting market outcomes is likely to be much more difficult under OFA than under current arrangements. Similarly, ex post analysis of market outcomes (for example, AEMO price event reports) in a world with OFA would become much more complex, particularly since firm access quantities are unlikely to be public information. This has implications for the analysis presented in this report and for stakeholders more generally. Reducing the ability of stakeholders to understand and forecast market outcomes reduces their ability to assess potential changes to policy and regulation, undertake commercial activities and manage risk. It also ultimately reduces the transparency of the NEM as a whole.

Conclusion

Adopting OFA will incur significant one-off implementation and on-going costs across the NEM. Combined with potential harm to the efficiency of transmission investment decision-making and increased risks and complexity, OFA is highly likely to yield net detriments, contrary to the National Electricity Objective.

1 Introduction

1.1 Background

Frontier Economics has prepared this report for a broad coalition of NEM participants on the Australian Energy Market Commission's (AEMC's) Optional Firm Access (OFA) proposal. The coalition of participants comprises:

- AGL
- Origin Energy
- Snowy Hydro
- Hydro Tasmania
- Stanwell

OFA will introduce significant changes to NEM wholesale market settlement and transmission planning and augmentation arrangements. In 2012, Frontier Economics drafted a report on behalf of the National Generators Forum (NGF)[1] critiquing the AEMC's original conception of the OFA proposal, as contained in the AEMC's Second Interim Report for the Transmission Frameworks Review[2] and the OFA Technical Report.[3]

This report:

- Outlines the AEMC's rationales for the OFA proposal and the nature of the problems OFA is designed to resolve
- Discusses the immaterial magnitude of efficiency losses due to 'disorderly bidding' found in earlier analyses and notes the perverse bidding incentives promoted by OFA
- Assesses the impact of the OFA proposal in relation to:
  - Dispatch efficiency: This is measured by comparing the economic resource costs of dispatch of the NEM under the Status Quo and OFA.

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1 Frontier Economics, *Optional Firm Access, A Report prepared for the National Generators' Forum*, October 2012, available from the AEMC website at: http://www.aemc.gov.au/getattachment/7bb8fd27-07ec-4775-82b6-25f3ad8dd3df/National-Generators-Forum-Frontier-Economics-attac.aspx (Frontier Economics October 2012 report).

2 AEMC, *Second Interim Report, Transmission Frameworks Review*, 15 August 2012, available from the AEMC website at: http://www.aemc.gov.au/getattachment/f8048831-fcc9-4313-97f0-8013d350f0c1/Second-Interim-Report.aspx (AEMC TFR Second Interim Report).

3 AEMC, *Technical Report: Optional Firm Access, Transmission Frameworks Review*, 15 August 2012, available from the AEMC website at: http://www.aemc.gov.au/getattachment/e9261cc9-c4b2-4e59-b110-b2cbd5e8237f/Technical-Report-Optional-Firm-Access.aspx (AEMC OFA Technical Report).

    - Distributional effects: The financial impact of OFA on consumers and on existing generators.
- Comments on the true optionality and 'firmness' of OFA rights and the implications for participant risk-management and hedging practices
- Discusses the implications of OFA for the:
    - Degree of centralisation/decentralisation inherent in transmission investment decision-making
    - Efficient coordination of investment in generation and transmission
- Comments on apparent inconsistencies and anomalies in the AEMC's access pricing model results.

1.2 About the rest of this report

This report is structured as follows:

- Section 2 examines the AEMC's rationales for OFA
- Section 3 discusses the effect of OFA on generator bidding incentives
- Section 4 explains the results of our dispatch analysis of OFA
- Section 5 highlights the participant risk and end-customer implications of OFA
- Section 6 addresses the implications of OFA for the generation-transmission investment coordination problem
- Section 7 raises a number of issues associated with the AEMC's access pricing model.
- Appendix A sets out our approach to dispatch modelling
- Appendix B sets out our modelling input assumptions
- Appendix C reiterates our stylised example of locational incentives under the existing transmission arrangements.

2 AEMC's rationales for OFA

In its Transmission Frameworks Review, the AEMC described OFA as having the potential to address a number of shortcomings it perceived in the existing NEM transmission and market arrangements.

For example, in its Final Report for the TFR, the AEMC stated that under OFA:[4]

- Generators would have the option of buying firm access rights to transmission networks to manage congestion risk. Giving generators the ability to secure firm access should create more revenue certainty. This may result in a lower risk-adjusted cost of capital, resulting in lower financing costs for power stations.
- Generators, rather than planners, would drive some part of the decision-making about future transmission development. In choosing to acquire firm access, generators would fund and guide the development of new transmission to underpin their access rights. This would introduce more commercial drivers on TNSPs and more commercial financing of transmission infrastructure. The approach should result in a closer alignment of generation and transmission investment and has the potential to minimise prices for electricity consumers in the longer term by minimising the total system cost of building and operating both generation and transmission.
- The owners of generation businesses would bear the costs of transmission development undertaken to support their access decision.
- OFA would support trade between generators and retailers in different regions of the NEM by providing a firmer hedge against inter-regional price differences than is currently available. Increased trade may enhance competition in both the wholesale and retail markets.
- Overall generator dispatch would be more economically efficient. The current incentive for generators to offer their electricity in a non-cost reflective manner during times of congestion would be reduced.

We question both the existence and materiality of the AEMC's claimed benefits of OFA and suggest that in most instances OFA is more likely to worsen perceived problems with the existing NEM design rather than alleviate them. The remainder of this report outlines our reasons for disbelieving the merits of the OFA proposal.

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4 AEMC, *Final Report, Transmission Frameworks Review*, 11 April 2013, available from the AEMC website at: http://www.aemc.gov.au/getattachment/c4773c34-c142-41da-95b0-35697b8b1109/Transmission-Frameworks-Review-Final-Report.aspx (AEMC TFR Final Report), pp.iii-iv.

3 Bidding incentives – now and with OFA

3.1 Background

One of the AEMC's stated rationales for OFA is to improve the economic efficiency of generation dispatch. Dispatch is efficient when the resource or opportunity costs of producing and transporting electricity to supply customers' demands is minimised. Broadly speaking, this requires that generators with the lowest operating costs are run or 'dispatched' first, and more expensive-to-run generators are utilised only when cheaper generators cannot supply additional power, either due to their own capacity limitations or the limitations of the transmission network.

The AEMC's Final Report for the TFR and its First Interim Report for OFA explained that the current NEM design can lead to inefficient dispatch.[5] Fully efficient dispatch requires generators to offer their available capacity to the market and system operator, AEMO, at or close to their marginal resource costs.[6] This enables AEMO to dispatch the cheapest generator bids first and only draw upon more expensive generators if required. However, generators in the current market can have incentives to bid in a non-cost-reflective or 'disorderly' manner. Specifically, generators who cannot be dispatched or fully dispatched due to transmission constraints can have incentives to offer their output at the market floor price (-$1,000/MWh), even though such generators incur a positive marginal cost from generating. Such behaviour can compromise the economic efficiency of dispatch because it could lead to AEMO dispatching low-bidding but high-cost generators ahead of generators with genuinely lower costs.

Both the AEMC and the AER have also claimed that disorderly bidding can have other harmful effects on the NEM – namely, wholesale spot price volatility, counter-price flows and negative settlement residues on interconnectors.[7]

By settling generators at a price that reflects their local demand-supply conditions (ie their local 'nodal' price), OFA is in part designed to encourage cost-reflective generator bidding and discouraging disorderly bidding. The AEMC has

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5 AEMC, *Final Report, Transmission Frameworks Review*, 11 April 2013, available from the AEMC website at: http://www.aemc.gov.au/getattachment/c4773c34-c142-41da-95b0-35697b8b1109/Transmission-Frameworks-Review-Final-Report.aspx (AEMC TFR Final Report), pp.ii, 5-6, 109.

6 Under this condition of efficiency, in an energy-only market, all generators will only recover their fixed costs to the extent that market prices are allowed to rise sufficiently high.

7 See AEMC TFR Final Report, pp.5-6; AEMC OFA First Interim Report, pp. v, 111, 135-136; AER, *Special Report, The impact of congestion on bidding and inter-regional trade in the NEM*, December 2012, available from the AER website at: https://www.aer.gov.au/node/18855 (AER Disorderly Bidding Report), pp.7-8.

previously gone as far as contending that the OFA proposal would "solve the problem of disorderly bidding".[8] In principle, settling generators at their local nodal prices should improve the economic efficiency of dispatch. However, as explained below:

- Even if OFA were to eliminate disorderly bidding altogether, the magnitude of any dispatch efficiency improvements are likely to be small and
- OFA can have other, unintended effects that offset any such benefits.

3.2 Impacts of disorderly bidding

3.2.1 Impact on economic efficiency of dispatch

Despite the ostensibly harmful appearance of disorderly bidding, there is scant evidence that it results in a material loss of productive efficiency. This lack of real harm is due to two reasons:

- Episodes of disorderly bidding tend to be rare and brief and largely occur during transmission outages[9]
- Underlying resource cost differences between the generators dispatched out-of-merit order tend to be relatively small

Consider the example highlighted by AEMO in its submission to the AEMC's TFR Issues Paper in 2012.[10] Appendix B of AEMO's submission discussed the events of 9 December 2009. On that date, a planned transmission outage between Wallerawang and Mt Piper led to rebidding that caused pool settlement to be $300 million higher than it otherwise would have been assuming no rebidding.[11] However, in an earlier report prepared for the NGF, we noted that the actual increase in generation resource costs attributable to that incident would have been no more than $0.3 million and quite possibly much less.[12] This is

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8 AEMC OFA Technical Report, p.12.

9 Analysis undertaken by the NGF in 2012 showed that of the 20 instances of counter-price flows on the NSW-Victoria interconnector that resulted from disorderly bidding, 17 arose during transmission outages. See Letter from Tim Reardon to John Pierce, 21 December 2012, available from the AEMC website at: http://www.aemc.gov.au/getattachment/2e8e753a-be28-40d4-8f51-cb52bbebd0d9/National-Generators-Forum-%E2%80%93-response-to-AER-Specia.aspx.

10 AEMO, *Transmission Frameworks Review – Submission to AEMC's Issues Paper*, 7 October 2010, available from the AEMC website at: http://www.aemc.gov.au/Media/docs/AEMO-b64b3c62-db16-4a2b-aa28-316545eb4b38-0.pdf.

11 This is not to say that there was no efficiency-related rationale for the rebidding that occurred.

12 Frontier Economics, *Transmission Frameworks Review – 1st Interim Report*, April 2012, available from the AEMC website at: http://www.aemc.gov.au/getattachment/59e09796-7f1f-496d-815d-3d702c127c77/National-Generators-Forum-Frontier-Economics-attac.aspx (Frontier April 2012 report).

because disorderly bidding in that case may have led to gas-fired and hydro peaking plant displacing cheaper coal-fired plant for just a few hours in respect of a modest volume of output. In most cases of disorderly bidding, the resource cost implications will likely be far less, as they would often lead to one similar cost coal-fired generator displacing another.

Frontier Economics has remarked on the low productive efficiency costs of disorderly bidding on a number of occasions. In 2008, we estimated the dispatch costs of disorderly bidding for the AEMC's Congestion Management Review (CMR) to be worth approximately 0.5% of aggregate generation resource costs across the NEM ($8 million) for 2007/08.[13] We updated this analysis for the NGF in 2013 using an expanded methodology and estimated the dispatch costs of disorderly bidding to lie between 0.02% and 0.22% ($1 million and $14 million) per annum for 2013-2015, with greater likelihood of the low end of that range being correct.[14] ROAM Consulting undertook modelling of disorderly bidding on behalf of the AEMC.[15] They found that the productive inefficiency costs of disorderly bidding were approximately $3 million for 2008/09 and 2009/10, and $15 million in 2010/11 (although the figure for 2010/11 was skewed by an extreme N-3 event that contributed $7.5 million of these costs).[16]

In its TFR Final Report, the AEMC commented that while the productive inefficiency costs of disorderly bidding had been small to date (given the similar fuel costs of generators in the NEM), "the likely greater spread of fuel costs amongst generators in the NEM in the future (including relatively high cost open cycle gas generators) may affect this outcome over time."[17] Indeed, ROAM's modelling suggested that eliminating disorderly bidding would produce negligible productive efficiency benefits until at least 2019/20 – in no scenario did aggregate benefits exceed $350,000 in present value terms for the period 2012/13 to 2019/20 inclusive. But even beyond 2020, real annual resource cost savings never exceeded $2.5 million. In total, ROAM forecast the present value productive efficiency benefits of eliminating disorderly bidding to be $4 – 11 million in total from 2012/13 to 2029/30 inclusive.[18]

We have undertaken a more comprehensive quantitative analysis of the costs of disorderly bidding and report the results in section 4 below.

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13 See AEMC, *Congestion Management Review, Final Report*, section B.4.1.2, pp.90-101.

14 Frontier Economics, *Economic Costs of Disorderly Bidding*, 2013.

15 ROAM Consulting, Modelling Transmission Frameworks Review, 28 February 2013 (ROAM report), available at the AEMC website at: http://www.aemc.gov.au/getattachment/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks.aspx.

16 ROAM report, Executive Summary (unnumbered) and pp.31-32.

17 AEMC TFR Final Report, p.6.

18 ROAM report, pp.50-51.

3.2.2 Impact on price volatility

As noted above, both the AEMC and the AER have argued that changes to eliminate disorderly bidding would help reduce price volatility and improve the financial reliability or 'firmness' of inter-regional settlement residue (IRSR) units as hedging instruments. The AEMC has suggested that this could increase the willingness of generators to contract and for investors to commit capital to generation.[19] Beyond this claim, the AEMC did not develop its contentions further or quantify the impact on OFA on wholesale price volatility.

We support the notion that the impact of OFA on spot price volatility and the willingness of NEM generators to contract is a crucial consideration in assessing the case for OFA. The volume of energy hedged via NEM derivatives is much greater than the volume of physical energy traded through the spot energy market. Further, participant decisions regarding generation entry and exit are much more directly tied to the contracting environment than short-term spot market outcomes. At the same time, contract prices tend to reflect market expectations regarding future spot market outcomes, as generators behave as if hedging and not hedging are substitutes on the margin.

Empirically speaking, we note that NEM market participants already engage in inter-regional trading freely, with or without hedging their exposures using IRSR units. It is accordingly not clear whether or how much inter-regional trading would increase if IRSRs were firmer. We also note that throughout the history of the NEM, there has been no evidence of a lack of willingness on the part of investors to commit capital to generation assets, indeed the NEM is characterised by a glut of generation.

In December 2012, the AER published a 'Special Report' examining the effects of disorderly bidding on wholesale spot prices and interconnector flows.[20] The report did not make any attempt to estimate the dispatch costs of disorderly bidding. However, it did seek to analyse the impacts of specific incidents of disorderly bidding.

The AER's report examined a number of instances of counter-price flows on the NSW-Victoria interconnector and the Qld-NSW interconnector from late 2009 to late 2012 and explained how they could be attributed to disorderly bidding. The AER expressed concern that to the extent disorderly bidding increased counter-price flows, this would reduce the usefulness of IRSR units as hedging instruments.

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19 AEMC OFA First Interim report, p.111.

20 AER Disorderly Bidding Report, *supra*.

The AER's analysis of disorderly bidding in Queensland focussed on how such bidding contributed to price volatility.[21] However, while some form of generator nodal pricing – such as that embodied in the OFA proposal – is likely to reduce the incidence of price outcomes close to the MFP, it is far from clear that the introduction of OFA would significantly reduce the likelihood of high spot prices under the conditions cited in the AER report. This is because generators with the ability to make constraints bind and/or regional reference prices rise would frequently have similar incentives to induce those outcomes under OFA as they have now, particularly if they received a reasonable allocation of firm access rights.[22] Curbing spot price volatility by reducing some large negative dispatch interval price outcomes but not significantly reducing even larger positive price outcomes would seem to offer few compelling long-term benefits to consumers.

3.3 Perverse bidding incentives created or magnified by OFA

Our April and October 2012 reports for the NGF explained that while the adoption of OFA could reduce incentives for generators to engage in certain forms of disorderly bidding, OFA would increase incentives to engage in other forms of non-cost-reflective bidding.[23] This means that the ultimate impact of OFA on the economic efficiency of dispatch is ambiguous.

Specifically, we noted that OFA could:

- Give generators incentives to physically or economically withhold capacity to create 'headroom' on transmission lines between their location and the regional reference node in order to be settled at higher prices. This will be referred to as 'headroom bidding'.
- Give generators with firm transmission rights incentives to bid below their avoidable resource costs in order to receive larger compensation from non firm generators than the operating loss on dispatched output during constraints. This will be referred to as 'bidding to bind'.

These incentives are described briefly below.

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21 AER Disorderly Bidding Report, see especially pp.15-16.

22 Consider the AER's discussion (p.15) of CS Energy's bidding incentives under conditions of binding Calvale to Wurdong constraints. If CS Energy possessed a reasonable quantity of firm access rights for its Callide plant under OFA, it would retain the incentive to bid Callide below-cost at low ramp rates in order to force Stanwell's Tarong plant to be backed-off and raise the Queensland RRP. The fact that Callide would be settled in the spot market at a low (or negative) local nodal price under OFA would not deter this behaviour, so long as CS Energy held significant firm access rights to the Queensland regional reference node. According to the AEMC's OFA First Interim Report, this is likely to be the case (see p.149).

23 See Frontier April 2012 report, pp.2-6; Frontier October 2012 report, pp.31-34.

3.3.1 Incentives for headroom bidding

The AEMC has itself previously noted that settling generators at their local nodal prices (an essential feature of OFA) can increase incentives for generators to:[24]

- Withhold a proportion of their capacity from the market and/or
- Offer their output at a price well in excess of their resource costs of production.

The reason for engaging in such conduct under nodal pricing is to prevent transmission constraints from binding and driving down the local prices upon which generators are settled. By producing less electricity, generators can help keep exporting lines unconstrained and benefit from the higher prices prevailing at the RRN.

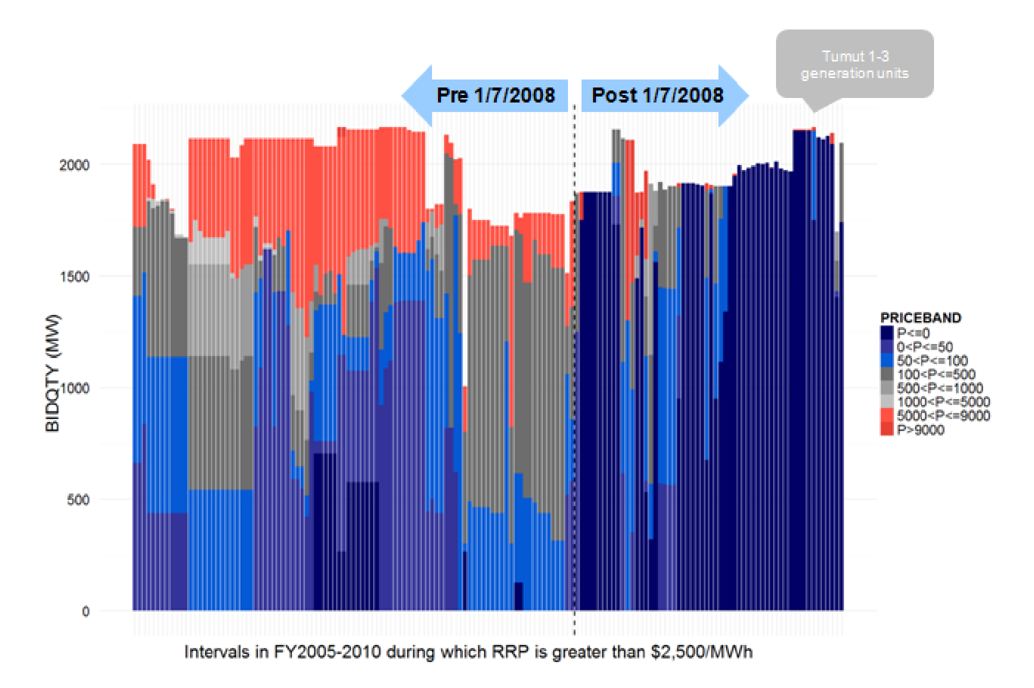
The sorts of behaviours described above – if engaged in only from time to time – are described as the exercise of 'transient market power', because firms operating in perfectly competitive markets would not have such incentives. The exercise of transient market power is not generally regarded as a market design problem.

Figure 1 below shows how Snowy's bidding of the Tumut plant at times of high prices changed following the abolition of the Snowy region. Before the change, Tumut was settled at its local regional Snowy price. As a result, at times of high NSW prices, Snowy offered much of its Tumut capacity at prices likely to be well above its marginal costs (eg > $100/MWh) in order to leave spare capacity or 'headroom' on lines to its north. This prevented the Snowy-NSW interconnector from binding and kept the Snowy regional price high (like the NSW price) at times of northward flows. After the change, when Tumut was included in the NSW region, Tumut generally offered most of its capacity at much lower prices. This is because Snowy no longer had an interest in preventing transmission lines to Tumut's north from binding.

To the extent that OFA leads to more generators throughout the NEM exercising transient market power to prevent constraints from binding and sustaining the wholesale prices upon which they are settled, the impact of OFA on dispatch efficiency is ambiguous.

24 AEMC, *Congestion Management Review, Final Report*, section C.5.3.2, p.191.

Figure 1: Tumut bidding changes at high-price times



Source: Frontier Economics analysis of AEMO data

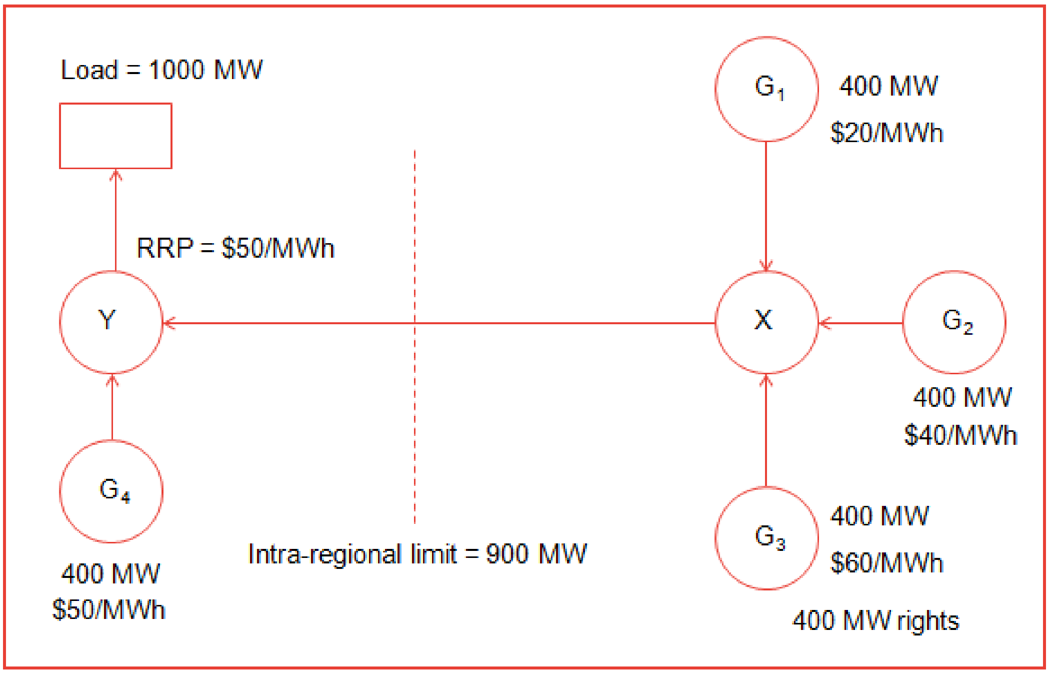
3.3.2 Incentives for bidding-to-bind

In addition to promoting headroom bidding, OFA may also create perverse incentives for generators to bid in a non-cost-reflective manner so as to induce constraints to bind. Such perverse incentives do not exist under the current regional settlement market design.

The incentives for generators under OFA to engage in 'bidding-to-bind' arise in circumstances where the payoffs from ownership of access rights exceed the operating losses they incur from being dispatched and settled below their marginal costs.

Consider the example in Figure 2. A load of 1000 MW can be served by four generators – G1 to G4. Each generator is labelled with its size (in MW) and marginal cost (in $/MWh). A transmission limit prevents more than 900 MW of combined output from generators G1, G2 and G3 supplying the load.

Figure 2: Bidding-to-bind incentives



Source: Frontier Economics

Under the current market design, no generator has an incentive to bid below its costs. Rather, assuming no exercise of transient market power by any generator, the load will be supplied by 400 MW from G1, 400 MW from G2 and 200 MW from G4. This results in a (regional reference) price at the load of $50/MWh, set by G4. G3 is not dispatched and earns no profit.

However, under OFA, G3 may have incentives to bid below cost in order to profit from its possession of 400 MW of access rights. These rights provide G3 with a payoff equal to 400 MW multiplied the difference between the price at the load (Y) and the price at G3's local node (X). By bidding just over 100 MW at a price below $40/MWh, G3 can cause the transmission constraint to bind. This causes the local nodal price at X – the price upon which G3 is settled under OFA – to fall to $40/MWh, set by G2. Under these conditions, G3 incurs an operating loss of $2000 per hour on its output (ie 100 MW x [$40/MWh - $60/MWh]). But G3 also makes a profit on its access rights of $4000 per hour (ie 400 MW x [$50/MWh - $40/MWh]). This results in a net profit for G3 of $2000 per hour (ie $4000 - $2000).

Furthermore, such bidding-to-bind behaviour by G3 has imposed an inefficient dispatch outcome, because G3's 100 MW output has displaced cheaper output from G4. The increase in the resource cost of dispatch is $1000 per hour (ie 100 MW x [$60/MWh - $50/MWh]).

3.4 Conclusion

As we have pointed out in the past, determining whether OFA is likely to improve the economic efficiency of dispatch is an empirical question. There are too many variables to take into account to be confident whether OFA will reduce or increase the overall resource costs of dispatch. While deterring current forms of generator disorderly bidding may improve dispatch efficiency, OFA could increase or introduce incentives to engage in other forms of non-cost-reflective bidding. We have undertaken a comprehensive quantitative modelling exercise to gain a better understanding of the likely dispatch effects of OFA and report the results in the next section.

4 Dispatch analysis of OFA

4.1 Overview

This section presents our analysis of the dispatch implications of OFA in two key areas:

- **Dispatch efficiency:** This is measured by comparing the economic resource costs of dispatch of the NEM under the Status Quo and OFA. One of the supporting arguments for OFA is that:

  > [under] Optional Firm Access, the incentive for bidding behaviour associated with managing or exploiting network congestion would be reduced.[25]

  However, several previous studies have confirmed that the economic costs of disorderly bidding are small relative to the total economic costs of serving demand in the NEM.[26] In addition, because OFA payments fundamentally change generators' payoffs from different bidding strategies, OFA could lead to different equilibrium outcomes in the market. It is possible that while the introduction of OFA could mitigate incentives for disorderly bidding, it may encourage other 'perverse' bidding behaviours that reduce economic efficiency. As discussed above, *a priori*, it is not clear that OFA will improve the efficiency of wholesale market dispatch.

- **Distributional effects:** In this report we also consider the financial impact of OFA on different segments of the market:
  - **The impact on consumers:** End consumers will benefit from OFA if they see reductions in their final retail bills. This study will compare final retail bills for typical residential customers under the Status Quo and OFA.
- **The impact on existing generators:** One argument in favour of the OFA proposal is that it improves financial certainty for generators[27] despite access prices increasing the already considerable fixed costs generators face. Although the purchase of network access rights is notionally voluntary, generators will face strong "Prisoners Dilemma"-style incentives to procure

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25 AEMC, *First Interim Report, Optional Firm Access, Design and Testing*, 24th July 2014. p30, http://www.aemc.gov.au/getattachment/1f15553d-e513-4d9a-9b96-f9549b9ae589/First-Interim-Report.aspx. (AEMC OFA First Interim Report).

26 Frontier Economics, *Economic Costs of Disorderly Bidding*, 2013.

ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013 (ROAM report), available at the AEMC website at: http://www.aemc.gov.au/getattachment/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks.aspx.

27 AEMC OFA First Interim Report, p19

access because the purchase of access by one generator reduces the compensation provided to (other) non-firm generators (discussed in more detail in Section 5.3.3). These extra costs will ultimately be passed on to end-use customers, with the timing of the pass-through depending on whether generators:

- raise their prices quickly, in which case consumers will quickly face the costs of generator access rights plus the other costs associated with OFA, including the costs of dealing with a significantly more complex market
- do not quickly raise their prices, in which case our analysis shows that a significant amount of additional capacity will become loss making and eventually exit the market, thereby driving up wholesale and retail prices

OFA is a complex scheme and a detailed description of our approach is covered in Appendix A. The assumptions used in the modelling are documented in Appendix B. Our results are described and discussed in this section.

In considering the results of our analyses there are two key issues that arise, discussed below.

Complexity

From a practical perspective, modelling the dispatch implications of OFA is extremely complex for two main reasons:

1. Half-hourly dispatch and pricing outcomes depend inextricably on inter- and intra-regional transmission constraints.[28] Understanding dispatch outcomes requires understanding complex tradeoffs and interactions across multiple constraints, generators bidding strategies and regions.
2. Fully exploring the range of perverse bidding opportunities possible under OFA requires consideration of a much larger set of possible strategies making it much more complex than investigating bidding incentives under the current arrangements. This has limited the extent to which the modelling reflects the full range of strategies that traders will inevitably identify as they constantly interact with the market. In this sense, our modelling represents only the tip of the iceberg of new opportunities that traders could exploit and disguise in the significantly more complex world of OFA. It is also worth noting that the modelling has been undertaken using the full set of 'system normal' constraints. The opportunities to exploit the perversities created by OFA under system

28 Our modelling included approximately 1000 (system normal) constriants each year. There are currently a total of roughly 10,000 normal, non-normal and discretionary constraints that AEMO currently uses in actual dispatch.

'non-normal' conditions has not been analysed and taken into account at all.

Modelling period

As a consequence of the need to include inter- and intra-regional transmission constraints, the modelling period is limited to the short to medium term – 2014/15 to 2016/17. The set of constraints is large and constantly in flux (see Figure 55). As such, it is not possible to make assumptions with the level of detailed required under OFA beyond a few years into the future. This is unfortunate. The impacts of OFA are likely to be seen beyond 2016/17, however in our opinion there is no robust way to estimate these impacts as the transmission constraints – which are the primary driver of financial flows in the NEM under OFA – cannot be known in sufficient detail beyond this period.

As such, the results for the three years presented in this report must at best be thought of as a proxy for outcomes in the longer term.

This additional modelling complexity resulting from OFA will also plague investors who use similar modelling approaches to understand investment opportunities as we have used in this review to examine the effects of OFA on individual generators. The additional analytical uncertainty created by OFA will have direct economic consequences in the cost of managing the associated investment risks. These are costs that will be ultimately borne by customers.

Scenarios

Our modelling considered a range of sensitivities beyond a base case. A high level summary of key assumptions for each case is presented in Table 1.

Table 1: Sensitivities modelled (differences to base case are bolded)

Sensitivity Name	Demand	Access Allocation	Bidding
Bidding	As Base	As Base	100% at MPF 100% at SRMC 80% at SRMC **70% at SRMC**
Bidding no Contract	As Base	As Base	100% at MPF 100% at SRMC 80% at SRMC **70% at SRMC** **100% pool exposure**

Sensitivity Name	Demand	Access Allocation	Bidding
High Demand	**NEFR2014 POE50 high demand FY2024/25**	As Base	As Base
Non-firm Access	As base	**All generators have 0 agreed access**	As Base
NSW focus	As Base	As Base	**More bidding options in NSW, Peakers can bid MPF** **SRMC bidding outside NSW**
QLD focus	As Base	As Base	**More bidding options in QLD, Peakers can bid MPF** **SRMC bidding outside QLD**
VIC focus	As Base	As Base	**More bidding options in QLD, Peakers can bid MPF** **SRMC bidding outside QLD**

The remainder of this section is set out as follows:

- Section 4.2 presents detailed results for our Base Case
- Section 4.3 outlines results for a number of sensitivities
- Section 4.4 summarises the modelling results

4.2 Base Case results

This section discusses the Base Case results. In brief, the Base Case shows that given the conservative approach we have taken to modelling bidding under OFA, there is likely to be very little impact in terms of gross economic efficiency benefit or distributional effect on retail prices from OFA (let alone net economic benefits). However, even in spite of our conservative modelling approach, there is a very large negative distributional impact on the profitability of existing generators.

The overall change in economic cost of dispatch under OFA is insignificant compared to the total cost of NEM dispatch. This is shown in Table 2.

Table 2: Summary of economic cost difference

Financial Year	Change in annual dispatch cost (million, OFA minus Status Quo)	% of annual NEM dispatch cost
2014/15	-$0.58m	-0.02%
2015/16	$0.44m	0.01%
2016/17	-$6.51m	-0.2%

Source: Frontier Economics

- Wholesale prices reduce under OFA in 2015/16 and 2016/17 in Victoria and in 2016/17 in South Australia. In other years and regions, wholesale prices are unchanged. If it is assumed that there are no other costs of introducing OFA and if retailers fully pass on the energy price savings customers are estimated to benefit from a reduction in price by a maximum of 1%.
- For this immaterial and unlikely retail price reduction for customers, generators will certainly experience a very large and negative financial impact due to OFA. This is because access charges add to the fixed cost of generators and if generators cannot pass on these charges to customers, or cannot pass them on quickly enough, more generators would become loss making than is presently the case. On this score, we estimate (Section 5.3.4) that under the average regional access prices from AEMC's modelling, an additional 5.5GW, or 12.5% of existing NEM capacity will make an EBITDA loss under OFA.

4.2.1 Binding transmission constraints

In terms of market settlement, the key difference introduced by OFA is that generators subject to binding transmission constraints will receive or make OFA payments depending on their access quantity and flowgate usage. Therefore, binding transmission constraints containing generation terms will change the payoffs and incentives of the generators involved, and drive the differences between the OFA and the Status Quo cases. Figure 3 to Figure 5 show the total hours of binding transmission constraints for the three years modelled in the Base Case. Only those constraints binding for more than 2 hours in a year are shown in the charts.

Some of the constraints that had a significant impact on prices and dispatch costs in the NEM in recent years, such as the Calvale-Wurdong constraints in Queensland, have already been built out and this is reflected in the 2014 constraint books. In the 2014 constraint books, most binding constraints occur in the south and affect generators in Victoria. The following three constraints have the biggest impact on generator bidding incentives and drive differences in economic costs and wholesale prices between the Status Quo and OFA base cases:

- V>V_NIL_RADIAL_10_1: This constraint affects Yallourn, Hazelwood, Bairnsdale and Jeeralang A & B. In AEMO's constraint books, its line rating is roughly halved in summer periods. This causes it to bind for the vast majority of the summer period in our modelling. Note that summer in our modelling spans December to March of the following year, which is consistent with the definition of the time-slice in the constraint book.
- T>>V_NIL_YPTX4_3H3Y2_64: This constraint affects many Victorian generators as well as interconnector flows to/from Victoria. This constraint binds for a small number hours during summer in the Status Quo case as a result of specific bidding outcomes. The constraint does not bind in the OFA case as headroom binding to avoid binding the constraint is observed. The interaction between this and previous constraint drives economic cost and wholesale price differences between the cases, which is discussed in more detail later in this section.
- V>>V_NIL_2B_R_R: This constraint also affects many Victorian generators as well as interconnector flows to/from Victoria. The constraint includes AGL's Loy Yang A, Macarthur and Oaklands Hill wind farms. The modelling shows there are times when Loy Yang A bids to bind this constraint in the OFA case to maximise AGL's portfolio profit and there are also times when it bids to keep headroom on this constraint, leading to both increases and decreases in economic costs. This is discussed further below.

