ROAM CONSULTING

ENERGY MODELLING EXPERTISE

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Report (EPR0019) to

AEMC

Modelling Transmission Frameworks Review

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EXECUTIVE SUMMARY

ROAM Consulting (ROAM) was appointed by AEMC to conduct quantitative modelling of three alternative policy packages developed during the Transmission Frameworks Review. Each alternative represents an integrated suite of reforms to the National Electricity Market (NEM) and followed an initial screening process that commenced with five separate packages. A full description of each of the packages is available from the AEMC Transmission Frameworks Review website. The three packages assessed by ROAM were:

(i) Package 1 - broadly reflects the status quo, with minor rule changes,

(ii) Package 2 - introduces a congestion pricing mechanism, and

(iii) Package 4 - introduces an option for generators to obtain a financially firmer level of access, known as Optional Firm Access (OFA).

ROAM was requested to assess the relative impacts of each of the packages on the productive, dynamic and allocative efficiency of the NEM. ROAM divided the project into two phases:

- Backcasting, and
- Forecasting.

The modelling undertaken has been extensive, involving both optimal long range transmission and generation planning, followed by half hourly market modelling of all cases to assess the detailed performance of flow paths, congestion, market prices and production levels. This modelling work has given a firm understanding of many of the issues associated with each of the packages. While there is no clear winner apparent from the modelling undertaken, the outcomes show that the existing package and both proposed packages are capable of delivering market outcomes that are closely aligned with theoretical best practice.

The overall finding is that the OFA model is capable of delivering lower total system costs than retaining the existing NEM rules, which rely on the RIT-T for transmission investment. The least cost outcome for the OFA model resulted when the most prospective new entry generator types chose to adopt firm access targets as follows:

Technology	Ideal Firm Access
Wind	30%
OCGT	90% (Peak Firm Access)
CCGT	60%
Interconnectors	50% (or lower)

As part of the modelling undertaken to compare the performance of the packages, future disorderly bidding was also modelled for Package 1, in the event of a continuation of existing NEM rules. The impact of disorderly bidding on system costs was found to be generally consistent with the backcast in the near term, however the cost of disorderly bidding is forecast to escalate over time due to increased penetration of low short run marginal cost renewable generation competing with relatively high cost thermal generation as the carbon price and gas fuel price escalates. Other attributes of the OFA model were also evaluated including whether there would be an increased willingness to contract in the OFA model, compared with the present rules.

A forecast of the NEM commencing at market start in 1998 has also been completed to estimate the extent to which overbuilding of transmission has occurred from that time to the present. As might be expected, hindsight is 20/20 vision, and some of the transmission development that has occurred since market start in most regions would not have been developed to the same level if the changes in demand growth and generation location had been known at the time that development decisions had to be made. This outcome does not necessarily identify a failing of the RIT-T planning methodology; the future remains uncertain under any planning methodology. This work is reported upon in an Appendix. Despite an apparent overbuilding of the transmission system in some areas of the NEM, an assessment of the existing network suggests that approximately 88% of existing generation capacity has implied firm access.

The primary conclusions are that:

1. The analysis suggests that in the context of the Australian NEM the potential gains in allocative and dynamic efficiency from incorporating transmission considerations into generation development decision making are relatively small. It also suggests that the RIT-T methodology presently followed is relatively successful in managing transmission costs if planning appropriately takes into account the changing dynamic in generation development. Nevertheless there is evidence that the RIT-T is suboptimal in total system cost terms and that the OFA methodology is capable of delivering higher allocative and productive efficiency.
2. The potential productive efficiency gains from removing the incentives for disorderly bidding have been found to increase into the future. The historical assessment of disorderly bidding supports the observations of market participants that such events are primarily triggered by non-system normal transmission events. Accordingly, the behavior of generation and the operation of settlements under the OFA package will be critically important during these periods.
3. Investigations of the effects of the different packages on the willingness for generators to enter into contracts shows that a generator with a high level of firm access has a higher average net revenue expectation compared with a non-firm generator under all levels of contracting. A generator with a high level of firm access is shown to have a higher standard deviation of revenue expectations under all levels of contracting, although it is towards the upside. The modelling completed is inconclusive on the matter of supporting an

increased willingness to contract as a result of firm access, although it does clearly show that a generator with firm access may expect to attract higher average net revenue compared with no firm access.

4. Operational and financial risk in the NEM is associated with market price outcomes. Although such outcomes may be considered a wealth transfer it is ultimately the price that consumers pay for electricity that is of key importance. As such it is suggested that this quantitative assessment be expanded to investigate in more depth market price implications and risk management costs for the generation sector. This could be part of a subsequent phase undertaken before or during the transition between Package 1 and the proposed options, Package 2 and Package 4.

In summary, Package 2 is expected to be effective in eliminating disorderly bidding but would not necessarily change future development outcomes. Package 4 should be effective both in eliminating disorderly bidding and in providing stronger market signals for generators as to the transmission costs of locating in different zones within a region of the NEM. The overall result in terms of the economic cost of Package 4 relative to the other packages will depend on the level of firm access chosen by different types of generators. In the event that high levels of firm access are chosen, the resulting system will require a higher level of transmission development, resulting in higher overall costs due to capital expenditure. At the other extreme, if generators choose to avoid paying for firm access and attempt to free ride on the existing transmission system, the result will be increased transmission congestion and higher overall costs due to increased operating costs. The optimum is expected to be near the levels we have computed, with generators of different types opting for firm access at a level that is optimum for their expected operating regime. It is the allocation of the risk of poor transmission planning decisions that is the focus of the proposed OFA model.

Backcasting was carried out for a period of three years in the past, including a full analysis of financial years 2008-09, 2009-10 and 2010-11, the last three full years for which data was available at the commencement of the project. The primary objectives of the backcasting phase were:

- To quantify the impact of disorderly bidding that has occurred in the last few years in order to have a basis for assessing the impact of a continuation of that aspect of the market.
- To benchmark the backcast modelling against actual market behaviour, so that the materiality of any issues identified in the forecasting phase could be judged against the history of real world outcomes.

Backcasting involved conducting modelling at the five minute level for each half hour[1] over the three years, and comparing the outcomes with actual market observations. A number of different backcasting cases were evaluated, each with particular purposes. Backcasting included actual observed bidding and 'realistic' bidding, (which ROAM models using a quadratic programming algorithm) with water values applied to hydro generation.

The backcasting included identification and correction of instances of disorderly bidding, so as to measure the efficiency improvements from elimination of disorderly bidding through adoption of either Package 2 or Package 4. Correction of disorderly bidding was made by simulating the Package 2 and Package 4 rules in the market dispatch model, thus creating several different backcasts. The efficiency gains, i.e. cost reduction benefits, from elimination of disorderly bidding in 2008-09, 2009-10 and 2010-11 were $2.9m, $3.5m and $14.9m respectively.

Forecasting was conducted to 2030, with the modelling extended to 2040 to minimise any end effects that could distort the modelling outcomes for the reporting period to 2030.

To assess the dynamic efficiency of the different packages, we applied a model that forecast the generation and transmission investment path for the next twenty years, taking account of the differences between the packages, as seen by investors. For this, an integrated resource planning tool (LTIRP[2]) was applied that found the least cost generation and transmission plan over the 20 year horizon. The key features of the three packages were compared using three specific mathematical formulations of long term planning, which were:

(i) Co-optimised - generation and transmission are developed in a co-optimised LTIRP without additional constraints, reflecting an idealized centrally planned future where all technology costs are known, demand for power is known with certainty, and development of generation and transmission is completed just in time to meet customer needs to a known reliability standard.

(ii) RIT-T - Where transmission follows generation in a process designed to approximate the current Regulatory Investment Test for Transmission (RIT-T). This methodology involves a two-step process whereby generation outcomes are used as an input for planning transmission, and transmission companies react to changes in existing and new generation so as to meet the objective of least cost transmission development in the face of uncertain generation development.

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[1] That is, modelling every 6th dispatch interval which coincides with the trading interval.

[2] LTIRP is ROAM's proprietary Long Term Integrated Resource Planner, which was applied for Treasury to compute the impact of various carbon prices to 2050 for Australia prior to the legislated introduction of a price on carbon from 1 July 2012.

(iii) OFA - Generation and transmission are co-optimised, subject to constraints relating to the application of the Firm Access Standard, representing a situation in which generators have the choice of taking into account the need for new transmission when deciding the location, size and technology type to build, and the usage of the grid by existing generators.

The co-optimised method provides an unrealistic but true least cost outcome. It does not represent any of the three packages, but rather is representative of a centrally planned electricity sector, and has been used as a benchmark to compare the outcomes of the three packages against. The modelling commenced with generation, interconnections between regions and intra-connections within regions reflecting the existing state of the NEM. Generator fuel costs, energy limitations and intermittent generation profiles are in accordance with present values. Furthermore, a complete set of transmission limits and constraint equations was developed at the zonal[3] level and incorporated into the LTIRP. The co-optimised outcome then builds the transmission and generation system so as to provide the least cost solution for projected generation and transmission costs that will reliably supply the future demand. This was carried out for three separate development alternatives in line with AEMO planning studies consultation[4] (NTNDP) demand and technology development scenarios.

For the co-optimised method, as with all the methods, the least cost forecast to 2030 was overwhelmingly made up of wind generation to meet the Renewable Energy Target (RET), and gas fired open cycle and combined cycle generation to provide responsive peaking and intermediate generation at times when renewables were insufficient to meet the prescribed reliability standard.

The RIT-T method replicated the present NEM rules to represent Package 1. This method allowed generation to build at locations within each region taking into account generation cost variables but without consideration of intra-connector augmentation costs. Intra-connector augmentations were presumed to be decided by transmission network service providers (TNSPs) on the basis of the RIT-T on reliability and/or market benefits, and paid for by consumers. Therefore, while the co-optimised method took account of all intra-regional and inter-regional transmission constraints in optimising the future system, the RIT-T method took account of the inter-regional transmission constraints but the algorithm considered the intra-regional constraints to be unlimited in its initial solution. This resulted in violation of some intra-regional limits, increasing over the next 20 years with increasing demand growth, particularly in the major load centres. A second pass of this model then froze the generation development plan computed from the first pass, and assessed the level of intra-connection development that would be needed to meet the

[3] i.e. subregional

[4] http://www.aemo.com.au/en/Electricity/Planning/Planning-Studies-2012-Consultation. The planning studies are also known as the National Transmission Network Development Planning studies (NTNDP).

RIT-T, seen from the perspective of the TNSPs in each region. This approach was considered to be a fair way of assessing the efficacy of the existing rules and the way that they account for the freedom of generators to build according to an open access transmission regime, but the need for TNSPs to factor in the generation developments to their future transmission plans.

The RIT-T method was also used to assess the dynamic efficiency of Package 2, which has been developed to discourage disorderly bidding but does not provide a materially different signal to generators as to where to develop than is provided by the present Package 1.

The OFA method modelled the proposed new set of NEM rules described by Package 4, whereby transmission augmentation results from generators making decisions as to the level of firm access that is optimum for their investment returns. This model again applied zonal inter- and intra-regional transmission limitations. For this method, when intra-connector transmission paths are deemed sufficient, by the incoming generators, to support new generation, there is no need for additional transmission investment. However, when congestion on intra-connectors is forecast, generators would make the decision to locate elsewhere or to fund the transmission augmentation costs. This would take the decision making out of the hands of TNSPs and put it in the hands of the generation developers. However, this method, which concentrates on the interests of generators only, does not necessarily conform to a prescribed reliability standard for customers. A further review of the adequacy of transmission development to achieve the reliability standard, which was foreshadowed by AEMC in preparing this package, is therefore inherent in the OFA process, and this has also been assessed quantitatively in the package of work described here.

The differences in generation and transmission development patterns between the methods were found to be quite substantial over the twenty years. The most significant difference between the RIT-T and OFA models is that the RIT-T model leads to much higher transmission costs, where generators locate without regard for the cost of transmission. Whilst variable generation costs are lower under the RIT-T, both fixed generation and transmission costs are lower under the OFA model which leads to a lower overall total system cost.

The impacts of the OFA model are most evident in the planning outcomes for the Queensland region. Substantial differences in the locational development of generation are projected when compared with the RIT-T model. However the differences in generation costs between zones within a region are not very significant according to AEMO NTNDP data. Consequently, the overall cost differences between the methods are not very large compared with the very large fixed and variable costs of operating the NEM. Therefore, although the inclusion of transmission costs has a material impact on the location of generation development within a region, the net impact on total system costs is minimal.

The difference in generation development costs within a region, based on the AEMO NTNDP data, may be relatively minor, but the data does not reflect the increased difficulties in obtaining development approval for sites near major cities, compared with sites that are in more remote zones. The data may therefore bias the generation development towards zones that incorporate major cities, such as the state capitals, which may undervalue the benefits of a change in the rules towards Package 4. Nevertheless the model is capable of assessing the relativities of the different methods to a high degree of resolution.

Table 1 shows the NPV of the variable and fixed generation costs and the transmission costs under the three alternative planning scenarios. This NPV represents the discounted, real cost of the annual repayments of generation and transmission capital expenditure which occurs between 2012-13 and 2029-30. Table 2 provides the real, undiscounted value of the full cost of generation and transmission investments which occur before 2029-30. For a capital investment in 2029-30, the complete cost of this project contributes towards the values in Table 2. In contrast, only a single annual repayment, discounted to June 2012 would contribute to the values provided in Table 1.

Table 1 – Division of Total System Cost ($m)

	Variable Generation Costs	Fixed Generation Costs	Transmission Costs
RIT-T	82,469	36,227	278
Co-optimised	82,503	36,199	146
Firm Access	82,523	36,203	163

Table 2 – Division of Total System Cost (Undiscounted $m)

	Variable Generation Costs	Fixed Generation Costs	Transmission Costs
RIT-T	194,181	82,151	1,529
Co-optimised	194,542	81,079	879
Firm Access	194,623	81,091	909

The modelling indicates that the benefit, on a NPV basis, of moving from the current RIT-T method of transmission planning towards the more co-optimised OFA approach is $85 million. However, the total saving in the full cost of investment is over $1.2 billion. The difference between these two values results from the fact that most development occurs in the later years of the study. Therefore, the discounted value of the impact of the OFA model in these later years is not fully captured.

The modelling approach and data are fully documented in this report. Should the market wish to have a greater understanding of various nuances to the packages and/or consideration of a wider range of generation and transmission costs and options, our work can be expanded to meet those needs.

Version History

Version History				
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Revision Type**
1.0	2012-08-20	Ian Rose Ben Vanderwaal Richard Bean Andrew Turley Nick Culpitt	Ben Vanderwaal	Draft Report
2.0	2012-10-19	Ben Vanderwaal Nick Culpitt	Ian Rose	Complete report incorporating feedback
2.1	2012-12-24	Ben Vanderwaal	Ian Rose	Final report incorporating minor updates and expanded discussion
2.2	2013-01-24	Ben Vanderwaal	Ian Rose	Revisions to executive summary. Addition of undiscounted market costs analysis in Section 6.4.1).
2.3	2013-02-26	Nick Culpitt	Ian Rose	Minor adjustments to Tables 5.1 and 5.2
2.4	2013-02-28	Nick Culpitt	Ian Rose	Final Report incorporating revisions to the executive summary.

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1) BACKGROUND

The AEMC has been tasked by the Ministerial Council on Energy (MCE) to review the National Electricity Market's (NEM) transmission regulatory arrangements (the Transmission Frameworks Review or TFR). The focus of the TFR is to ensure that development and operation of transmission networks going forward will support competitive generation and retail sectors in an uncertain policy environment while maintaining reliability and security of supply.

The expansion of Australia's renewable energy targets and the introduction of a carbon price from 1 July 2012 means the nature and pattern of generation investment will continue to evolve in the future, as the energy sector transforms from one dominated by large fossil fuel generators to one with a greater mix of smaller low emission and renewable generators. Unlike fossil fuelled generators, for which the fuel can be shipped to locations that make best overall use of resources, including electricity transmission, gas pipelines, and available labour, renewable generators must be built at the energy source. This is likely to have implications for congestion and network development, as transmission may be weak in especially windy, sunny, wet or coastal locations, the last mentioned in association with wave power, ocean currents, tidal, or offshore wind. Over the long term, a balance between the quality and cost of renewable and non-renewable generation resources and the cost of transmission augmentation is sought.

In its First Interim Report[5] for the TFR the AEMC set out five alternative policy packages for addressing these issues. The AEMC is assessing the likely efficiency of these packages taking into account a substantially changed policy environment going forward. Following feedback and industry consultation from the First Interim Report AEMC focussed its attention on three of the policy packages. Package 1 broadly reflects the status quo; Package 2 introduces a congestion pricing mechanism; and Package 4 introduces an option for generators to obtain a financially firmer level of access to the transmission network. A detailed description of the alternative packages is presented in the AEMC First Interim Report for the TFR.

The modelling undertaken here has been informed by AEMC's deliberations for the Second Interim Report published on 15 August 2012[6], and the Technical Report on Optional Firm Access also released on 15 August 2012. As mentioned in the Second

[5] http://www.aemc.gov.au/market-reviews/open/transmission-frameworks-review.html

[6] http://www.aemc.gov.au/market-reviews/open/transmission-frameworks-review.html

Interim Report, the AEMC is undertaking quantitative analysis to provide further input into their assessment of the relative costs and benefits of the alternative access models. This report has been privy to the deliberations of AEMC prior to the release of the Second Report and has used the principles outlined in the Second Interim Report and the Technical Report on Optional Firm Access to assist in detailed consideration of the packages.

The packages have been modelled under a range of probable scenarios, in particular reflecting the expanded RET and the price on carbon from July 2012. The AEMC appointed ROAM to undertake a rigorous modelling exercise that assesses the productive, allocative and dynamic efficiency of Packages 2 and 4, relative to Package 1.

This report provides quantitative and qualitative analysis of the three packages, using market modelling as a basis for comparing the economic efficiency of the packages.

2) Overview of Modelling Tasks

A key aspect of the modelling is the quantitative assessment of the past performance of the NEM, with particular reference to the impact of transmission congestion. This was followed by comprehensive forecasting of the future development of the NEM under the conditions anticipated by each of the packages. This section summarises the various tasks undertaken.

Backcast - Modelling a congestion pricing mechanism (Package 2)

The first task required backward looking modelling to consider what the likely outcomes would have been over the last three years if a congestion pricing mechanism had been in place. The difference in generator trading behaviour and resulting dispatch outcomes have been analysed along with marginal cost data to determine the potential productive efficiency gains that may be achieved, should the Package 2 mechanism fully remove the incentive for disorderly bidding.

Forecast - Modelling a congestion pricing mechanism (Package 2)

The second task considered what outcomes are likely to result going forward with a congestion pricing mechanism, compared with Package 1. The period from 2012-13 to 2029-30 has been modelled. The forecast period has been assessed in a planning phase applying ROAM's Long Term Integrated Resource Planner[7] (LTIRP), followed by more detailed 2-4-C[8] half-hourly dispatch modelling to capture time sequential market impacts relating to generator trading and transmission limitations.

This modelling reflects a situation where:

- generators respond, at the margin, to local price signals, rather than regional price signals as at present;
- generators have limited locational investment signals in place (although these may be slightly different from Package 1 as generators will consider different factors); and

[7] This is ROAM's proprietary integrated resource planning model, which co-optimises long term generation and transmission development and is described in Appendix A).

[8] 2-4-C is ROAM's time sequential market forecasting software, which models the NEM at an equivalent level to that of the NEMDE dispatch software used by AEMO to dispatch the NEM, using constraint equations to model congestion in the NEM, either in backcasting or forecasting mode.

- transmission investment occurs according to existing processes, in particular the RIT-T as set out in the Rules and supplemented by AER's guidance.

The AEMC wished to assess whether implementing a congestion pricing mechanism is likely to result in more predictable dispatch outcomes compared with Package 1, given that this could be argued to reduce generators' risk and lead to a greater willingness to enter into forward hedge contracts.

Forecast - Modelling an optional firm access mechanism (Package 4)

Further to the forecasting for Package 2, the situation going forward in response to the proposed Package 4 optional firm access mechanism has been investigated applying the LTIRP and 2-4-C modelling. A key goal in this assessment was to determine the shape of the total system cost curve as a function of the level of firm access that generators choose to purchase. This outcome informs the question as to whether the Package 4 proposal may deliver allocative and dynamic efficiency gains over the longer term, by more fully exposing generators to the cost of transmission in their investment decisions.

3) KEY MODELLING ASSUMPTIONS

3.1) MODELLING SCENARIOS

For the forecast assessment, three scenarios or themes with varying macroeconomic drivers such as demand and energy expectations, gas prices, carbon prices and other factors have been considered. These have been taken from the 2012 AEMO planning studies consultation[9] (NTNDP) and 2012 AEMO Load Forecasting reports.[10] ROAM has selected Scenarios 1, 2 and 3 from the AEMO planning studies, as these scenarios have a higher demand growth expectation, which is more likely to highlight potential changes in efficiency under the alternative packages. For completeness, the three AEMO planning scenarios applied in this modelling are presented below.

Table 3.1 – Modelling Scenario Settings (as per the 2012 AEMO planning studies)

		Scenario 1	Scenario 2	Scenario 3
	Scenario Title	**Fast Rate of Change**	**Fast World Recovery**	**Planning**
Economic	**Economic growth**	High	High	Medium
Economic	**Commodity prices**	High	High	Moderate
Economic	**Productivity growth**	High	High	Moderate
Economic	**Population growth**	High	High	Moderate
Greenhouse	**Carbon Reduction Target**	High 25% reduction Treasury high scenario	Medium 5% reduction Treasury core scenario	Medium 5% reduction Treasury core scenario
Greenhouse	**Renewable Energy Target**	Remains	Remains	Remains
Technology	**R&D**	Strong	Moderate	Moderate
Technology	**Distributed generation penetration**	High	Moderate	Moderate
Technology	**Penetration of Electric Vehicles**	High	Moderate	Moderate

The following table describes the key data elements of the scenarios.

[9] http://www.aemo.com.au/en/Electricity/Planning/Planning-Studies-2012-Consultation. The planning studies are also known as the National Transmission Network Development Planning studies (NTNDP).

[10] http://www.aemo.com.au/en/Electricity/Forecasting/2012-Forecasting-Data

Table 3.2 – Scenarios Modelled

	Scenario 1	Scenario 2	Scenario 3
Title	Fast Rate of Change	Fast World Recovery	Planning
Demand Forecast[11]	H10 (LTIRP) H10 + H50 (2-4-C)	H10 (LTIRP) H10 + H50 (2-4-C)	M10 (LTIRP) M10 + M50 (2-4-C)
Carbon Price Trajectory Scenario	High	Core	Core
Technology Costs	2012 Worley Parsons Scenario 1	2012 Worley Parsons Scenario 2	2012 Worley Parsons Scenario 3
Gas Prices	2012 ACIL Scenario 1	2012 ACIL Scenario 2	2012 ACIL Scenario 3

3.2) VARIATIONS FROM THE NTNDP DATA SET

In order to assess key points of interest for this review some minor variations from the published NTNDP data sets have been made. The reasons for the variations are also discussed:

- Capital costs for generators close to the reference node have been increased by 10% in order to test the firm transmission access mechanism; this is intended to reflect the relative scarcity of development sites close to the reference nodes in major capital cities, and the likely additional cost of permitting appropriate sites; this increase may underestimate the increase in cost of development near cities relative to sparsely populated areas in each region but is sufficient to demonstrate the principles of the different packages;
- ROAM has estimated OCGT capital cost values based on the relative capital cost of OCGT and CCGT technologies, according to the 2010 NTNDP data set, applied to the CCGT 2012 NTNDP capital cost. This was necessary as OCGT costs were not published in the initial 2012 NTNDP consultation. This has produced an OCGT capital cost of $765/kW, which is in line with the final published 2012 NTNDP data set of $732/kW;
- Water values have been added for hydro generation. The methodology used to establish water values is detailed in Section 4.1.3).