We note that the above three constraints drive differences between the Status Quo and OFA cases in all years (see Section 4.2.3). Yet there are reasons to question the veracity of the information contained in the 2014 constraint books from which these results are derived. For example, despite the fact that AEMO's 2014 transmission book halves the line rating of V>V_NIL_RADIAL_10_1 in summer, this does not seem to be reflected in the actual market outcomes according to AEMO's most up-to-date constraint report.[29] Further, a halving of the line rating for this constraint would also sit uneasily with AEMC/AEMO's access pricing modelling, which shows generators in the Latrobe region such as Yallourn having the lowest access prices in the NEM.[30]

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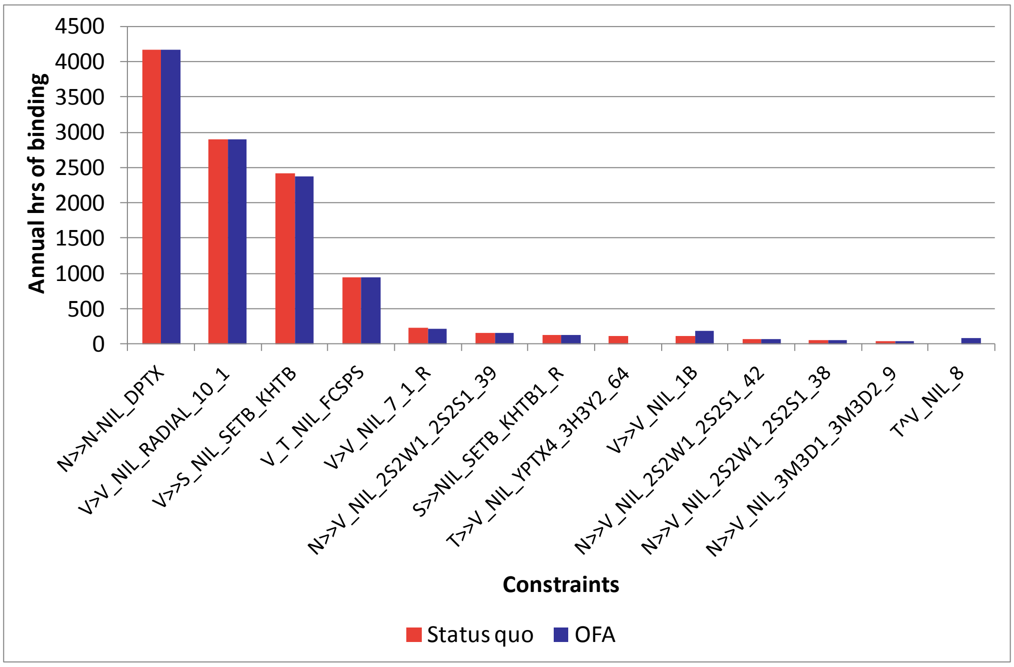
29 AEMO, *Monthly Constraint Report – December 2014*, Jan 2015, pp 4-5.

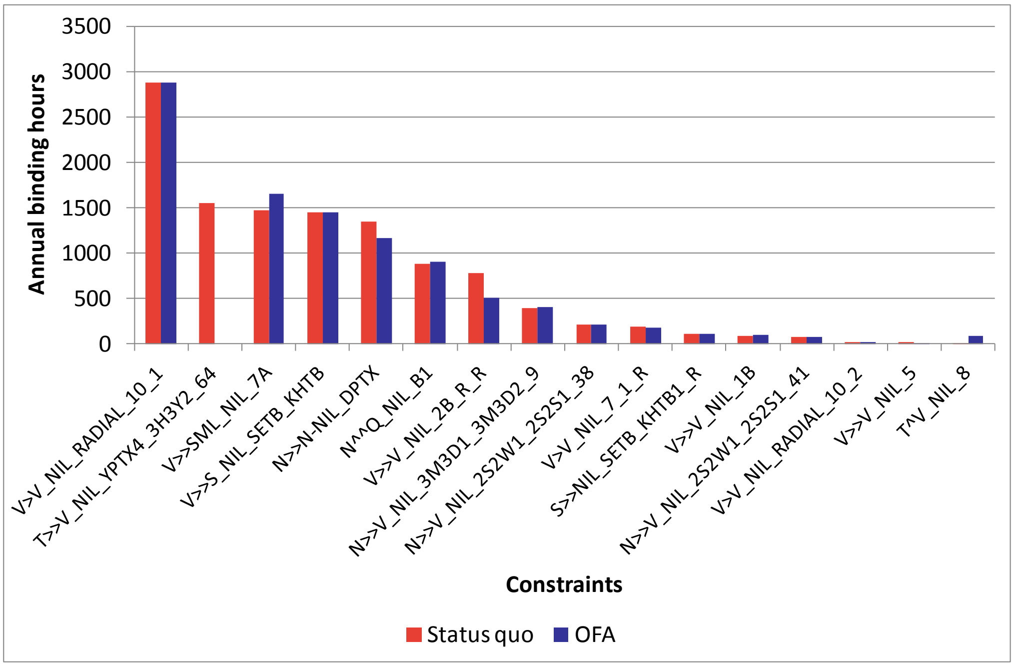
30 AEMC, *Supplementary Report: Pricing Optional Firm Access, Design and Testing*, 31 October 2014 http://www.aemc.gov.au/getattachment/6196b41a-a47b-46b5-85a7-b35ca3eebd69/Supplementary-Report-on-Pricing.aspx (AEMC Supplementary Report 2014), p.45. Most Victorian generators in this chart have significantly lower access prices than the rest of the NEM.

Figure 3: Binding transmission constraints in financial year 2014/15



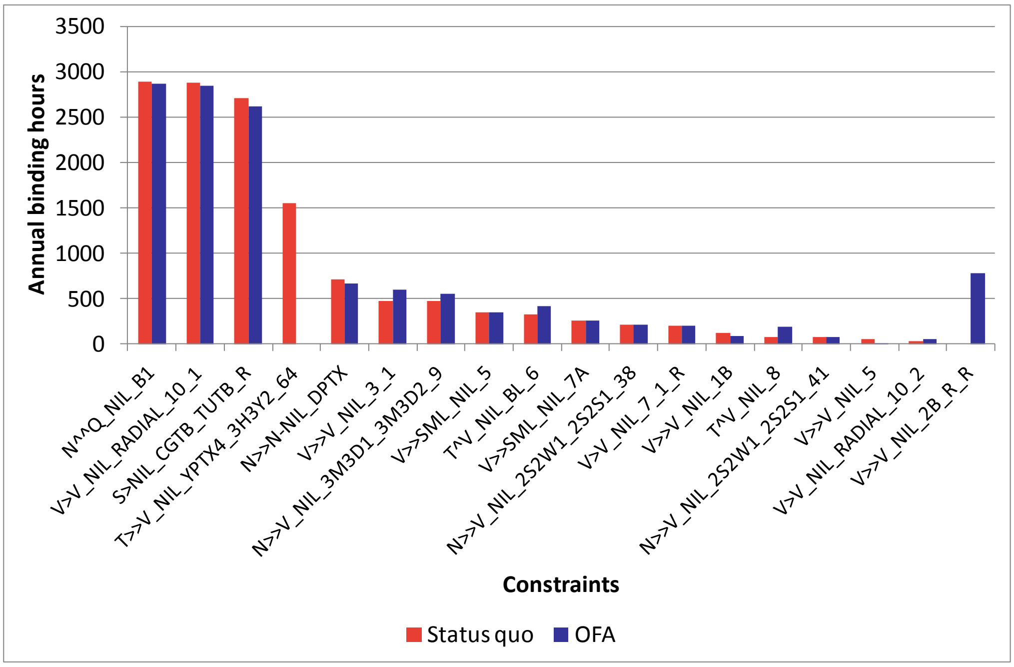
Source: Frontier Economics

Figure 4: Binding transmission constraints in financial year 2015/16



Source: Frontier Economics

Figure 5: Binding transmission constraints in financial year 2016/17

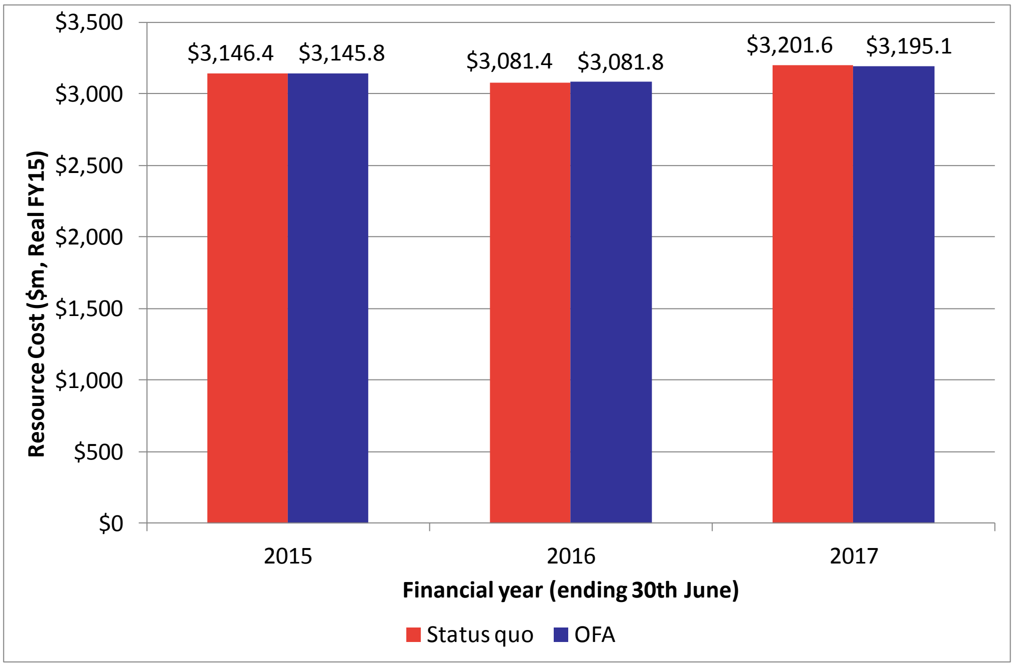


Source: Frontier Economics

4.2.2 Economic cost of dispatch

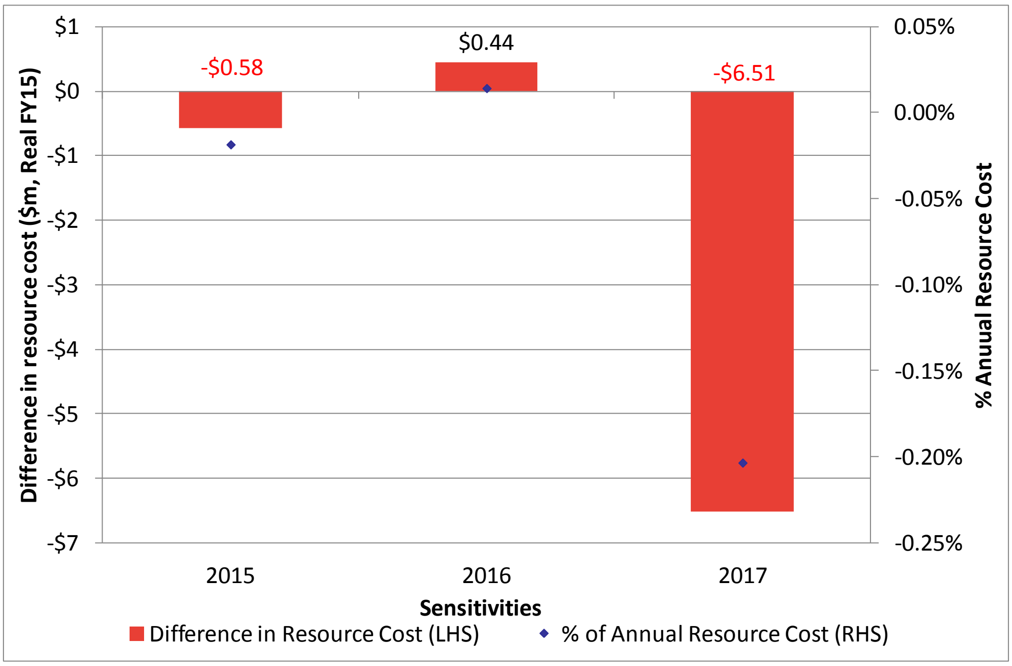
Over the modelling period, the annual change in the economic cost of dispatch is insignificant compared to the total dispatch cost of the NEM. Figure 6 shows the total dispatch cost of the NEM for both the OFA and the Status Quo cases. Figure 7 displays the change in dispatch costs both in absolute terms and as percentage of total dispatch costs. A positive value in Figure 7 indicates higher cost under OFA. The results suggest that the changes in economic cost due to OFA are very small and can be ambiguous. In financial year 2014/15, OFA leads to cost savings of $0.58 million but in financial year 2015/16 the economic cost is higher under OFA by $0.44 million. Economic cost savings under OFA in financial year 2016/17 are around $6.5 million dollars, which represents only 0.2% of total dispatch cost of the NEM.

Figure 6: Base Case NEM economic cost of dispatch



Source: Frontier Economics

Figure 7: Change in Base Case economic costs (OFA *minus* Status Quo)



Source: Frontier Economics

The drivers of these small changes in economic costs are as follows:

- The cost of disorderly bidding, which OFA is intended to address, is small compared to the total cost of serving load in the NEM. As pointed out in earlier studies (See Footnote 14), estimates of the annual economic cost of disorderly bidding are typically less than $10 million, which is much less than 0.5% of the annual total dispatch cost in the NEM.
- Generators engage in headroom bidding under OFA, where they withhold capacity in order to keep constraints open and avoid having to make OFA payments. The increase in dispatch cost due to headroom bidding offsets the benefit from reduced disorderly bidding. It is possible that the overall change is such that the total annual economic cost of dispatch can increase under OFA, as is seen for 2015/16. This is discussed further in Section 4.2.4.
- Due to computational constraints, the Base Case has not identified instances of Bidding-to-Bind where an out-of-merit order generator bids its capacity below its marginal cost, although there are instances where baseload plant offer more capacity in the OFA case at SRMC to bind constraints and earn access payments on a wider portfolio of plant. Below cost bidding is not observed in the modelling because bidding to bind under OFA requires the consideration of more nuanced bidding options than those allowed for in our modelling (ie beyond simply allowing plant to offer all capacity at the MPF). Allowing for these more nuanced options has not been possible due to computational constraints. The sensitivities, however, are able to confirm that bidding to bind can occur under OFA and that when it does, it leads to higher dispatch cost. To the extent that the Base Case is not configured to identify such instances of Bidding-to-Bind, it is likely to *underestimate* the economic cost of dispatch under OFA.

4.2.3 Causes for dispatch cost differences

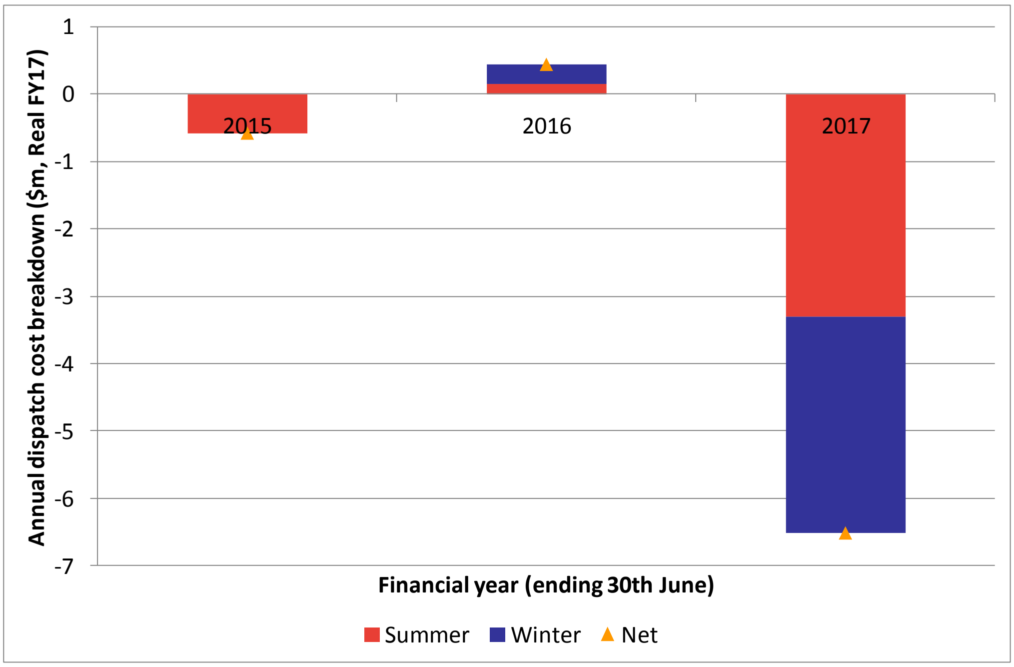
Figure 8 shows the breakdown of dispatch cost by season for the years modelled in the Base Case. The three constraints identified above – V>V_NIL_RADIAL_10_1, T>>V_NIL_YPTX4_3H3Y2_64 and V>>V_NIL_2B_R_R – drive the majority of economic cost differences between the cases. The modelling shows that this can result in both net increases and decreases in annual economic dispatch costs; however, in both cases the total change in costs is small (less than 0.5% of the total cost of dispatch).

In financial year 2014/15, where OFA results in an immaterial cost saving, the differences in dispatch costs are mainly attributable to the summer period (Dec – March as per the definition in the constraint book). Small economic costs associated with disorderly bidding with regard to V>V_NIL_RADIAL_10_1, T>>V_NIL_YPTX4_3H3Y2_64 binding in the Status Quo are avoided under OFA.

In financial year 2015/16, OFA results in additional costs, and both summer and winter contribute roughly the same amount to the increase in dispatch costs. In summer, Hazelwood bids to maintain headroom and avoid T>>V_NIL_YPTX4_3H3Y2_64 binding in the OFA case, which results in an increase in dispatch costs. In winter, very similar effects are seen with regard to Loy Yang B bidding to maintain headroom and avoid V>>V_NIL_2B_R_R binding.

In financial year 2016/17, where OFA results in a very small cost saving, summer and winter periods contribute roughly equally to the reduction in dispatch cost. Outcomes in 2016/17 are more complex than earlier years, and so the rest of this section will examine the main drivers for the results obtained for this year in both seasons.

Figure 8: Dispatch cost breakdown by season (OFA *minus* Status Quo)



Source: Frontier Economics

Summer of 2016/17

In the summer of 2016/17, the results are primarily driven by the interaction between constraints V>V_NIL_RADIAL_10_1 and T>>V_NIL_YPTX4_3H3Y2_64. As discussed in Appendix B, the transmission constraint equations evolve over time, and we are unsure whether those equations as they are in the current 2014 constraint book will still be applicable in 2016/17.

In the Status Quo, both constraints bind and Latrobe Valley generators engage in market price floor bidding, which limits the flow on Basslink into Victoria. Under

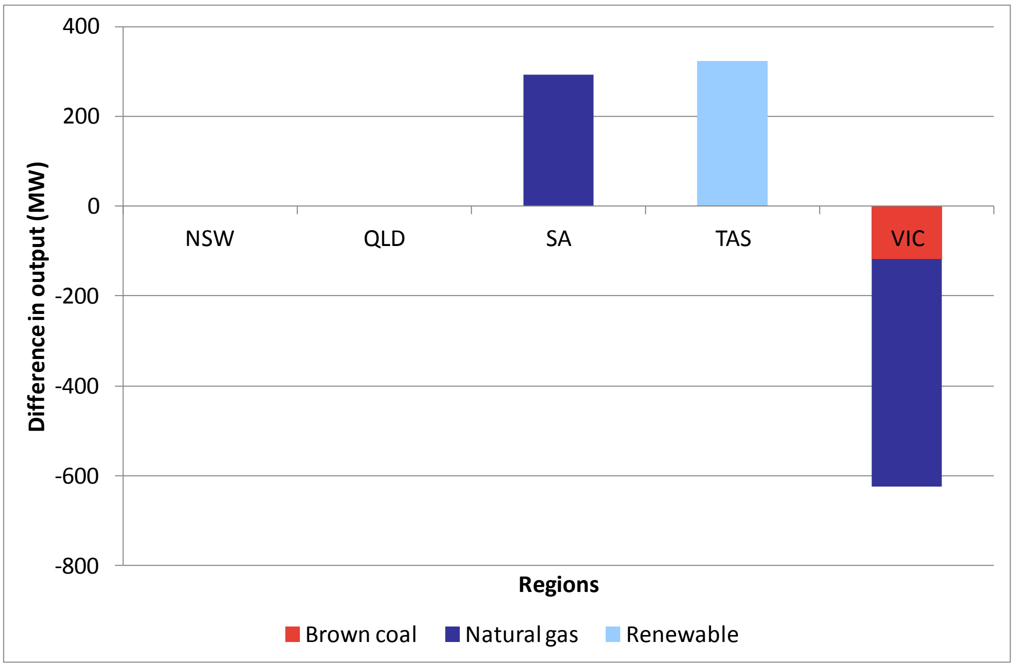
OFA, Hazelwood withholds capacity in order to avoid binding T>>V_NIL_YPTX4_3H3Y2_64 and having to make OFA payments. Typically this would result in a straightforward increase in costs as more expensive generations (e.g., gas) would replace Hazelwood output, as is seen in 2015/16. However, in 2016/17, this is complicated by the interaction between the constraint Hazelwood seeks to avoid binding and the other constraint cited above:

- As noted above, the reduction in Hazelwood output under the T>>V_NIL_YPTX4_3H3Y2_64 constraint allows greater imports over Basslink, supported by increased hydro generation in Tasmania.
- Reduced output from Hazelwood "makes space" for increased Yallourn production under the V>V_NIL_RADIAL_10_1 constraint.

The increase in Yallourn's output due to the relaxation of the V>V_NIL_RADIAL_10_1 constraint partially compensates for the reduction in Hazelwood output. In some summer demand points modelled in 2016/17, the overall effect is that the increase in other cheaper generation offsets the reduction in Hazelwood's output. Figure 9 shows the regional output change by fuel for an example demand point modelled. The additional cheap generation replaces some Victorian gas generation and leads to a reduction in dispatch cost.

Put simply, at certain demand points, the reduction in Hazelwood output caused by headroom bidding is more than offset by cheaper production from Yallourn and Tasmanian hydro, leading to an economic cost reduction under OFA.

Figure 9: Difference in output – example from FY16/17 summer (positive bars represent increases in production under OFA)



Source: Frontier Economics

It is important to note that such a complicated trade-off does not always lead to an overall increase in cheap energy production. As seen in 2015/16 and discussed further in Section 4.2.4, headroom bidding can also lead to higher dispatch costs if there is not a net increase in low cost energy. The saving identified in 2016/17 only arises due to an interaction effect across multiple constraints and as such it may not be robust to changing market and network conditions.

We would emphasise that the existence of the V>V_NIL_RADIAL_10_1 constraint is crucial to the results shown in this section. If the V>V_NIL_RADIAL_10_1 constraint was absent (or did not have its line rating halved during summer, in line with recent experience), the reduction in Hazelwood output would not have been offset by an increase in Yallourn generation. In the absence of the increased Yallourn output, Hazelwood's reduced generation would have to be made up by more expensive generators. This would be likely to reduce the difference in dispatch cost between OFA and the Status Quo, or even lead to a higher dispatch cost under OFA for some of the demand points in 2016/17 summer.

Winter of 2016/17

The main contribution to the lower economic costs in winter under OFA is the constraint V>>V_NIL_2B_R_R. Among other things, it constrains-off AGL's Loy Yang A, Macarthur and Oaklands Hill wind farms as well as interconnector flow from Victoria to NSW. In the Status Quo, AGL withholds Loy Yang A's capacity so that the constraint does not bind and therefore does not block the import of higher regional reference prices from NSW to Victoria. Under OFA, the entire capacity of Loy Yang A is offered, which causes the constraint to bind. Although this leads to a somewhat lower RRP in Victoria compared to the Status Quo, the reduction in AGL's pool revenue is more than offset by OFA payment to the Macarthur and Oaklands hill wind farms[31], which also belong to AGL. These OFA payments are made by other generators in Victoria.

In this case, AGL's incentives to maximise pool revenue at Loy Yang A and other dispatching plant in the Status Quo are overwhelmed by the OFA settlement payments it receives in respect of its non-dispatching wind farms under OFA. This results in a reduction in economic costs, as Loy Yang produces more, but it also produces an important distributional effect whereby other generators who are operating make a net payment to AGL wind farms which are not.

This demonstrates the potential benefit of holding firm access for non-baseload plant within a wider portfolio. Access payments for plant that have large firm access rights but which are not dispatched may be significant.

Currently, the OFA design does not suggest that the transitional allocation of rights to existing wind farms would be different to the transitional allocation to other existing generators. Consequently, wind farms under the transitional allocation may receive access rights close to their registered capacity. This is much higher than their typical output, which is subject to the availability of wind that in some regions is anti-correlated to times of high prices. At some of the demand levels modelled, the large difference between allocated access and actual output result in large OFA payments to wind farms. Generally speaking, transitional access under OFA may lead to windfall payments to existing wind farms and peaking plant. In the case of wind farms, there are a number which typically do not operate at high levels during times of high prices, making these rights even more valuable.

4.2.4 Perverse bidding behaviour – Headroom Bidding

In the Base Case, Headroom bidding occurs under OFA around the constraint T>>V_NIL_YPTX4_3H3Y2_64. There are several demand points where this leads to higher dispatch costs. Here we concentrate on one of them in financial year 2014/15. The demand levels modelled are shown in Table 3.

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31 Note that the wind farms are dispatched at the same, low level in all both the Status Quo and OFA cases and are not constrained off, what changes is the access payments that arise when the relevant constraint binds in the OFA case.

Table 3: Headroom Bidding case – example demand levels

RegionId	Demand (MW)
NSW	8314.6
QLD	6123.9
SA	2156.6
TAS	1209.4
VIC	6611.1

Source: Frontier Economics

The constraint binds under the Status Quo and Hazelwood engages in disorderly bidding. Under OFA, such behaviour would lead to OFA payments being made by Hazelwood.[32]

Figure 10 shows that under OFA, Hazelwood withholds its capacity so that the constraint remains open, despite an increase in dispatch from other generators and increased flows into Victoria. Note that the height of the bar represents flowgate usage, which is output/flow multiplied by the LHS coefficient of the relevant generator/interconnector.

In this instance, the economic cost due to headroom bidding under OFA is much larger than that of disorderly bidding under the Status Quo. When a brown coal generator engages in disorderly bidding under the Status Quo, it is dispatched in preference to some other cheaper generators. However, since the fuel costs for brown coal generators tend to be similarly low, the resulting increase in dispatch cost is small. Conversely, when brown coal generators bid to maintain headroom in response to OFA, the withheld output often has to be made up by much more expensive generators that are marginal or infra-marginal in the merit order. Although the usual tendency for dispatch costs to rise in response to withholding can be complicated by the existence of multiple constraints (as discussed in Section 4.2.3)[33], at this demand point, there is an overall reduction in output from cheap brown coal and renewable generators.[34] This is made up by increased dispatch of more expensive gas plant. Figure 11 shows the change in output by fuel type for this demand point.

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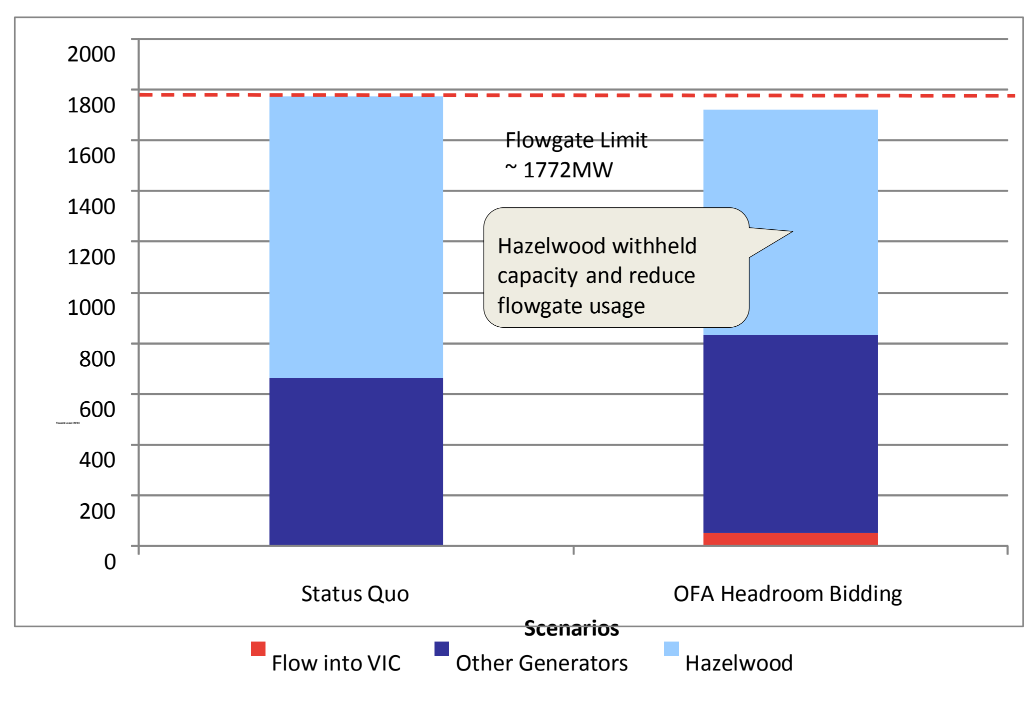
32 Loy Yang B would also make OFA payment. Both Loy Yang B and Hazelwood belong to the same owner, which increases the incentive to keep the constraint open.

33 As explained in 0.0.0, there is interaction between the "T>>V_NIL_YPTX4_3H3Y2_64" and "V>V_NIL_RADIAL_10_1" constraints, Hazelwood's withdraw relaxes the RADIAL constraints, which leads to an increase in Yallourn production,

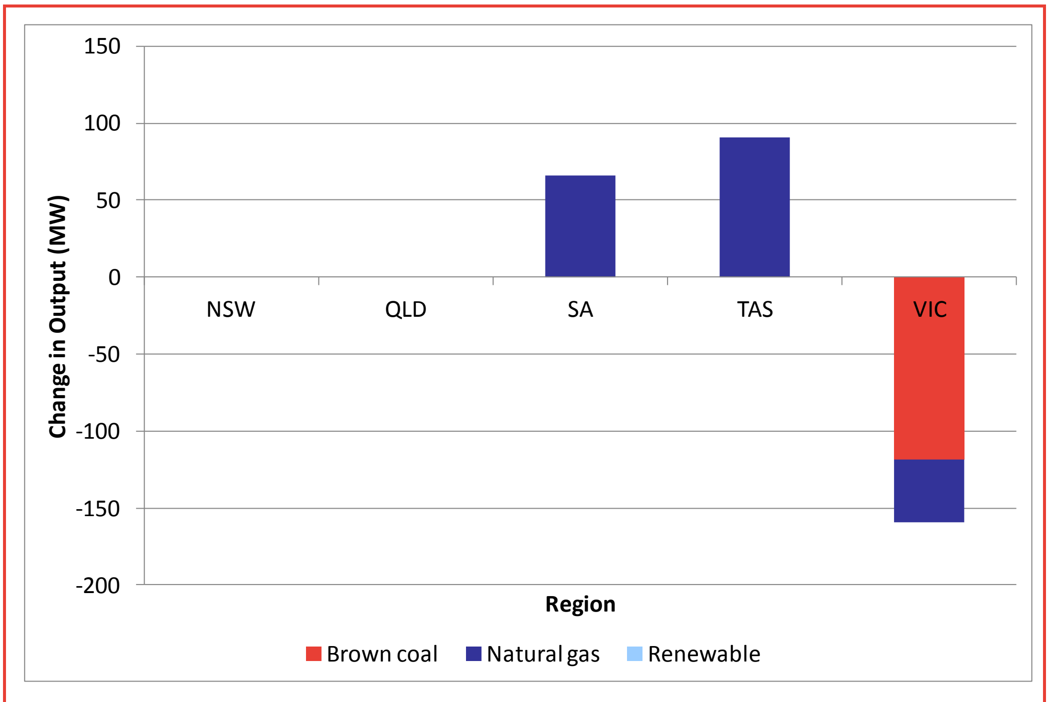
34 In particular, despite increased flow on Basslink, there is an increase in Tasmania gas generation instead of hydro.

Figure 10: Headroom bidding on constraint T>>V_NIL_YPTX4_3H3Y2_64



Source: Frontier Economics

Figure 11: Change in regional output by fuel (OFA *minus* Status Quo)



Source: Frontier Economics

Headroom bidding under OFA in this case increases resource costs by $9,160/hour relative to the Status Quo. The resource cost increase due to headroom bidding more than offsets the decline in resource costs due to discouraging disorderly bidding, as expensive gas generators are dispatched more in the OFA case.

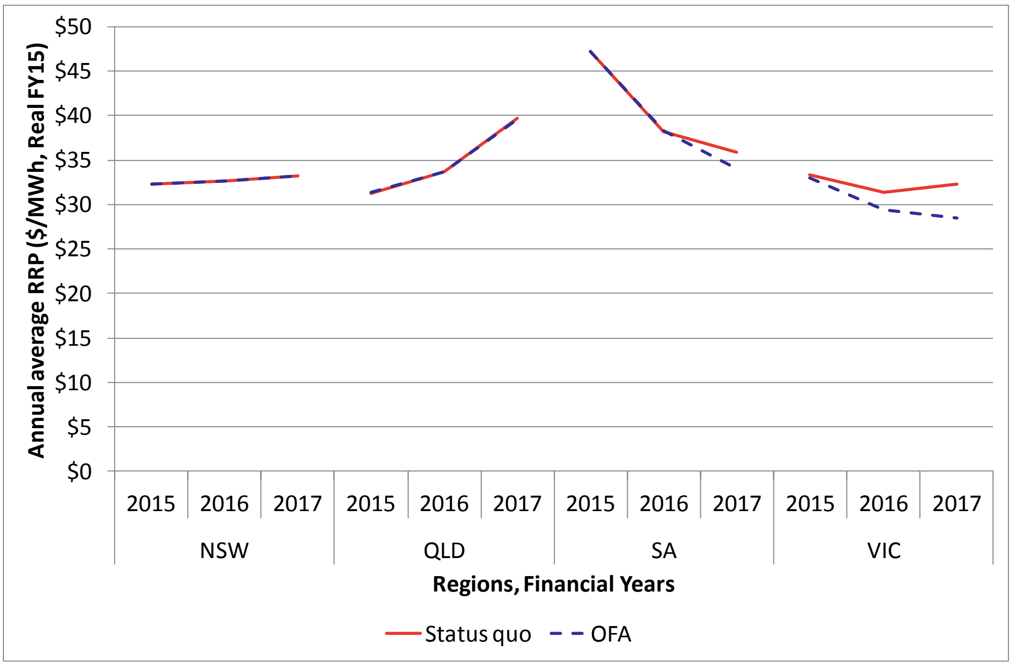
4.2.5 Wholesale and retail electricity prices

Wholesale price impact

Figure 12 shows the annual average regional reference prices for both the Status Quo and OFA cases. Modelled wholesale prices are generally low in all NEM regions (except for SA in 2014/15), which is consistent with the overall low demand conditions across the NEM. Pool prices in Victoria and South Australia are lower in the later years due to modelled new wind entrants to meet the LRET. This is shown in Figure 13. Recall that investment results from *WHIRLYGIG* are independent of the assumption of Status Quo or OFA arrangements and common to both cases.

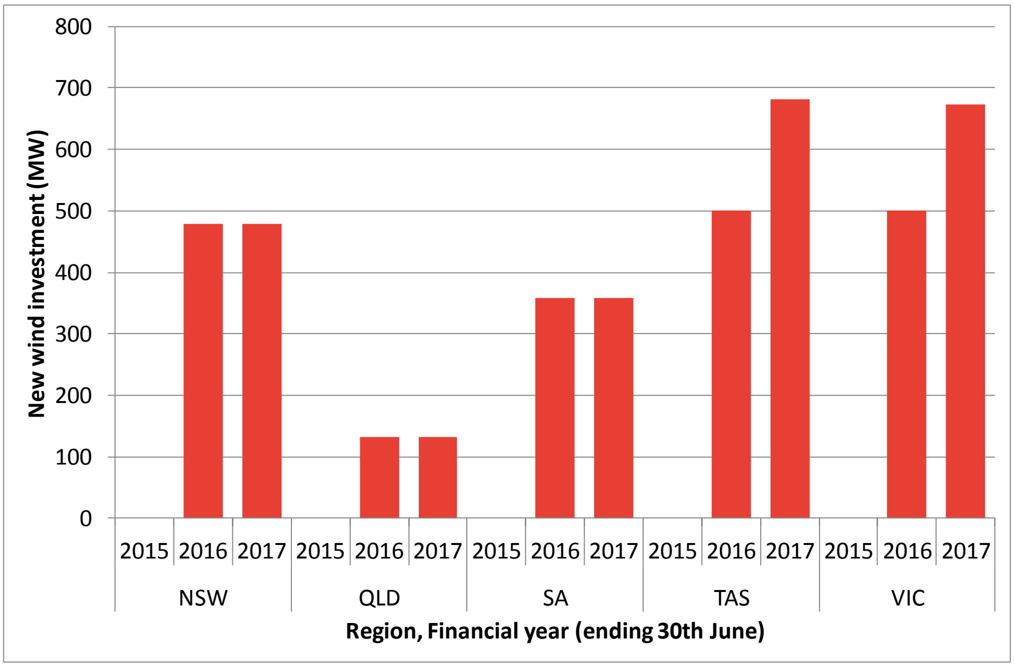
Reductions in wholesale prices in the OFA case relative to the Status Quo, seen in Victoria in 2015/16 and 2016/17 and South Australia in 2016/17, are driven by lower SRMC plant setting prices at various times across the year consistent with the explanations of economic cost changes in Section 4.2.2. For example, when Loy Yang A offers more capacity under OFA to bind constraints, this results in reduced dispatch from gas plant, reducing economic costs and also leading to lower SRMC plant setting marginal prices in Victoria and South Australia.

Figure 12: Regional reference prices – Base Case



Source: Frontier Economics

Figure 13: New wind investment – Base Case (common to both Status Quo and OFA cases)



Source: Frontier Economics

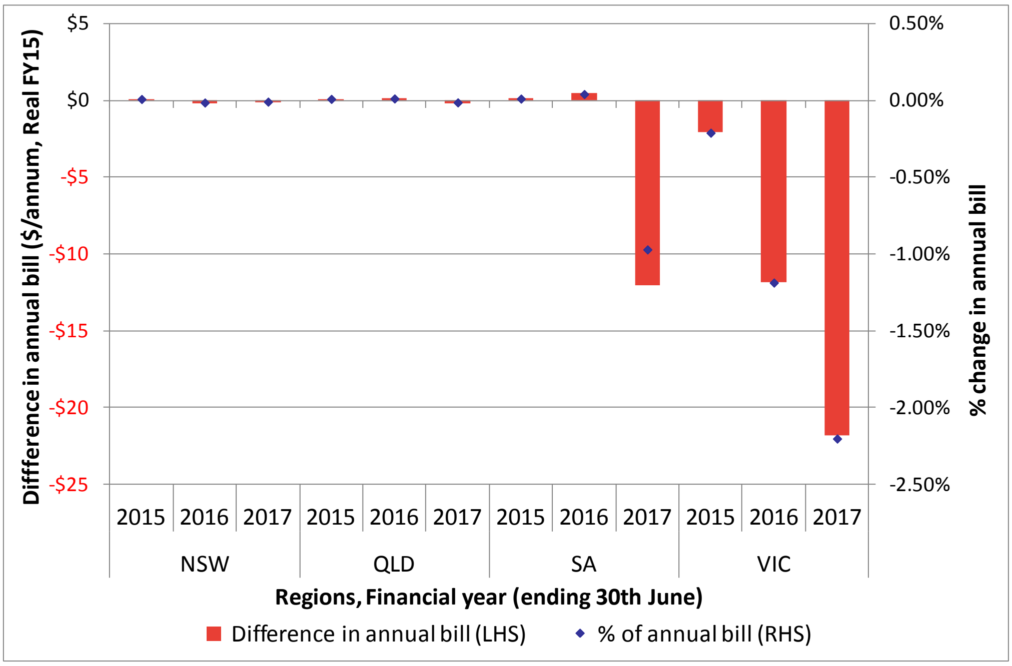
Since generators in Victoria are affected the most by transmission constraints from AEMO's 2014 constraint book, OFA has the biggest impact on pool prices in this region. Annual average pool prices are lower under OFA compared to the Status Quo: from $0.36/MWh lower in financial year 2014/15 to $3.73/MWh lower in 2016/17. The growing gap is attributable to the same factors as identified in Section 4.2.3. Due to interconnector flows from Victoria, the average pool price in South Australia is also lower under OFA by $1.86/MWh in financial year 2016/17.

Because there are very few binding constraints affecting generators in NSW and Queensland, OFA has little impact on the incentives of generators in the two regions. The abundant supply relative to low demand in NSW also dampens the effect of interconnector flows from the southern regions.

Change in final retail bills – all other being equal

Price changes in the wholesale electricity market benefit consumers only to the extent that they lead to reductions in retail electricity bills and that other costs of OFA do not offset these reductions. Figure 14 shows, for a representative residential consumer, the change in annual retail electricity bills both in absolute dollars and as percentages of the total amount, assuming that there are not other costs or negative consequences from OFA other than the narrow dispatch effects. A positive number indicates the value is higher under OFA.

Figure 14: Change in retail electricity bills – Base Case (positive bars indicate higher bills under OFA)



Source: Frontier Economics

Since there is close to no change in pool prices in NSW and Queensland, the changes in the final retail bills for those two regions are negligible. Even in Victoria, the reduction retail bill is close to zero in financial year 2014/15 and roughly $22 dollars in 2016/17. Even the maximum reduction of $22 dollars represents just over 2% reduction in the total amount. Therefore the gross benefits of OFA for final consumers are immaterial, which means that once the costs and other impacts of OFA are likely to easily outweigh any positive effect for customers.

For example, these gross benefits to consumers are likely to be transient as the largest (and certain) effect of OFA is to reduce the financial viability of generators and this may result in reduced maintenance spend, plant exit and/or delayed investment over the longer term. These decisions are likely to cause wholesale prices to rise to reflect the cost of firm access. This is discussed in more detail below.

4.3 Sensitivity results

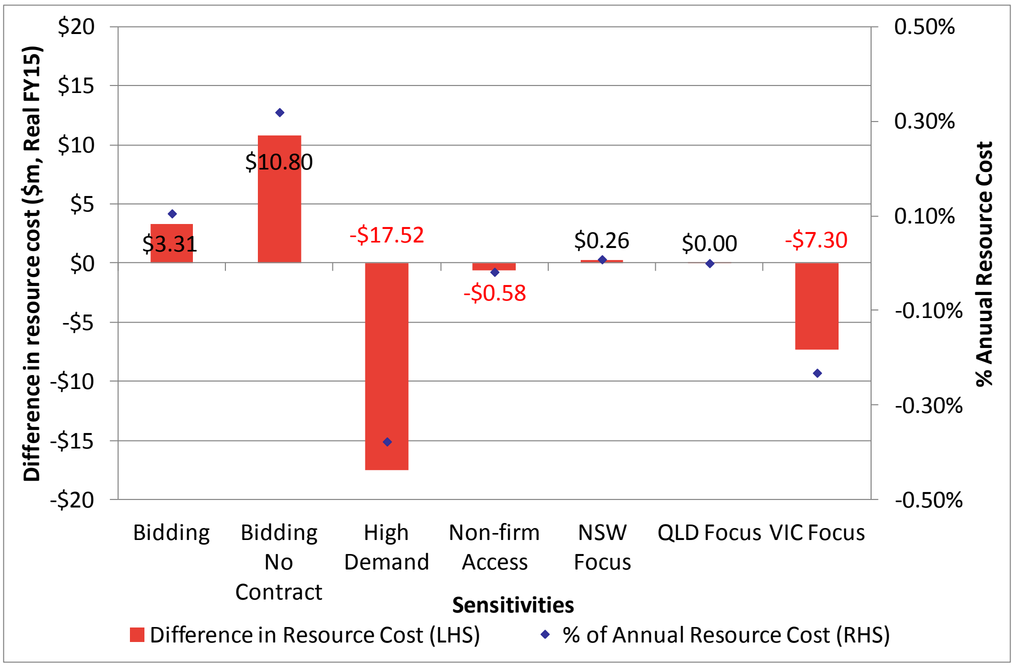
This section reports dispatch cost outcomes for financial year 2014/15 from various sensitivity tests. A summary of those sensitivities can be found in Appendix B. The first part of this section discusses the outcome of each sensitivity. The results demonstrate that the impact of OFA on economic costs can be both positive and negative and is sensitive to input assumptions. In addition, the changes in economic cost are small unless unrealistically extreme assumptions are used.

The setup in some of the sensitivities allows for more granular treatment of bidding behaviour. As a consequence, the model has identified instances of Bidding to Bind, which is presented in Section 4.3.2.

4.3.1 Change in economic costs of dispatch

Figure 15 shows the changes in economic costs under different sensitivities for financial year 2014/15. A positive number indicates the value is higher under OFA.

Figure 15: Economic costs sensitivities – financial year 2014/15 (positive bar means economic costs are higher under OFA)



Source: Frontier Economics

Non-firm Access

This scenario assumes that no generator has agreed access on the network. It has almost identical outcome to the Base Case. This is not surprising as the actual entitlements after scaling is the same when everyone is firm compared to when everyone is non-firm.[35]

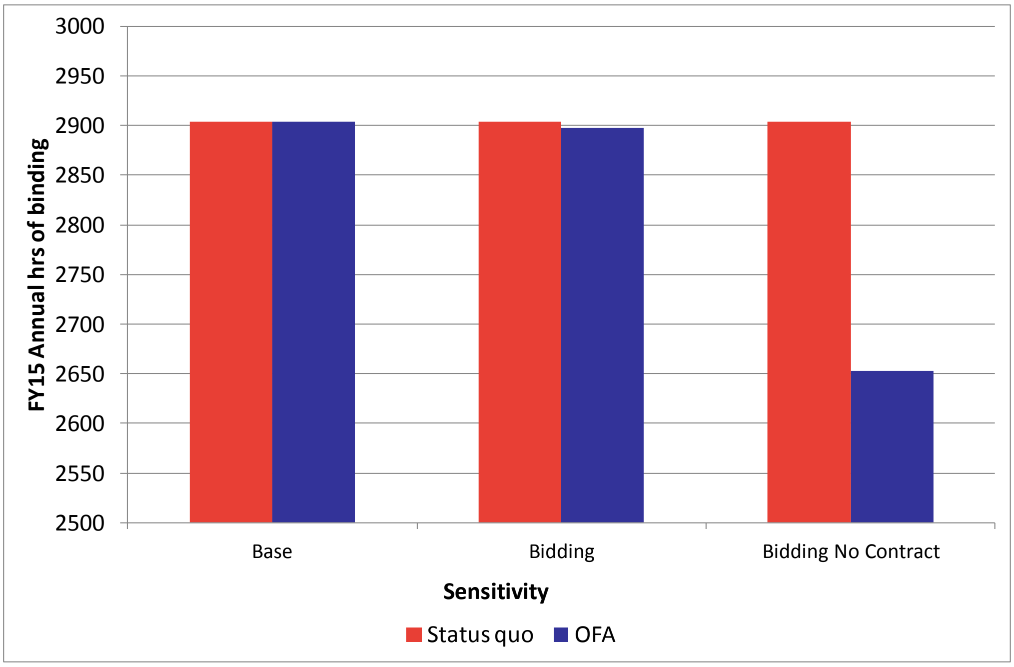
Bidding and Bidding no Contract

The "Bidding" sensitivity assumes that generators can engage in more aggressive bidding behaviours by withholding more of their capacity. The "Bidding No Contract" sensitivity further assumes that there are no financial contracts. This raises economic costs and wholesale prices in both the Status Quo and OFA cases for each sensitivity. Both sensitivities result in small increases in economic costs and small reduction in wholesale prices under OFA relative to the Status Quo. The economic cost is higher under OFA by $3.31 million in "Bidding" and $10.8 million in "Bidding no Contract". Allowing generators to withdraw more

35 There will be some difference on flowgates when some generators were originally *part-firm* because their allocated access is less than their capacity. However, this would matter only if the relevant transmission constraint binds. Further, with the exception of NSW Snowy generators and Tasmania generators, the part-firm generators' allocated access is quite close to their capacity. Therefore the overall impact is very small.

capacity than in the Base Case leads to more instances of headroom bidding. Under these sensitivities, Headroom bidding appears not only around constraint T>>V_NIL_YPTX4_3H3Y2_64, but around V>V_NIL_RADIAL_10_1 as well. This is shown in Figure 16.

Figure 16: Binding hours of V>V_NIL_RADIAL_10_1



Source: Frontier Economics

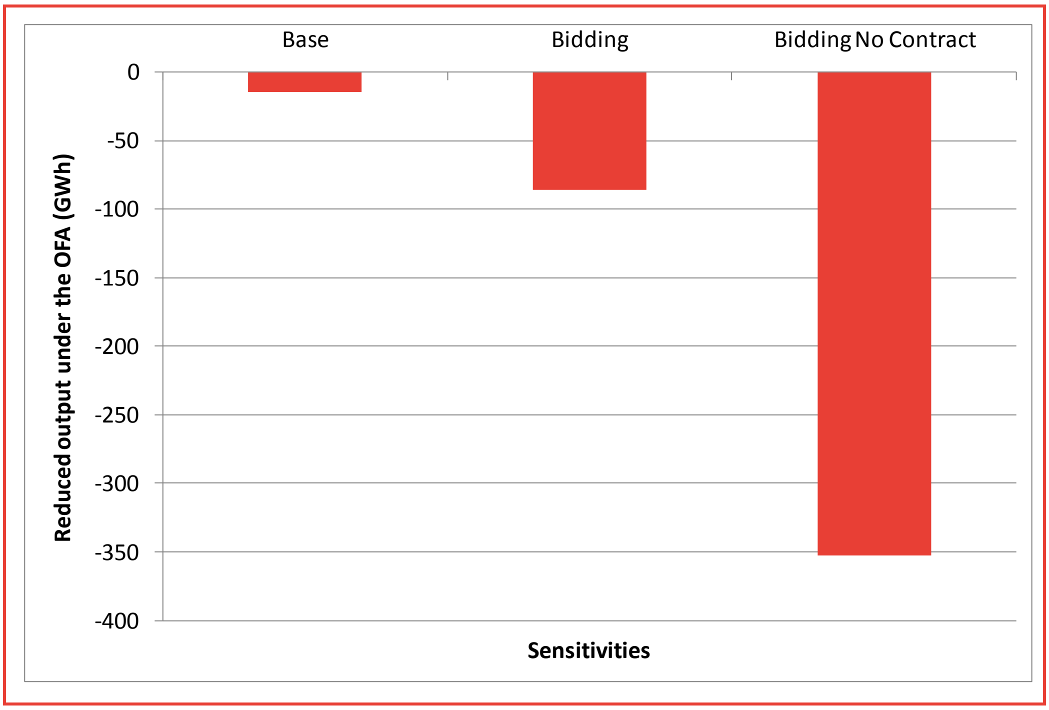
It can be seen that in the Base Case, this constraint always binds for the designated December to March summer period, both in the Status Quo and the OFA case. When generators are allowed to withhold more capacity, it is easier for them to decrease output to keep the constraint open. In the Bidding sensitivity, OFA provides the two base loaders behind the constraint, Yallourn and Hazelwood, with incentives to pull back their capacity sufficiently to keep V>V_NIL_RADIAL_10_1 open for a small amount of hours.

Relative to the Base Case, more strategic bidding results in higher pool prices under both the Status Quo and OFA. Wholesale prices are slightly lower under OFA relative to Status Quo. This is because the higher level of prices increase potential differences between local and regional prices during times of congestion, creating stronger incentives for headroom bidding under OFA.

This is most clear in the Bidding No Contract sensitivity where, in the absence of financial contracts, generators engage in more strategic behaviour and price levels are significantly higher in this sensitivity. Additionally, there is a significant amount of headroom bidding under OFA around the radial constraints, which causes the constraints to bind for fewer hours, as shown in the far right of Figure

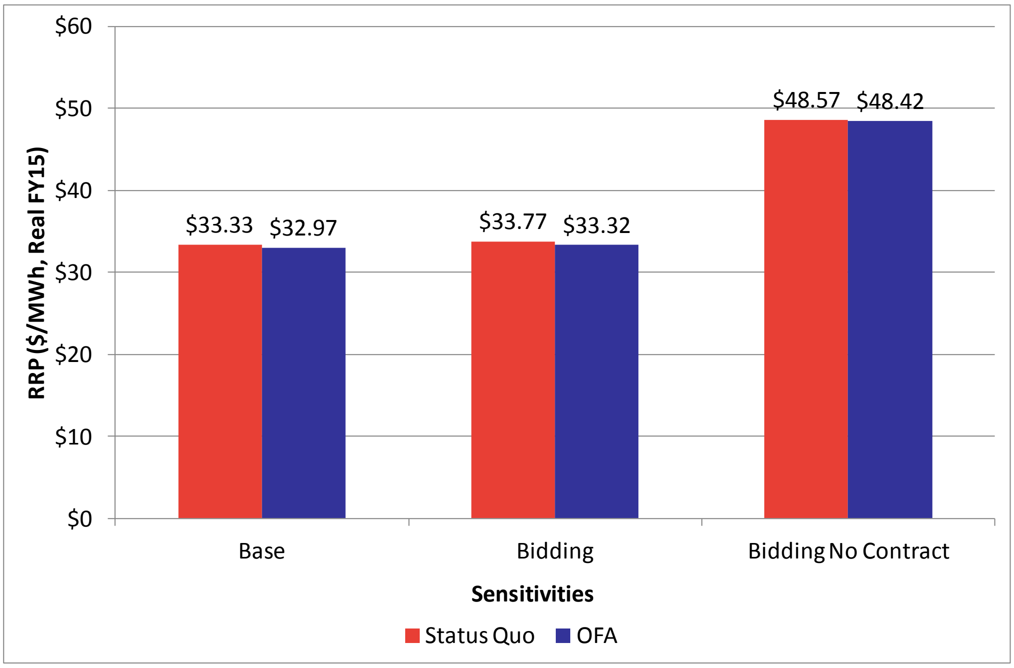
16. Figure 17 shows the annual reduction in output for Hazelwood and Yallourn under OFA compared to the Status Quo. The reduced output is primarily made up by more expensive black coal or gas generation across the NEM. Figure 18 shows the annual average pool prices in Victoria in the sensitivities.

Figure 17: Reduction in output for Yallourn and Hazelwood under OFA (relative to Status Quo) by scenario, 2014/15



Source: Frontier Economics

Figure 18: Victoria annual average RRP by sensitivity, 2014/15



Source: Frontier Economics

High Demand

The "High Demand" sensitivity uses POE 50% high demand for 2024/25 from AEMO's NEFR2014 forecast, but keeps supply and constraint equations the same as for FY14/15. The result shows that there is larger cost saving of around $17.5 million under OFA. This is because under higher demand, constraints bind more often and hence there is larger benefit from reduced disorderly bidding. However, it needs to be noted that, even if the absolute change in economic costs is larger in this case, the total economic costs are also much higher due to high demand. The change in percentage terms is still only 0.4% of total dispatch costs. Further, such saving is achieved only when unrealistically high demand relative to supply and transmission capacity has been assumed.

Regional focus sensitivities

The "Regional focus sensitivities" consists of three runs for NSW, Queensland and Victoria. In each run, more granular bidding assumptions are applied to generators in the relevant regions. This includes allowing peakers to bid market price floors. Generators in other regions were assumed to offer their capacities at SRMC. In the NSW and Queensland runs there is close to zero impact under OFA, because there is few constraints binding for generators in those regions. OFA has higher saving of roughly $7.3 million in the Victoria run due to reductions in disorderly bidding and instances of bidding to bind and headroom bidding. Given that transmission constraints bind mostly in Victoria, allowing peakers to bid MPF exacerbates the problem of disorderly bidding. This sensitivity has also confirmed the existence of Bidding to Bind, which will be discussed in more details in Section 4.3.2. As explained in Appendix A, the perverse bidding behaviours are harder to exhaustively model than disorderly bidding due to the latter's requirement of a much larger strategy space. Therefore, *SPARK* results will tend to underestimate the resource costs under OFA as a consequence of underestimating the level of Headroom bidding and Bidding to Bind.

4.3.2 Perverse bidding behaviour – Bidding to Bind

Despite the computational constraint, *SPARK* has identified instances of Bidding to Bind in the VIC focus run, which occurred around the constraint T>>V_NIL_YPTX4_3H3Y2_64. Under OFA, *SPARK* has found that at one demand point (demand level shown in Table 4), Jeeralang A and Valley Power bid part of their capacities below their marginal cost and cause the constraint to bind, as shown in Figure 19.

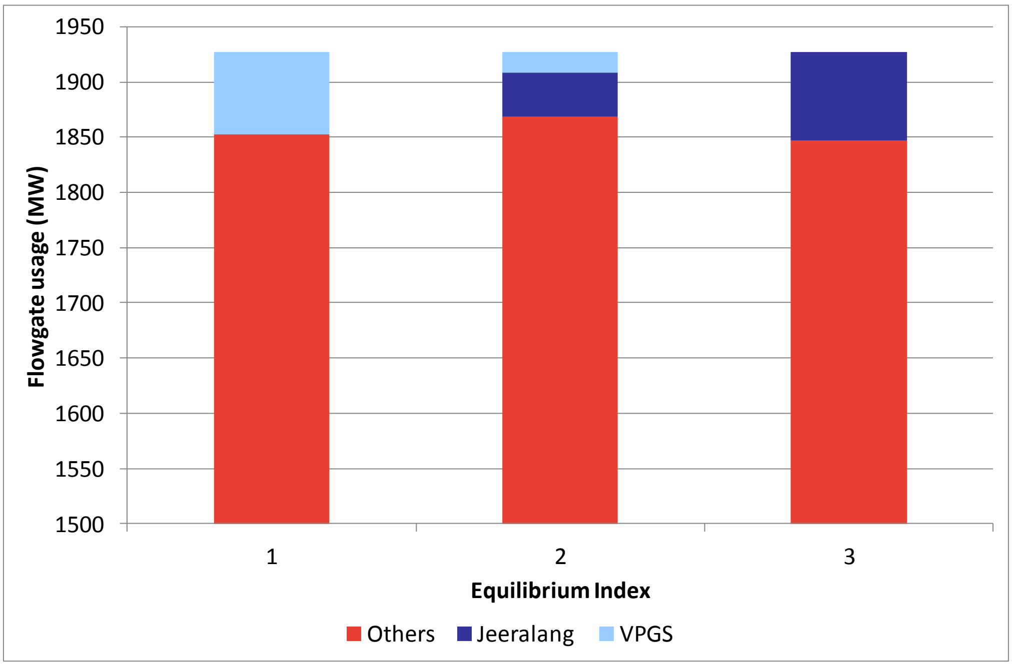
Table 4: Bidding to Bind – demand levels

RegionId	Demand (MW)
NSW	9082.9
QLD	5864.8
SA	2781.1
TAS	1337.3
VIC	8335.9

Source: Frontier Economics

The RHS of the transmission constraint is above 1900 MW, and the red bar represents the combined flowgate usage from all other generators and interconnector flows. Jeeralang A and Valley Power's output are shown in dark and light blue, respectively.

Figure 19: Bidding to bind of constraint T>>V_NIL_YPTX4_3H3Y2_64



Source: Frontier Economics

Figure 19 shows that the constraint can be bound by the output of a single generator or the combination of both. To illustrate the actual incentive, we focus on the equilibrium where Jeeralang A binds the constraint by itself. In this equilibrium, the dispatch outcome is such that:

- Victoria RRP = $109.58/MWh and flowgate price = $41.59/MWh
- Jeeralang A output = 87.35 MW (RRN basis) and marginal cost = $129.97 MW (RRN basis)
- Jeeralang A's actual entitlement after scaling is 138.45 MW, compared to its flowgate usage of 80.03MW.
- For half an hour, Jeeralang A
  - Makes a dispatch loss of (129.97 – 109.58)*87.35*0.5 = $870.14
  - But receives OFA payment of (138.45-80.03)*0.5*41.59 =$1214.94
- Therefore, Jeeralang makes a net profit of 1214.94 – 870.14 = $344.8

It is worth noting that the above calculation is performed on Jeeralang A alone. It demonstrates that even if it was a standalone asset, it could profitably gain by binding the constraint. In reality, both Jeeralang A and B belong to the same owner and are behind the constraint. Since both would be out of the merit order with SRMC bidding, the fact Jeeralang A binds the constraint means that the same owner would also earn OFA payments on Jeeralang B. Hence bidding to bind would be more profitable than demonstrated in the calculation above. (This is properly taken into account in *SPARK*'s calculation.)

The exact economic cost of such bidding to bind can be quantified by

- re-dispatching the same demand point
- assume peakers do not bid below their marginal cost, and
- assume all other generators' bids remain unchanged.

The result of such re-dispatch shows that the cost of bidding-to-bind is \$8076/hour, or roughly 1.1% of the economic costs for the demand point. *SPARK* modelling is fundamentally constrained by the discreteness of modelled bidding steps and the geometric growth of strategy combinations. Despite this, our modelling still demonstrates that bidding-to-bind can happen profitably in the NEM under OFA. In reality, generators in the NEM would have much more freedom to tailor their bids to exploit bidding to bind opportunities than we have been able to capture through the present modelling exercise. Therefore, it can be expected that bidding-to-bind would occur much more often in reality if OFA were implemented.

4.4 Summary of results

The introduction of OFA will fundamentally change the incentives of generators operating in the wholesale electricity market as well as adding extra fixed costs that the generators will attempt to recover in the same way they attempt to recover their fixed generation costs through the NEM. The change in the economic cost of dispatch (ignoring other offsetting impacts) in the Base Case and sensitivities under OFA is negligible, especially compared to the size of the NEM. Even under extreme assumptions where OFA ought to be most beneficial the effect of OFA on dispatch efficiency is immaterial and ambiguous. Cost savings from OFA do not exceed 0.5% of NEM dispatch costs in the base case or 1% of NEM dispatch costs in the more extreme sensitivities. Although not quantified in this report, OFA would involve significant one-off implementation and ongoing costs in the NEM. Since the efficiency improvement is minimal, or can even be negative, OFA is very likely to lead to higher overall cost to the market and be net detrimental.

Our modelling has confirmed two perverse bidding behaviours, Headroom bidding and bidding to bind, can arise under OFA. These behaviours arise under OFA because OFA payments provide different incentives for generators to "game" the transmission constraints to their advantage. OFA does not change the fact that (potential) network congestion can cause economic inefficiencies. It merely changes the symptoms of congestion from disorderly bidding under the current arrangements to the alternatives identified in this report.

5 Participant risks and end-customer implications of OFA

This section discusses the risk impacts of OFA on generator participants in the NEM wholesale market. We first discuss the types of risks faced by generators under the current arrangements and how these change under OFA. The implications of these changes are then discussed.

5.1 Risks currently faced by generators

Currently, generators earned a margin from the NEM pool based on their:

- level of generation, *G*
- regional reference price, *RRP*, and
- marginal cost, *C*

This margin is calculated as:

$$Margin\$ = (RRP - C) \times G$$

Under this settlement arrangement, generators face:

- **Price risk:** uncertainty over the price the generator will receive – because the RRP will vary over time, and can sometimes be extremely volatile. To the extent a generator enters a financial derivative contract, price risk can still arise in the form of *basis risk*, if the price at which the generator is settled is different from the price at which the derivative contract is settled.
- **Dispatch risk:** uncertainty over the extent to which the generator is dispatched given its bid, the RRP and the level of network congestion.
- **Outage risk:** uncertainty over the generator's ability to produce output – because the generator may experience forced outages.
- **Cost recovery risk:** uncertainty over whether the generator earns enough to remain viable – due to the risk that revenues to do not cover the considerable fixed costs associated with financing generation assets.

Dispatch risk arises when there is congestion in the transmission network that impacts on the level of generation – that is, when flows across one or more network elements reach their prescribed limits. Without congestion, a generator could be confident that it would always be dispatched when its bid price was less than the loss-adjusted RRP. This is not the case in the presence of congestion. In other words, dispatch risk fundamentally arises because congestion leads to a disconnect between the basis on which generators are dispatched and the basis on which they are settled. However, it would not be economic to augment the network to a level that no congestion ever occurred, just as it would not be economic to build enough freeways to ensure no traffic delays.

Generators can manage dispatch risk via so called 'disorderly bidding'. Two outcomes are possible:

- A generator can be **constrained on**, meaning capacity is dispatched despite the RRP being less than the loss-adjusted offer price of that capacity. This occurs when the generator’s output reduces congestion. Generators can partially manage this risk by bidding at the market price cap (MPC) to avoid dispatch.
- A generator can be **constrained off**, meaning capacity is not dispatched despite the RRP being greater than the loss-adjusted offer price of that capacity. This occurs when the generator’s output increases congestion. Generators can partially manage this risk by bidding at the market floor price (MFP) to maintain dispatch.

Generators’ incentives to respond to dispatch risk in these ways is peculiar to the current NEM design. Under a market design incorporating nodal pricing (in which generators are settled at their local nodal price), generators would effectively swap dispatch risk arising from congestion for price or basis risk associated with the difference between the generator's nodal price and the RRP. This means that under nodal pricing, a generator can be more certain it would be dispatched at a given local price; but it would instead be exposed to the risk that congestion means that the nodal marginal price is significantly lower than the RRP at which it may have struck contracts. Under nodal pricing with no firm access agreements, generators no longer have incentives to bid MFP when they are constrained off, as this would potentially result in a negative local price. This would avoid inefficiencies that arise when higher cost plant are dispatched due to disorderly bidding in preference to lower cost plant. However, a key point to note is that nodal pricing **does not** change the fact that generators face risks from congestion; it merely changes the nature of the risk and incentives around generators' responses.

Putting theory aside, in practice, the economic costs of disorderly bidding arising from congestion are relatively low whereas there are considerable benefits in terms of simplicity from a regionally priced market. In particular, the NEM’s regional market design has proved highly effective in facilitating wholesale contracting and competition within regions.

AEMC perspective on the current arrangements

The AEMC appears to regard regional pricing – rather than congestion – as responsible for a number of problems under the current NEM design. This is most explicit in the Staff Paper:

> In summary, there is an inconsistency between:
>
> - NEM dispatch: which is a local market clearing process; and
> - NEM settlement: which is designed to reflect a regional market clearing process.
>
> It is this fundamental inconsistency within the NEM design which lies at the root of problems such as disorderly bidding and access uncertainty. To address these issues, the inconsistency must be addressed.[36]

In our view, the AEMC has misdiagnosed the underlying cause of the issues manifesting in the NEM. The fundamental cause of the issues it refers to is **congestion**, not the **market pricing mechanism**. The way congestion manifests in the NEM – through disorderly bidding and access uncertainty – is attributable to the specific design of the market. Under different market arrangements such as nodal pricing, the manifestations of congestion would still arise but in a different form.

Therefore, OFA does not eliminate but changes how the symptoms of how congestion will manifest itself in the market. Accordingly, OFA changes the nature of risks faced by generators.

5.2 Changes brought about by OFA

Under OFA, generators earn a margin from the NEM pool based on their:

- level of generation, *G*
- level of access, *A*
- regional reference price, *RRP*
- local marginal price, *LMP*
- access price, *AP*, and
- marginal cost, *C*

36 AEMC, *Optional Firm Access, Transmission Frameworks Review, AEMC Staff Paper*, 11 April 2013, p4.

Consistent with the AEMC's treatment[37], this margin is calculated as:

$$\begin{aligned} Margin\$ &= LMP \times G + (RRP - LMP) \times A - C \times G - AP \times A \\ &= (LMP - C) \times G + (RRP - LMP) \times A - AP \times A \\ &= dispatch\ margin + access\ margin - access\ cost \end{aligned}$$

Under OFA, generation is settled against a local marginal price (i.e. generation is nodally priced); subtracting marginal costs, this produces the dispatch margin. OFA also includes a transmission rights element which is settled via the access margin; these rights may come at a price (access price) or they may be provided at no cost (transitional rights).

Under this settlement arrangement, generators will continue to face a number of risks arising from congestion:

- **Price risk:** the LMP will vary, as the RRP presently does.
- **Dispatch risk:** dispatch may be still affected by congestion under some circumstances.
- **Outage risk:** the generator will still experience forced outages.
- **Basis risk:** the access margin depends on the difference between the local and regional prices.
- **Access margin risk:** the access margin also depends on the level of access; this can be scaled below agreed firm access levels at times of congestion. Essentially, there is a risk firm access quantities are reduced via the scaling process and this risk is likely to be heightened at the time they are most valuable. This is analogous to being constrained off under the current arrangements.
- **Cost recovery risk:** the risk that revenues to do not cover the considerable fixed costs associated with financing generation assets *plus* any fixed costs of firm access.

These changes are likely to lead to different, rational responses from generators, in particular, headroom bidding by non-firm and partially-firm generators (to ensure the 'import' of a higher regional price) and bidding to bind by firm generators at times when bidding below cost can trigger an access payment such that a generator earns a net profit. Given that the level of congestion depends on network capacity, not pricing arrangements, there is no *a priori* reason to think that occurrence of congestion would result in more efficient outcomes under OFA than under the current arrangements. However, this is an empirical question, which has been investigated in our accompanying quantitative report. Our quantitative analysis concludes that the change in annual dispatch cost under OFA can be higher or lower depending on the input assumptions. In addition,

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37 ibid, p11, equation 2.7.

the magnitude of changes is immaterial compared to the size of the NEM. In the base case modelled, the annual reduction in dispatch cost under OFA is no more than 0.2% of the NEM total dispatch cost.[38]

Under OFA, generators are also exposed to new and increased risk. Basis and access margin risk are specific to the OFA model and involve significant complexity to forecast and manage. More important is the increased risk of cost under-recovery that arises due to relative to higher, access cost inclusive fixed costs.

Cost recovery risk is very different to current dispatch risk. Under the current arrangements, if a generator is constrained off, it **foregoes profit** at a high regional price. Under OFA, if access margins are less than access costs the generator faces a **cash loss** as it must still pay for access. From a purely economic perspective a risk neutral generator should be indifferent, however from a cash flow perspective this is a fundamentally different category of risk. This is exacerbated if generators are risk averse, as many tend to be in practice.

5.3 Impact on existing generators

OFA affects existing generators' profits mainly via two channels: OFA payments (to or from a generator) made during market settlement and fixed charges for agreed access amounts on the network. While the former may improve some generators' risk profiles by providing access to the regional reference prices during congestion supporting a higher level of hedge sales under system normal conditions, such benefits are likely to be overwhelmed by the extra fixed costs generators incur in the form of access charges, especially if generators are unable to pass these costs through to customers quickly.

5.3.1 Caveat of using system normal constraints

Our analysis below indicates that some generators are likely to see a slight improvement in their risk profile under OFA, which supports higher contracting levels. This outcome is strongly dependent on the inclusion of only a subset of system normal transmission constraints in the modelling, as this is the only data available from AEMO's constraint books.

The results need to be interpreted with caution as we have not included non-system normal constraints (such as those related to generation and transmission outages) in the modelling. Network outages typically have large impacts on generation output and access to regional reference prices. Further, the relevant flowgate capacity typically reduces drastically during outages, which implies that even generators with "firm" access can see a large scaling back of their

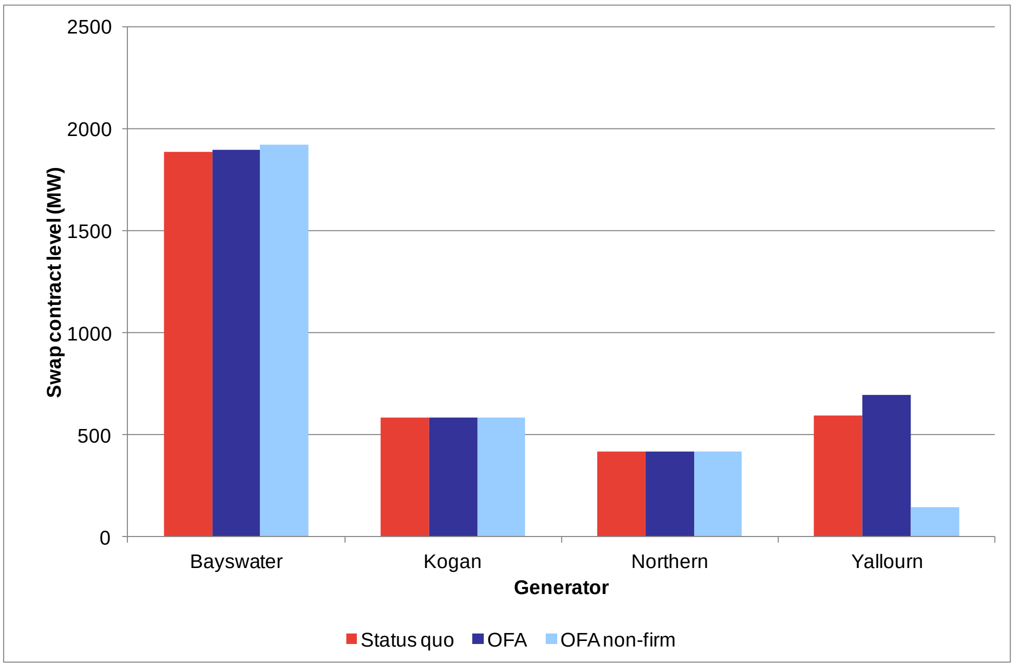
38 Frontier Economics, *Modelling Optimal Firm Access,* Feb 2015. Section 4.

entitlements (see Appendix A). It is doubtful whether OFA would still lead to the same amount of improvement to generators' contract position if outage constraints were also considered.