[11] H10, H50, M10 and M50 refer to the 'High' and Medium' growth energy forecast targets under 10% and 50% probability of exceedence peak demand conditions respectively

The 2012 AEMO load forecasts are provided to 2031-32; however, peak demand and energy forecasts for the LTIRP modelling were extended out to 2040 to provide a sufficient planning horizon to produce robust planning outcomes to 2030. For demand and energy forecast extrapolation beyond the period of published data, ROAM has designed a methodology based on forecast population growth. This methodology is essentially an extrapolation of energy consumption on a per capita basis. ROAM considers this is an appropriate method for computing future energy consumption, as it relates consumption to expectations of population, rather than simply extrapolating energy use from the relatively short forecasts published by industry.

ROAM has used ABS (Australian Bureau of Statistics) population forecasts[12] to compute electricity consumption per capita over the published forecast period. The relationship between population and per capita consumption is then assumed to continue past this period, subject to the long-term population forecasts provided by ABS.

3.3) TRANSMISSION AUGMENTATION COSTS

ROAM has assessed a number of recently completed or proposed transmission augmentation projects with a focus on the most recent Powerlink revenue proposal.[13] Powerlink's revenue proposal shows that the cost of 500 kV DCST[14] operating at 275 kV is in excess of $2m/km (Halys to Blackwall). The cost of 275 kV DCST is in excess of $1m/km (see Calvale to Stanwell). The cost of Halys to Greenbank DCST is in the vicinity of $3m/km as it includes more urban areas. These costs are for overhead lines. The cost of underground cable for the equivalent voltages would be many times higher; however, this is only necessary where overhead easements are impossible; for example, suburban Sydney.

275 kV lines can comfortably provide 1,000 MW per circuit, and 500 kV lines 2,000 MW per circuit. Based on this high level analysis it has been determined that **$2,000/MW/km** provides a reasonable estimate for the cost of new transmission, including the additional cost of substation equipment at each end of the line**.** Sensitivities have been provided with transmission valued at $1,000/MW/km and $3,000/MW/km. Increasing capacity on existing HVDC interconnector links is costed at $4,000/MW/km for all cases.

[12] http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/3222.02006%20to%202101
[13] http://www.aer.gov.au/node/7945
[14] Double circuit steel tower construction.

Transmission capital costs are multiplied by the estimated distance between zones. Distances between zones are presented in Table 4.5 in the following section.

This methodology has been consistently applied to both intra-regional transmission and to interconnectors. An interconnector upgrade therefore represents an increase in the actual capacity of transmission between two regions. The capacity to transfer between regions can also be increased through investment in intra-regional transmission if congestion on these flowpaths is restricting the transfer capacity of the existing interconnector.

4) MODELLING METHODOLOGY AND DATA PREPARATION OVERVIEW

4.1) APPROACH TO THE BACKCAST

Since the outcomes from previous years are known exactly, it may not be obvious what role backcasting plays in this assessment. The reason for the backcasting is to verify that the forecasts provided in this modelling can be relied upon. The best way to ensure this is to forecast the past, and then compare that with history, so that any differences are observed and can be taken account of when forecasting the future. Backcasting is a complex exercise, as it attempts to take into account every event, such as bidding, constraints, energy limitations, outage events, intermittent generation profiles, ramp rates, demand profiles, and so forth, and reduce these to a set of formulae that can replicate the past in a fully automated time-sequential way for each half hour over a three year period.

The outcome of the backcasting exercise determined the extent to which productive inefficiencies in the NEM could have been reduced under the definition of Package 2, where the incentives for disorderly bidding are removed. To do this all instances of disorderly bidding had to be replaced by modelling the NEM with the Package 2 rules which discourage disorderly bidding by implementing a congestion pricing mechanism at those periods. The analysis has identified the productive efficiency gains of such a change in market rules. The backcasting outcomes have also been used to develop baseline performance metrics for the forecasting component.

4.1.1) Benchmarking Backcast Outcomes

ROAM has benchmarked the outcomes of a three year backcast applying the 2-4-C dispatch engine against actual historical market outcomes to ensure that the backcast provides an accurate reflection of the past. A three year backcast has been completed investigating the financial years 2008-09 to 2010-11. Extending the backcast prior to this was not pursued due to the Snowy boundary change on 1 July 2008 (which incorporated significant changes to the constraint equations in NSW and Victoria). Complete data for the most recent financial year 2011-12 was unavailable for this project.

ROAM has used all relevant data needed to perform backcasting such as bid records, demand data, constraint equations, marginal loss factors, and relevant generator parameters. The data source for historical bids was the YESTBIDS directory on NEMMCO and AEMO's "NEMWEB" web site. ROAM processed the files from this directory to ensure that only bids that applied in a particular half hour period are used. For each trading period (30 minutes) the latest bid offer up to five minutes before the end of the trading period was applied. Therefore, the ROAM 'trading interval' backcast is actually a simulation of the 6^{th} 'dispatch interval' of each trading interval. Any comparison with reality uses the market outcomes observed in the 6^{th} dispatch interval of each trading interval, and therefore is a subset of the actual dispatch intervals experienced in history. However, as the forecasting was to be conducted in half hourly time intervals in the future, this was considered the most appropriate approach to the backcast.

ROAM has performed this process previously, for example in solar generation research, in order to investigate the volatility in prices during high solar insolation periods.

ROAM has used the actual dispatch outcomes to benchmark the backcast as part of modelling Package 1. As discussed, the backcast has also been configured to reflect the congestion pricing arrangements that would be expected under Package 2, and the two streams of dispatch outcomes have been compared on a trading interval basis over the three year period.

4.1.2) Bidding Scenarios

In the backcast, ROAM considered five bidding scenarios to capture five different annual cost of supply outcomes. The actual historical observed generation dispatch outcomes have been assessed to calculate a sixth cost of supply scenario. In the backcast, periods of observed disorderly bidding have been removed to quantify the potential increase in productive efficiency that may result with the assumption that Package 2 does fully incentivise generators not to practice disorderly bidding.

Historical trading interval bidding

ROAM has extracted historical bidding information, demand, system normal constraint equations and relevant generator parameters (capacity, ramp rates, loss factors) from existing databases maintained by ROAM on a dispatch interval basis. This bidding scenario provides a benchmark of the 2-4-C modelling outcome against history. It is acknowledged that there are a number of dynamic system events which may not be captured with half-hourly trading interval modelling. The effects of five-minute dispatch intervals and 30-minute trading intervals (the 5/30 effect) results in very short term events being smoothed in the 30-minute trading interval modelling in which only $1/6^{th}$ of dispatch intervals are used. Additionally, generator ramp rates are not typically a limitation over a 30-minute interval. In this modelling, non-system normal transmission events and associated constraint equations are not captured. Generators attempt to extend periods of congestion by offering the minimum ramp rate allowed and rebidding capacity into lower price bands. These events have been captured to the extent possible based on the information provided in the YESTBIDS data.

Historical trading interval bidding with disorderly bidding removed

ROAM maintains a database of bid offers, prices, interconnector data and other pre-dispatch data. We have developed a system for analysing market events and pre-dispatch information to understand the behaviours which have led to unusual outcomes.

The approach used was to perform the backcast, but with the tendency for generation to bid disorderly because of constraints removed so as to model the effect of implementing Package 2. In order to do this, the complete set of pre-dispatch bids applying for the period 1 July 2008 to 30 June 2011 was obtained, and rebids referring to the occurrence of constraints were removed. The rebid reasons were examined in detail – reasons which mentioned a named constraint, an abbreviated or misspelled form of the word “constraint”, “binding” had the associated bids removed. This process did not remove rebids for constraints such as lightning, valve, pondage, plant, environmental, gas, fuel, coal or unit constraints, as these would not be expected to be associated with disorderly bidding. The objective of this approach is to determine the bid that would have been prevailing in a given period had the rebids relating to constraints not been applied.

The list of named constraints was developed by examining the rebid reasons and searching for four characters: the caret, the underscore, the greater-than sign, and the colon. In all AEMO constraint names, at least one of these characters is present. Some rebid reasons refer to a named constraint without the actual word “constraint” or “binding” and thus these rebid reasons needed to be considered as well.

Disorderly bidding is characterised by periods of observed rapid shifts of generator capacity between price bands. Of specific importance to this analysis is the movement towards lower price bands in order to maximise dispatch during periods of congestion. Therefore, disorderly bidding has only been removed if the rebid represented a movement towards lower price bands. The benefit of this approach is that it closely resembles the bidding that would be expected given the changes to market rules embodied under the congestion pricing mechanisms proposed under Packages 2 and 4.

An example of the result of this approach is provided in Figure 4.1 and Figure 4.2. These figures illustrate the rebidding of Bayswater on 7 December 2009.

Figure 4.1 – Bayswater – Actual Bids – 7 December 2009

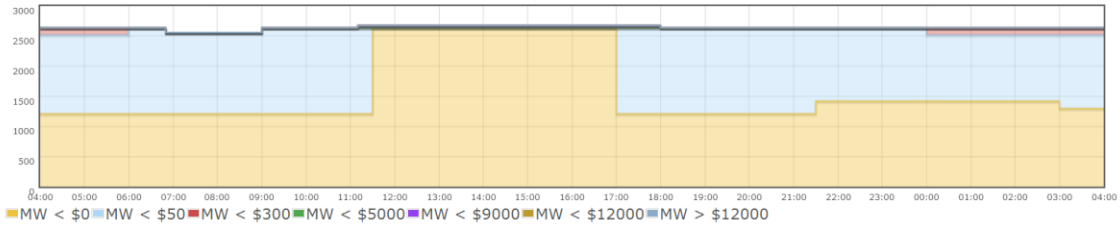


Figure 4.2 – Bayswater – Disorderly Bidding Removed – 7 December 2009

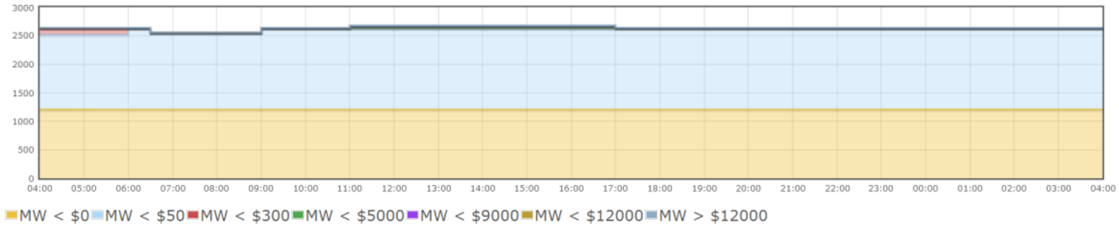


Figure 4.1 shows the bids for Bayswater which applied on the day.[15] Almost the entire capacity of Bayswater was bid at the market price floor between 11:30 am and 5:00 pm. This rebid to the floor is deemed to be disorderly bidding and has therefore been removed. A focus on the Bayswater 1 Unit (BW01) and the bids that would have applied between 1:00 and 1:30 pm provides a clear example of the disorderly bidding process. The bids that were supplied for this period are provided in Table 4.1. Only the first three bid bands were meaningful in this period, so the upper bid bands are not shown.

[15] Note that all bidding results are presented on a trading interval basis. The bid that applied in the final dispatch interval is used as representative of the trading interval.

Table 4.1 – Bayswater 1 Bids for 7 December 2009 1:00 pm					
Rebid Date and Time		**Band**			**Rebid Explanation**
		1	**2**	**3**	
	Price ($/MWh)	**-957.9**	**21.07**	**32.57**	
2/12/2009 11:44	**Load (MW)**	310	310	40	Original Bid
6/12/2009 15:03	**Load (MW)**	310	350	0	1450 ADJUSTMENTS DUE TO LD1
7/12/2009 06:45	**Load (MW)**	310	350	0	NIL CHANGE TO UNIT BID
7/12/2009 11:08	**Load (MW)**	310	350	0	1100 CONFIRMED OVERLOAD CAPABILITY
7/12/2009 11:25	**Load (MW)**	660	0	0	1120 CONSTRAINT MANAGEMENT
7/12/2009 11:39	**Load (MW)**	660	0	0	1135 CONSTRAINT MANAGEMENT

The final row of the above table shows the bid that applied at time of dispatch. The entire capacity of the unit was bidding at the floor. The process for removing disorderly bidding incorporated the information provided by each rebid for this period. The bid which applies in the disorderly bidding removed simulations is that bid which preceded the first rebid which referenced constraints. Therefore, the rebid which was supplied at 7/12/2009 11:08 am is used. i.e. the fourth bid offer for the 1:00 pm dispatch interval provided over the five days leading up to 7th December 2009. This rebid immediately preceded a rebid at 11:25 am which was deemed to constitute disorderly bidding, therefore the 11:25 am bid and all subsequent rebids are ignored. The other units of Bayswater exhibited similar bidding histories for this period.

Only rebids which represent a movement of capacity into lower bids bands are considered for removal. This eliminates the removal of bidding behaviour which would not necessarily be discouraged under a congestion pricing mechanism. For example, a generator downstream of a constraint may withhold capacity into higher price bands in an exploitation of transient pricing power. This behaviour would not necessarily change under the packages presented by the AEMC and has therefore not been removed from the backcast.

This analysis illustrates the application of the process to a particular generator. A more detailed analysis of the outcomes of this process is provided in subsequent sections of this report. A number of events, including the 7^{th} December 2009 event described above, have been the subject of greater interrogation. The impact of disorderly bidding on dispatch for a region as a whole has been presented. The impact of disorderly bidding on dispatch costs has been inferred from the differences in dispatch.

QP Bids

QP Bids[16] refers to generator bidding behaviour developed with ROAM's quadratic programming algorithm by analysing the historical relationship between dispatch and price for each generator. The QP Bids implicitly capture a level of contract cover, but do not capture instances of disorderly bidding[17]. QP bidding is considered well behaved. This scenario has been used to quantify the cost of supply under Package 2 compared with the abovementioned historical trading interval bidding with disorderly bidding removed. This provides a benchmark of the operation of the QP Bids outcomes which informs the relativity of the forecasting applied using this approach, described further in the forecasting section below.

QP Bids with disorderly bidding added

The QP Bids backcast is re-simulated with ROAM's disorderly bidding approach added. This method is used to simulate race-to-floor disorderly bidding behaviour in the forecast and is provided here as a benchmark of this process. The implementation of race-to-floor disorderly bidding is outlined in appendix section D.3).

4.1.3) Water Value

The removal of disorderly bidding can result in significant changes in the energy generated from hydro facilities. However, the NTNDP generator assumptions do not include water value in assessing the dispatch cost for hydro generation. Therefore, the

[16] Our QP (Quadratic Programming) algorithm derives an equivalent set of forward bids by analysing past bids, generation dispatch and market clearing prices for all generators to formulate a set of bids comprising up to ten bid bands for each generating unit, typically peak and off peak, that delivers the equivalent dispatch and pricing outcomes as history. This approach provides a means for forecasting the future, while capturing the essential bidding strategies of the past, including contractual positions. Further detail is provided in Appendix D).

[17] Instances of disorderly bidding are captured by the QP analysis; however, as such periods are generally transient their overall impact on the 'average' trading behaviour is very small, as they are rare compared with periods when disorderly bidding does not occur.

resulting cost of disorderly bidding can be misleading unless the water value is accounted for.

For example, a high level of hydro generation may be observed in a period in which hydro generators bid significant levels of capacity at low prices. If these bids are deemed to be disorderly they will be removed in the disorderly bidding removal process. Therefore, it is likely that hydro generation would be significantly lower after removing disorderly bidding. This may result in disorderly bidding appearing to decrease the cost of dispatch as hydro generation has a very low cost in the NTNDP assumptions. However, this approach neglects the fact that hydro generation is energy limited. Any additional generation that results from disorderly bidding must lead to a reduction in generation in some other period. This generation would need to be replaced with marginal thermal generation. This is problematic as the backcast does not impose energy limits on any generators.

To account for the value of differences in water usage, ROAM has used an approach which incorporates historical capacity factors and price durations. For example, a hydro generator may have a historical capacity factor of 10% in the three year backcast period. An additional MWh of generation during a period of disorderly bidding will result in one MWh reduction in generation in another period. ROAM has assumed this to occur at a regional price corresponding to the 10th percentile over the same three year period. The underlying assumption is that the reduction in hydro generation in this period is replaced by an additional MWh of the marginal generator at this price. It is also assumed that the price at this point corresponds to the short run marginal cost of the marginal generator. While the assumption of the price point corresponding to the 10th percentile may seem arbitrary, it is intended to be an even handed assumption that is neither biased towards an overly high value of water that would, if used, result in an overestimate of the benefits of removing disorderly bidding; nor an unrealistically low value of water that would underestimate the benefits of removing disorderly bidding. Hence the estimates we have provided should be regarded as an order of magnitude check of the impact of removing disorderly bidding rather than an attempt to ascribe high accuracy to an inherently uncertain calculation.

The water values used by ROAM in the backcast analysis are provided Table 4.2. It is acknowledged that this is a broad approximation and therefore, a range of sensitivities to these values have been assessed.

Table 4.2 – Water Values for Hydro Generation			
Station	**Water Value ($/MWh)**	**Station**	**Water Value ($/MWh)**
Barron Gorge	24.78	Liapootah	25.81
Bastyan	69.91	Mackintosh	27.18
Blowering	37.55	Meadowbank	28.27
Bogong / McKay Creek	48.25	Murray	37.34
Catagunya	25.81	Poatina	33.29
Cethana	26.04	Reece	28.29
Dartmouth	88.14	Shoalhaven	109.92
Devils Gate	25.89	Tarraleah	23.78
Eildon	59.11	Trevallyn	25.98
Fisher	24.70	Tribute	34.34
Gordon	45.28	Upper Tumut	36.80
Guthega	31.49	Lower Tumut	57.36
Hume	27.95	Tungatinah	29.14
John Butters	29.63	Wayatinah	25.81
Kareeya	20.87	West Kiewa	29.68
Lake Echo	46.65	Wilmot	30.30
Lemonthyme	25.42	Wivenhoe	85.13

4.2) Approach to the Forecast

For the forecast assessment of the alternative Packages 1, 2 and 4, ROAM has developed a multi-stage approach. As the first step, LTIRP was configured to model the impacts of the packages over the long term in relation to generation and transmission development outcomes. The LTIRP broadly captures all of the productive, allocative and dynamic efficiencies that may result from the alternative packages, but is unable to provide an assessment of the potential impact of transient congestion on generator behaviour because, being a least cost model, it cannot incorporate strategic bidding. To investigate the shorter term impacts of generator behaviour under the alternative packages, the 2-4-C dispatch and pricing model was then applied at a half-hourly time resolution, based on the investment outcomes from the LTIRP modelling. This multi-stage approach is explained in more detail below.

4.2.1) Applying the LTIRP

To minimise end effects[18] from significantly influencing the simulation result, the forecast period for the least cost expansion modelling is to 2039-40, and then only the development to 2029-30 is reported on in this report. This is an approach that is commonly used to eliminate 'end effects' resulting from decisions made in the last few years of a long term model.

There are several modes in which the LTIRP may be run, each of which is a 'least cost' model, but subject to different constraints. For this complete assessment we have configured the LTIRP in three alternative ways including:

(i) Co-optimise generation, inter- and intra-regional transmission;

(ii) Co-optimise generation and inter-regional transmission, with intra-regional transmission decided by the existing RIT-T methodology;

(iii) Co-optimise generation and inter-regional transmission, with intra-regional transmission decided by firm access.

As Package 2 does not expose generation development to intra-regional transmission costs, since these are fully recovered from end users, this implies that the generation and transmission development plan will be the same under the Package 1 and Package 2 frameworks, at least to the extent that can be identified quantitatively. In the Package 1 and 2 forecast, the LTIRP is configured as per point (ii) above. This configuration of the LTIRP for Package 1 and 2 is detailed in Appendix section A.2). In the Package 4 forecast the LTIRP is configured as per point (iii) above. This configuration of the LTIRP for Package 4 is detailed in Appendix section A.3). The model has also been applied in accordance with Point (i) above in order to provide a theoretical comparison with the market focussed packages of Point (ii) and Point (iii).

Establishing the zonal resolution

This modelling has been conducted at a zonal resolution level for generation options and transmission development requirements. Where meshes exist between zones, a DC load

[18] End effects are modelling artefacts whereby the model produces short-sighted investment decisions based on a limited modelling timeframe. An example of an end effect is avoiding high capital cost, low variable cost plant in favour of low capital cost, high variable cost plant to provide energy in the final years of the study period.

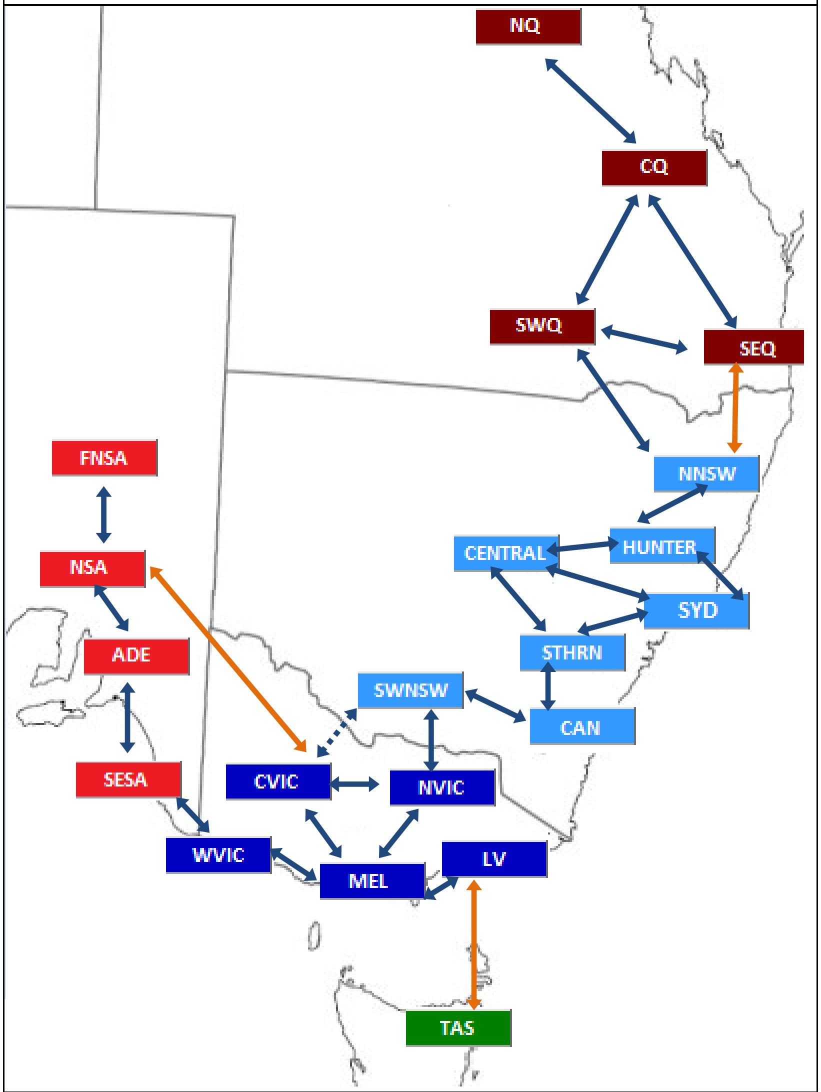
flow approximation[19] of the flows on the flowpaths has been implemented. The modelled configuration of the NEM is described in Table 4.3 and shown in Figure 4.3.