5.3.2 Generators' risk profiles

We chose one baseload generator from each of the NEM regions to study the impact of OFA on generators' contract positions. Bayswater, Kogan Creek and Northern were chosen because they are the cheapest generators in their respective regions. For Victoria, Yallourn was chosen because it is the baseload generator affected the most by transmission constraints. The analysis focused on the summer of financial year 2014/15, as most transmission constraints affecting generators bind during the summer for that year. For simplicity, it is assumed that generators will only sell flat swaps. In order to demonstrate the importance of having firm access on the network, we have dispatched an extra run by assuming the chosen baseloaders do not have any agreed access, which means that their entitlement will be scaled back first on congested flowgates. The analysis was done by first finding the market outcome in *SPARK* and then conducting the contract analysis in *STRIKE*. The results are shown in Figure 20.

Figure 20: Generator contract positions, summer financial year 2014/15



Source: Frontier Economics

The impact of OFA is most clear on Yallourn as the other generators are not constrained-off during financial year 2014/15.[39] Due to the binding transmission constraints in Victoria, it is only optimal for Yallourn to sell swaps at roughly 60% of its capacity in the Status Quo. As expected, OFA does slightly improve Yallourn's risk profile and facilitates a slight increase in its optimal contracting level under the assumption that Yallourn has a firm access amount equal to 95% of its capacity. However, if it is non-firm under OFA, Yallourn's ability to sell swaps rapidly deteriorates, and is even lower than it is in the Status Quo. This is because Yallourn's entitlements are scaled back prior to other firm generators' entitlements[40] and consequently it has very limited access to the regional reference price.

5.3.3 OFA is not optional

If Yallourn did not have firm access under OFA, its (non-firm) entitlement would be scaled back ahead of other generators with firm access. The above section demonstrates that under these circumstances, its contract position would rapidly deteriorate. In addition, a non-firm Yallourn's total profit would be lower due to the larger OFA payment it has to make, especially in the short to medium term.

Table 5 shows the OFA payment and Yallourn's operating margin, defined as pool revenue minus fuel cost, for both when it is firm and non-firm. Recall that being firm or non-firm might change the payoff and incentives of the generator, but not the dispatch process given the bids. Therefore, there is a slight difference in Yallourn's operating margin due to its different equilibrium strategies between the two cases. More importantly, if Yallourn is non-firm while other generators are firm, it goes from receiving a $4 million OFA payment to making a $33 million OFA payment. This net effect represents a more than 15% reduction from its original operating margin.

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39 Bayswater's contract position increases very slightly from the Status quo to the OFA cases. This is due to slight changes in Bayswater's output and prices as the result of Yallourn's dispatch changes across the runs.

40 Yallourn has a the highest coefficient on the V>V_NIL_RADIAL_10_1 constraint meaning it is most effected by scaling. This constraint binds across summer in all years of the modelling.

Table 5: Yallourn's annual operation margin and OFA payments

Case	OFA Payment to Yallourn ($m)	Operating Margin (Pool Rev minus fuel cost, $m)	Operating Margin net off OFA Payment ($m)
OFA, Yallourn firm	$4.09	$239.20	$243.29
OFA, Yallourn non-firm	-$33.28	$239.64	$206.35

Source: Frontier Economics

This example helps illustrate the point that for generators behind binding transmission constraints, OFA is not 'optional'. This lack of optionality arises due to the "Prisoner's Dilemma" nature of the strategic situation they face. If all generators behind a constraint could agree to remain non-firm, they would collectively maintain a certain level of profitability. But because firm generators receive OFA payments from non-firm counterparts, individual generators often have a private incentive to 'defect' (or 'confess' in the Prisoner's Dilemma terminology) and acquire firm access rights. This makes it a dominant strategy for all generators to seek to acquire access rights, which leaves them collectively worse off. Consider that for any generator, *X*:

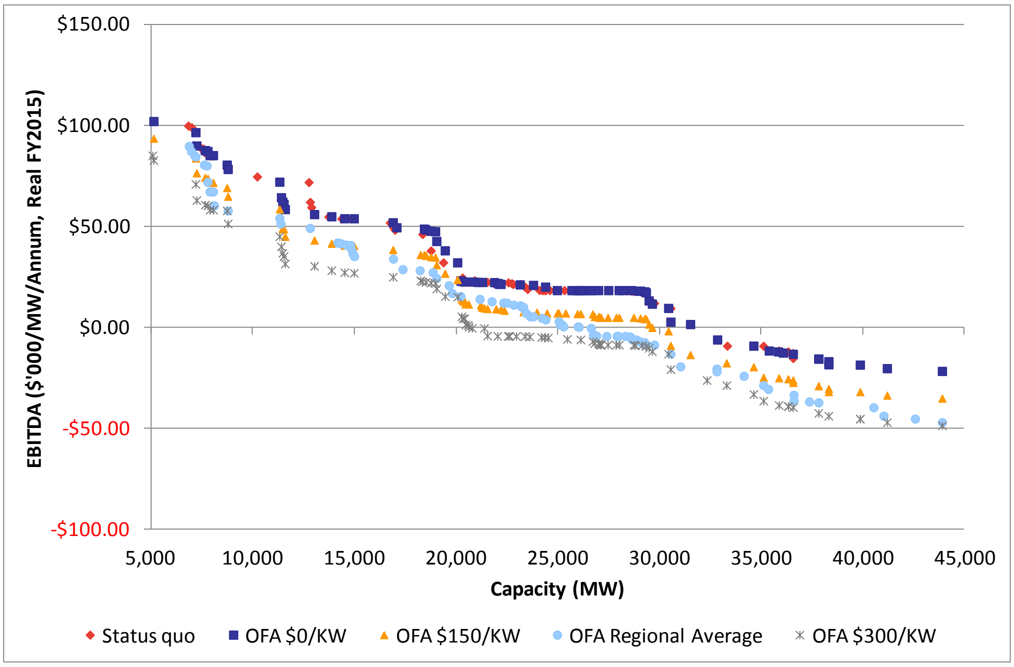
- If other generators are not firm, being firm means that X's actual entitlement will only be scaled back *after* scaling is performed on other generators.
- If other generators are firm, being firm ensures that X's actual entitlement is *not* scaled ahead of the others.

Therefore, generators will be under the pressure to acquire access. After the transitional period, the access prices they have to pay are likely to have a large impact on their profitability.

5.3.4 Generators' profitability across the NEM

Figure 21 shows the impact of access charges on generator profitability in terms of EBITDA. The vertical axis shows the EBITDA profit of the generators sorted by descending order and the horizontal axis shows the cumulative capacity.

Figure 21: NEM wide generator profitability



Source: Frontier Economics

The red and dark blue series show the Status Quo and the OFA profits when access rights are provided at no cost. The two curves are very close to each other, as OFA payments are essentially transfers between generators. Even without access charges, more than 12.4GW, or roughly 30% of NEM capacity will make EBITDA losses to some degree. This is consistent with the low level of demand in recent years.

The AEMC's Supplementary Report produces indicative access prices for different connection points, which can vary by access term length and amount. The light blue series shows generator profitability under OFA using the regional average access price estimates from the AEMC's analysis. These regional average prices are from the "baseline" case of AEMC's report, which assumes an access amount of 400MW and a term length of 20 years.[41]

The light blue series shows the effect of applying regional average prices from AEMC's indicative prices.[42] The prices are:

- NSW: $200/kW
- Queensland: $350/kW

41 AEMC Supplementary Report 2014, p37

42 Ibid, p55. The regional average price are based on a real, pre-tax WACC of 6.4%.

- South Australia: $280/kW
- Victoria: $80/kW

The AEMC's Supplementary Report does not show access prices for Tasmania. Consequently this report uses $250/KW as a proxy for Tasmanian access prices, which is roughly the NEM average.[43] Under those prices, about an additional 5.5GW, or 12.5% of existing capacity will make an EBITDA loss in 2014/15. Should this occur, generators may reduce maintenance spend or retire plant to mitigate their losses. Such outcomes would reduce supply, raising pool prices and ultimately retail bills. Wholesale costs of energy could ultimately be higher under OFA than under the Status Quo.

The yellow and grey series shows the outcome if an alternative $150 or $300/KW access price is uniformly applied to the NEM.

Note that section 7 discusses our concerns with the indicative access prices published by the AEMC.

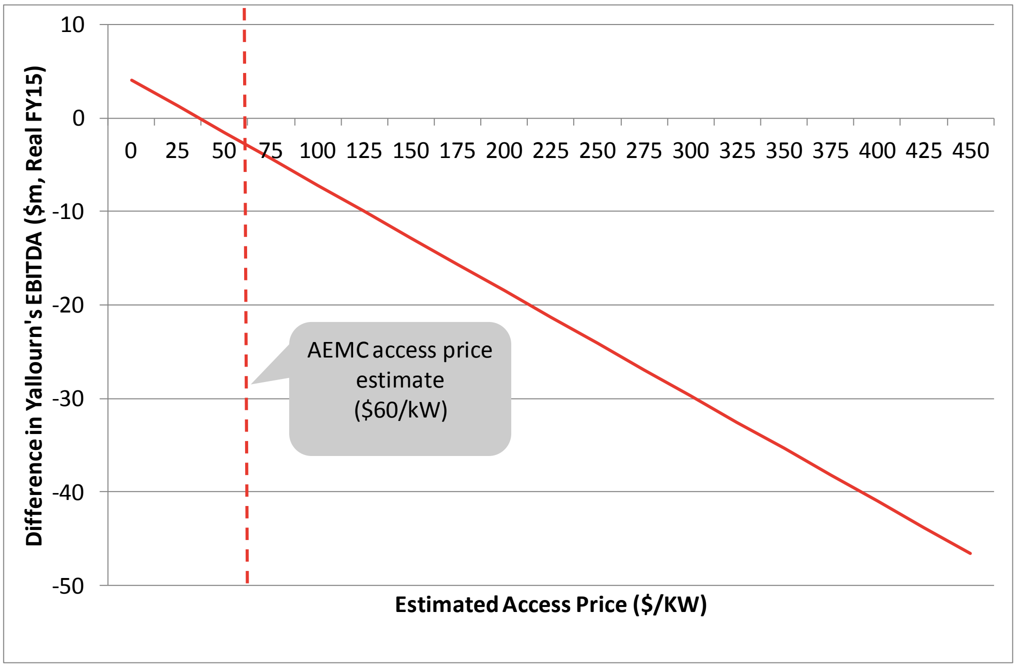
5.3.5 Impact on baseload generators

As there is large amount of uncertainty surrounding the AEMC's indicative access prices, it is useful to examine the impact of various access prices on the generators' profitability.

The difference in profit between the Status Quo and the OFA cases for Yallourn serves to illustrate this point. The dark blue line in Figure 22 shows the difference of Yallourn's EBITDA between OFA and the Status Quo. Recall that OFA improves Yallourn's revenue and contract position compared to the Status Quo because it is often constrained-off. Second, as shown in Figure 20, Yallourn would be forced to purchase access under OFA, as staying non-firm would mean that it had to make large OFA payment to other generators and would see a significant deterioration in its contract position. It can be seen from Figure 22 that the improvement in Yallourn's EBITDA is quickly washed out by access charges. Even under the AEMC's very low $60/kW access prices, Yallourn is worse off compared to the Status Quo by $2.7 million. If the AEMC's NEM average of $250/kW were applied, Yallourn would be worse off by roughly $24 million under OFA.

43 The results are not sensitive if any number between $200-300/kW for Tasmania is used,

Figure 22: Yallourn's EBITDA comparison between OFA and Status Quo



Source: Frontier Economics

5.3.6 Summary of generator impacts

OFA's adverse impact on generator profits is large. Although it does marginally improve risk profiles for firm generators that are likely to be constrained-off, such benefits are easily overwhelmed by the access charges that generators will have to pay in order to acquire firm access on the network in the long term. Given the current and expected low demand level in the foreseeable future, many generators will find it difficult to recover these extra access charges. Using the AEMC's regional average access prices, an additional 5.5GW, or 12.5% of NEM generation capacity will become loss making on an EBITDA basis as a result of OFA being introduced. Over time, the need to acquire access rights is likely to create a barrier to entry for generators in the NEM.

For those generators who are regularly constrained off under current arrangements, as is seen for Yallourn in our modelling, moving to OFA with a high level of firm access may slightly reduce generator risk profiles and facilitate a small increase in optimal hedging levels. To the extent that firm access comes at no cost then this represents an improvement to generators, however, charging low access prices offsets this improvement. Access prices greater than $50/kW leads to reductions in expected profit. This illustrates that the benefits to generators from OFA of increased firmness are most likely to be outweighed by even small access costs. Additionally, if the same generator chooses to remain non-firm whilst other generators are predominantly firm, then generator risk greatly increases and optimal hedging levels are significantly lower. This outcome belies the optional description of OFA.

5.4 Implications for end-customers

Firm access rights are likely to be expensive; the AEMC's preliminary estimates of access prices range from $0-1500/kW, averaging $250/kW. The imposition of these additional fixed costs will either act to erode generation margins and result in earlier plant retirements which will cause wholesale prices to rise, or generators will be able to pass these costs through to customers. Either way, customers will pay for OFA. Our modelling (above) shows that applying the average regional access prices in the AEMC's baseline estimate results in an additional 5.5 GWh, or roughly 12.5%, of existing NEM generating capacity making an EBITDA loss.

In many regards, the OFA proposal represents a form of risk and cost allocation rather than improving economic efficiency. Recent declines in peak demand in the NEM have resulted in surplus generation and transmission capacity relative to current needs. The costs associated with uneconomic generation assets are already borne by generation investors, consistent with the energy-only design of the market. However, the costs associated with excess transmission assets are currently borne by consumers. This is the result of the regulatory framework for networks in the NEM, in which the regulator effectively approves network investments on behalf of consumers and networks are then insulated from the implications of underutilised assets.

OFA would, in effect, reallocate a proportion (and in the long run potentially all) of the cost of existing transmission assets to generators in the first instance via access payments. However, in an energy-only market like the NEM, this is likely to have one or more of the following consequences:

- Existing generators choose to reduce maintenance expenditure and/or retire sooner than otherwise as their expected profitability is reduced due to either being settled at (lower) nodal prices or having to pay for firm access rights.
- Prospective new generators – facing higher entry costs – delay entry to the point where growth in demand leads to a sufficiently large rise in expected wholesale prices to *at least* compensate them for having to either be settled at nodal prices or pay for firm access rights, In fact, investors may rationally add a risk premium to their costs of capital to account for the possibility that access prices or conditions could change over time.
- The market price cap is raised as policy-makers develop concerns about meeting the NEM reliability standard.

Whilst allocating the full cost of sunk transmission investments to consumers may not be considered fair, it is not clear that reallocating a significant proportion of this cost to generators in the first instance represents an improvement for economic efficiency and consumers in the long run.

In a best case, an initial reallocation of transmission costs to generators would ultimately result, via increased long run wholesale prices, in an indifferent outcome for consumers. In the worst case, such a change could result in unanticipated costs on generators that could create a demand for additional, incremental regulation in a manner similar to what has occurred in European and North American jurisdictions. In particular, Australian policy-makers may respond – as they have in Britain and elsewhere – to the anticipated exit of generators through the adoption of capacity mechanisms that are directly funded by consumers.

In conclusion, there is unlikely to be any net benefits under OFA, and a comprehensive cost-benefit analysis (which the AEMC is obliged to conduct) would almost certainly find that OFA will result in a net economic cost. There is little doubt that OFA will add significant complexity to the market and this will manifest itself as additional risk and costs to participants, which will be ultimately borne by customers. Therefore it is very hard to see how OFA is consistent with the National Electricity Objective.

6 Efficient investment coordination and OFA

6.1 Background

Another of the AEMC's key motivations for proposing OFA is to improve the coordination between generation and transmission investment. In its First Interim Report for the TFR, the AEMC commented that its objective for transmission frameworks was:[44]

> ...to incentivise investment and operational decisions across transmission and generation to minimise the expected total system costs faced by consumers.
>
> ...For example, a generator's decision on where to locate will influence the need for and cost of additional network capacity. Similarly, spare network capacity will influence the locational decisions of generators.
>
> The framework and incentives governing transmission investment and operation therefore need to be co-optimised to promote efficient market outcomes overall.

The TFR Final Report highlighted what the AEMC perceived to be shortcomings in the existing NEM arrangements:[45]

> The regulated planning approach has the potential to distort competitive market outcomes in terms of generation investment. Network planning generally involves TNSPs predicting the least-cost combination of generation and transmission to meet forecast load, and to plan the network accordingly. It can potentially result in imperfect co-optimisation. A TNSP knows the costs of transmission, but has imperfect information regarding the costs of generation, and has little incentive to forecast accurately the benefits accruing to generators.
>
> ...The TNSP's transmission investment decisions may have an effect on generators' investment decisions, by reducing congestion in certain parts of the network, and therefore encouraging generator investment in those areas. This creates a bias towards the generation and transmission development path that the TNSP predicts, even where a lower cost combination exists...
>
> ...Whenever the regulated planning approach delivers a transmission path that is not co-optimised with generation investment, the result is a higher combined cost of generation and transmission than could otherwise be achieved. These costs are borne largely by electricity consumers, who have only limited influence on these investment decisions.

44 AEMC TFR First Interim Report, p.17.

45 AEMC TFR Final Report, pp.104-106.

The AEMC appears to suggest that OFA would improve the coordination of transmission and generation investment in two principal ways:

- First, OFA would promote 'market-led' and more decentralised transmission investment decision-making than the current planning and investment regime because generators' purchases of firm access would "fund and guide network expansion".[46]
- Second, OFA would "create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM."[47] Further:[48]

> The optional firm access model should achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated planning approach. Optional firm access makes the cost of transmission part of a generator's investment decision. The investor should seek the location for a power station which minimises the combination of its operating and establishment costs and the cost of transmission. In making a locational decision a generator would therefore account for both its private costs and also the costs to the transmission network. Better co-optimisation of investment in other energy networks, where they are used as fuel sources, should also result.

In our view, the AEMC's assessment of the current arrangements and its support for OFA overlooks three key points:

- The existing NEM arrangements incorporate a number of features that promote efficient coordination of transmission and generation investment.
- There is no evidence that the existing arrangements have or are likely in future to result in materially sub-optimal coordination of transmission and generation investment (*ex ante*).
- The OFA pricing arrangements reflect a more rather than less centralised approach to the coordination of generation and transmission investment compared to the existing arrangements. As such, the proposed arrangements are likely to result in less efficient co-optimisation of investment in transmission and generation than at present.

Finally, the role of the RIT-T and the proposed means of accounting for benefits to generators under OFA are highly problematic; yet these mechanisms are central to how OFA would operate and the incentives it would provide.

These issues are discussed in turn below.

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46 AEMC TFR Final Report, p.67, 106.

47 AEMC TFR Final Report, p.106.

48 AEMC TFR Final Report, p.107.

6.2 Existing signals promoting efficient coordination

Frontier Economics' October 2012 report for the NGF commented that locational signals under the current transmission planning arrangements are more powerful than is commonly assumed. These signals are additional to those provided through the wholesale market – namely, the use of marginal rather than average loss factors, the risk of being constrained-off due to intra-regional congestion and inter-regional price variation. They are also additional to the extremely important locational signals from outside the market and transmission arrangements, such as the availability and cost of fuel, water for cooling purposes and land. These external signals are typically much more influential drivers of generation locational decisions than the signals provided through the transmission and wholesale market frameworks.

Frontier Economics' October 2012 report noted that the locational signals under the existing transmission regime arise through the operation of the Regulatory Investment Test for Transmission (RIT-T) and participants' expectations of how the RIT-T will be applied in future. The RIT-T is a cost-benefit test that TNSPs in the NEM are obliged to apply and satisfy before undertaking a significant regulated network augmentation. Our report provided a stylised example of a generator's locational decision and demonstrated how the RIT-T provides strong incentives for proponents to locate where the combined costs of generation and transmission is minimised. This stylised example is reproduced in Appendix C below.

Fundamentally, the RIT-T provides strong generator locational signals because:

- A TNSP's decision to undertake a transmission investment helps make a remote generation investment more profitable and a local generation investment less profitable
- Conversely, a TNSP's decision not to undertake a transmission investment does the opposite – it helps make a local generation investment more profitable and a remote generation investment less profitable.

Accordingly, contrary to the view of the AEMC, new generation investors in the NEM do face a signal regarding the long run costs of transmission.

The AEMC's concern with the locational signals provided under the existing arrangements appears to be that the efficiency of TNSPs' planning processes may be undermined because TNSPs have imperfect information about the costs of generation and little incentive to accurately forecast benefits to generators.

Putting to one side the far more serious issues with transmission planning under OFA (see Sections 6.4 and 6.5 below), there are good reasons to expect that TNSPs' imperfect knowledge about generation costs will not lead to systemically inefficient transmission-generation investment decisions.

First, as noted in our October 2012 report for the NGF, the application of the RIT-T involves an extensive multi-round public consultation process. To the extent that a TNSP's analysis is based on flawed assumptions about the costs of different generators, or the costs of demand response or other options, stakeholders have an incentive and an opportunity to comment on and correct those assumptions. Further, any interested party can raise a dispute over the TNSP's final RIT-T assessment with the AER, who must then make a determination on the matter. The desire to avoid such disputes gives TNSPs incentives to undertake their RIT-Ts carefully and take account of all relevant information provided through the consultation process.

Second, to the extent that TNSPs continue to lack perfect information about generators' costs even after going through a RIT-T consultation process, it is not clear that this means TNSPs will mistake generators' costs in a manner that will lead to inefficient planning decisions. For example, if a TNSP understates the costs of prospective generators in different locations to a similar degree, this should not change the relative merits of augmenting in one direction or another. More generally, there is no reason why TNSPs should make systematically biased (serially correlated) errors in estimating generators' costs such as would distort investment decisions that are typically made over a period of time.

These conceptual arguments have been borne out in practice, as discussed below.

6.3 No evidence of poor coordination

Unsurprisingly, given the extent of locational signals provided by and outside the current transmission arrangements, the AEMC has not produced any concrete evidence that the existing arrangements have resulted in materially sub-optimal coordination of transmission and generation investment on an *ex ante* basis.

Indeed, the AEMC's TFR Final Report conceded:[49]

> There is limited firm evidence that the current arrangements have caused significant coordination issues to date.

However, as it did regarding the future costs of disorderly bidding, the report warned:

> They [coordination issues] may, however, increase in significance in the event of changing patterns of demand, technological change, investment in smaller and more dispersed generation, and increased uncertainty concerning the development path that best satisfies the National Electricity Objective.

The report also referred to modelling undertaken by ROAM Consulting that purported to show that under favourable assumptions, OFA could offer

49 AEMC TFR Final Report, p.iii.

aggregate savings of $85 million ($2012/13) in net present value terms, or less than 0.1% of total system costs, over the period 2013 – 2030 from better coordination of generation and transmission investment. Most of the benefits would accrue in the later years, as little investment was likely to be required over the next decade. The ROAM modelling also showed that under most other assumptions, OFA would result in additional cost.

To provide some perspective on the extent of potential coordination shortcomings in the NEM, it is worth examining some key generation investment decisions that have occurred over the history of the market. This should help ascertain whether transmission frameworks are likely to have contributed to material inefficiencies. We have presented a number of case studies in the Boxes below.

Box 1: Millmerran 850 MW super-critical black coal power station

The Millmerran power station is an 850 MW super-critical black coal generator located near the town of Millmerran on the Queensland Darling Downs. It was developed by Intergen and entered full service in early 2003. Millmerran originally connected to Powerlink's network at Bulli Creek, enabling larger southward exports on QNI to NSW and flows into south-east Queensland through Tarong. However, Powerlink upgrades from Millmerran to Middle Ridge (2005) and Middle Ridge to Greenbank (2007) facilitated substantially increased flows to Brisbane and the Gold Coast (see network diagram below).

This raises the question of whether, had the proponent of Millmerran faced a LRIC-type charge, it would likely have developed a generator elsewhere. We note that it is highly likely a large generator would have been developed somewhere in south-central Queensland due to the strong load growth anticipated at that time, and it is highly unlikely that such generation development would feasibly have been able to occur in south-east Queensland.

In its 2002 Annual Report, Powerlink stated:

"Powerlink's 2002 Annual Planning Report indicates that electricity usage in Queensland is expected to continue to grow strongly during the next 10 years, with highest growth areas including the areas around Brisbane, Logan and the Gold Coast/Tweed region. Annual energy to be delivered by the Queensland transmission grid is forecast to increase at an average rate of 3.25% per annum over the next decade.

"This high level of load growth will require substantial augmentation of the capability of the Queensland transmission network to ensure grid capacity keeps pace with demand. "

We also note that at the time Intergen was planning Millmerran, the 860 MW Callide C power station was being developed in central Queensland. That increased the load on the central to southeast Queensland lines and those lines were expected to remain congested for the foreseeable future. This suggests that Millmerran's intended location was broadly sensible.

Further, we understand that Intergen was originally planning to locate at Middle Ridge – ie Intergen was going to build the Millmerran to Middle Ridge line itself. However, Intergen struck delays due to community opposition and reverted to a more westerly location. Moreover, at the time Millmerran committed, there were no Powerlink plans to build a future line between Millmerran and Middle Ridge. In fact, given the strong community opposition encountered by Intergen, it was considered that such a route would not be viable. However, this faded over time as the Middle Ridge load increased.

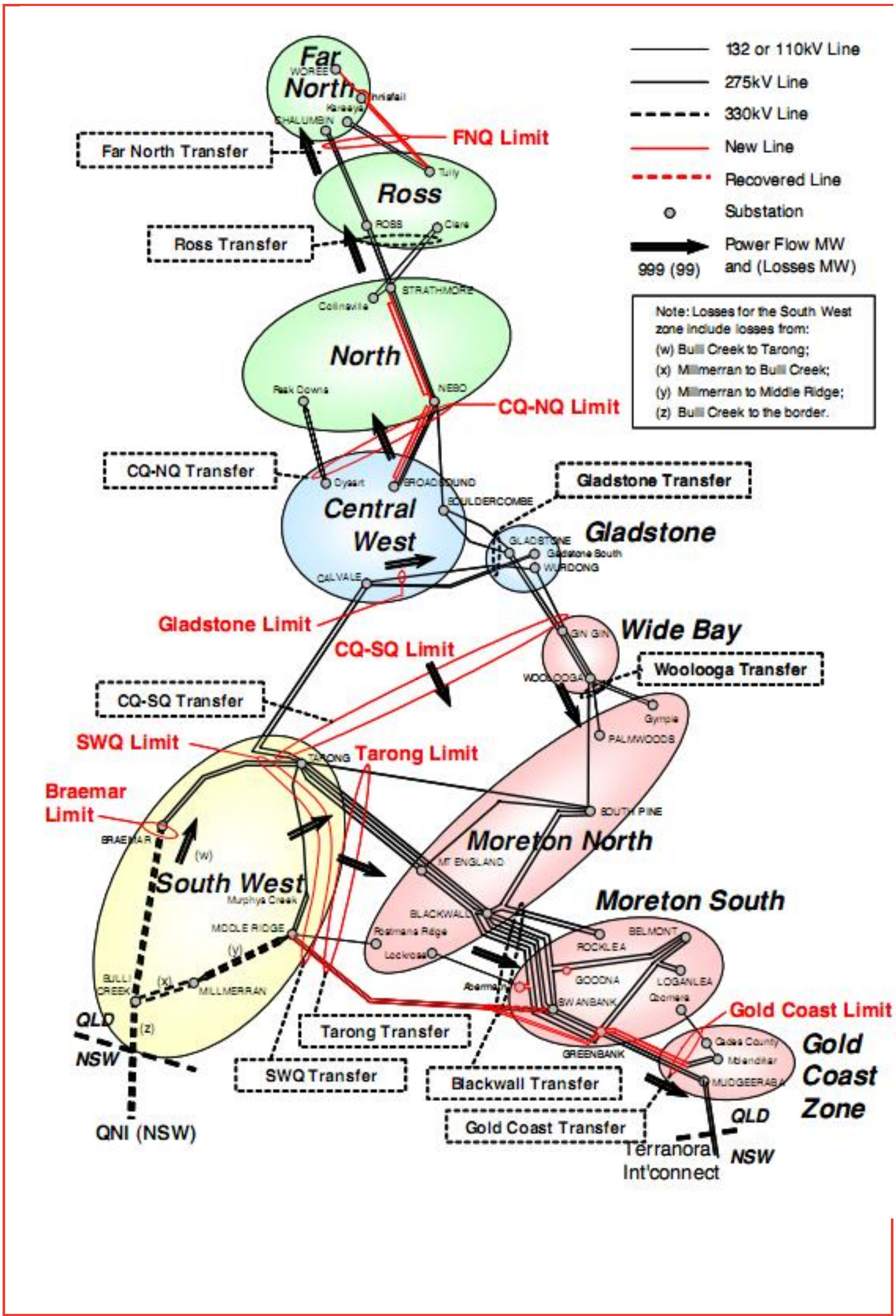
In its 2004/05 Annual Report, Powerlink justified the Millmerran to Middle Ridge extension as: "To meet the demand for electricity in the Darling Downs area which is growing rapidly and also to cater for a predicted future need in the Logan region."

It could be speculated that had Millmerran power station not been developed where it was, Powerlink could have instead reinforced the Tarong to Middle Ridge line to supply increased load in the Darling Downs. However, Powerlink considered that given the Millmerran to Bulli Creek line built – and paid for – by Millmerran, building a line from Millmerran to Middle Ridge was a cheaper option. Therefore, it is extremely unlikely that the lack of a locational signal for Millmerran promoted inefficient investment.

In its 2005/06 Annual Report, Powerlink justified the Middle Ridge to Greenbank extension as: "To ensure continued reliability of electricity supply for the Logan and Gold Coast regions, and to reinforce the electricity network supplying South East Queensland."

It could be speculated that had Millmerran power station not been developed where it was, Powerlink could have instead reinforced the Tarong to Greenbank network. However, not only would this have been extremely costly, it would have forsaken the diversity of supply provided by reinforcing an additional path into south-east Queensland for QNI northward flows.

In summary, it is difficult to make a case that the lack of a LRIC charge on Millmerran resulted in an inefficient combination of generation and transmission investment in southern Queensland, based on the information available at the time, or even in subsequent years.



Source: Intergen website (http://www.intergen.com/millmerran/); Powerlink Annual Reports and Annual Planning Reports (http://www.powerlink.com.au/About_Powerlink/Publications/); Frontier Economics analysis

Box 2: Uranquinty 640 MW OCGT power station

Uranquinty Power Station is a 640 MW gas-fired peaking power station – one of the largest open cycle gas turbine (OCGT) power stations in Australia. It entered service in early 2009. Uranquinty is located near Wagga Wagga in NSW and exports power into TransGrid's 330 kV network. According to its present owners, Origin Energy, the location for Uranquinty was chosen due to its close proximity to existing gas pipeline infrastructure and existing high voltage transmission lines.

At the proposal stage, the proponent, Wambo Power Ventures, commissioned modelling by HMA Consulting (HMAC) to assess the extent to which the dispatch of Uranquinty might be inhibited by limitations on the 330 kV network both northward (towards Sydney) and southward (towards Victoria).

HMAC engaged ROAM Consulting to undertake 'generation scheduling' (dispatch) modelling and undertook load flow and stability modelling itself. The dispatch and load flow modelling was undertaken for the years 2008, 2013 and 2018. The stability modelling considered conditions of high power flows from Snowy to NSW and from Snowy to Victoria.

The dispatch modelling assumed that:

- Uranquinty would bid at $50/MWh – the scope to increase dispatch through disorderly bidding was not considered.
- No major transmission reinforcements were allowed for between NSW, Snowy and Victoria

The ROAM and HMAC modelling concluded that:

- Under (then) present market conditions, there appeared to be no restrictions imposed by the network on Uranquinty exporting 600MW when bidding at $50/MW.
- With high power transfers north from Snowy, Uranquinty improved transient stability quite significantly.
- With high power transfers south from Snowy, stability was not a problem – the presence of Uranquinty had insignificant effect

The only conditions under which constraints on Uranquinty arose were in the load flow modelling, during an outage of one of the four 330 kV lines north of Snowy. However, HMAC estimated that such an outage would only restrict Uranquinty's generation for 8 hours every 5 years; a loss of 0.37% of its expected generation output.

In summary, this contemporaneous evidence provided by the HMAC report suggests that the business case for Uranquinty was not based on either:

- An expectation that the transmission network between the generator and the NSW or Victorian RRNs would be augmented in response to the making of the generation investment
- The scope for obtaining priority network access via a strategy of disorderly bidding.

Rather, the investment was made on the empirically verified basis that the existing network was sufficient to allow virtually full dispatch of the plant at peak loading times. This is consistent with the results that could be expected in an efficient market.

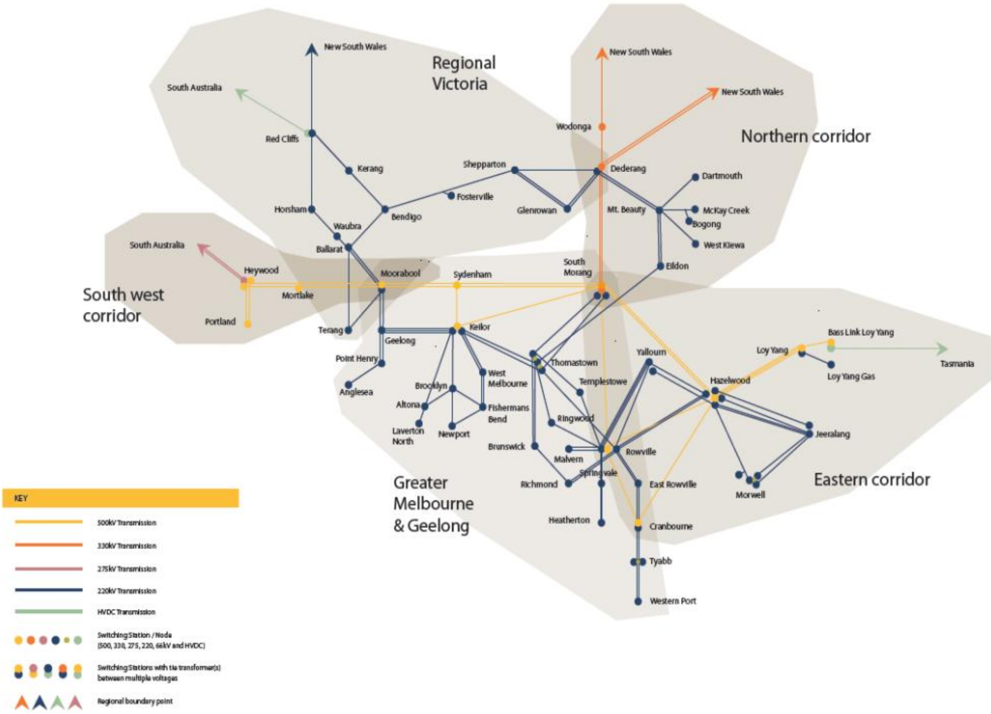
Source: Origin Energy website (http://www.originenergy.com.au/2724/Uranquinty-Power-Station); HMA Consulting, Export Capability of Proposed Uranquinty Power Station*, 25 July 2006 (http://www.aemc.gov.au/getattachment/745f6b38-1d36-40c3-80a1-39f90c1b51fd/Babcock-and-Brown-12-March-2008-Uranquinty-Export.aspx) ;TransGrid Annual Planning Reports (http://www.transgrid.com.au/network/np/Pages/default.aspx); Frontier Economics analysis*

Box 3: Mortlake 550 MW OCGT power station

Mortlake power station is a 550 MW OCGT generator built near the township of Mortlake in south-west Victoria, about 200km west of Melbourne. It is the largest gas-fired generator in the State.

According to the developer, Origin Energy, the Mortlake site was chosen due to a range of factors, including its access to the existing 500 kV network. The plant is located adjacent to the existing Moorabool to Heywood 500 kV line. It is also not far from Origin's gas reserves in the offshore Otway Basin. The plant is supplied via an 83 km dedicated underground natural gas transmission pipeline from the Otway Gas processing plant near Port Campbell. The pipeline stretches through the Timboon, Brucknell, Garvoc and Terang districts.