Table 4.3 – NEM Zones Modelled

Zone Name	Description
NQ	North of, and including Nebo
CQ	South of Nebo and North of (and including) Gladstone and Calvale
SWQ	West of Middle Ridge and Tarong
SEQ	South of Gladstone, South East of Tarong and Middle Ridge
NNSW	North of, and including, Tamworth
Hunter	South of Tamworth and north of Sydney
Central	West of Bayswater and Sydney, North of Bannaby
SYD	Sydney Metropolitan area
STHRN	South of Sydney, including Bannaby, Marulan and Kangaroo Valley
CAN	North of, and including, Canberra and South of Marulan
SWNSW	SWNSW Hydro and Wagga
NVIC	North East of South Morang
CVIC	All of Central and North West Victoria. Southern points at Ballarat
LV	East of Melbourne
MEL	Melbourne Metropolitan area
WVIC	West of Moorabool
SESA	South of Tailem Bend
ADE	West of Tailem Bend, South of and including Para
NSA	North of Para, South of Davenport
FNSA	North of and including Davenport. Includes Western Peninsula
TAS	All of Tasmania

[19] The DC load flow approximation has been derived from the impedance (susceptance) of all the lines making up each of the meshes, and provides a linear approximation to the full AC power flows that represent the network performance accurately, taking into account the nonlinear nature of power flows. The DC load flow approximation is also used in the NEMDE dispatch engine and the approach ROAM has adopted ensures that flows on each of the inter-zonal lines are reflective of the actual flows that would apply for each dispatch interval, to the desired accuracy needed for dispatch modelling.

Figure 4.3 – Zonal NEM Model and Flowpaths



Blue arrows signify the AC transmission lines between the zones of the NEM, while the orange arrows signify high voltage DC links. The physical link between SWNSW and CVIC is not explicitly modelled; its capacity is captured in the interconnector link between SWNSW and NVIC to simplify the DC load flow for the interconnector model.

Establishing zonal load distribution factors

Establishing the load expectation at each defined zone is of key importance. Maximum and minimum demands, as well as load shape within each zone are strong factors in determining the least cost size, type and timing of generation and transmission augmentations. The regional load has been distributed to the zones based on an analysis of the types of load present within each zone. The distribution of load to zones also changes over time to account for changes in industrial demand[20] and projected growth rates for the various zones within regions. The weightings are as follows, calculated based on a combination of analysis of published documents and load flow analysis of system snapshots published by AEMO.

Table 4.4 – Zonal Load Distributions Modelled as percentage of regional demands

Zone Name	2012-13		2029-30	
	Peak	Off-peak	Peak	Off-peak
NQ	9%	19%	8%	18%
CQ	21%	34%	19%	31%
SWQ	7%	7%	16%	15%
SEQ	63%	40%	57%	36%
NNSW	6%	4%	6%	4%
Hunter	19%	31%	19%	31%
Central	5%	7%	5%	7%
SYD	53%	39%	53%	39%
STHRN	6%	7%	6%	7%
CAN	6%	5%	6%	5%
SWNSW	5%	7%	5%	7%
NVIC	5%	6%	5%	6%
CVIC	8%	7%	8%	7%
LV	5%	6%	5%	6%
MEL	81%	80%	81%	80%
WVIC	1%	1%	1%	1%
SESA	6%	9%	5%	6%
ADE	71%	59%	59%	39%
NSA	12%	12%	10%	9%
FNSA	11%	20%	26%	46%
TAS	100%	100%	100%	100%

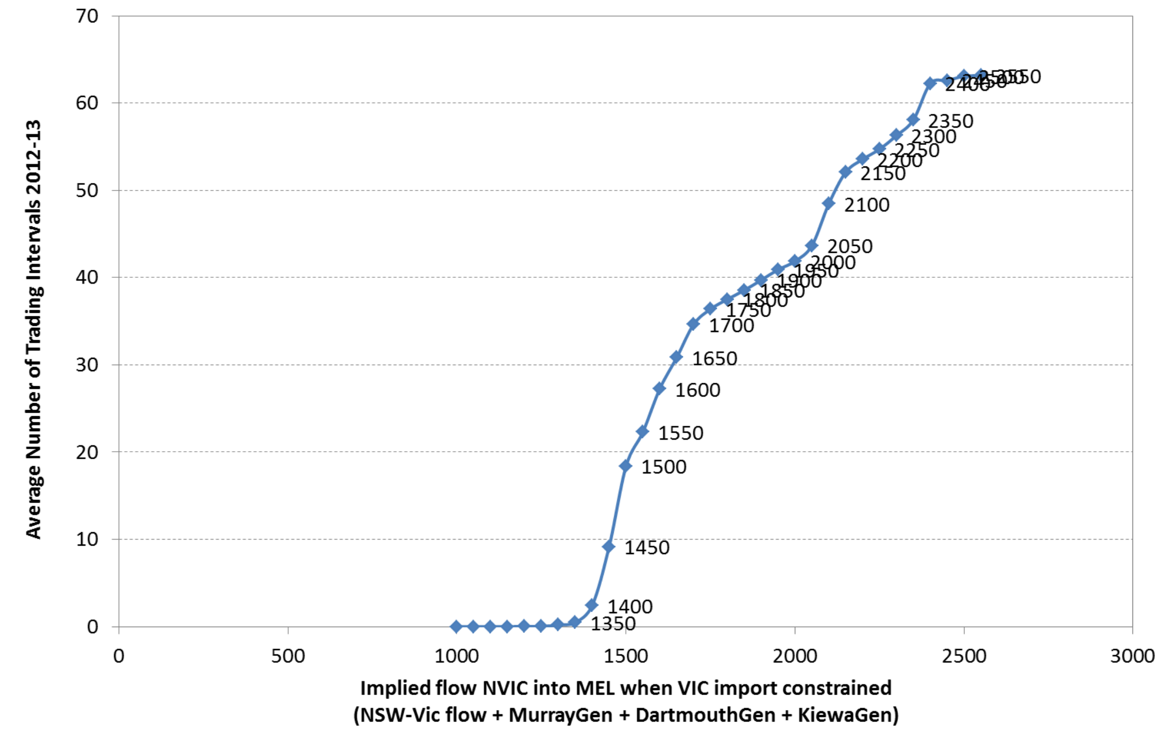
Establishing existing network limitations

The existing transmission capacity between zones has been determined through an assessment of constraint outcomes in dispatch modelling, moderated against a range of publicly available data sources. ROAM has developed approximately 800 system normal

[20] For example, the projected increases in gas extraction, pumping and compression demand in south-west Queensland.

thermal constraint equations which represent the thermal capacity of all transmission lines chosen to represent inter-zonal transfers. The methodology for development of thermal constraint equations is discussed in greater detail in Appendix A). ROAM has then performed dispatch modelling with this custom constraint set. The transmission capacities[21] used in the LTIRP modelling have been determined by observing the minimum transfer capacity between zones in 2-4-C during periods in which a constraint on that flowpath was binding. This method therefore captures the most onerous thermal transmission limit for each inter-zonal flowpath. For example, Figure 4.4 presents an analysis of the implied transmission limit between NVIC and MEL based on a forecast assessment for the 2012-13 year. The figure illustrates the number of trading intervals that were found to be a limitation on imports into MEL based on the VIC-NSW interconnector flow and the dispatch of the Murray, Dartmouth and Kiewa power stations. This shows that the constraint analysis determines that a limit on flow between NVIC and MEL occurs from as low as 1400MW. Higher limits may be achieved at times of favourable dispatch conditions and higher thermal ratings during lower ambient temperatures.

Figure 4.4 – Estimated transmission limit from dispatch analysis



[21] These are also referred to as transmission limits.

It is acknowledged that in the Australian NEM there are a range of voltage and transient stability limits that may prevent the network from operating up to its thermal limitations. Where such stability limits exist and are a material factor they have been accounted for through a reduction in the thermal limit.

The transmission line transfer limits and distance between intra-regional zones applied in the model are shown in the table below[22].

Table 4.5 – LTIRP Transmission Line Transfer Limits and distance between zones

Link Name	From	To	Transmission Limit (Forward / Reverse) [MW]	Distance between Zones [km]
QNI	NNSW	SWQ	486 / 1078	415
Terranora	NNSW	SEQ	105 / 234	375
VIC_NSW	NVIC	SWNSW	1500 / 1500	150
Basslink	TAS	LV	594 / 469	320
Heywood	WVIC	SESA	460 / 460	125
Murraylink	CVIC	NSA	220 / 220	150
NQ to CQ	NQ	CQ	1501 / 1501	600
CQ to SEQ	CQ	SEQ	1421 / 1421	500
CQ to SWQ	CQ	SWQ	1313 / 1313	385
SWQ to SEQ	SWQ	SEQ	5288 / 5288	130
NNSW to Hunter	NNSW	Hunter	929 / 929	220
Hunter to SYD	Hunter	SYD	5033 / 5033	155
Hunter to Central	Hunter	Central	3394 / 3394	140
Central to SYD	Central	SYD	1425 / 1425	105
STHRN to Central	STHRN	Central	3394 / 3394	140
STHRN to SYD	STHRN	SYD	2109 / 2109	120
CAN to STHRN	CAN	STHRN	2304 / 2304	115
SWNSW to CAN	SWNSW	CAN	2022 / 2022	85
NVIC to MEL	NVIC	MEL	1422 / 1422	216
NVIC to CVIC	NVIC	CVIC	284 / 284	490

[22] The inter-regional limits are consistent with those used by AEMO in a wide range of modelling work, including marginal loss factor forecasts. See Section 3.16 of: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/~/media/Files/Other/loss%20factors/MLF_2012_13_Main_Report_16_MLf.ashx

Table 4.5 – LTIRP Transmission Line Transfer Limits and distance between zones				
Link Name	**From**	**To**	**Transmission Limit (Forward / Reverse) [MW]**	**Distance between Zones [km]**
LV to MEL	LV	MEL	8907 / 8907	136
MEL to WVIC	MEL	WVIC	2011 / 2011	300
MEL to CVIC	MEL	CVIC	542 / 542	450
SESA to ADE	SESA	ADE	547 / 547	380
ADE to NSA	ADE	NSA	537 / 537	100
NSA to FNSA	NSA	FNSA	493 / 493	200

Establishing the Firm Access Allocation for Incumbent Generation

ROAM has evaluated a level of firm access for existing generation and interconnectors which is commensurate with the level of effective firm access under the current market conditions. The AEMC has advised that preference will be given to generation over interconnectors in the allocation of firm access in the event of adoption of Package 4. The proposed Firm Access Standard (FAS) suggests that firm access should be provided to generators purchasing firm access at all times when the transmission system is fully available.

In the modelling, generation is allowed to procure either peak or off-peak firm access. The off-peak firm access applies to all periods and requires that all off-peak firm access generation must be dispatchable at all times. Therefore, the off-peak firm access is based on the assumption that load at local zones upstream of a given flowpath is at the minimum. Peak firm access adds to the volume of generation that is required to be dispatchable but uses a more relaxed assumption with respect to local demand.[23]

In the allocation of firm access to incumbent generation, open cycle gas fired generation technologies has been allocated peak firm access only, with all other generation allocated off-peak access. Off-peak access also implies peak access. The conditions that have been used in applying the FAS are as follows:

[23] The assumed level of demand in the peak-firm access is approximately the 25th percentile for each zone in a given year. The LTIRP is not a time-sequential model and therefore cannot specify a time of day that is assumed to comprise peak periods.

- All support generation not dispatched. i.e. generation that supports a higher flow is not dispatched;
- Minimum load at the local zone and other zones in the flowpath towards the reference node for off-peak firm access;
- A moderate level of local load has been used for peak-firm access;
- Maximum generation from all upstream generation competing for the flowpath towards the reference node.

Approach applied in modelling

ROAM has used an approach whereby the maximum access has been allocated to generation on the condition that this does not result in an immediate need for any transmission augmentations. This analysis incorporates the level of generation at each node, the regional demand observed in each zone, the capacity of existing transmission and the DC load flow approximation. Firm access has been allocated up to the point where the FAS operating in either peak or off-peak periods would require immediate transmission investment. Where the existing network is insufficient to provide for 100% firm access to generators at a given zone, or collection of zones, the proportional available level of firm access has been allocated to all affected generators equally. i.e. if there is 100MW of generation upstream of a 70MW limit, then all generators would be allocated a firm access level which is 70% of the generators capacity.

After all generation has been allocated its maximum level of firm access, any spare capacity has been allocated to interconnectors. Any generation which is located at the reference node is assumed to have 100% firm access. The resulting initial level of firm access on the basis of this assessment is presented in Table 4.6 below. Note that the percentage allocation of peak and off-peak firm access is consistent in each zone. This is due to the assertion that off-peak generation will want at least the same level of access at peak times. As such, depending on the balance of demand and generation capacities within each zone it may be that transmission limitations result in either peak or off-peak access being the binding constraint. A peak access limitation will be reflected in off-peak firm access availability, and vice-versa.

Table 4.6 – Zonal Initial Firm Access				
Zone Name	**Off-peak Generation (MW)**	**Off-peak Firm Access (%)**	**Peak Generation[24] (MW)**	**Peak Firm Access (%)**
NQ	571	84%	1023	84%
CQ	4853	84%	4853	84%
SWQ	4213	87%	5583	87%
SEQ	885	100%	885	100%
NNSW	0	100%	0	100%
Hunter	9088	93%	9802	93%
Central	2320	55%	2320	55%
SYD	176	100%	176	100%
STHRN	650	76%	650	76%
CAN	326	76%	326	76%
SWNSW	2254	76%	2918	76%
NVIC	2140	82%	2140	82%
CVIC	245	100%	245	100%
LV	6545	100%	7420	100%
MEL	160	100%	1132	100%
WVIC	585	100%	1135	100%
SESA	325	100%	446	100%
ADE	658	100%	2211	100%
NSA	710	50%	1026	50%
FNSA	880	50%	937	50%
TAS[25]	2497	100%	2660	100%
Basslink [LV]	594	100%	594	100%
Basslink [TAS]	469	100%	469	100%
QNI (QLD) [SWQ]	486	0%	486	0%
QNI (NSW) [NNSW]	1078	0%	1078	0%
Terranora (QLD) [SEQ]	105	100%	105	100%
Terranora (NSW) [NNSW]	234	0%	234	0%
VIC-NSW (NSW) [SWNSW]	1500	0%	1500	0%
VIC-NSW (VIC) [NVIC]	1500	0%	1500	0%
Heywood (VIC) [WVIC]	460	100%	460	100%
Heywood (SA) [SESA]	460	47%	460	47%
Murraylink (VIC) [CVIC]	220	0%	220	0%
Murraylink (VIC) [NSA]	220	0%	220	0%

[24] Peak generation is inclusive of generation with both off-peak and peak firm access.

[25] The Tasmania region is treated as a single zone in the modelling and therefore it is implied that all generation can be dispatched to meet demand at the reference node.

In relation to the modelling of Package 4, the initial level of firm access applied for existing generation is not in itself a significant factor. However, this setting may be a cause for difference between the modelling of the alternative packages. This is discussed further in the modelling outcomes section below.

Establishing the Firm Access Allocation for New Entrant Generation and interconnector augmentation

ROAM has configured the LTIRP with a range of assumed levels of firm access purchased by each new entrant generation technology[26]. The assumed percentage of firm access purchased by each new entrant technology has been varied to assess the level of firm access expected to be sought by new entrant generation[27]. This analysis involves both a quantitative analysis of the resulting generation and transmission development and a qualitative assessment of the benefits of firm access for new entrant generation technologies. The firm access cases for new entrant generation and interconnector augmentations are listed in Table 4.7. The generation types assessed are by far the dominant forecast new entrants in the next 20 years, and provide a wide range of operating characteristics from extreme peaking to base load operation. All new entrant OCGT is assumed to procure peak firm access. All other technologies are required to purchase off-peak firm access.

The level of firm access assigned to interconnector augmentations will be driven by market participants based on their own valuation of interregional trading. Interconnector upgrades have been allocated a 50% firm access to each reference node to provide a mid-point for this aspect of the FAS. A sensitivity case to this assumption has been completed and shown to result in a relatively small change in the total system cost[28].

[26] The new entrant technologies listed are those that, based on LTIRP modelling, are expected to dominate, based on present market rules and forecast technology cost trends. New solar technologies are intermittent and show similar characteristics during the daytime to wind, and therefore would be expected to have similar outcomes to that of wind. More detailed modelling of alternative technologies may be of benefit in the future if the pace of technology development changes.

[27] The level of firm access of each generator is a decision of the generator, considering its market position. The OFA model cannot be implemented directly in the linear program optimisation to compute the level of firm access that would be chosen by different types of existing and future generation as this is a non-linear problem. Therefore the model was run many times, choosing different combinations of firm access for different generators to assess the change in the overall cost of supply

[28] It is recommended that further investigation into the level of firm interconnector access be undertaken if participants believe this to be a material factor.

Table 4.7 – New Entrant Firm Access Cases				
Case	**Wind**	**OCGT**	**CCGT**	**New ICs**
1	100%	100%	100%	50%
2	60%	100%	100%	50%
3	30%	100%	100%	50%
4	60%	60%	100%	50%
5	60%	100%	60%	50%
6	60%	60%	60%	50%
7	30%	100%	60%	50%
8[29]	**30%**	**90%**	**60%**	**50%**
No FA	0%	0%	0%	0%

Establishing a mechanism for incumbent generation to procure an alternative level of firm access

The AEMC has proposed that the level of firm access allocated to incumbent generation will be sculpted over time. ROAM has therefore implemented the ability for each generator to transition to an alternative firm access level. These transitions have been included where they are observed to result in a movement towards a lower cost outcome. The methodology behind this process is discussed in greater detail in subsequent sections of this report.

Assessing the Relationship between Generation and Transmission

Further sensitivities have been performed to determine the relationship between the total cost of transmission and generation. The LTIRP can be coerced into developing more transmission by increasing the level of firm access required by new entrant generation. In cases where the level of firm access is very high, the level of transmission built will exceed the amount required to deliver a low cost outcome.

Similarly, low transmission development plans can be determined by assuming that no new entrant generation desires firm access. In this case, only transmission required to meet the reliability standard will be developed and the total cost of the system will exceed the cost delivered by some optimum level of transmission because the generation built will not be consistent with the lowest system cost.

[29] Scenario 8 has been selected for the comparative analysis presented in the modelling outcomes.

The resulting generation and transmission developments of these sensitivities have been analysed to determine the total cost at a range of firm access levels.

4.2.2) Market Time Sequential Dispatch Modelling

Following the LTIRP modelling, the resulting new entrant generation and transmission build program has been transferred from the LTIRP to the 2-4-C time sequential model. The NEM was then simulated to 2030 for each of Package 1, 2 and 4, taking into account potential types of disorderly bidding behaviour.

In all forecasting, ROAM has simulated a large number of Monte Carlo iterations as generator outage patterns in the future are unknown. This provides both an expectation of future costs and a guide to the range of costs, allowing ROAM to assess volatility of prices where applicable. ROAM has also simulated two levels of demand: the 10% PoE (Probability of Exceedence) and 50% PoE demand cases for the respective economic energy growth outlook for each scenario (high and medium). ROAM has developed the evolving constraint equations to represent the transmission development plan over the duration of the outlook based on the LTIRP outcomes for the alternative packages.

Package 1 and 2 have been initially simulated using historical bidding profiles, derived from our customised QP Bids methodology. This delivers the proportion of intervals when disorderly bidding *could* occur, and thus provides a realistic estimate of the proportion of time that Package 1 and 2 *could* diverge. We have then implemented disorderly bidding for those periods to assess the outcomes, with and without disorderly bidding.

The presence of a congestion pricing mechanism under Package 2 and optional firm access under Package 4 is intended to reduce the incentive for generators to bid disorderly, and accordingly the bidding for the Package 2 and Package 4 simulations do not incorporate disorderly bidding.

Transmission development associated with the development of new entrant capacity *with* optional firm access is incorporated into the representation of the network in the 2-4-C modelling, through the expansion of constraint equations. This also applies to upgrades of interconnectors identified in the LTIRP.

When assessing generator revenues, the impact of congestion has been considered. Under the Package 2 arrangements compensation payments have been evaluated based on the proposed rules for the package. Under Package 4, those generators that have entered into firm access agreements will be assured of not being impacted by congestion, either through not being constrained, or through compensation payable by generators without firm access. Those generators without firm access agreements will either be impacted by congestion or will have to pay compensation for causing congestion, according to the rules of Package 4.

QP Bids

This scenario has been used to develop an estimated cost of supply for Package 2 and Package 4. It is acknowledged that participants have suggested that under Package 2 and Package 4 there may be new types of disorderly bidding that may replace the inefficiencies which may occur under the existing Package 1 framework. These potential events have not been reported on in this assessment.

QP Bids with disorderly bidding added

This scenario is used to develop an estimated cost of supply for Package 1. Race-to-floor disorderly bidding is implemented as described for the backcast.

Water Value

Water values have been calculated for use in the forecast using a methodology consistent with that described in Section 4.1.3).

Assessing Willingness to Contract

An assessment of the willingness for generators to contract has been completed based on a net revenue certainty principle. In this assessment a sensitivity study has been completed to analyse the net revenue that a firm and non-firm generator may expect to receive under varying levels of contract cover.

Evaluating the impact of transmission outages

Various submissions to the transmission frameworks review, but in particular, by Origin Energy, suggest that a significant proportion of disorderly bidding and market inefficiencies occur during periods of planned or unplanned network outages. Accordingly, the modelling has attempted to capture the impact of these events, even though they may be quite rare considering the low forced outage rates of each individual transmission element.

In order to assess the potential impact on productive efficiency of network outages ROAM has undertaken the following modelling investigations:

1. Identifying a representative network outage condition within each region of the NEM;
2. Modelling the NEM for each of the network outage conditions identified below in force for the full 2012-13 to 2029-30 study period;
3. Modelling with both QP Bids and QP Bids with disorderly bidding incorporated, which inherently captures the higher incidence of disorderly bidding expected in a system with a higher level of congestion;
4. Determining the change in system variable costs over the forecast period comparing the alternative bidding scenarios;
5. Estimating the probability of the network being in an outage state;
6. Determining the additional system variable cost that may be attributable to network outage conditions by multiplying the probability of the network being in an outage state by the increased annual system variable cost evaluated in step 4.

The lines chosen to model the network outage condition in each region are:

- Queensland: Tarong to Blackwall
- New South Wales: Yass to Bannaby
- Victoria: Hazelwood to Rowville
- South Australia: Davenport to Bungama.

Each of these lines is a major flow path on an intra-connector in the region where it is located.

5) Backcast Outcomes

5.1) Backcast Scenarios

The key quantitative outcomes of the backcast modelling are provided in Table 5.1 without water values and Table 5.2 with water values. A full suite of outcomes for the modelling undertaken is included. The key finding for the transmission frameworks review is the efficiency gain from removing disorderly bidding, which forms the remainder of the discussion of this chapter. This is summarised in the column titled ‘Package 2’, which states the saving in costs from removing disorderly bidding on an annual basis.

Table 5.1 – Backcast of Total Market Variable Costs ($m) – Without Water Values[30]

	Historical Bids			QP Bids	
	Package 1	Package 2		Package 1	Package 2
Year	Actual historical outcomes	Backcast with historical bids	Cost of Disorderly Bidding	Backcast with QP bids disorderly bidding added	Cost of Disorderly Bidding (QP)
2008-09	**2955.4**	2951.1	0.5	2883.4	0
2009-10	**2965.9**	2962.4	1.9	2877.7	0.1
2010-11	**2865.2**	2860.3	14.3	2785.0	0

[30] The outcomes of the table are intended to be interpreted as follows:

- *Actual historical outcomes* are the baseline for the back-casting exercise;
- *Backcast with historical bids* provides a modelling baseline to illustrate how well the 2-4-C model may replicate the events of the past, including the effects of disorderly bidding;
- *Cost of Disorderly Bidding* provides the primary measure for the potential improvement in productive efficiency on the basis that Package 2 fully incentivises generators not to exercise disorderly bidding when compared against the *Backcast with historical bids* case.
- *Backcast with QP Bids, disorderly bidding added* provides a benchmark of the total system variable costs under this generator bidding approach when compared with the *Backcast with historical bids* case. This indicates the potential absolute difference in total system variable costs that may be presented in the modelling. However, it is the difference in costs with and without the effects of disorderly bidding that is the focus of the forecasting exercise.
- *Cost of Disorderly Bidding (QP)* provides the primary measure for the potential improvement in productive efficiency on the basis that Package 2 fully incentivises generators not to exercise disorderly bidding when applying the QP bidding methodology.

Table 5.2 – Backcast of Total Market Variable Costs ($m) – With Water Values					
	Historical Bids			QP Bids	
	Package 1	Package 2		Package 1	Package 2
Year	Actual historical outcomes	Backcast with historical bids	Cost of Disorderly Bidding	Backcast with QP bids disorderly bidding added	Cost of Disorderly Bidding
2008-09	**3260.0**	3236.0	2.9	3142.2	0
2009-10	**3307.5**	3293.0	3.5	3178.6	0
2010-11	**3291.8**	3274.4	14.9	3169.3	0

Performance of the ROAM Backcast

The ROAM backcast of historical bids is shown to accurately model observed market outcomes. The projection of total market variable cost is within 0.3% of the historical value without water values and 0.8% with water values. Some differences occur as a result of factors such as ramp rates and transmission outages and their effect on constraint equations.

Impact of Disorderly Bidding on Dispatch Efficiency

The impact of disorderly bidding is examined in greater detail in Section 5.2). In summary, Table 5.1 shows that the cost of disorderly bidding is approximately 16.7 million dollars over the three year period (without applying a water value). This cost increases to over 21 million dollars when the appropriate water value is applied. Disorderly bidding results in a higher cost of dispatch in each year. The most significant impact is observed in the 2010-11 financial year. **The results presented in the following sections incorporate the application of a water value.**

The outcomes show that the backcast with QP bids has the same total market variable cost outcome with and without applying the disorderly bidding implementation, to the accuracy of $100,000 per annum. This suggests that under intact transmission and well behaved system conditions the incidence and severity of disorderly bidding is very small, under the implementation of disorderly bidding developed for this assessment. The magnitude of dispatch changes in the disorderly bidding case results in dispatch costs increasing by only $50,000 per annum. This shows that historical disorderly bidding is observed to be due primarily to non-system normal transmission conditions. As such, the forecasts of the cost of disorderly bidding that is presented in the following sections should be considered a lower bound, in the absence of non-system normal transmission conditions, which are discussed separately.

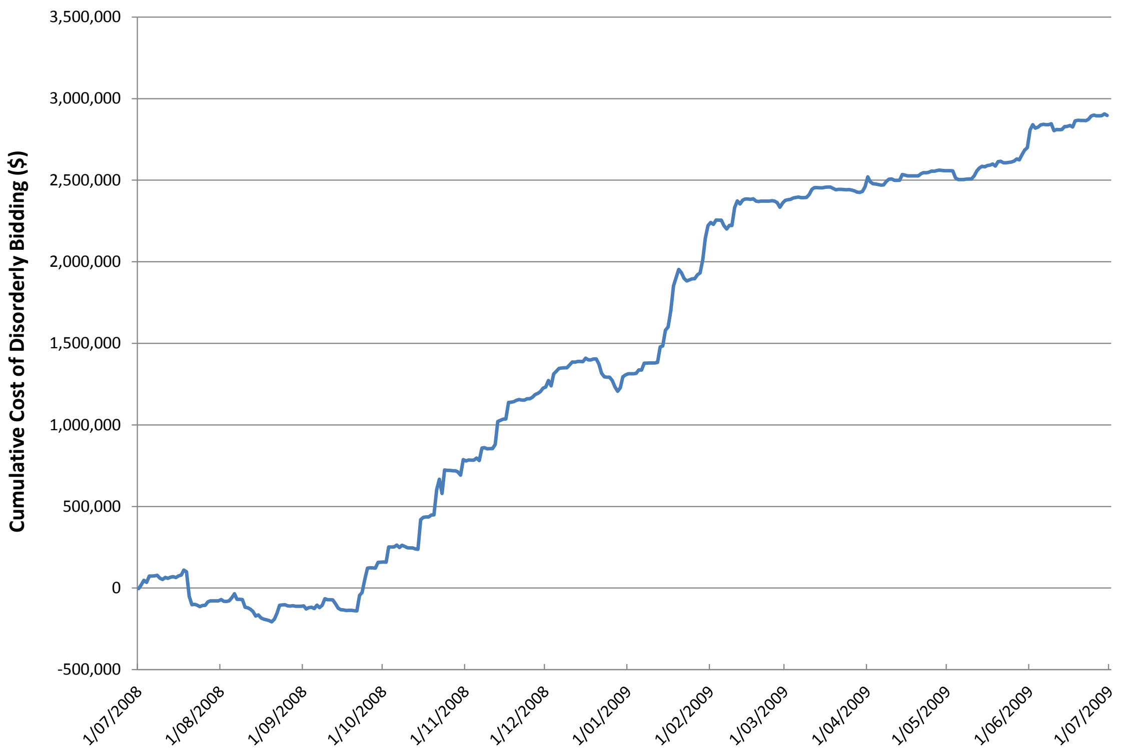
5.2) ANALYSIS OF DISORDERLY BIDDING

5.2.1) 2008-09 Financial Year

The 2008-09 financial year did not exhibit large scale disorderly bidding events such as those which have been observed in the 2009-10 financial year, although there are a considerable number of smaller events. The cost of disorderly bidding was the lowest of the three years modelled in this analysis. The cost of disorderly bidding was estimated to be 2.9 million dollars.

The following figure illustrates the impact of disorderly bidding over time. Note that a positive value represents a decrease in the cost of production resulting from the removal of disorderly bidding.

Figure 5.1 – Cumulative Cost of Disorderly Bidding – 2008-09



21 October 2008

The 21st of October provides an example of the impact of a localised transmission constraint. Specifically, Jeeralang B engaged in disorderly bidding as a result of an intra-regional constraint. Figure 5.2 shows the historical bids which applied for Jeeralang B. The results of the disorderly bidding removal process are provided in Figure 5.3. It is evident from these figures that the capacity of Jeeralang B has moved from bids between $0/MWh and $10,000/MWh to below $0/MWh between 10:00 am and 8:00 pm.

Figure 5.2 – Jeeralang B – Actual Bids – 21 October 2008

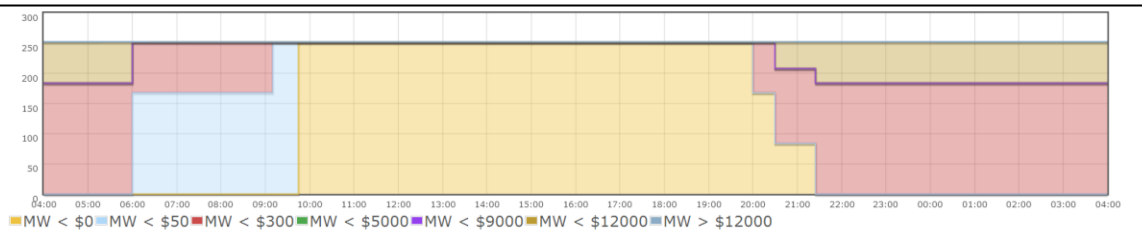
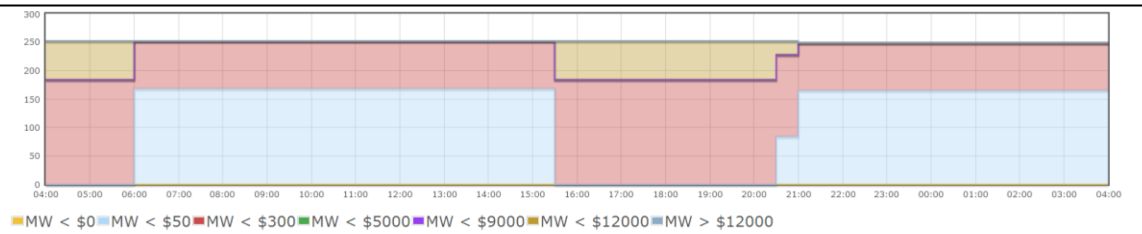


Figure 5.3 – Jeeralang B – Disorderly Bidding Removed – 21 October 2008



An analysis of the critical bids relating to the unit 'JLB01' for 21 October 3:00 pm is provided in Table 5.3. The bid applied in the historical database is for the entire capacity at the market floor price. However, given that this rebid was a response to congestion (VIC INTRA REG CON), this rebid has been removed in the sensitivity study. Therefore, the bid prevailing in the backcast with disorderly bidding removed is the last bid made before this disorderly rebid. Therefore, capacity in this backcast is withheld to almost $300/MWh. Similar bidding histories are observed for the other units of Jeeralang B.

Table 5.3 – Jeeralang B Unit 1 Bids for 21 October 2008 3:00 pm						
Rebid Date and Time		**Band**				**Rebid Explanation**
		1	**2**	**7**	**10**	
	Price ($/MWh)	**-962.6**	**0.72**	**279.88**	**9625.76**	
20/10/2008 10:52	**Load (MW)**	0	81	0	0	Original Bid
20/10/2008 19:19	**Load (MW)**	0	0	60	24	BAND ADJ DUE TO PD MARKET CONDITIONS @ 19:19
21/10/2008 9:24	**Load (MW)**	84	0	0	0	BAND ADJ DUE TO VIC INTRA REG CON @ 09:23

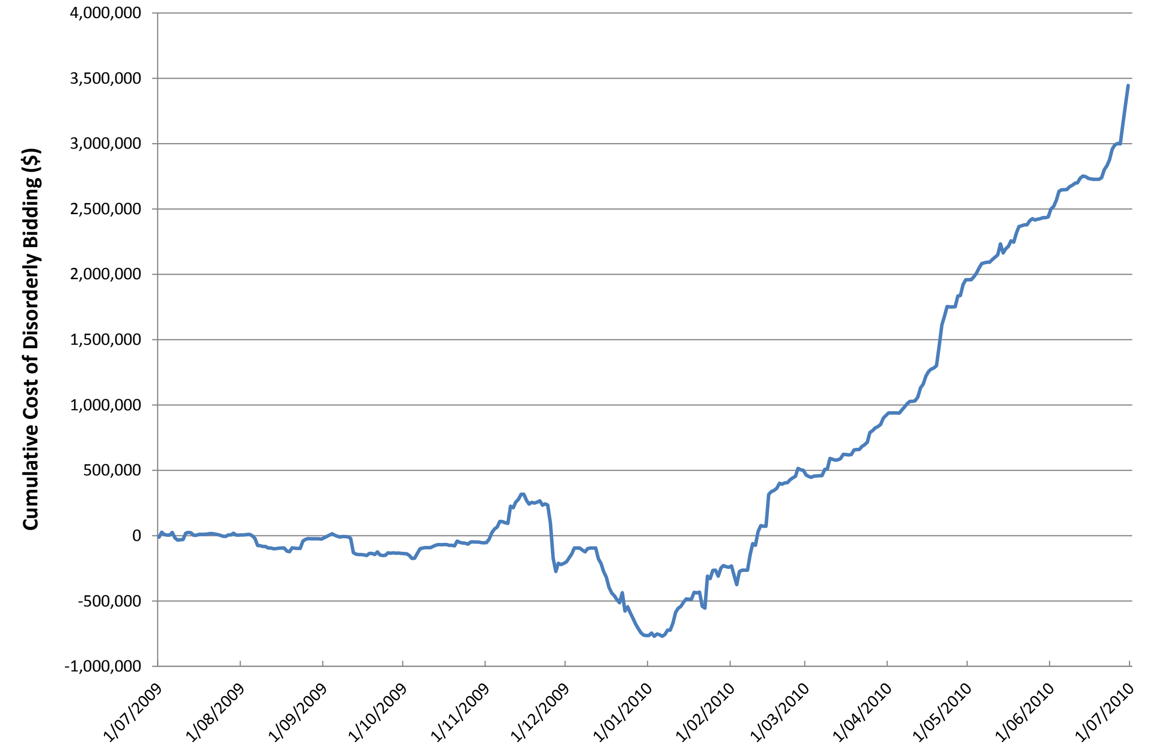
As a result, Jeeralang B's dispatch was significantly reduced after the removal of disorderly bidding. This generation was replaced by increased dispatch at a range of units throughout the NEM. Jeeralang B's SRMC is reasonably high at over $70/MWh. Consequently, the removal of disorderly bidding leads to a reduction in system costs. During this event, system costs were reduced by approximately $20,000/hour after Jeeralang B's disorderly bid was removed.

5.2.2) 2009-10 Financial Year

The cost of disorderly bidding observed in 2009-10 was comparable with that observed in 2008-09. However, there were numerous events which exhibited large volumes of capacity engaging in disorderly bidding. Some of these events are examined in greater detail in this section. The cost of disorderly bidding was approximately 3.5 million dollars.

The cumulative cost differences are presented in Figure 5.4.

Figure 5.4 – Cumulative Cost of Disorderly Bidding – 2009-10



7 December 2009

This period is well documented as an event where disorderly bidding occurred throughout New South Wales. Results are presented here to demonstrate the ability of the backcast to identify and remove disorderly bidding. The primary constraint which triggered this event involved congestion between Mt Piper and Wallerawang. The bid stack for all NSW generators is presented in the following figures.

Figure 5.5 – New South Wales – Actual Bids – 7 December 2009

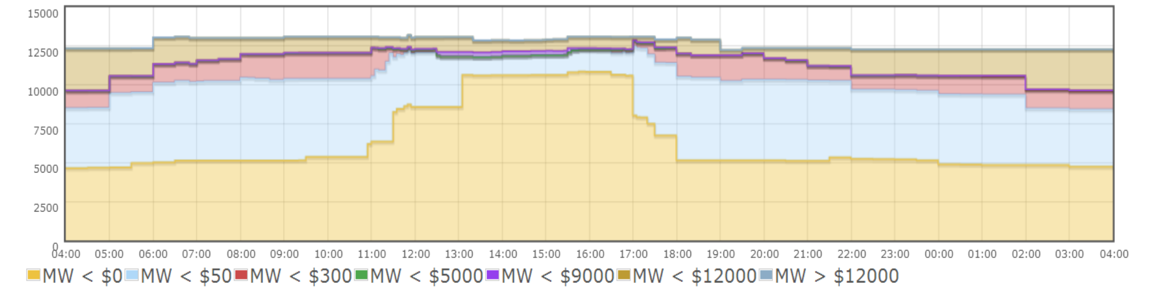
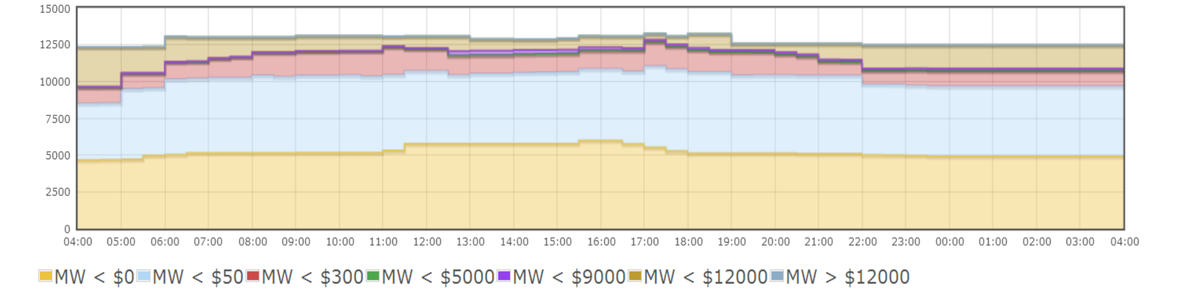


Figure 5.6 – New South Wales – Disorderly Bidding Removed – 7 December 2009



It is evident that the disorderly bidding removal process has eliminated the majority of the race to floor rebids. Rebids were observed to be removed for a number of generators such as Tumut, Mt Piper and Bayswater.

The disorderly bidding removal process is a systematic and automated procedure. As a result, some disorderly bids were found to be "missed" by the procedure. This was found to be the case for Uranquinty which made a rebid earlier in the day. This rebid involved moving capacity to both the market floor price and $0/MWh price bands. The reason quoted in the rebid information was "0900 EST (N) CHANGE IN PDS". Later rebids did mention constraint management. However, after the removal of disorderly bidding, the prevailing bid could still potentially be characterised as "disorderly". However, this omission may also be considered a strength of the disorderly bidding removal process. The 7 December 2009 was also characterised by extreme temperatures and high New South Wales pool prices. Therefore, the rebid by Uranquinty (from all capacity withheld to high prices to all capacity at low prices) may have been the outcome even if no congestion had occurred.

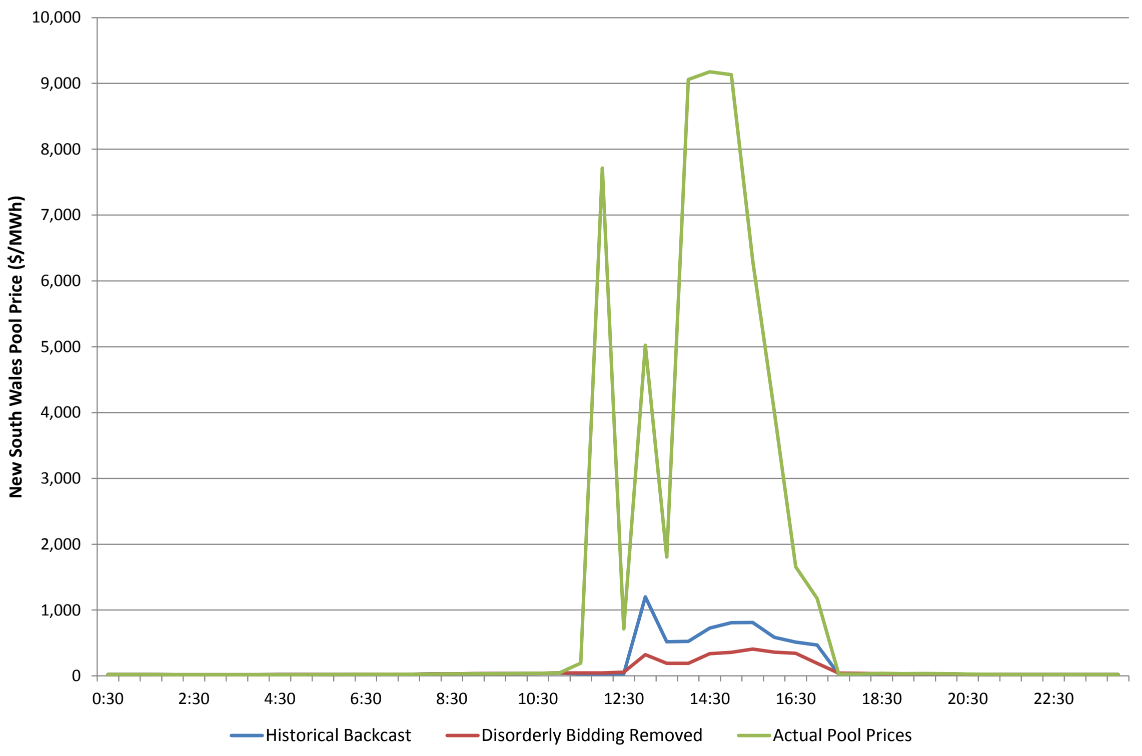
Similarly, the withholding of capacity by Wallerawang is not adjusted in the disorderly bidding simulation. Wallerawang was downstream of the constraint and was able to use its resulting transient pricing power to increase pool prices and therefore portfolio revenues. This behaviour would still have been a feasible outcome under a congestion pricing mechanism which does not result in compensation of payments for constrained on generation. Therefore, the incentives for generators to exercise transient pricing power which results from congestion would not necessarily be impacted.

A limitation of the disorderly bidding removal methodology, as applied in the backcast, is that the effects of ramp rate rebids are not incorporated. These limitations tend to increase the duration and impact of disorderly bidding events. As a result, the magnitude of the impact of disorderly bidding may be underestimated.

Despite the large changes in dispatch which occurred, the net impact of disorderly bidding on dispatch cost was found to be a small proportion of total dispatch cost over this period. This is not surprising since the reduction in dispatch at Bayswater and Tumut which resulted from the removal of disorderly bidding was balanced by an increase in the dispatch of a wide variety of generators across the NEM. This period is illustrative of the ability for disorderly bidding to be significant in terms of dispatch volumes but not to the same degree on dispatch costs. This is driven by the similarity in costs between many generators in the NEM and will be discussed in greater detail in the context of the forecast results.

The historical bids backcast did not capture the extreme peaks in pool price that were observed in history. This is a result of small differences between the databases such as the constraint equations which are applied. At high prices, only minor differences are required to cause large differences in pool prices. However, pool prices in the backcast exceeded $1,000/MWh and followed a similar trend to those observed in history. Figure 5.7 shows the New South Wales pool prices in the two backcasts for this day compared with history.