We note that if Origin Energy had sought to minimise its gas pipeline costs from the Otway gas processing plant, it could have – at least in principle – connected to the 220 kV line serving Terang (see diagram below).



Source: SP AusNet

Terang is approximately 20 km closer to the gas processing plant than Mortlake (see map below). However, Origin clearly came to the view that it was worth incurring higher gas pipeline costs to enable connection to the much higher capacity 500 kV network. This strongly suggests that the developers of Mortlake took into account its long term ability to be dispatched and did not just seek to minimise their out-of-pocket expenses on the basis that SP AusNet would upgrade the 220 kV network around Terang to accommodate the output of the plant.

Source: Origin Energy (http://www.originenergy.com.au/files/Mortlakefactsheet2.pdf); SP AusNet 2014-17 revenue proposal (http://www.aer.gov.au/sites/default/files/SP%20AusNet%202014-17%20revenue%20proposal%20p.pdf); Frontier Economics analysis

These case studies show that key generation locational investment decisions made during the NEM's history could not be said to have been materially inappropriate given the information available at the time.

In all cases, it appears that proponents:

- Made careful assessments of their future likely dispatch given expected levels and patterns of load growth and network augmentation and
- Did not invest on the basis that TNSPs would be subsequently compelled to upgrade their networks in response to the proponent's investment primarily to increase their generator's ability to export power.

These observations do not support the AEMC's concerns that the existing transmission frameworks promote inefficient coordination of transmission and generation. Rather, they attest to the likelihood that even during periods of strong growth in demand, any costs from imperfect coordination between generation and transmission investment was negligible. This serves to highlight the deeply flawed approach to representing the current planning arrangements taken in ROAM/EY's modelling (see Box 4).

Moreover, as there is unlikely to be substantial investment in grid-connected generation and transmission over the next decade, we suggest that the magnitude of any coordination inefficiencies will be even smaller for the foreseeable future than it has been over the 16 years since market-start.

Box 4: ROAM / EY modelling – Begging the question?

In January 2015, the AEMC published a report by consultants Ernst & Young (EY) entitled "Modelling the Impact of Optional Firm Access in the NEM". This report followed a 2013 report by ROAM Consulting prepared for the AEMC's Transmission Frameworks Review (TFR). Both the EY and ROAM reports sought to quantify the value of gains in dynamic investment efficiency attributable to moving from the current transmission planning arrangements to OFA.

Both the EY and ROAM reports:

- Used the same proprietary 'LTIRP' model to represent generation and transmission investment outcomes under the existing ('RIT-T') and proposed ('OFA') planning arrangements.
- Represented the current RIT-T arrangement in the same way – based on the concept that 'transmission follows generation'. Specifically, EY/ROAM assumed that generators invest first without regard to intra-regional transmission capacity and that TNSPs subsequently invest to satisfy the RIT-T given the locational, technological, size and timing investment choices made by generation proponents. In practice this means that EY's modelling produces a pattern of generation investment over 25 years consistent with a completely unconstrained grid and then 'backfills' transmission investment conditional on generation investment. This acts to set a highly inefficient baseline against which to measure the worth of OFA.
- Undertook an 'OFA' case that assumed that, as a consequence of the operation of the OFA arrangements, socially optimal investment, co-ordinated generation and transmission investment would occur subject to demand for firm access. In practice, OFA does not ensure socially optimal investment as the detrimental impact of any investment are not considered (unlike the current RIT-T arrangements).
- Found that in spite of tilting the analysis in favour of OFA, the net present value of the benefits of moving from the current arrangements to OFA under base case assumptions was approximately \$85 million (equivalent to 0.1% of the total NPV

system costs).

It is clear from our prior discussion of the operation and track record of the current arrangements that EY and ROAM have constructed a reference case that does not accurately reflect present transmission planning behaviours and outcomes. If the EY/ROAM representation were even broadly accurate, the history of the NEM would be littered with examples of clearly inefficient generation and transmission investment decisions (given the information known at the time). However, neither EY/ROAM nor the AEMC have been able to cite such examples. In fact, ROAM itself undertook a detailed assessment of transmission risks for the Uranquinty project in 2006 (see Box 3), it is clear that (at least private) generation investors devote considerable attention and resources to understanding prevailing and potential future patterns of transmission congestion before they invest. Generators do not invest oblivious to congestion and to assume that they do is to artificially create a problem for OFA to solve.

In short, it appears that the modelling undertaken by EY and ROAM has been confected to produce a result that favours OFA by assuming inefficiency in the existing arrangements where there is no evidence of such inefficiency. Such modelling is simply an enumeration of the starting assumptions rather than offering real insight regarding the impact of the proposal.

6.4 OFA increases centralisation of investment decision-making

Frontier Economics' October 2012 report for the NGF explained why the OFA proposal offers a more rather than less centralised approach to the coordination of generation and transmission investment compared to the existing arrangements.

This is because:

- Under the OFA proposal, TNSPs would be obliged to plan their networks to satisfy the demand for firm access rights in addition to reliability standards.
- The price of firm access rights would be:
  - The NPV cost of forecast transmission investment given the need to underwrite the financial firmness of the access rights *less*
  - The NPV cost of forecast transmission investment absent the need to underwrite the financial firmness of the access rights
- The determination of forecast transmission investment under both of these states of the world would be based on the outworkings of an 'element-based expansion model' developed by the TNSP (or AEMO).
- The modelling would take into account:
  - Initial spare capacity on the relevant network element
  - Annual flow growth on the element based on expected load growth, the need to maintain reliability standards and expected future firm access applications
  - Lumpiness, reflecting the relative size of incremental capacity expansions

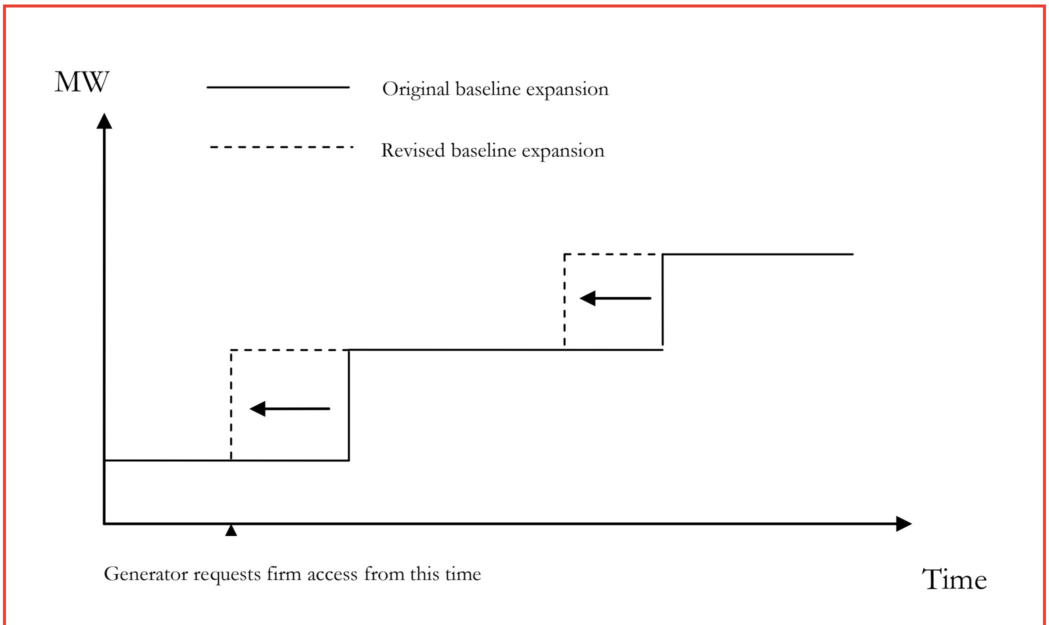
- How a particular request for access rights affected the need for transmission investment

This means that prices applicable to a particular access rights request would be highly dependent on the model developer's views regarding future generation and transmission investments and power flows in different locations into the distant future.

Our October 2012 report went through a stylised example in which a generator could choose between procuring access rights at two locations (A and B) the same distance from load with the same level of initial spare capacity.

Under these conditions, access prices would only differ to the extent that the TNSP considered that baseline transmission development at the two locations will differ. If the TNSP expected more generation development in future at A than B, this would mean that the baseline expansion for branch elements to location A (Figure 23) will look quite different to the baseline expansion for branch elements to location B(Figure 24).

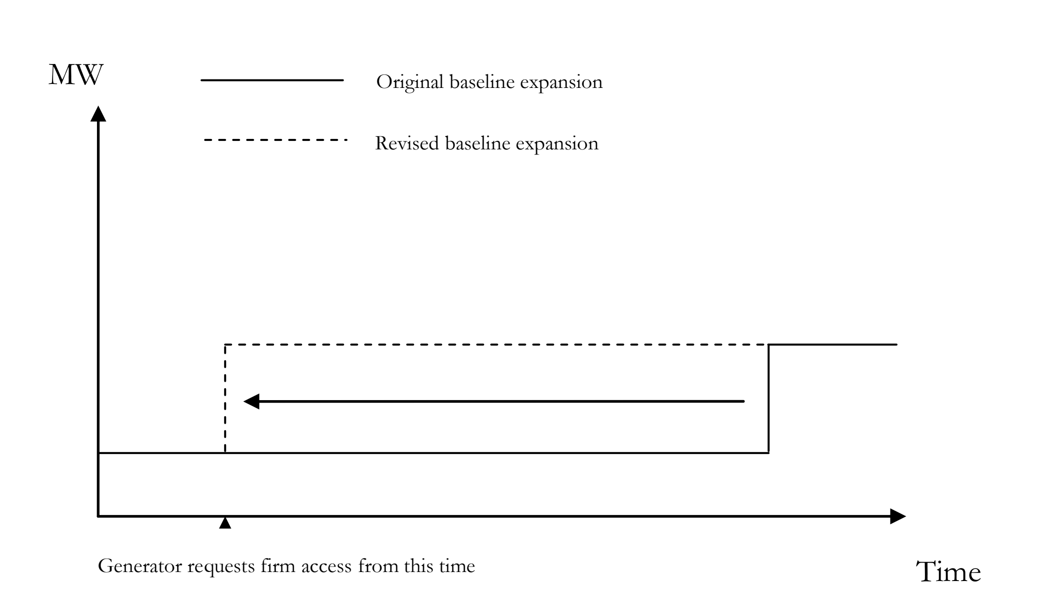
Figure 23: Example baseline expansion plan to location A



Source: Frontier Economics

Due to the 'lumpiness' of transmission investment relative to the size of new increments of generation, an application for firm access at location A would do less to bring forward estimated transmission investment than an otherwise identical application at location B. As a result, the price for firm access at location A would be lower than the price at location B.

Figure 24: Example baseline expansion plan to location B



Source: Frontier Economics

Our October 2012 report noted that the existing transmission planning process using the RIT-T requires TNSPs to make assumptions about current and future generation locations and costs. We commented that the key question is whether the OFA proposal puts more or less weight on TNSPs' *ex ante* views of future generation investment patterns than the existing arrangements. In our view, the OFA proposal puts more weight on TNSPs' views than the existing arrangements because:

- Under the existing arrangements, TNSPs are principally and unavoidably required to forecast what generation may need to be developed to meet network reliability standards. These forecasts are the subject of stakeholder scrutiny through the RIT-T process.
- Under the OFA proposal, TNSPs are required to forecast all generation investment (reliability-driven and non-reliability-driven) and the extent to which generation proponents are likely to make firm access applications. The extent of any public consultation or accountability for these forecasts is unclear.

We then discussed the importance of TNSPs' views under the existing transmission frameworks and under OFA in the context of a both a 'single-shot' investment case and a 'multi-investment' case.

Our report commented that in the straightforward 'single-shot' investment case, both the current arrangements and the OFA proposal:

- placed similar reliance on TNSPs' views of future generation development and

- provided effectively the same locational signals.

However, in more complicated 'multi-investment' cases, TNSPs' longer-term views of generation developments become more relevant than under the current arrangements. We provided an example in which the OFA proposal could lead to different investment outcomes than under the current arrangements for no other reason than the TNSP's view of likely patterns of future generation investment.

Accordingly, we rejected the notion that the OFA proposal promotes 'market-led' investment decision-making. Rather, the OFA proposal would result in a more centralised approach to market development, in that it promotes generation investment in accordance with the TNSP's prior and untested expectations.

AEMC response to greater centralisation concern under OFA

In its TFR Final Report, the AEMC rejected our criticism that the approach to access pricing under OFA would produce generation investment outcomes in line with the TNSP's expectations. The AEMC commented that 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. This would be the case if a request for access used up remaining spare firm network capacity at a location (as in the above Figures) and required immediate augmentation to be undertaken. However, the AEMC pointed out that if a generator seeks firm access at a location with a very high level of spare capacity – and spare capacity would remain after fulfilling the access request – higher assumed levels of generation at that location would lead to higher access prices. This would mean that the TNSP's forecasts in this situation would become self-denying rather than self-fulfilling.

We consider it an odd response for the AEMC to accept that access prices either drive generation investors towards or away from the locations the TNSP expects. Any access pricing methodology should strive to be as neutral as possible regarding the *TNSP's expectations* of future generation development, and ideally rely as little as possible on those expectations. This is what we regard as the essence of a decentralised approach to transmission investment.

Moreover, if a generator is choosing between locations with plentiful spare capacity – such that the network can accommodate the full output of the new and pre-existing local generators – then there is no economic reason for charging any access price to that new generator at any of those locations. The fact that the OFA access pricing methodology would over-charge a generator under these circumstances is not an argument in its favour.

In our view, any coordination benefit from OFA must come in circumstances where a generator proponent is choosing between locations and at least one of those locations requires a network augmentation to accommodate the generator's access request. In these circumstances, we have shown in our October 2012 report that the access pricing methodology would promote generation investment similar to those under the current transmission arrangements in the single-shot case and in line with the TNSP's prior expectations in the multi-investment case. The result is effectively increased centralisation of investment decision-making, which is likely to lead to inefficient outcomes.

6.5 Potentially detrimental OFA planning criteria

The above discussion of access pricing under OFA ignores the AEMC's proposed changes to the planning criteria for transmission reliability investment set out in its First Interim Report for OFA. Unfortunately, the proposed changes are potentially highly detrimental to the efficiency of transmission network investment in the NEM.

The importance of transmission planning criteria arises because the amount of network capacity the TNSP is obliged to develop irrespective of generator firm access requests in order to meet customer reliability standards is a key variable influencing both:

- demand for firm access rights and
- the pricing of firm access rights

The AEMC has confirmed that TNSPs would still need to invest in the network to meet their jurisdictional reliability standards for customer load.[50] Clearly, if a generator believes that a TNSP will need to invest in order to meet reliability standards and this investment will make available additional network transfer capability, the generator will be less willing to independently request and pay for firm access rights.

In the OFA First Interim Report, the AEMC accepted that there would continue to be a role for the RIT-T under OFA, in relation to planning to meet customer reliability standards. The AEMC regarded planning to meet such standards as an unavoidable 'distortion' to market-led transmission investment.[51]

However, in a clear departure from the existing planning arrangements, the OFA First Interim report reiterated the AEMC's intention from the TFR Final Report to exclude benefits (and costs) to generators from RIT-T assessments.[52] This would effectively mean that reliability investment planning would be based on a least-cost (to consumers) criterion – the TNSP would select the option that met reliability standards at least cost. This would effectively undo the AEMC's and AER's 2009-10 reforms to convert the original two-limbed regulatory test for

50 AEMC OFA First Interim Report, p.132.

51 AEMC OFA First Interim Report, p.134.

52 AEMC TFR Final Report, pp.43-44; AEMC OFA First Interim Report, pp.133-137.

network investment (ie with a 'reliability' limb and a 'market benefits' limb) into a single market benefits criterion test. Reliability transmission planning would revert to using a cost-effectiveness criterion. Cost minimisation may not be consistent with maximising overall net economic benefits and it would be difficult to see how this proposal could satisfy the National Electricity Objective.

As a 'recommended' rather than 'core' part of its OFA proposal, the AEMC suggested that RIT-T assessments could incorporate generator benefits, but only to the extent generators signalled their willingness to pay for firm access made available through a reliability-driven investment.[53] This signalling would operate through 'contingent auctions' run by TNSPs across multiple options for meeting a reliability standard. Generators would be able to bid for firm access provided by one or other option and the value of their bids (less the incremental costs of providing them with firm access) would serve to reduce the effective cost of the option they bid for. The AEMC provided an example showing how generator bids for firm access offered by two different reliability options could reverse the ranking of the options as against a pure cost minimisation approach – see Figure 25.

Figure 25: Reliability planning – role of contingent auctions

Table A.2 Pricing of Firm Access

	Option 1 (Generator A costs)	Option 2 (Generator B costs)
Cost to TNSP of providing reliability expansion alone	$100m	$150m
Additional cost of providing firm access	$90m	$130m
Generator bid	$120m	$220m

Source: AEMC OFA First Interim Report, p.140

Without the contingent auction, the TNSP would choose Option 1 for meeting the reliability standard, as the cost of Option 1 ($100 million) is lower than the cost of Option 2 ($150 million). However, allowing for generators' bids for firm access would make Option 2 the preferred option because despite Option 2 incurring higher overall resource costs, Generator B is willing to pay more for firm access and hence the net direct cost of Option 2 to the TNSP's customers is lower[54]. This approach ignores detriments to any 3rd parties and may lead to

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[53] AEMC OFA First Interim Report, pp.136-141.

[54] Option 1 has overall resource costs of $100m, but a 'net' cost of $70m = $100m + $90m - $120m.

inefficient investments. That is, whilst Generator B might be willing to pay a large access fee such that Option 2 is undertaken, and this may lead to lower net direct costs to consumers, if a 3rd party (Generator C) losses $30m under Option 2 then this outcome is socially sub-optimal. This is discussed further in the box below.

The AEMC's proposed approach to accounting for generator benefits is fundamentally flawed for the same reason that transmission planning is not left to market forces more generally – any given transmission investment can affect many parties in different ways and it is very difficult to capture all of these impacts through a private bargaining process. This is the fundamental issue associated with the network externalities of transmission investment – privately optimal outcomes are not necessarily socially optimal.

The current RIT-T addresses this problem by estimating the impact of transmission investment on all market stakeholders through a modelling process. However, the AEMC's proposed contingent auction approach only takes account of the interests of generators who stand to gain from a particular investment and are willing to pay for it. Any transmission investment will tend to benefit some generators, but typically this will at least partially be at the expense of other generators. If generators cannot signal their willingness to pay for a particular option to *not* go ahead, then there is no guarantee that the proposed process will lead to the most net beneficial option. Conversely, even generators who do stand to benefit from an augmentation may choose to 'free-ride' and not purchase firm access (see Box below). Reaching an efficient outcome will only occur by coincidence.

Under these circumstances, it would be far better for the current RIT-T planning process to be maintained – despite the TNSP's imperfect information about generator costs – than to move to an evaluation approach that effectively disregards some potentially large impacts of a transmission investment.

Box 5: AEMC's flawed approach to reliability planning

The current RIT-T seeks to identify the option that maximises net market benefits, even when the investment is motivated by the need to satisfy a reliability standard. This involves choosing the size of augmentation such that marginal benefits = marginal costs (MB=MC). Assuming diminishing marginal benefits (in $/MW) of larger augmentations, a smaller augmentation would not maximise market benefits because MB>MC – ie it would be possible to increase total benefits by expanding the augmentation; conversely, a larger augmentation would yield MB<MC and so would not maximise market benefits either.

The purpose of an augmentation is to increase the potential flow of power between two locations. These locations can be described as the exporting node and the importing node.

Option 2 has overall resource costs of $150m, but a 'net' cost to the TNSP of $60m = $150m + $130m - $220m.

Other things being equal, a larger augmentation will make:

(i) Consumers at the importing node better off

(ii) Generators at the exporting node better off

(iii) Consumers at the exporting node worse off

(iv) Generators at the importing node worse off

From MB=MC, we know that the optimally-sized augmentation must be such that the net effect on welfare of a 1 MW increase in size is zero: ie the net change in (i)+(ii)+(iii)+(iv)=0; the benefits to (i) and (ii) from a 1 MW increase in size are exactly offset by the losses to (iii) and (iv).

Now, assume the TNSP has identified two augmentation options for meeting reliability standards, one larger than the other. If consumers are (in net terms across both nodes) indifferent between them, the choice will come down to which option will attract more offers ($) from generators for (firm) 'reliability access'.

From the above, it is clear that generators at the exporting node will be better off from a larger line. If they can signal a willingness to pay for a larger line, but generators at the importing node cannot signal their desire for a smaller line, then the augmentation will be inefficiently large (and/or inefficiently located).

[On the other hand, if there are many generators at the exporting location, they may each have incentives to free-ride on the reliability access offers of other exporting generators.]

Consider the AEMC's stylised example in section A.4 (pp.140-141). It finds the more costly option (2) to be preferable because generator B is willing to contribute such a large amount ($220m) that the net direct cost to consumers of option 2 to consumers is lower than option 1 ($60m vs $70m). But what if a local generator close to the load loses $30m under option 2 but only $10m under option 1? It is prevented from signalling this to the TNSP. The outcome will then be sub-optimal.

The OFA First Interim Report dismisses the risk of inefficient over-investment by saying (p.34):

"...we consider that if generators signal that such build is efficient for them, and they are paying for the costs of this build, then such a situation would not be inefficient." (emphasis added)

This ignores the spillover effects of an augmentation on other parties. The current RIT-T rightly looks at all the winners and losers from a transmission investment, rather than just looking at the winners, as OFA does.

6.6 Conclusion

The AEMC has presented no evidence that the current arrangements for transmission planning in the NEM encourage inefficient coordination between transmission and generation investment. Our analysis of the existing arrangements demonstrates that investors in both transmission and generation have incentives to coordinate efficiently and an examination of actual generation investment decisions is consistent with efficient outcomes given the information available at the time.

The AEMC's proposed approach to reliability planning raises serious concerns about the efficiency of reliability-driven augmentations under OFA.

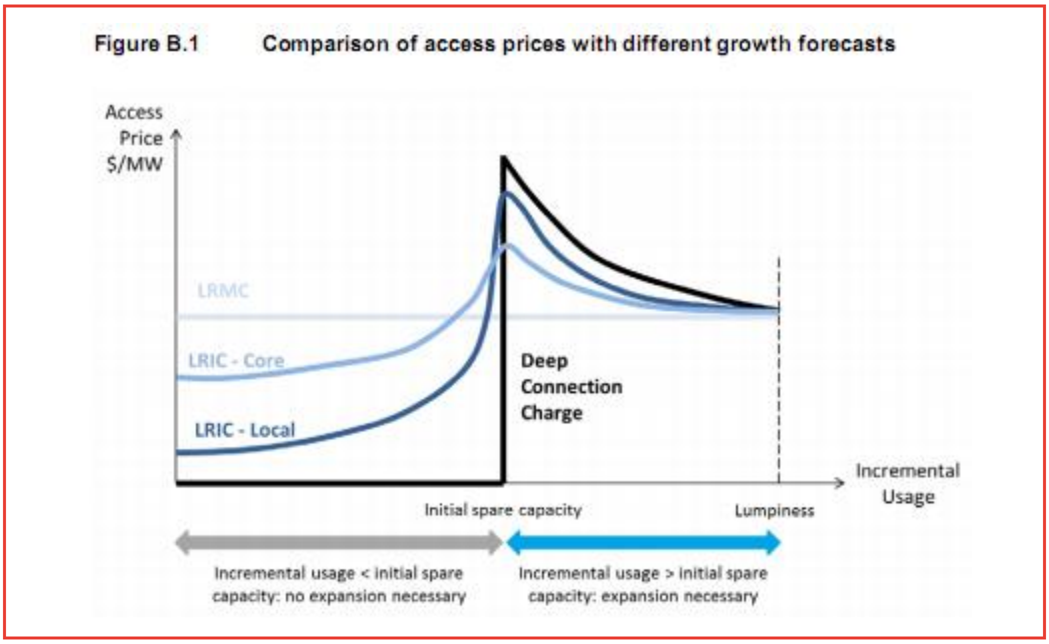
7 Issues with AEMC's access pricing model

The AEMC's Supplementary Report: Pricing[55] explains its methodology for setting optional firm access prices in more detail than its previous reports. This report is accompanied by a qualitative review of the Energy Market Consulting Associates (EMCa)[56] which ultimately concludes that the model would need significant further refinement to be practically useful. We have identified a number of apparent issues and inconsistencies in the OFA pricing model outcomes.

7.1 Apparent inconsistent results

We examined the access pricing outcomes produced by the AEMC's prototype pricing model that were published in its Supplementary Report. We compared those outcomes to what would be expected based on the AEMC's illustration of the relationship between LRIC, LRMC and Deep connection charges (see Figure 26 below).

Figure 26: Comparison of access pricing approaches



Source: AEMC Supplementary Report: Pricing, p.59.

The relationship suggested in this figure implies that if at a particular location:

- LRMC > LRIC, then LRIC > Deep connection (left hand side of figure)

55 AEMC, *Optional Firm Access, Design and Testing, Supplementary Report: Pricing*, 31 October 2014.

56 EMCa, *Review of Prototype Optional Firm Access Pricing Model*, October 2014 (EMCa report).

- LRIC > LRMC, then (usually) Deep connection > LRIC (right hand side of figure)

We agree with the logic of these relationships, based on the AEMC's definitions for each of these terms. Our analysis of the AEMC's results indicates that there are numerous outcomes that seem to be at odds with the logic of these relationships. This is discussed in more detail below.

7.1.1 How the pricing model calculates LRMC, LRIC and Deep Connection prices

Whilst the AEMC has released its Supplementary Report, the pricing model itself and a detailed user manual there is a paucity of information on how the LRMC, LRIC and Deep Connection costs are calculated in the model. For example, there are no worked examples of the LRIC and Deep Connection costs for any system beyond a two node, single line system. Neither is there a mathematical description of the cost calculations (despite large amounts of detail being provided on some of the flow calculations). Stakeholders would likely benefit from increased transparency around how these calculations are formulated and implemented in the model.

From what has been provided, a summary of the access pricing calculations is as follows:

- **LRIC** is defined as the change in NPV cost between a baseline augmentation plan (without an incremental request for access) and an adjusted augmentation plan reflecting an incremental access request. Changes in the adjusted augmentation plan over the entire modelling period lead to changes in cost in each modelled year, all of which feed into the NPV cost and the final LRIC results. LRIC is reported in millions of dollars and also divided by the access request volume to produce a \$/kW LRIC result.
- **Deep Connection** is determined calculated with regard to the same augmentation and adjusted augmentation plans. The only difference being that the deep connection results reflects changes in investment and cost in the first year of the access request only, not over the entire modelling period as in the LRIC calculation. This is a critical point – **both the LRIC and Deep Connection results rest on the same underlying power flow modelling and augmentation results**. As such, observed issues with Deep Connection results, which are easier to isolate as they reflect single year results as opposed to an aggregation over the entire modelling period, strongly imply that there is also an issue with the LRIC outputs of the model.
- **LRMC** outcomes are independent of the magnitude of the access request and "were no spare capacity and no lumpiness in the network". LRMC simply reflects the assumed \$/MW expansion cost and is independent of modelled power flows and augmentation paths.

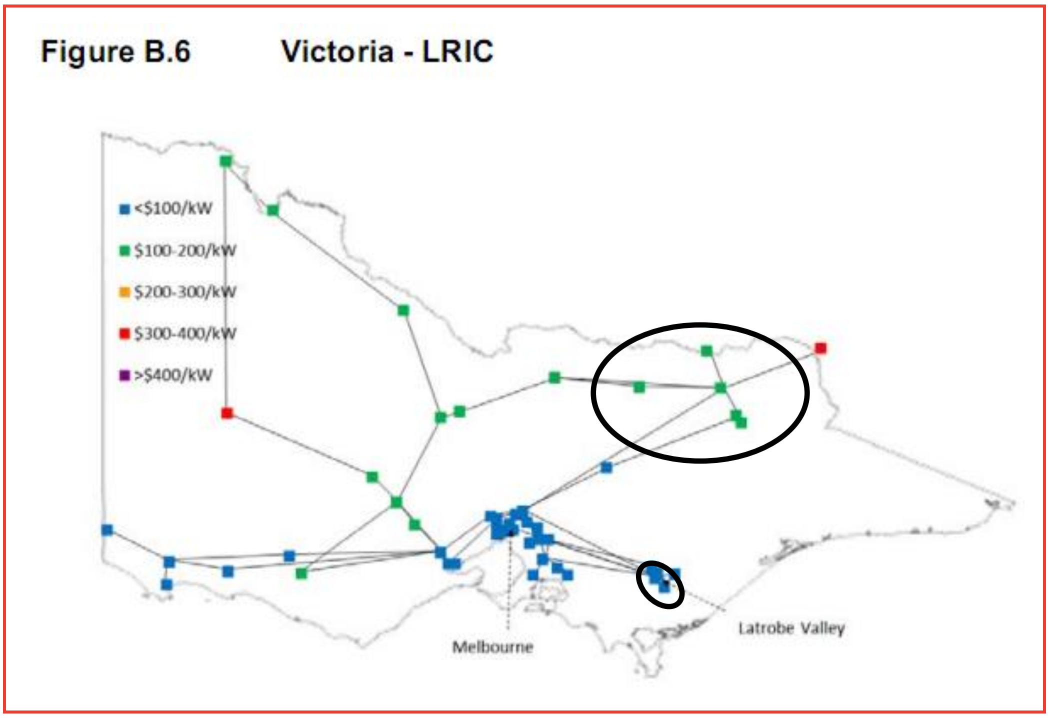
The following sections discuss a number of erroneous pricing outcomes in the Supplementary report, and our own analysis.

7.1.2 Examples of anomalous pricing outcomes

A number of the pricing outcomes presented in the Supplementary Report do not conform to the logical set of relationships described above. Some examples of these anomalies are set out below. Many other cases may potentially exist and could be identified with more precise data.

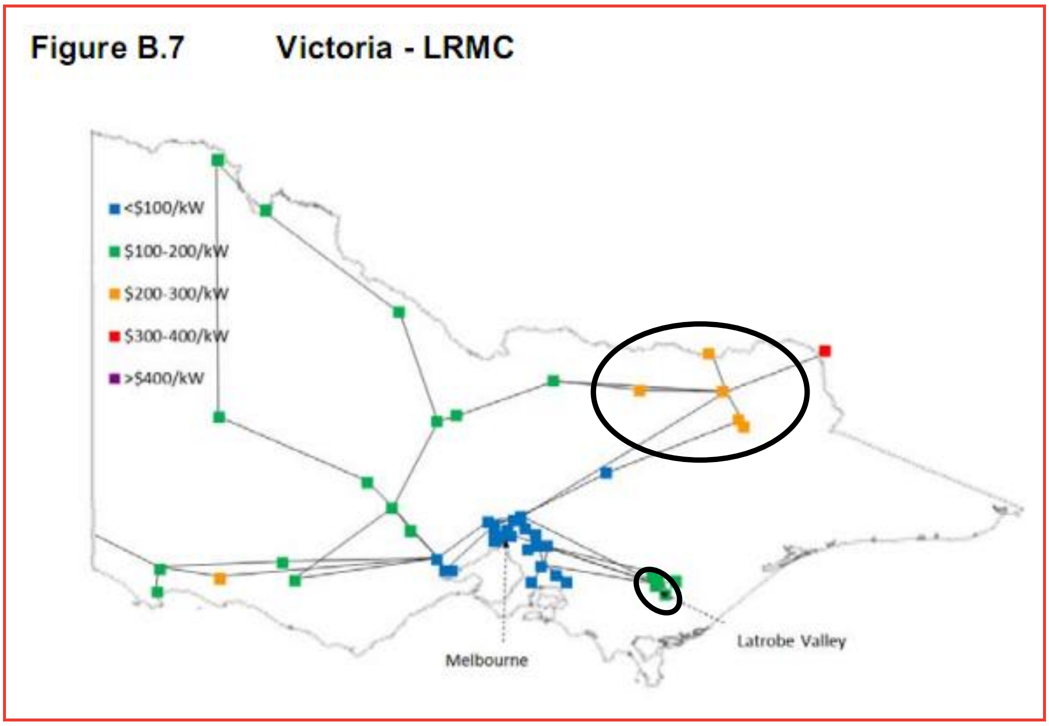
Victoria

Figure 27: Victoria – LRIC



Source: AEMC Supplementary Report: Pricing, p.64

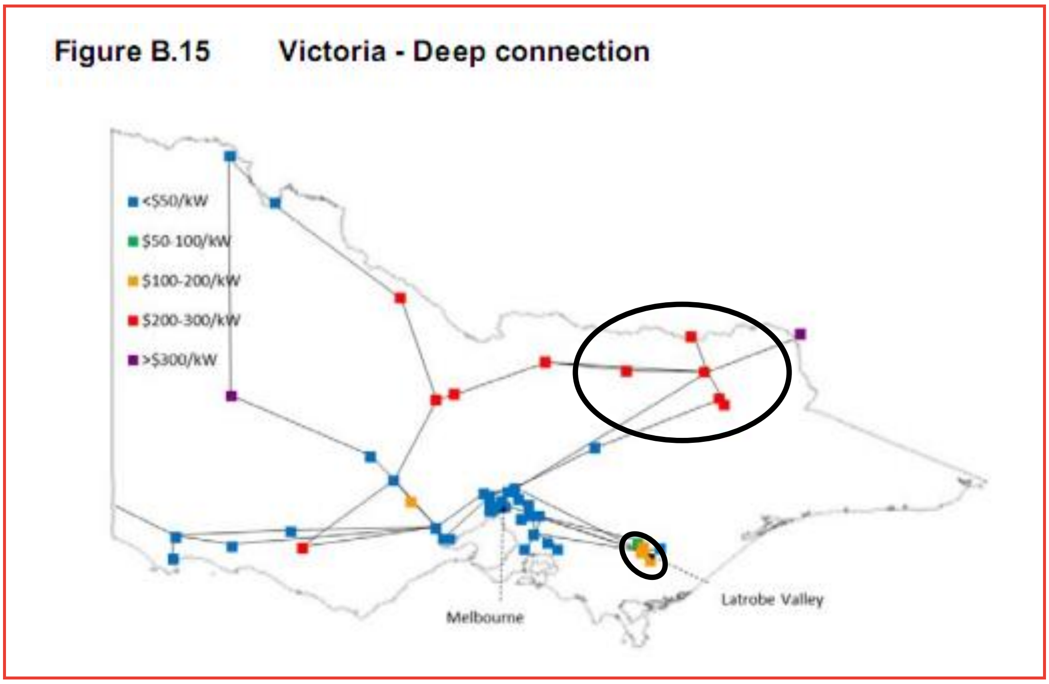
Figure 28: Victoria – LRMC



Source: AEMC Supplementary Report: Pricing, p.64

At the black circled locations, LRMC > LRIC. Therefore, one would expect LRIC > Deep connection. However, the opposite is the case, as shown below.