Figure 5.7 – New South Wales Pool Price ($/MWh) – 7 December 2009



Although the historical backcast was not able to capture the super peak pool prices observed in history, pool prices were considerably higher than they otherwise would have been because of disorderly bidding. This accounted for an increase in total market settlements over the day in excess of 20 million dollars (approximately a 94% increase). This value represents a wealth transfer rather than a loss of economic efficiency. The focus of the backcast analysis has been to find the cost of disorderly bidding with respect to dispatch costs rather than its impact on individual market participants.

15 February 2010

This period has been chosen to demonstrate the comparatively large impact that a single disorderly bidding event can have on dispatch costs. Mt Stuart bid its entire capacity at the market floor price in a number of periods throughout the day. The bid stacks for Mt Stuart are presented below.

Figure 5.8 – Mt Stuart – Actual Bids – 15 February 2010

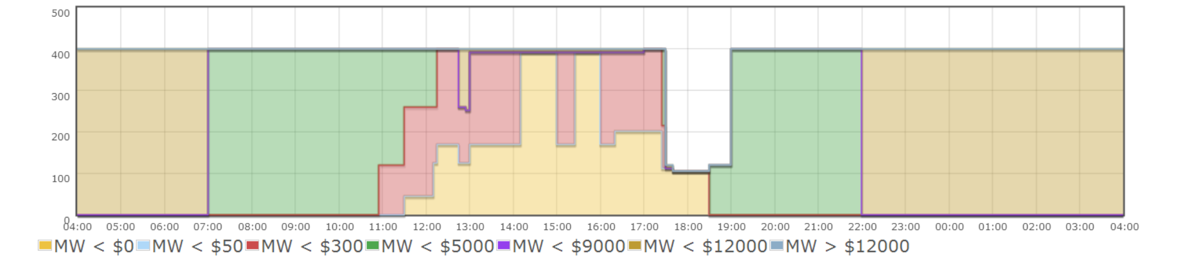
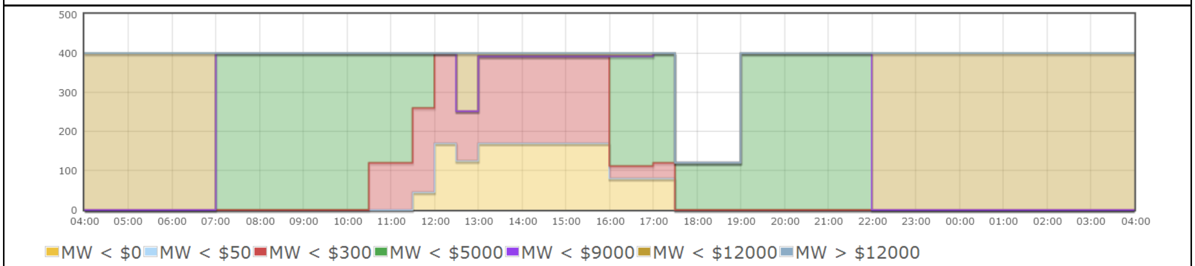


Figure 5.9 – Mt Stuart – Disorderly Bidding Removed – 15 February 2010



The bids for Mt Stuart at 4:00 pm have been analysed in greater detail. The outcomes are presented in Table 5.4. The bids of each unit have been combined and summarised.

Table 5.4 – Mt Stuart Bids for 15 February 2010 4:00 pm

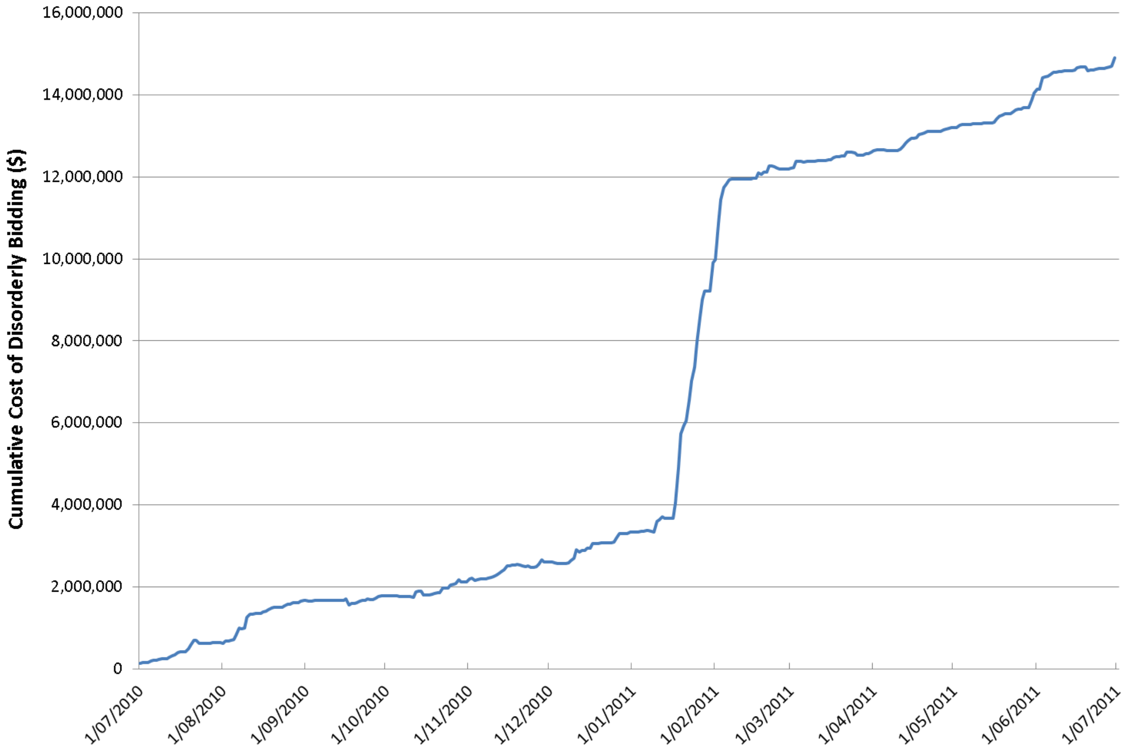
Rebid Date and Time		Band 1	Band 6	Band 7	Band 8	Band 9	Rebid Explanation
	Price ($/MWh)	-1032.1	104.71	246	450	9100	
14/02/2010 10:53	Load (MW)	0	0	0	400	0	Original Bid
15/02/2010 14:30	Load (MW)	170	95	127	0	8	Various Rebid Explanations not involving constraints
15/02/2010 15:20	Load (MW)	360	0	32	0	8	CONSTRAINT MANAGEMENT - SL

The final bid which applied in the historical database resulted in a much higher level of dispatch at Mt Stuart compared with the backcast with disorderly bidding removed. Mt Stuart's SRMC is one of the highest in the NEM and this was found to increase system cost. Over four hours, this event resulted in a cost of disorderly bidding of approximately $240,000.

5.2.3) 2010-11 Financial Year

Disorderly bidding had a significant impact on dispatch efficiency in the 2010-11 financial year. The vast majority of the cost difference resulted from a single prolonged event. This event is examined in greater detail in this section. The cost of disorderly bidding was 14.9 million dollars. Figure 5.10 tracks the cumulative cost difference over the year resulting from disorderly bidding.

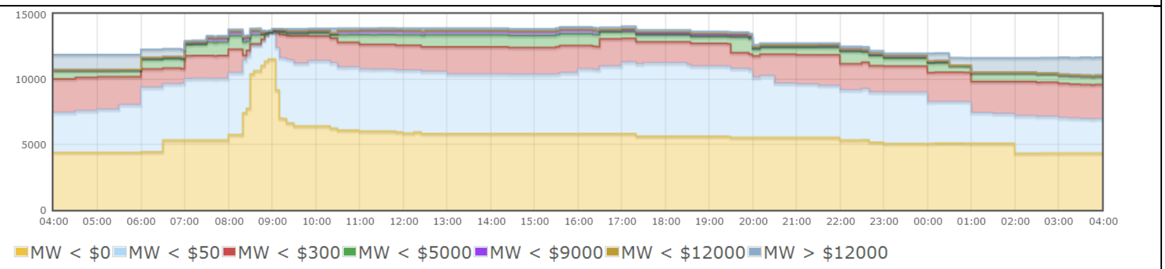
Figure 5.10 – Cumulative Cost of Disorderly Bidding – 2010-11



10 August 2010

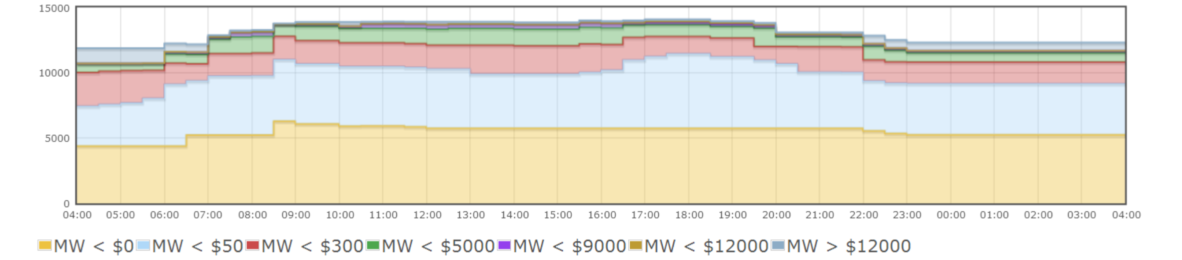
This period provides an example of the ability of the disorderly bidding removal process to accurately model congestion events which were of short duration. Figure 5.11 shows that a considerable volume of NSW capacity was bidding at the market floor between 8 am and 9 am.

Figure 5.11 – New South Wales – Actual Bids – 10 August 2010



The majority of the additional market floor price bids are found to be eliminated in the disorderly bidding removed database. This is demonstrated in Figure 5.12.

Figure 5.12 – New South Wales – Disorderly Bidding Removed – 10 August 2010



The disorderly bidding which occurred in this event resulted in an increase in production costs of almost $100,000.

18 January 2011 – 3 February 2011

The cost of disorderly bidding over this 17 day period was found to be almost 7.5 million dollars. This event therefore constitutes over half of the cost of disorderly bidding calculated for the entire financial year. The bulk of this cost difference is driven by a significant reduction in generation by Mt Stuart resulting from the removal of disorderly bidding. The removal of disorderly bidding leads to a reduction in Mt Stuart's generation over this period of almost 20 GWh. This volume constitutes over half of Mt Stuart's generation in 2010-11.

An example of the bid stack for Mt Stuart over this period is shown below for 24 January 2011.

Figure 5.13 – Mt Stuart – Actual Bids – 24 January 2011

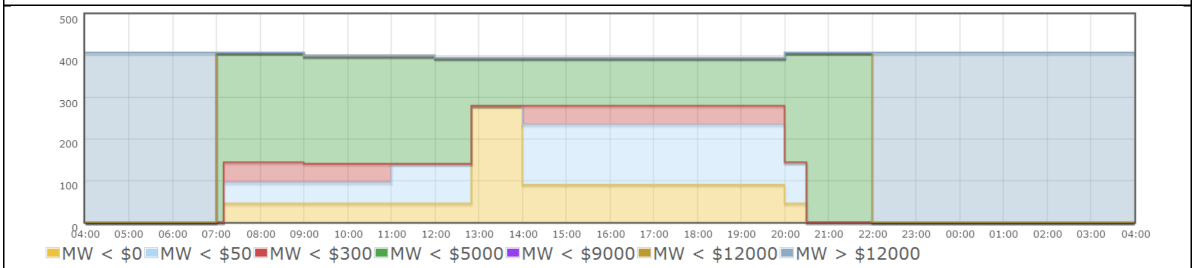
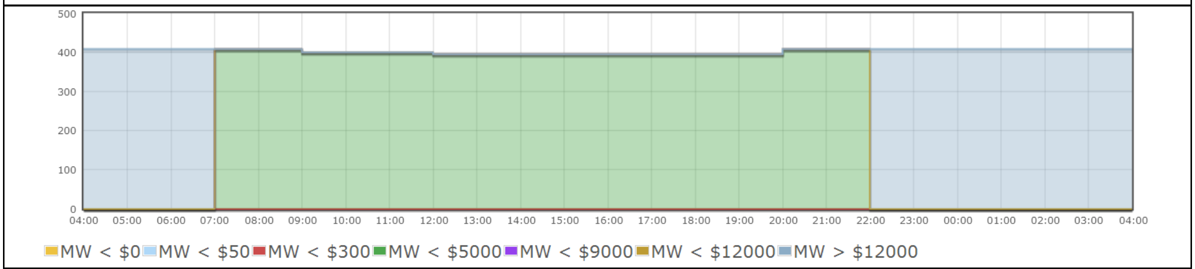


Figure 5.14 – Mt Stuart – Disorderly Bidding Removed – 24 January 2011



In the disorderly bidding removed backcast, the capacity of Mt Stuart is withheld to a capacity of $500/MWh. However, during the day, progressively more capacity was rebid into lower bid bands. In the bid applied in the real market, both units 1 and 2 of Mt Stuart were bidding their entire capacity at the market floor price. Many similar events can be observed over the 17 day period. The most common rebid explanation provided in rebids which involved significant capacity bidding at the floor was "CONSTRAINT MANAGEMENT – Q>>X_809_832_1 SL". This constraint is paired with the following description:

> "Out = Rocklea to South Pine (809) and Tarong to South Pine (832) 275 kV lines, avoid overloading Blackwall to South Pine (838) 275 kV line on trip of Mt England to South Pine (825) 275 kV line"

AEMO's NEM Constraint Report 2011[31] provides some additional commentary on this constraint:

> "These constraint equations were constructed for the multiple outage case following the Queensland floods in January 2011 and the binding results have been combined. Q>>X_809_8818_832_1 including the outage of the Blackwall to Rocklea (8818) 275 kV line, however there are only minor factor changes between it and Q>>X_809_832_1."

Therefore, this constraint represents an N-3 condition which resulted in onerous restrictions for Queensland generation. Mt Stuart has a positive coefficient in this constraint equation. Therefore, Mt Stuart has incentives to bid disorderly in order to maximise dispatch as there were regular instances of high prices over this period.

Given the unusual circumstances surrounding this constraint, the impact of disorderly bidding observed in 2010-11 may not be representative of an expected magnitude. However, it does show that disorderly bidding tends to become manifest under

[31] http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report

conditions of increased congestion resulting from line outages, and this is likely to continue under future market conditions as generation and demand patterns change.

5.3) IMPACT OF WATER VALUE

The results detailed above are sensitive to the water value applied to hydro generation in the analysis, as described in some detail earlier. An increased water value estimate tends to increase the cost of disorderly bidding. This is due to the application of a water value during periods in which hydro generation increases its dispatch by rebidding in a disorderly manner. The following charts show the impact of a varying water value for the backcast. Ideally, it would be possible to assign a water value to all hydro generators prior to conducting modelling. However, the water value is a dynamic variable, subject to change whenever other system conditions change, such as the introduction of a carbon price, or a major thermal generator outage. Therefore we have considered a range of water values in assessing the impact of disorderly bidding during the modelling process.

The outcome presented for 2008-09, as shown in the following figure, shows that hydro generation played a significant role in disorderly bidding. The range of water values applied shows that disorderly bidding may be evaluated to be in the order of less than 0.5 million dollars to in excess of 5 million dollars.

In the 2009-10 year there was little activity in the first half of the year. During December disorderly bidding reduced dispatch costs for all but the highest water values. This suggests that disorderly bidding increased hydro dispatch. The decrease in hydro generation when disorderly bidding is removed results in the cost of dispatch increasing, when the water value applied is lower than the average cost of generation that is displaced.

It is evident that the 2010-11 backcast is the least sensitive to water values. This result supports analysis which shows that significant disorderly bidding events in 2010-11 were not driven by hydro generation.

Figure 5.15 – Water Value Sensitivities – 2008-09

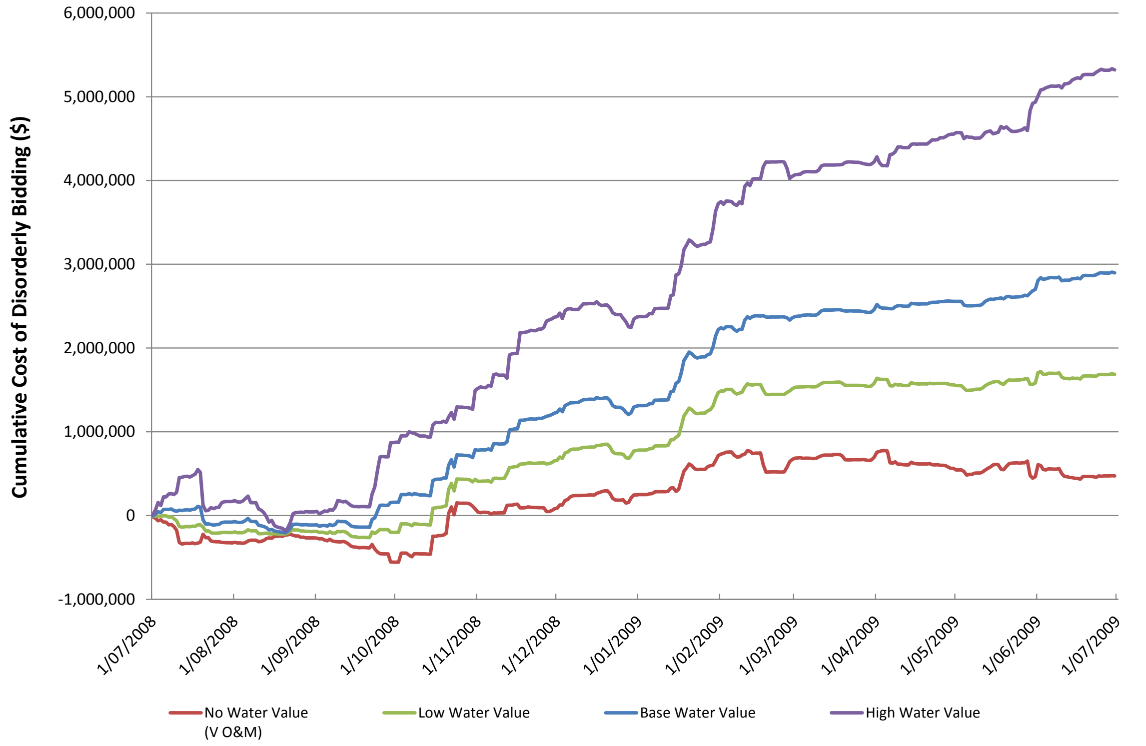


Figure 5.16 – Water Value Sensitivities – 2009-10

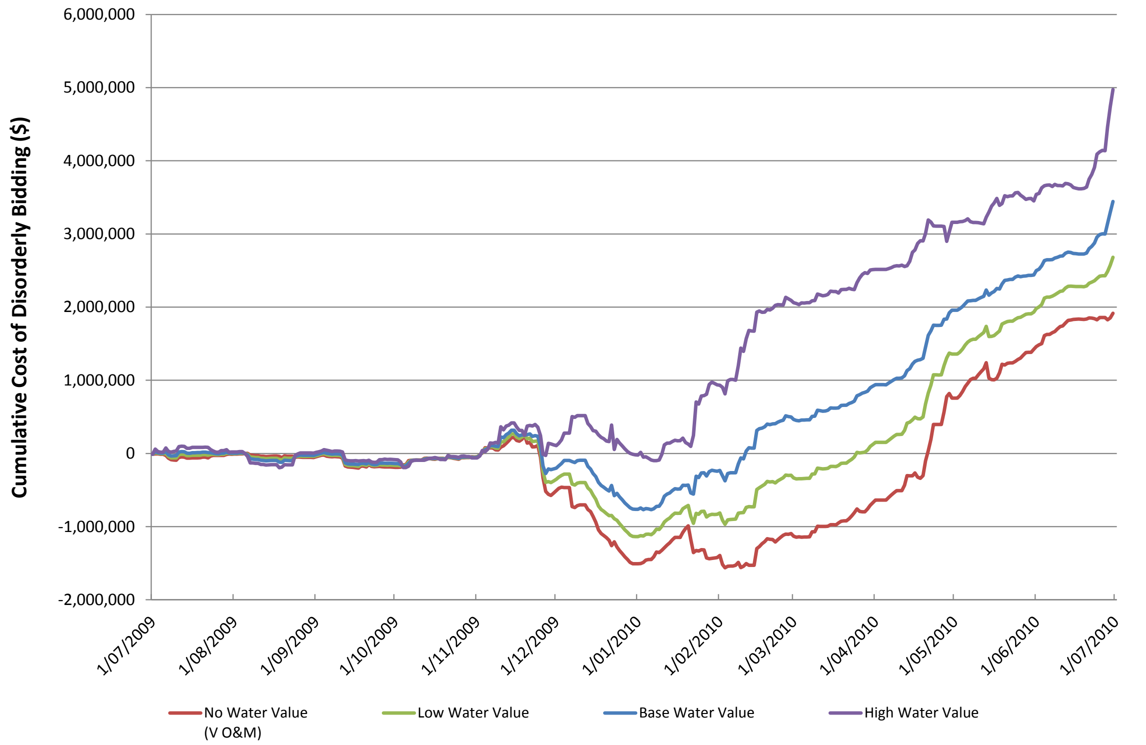
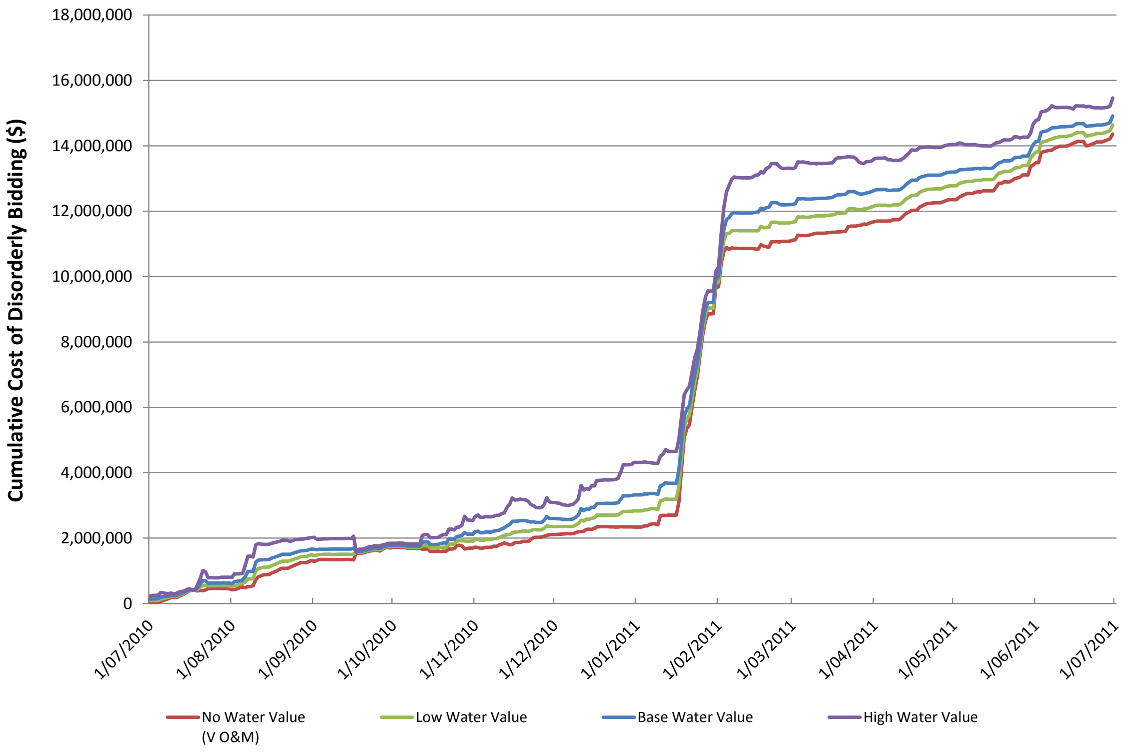


Figure 5.17 – Water Value Sensitivities – 2010-11



5.4) SUMMARY OF CHAPTER

The modelling of the impact of disorderly bidding and its removal is complex, when the changes in market costs are the main interest. Hydro generation is a significant contributor to peak generation in the NEM, and peak demand periods are most likely to be periods when disorderly bidding is experienced. Furthermore, hydro generation is remote from the major load centres in the Snowy Mountains, the Victorian Alps, Tasmania, and smaller centres throughout the Eastern States. Hence assigning a value to the water used with and without disorderly bidding was a significant experimental process conducted for the backcasting.

For the values of water that were considered most likely in deriving the impact of disorderly bidding, the cost of disorderly bidding to the market was only a small proportion of overall market cost. However, the associated market impacts were experienced quite frequently.

A further factor that became apparent is that disorderly bidding is mainly confined to periods of transmission outages. Therefore attention has been given in the forecasting section to an initial assessment of the forecast cost of disorderly bidding under outage conditions, as well as system normal conditions.

6) Forecast Outcomes

6.1) Introduction

Forecasts of the impact of each of the packages on both dispatch and market development are the focus of this study. Both Package 2 and 4 alter the incentives of market participants in responding to congestion in the market, compared with Package 1. This has been quantified in the backcast process, and further coverage of the issue through forecasting is provided in Section 6.2).

Packages 2 and 4 will also impact on the development of generation and transmission over time, as discussed in Section 6.3). The outcomes of the long term market developments provided in Section 6.4) illustrate the likely effects of these packages on market development and in particular, total system costs.

In addition to the core scenarios modelled, the results of a number of sensitivities have been provided. Sensitivities modelled include:

- A high transmission cost
- Regional transmission outages

The costs presented in this section are defined as follows:

- All annual values are presented as real mid-2012 dollars unless otherwise stated;
- Existing generation capital cost is zero, representing sunk costs;
- Existing and new entrant generation variable costs (fuel, O&M and carbon price) and fixed O&M are included;
- New entrant generation and transmission capital costs are annuitised. For example, if a new transmission development occurs in 2027-28, then only two years of the annualized capital repayment is included in the total system cost NPV[32];
- NPV is presented as real discounted dollars. A real pre-tax discount rate of 9.79% has been applied in all financial assessment[33];

[32] Net present value

[33] The AEMC TFR reports suggest that the Package 4 OFA model may reduce investment risk for generators and therefore ultimately reduce their financing costs. A low risk discount rate of 8.78% has previously been suggested in AEMO planning studies. It is unclear however how a different discount rate can be applied to generators and transmission in the LTIRP modelling and then alternative cases compared on the same basis.

- Transmission assets are revalued annually in accordance with AER revenue assessments for all TNSPs. Consequently, discounting transmission capital costs in the LTIRP modelling at the same assumed real discount rate as for generation assets may tend to understate the relative cost of transmission to total costs as seen by end users. However, this could be the subject of further detailed assessment, if deemed appropriate.

The results in this section primarily relate to the NTNDP Scenario 2 set of assumptions. A single scenario is provided to simplify the presentation of the outcomes. Detailed generation and cost outcomes are provided for the three alternative planning methodologies previously mentioned. These three methods are as follows:

- **Co-optimised**[34]: Where generation and transmission are developed in a co-optimised LTIRP covering all inter-regional and intra-regional transmission constraints, and allowing for the costs of future development of any or all generation and transmission needed to meet the demand with a price of unserved energy. This is a theoretical situation providing a reference point against which other options are assessed, and represents a situation with a perfectly known future.
- **Package 1 and 2** development: Where transmission follows generation in a process designed to approximate the current RIT-T. This methodology involves a two-step process whereby generation outcomes are used as an input for planning transmission. See Section A.2) for a more detailed explanation of this process.
- **Package 4**: Generation and transmission are co-optimised, subject to constraints relating to the application of the firm access standard. The assumed level of firm access for new entrants, as a percentage of capacity is as follows:
  - Wind: 30%
  - OCGT: 90% (Peak Firm Access)
  - CCGT: 60%
  - Interconnectors: 50%

  This set of firm access assumptions was found to minimise total system costs when considering all of the cases shown in Table 4.7. The firm access modelling

[34] This represents a theoretical case where the costs of all generation and transmission built over a 30 year period are known ahead of time. This is a useful reference case but does not reflect any real world uncertainty in demand forecasts or development costs.

presented also includes a number of firm access transitions for incumbent generation.

The co-optimised outcome represents the optimum generation and transmission development plan possible under any package. Where possible, ROAM has adjusted firm access decisions for both existing and new entrant generation to guide the firm access solution towards this co-optimised outcome. However, only a certain degree of accuracy is possible. The application of the FAS in the LTIRP requires a number of approximations that restrict the ability to optimally allocate firm access. The optimum level of firm access requires an assessment of locational factors, generation technology considerations and investment timing. Therefore, the allocation of a fixed percentage of firm access to each technology produces a somewhat suboptimal outcome. With greater refinement, it is probable that the firm access outcome would more closely shadow the co-optimised outcome.

In reality, transmission investment would be supported by an even more rigorous analysis of the transmission required to meet the FAS. This analysis would be based on detailed dispatch modelling and take into account operating conditions which are specific to a given location. This level of specificity is not possible in the zonal approximation used in the LTIRP.

ROAM suggests that the co-optimised outcome should be interpreted as a surrogate for the optimum allocation of firm access. There is however, no guarantee that generators will acquire firm access to approach such an allocation.

6.2) PRODUCTIVE EFFICIENCY UNDER CONGESTION PRICING

ROAM has proceeded in modelling Package 1 and 2 under the assumption that the development of generation and transmission is unchanged under Package 2. This approach is consistent with the AEMC's First Interim Report[35] which states that "The SACP is unlikely to have any impact on transmission planning or investment". Therefore, the only differences in costs that occur between these two packages result from the adjustment in the incentives to engage in disorderly bidding.

[35] See http://www.aemc.gov.au/market-reviews/open/transmission-frameworks-review.html

The outcomes of the long term development plans have been transferred to the time-sequential modelling.[36] ROAM has used the QP Bidding method to determine a baseline set of bids which are assumed to be "well behaved" with respect to disorderly bidding resulting from congestion. Therefore, the QP bids are used to calculate the production costs which would occur under the bidding incentives embodied by Package 2.

To determine the costs of production which occur under the present bidding incentives, ROAM has implemented a disorderly bidding methodology which provides generation with the ability to "race to the floor" to avoid curtailment. This methodology is a turn based process that will only result in generation engaging in disorderly bidding if a more profitable outcome is obtained. The assessment as to whether the disorderly bidding strategy results in a profitable outcome for a given station takes into consideration the reaction of other participants, the potential clamping of interconnectors and changes in pool price outcomes.

The disorderly bidding process is implemented on a station basis rather than on a portfolio basis. This methodology may therefore potentially be undervaluing the productive inefficiencies which result from disorderly bidding.

The productive efficiency gains observed from the removal of disorderly bidding under each scenario are shown in Table 6.1. These gains include the application of water values.

[36] The outcomes of the long term development plans are presented in subsequent sections of this report. These outcomes include future development of both generation and transmission (through the evolution of constraint equations).

Table 6.1 – Productive efficiency gain ($)						
	Scenario 1		**Scenario 2**		**Scenario 3**	
	Difference (Real)	**Difference (Real Discounted)**	**Difference (Real)**	**Difference (Real Discounted)**	**Difference (Real)**	**Difference (Real Discounted)**
2012-13	23,000	22,000	24,000	22,000	22,000	21,000
2013-14	39,000	34,000	44,000	38,000	46,000	40,000
2014-15	23,000	19,000	50,000	39,000	110,000	84,000
2015-16	-3,000	-2,000	-90	-60	27,000	19,000
2016-17	8,100	5,300	55,000	36,000	-6,000	-4,000
2017-18	130,000	79,000	98,000	59,000	4,100	2,400
2018-19	-2,000	-1,000	220,000	120,000	34,000	18,000
2019-20	3,200,000	1,600,000	-50,000	-30,000	110,000	55,000
2020-21	4,700,000	2,100,000	890,000	400,000	180,000	82,000
2021-22	1,700,000	700,000	700,000	290,000	110,000	44,000
2022-23	5,300,000	2,000,000	1,500,000	560,000	190,000	73,000
2023-24	3,600,000	1,200,000	410,000	140,000	460,000	160,000
2024-25	1,100,000	330,000	3,600,000	1,100,000	1,100,000	330,000
2025-26	3,700,000	1,100,000	5,700,000	1,600,000	990,000	280,000
2026-27	3,900,000	1,000,000	5,700,000	1,500,000	1,600,000	430,000
2027-28	2,200,000	530,000	4,300,000	1,000,000	2,100,000	500,000
2028-29	1,400,000	300,000	6,100,000	1,300,000	5,600,000	1,200,000
2029-30	1,100,000	220,000	3,200,000	630,000	5,200,000	1,000,000
NPV Difference	-	11,200,000	-	8,800,000	-	4,300,000

From this result it is evident that the potential gains from removing the incentives for generators to engage in disorderly bidding in response to congestion are relatively small. There are a number of reasons why this is the case. Primarily, the differences between the costs of generation in the NEM are not substantial. This is particularly true given the introduction of a carbon price and the assumption of relatively high escalation in gas prices which tends to draw the energy cost of gas and coal plant closer together over time. Therefore, a rearrangement of dispatch outcomes between units does not necessarily result in a material change in the cost of production.

This effect is compounded when considering that generation in a given location tends to be of a similar type. For example, the Latrobe Valley is characterised by large volumes of low cost brown coal generation. Similarly, southern New South Wales is dominated by hydroelectric generation and an increasing level of wind development. Therefore, generators that are competing for limited access are often of the same or similar technology or production cost. Any change in the dispatch of generation at a given location is likely to have a small impact on dispatch costs.

A low cost of disorderly bidding observed in a given year does not necessarily imply that congestion was infrequent. It has been discussed above that the economic cost impacts of disorderly bidding may be small; however wealth transfers due to pricing outcomes may be significant. Furthermore, a profitable implementation of the race to floor bidding strategy is not assured, because the regional price may reduce below the real or contracted price that the generator faces.

The costs of introducing disorderly bidding are forecast to increase throughout the study. The earlier years show very low, and sometimes negative, cost increases resulting from disorderly bidding[37]. The low cost of disorderly bidding is also a result of modelling system normal conditions throughout.

The increase in costs during the study occur as a result of the evolution of the system over time. The introduction of substantial levels of wind generation creates significant differences between the costs of generation technologies subject to the same constraint. Therefore, disorderly bidding which results in the curtailment of wind generation can have a significant impact on the potential cost of disorderly bidding. Similarly, the flowpaths for which congestion is an issue evolve throughout the study. Emerging congestion issues are generally the result of the introduction of both wind and thermal generation in remote zones. Therefore, the combination of increased congestion and high volumes of both wind and thermal generation create an environment in which disorderly bidding has the potential to increase production costs. However, even in the later years of the study, the level of inefficiency added by implementing disorderly bidding is a very small proportion of the total cost of production in the market.

6.2.1) Evaluating the impact of transmission outages

Numerous stakeholders have suggested that the majority of congestion issues arise from the occurrence of transmission outages. Sensitivity analysis has been performed to determine the impact of transmission outages on dispatch costs.

[37] As described previously, benefits, that is, reduction in costs, may actually result from disorderly bidding depending on the relative costs of the generators affected by the disorderly bidding events.

ROAM has analysed the potential for transmission outages to materially impact the effect of disorderly bidding on dispatch efficiency (for methodology see Section 4.2.2). The results of these studies are shown in Table 6.2. These results are comparing the costs of production between Package 1 and Package 2 under the Scenario 2 assumptions.

The first column shows the increase in system cost as a result of the network outage being in place for the entire duration of the study, compared with the No Outage case. This shows that the reduced network capability results in a higher dispatch cost in general. The significantly higher dispatch cost reported for the QLD outage case is due to this network outage resulting in unserved energy which is costed at $55,000/MWh. The second column in the table shows the cost of disorderly bidding given the network status. The No Outage case reflects the value presented for Scenario 2 in Table 6.1 above. The transmission outages selected for the Queensland and New South Wales regions result in an order of magnitude increase in the cost of disorderly bidding due to the increased propensity for higher cost gas fired generators to exercise disorderly bidding, increasingly at the expense of relatively low cost coal, hydro and wind generation. However, the transmission outages selected for the Victoria and South Australia regions have not resulted in a materially different cost of disorderly bidding due to the relatively low cost of generation which is located upstream of the network outage.

Table 6.2 – Productive Efficiency Gains – Transmission Outage Sensitivities (Scenario 2)

Outage Case	Additional Cost Incurred due to Transmission Outage (without disorderly bidding) (NPV $m)	Increase in Productive Efficiency from removal of disorderly bidding (NPV $m)
No Outage	-	8.8
NSW Outage	71.2	96.5
QLD Outage	7,077.4	91.4
VIC Outage	95.6	4.1
SA Outage	155.3	3.2

To consider transmission outages in assessing the expected cost of disorderly bidding requires an estimate of the probability that major transmission outages occur. For example, if the probability of a transmission outage in a region in a given period is assumed to be 5%, then a 5% weighting may be applied to each outage scenario (coincident outages are ignored). Under this assumption, the expected NPV of the cost of disorderly bidding increases from $8.8m to $18.6m over the outlook period. This issue could be explored in more depth based on a thorough review of all single outages in all regions on intra-regional flowpaths, along with their relative probabilities. The modelling undertaken to date is a representative sample of the impact of outages but is not exhaustive.

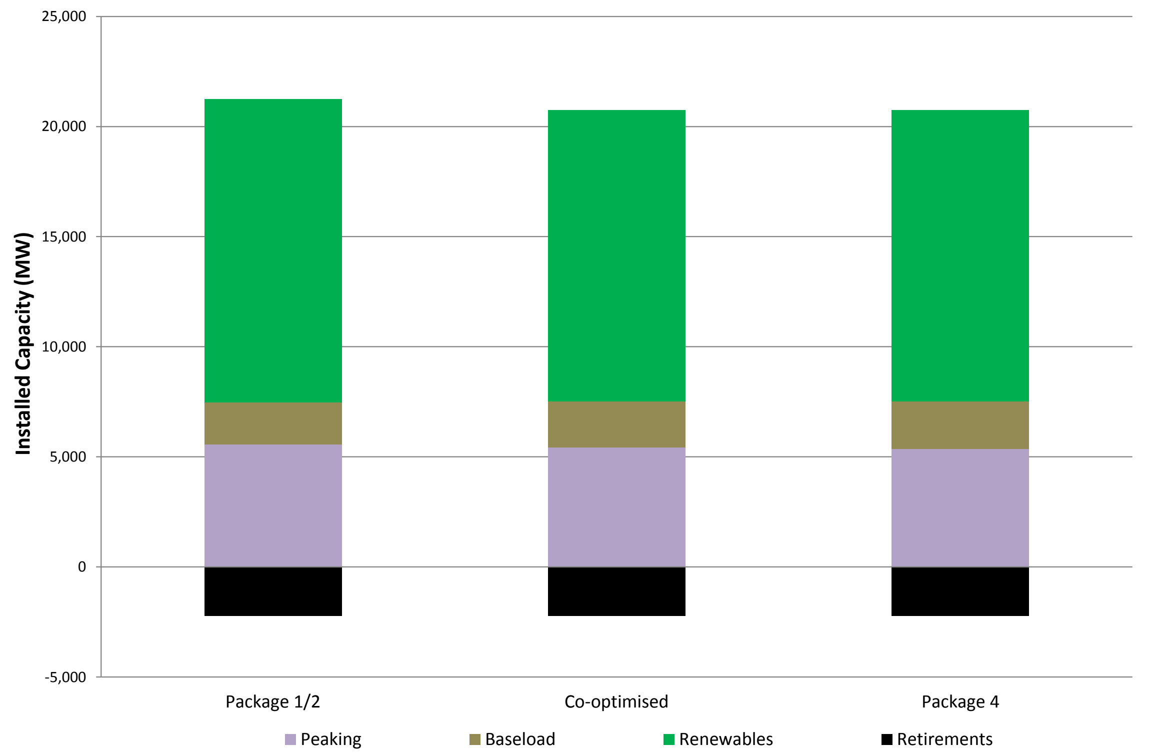
6.3) GENERATION AND TRANSMISSION OUTCOMES

Figure 6.1 illustrates that the majority of generation development observed in the LTIRP forecast to 2030 is wind generation. The decreasing cost of wind generation and the Renewable Energy Target (RET) contribute to the attractiveness of investment in wind generation. The carbon price and increasing gas costs also contribute to the incentives for renewable development.

While new entrant wind generation meets a large proportion of the assumed demand growth, due to the intermittency of wind generation, peaking plant is needed to provide reliable generation during peak periods. Open cycle peaking gas generation therefore accounts for a significant proportion of the new thermal development.

The capacity installed under each planning approach is similar. The Package 1 and 2 development outcome includes a marginally higher level of renewable generation. However, the total capacity of renewable generation is not easily interpreted. Factors such as intra-regional losses and zonal wind capacity factors also contribute to the “value” of this capacity.

Figure 6.1 – NEM generation development (Scenario 2)



The regional generation development under each planning approach is provided in Figure 6.2. These results show a similarly low level of diversity with respect to the regional capacity installed under each of the three planning mechanisms. The development of wind generation is distributed throughout the NEM. However, the bulk of thermal development occurs in Queensland and Victoria. The Victorian thermal development in part acts to offset the retirement of brown coal generation enforced by the Contract for Closure mechanism (CFC)[38].

[38] This phase of modelling was conducted prior to the abandonment of contracts for closure (CFC) of high emissions generation by the Commonwealth. However, the modelling has shown that the optimum replacement plant would be new gas fired base load generation in the same locations. So the materiality of the modelling is unchanged with or without the CFC.

Figure 6.2 – Regional generation development (Scenario 2)

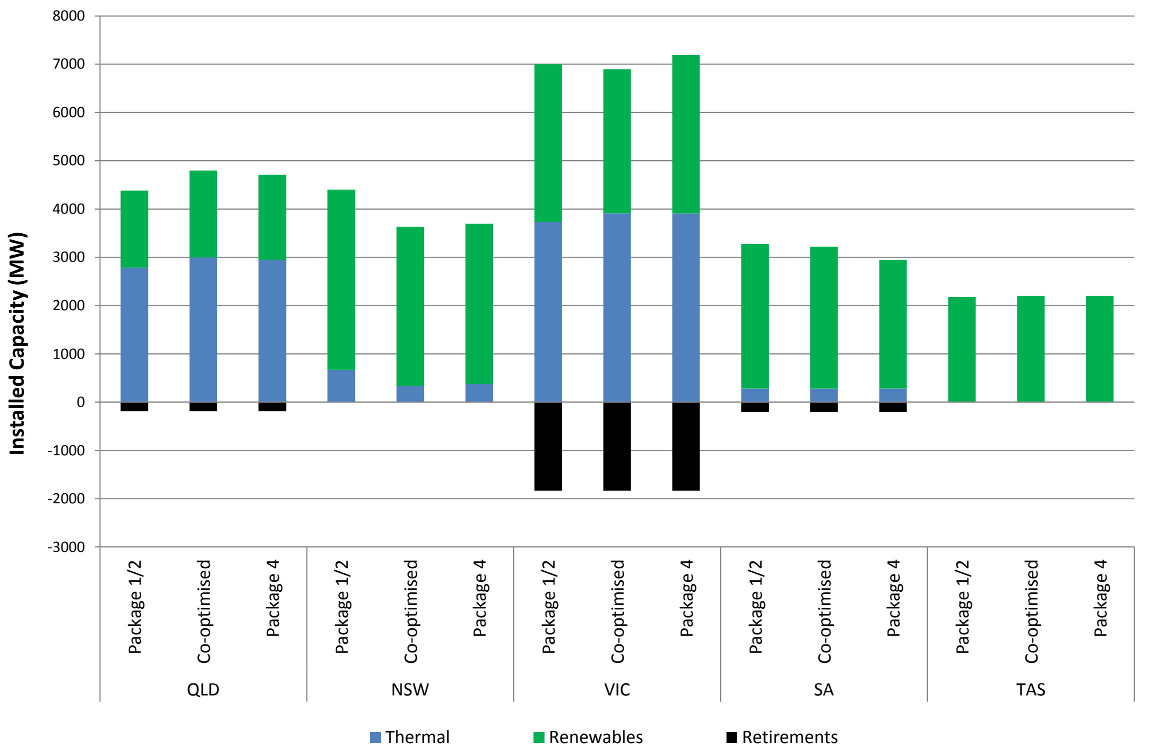


Figure 6.3 to Figure 6.6 illustrate the installation and retirement of generation that occurs on a zonal level. An assessment of these generation outcomes in conjunction with the transmission development (provided in Figure 6.7 and Figure 6.8) demonstrates the effects of alternative development criteria. These outcomes exhibit significant diversity in both generation and transmission development. This is particularly the case in Queensland and New South Wales.