Figure 29: Victoria – Deep connection



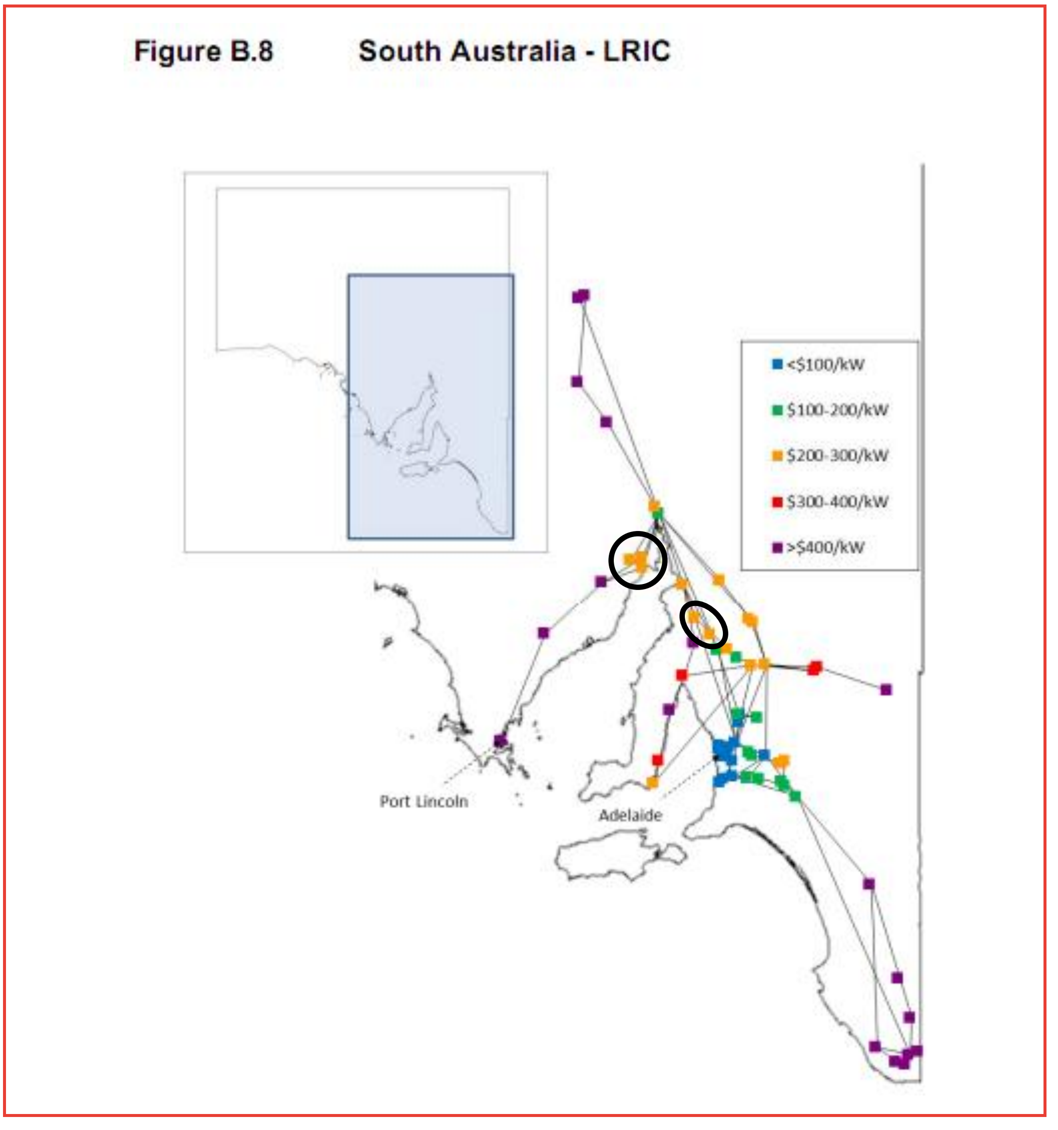
Source: AEMC Supplementary Report: Pricing, p.69

This suggests there is an error in the either pricing prototype model or the way in which its results have been presented.

South Australia

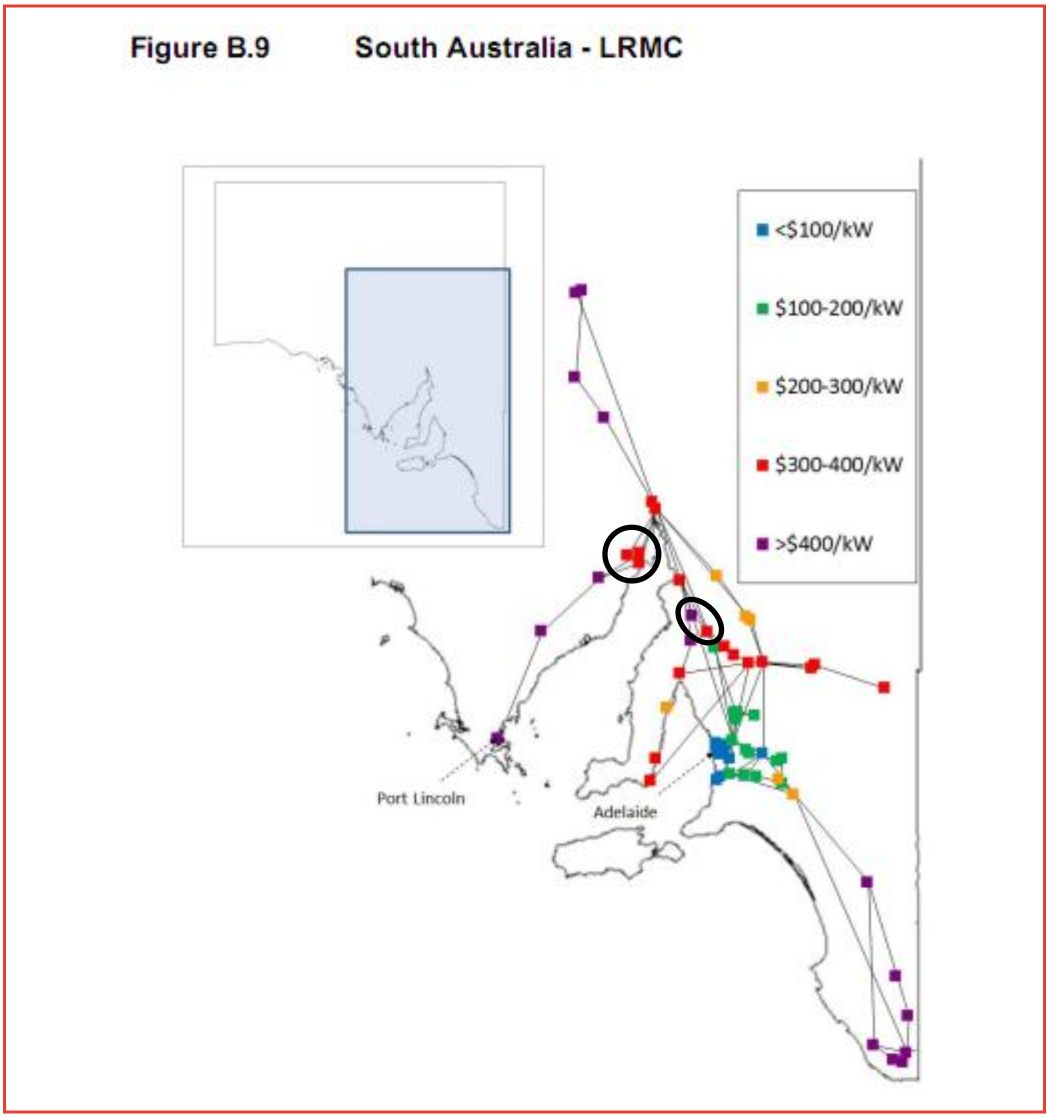
Similar anomalies can be identified in the South Australian results.

Figure 30: South Australia – LRIC



Source: AEMC Supplementary Report: Pricing, p.65

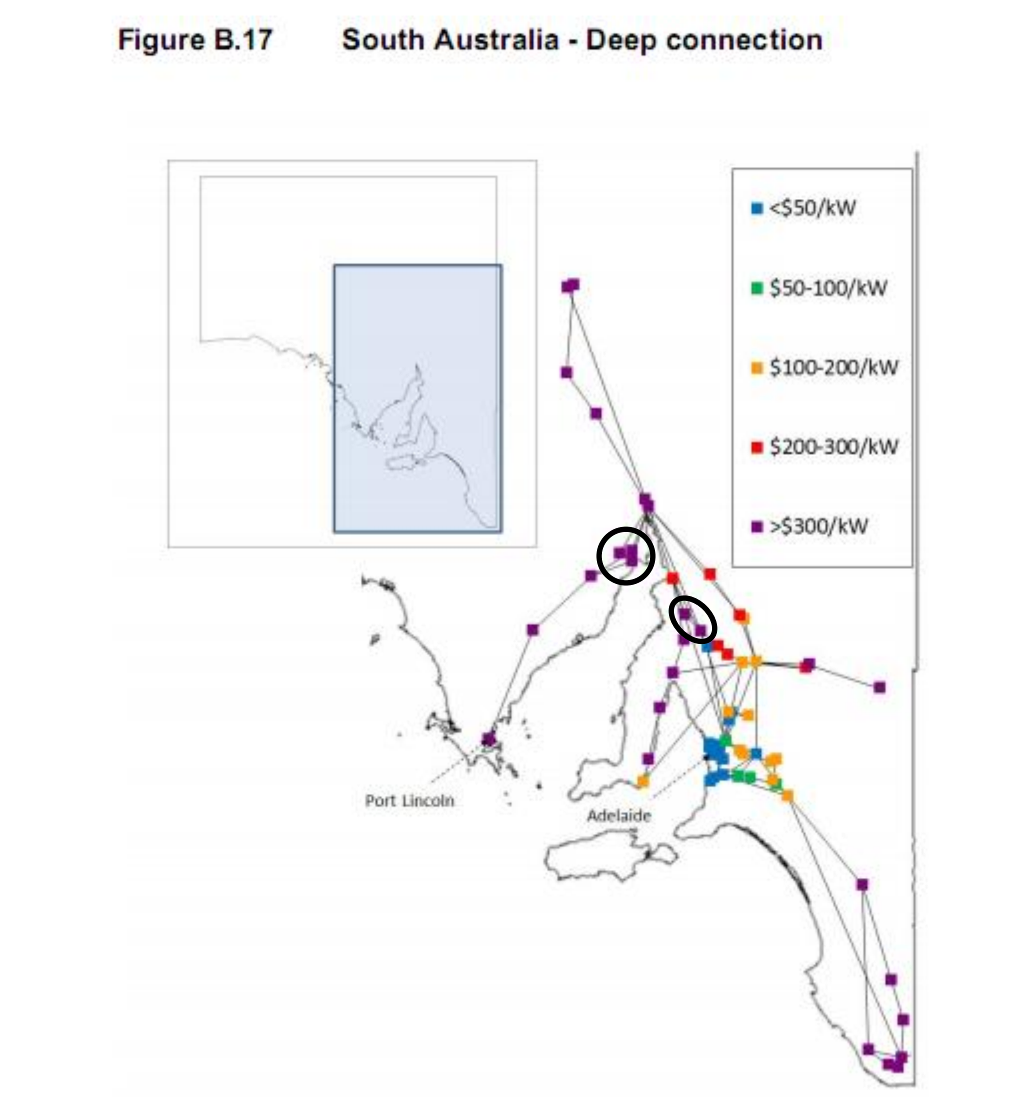
Figure 31: South Australia – LRMC



Source: AEMC Supplementary Report: Pricing, p.65

At the black circled locations, LRMC > LRIC. Therefore, one would expect LRIC > Deep connection. However, the opposite is the case, as shown below.

Figure 32: South Australia – Deep connection

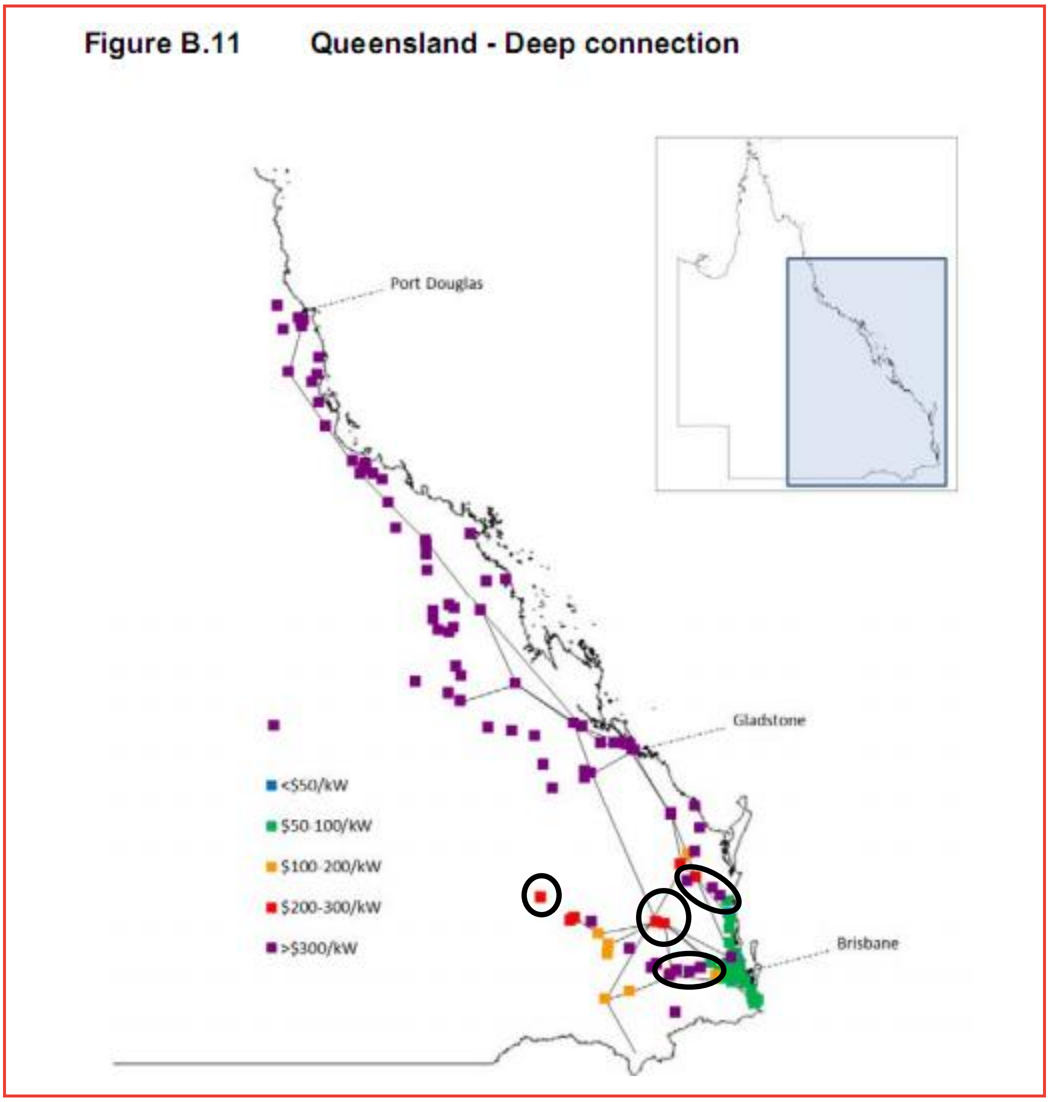


Source: AEMC Supplementary Report: Pricing, p.70

Queensland

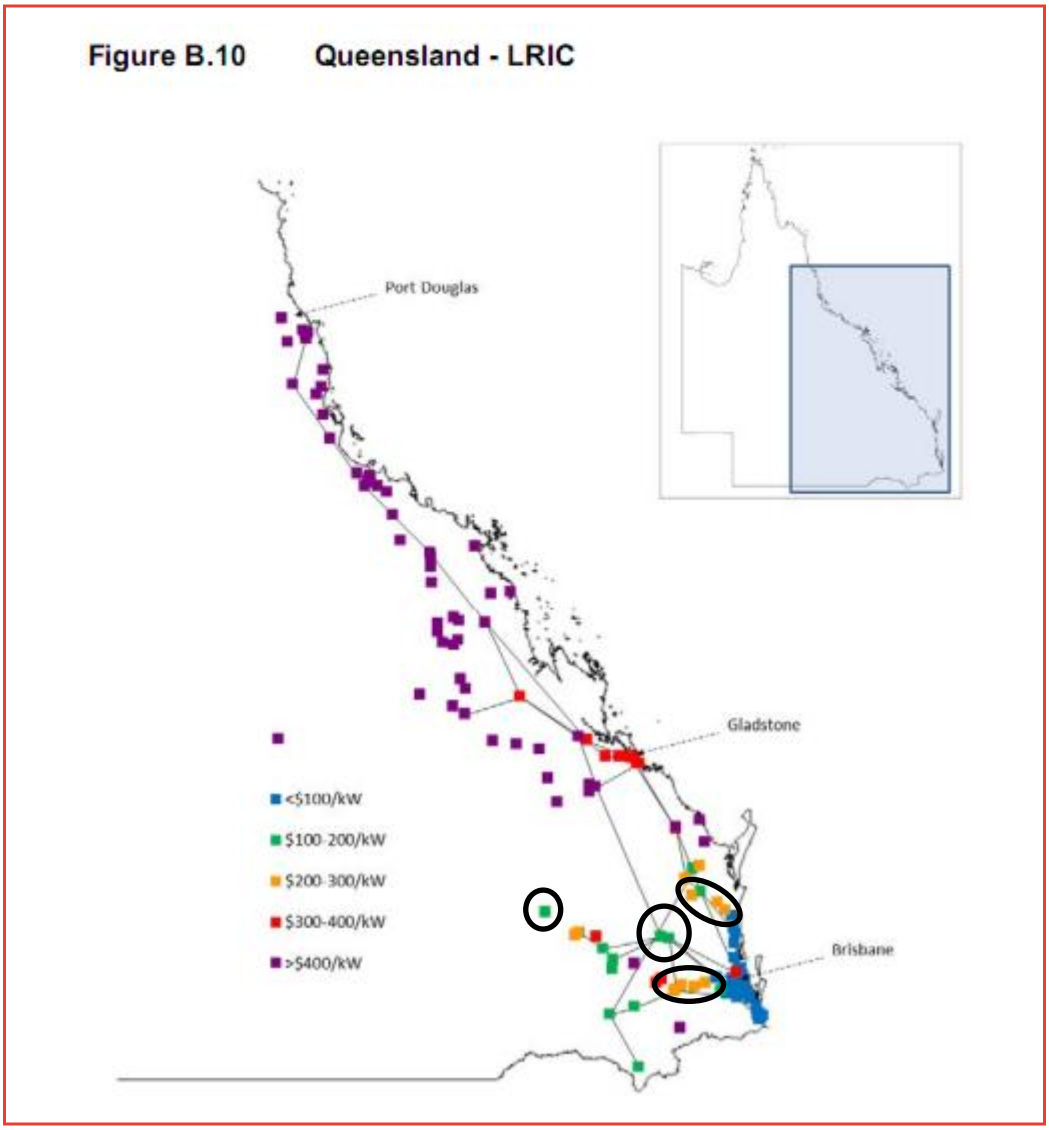
Slightly different anomalies – but still suggesting an error in the pricing model – can be identified in the Queensland results.

Figure 33: Queensland – Deep connection



Source: AEMC Supplementary Report: Pricing, p.67

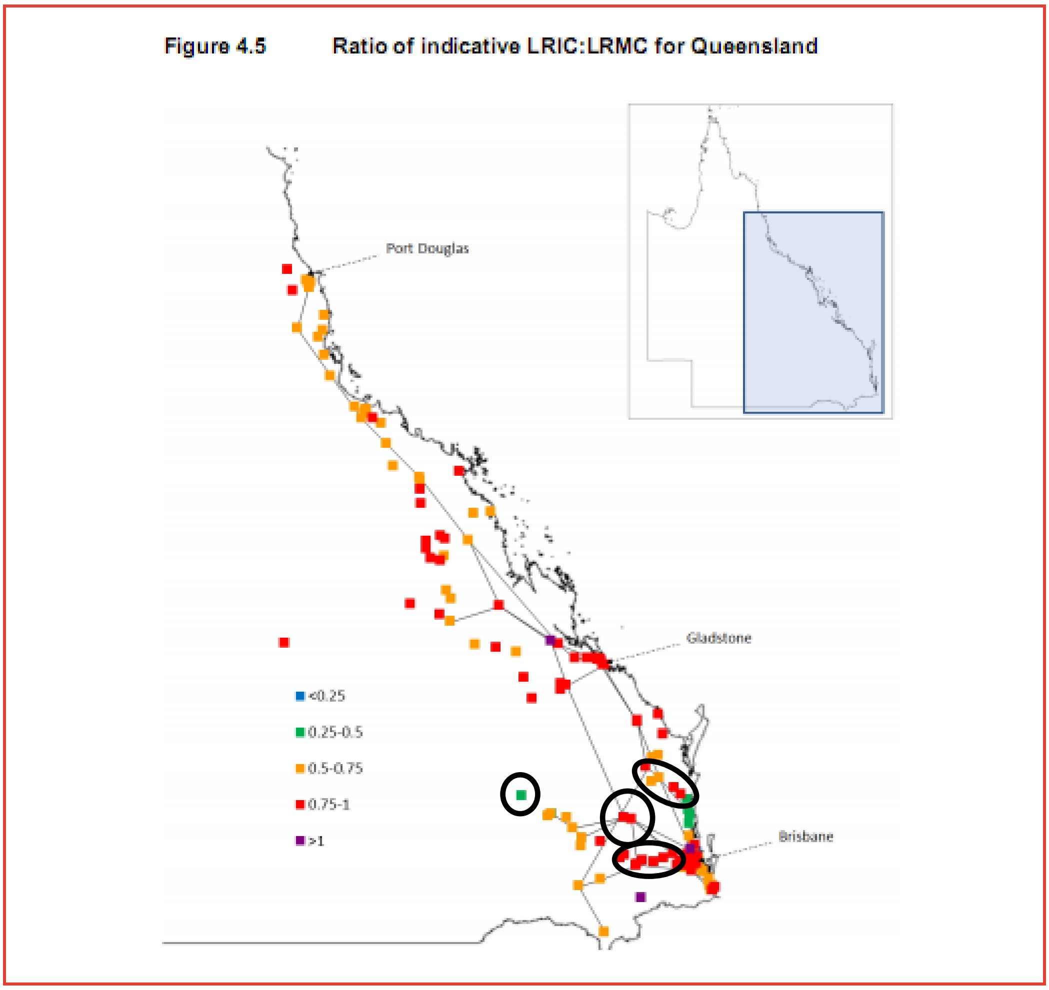
Figure 34: Queensland – LRIC



Source: AEMC Supplementary Report: Pricing, p.67

At the black circled locations, Deep connection > LRIC. Therefore, one would expect LRIC > LRMC and accordingly, LRIC:LRMC>1. However, the opposite is the case, as shown below.

Figure 35: Queensland – Ratio of LRIC:LRMC



Source: AEMC Supplementary Report: Pricing, p.42

Once again, this suggests the pricing prototype model has an error or there is an error in the way the results have been presented.

7.2 Apparently erroneous model outcomes

The EMCa report details a number 'possible anomalies'[57] that can be obtained from the access pricing model. Two of these findings are particularly concerning and are borne out by our own analysis using the model.

7.2.1 Non-equivalence of incumbent versus generic access

The model produces different results for a given access request depending on whether the access is entered as an incumbent access level assumption or as an

57 EMCa Report, p15

incremental access request. For example, the user manual details how to calculate results for the default access requests for *node 33* which is the Loy Yang node (node 3LYB500). Given that the description of the model states that investment decisions solely involve decisions to duplicate transmission lines (with identical unit costs), one would expect that a generic access request of 400 MW would produce the same LRIC result as an increase of the assumed firm access level at Loy Yang B of 200 MW[58] plus a generic request for 200 MW, as the same total access level is modelled in both cases. However, this is not the case.

Table 6 presents the outcomes when firm access is increased at Loy Yang B by 200 MW and 600 MW. Materially different LRIC results are reported by the model. In the case where 1200 MW of total access is requested, the LRIC is $93.8/kW if the entire request is generic and $110.4/kW if 600 MW of this request is allocated to Loy Yang B. This results in a difference in annual access prices of almost $20m per annum, we would note that this discrepancy is more than the annual operating profit of numerous large generators over recent years.

Table 6: Generic versus incumbent access for a range of total access request levels (Loy Yang B firm access increased by 200 and 600 MW)

Case	200	400	600	800	1000	1200
LRIC results $/kW						
Original	$36.2	$59.0	$64.2	$66.3	$89.5	$93.8
LYB + 200	n/a	$60.4	$65.0	$71.8	$91.6	$100.1
LYB + 600	n/a	n/a	n/a	$73.4	$105.7	$110.4
Differences $/kW						
LYB + 200		$1.4	$0.8	$5.5	$2.1	$6.3
LYB + 600				$7.1	$16.2	$16.6
Differences $m pa						
LYB + 200		$0.55	$0.48	$4.39	$2.10	$7.52
LYB + 600				$5.65	$16.18	$19.91

Source: Frontier Economics analysis using the AEMC Access Pricing Model

It is concerning that the access pricing model yields variable results that depend on how firm access is entered into the model. This may be indicative of fundamental issues with the calculations that the model performs.

58 Entered by changing the *aemc-access.csv* input file.

7.2.2 High access prices under conditions of spare capacity

LRIC and Deep Connection results produced by the model do not reduce in line with reductions in firm access or demand growth.

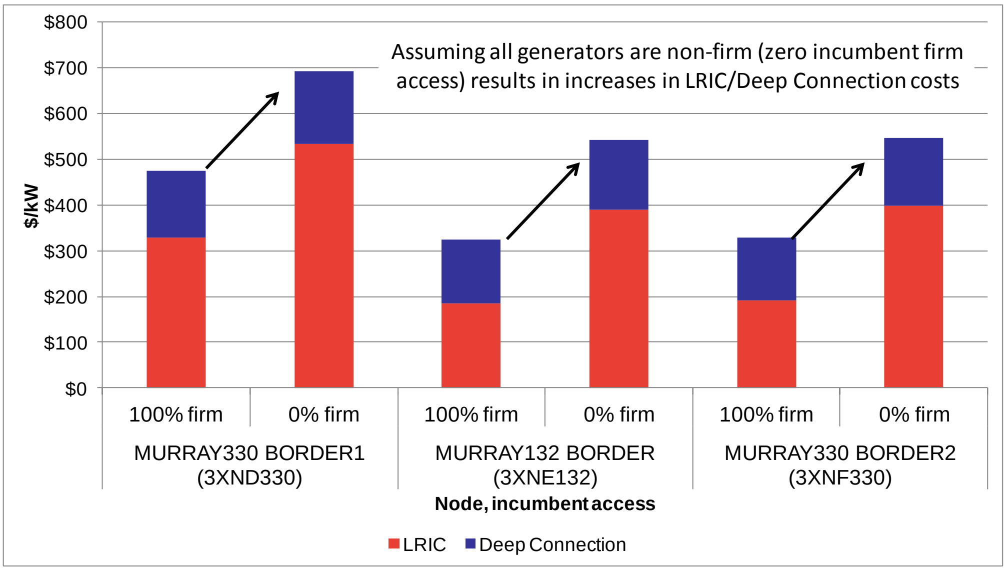
Reducing demand growth does lead to lower LRIC and Deep Connection cost estimates, however many of the reductions do not seem consistent with inputs. For example, if the input demand is made flat – no growth in POE 10 input demand levels and long term growth factors set to 0.01% - then the model does produce lower prices but there are still a material number of nodes with non-zero Deep Connection charges and none of the LRIC estimates fall to zero. This result seems inconsistent with a network that currently has significant spare capacity to meet reliability standards.

More concerning are outcomes when incumbent firm access is assumed to be lower. Intuitively, if there is less requirement from incumbents for firm access at the start of the modelling period then, other things being equal, the cost of incremental access should be lower under both LRIC and Deep Connection approaches.

This is not the case and is most clearly demonstrated when incumbent firm access is set to zero. The default input for incumbent firm access in the Victoria model is that all generators are firm for 100% of capacity. This equates to 11,273 MW of firm access across all the Victorian generators. This produces LRIC and Deep Connection costs that can be as high as $500/kW, for example in the area near the NSW border.

Reducing firm access to zero for all incumbents, that is freeing up over 11 GW of access capacity on the network, leads the model to report higher LRIC and Deep Connection costs. This is shown in Figure 36 for a sample of nodes near the NSW border however the result occurs for around 75% of the nodes in the model.

Figure 36: Impact of reducing incumbent firm access



Source: Frontier Economics analysis using AEMC pricing model for Victoria with incumbent firm access set to zero, results shown for a 400 MW access request

To reiterate, the model predicts a higher cost for providing firm access against a baseline of zero MW provided to incumbents than against a baseline of 11,273 MW provided to incumbents. This outcome brings the veracity of the modelling results into question. At the very least the AEMC needs to explain these apparently anomalous results.

7.3 Conflicts with congestion modelling

The AEMC's report shows that many Victoria generators in Melbourne and the Latrobe Valley will pay less than $100/kW for their access rights, which makes the two sub-regions cheapest in terms of access charges in the NEM.[59] However, this seems to be contrary to our constraint modelling results where the two constraints identified in Section 4.2.1 bind for generators in those two subregions. In particular, it is worth noting that the line rating for the constraint V>V_NIL_RADIAL_10_1 is halved during summer in AEMO's 2014 thermal constraint book. If congestion is an issue in Victoria, one would expect the Victorian average access price to be much higher than the current $80/kW. Had we used, say, the NEM average level of $250/kW for Victoria instead, the "OFA Regional Average" series would show that an additional 8.7GW, or roughly 20% of NEM capacity (above the $0/kW price level) would make an EBITDA loss.

59 AEMC Supplementary Report: Pricing, p.45. Most Victoria generators in this chart have significantly lower access prices than the rest of the NEM.

Appendix A – Approach to modelling OFA

The OFA settlement process for generators in our modelling is based on the approach outlined in the AEMC's Technical Report for the Transmission Frameworks Review.[60] This section provides a detailed description of our treatment of OFA settlement for generators. Our modelling has included all intra- and inter-regional transmission constraints published in AEMO's 2014 constraint books. However, we assume that the interconnectors do not have any agreed access amount and OFA payments accruing on the interconnectors are not owned by any generators.[61]

Generator payoff under OFA

OFA settlement is based on the principle that a constrained-off generator will be compensated for the difference between the relevant regional reference price (RRP) and its local marginal price (LMP) up to its network access amount[62]:

$$Pay = LMP * G + (RRP - LMP) * A \quad (1)$$

where G is output and A is level of the network access. Note that if the generator is not constrained off, $LMP = RRP$ and the generator receives exactly its spot market revenue. An alternative expression that is mathematically equivalent to the above, but more similar to the current NEM settlement, is the following[63]

$$Pay = RRP * G + (RRP - LMP) * (A - G) \quad (2)$$

The first part is the current pool settlement whereas the second part is the OFA payment, which can be positive or negative depending on the level of output and access amount.

In practice, the implementation of OFA is likely to be more complicated for several reasons:

60 AEMC, *Technical Report: Optional Firm Access. Transmission Frameworks Review, AEMC Staff Paper*, 11 April 2013, available from the AEMC website at:

http://www.aemc.gov.au/getattachment/7e308487-d5d8-4170-a277-3d69c3069d12/Transmission-Frameworks-Review-Technical-Report-Op.aspx (AEMC TFR Final Technical Report)

61 At this stage, it is unclear how agreed access will be allocated to interconnectors and who will own them at the initial stage if the OFA is implemented. Although we assumed no agreed access on the interconnectors, they still need to be taken into account in the settlement process. See section **Error! Reference source not found.** of our report. For a detailed treatment of the OFA on interconnectors, see AEMC TFR Final Technical Report, Section 9 and 12.

62 AEMC TFR Final Technical Report, p5.

63 Ibid, p6

- Transmission network constraints are represented by AEMO's constraint equations, which are also referred to as *flowgates*. A generator can appear on multiple flowgates. Therefore
  - *Access* to the network needs to be converted into *entitlement* on flowgates, and
  - *Output* of the generator needs to be converted into *usage* of the flowgates.
- Generators without *agreed access* still have *non-firm* access and can have positive, *non-firm* entitlements on the flowgate. Consequently, they can potentially receive OFA payments.
- Access/Entitlements might need to be scaled back to *actual entitlements* when transmission constraints bind. A scaling algorithm will be applied to all generators on a constrained flowgate.
- Constrained-on generators will not receive OFA payments but their output will expand flowgate capacity and affect actual entitlements of other generators on the flowgate.
- Many constraints are of an inter-regional nature and involve interconnector terms.

In the actual OFA settlement, payments to a generator need to be calculated on each flowgate it participates in. Hence, the total payment to or from that generator is given by the following equation

$$Payoff_i = RRP * G_i + \Sigma_k[(E_{ik} - U_{ik}) * FGP_k] \quad (3)$$

Where

- G_i is the output of generator i
- FGP_k is the *flowgate price* for k. It is the dual of the corresponding constraint equation. Note that $FGP_k = 0$ if the constraint is not binding.
- E_{ik} is the *actual entitlement* i holds on flowgate k. (see 'Entitlement scaling' below for more details)
- $U_{ik} = \alpha_{ik} * G_i$ is the *usage* of flowgate k by i, where α_{ik} is the *participation factor* of i on k. The participation factor is the coefficient of the LHS term from the corresponding NEMDE constraint equation.

Note that the above equation does not apply to flowgate support generators, [64] which, according to the AEMC's design, receive no OFA payment when they are constrained-on.[65]

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64 A flowgate support generator's output relieves the transmission constraint. For example, in a "<=" type constraint, a generator on the LHS is a flowgate support generator if its coefficient (participation factor) is negative.

It can be seen from equation (3) that for the net total payment to be zero on each flowgate k, the sum of actual entitlements needs to equal the sum of usage across all relevant generators. That is, for each k,

$$\Sigma_i E_{ik} = \Sigma_i U_{ik} \quad (4)$$

Determining access component

There are three types of access components: firm, non-firm and super-firm access. Each generator's level of each access component depends on its agreed access, capacity and availability. Let AA be the agreed access of a generator, RC be its capacity and $Avail$ be its availability. Each access component is determined according to the following formula[66]:

- Firm access: $A_F = \min\,(AA, RC)$
- Non-firm access: $A_{NF} = \max\,(Avail - AA, 0)$
- Super-firm access: $A_{SF} = \max\,(AA - RC, 0)$

The firm access component is capped by a generator's capacity (*RC*). The level of agreed access over and above a generator's capacity constitutes the super-firm component. The non-firm component is excess *availability* over and above the agreed access amount. A generator can have *either* a non-firm *or* super-firm component, but not both, as shown in the following example from the AEMC's Technical Report:

Figure 37: Example of agreed access by each component

Generator	Nodal Values				
	AA	RC	A_F	A_{NF}	A_{SF}
A (firm)	500	500	500	0	0
B (part-firm)	300	500	300	200	0
C (super-firm)	800	500	500	0	300
D (non-firm)	0	500	0	500	0
Total					

Source: AEMC Technical Report: Optional Firm Access. Transmission Frameworks Review, p.207

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65 Ibid, p16

66 Ibid, p206

Entitlement scaling

The scaling algorithm calculates the *actual entitlement* on flowgate k for each generator i, based on its network access level A_j and the flowgate capacity FGX_k. Because OFA payments are relevant only if the flowgate is binding ($FGP_k <> 0$), the discussion below will assume that we are dealing with a **binding flowgate**. The scaling process on each flowgate is performed separately. Therefore, this subsection will suppress subscript k in order to aid readability.

The scaling process is more complicated with the presence of flowgate support generators and interconnectors in the inter-regional constraints. In this section we assume the relevant flowgate is an intra-regional constraint without flowgate support generators. Flowgates with support generators and/or involving interconnector terms will be discussed in 'Constrained-on generators' and 'Inter-regional transmission constraints' below.

Allocate target entitlement

Let j denote firm (F), non-firm (NF) or super-firm (SF) component, the corresponding target entitlement, ET_{ij} is

$$ET_{ij} = \alpha_i * A_j$$

An example of target entitlement is shown in Figure 38.

Figure 38: Example of target entitlement

Generator	Nodal Values					α_i	Flowgate Values		
	AA	RC	A_F	A_{NF}	A_{SF}		ET_F	ET_{NF}	ET_{SF}
A (firm)	500	500	500	0	0	0.3	150	0	0
B (part-firm)	300	500	300	200	0	0.8	240	160	0
C (super-firm)	800	500	500	0	300	0.6	300	0	180
D (non-firm)	0	500	0	500	0	0.8	0	400	0
Total							*690*	*560*	*180*

Source: AEMC Technical Report: Optional Firm Access. Transmission Frameworks Review, p.207

Scaling to actual entitlement

It can be proven[67] that whenever there is congestion, the sum of total target entitlements is strictly larger than flowgate capacity, FGX. Hence scaling of target entitlements is required to ensure

$$\Sigma_i E_i = \Sigma_i U_i$$

As specified in the Technical Report[68], there will be two scaling parameters, K_F and K_{NF}, applied to all generators on the relevant flowgate.

Figure 39: Entitlement scaling principle

Entitlement scaling is based on the principles:

- total actual entitlements must equal flowgate capacity;
- a single *firm scaling factor* is applied to all firm and super-firm entitlements, and a single *non-firm scaling factor* is applied to all non-firm entitlements;
- firm entitlements are only scaled back when non-firm actual entitlements have been scaled back to zero; and
- super-firm actual entitlements are only provided to the extent necessary to offset the scaling back of firm entitlements: ie the sum of firm and super-firm actual entitlements is no higher than the firm target entitlement.