Figure 6.3 – QLD generation development (Scenario 2)

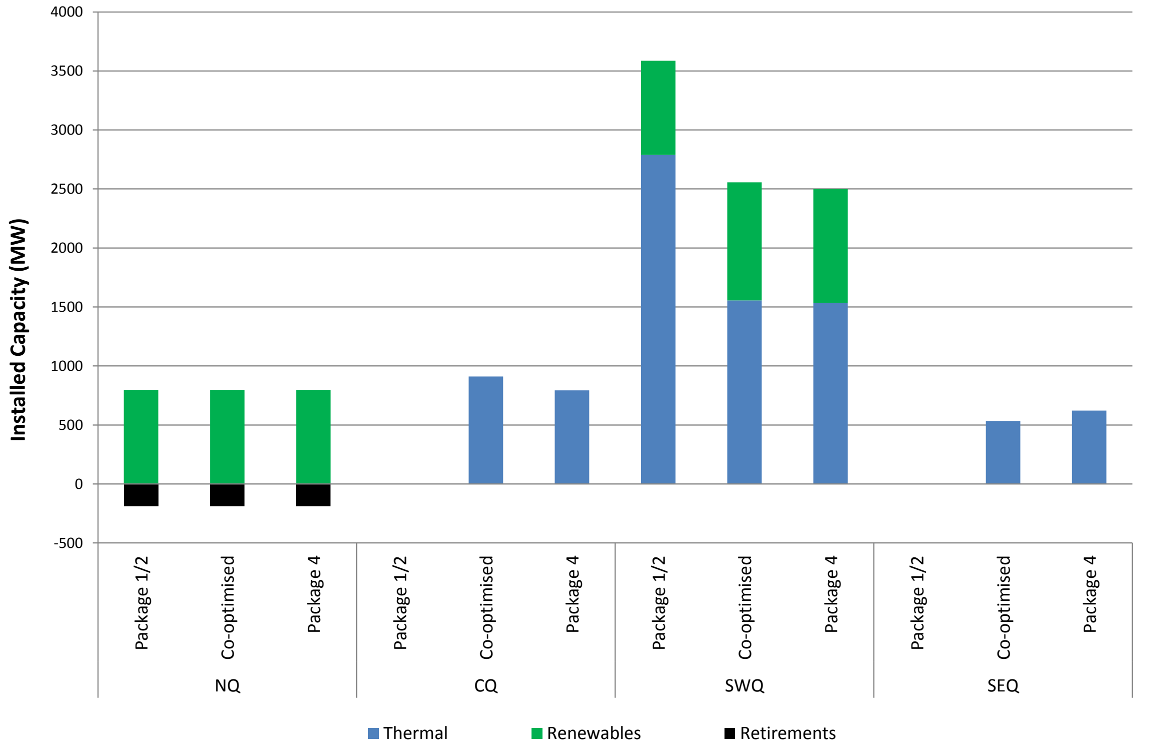


Figure 6.4 – NSW generation development (Scenario 2)

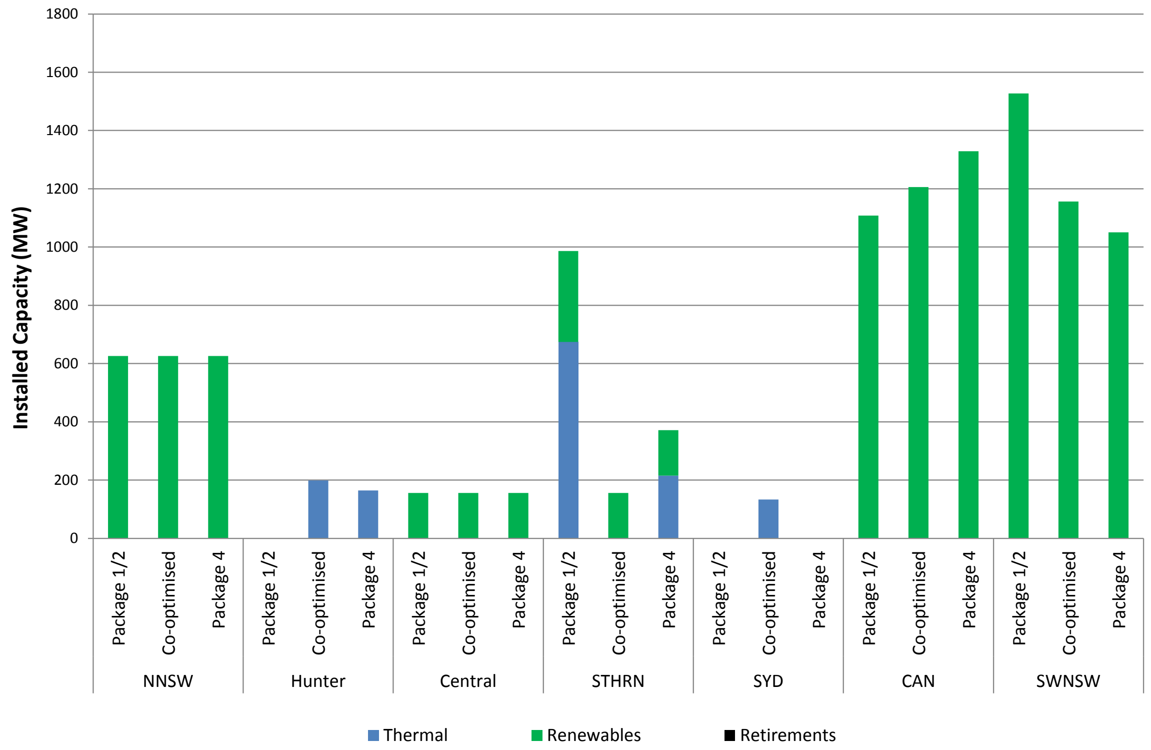


Figure 6.5 – VIC generation development (Scenario 2)

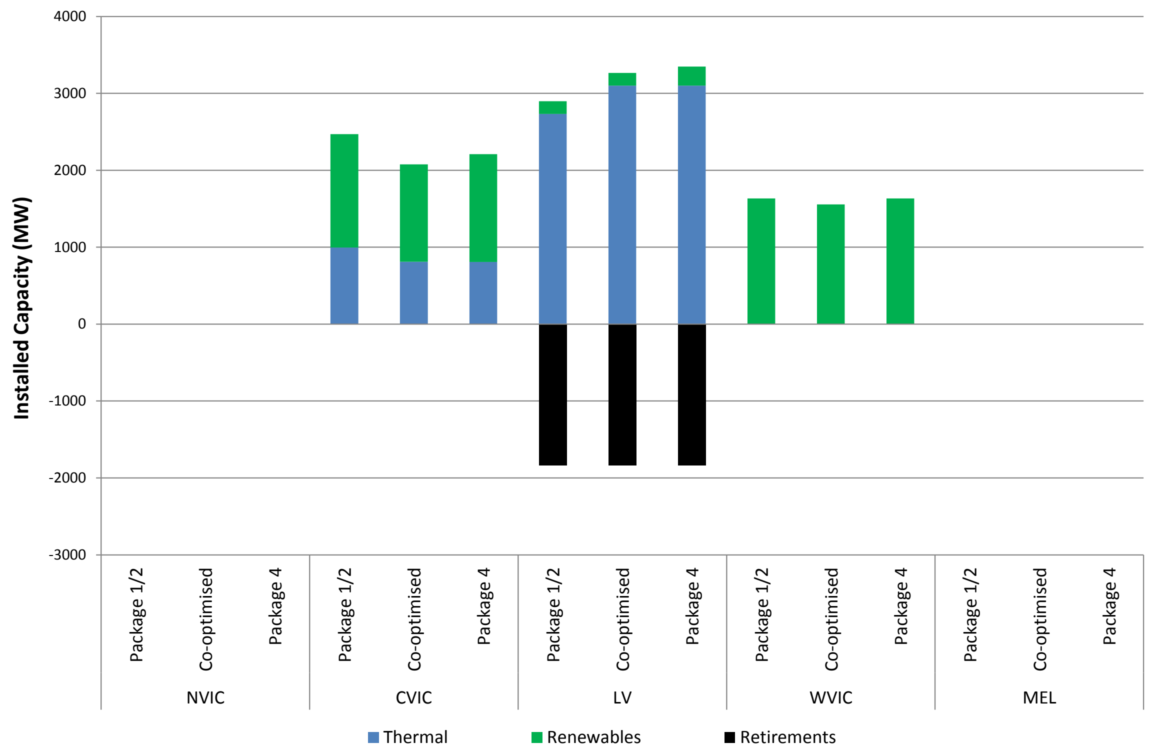
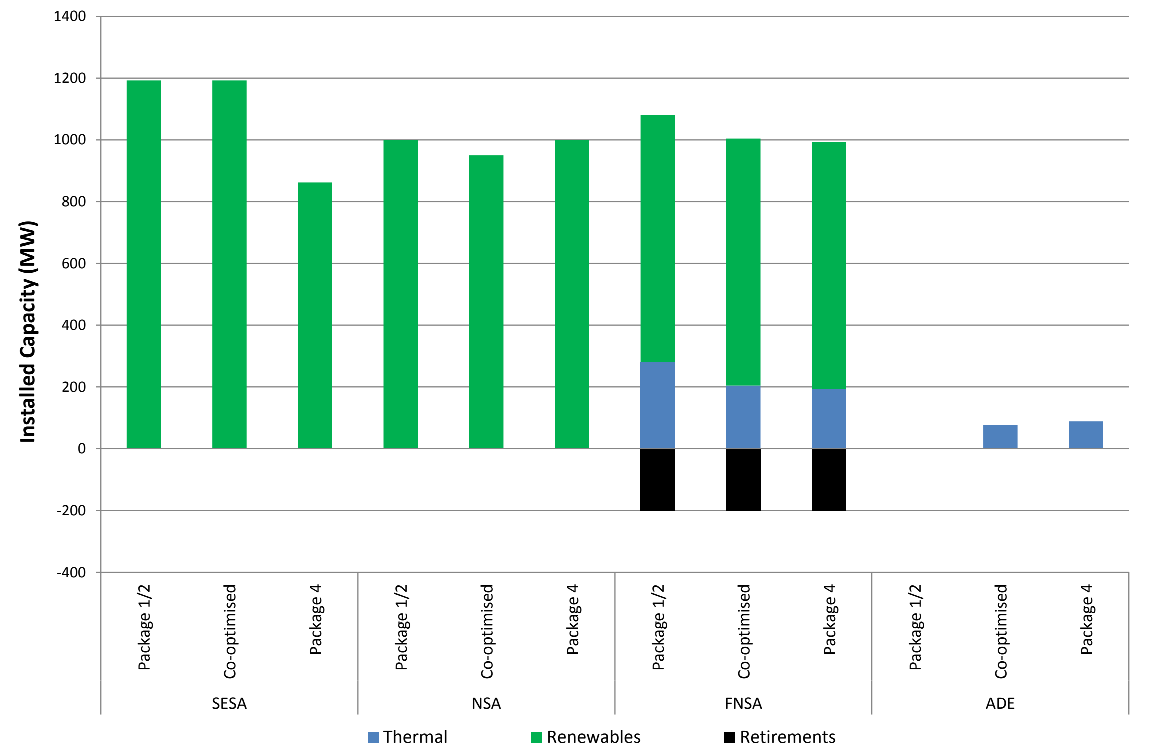


Figure 6.6 – SA generation development (Scenario 2)



The interaction between generation and transmission in SEQ and SWQ provides the clearest example of the differences between the packages. In each of the three developments, an equivalent amount of wind generation is installed in SWQ (wind generation is unavailable as a technology in SEQ). However, the level of thermal development in each zone differs substantially.

In Packages 1 and 2, new generation is developed independently from the prevailing transmission limit between SWQ and SEQ[39]. As a result, all thermal generation locates in the zone which provides the lowest cost of supply, in this case, SWQ. In the co-optimised outcome, a proportion of the generation development is moved to both SEQ and CQ. This movement away from the least cost supply zone is an illustration of the LTIRP simultaneously assessing both generation and transmission costs in making locational decisions. The LTIRP would prefer to reduce the amount of generation located in SWQ to avoid the cost of new transmission. This is evident in Figure 6.7 which shows that significant transmission development was needed under the RIT-T (Package 1 and 2). This transmission was not required under either the co-optimised or the firm access planning models. The need for new transmission was completely removed by the more efficient generation development in the co-optimised outcome.

An additional facet of the FAS is that it no longer provides for market driven transmission augmentations to occur. Transmission can only be justified by either the reliability standard or by firm access procurement. For example, it was observed that the co-optimised outcome resulted in significant investment in the transmission flowpath between SWNSW and CAN. This investment was initially restricted by the FAS given the level of generation installed in SWNSW since the reliability standard would be met without the upgrade. The outcome of the firm access scenario was found to approach the co-optimised outcome when existing hydro generation firm access in SWNSW was lifted to represent it requesting a higher level of firm access at a future time. The procurement of this additional access by hydro generation is therefore the driver which provides for the transmission investment between SWNSW and CAN observed in Figure 6.7.

[39] The LTIRP also considers transmission losses between zones.

Figure 6.7 – QLD and NSW transmission development (Scenario 2)

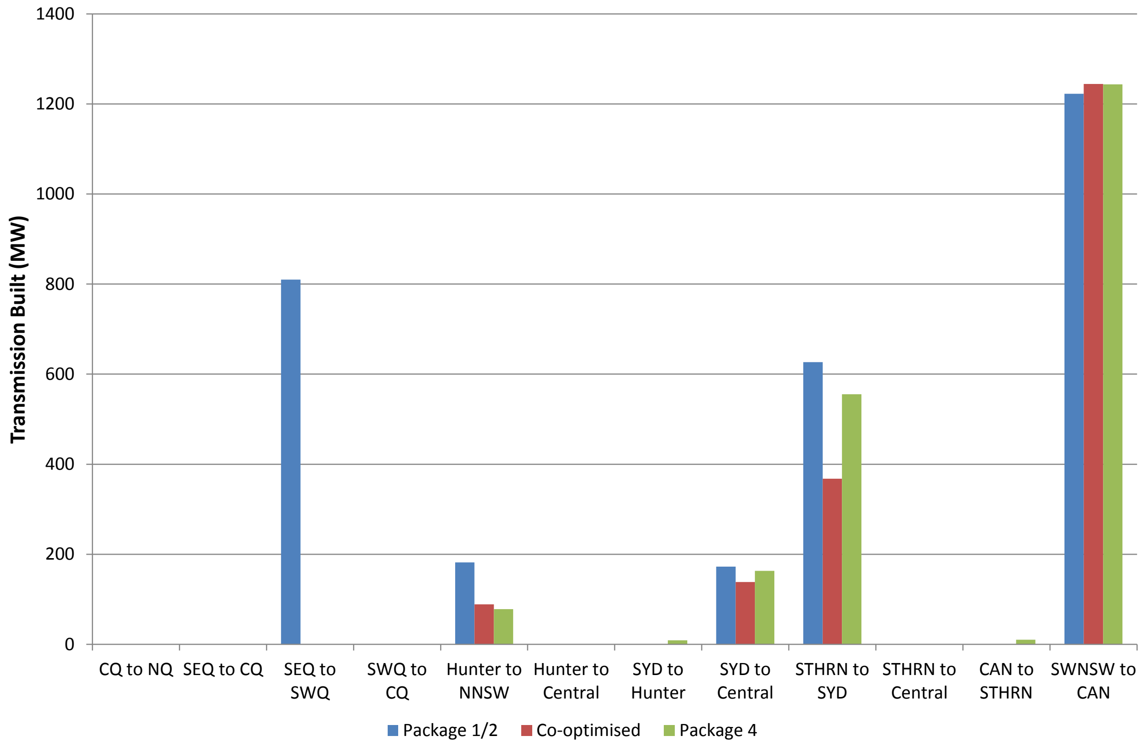
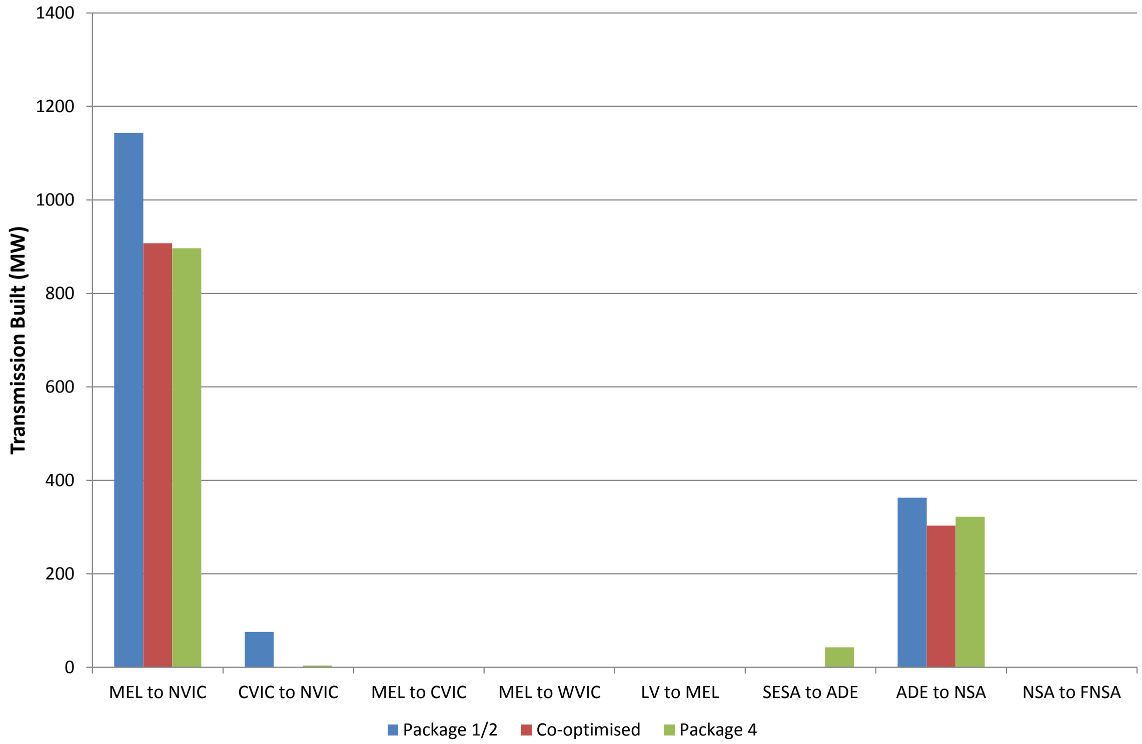


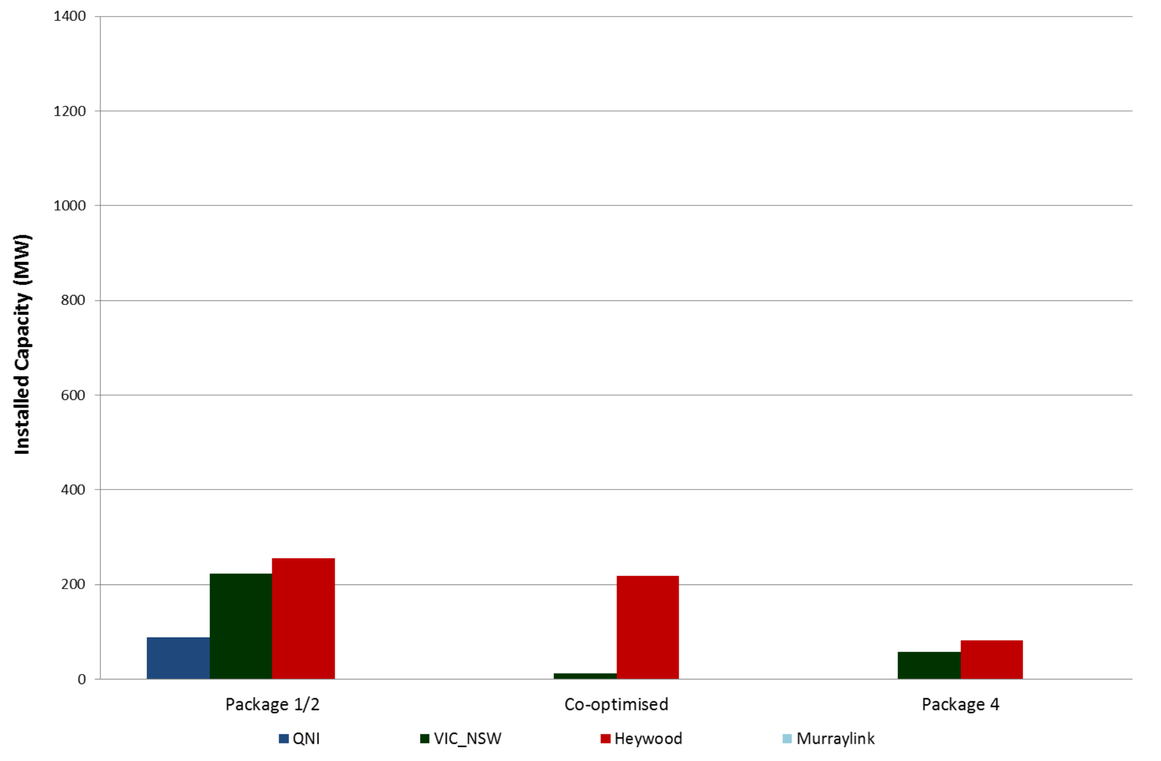
Figure 6.8 – VIC and SA transmission development (Scenario 2)



The forecast interconnector development is shown in Figure 6.9. The level of interconnector development is small compared with key intra-connector flowpath development. Under Package 4 a 50%[40] firm access setting has been applied in the modelling which effectively requires augmenting the flowpath between the interconnector and the reference node in conjunction with interconnector upgrades. In this scenario this setting suppresses interconnector augmentation in favour of relocating generation development which is similar in cost between regions. Under Package 4, wind generation in particular is developed to a higher level in Victoria and lower in SA, compared with Package 1 and 2, which reduces the need to augment the Heywood interconnector. Similarly there is a shift in generation development between NSW and Victoria under Package 4 compared with Package 1 and 2 to reduce the requirement for a VIC_NSW interconnector upgrade and avoid the 50% firm access upgrade cost. Although important, these changes in transmission capacity decisions are relatively small.

[40] Firm access for interconnector development will necessarily require network augmentation on the intra-connector flow path between the regional reference nodes if there is no spare capacity on the intra-connector flowpath; which is the situation in the NEM. Therefore, a higher level of firm access requirement for interconnectors will tend to result in a lower likelihood for interconnector development, because the effective cost of the interconnector upgrade also includes multiple intra-regional upgrades. Consequently, very little interconnector and intra-connector development to support the interconnector firm access eventuates. Further modelling is recommended to investigate this relationship.

Figure 6.9 – Interconnector development (Scenario 2)



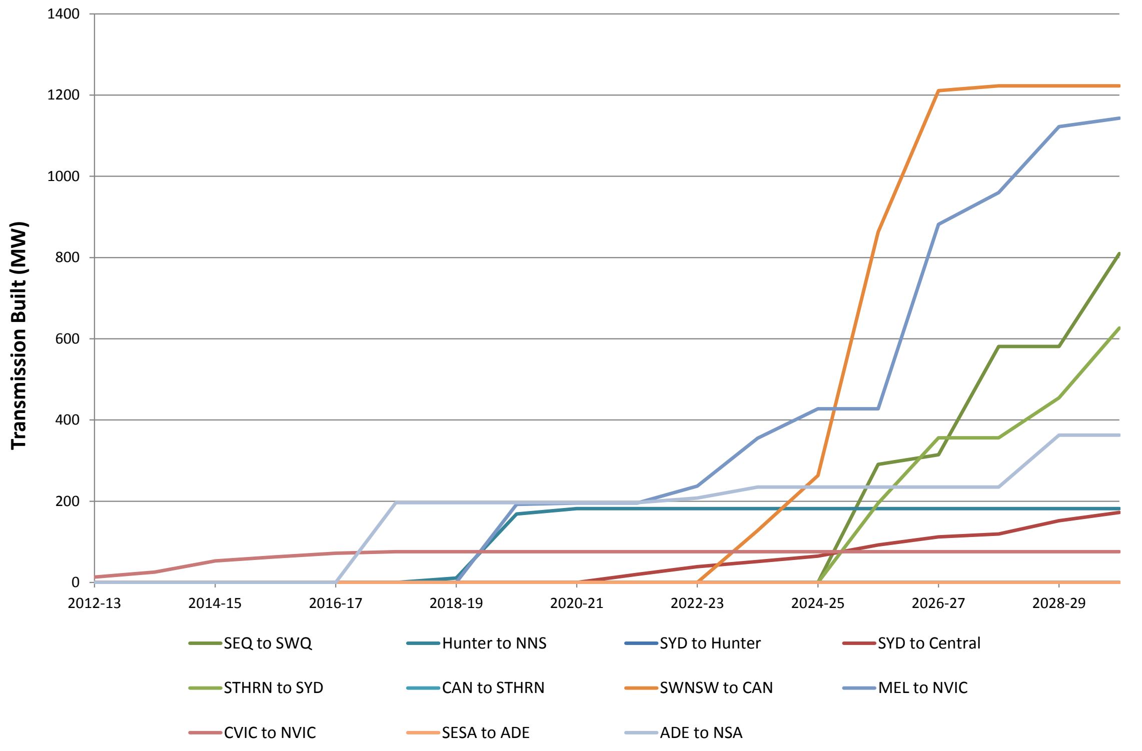
6.3.1) Transmission Development Timing

Both the magnitude and timing of transmission investment is of critical importance in analysing the merits of optional firm access. The development of transmission over time in each of the packages is illustrated in Figure 6.10, Figure 6.11 and Figure 6.12.