Source: AEMC Technical Report: Optional Firm Access. Transmission Frameworks Review, p.208

Let EA_{ji} be the *actual entitlement* for generator i, where j represents firm (F), non-firm (NF) and super-firm (SF) component:

$$EA_{Fi} = K_F * ET_{Fi} \quad (5)$$

$$EA_{NFi} = K_{NF} * ET_{NFi} \quad (6)$$

$$EA_{SFi} = \min\{ET_{Fi} - EA_{Fi}, k_F * ET_{SFi}\} \quad (7)$$

The scaling outcome needs to ensure that total actual entitlement equals flowgate capacity, so that

$$\Sigma_i[EA_{Fi} + EA_{NFi} + EA_{SFi}] = FGX \quad (8)$$

Actual entitlement for each component can only be *scaled down* from its target level. That is, K_F and K_{NF} are both between 0 and 1. The calculation is then implemented through a goal-seeking algorithm so that equations (5)-(8) are satisfied. The total actual entitlement after scaling is then

67 Ibid, pp207-208

68 Ibid, p208

$$E_i = EA_{Fi} + EA_{NFi} + EA_{SFi}$$

An example of entitlement scaling is shown in Figure 40. In the first scenario, the flowgate capacity is low so that non-firm actual entitlement is scaled to 0 and firm actual entitlement is also scaled below its target level. In the second scenario, there is sufficient flowgate capacity to provide some positive actual entitlement to the non-firm component.

Figure 40: Actual entitlement scaling

	Target Entitlements			Actual E: scenario 1 k_F=0.6; k_{NF}=0				Actual E: scenario 2 k_F=1; k_{NF}=0.2			
Generator	*Firm*	*NF*	*SF*	*Firm*	*NF*	*SF*	*All*	*Firm*	*NF*	*SF*	*All*
A	150	0	0	90	0	0	90	150	0	0	150
B	240	160	0	144	0	0	144	240	32	0	272
C	300	0	180	180	0	108	288	300	0	0	300
D	0	400	0	0	0	0	0	0	80	0	80
Total	690	560	180	414	0	108	522	690	112	0	802

Source: AEMC Technical Report: Optional Firm Access. Transmission Frameworks Review, p.209

Constrained-on generators

A generator is considered a flowgate support generator if its output relieves the relevant transmission constraint. Under the current design, if a generator is a gate keeper on flowgate k, it will not receive OFA payments on this flowgate. Its actual entitlement on k is set equal to its usage

$$E_{ik} = U_{ik} = \alpha_{ik} * G_i$$

The output of flowgate support generator expands the flowgate capacity. Therefore, the scaling algorithm needs to make the corresponding adjustment to gate capacity so that

$$FGX'_k = FGX_k - \Sigma_i \alpha_{ik} * G_i$$

for all i that are gate keepers on this flowgate. Since the flowgate support generator's usage of the flowgate is *negative,* the addition of flowgate capacity is done by subtracting a negative term.

Since the actual entitlement for the gate keepers have been set equal to their usage, they are *excluded* from the scaling algorithm for this flowgate after adjusting the flowgate's capacity.

Inter-regional transmission constraints

Some transmission constraints are of an inter-regional nature in that they include flows on interconnectors. Technically, the OFA settlement process uses "directed interconnectors" (one for each flow direction for an interconnector) to calculate OFA payments on interconnectors, or DIP – Directed Interconnector Payment.[69] In the current modelling exercise we only concentrate on the payoff of generators and assume that no generator owns the OFA payments on the interconnectors. Consequently, the presence of interconnector terms does not directly change the payoff calculation for the generators as set out in equation (3), but it does affect the entitlement scaling process.

Flowgate Support

A *directed* interconnector will be considered *not* participating in the OFA settlement if its flow relieves the constraint, just like a flowgate support generator. However, similar to a flowgate support generator, the flowgate capacity is expanded by the usage of this directed interconnector. Let F_{ik} be the flow on a directed interconnector that relieves the constraint, the adjusted flowgate capacity is then[70]

$$FGX_k = FGX - \Sigma_i \alpha_{ik} * F_{ik}$$

Entitlement Scaling with Interconnector Flows

Directed interconnectors that provide flowgate support will receive no OFA payment. Consequently, they will be excluded from the rest of the scaling process after adjusting the flowgate's capacity.

Other directed interconnectors will be included in the scaling process together with generators from the same flowgate. However, since there is no capacity or availability concept for an interconnector, the current OFA design specifies that[71]

- The target firm entitlement on an directed interconnector equals $\alpha * A$
- The target non-firm and super firm entitlements on a directed interconnected are always 0

The rest of the scaling process will proceed as described previously. As noted in the AEMC's Technical Report,[72] with inter-regional transmission constraints, it is

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69 Ibid, section 9

70 The sign of the term $\alpha_{ik} * F_{ik}$ captures the factor that flow relieves the constraint. For example, in a "<=" type constraint, the flow relieves the constraint if and only if $\alpha_{ik} * F_{ik} < 0$. Hence subtracting a negative term increases the RHS of the constraint. The same argument in the opposite direction will apply for ">=" constraints.

71 Ibid, page 111

possible that there will be residual flowgate capacity once all firm and non-firm target entitlements have been met. This is because the non-firm *target* entitlements for interconnectors are set at 0. In this instance, the residual is equally allocated to the relevant directed interconnectors as non-firm *actual* entitlement.

Perverse bidding behaviour under OFA

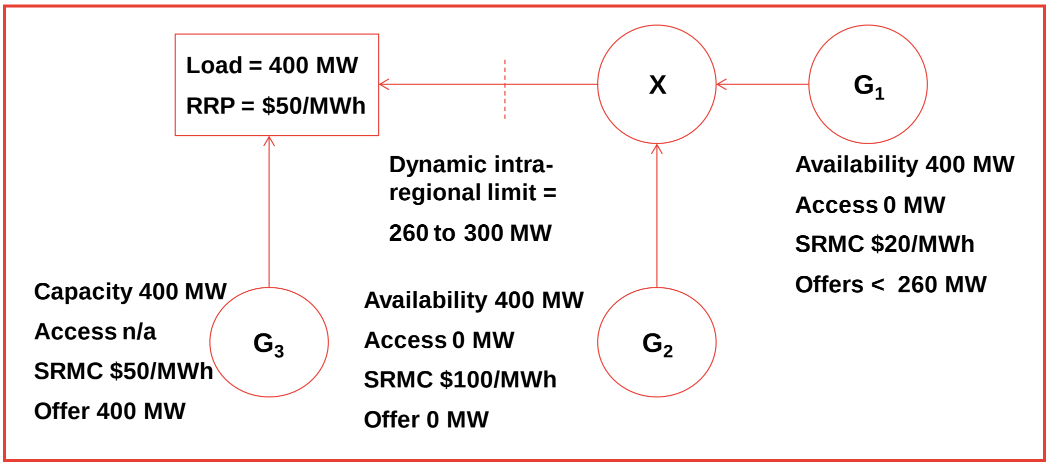
Since OFA alters the settlement process, it also changes the payoffs of generators from different bidding strategies. This can encourage perverse bidding behaviours that cause inefficiency in the dispatch process.

Headroom bidding

When a constraint binds, those generators whose flowgate usages are larger than their actual entitlements will make OFA payments, which means they will receive less than the RRP for their output. In addition, the limits of many flowgates change depending on market conditions. In order to avoid having to make OFA payments, generators with insufficient access may have an incentive to reduce output so that transmission constraints do not bind and local marginal prices remain equal (on a loss-adjusted basis) to regional reference prices.

Figure 41 provides a stylised example of such 'headroom bidding'. For simplicity it is assumed that both G1 and G2 do not have any access on the network and their participation factors are 1. Similar incentives will arise for generators with firm access rights if there is sufficient scaling back of their entitlements when constraints bind.

Figure 41: Example headroom bidding



Source: Frontier Economics

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72 Ibid, page 112

In this example, both G1 and G2 have 0MW firm target entitlement and 400MW non-firm target entitlement. When the constraint binds, their actual entitlements will be equal to 130-150 MW depending on the actual limit of the flowgate. Without knowing exactly the limit at the time of its dispatch, G1 will be hesitant to offer more than 260MW of its capacity into the market. For example, suppose G1 were to offer 280MW. From the 20MW extra capacity offered, the maximum extra revenue it could receive from the pool prices would be (50-20)*20 = $600/hr. However, if the constraint were to bind at say 280MW, G1's actual entitlement would be 140MW, and it would have to make an OFA payment of 30*(280-140)=$4200/hr, which is much larger than the potential extra profit it can receive.

The consequence of these incentives is that the more expensive generator G3 is dispatched more than would be necessary if G1 did not have to make the access payment, which leads to economic inefficiency of up to $1200/hr[73], depending on the actual limit of the line.

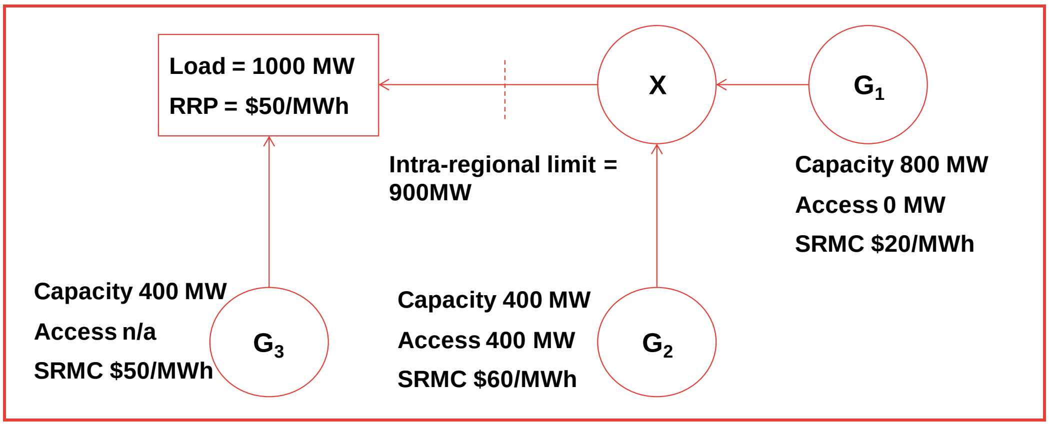
Bidding to bind

'Bidding-to–bind' is another form of perverse bidding behaviour. Suppose there is a generator bidding cost-reflectively that is not being dispatched due to its high marginal cost. Accordingly, when the constraint to which it has flowgate rights does not bind, the generator neither receives any revenue from the pool nor any OFA payment. However, if the flow on the line is close to its limit, the generator might find it profitable to offer just enough capacity below its cost to get dispatched and bind the constraint. The generator makes some losses on its dispatched quantity, but it might gain more than it loses from OFA payments.

Figure 42 provides an example of bidding-to-bind. For simplicity, it is assumed that only G2 has agreed access on the network and the participation factors of all generators are 1.

73 Being $30/MWh multiplied by 40 MW in the case that the intra-regional limit actually turns out to be the full 300 MW.

Figure 42: Example of Bidding to Bind



Source: Frontier Economics

When all generators bid their capacities at SRMC, G2 will not be dispatched and, since the flow on the line is only 800MW, the constraint does not bind. G2 receives no pool or OFA payment. However, G2 can bid 100 MW of its capacity at $0/MWh and bind the constraint. The RRP remains at $50/MWh as G3 is still dispatched for 100MW. However, due to the constraint binding, the price at X diverges and is set by G1's bid at $20/MWh. G2 makes a dispatch loss, as its marginal cost is higher than the regional reference price, of (50-60)*100 = -$1000/hr. However, its actual entitlement is 400MW (due to it being the only firm generator) and receives an OFA payment of (400-100)*(50-20)= $9000/hr. The associated cost of inefficient dispatch (G2 displacing G3) is 100*(60-50)=$1000/hr.

The two stylised examples provided above illustrate the basic principles behind some of the perverse bidding behaviours that could arise under OFA. However, these examples do not take account of the strategic reactions of other generators. For example if G1 is engaged in headroom bidding, G2 is incentivised to bid to bind and vice versa.

Similarly, OFA and the presence or absence of firm access rights changes generator payoffs and alters bidding incentives more generally. This is particularly the case for portfolios of generation and in the case of multiple, interacting transmission constraints. In these cases, OFA can lead to complex incentives, for example bidding baseload plant to bind constraints in order to earn access payments on plant that are firm but not dispatching (e.g. peakers and wind plant) within the same portfolio.

We have sought to model the general and specific effects of OFA on bidding and dispatch using *SPARK*, which uses game theory to identify equilibrium bidding behaviours under OFA.

It is worth noting that modelling NEM market outcomes in terms of dispatch, flows and prices is an order of magnitude more complex than under current arrangements. From a modelling perspective, increased complexity arises from:

- The need for accurate input data on transmission constraints for the entire modelling period. Some transmission constraints are only applied under contingent conditions (non-system normal constraints), conditions that are themselves difficult to forecast). Even for the system normal constraints, AEMO does not publish the complete set and the data that is published has included material errors in the past. Finally, transmission constraints are constantly changing which limits their applicability to only a few years in the short term. This is discussed in more detail in Appendix B.
- There are more avenues to game the market under OFA than the current arrangements. Under current arrangements, generator incentives can be meaningfully modelled by considering physical and economic withholding strategies for *key plant* and relatively simple disorderly bidding strategies (e.g. bid all capacity at MFP). Under OFA, many more strategies need to be considered – nuanced withdrawal strategies to capture incentives to headroom bid that arise for *all plant* and revised bidding to bind strategies. This is explained in more detail in the final part of this Appendix.

In combination, these factors make forecasting market outcomes under OFA more difficult than current arrangements. Similarly, ex-post analysis of market outcomes (for example, AEMO price event reports) in a world with OFA would be much more complex, particularly since firm access quantities are unlikely to be public information. This has implications for the analysis presented in this report and for stakeholders more generally. Reducing the ability of stakeholders to understand and forecast market outcomes reduces their ability to assess potential changes to policy and regulation, undertake commercial activities and manage risk; it also ultimately reduces the transparency of the NEM as a whole.

Frontier Economics' modelling framework

This modelling will be conducted using Frontier Economics' three electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. The key features of these models are as follows:

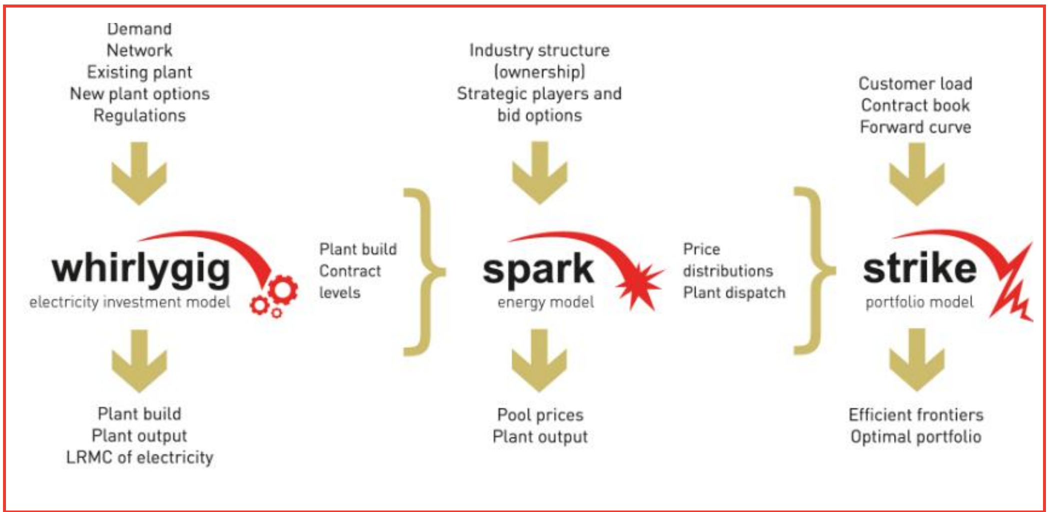
- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load, including the cost of any plant required to meet any regulatory obligation. *WHIRLYGIG* will provide forecast investment path for the current modelling.
- *SPARK* identifies optimal and sustainable bidding behaviour strategy for generators in the electricity market using game theoretic techniques. This is a very important difference between Frontier's approach and other analysts.

Instead of making arbitrary and dubious assumptions about possible patterns of bidding for the purposes of calculating a price our approach has bidding behaviour as a model *output* rather than an *input*. The model determines the optimal pattern of bidding by having regard to the reaction by competitors to a discrete change in bidding behaviour by each generator to increase profit (either by attempting to increase price or expand market share). Once the profit outcomes from all possible actions and reactions to these actions are determined the model finds the equilibrium outcome based on standard game theoretic techniques. An equilibrium is a point from which no generator has any incentive to unilaterally deviate. The current modelling will use *SPARK* to investigate the dispatch outcome of the wholesale electricity market, including the perverse bidding behaviour under OFA discussed above.

- *STRIKE* is a model that uses portfolio theory to find the best mix (portfolio) of available electricity purchasing options (spot purchases, derivatives and physical products. *STRIKE* uses the output of *SPARK* to provide a distribution of spot (and contract) prices to be used in the optimisation of the suite of purchasing options. *STRIKE* will be used to analyse the generator contracting decisions and risk profiles for the current modelling.

The models, and their inter-relationships, are illustrated in Figure 43.

Figure 43: Model inputs and outputs



Modelling approach

This study will assess OFA's impact on the wholesale electricity market under a Base Case and a number of sensitivity scenarios. The Base Case spans financial year 2014/15 to 2016/17. As explained in more details in Appendix B, this is because modelling market settlement under OFA requires detailed and accurate transmission constraint information, but the currently available constraint information (published by AEMO) are increasingly inaccurate for years further into the future.

The analysis will investigate the difference in the economic cost of dispatch, wholesale prices and final retail bill impacts for the entire modelling period between OFA and the Status Quo. In addition, it will study the impact of OFA on generators' profitability by focusing on financial year 2014/15. The sensitivities will further test the economic cost changes under OFA by using alternative input assumptions or by giving more granular bidding assumptions to a particular region. A more detailed description of the sensitivity scenarios can be found in Appendix B.

For both OFA and the Status Quo, the study will use the same plant investment forecast from a single *WHIRLYGIG* run. This ensures that the generation supply used in both scenarios remains the same, and the assessment of the OFA's effect on the dispatch outcomes of the wholesale electricity market can be made on a consistent basis.

Annual generator profit positions are based on market dispatch outcomes from *SPARK*. In addition, wholesale price forecasts from *SPARK* are used in Frontier's retail model to work out the retail bill for end customers.

Modelling perverse bidding behaviour under OFA *vs.* disorderly bidding under the Status Quo

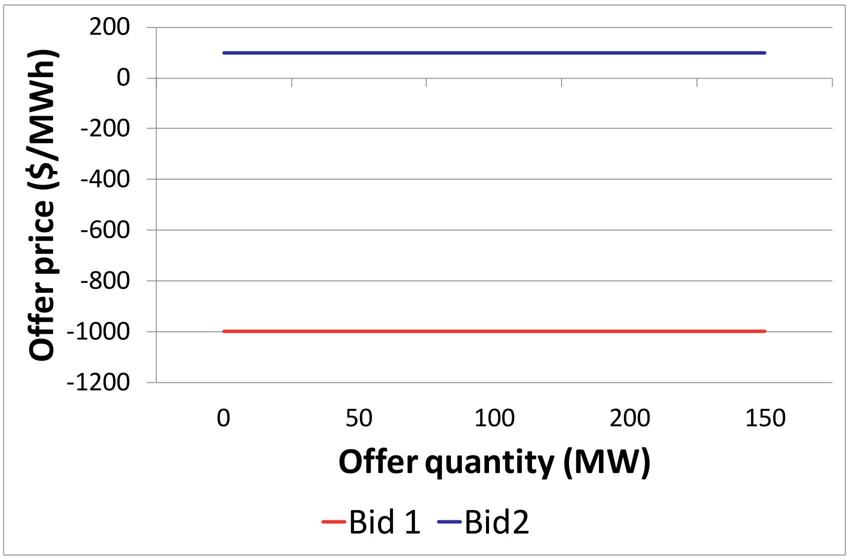
The perverse bidding behaviours under OFA discussed above are much more complex to model than disorderly bidding under the Status Quo. This is because modelling headroom bidding and bidding to bind under OFA necessitates modelling more options for a larger set of generators than modelling disorderly bidding under the current arrangements.

To model disorderly bidding under the Status Quo, it is sufficient to assume that a constrained-off generator will offer all of its capacity at the market price floor in order to maximise its dispatch. The generator's incentive is more nuanced when it comes to perverse bidding behaviour under OFA. It needs to bid "just enough" to game the constraints. That is,

- for bidding to bind, the generator needs to offer enough capacity below cost so that it gains OFA payments, but not too much so that it incurs large dispatch loss.
- for headroom bidding, the generator needs to withdraw enough capacity so that the constraint remains open, but not too much so that it forgoes large pool revenue.

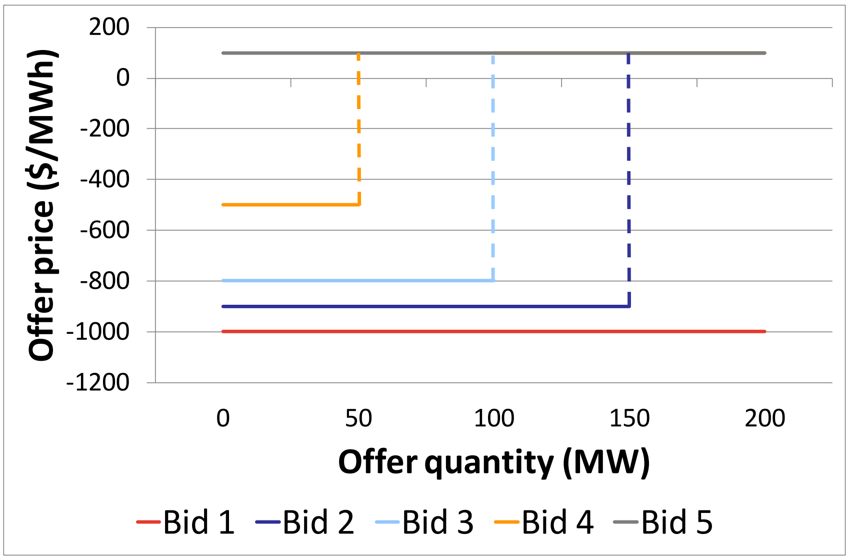
Further, a generator can appear in multiple constraints, which might further complicate the trade-offs above and be part of a larger portfolio, complicating such trade-offs yet again. This requires more bidding options to be modelled for each generator in *SPARK*. While in practice the generators can quickly figure out their best strategy through repeated learning, it is computationally very demanding to model every possible bidding strategy across the entire NEM in *SPARK*. Figure 44 and Figure 45 provide an illustrative comparison of a stylised disorderly bidding curve and a stylised Bidding-to-Bind bidding curve. As an example, had the bidding curve in Figure 44 be applied to 10 generators, this would result in 2^10 = 1024 unique combinations of bids across all 10 generators. On the other hand, applying the bidding curve in Figure 45 to 10 generators (each with 250MW capacity) would lead to 5^10 = 9,765,625 combinations, approximately 10,000 times more combinations which, under a Cournot game theoretic bidding approach, requires 10,000 times the computing resources.

Figure 44: Stylised bidding curve for disorderly bidding



Source: Frontier Economics

Figure 45: Stylised bidding curve for bidding-to-bind at 50MW increment



Source: Frontier Economics

As discussed above, in the Base Case we model the entire NEM, which necessarily limits the total number of bidding combinations. Since disorderly bidding under the Status Quo is much easier to model than the perverse bidding behaviours under OFA, this limitation on total bidding combinations means that the *SPARK* modelling results will tend to capture more disorderly bidding in the Status Quo than perverse bidding under OFA, that is, it will underestimate the dispatch costs associated with perverse bidding behaviour under OFA.

We have structured our analysis to make the cases as comparable as possible but this underestimation of the extent of headroom bidding and bidding to bind cannot be avoided. As a result our analysis errs on the side of underestimating detriments under OFA.

Appendix B – Input assumptions for dispatch analysis of OFA

This section provides an overview of the input assumptions used in our modelling. Frontier has used a range of public sources and, for supply side costs and operating parameters, our own in-house estimates. Those estimates are consistent with those used in our recent wholesale modelling for the Australian Energy Market Commission's price trends report. Our approach to generating these estimates is discussed in more details in Appendix A of our report for the AEMC.[74]

The key input assumptions in terms of impact on modelling wholesale outcomes are:

- Demand
- Carbon and LRET assumptions
- Fuel and Capital costs
- Plant retirement
- Transmission Constraints
- Assumed OFA allocations

Each of these key assumptions is discussed below.

Demand

Energy forecast

Our demand assumption is based on the medium scenario of AEMO's 2014 National Electricity Forecast Report (NEFR)[75]. With the exception of Queensland, there is little to negative growth in electricity demand in the NEM. This is due to a number of factors:

- lower forecast per capita residential consumptions
- higher forecast rates of energy efficiency and rooftop PV uptake

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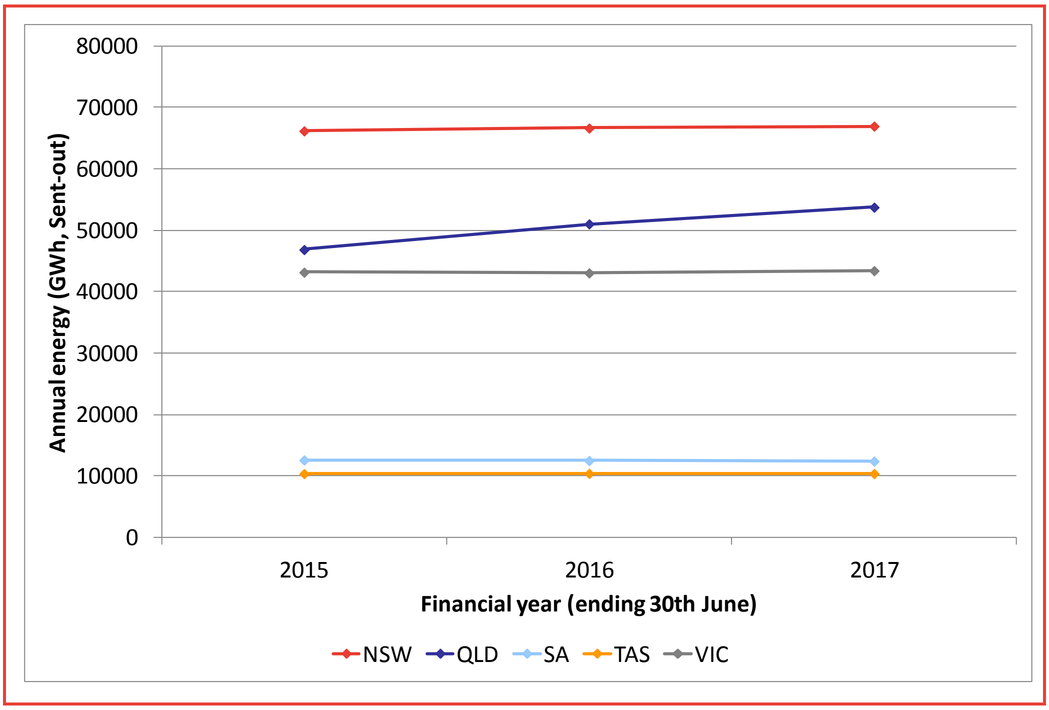
74 Frontier Economics, *2014 Residential Electricity Price Trends – Final Report*, Appendix A. http://www.aemc.gov.au/getattachment/e3d6d43f-4046-4527-9ada-5bfb3da70493/Frontier-Economics-%E2%80%93-2014-Residential-Electricity.aspx

75 http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report

In Queensland, these factors are more than offset by the increase in demand arising from the new LNG facilities at Gladstone that will be commissioned over the modelling period.

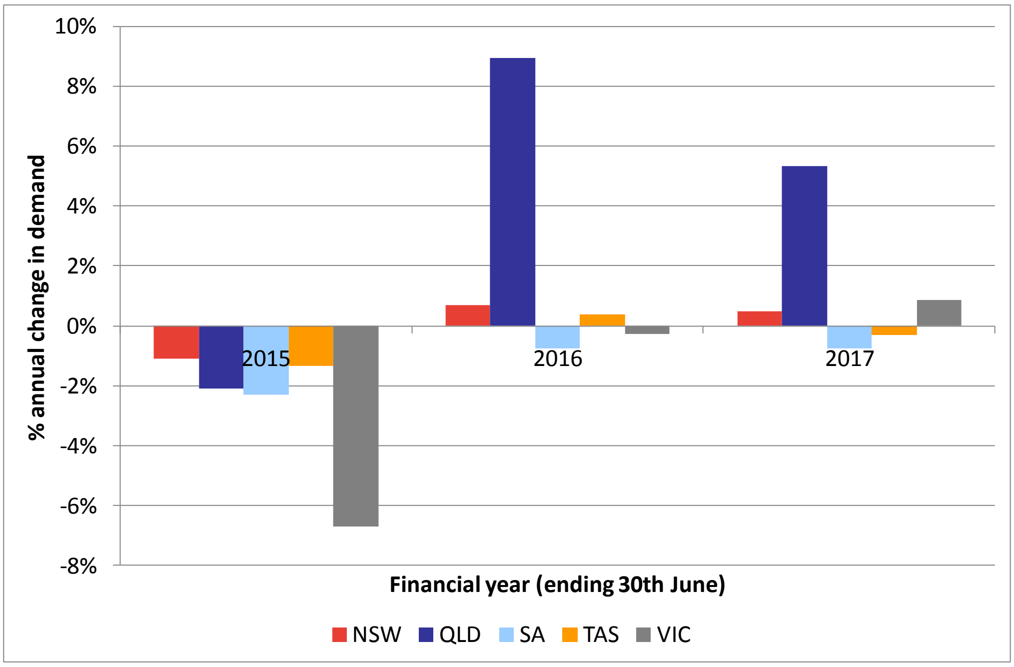
Lower system demand, other things being equal, leads to lower forecast pool prices. Energy forecasts used in our modelling are shown in Figure 46 and Figure 47 below.

Figure 46: Demand forecasts



Source: AEMO NEFR 2014 medium scenario

Figure 47: Annual percentage changes in demand

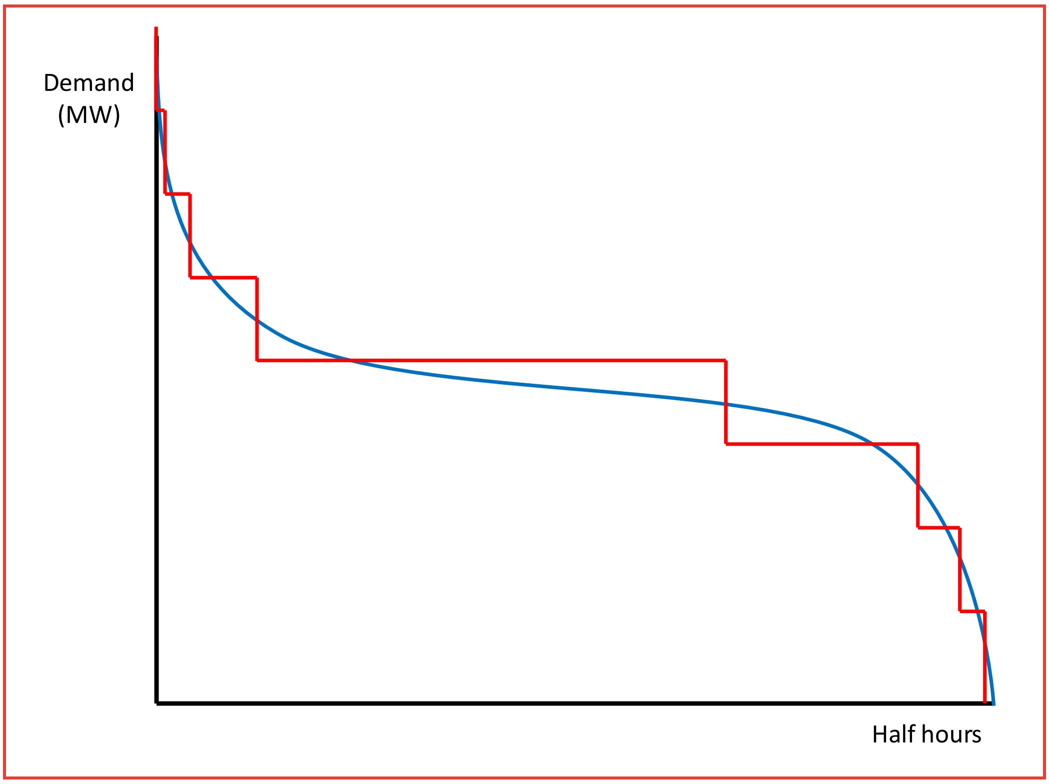


Source: AEMO NEFR 2014 medium scenario

Demand clustering

In order to reduce computational time, *SPARK* models half-hours in a year by first clustering those "similar" half-hours into the same demand point. As illustrated in Figure 48, demand points representing the "flat" segment of the duration curve often contain many half hours. In actual modelling, this is implemented with a statistical method called hierarchical clustering. The algorithm groups similar half hours in terms of demand levels across multiple dimensions (i.e., regions in the NEM) into the same demand point. This ensures that the correlation of demand across the NEM at each half hour is retained in the model.

Figure 48: Clustering demand points (illustrative only)



Source: Frontier Economics

Carbon and LRET

We assume that there is no carbon price for the modelling period. LRET is assumed to be at the current legislated level, which will reach 41,000 GWh in the 2020s. The effect of LRET is to encourage renewable investment, which will be modelled in the *WHIRLYGIG* stage. More renewable investment tends to suppress pool prices due to their close to zero marginal cost of production.

Fuel and capital costs

In recent years, Frontier Economics has developed its own framework for estimating key supply side inputs – capital costs, fuel prices, O&M costs and new entrant operating parameters.

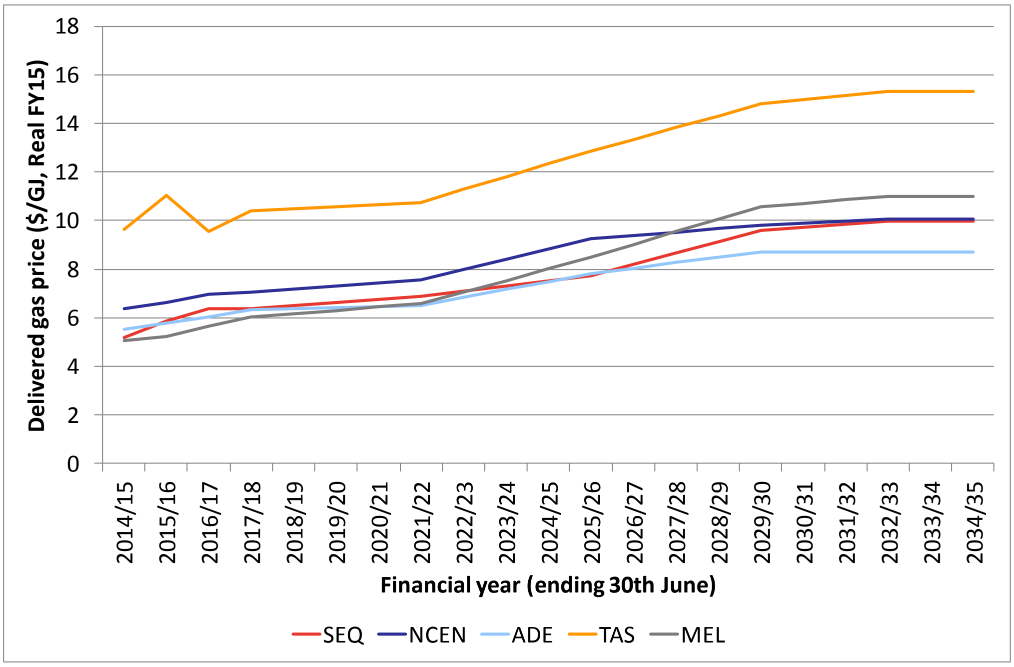
Fuel price

Frontier's fuel prices are based on modelling and analysis of the Australian gas and coal markets, which reflects current estimates of key inputs such as the number of LNG trains and long term export coal and LNG prices.

Gas prices

Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Figure 49 shows the gas price forecast for selected NEM subregions.

Figure 49: Gas prices for selected subregions

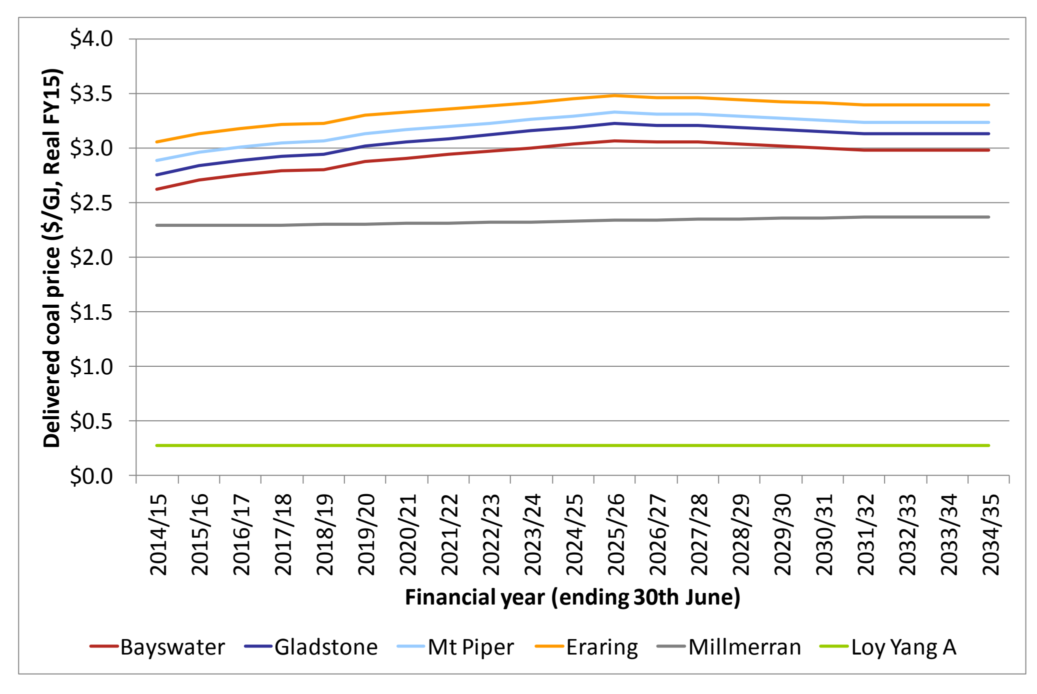


Source: Frontier Economics

Coal prices

Coal prices are driven by demand for coal, international export coal prices (for export exposed power stations), foreign exchange rates and underlying resource costs associated with coal mining. Figure 50 shows the coal price forecast for some coal-fired generators.

Figure 50: Coal prices for selected power stations



Source: Frontier Economics

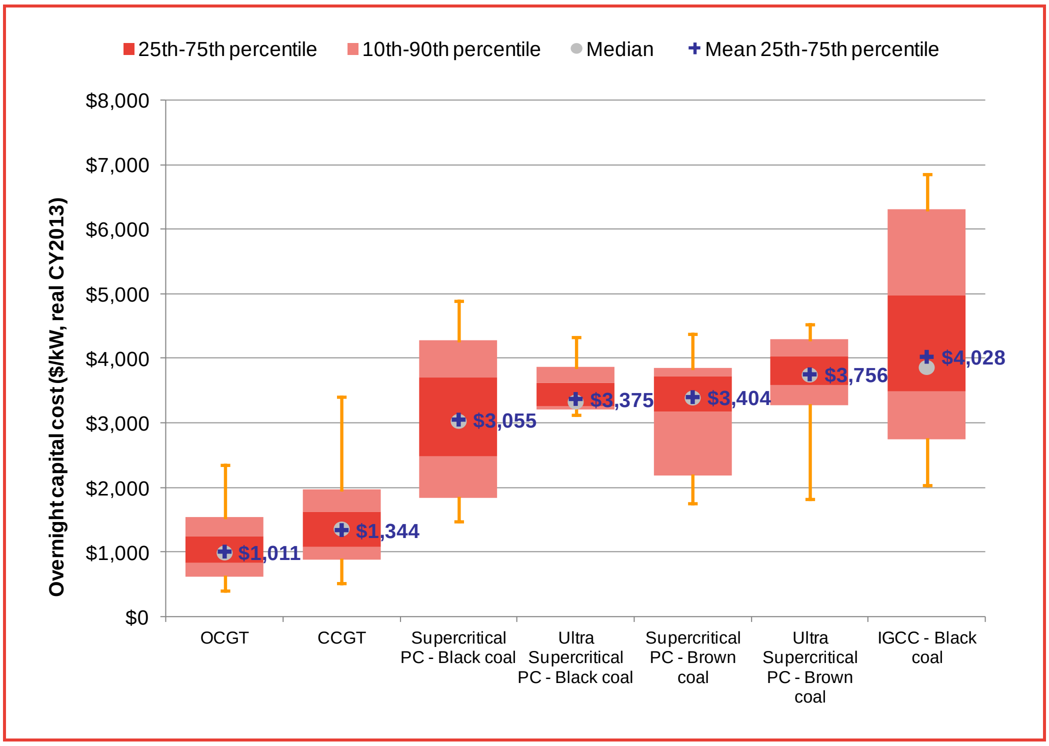
Note that Bayswater, Gladstone, Mt Piper & Eraring are export exposed, while Millmerran and Loy Yang A are mine mouth stations.

Capital cost

Frontier's capital cost estimates are based on a detailed database of actual project costs, international estimates and manufacturer list prices. Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from EPRI[76]) and manufacturer list prices. These estimates are converted to current Australian dollars. Our estimate is then taken as the mean over the middle two quartiles of the data (the 25th to 75th percentiles). The range of estimates and the final number used in the modelling are shown in Figure 51 and Figure 52 for thermal and renewable technologies respectively. The movement of capital cost over time are driven by factors such as real cost escalation of domestic costs (essentially labour), exchange rates and technological improvement.

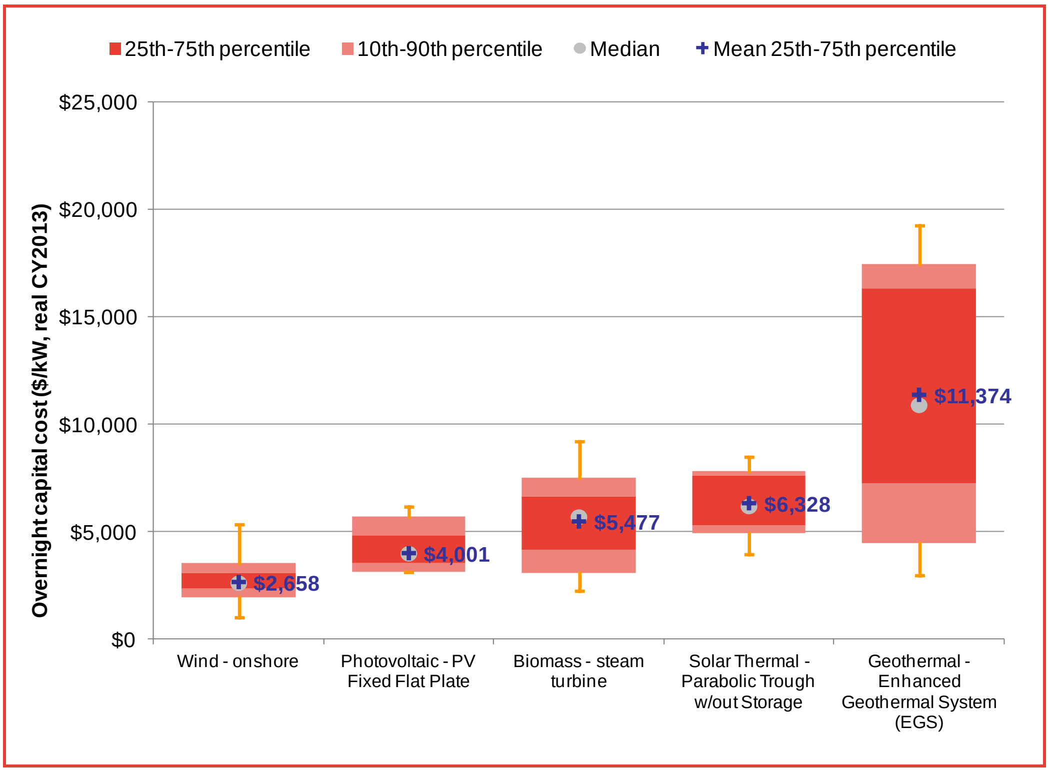
[76] See http://www.epri.com.

Figure 51: Capital cost estimate for thermal generators



Source: Frontier Economics

Figure 52: Capital cost estimate for renewable generators



Source: Frontier Economics

Plant retirement

Since the focus of the current modelling exercise is to examine the impact of the OFA on dispatch outcome of the wholesale electricity market and the modelling period from financial year 2014/15 to 2016/17 is relatively short, we will not explicitly model plant retirement. However, we have incorporated recent public plant retirement or mothballing announcements in our modelling:

- NSW: Redbank[77] and Wallerawang[78]
- Queensland: Collinsville and Swanbank E (mothballed)[79]
- Victoria: Morwell[80]
- South Australia: Playford B[81]

No other retirements or mothballings have been included in the modelling.

Transmission constraints

Accurate information on transmission constraints is crucial to modelling generator incentives and market outcomes in OFA. OFA payments occur when transmission constraints bind and depend totally on the details of the constraints. Currently the only public source for transmission constraint is published by AEMO in their constraint books. This study uses AEMO's 2014 constraint books[82], which are the most up-to-date source of transmission constraint

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77 http://www.abc.net.au/news/2014-11-04/redbank-closure-the-tip-of-the-iceberg-for-power-industry3a-gr/5864286

78 http://www.energyaustralia.com.au/about-us/media-centre/current-news/wallerawang-power-station-closure-november

79 AEMO, *QLD Generation Information*, 8th Aug 2014

http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/esoo/2014/Generation_Information_QLD_2014_Aug_15.ashx

80 http://www.smh.com.au/business/latrobe-valley-brown-coal-plant-mothballed-20140729-zy5k7.html

81 AEMO, *SA Generation Information*, 8th August 2014

http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/esoo/2014/Generation_Information_SA_2014_Aug_15.ashx

82 For thermal constraints, see

http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/esoo/2014/ESOO%20Update/2014_ESOO_Thermal_Constraints.ashx

For stability constraints, see

http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/esoo/2014/ESOO%20Update/2014_ESOO_Stability_Constraints.ashx equations. However there are some issues regarding AEMO's constraint books that will limit the accuracy of the modelling.

Currently the AEMC's design does not make it clear as to which constraints will be included for OFA payment. According to the AEMC's Technical Report[83]:

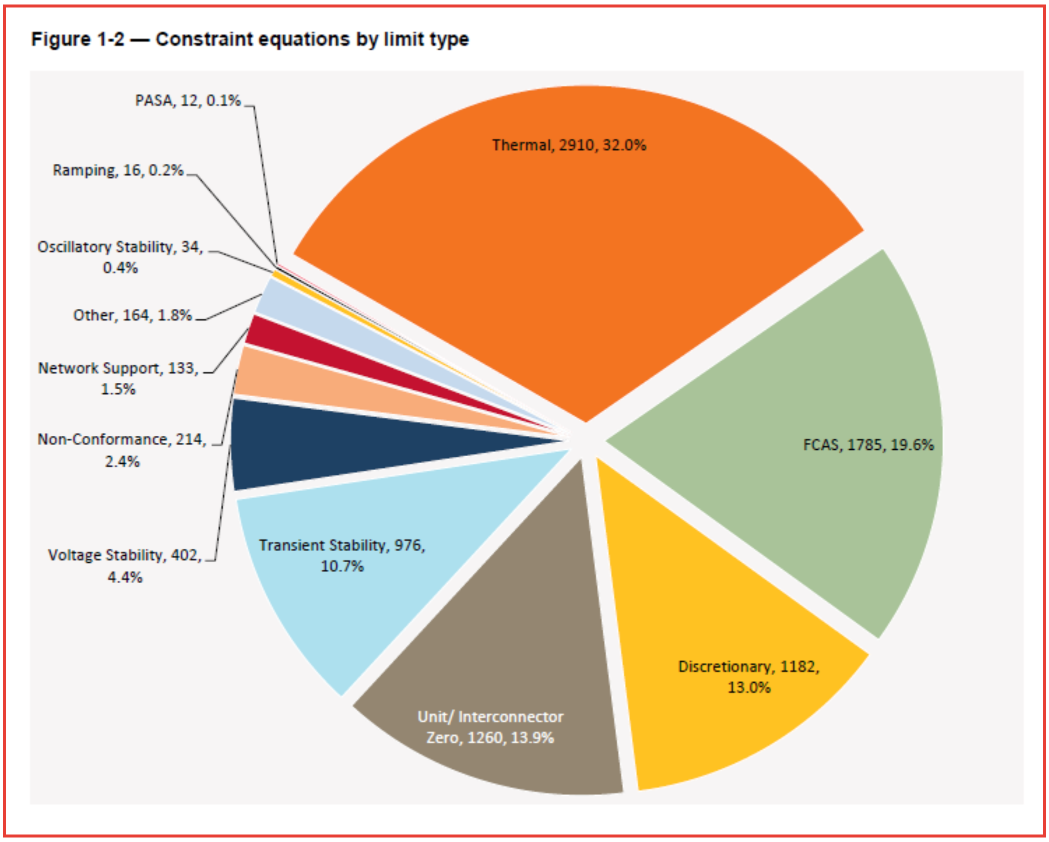
> [...] any constraint that arises as a result of limitation on TNSP networks and for which a constrained generator is not compensated under current arrangements.

It is clear that all thermal and stability constraints under system normal and outage conditions constitute flowgates in OFA. AEMC's technical report also lists FCAS separation constraints and constraints on regulated interconnector flows as flowgates. However, the constraint books published by AEMO to date only contain thermal and stability constraints under the *system normal conditions*. Further it appears that only a subset of system normal constraints have been published in the constraint book. AEMO's report shows that as of December 2013 Figure 53), there were 2910 thermal constraint equations and 1412 stability constraints (oscillatory, voltage and transient). However the 2013 thermal constraint book contained only 2373 thermal and 106 stability constraints.

Putting aside system non-normal constraints temporarily, AEMO does not typically publish a complete set of system normal constraints. This limits the ability of participants to assess market outcomes. AEMO rationale for excluding constraints may be that a number of system normal constraints are unlikely to materially impact on dispatch, however AEMO can never know what market conditions various stakeholders may wish to consider (alternate policy, new investment, etc) and the extent to which these lead to previously unseen congestion on the network.

83 AEMC TFR Final Technical Report, pp32-35

Figure 53: Number of constraint by type



Source: AEMO, NEM Constraint Report 2013, p.8

There are also concern regarding the accuracy of the constraint equations included in AEMO's constraint books. During Frontier's previous study on disorderly bidding, Frontier and other market participants pointed out that the line rating in the western ring constraints were incorrect in AEMO's 2012 constraint books. These errors were never rectified and the inaccurate data remains on AEMO's website[84] with no comment. It is unclear whether similar errors are present in the current constraint book used for this study.

Non system normal constraints are important in understanding market settlement under OFA as they often have a large impact on generators' output. Outage constraints are imposed to reflect generation and transmission outages and discretionary constraint are applied on an ad hoc basis by AEMO to ensure system security and to avoid outcomes deemed undesirable, such as including clamping constraint on interconnector flow to avoid negative settlement residues.

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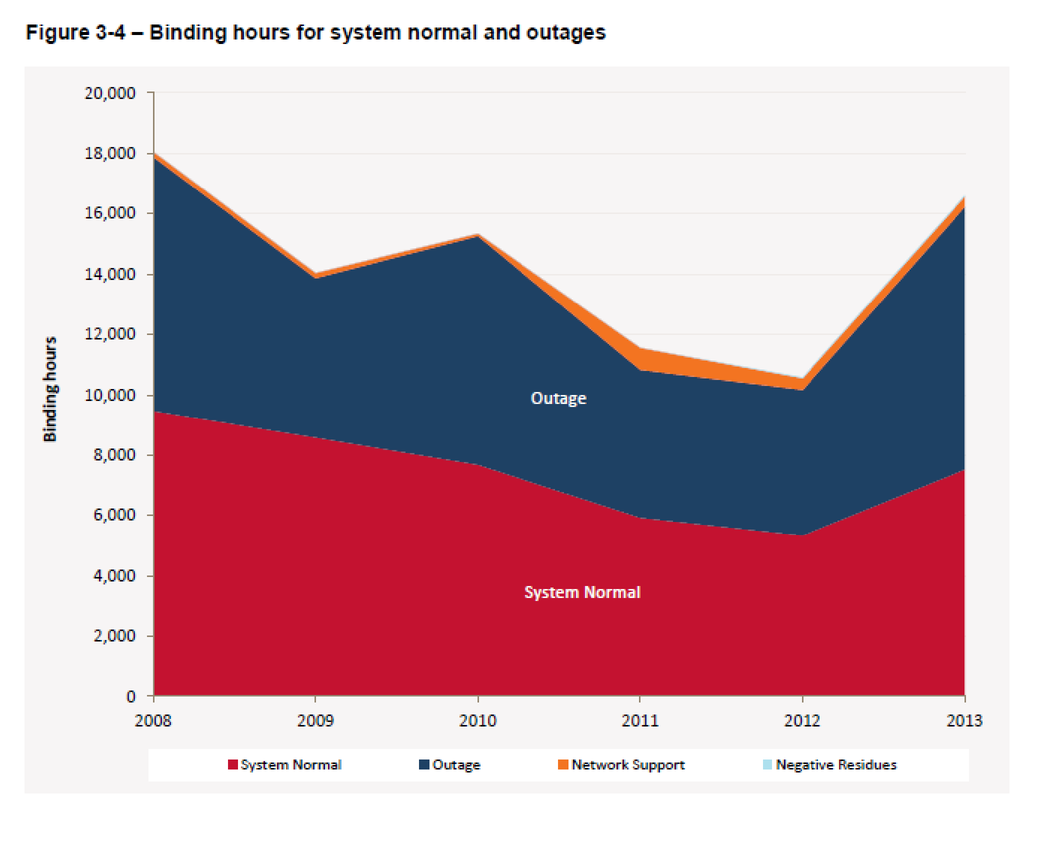
84 See http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_ConstraintWorkbook.ashx.

System non-normal constraints bind frequently, and more importantly, are more highly correlated with extreme market events. The imposition of system non-normal constraints, which impose harder limits on the transmission system, will regularly lead to a generator's actual entitlement being scaled back by a large amount under OFA. In such circumstances, even firm generators are unlikely to receive full allocations of access to regional prices. Hence despite the name of optional ***firm*** access, the constrained off generators will likely receive little OFA payment as times when it is most valuable.

Figure 54: Binding hours for system normal and outages



Source: AEMO, NEM Constraint Report 2013, p.19

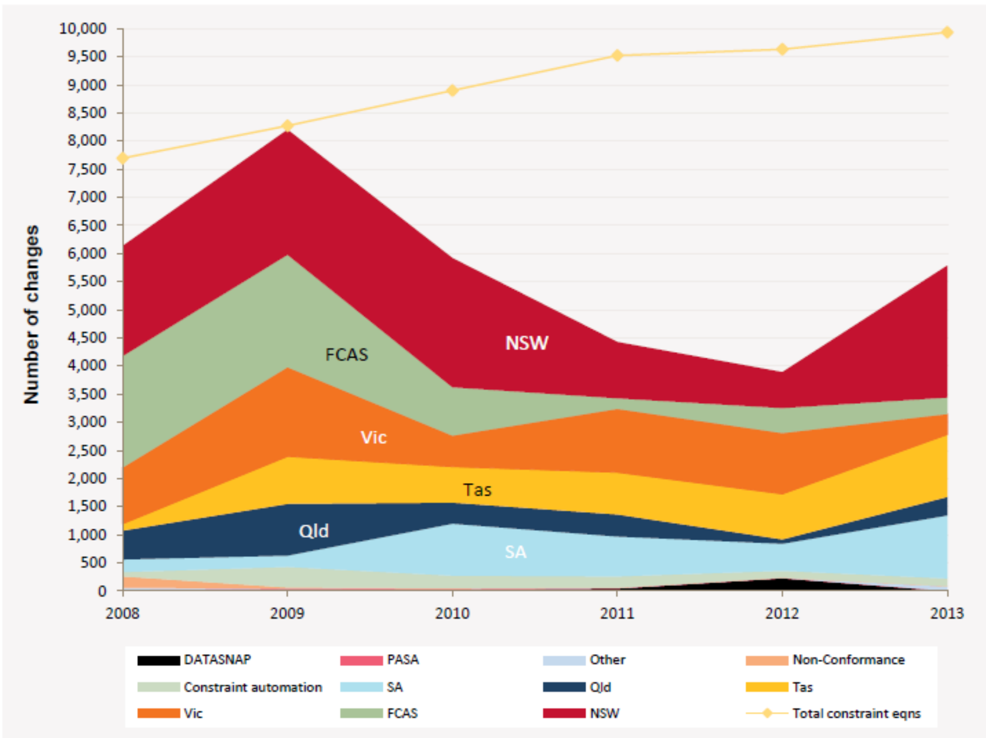
Figure 54 shows that close to 50% of constraint binding hours in 2013 are due to outage constraints. The absence of the outage constraint equations in AEMO's constraint book will limit the study by reducing the incidence of binding constraints in both the Status Quo and OFA cases. It will also reduce extent to which OFA is forecast to alter market outcomes as OFA can only produce different outcomes when transmission constraint bind.

Finally, constraint equations are updated every year to reflect the changing network conditions and expansion plans. Figure 55 shows that there are thousands of changes to constraint equations each year and the total number of constraint equations changes of all types have grown from just above 7500 in

2008 to close to 10,000 by December 2013. The constantly expanding and evolving nature of constraint equations makes it difficult to properly assess the impact of OFA in later years, as network congestion is likely to be built out over time.

Figure 55: Number of constraint equations and changes by years

Figure 2-1 – Constraint equation changes per calendar year, 2008 to 2013



Source: AEMO, NEM Constraint Report 2013, p.11

Our modelling has incorporated the planned Heywood Upgrade in financial year 2016/17. This is also reflected in AEMO's 2014 constraint equations.

Assumed initial OFA allocation

As set out in AEMC's first interim report, at the initial stage of implementing OFA, existing generators will be allocated transitional agreed access amount depending on their capacities and the network capacities in the regions. Generators in regions experiencing more congestion according to AEMO's modelling[85] will be allocated less than their full capacities. Our Base Case

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85 AEMO, *Transitional Access Allocation Report*, June 2014 http://www.aemc.gov.au/getattachment/441c900e-e0b8-4e8d-9cf8-bee5fd41ee29/AEMO-Transitional-Access-Allocation-Report.aspx

modelling will assume that all existing generators will receive firm access amount according to AEMC/AEMO's Base case allocation result, as shown in Figure 56. Generators in South Western Queensland, NSW Snowy, Northern Victoria, Melbourne, South East South Australia and Tasmania will receive firm access substantially less than their capacity. (Tasmanian generators will be allocated 63% of their capacity.[86])

Figure 56: Initial access as percentage of generators' capacity

Sub-Region	Base	Taper	Off-peak	Windy	Winter	Mothball	Flowgate
Northern Queensland	100%	100%	100%	100%	100%	100%	100%
Central Queensland	99%	99%	97%	97%	96%	99%	99%
Brisbane	100%	100%	100%	100%	100%	100%	100%
South Western Queensland	84%	84%	84%	85%	82%	84%	82%
Hunter Valley NSW	100%	97%	100%	100%	100%	100%	100%
Central Coast NSW	100%	100%	100%	100%	100%	100%	100%
Sydney	100%	100%	100%	100%	100%	100%	100%
Western NSW	100%	90%	100%	100%	100%	100%	100%
Southern NSW	100%	80%	99%	100%	100%	100%	100%
NSW Snowy	63%	73%	26%	48%	60%	63%	63%
Victoria Snowy	100%	100%	92%	96%	100%	100%	100%
Northern Victoria	87%	87%	100%	93%	100%	87%	87%
Latrobe Valley	95%	95%	91%	96%	95%	95%	95%
Melbourne	86%	86%	100%	100%	100%	86%	86%
Western Victoria	100%	100%	100%	100%	93%	100%	100%
South Eastern South Australia	90%	90%	88%	60%	74%	90%	90%
Adelaide	100%	100%	100%	100%	100%	100%	100%
Northern South Australia	97%	97%	90%	87%	86%	99%	97%

Source: AEMC, First Interim Report, Optional Firm Access, Design and Testing, Appendix B, pp.149-151

The access percentages above have been applied to all plant within each area of the NEM – baseload, peaking and wind consistent with our understanding of the AEMC's position. As will be demonstrated in this report, providing wind farms and peaking facilities, which do not necessarily need to be dispatched as times of congestion, with firm access under transitional arrangements is likely to lead to significant access payments accruing to these generators (paid by other participants).

Scenarios modelled

This study will investigate a Base Case, which uses the inputs from earlier in this Appendix. The Base Case will cover financial years 2014/15 to 2016/17. While the potential starting date for OFA is later than financial year 2016/17, the

86 AEMC, *First Interim Report, Optional Firm Access, Design and Testing,* 24th July 2014, p151.

choice of the modelling period is limited by the validity of the constraint equations published by AEMO. As pointed out in the section 'Transmission constraints' above, in the current 2014 books, constraint equations relating to years further in the future are unlikely to accurately reflect the network condition at the time. We chose the modelling period of 2014/15 to 2016/17 so that the constraint equations applied are more likely to be up-to-date with current network conditions.

In the Base Case, we restrict bidding to baseload stations, which have the option to offer their capacity at SRMC, withdraw 20% of their capacity (offer 80% at SRMC), or bid their entire capacity at the market price floor. The option of market price floor bids is needed to capture disorderly bidding when generators are constrained off. Other stations are assumed to offer their capacity at SRMC. The assumption that only large, baseload generators can bid strategically is consistent with observed behaviour and reflects limitations in the size of the strategy space that can be modelled in realistic timeframes.[87]

We will also investigate a number of sensitivities to study the impact of OFA under different assumptions. Each sensitivity is run for financial year 2014/15.

- **Bidding:** In addition to the base case strategy sets, Generators can also choose to withdraw 30% of their capacity from the market (offer 70% at SRMC).. This increases the level and extent of strategic bidding in both the Status Quo and OFA cases.
- **Bidding no Contract:** Use the same bidding assumption as in the Bidding sensitivity, but assumes that there is no financial contract sales, i.e., generators are 100% exposed to spot prices. . This further increases the level and extent of strategic bidding in both the Status Quo and OFA.
- **High Demand:** Use NEFR2014 High, POE50 demand forecast for FY24/25 but keep supply and constraint equations the same as FY14/15. This results in a case with greater levels of congestion than currently observed and acts as a proxy for modelling further into the future than 2016/17. Figure 57 shows the demand under this scenario.
- **Non-firm Access:** Assume *every generator* has 0 agreed access amount, i.e. all generators are non-firm. Under this assumption, generators still receive firm access quantities in line with their capacity and coefficients in binding constraints, i.e. OFA is not optional.
- **Regional Focus:** Three regional focus sensitivities for NSW, Queensland and Victoria. In each regional focus run, the modelling assumes that all strategic players are within a single region. This allows for a larger strategy

87 If there are N strategic players with k discrete strategies each, the number of strategy combinations is N^k at each demand point.

space to be modelled in the chosen region at the expense of a lack of strategic bidding in all other regions. Peakers in the focus region are allowed to bid MPF, which intensifies the disorderly bidding behaviour as well as making strategic Bidding-to-Bind behaviour more likely under OFA. Generators outside the region offer all their capacity at SRMC.

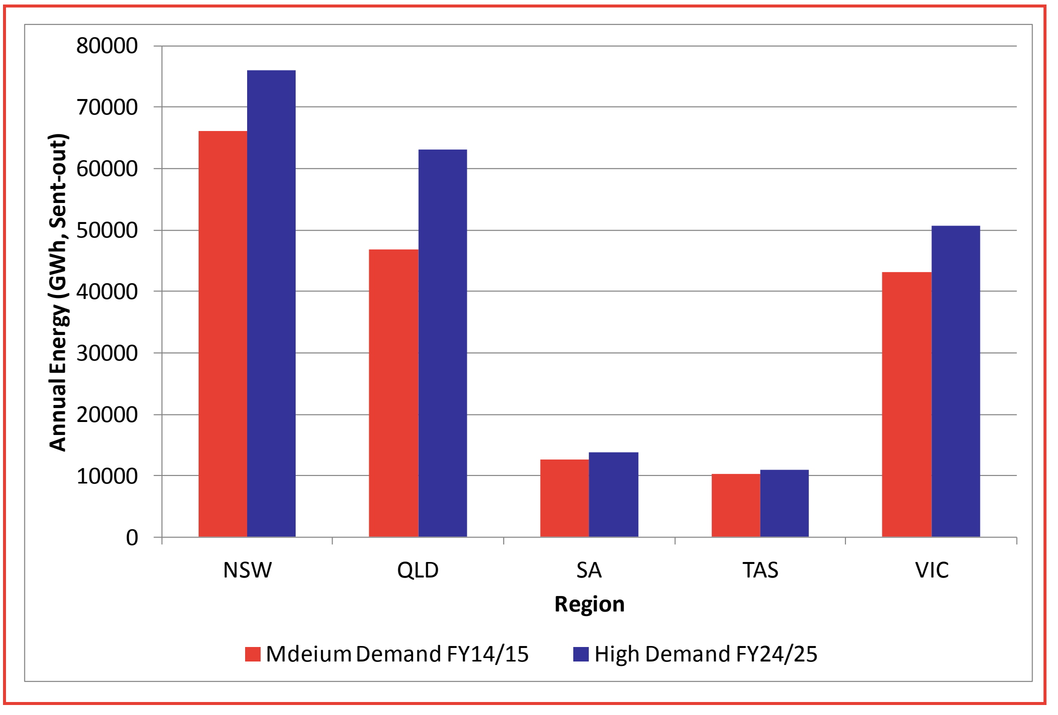
Table 7 summarises the sensitivities studied.

Table 7: Sensitivities modelled (differences to base case are bolded)

Sensitivity Name	Demand	Access Allocation	Bidding
Bidding	As Base	As Base	100% at MPF 100% at SRMC 80% at SRMC **70% at SRMC**
Bidding no Contract	As Base	As Base	100% at MPF 100% at SRMC 80% at SRMC **70% at SRMC** **100% pool exposure**
High Demand	**NEFR2014 POE50 high demand FY2024/25**	As Base	As Base
Non-firm Access	As base	**All generators have 0 agreed access**	As Base
NSW focus	As Base	As Base	**More bidding options in NSW, Peakers can bid MPF** **SRMC bidding outside NSW**
QLD focus	As Base	As Base	**More bidding options in QLD, Peakers can bid MPF** **SRMC bidding outside QLD**
VIC focus	As Base	As Base	**More bidding options in QLD, Peakers can bid MPF** **SRMC bidding outside QLD**

Source: Frontier Economics

Figure 57: High Demand forecast



Source: AEMO NEFR 2014, medium and high scenarios

Appendix C – Locational signals under the current RIT-T

This Appendix reproduces section 2.1 of our October 2012 report for the NGF, with minor edits to reflect the standalone presentation.

The locational signals provided under the current transmission planning arrangements are more powerful than is commonly assumed. These signals arise through the operation of the RIT-T, including participants' expectations of how the RIT-T will be applied in future. The importance of the RIT-T lies in how it is used by TNSPs to determine where and when transmission investment ought to be undertaken to ensure reliability standards are maintained. Generators will tend to find it profitable to locate in areas where the TNSP considers that new generation will be built and hence has augmented or will augment the transmission network, thereby reducing actual and expected congestion. The AEMC acknowledges that TNSPs' current planning processes send implicit locational signals to generation investors. Indeed, this is what lies behind the AEMC's concern that TNSPs' lack of information about generator costs can result in poor co-optimisation between generation and transmission investment.

The issue is therefore not the *existence* of signals created by the RIT-T, but the *integrity* and *appropriateness* of those signals as compared to the signals provided by alternative arrangements such as the OFA proposal.

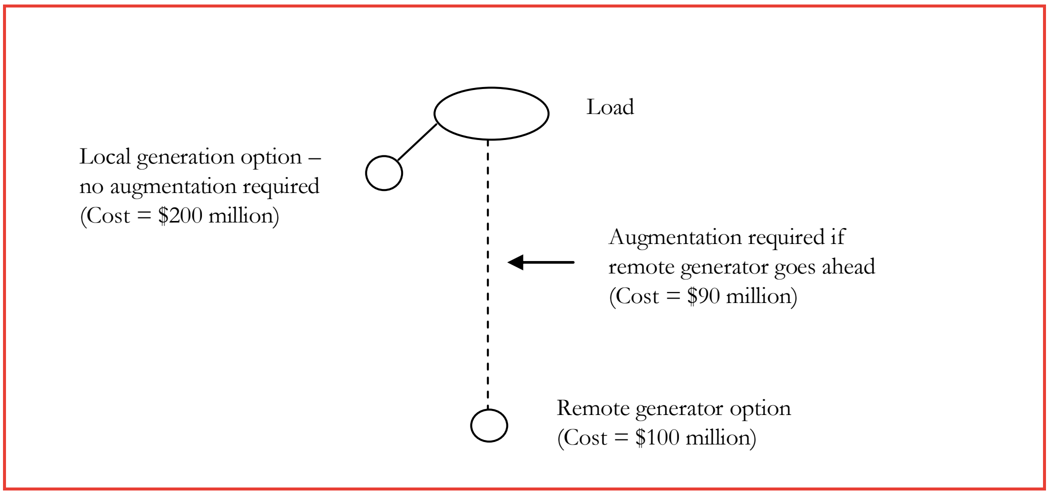
Consider the following stylised example:

- Satisfaction of reliability standards requires additional supply to meet demand
- Investors have a choice between two locations for generation investment, described as 'local' and 'remote'
- Assume that:
  - The expected pattern and duration of power output of a new generator at both locations is the same
  - The operating costs of a new generator at both locations is the same and hence ignored for the remainder of the example
  - Capital costs at the local location are $200 million
  - Capital costs at the remote location are $100 million
  - If the generator locates locally, no transmission investment is necessary
  - If the generator locates remotely, $90 million of (non-lumpy, right-sized) transmission investment is necessary

These data are represented in Figure 58 below.

In considering whether it ought to invest in transmission to facilitate power flows from the remote generation option, the TNSP is obliged to undertake the RIT-T. Under the RIT-T, the TNSP needs to compare the combined cost of generation and transmission at the remote location with the cost of generation at the local location. Contrary to the view expressed in the AEMC's Technical Report on OFA, the TNSP does not simply consider which option yields the lowest transmission cost.[88] This is because under the RIT-T, a TNSP needs to consider the full 'market benefits' of an augmentation option and its alternatives.[89] In the context of this example, the TNSP needs to consider which option yields the larger net market benefit or the smaller net market cost, taking into account the total costs of transmission and generation (as well as other variables such as the degree of load shedding, etc).

Figure 58: Locational signals from the RIT-T



Source: Frontier Economics

Given the example figures above, the TNSP would find that it was appropriate to undertake the augmentation because the combined generation and transmission cost of power from the remote option ($190 million) was lower than the cost of power from the local generation option ($200 million) – see Table 8 below.

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88 Technical Report, pp. 40 (footnote 56) and 87.

89 AER, *Regulatory investment test for transmission, Final*, June 2010, clause (1), p.3.

Table 8: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option costs ($m)
Transmission	Augmentation	90	190
	Remote generation	100	
Generation	Local generation	200	200

Source: Frontier Economics

The proponent of a generation investment would have an incentive to make such calculations internally, even before the RIT-T was applied to the augmentation by the TNSP. For example, before investing in the remote generation option, a proponent would have an incentive to conduct the analysis to gain some confidence that the augmentation would satisfy the test and proceed. Likewise, before investing in the local option, an investor would have an incentive to conduct the analysis. In doing so, it would find that it was not worthwhile to develop the local option, as the augmentation (along with the remote generator option) would be likely to go ahead and harm its proposed project.

Alternatively, if the capital cost of the remote option was higher (say, $120 million) and combined with the cost of the augmentation ($210 million) was more than the cost of the local generator option ($200 million), neither the augmentation nor the remote generator would proceed – see Table 9.

Table 9: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option costs ($m)
Transmission	Augmentation	90	210
	Remote generation	120	
Generation	Local generation	200	200

Source: Frontier Economics

If the investor undertook similar analysis, it would realise that the local project was the most beneficial and should proceed, given that the augmentation was unlikely to go ahead and compromise the viability of its project. Similarly, a proponent of the remote generator would realise that it was pointless to develop such a plant.

In this way, prospective investors' expectations of how the RIT-T will be applied in the short and the long terms should provide investors with positive (albeit imperfect) locational signals.

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