Clearly, significant transmission development is forecast not to occur in the early years of the study. It can therefore be inferred that there are no flowpaths under the current conditions which could be augmented for a net economic benefit. Even if these opportunities were to exist, the LTIRP has the ability to delay these investments to obtain a higher net benefit. The lack of early transmission development is also indicative of the low forecast demand growth. As a result, there is little need for investment in new transmission capacity until around 2017-18. This is consistent with the recent views of the TNSPs, based on their latest Annual Planning Reports.

Transmission development occurs at a higher level under the RIT-T planning mechanism. The comparative investment in transmission between the co-optimised outcome and under Package 4 is similar for the majority of flowpaths.

Figure 6.10 – Transmission development timing (Package 1 and 2, Scenario 2)[41]



[41] This is forecast development under the RIT-T.

Figure 6.11 – Transmission development timing (Co-optimised, Scenario 2)

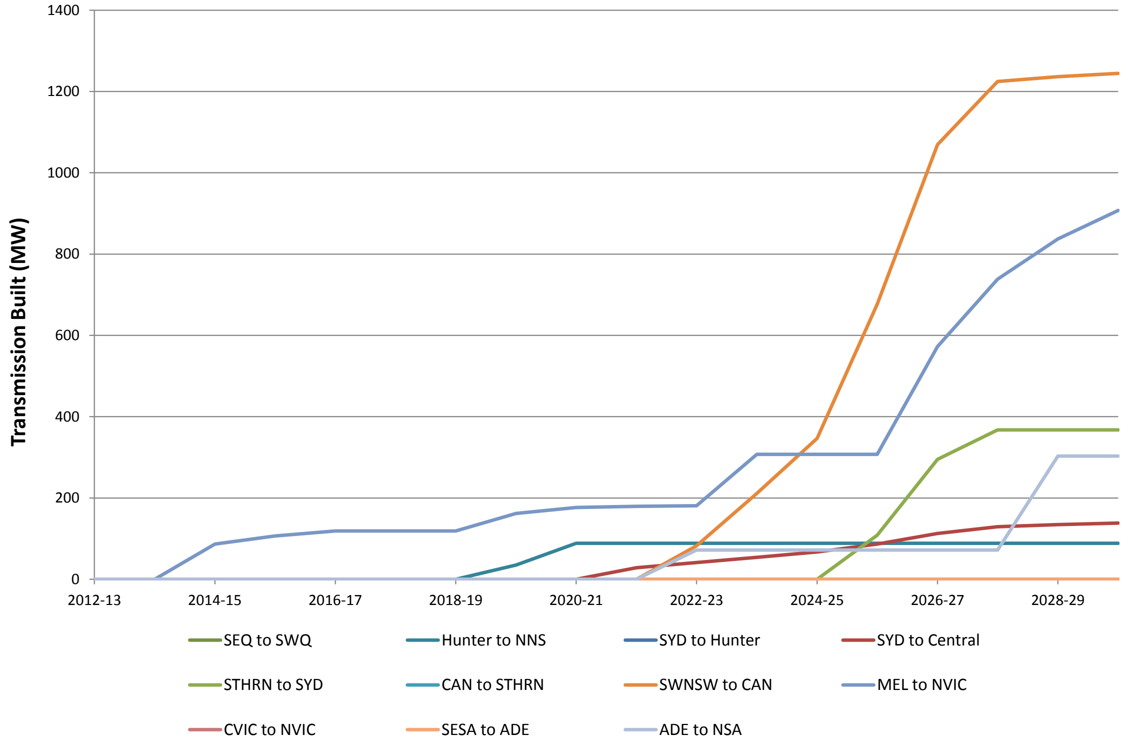
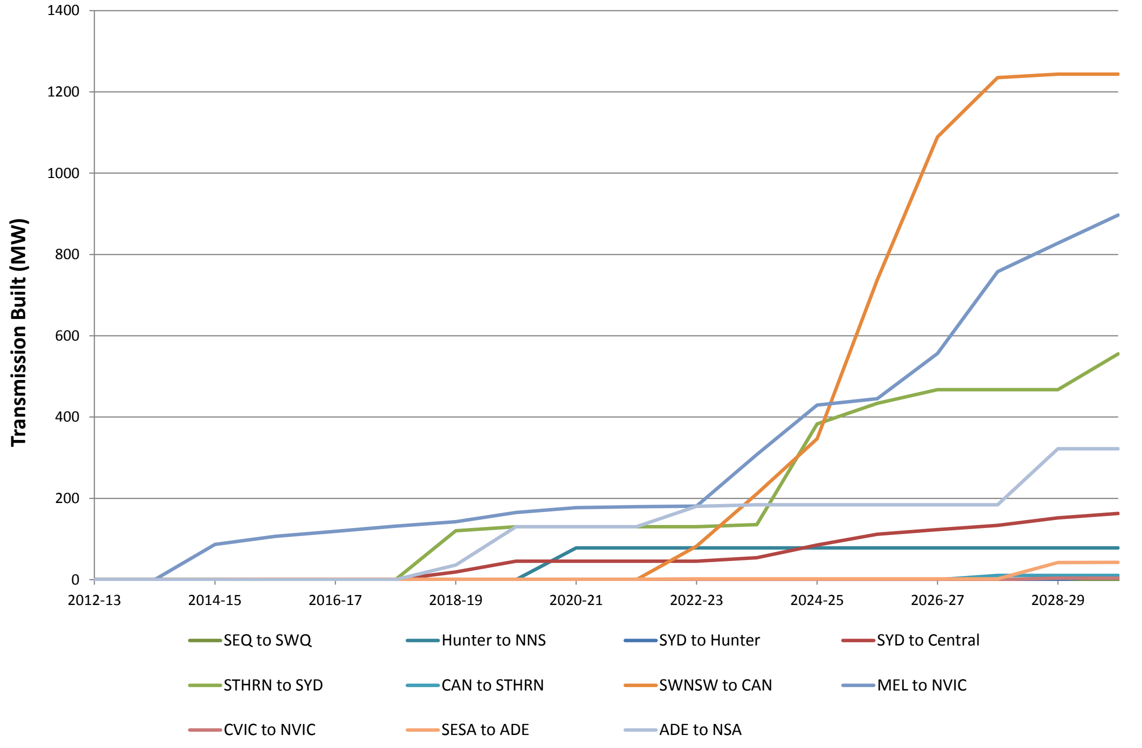


Figure 6.12 – Transmission development timing (Package 4, Scenario 2)



6.4) LONG TERM CAPITAL AND VARIABLE COST PROJECTIONS

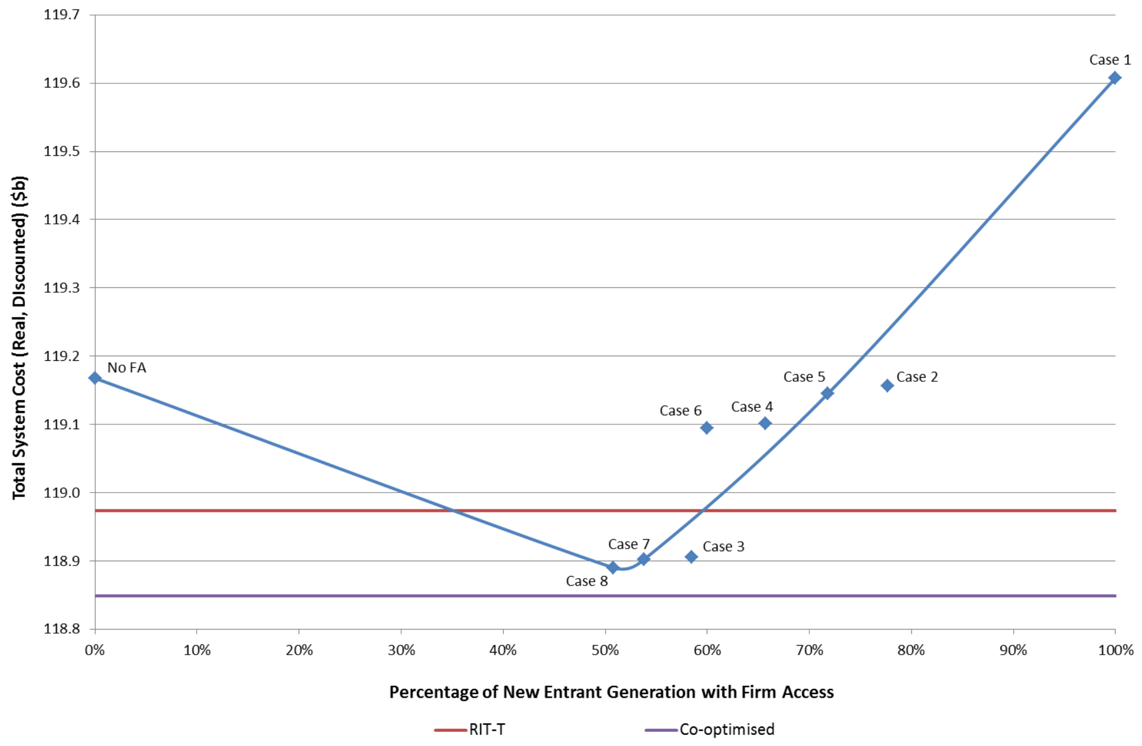
In addition to assessing the potential productive efficiencies which result from the removal of disorderly bidding incentives, ROAM has used the LTIRP to assess the potential for Package 4 to produce allocative and dynamic efficiency gains. For the purposes of comparison, ROAM has also produced an outlook for the case where generation and transmission is fully co-optimised. Given the assumptions provided to the LTIRP, the co-optimised approach produces an outcome that represents the lowest possible cost because it eliminates investment uncertainty over 30 years of future development. It also allows for an 'economic level of congestion' in system cost terms which is the focus of this modelling. Again it is acknowledged that risk is a function of market prices which may reduce the acceptable level of congestion risk. Therefore, any movement away from the co-optimised planning approach will necessarily increase the cost of the solution. The decoupling of generation and transmission co-optimisation used to simulate Package 1 and 2, and the introduction of additional constraints required by the FAS to simulate Package 4, both result in increased total system costs relative to co-optimisation. This is illustrated in Figure 6.13 below.[42] The new entrant firm access case options table is repeated for convenience. The figure shows that a broad minimum in the Package 4 outcomes occurs around the 50% firm access level across all generators. With no firm access, costs increase, while with full firm access, costs are also well above the minimum.

Firm access case 6 illustrates the potential impact of a poor firm access allocation between technologies. In this scenario, new entrant wind and peaking generation opt for the same level of firm access as a percentage of installed capacity. The resulting level of firm access is comparable to other firm access cases that have lower system costs (i.e. around 60% of aggregate installed generation capacity). This demonstrates that intermittent generation does not benefit from, or utilize, high levels of firm access to the same extent as peaking generation. On the other hand, schedulable generation including OCGT and CCGT plant will benefit from being able to guarantee dispatch to a level which approaches their availability. This is shown by case 3 and case 7 having a similar total cost, while case 8 results in the lowest total cost of the options evaluated, where the OCGT firm access allocation is reduced below 100% in line with generator availability.

[42] For simplicity, the impact of disorderly bidding on system costs has not been provided in this figure. Given the magnitude of the difference, this information would not add any value to the illustration of system costs. Both Package 1 and 2 can therefore be considered to result in the cost shown by the "RIT-T" value.

Table 6.3 – New Entrant Firm Access Cases				
Case	**Wind**	**OCGT**	**CCGT**	**New ICs**
1	100%	100%	100%	50%
2	60%	100%	100%	50%
3	30%	100%	100%	50%
4	60%	60%	100%	50%
5	60%	100%	60%	50%
6	60%	60%	60%	50%
7	30%	100%	60%	50%
8	**30%**	**90%**	**60%**	**50%**
No FA	0%	0%	0%	0%

Figure 6.13 – Total System Costs: USE valued at MPC (Scenario 2)



With reference to the scale on the y-axis in the chart, it is clear that the difference in total system cost over the 17 year outlook period between the co-optimised method and the RIT-T approach is small in relation to total fixed, variable and fuel costs. The difference between the RIT-T approach and the co-optimised approach is somewhat more than $100 million, with the FAS approximately $100 million lower in cost than the RIT-T at the minimum. This small difference is to be expected, as the fixed costs of generation, the expenditure on renewable generation to meet the RET, and the large costs of fuel and carbon price tend to swamp the differences in capital costs of development of transmission and new fossil fuel generation. Although relatively large differences in locational generation and transmission development decisions are observed, the resulting cost differences are small. This outcome reflects the relatively small margins which exist in the locational cost components for generation provided in the NTNDP data set and the relatively small cost of transmission compared with generation capital and operating costs. This analysis therefore suggests that in the context of the Australian NEM the potential gains in allocative and dynamic efficiency from incorporating transmission considerations into generation development decision making are relatively small. It also suggests that the RIT-T methodology presently followed has been successful in managing transmission costs and would continue to be in the future if planning appropriately takes into account the changing dynamic in generation development. Nevertheless there is evidence that the RIT-T is suboptimal in total system cost terms and that the OFA methodology is capable of delivering higher allocative and productive efficiency.

A further reason the cost difference between the RIT-T and co-optimised methods is small is that both effectively plan transmission to allow for the most efficient level of congestion. This is in contrast to Package 4, which can result in both over and under building of transmission resulting from the application of the FAS. ROAM has attempted to reduce this inefficiency through transitional firm access allocation. However, only a moderate level of accuracy can be reasonably achieved in this regard. In Figure 6.13 firm access total system cost falls below that observed in the RIT-T outcome, and approaches that of the theoretical optimum provided by co-optimisation without uncertainty.

Transmission planning under all planning approaches described here incorporates complete and perfect knowledge of future generation development. Therefore transmission investments will not occur if they may be beneficial in the short term but do not produce long term benefits. In reality, the uncertainty of future events can lead to both over and under-investment in transmission.

Table 6.4 presents the total system cost evaluated as the total capital and fixed costs from the LTIRP modelling and the variable costs from the 2-4-C modelling. This outcome reflects the marginally higher cost resulting from disorderly bidding under Package 1 compared with Package 2. Under the most favourable allocation of firm access, Package 4 delivers the lowest long term cost in the modelling studies compared with Package 1 and Package 2.

Table 6.4 – Total System Costs under alternative packages (Scenario 2)			
NPV of 2012-13 to 2029-30 with weighted 10% and 50% POE demand for each outlook	**Total Market Variable, Fixed and Capital Costs ($m)**		
	Package 1	**Package 2**	**Package 4**
	QP Bids with disorderly bidding	**QP Bids**	**QP Bids**
Scenario 1	161,228	161,217	161,156
Scenario 2	118,983	118,974	118,890
Scenario 3	110,246	110,242	110,166

Table 6.5 – Total System Costs differences under alternative packages (Scenario 2)		
NPV of 2012-13 to 2029-30 with weighted 10% and 50% POE demand for each outlook	**Reduction in Total Market Variable, Fixed and Capital Costs from Package 1 ($m)**	
	Package 2	**Package 4**
Scenario 1	11.2	71.9
Scenario 2	8.8	92.9
Scenario 3	4.3	80.0

Table 6.6 shows the division of total system cost between generation (both fixed and variable) and transmission. The cost of transmission is low compared to generation. This is mainly because existing transmission is treated as a sunk cost which is the same for all packages. It is for this reason that significant divergence between all three packages does not occur.

Table 6.6 – Division of Total System Cost ($m) (Scenario 2)			
	Variable Generation Costs	**Fixed Generation Costs**	**Transmission Costs**
RIT-T	82,469	36,227	278
Co-optimised	82,503	36,199	146
Firm Access	82,523	36,203	163

The division of system costs shows that both generation and transmission fixed costs are minimised under the co-optimised planning outcome, with variable generation costs trending toward the average of the RIT-T and OFA models. The most significant difference between the RIT-T and OFA models is that the RIT-T model leads to much higher transmission costs, where generators locate without regard for the cost of transmission. Whilst variable generation costs are lower under the RIT-T, both fixed generation and transmission costs are lower under the OFA model which leads to a lower overall total system cost.

Justification for Low Transmission Cost

There are a number of factors which contribute to the relatively low transmission cost observed in the table above:

1. **Discounting and annuitising of investments**

   We have discussed previously that transmission development tends to occur in the later stages of the study. Therefore, any investment in transmission is heavily discounted. In addition, the cost of transmission only includes the assumed annual repayments that occur before 2030. This method eliminates the end effects which would otherwise occur. Therefore, an investment in 2025-26 for example, would only include 5 annual repayments, heavily discounted. This is discussed further in Section 6.4.1) below.

2. **Reduced congestion**

   As previously mentioned, the forecast level of demand growth is low and therefore, the level of thermal generation development is initially slow. Congestion is therefore initially quite low. In addition, there are a number of characteristics of the LTIRP that tend to produce lower levels of congestion than may occur in reality. For example, hydro generation is energy limited but the LTIRP is able to effectively “move” hydro generation between periods in order to avoid congestion if this minimises cost. This behaviour is not necessarily consistent with the profit maximising behaviour that would be expected in the market.

3. **Categories of transmission not considered**

   There are a number of categories of transmission which are not captured by the zonal approximation of the transmission system:

   - Replacement costs contribute a significant portion of transmission investment. These are not considered in this modelling. It is assumed that replacement cost is relatively independent of generator’s locational decisions.
   - Non-network capital costs are not considered.

- Load driven network augmentations are only partially accounted for. Transmission investment does occur to provide reliable supply to load in the LTIRP. However, this analysis occurs on the zonal level only. Therefore, any intra-zonal load reliability issues are not captured. Again, these investments are considered to be relatively independent of generation. The congestion that is resulting in the need for many such investments does not impact on a generator's access to the RRN. Therefore, the cost of such investments would be recovered from customers, rather than provided for under the firm access model.

4. Using a probabilistic rather than deterministic planning standard

All transmission planning in the LTIRP is comparable to the probabilistic planning approach used in Victoria and South Australia. The outcomes of the deterministic planning used in Queensland and New South Wales will not be reflected in the LTIRP modelling. A limitation of the LTIRP is that it does not consider random generator outages. Therefore, at times of peak load, generation in a given location can always be relied upon at its full capacity adjusted for its average annual outage planned and forced outage rate.

The difference between the LTIRP's transmission planning methodology and the deterministic approach is clearly evident in considering the CQ to NQ limit. In 2005, transmission augmentation was deemed necessary to maintain reliable supply to North and Far North Queensland for periods when the Townsville Power Station is out of service. However, the LTIRP is able to dispatch all generation in North Queensland (considering energy limits of North Queensland hydro generation) at times of peak demand if necessary. Therefore the need for transmission in the LTIRP modelling is delayed well beyond what is required when using a deterministic approach.

This is not necessarily a limitation of the modelling approach. These transmission investments are justified under the reliability arm of the RIT-T. Therefore, the methods used to plan and justify these augmentations would not be altered under the Firm Access Standard. The modelling results provided in this report do not seek to quantify the merits of either probabilistic or deterministic planning. In general, the LTIRP's lack of consideration of both transmission and generation outages, except for the sensitivity cases for specific outages, results in a somewhat optimistic assessment of the capability of the system to meet demand.

This has been assessed in an additional study we conducted and reported on in Appendix E). For that study the LTIRP was applied to build the transmission system as the optimum system if built in 2013, but with generation as it is at present, and with generation installed as it is in the RIT-T generation development scenario out to 2030. Furthermore the interconnection capacity has been set at the present interconnection capacity. We have found that there are some inter-regional and intra-regional flowpaths that are operating at or almost at capacity while others are being utilised at well below their present capacity. The reasons this has occurred are detailed in the Appendix. However, there are a number of clear trends that can be seen by inspecting Table E.1. Clearly, the high capacity corridors to the state capitals are and will continue to be heavily used. This includes:

Corridor Description and Existing Capacity in 2013	Corridor nomenclature
Surat Basin to Brisbane (5288 MW)	SEQ to SWQ
Hunter Valley to Sydney (5033 MW)	SYD to Hunter
Latrobe Valley to Melbourne (8907 MW)	LV to MEL
Northern SA to Adelaide (537 MW)	ADE to NSA

The emerging corridors which are forecast to need rapid development, due to the anticipated development of new generation, particularly wind and gas fired generation, include:

Corridor Description	Corridor nomenclature
Hunter Valley to Northern NSW	NNSW to Hunter
South West NSW to Sydney	SWNSW to CAN + CAN to STHRN + STHRN to SYD
Western NSW to Sydney	SYD to W-NCEN
Melbourne to Northern Victoria	MEL to NVIC
Central Victoria to Northern Victoria	CVIC to NVIC
Northern SA to Adelaide	ADE to NSA

There are also a number of areas where circumstances have changed, and corridors are no longer as heavily used as in the past, including:

- Melbourne to Western Victoria, which is due to the reduction in exports from brown coal generators in Latrobe Valley to Western Victoria and South Australia, as local generation has developed in both those areas

- Central Queensland to Southern Queensland, as load has grown in Central and Northern Queensland and reduced available generation to export to South East Queensland.

6.4.1) Undiscounted Market Costs

The long term modelling of the alternative packages is necessarily compared on a discounted NPV basis to account for varying costs over time and the time value of money. As discussed above, the NPV analysis may appear to show very small differences between the packages when capital investment occurs far into the future. The real capital and variable cost incurred in each of the packages provides an alternative assessment of the relativity between the packages. The real costs presented in the table below also remove any annualising of capital investments. That is, the results presented represent sum total of investment decisions which occurred within the study period.

Table 6.7 – Division of Total System Cost (Undiscounted $m) (Scenario 2)

	Variable Generation Costs	Fixed Generation Costs	Transmission Costs
RIT-T	194,181	82,151	1,529
Co-optimised	194,542	81,079	879
Firm Access	194,623	81,091	909

This outcome shows:

- The RIT-T approach leads to installation of generation in locations which deliver the lowest variable operating cost
- The RIT-T approach leads to a significantly higher capital spend on transmission in order to support delivery of generation supply to customers
- The total of real cost of supply for capital spend plus operating expenses for the period 2012 to 2030 is around $1.24 billion lower in the OFA and $1.36 billion lower in co-optimised compared with the RIT-T approach
- Whilst the annual variable generation supply costs are greater in 2030 under OFA compared with RIT-T, the reduced capital repayments result in a net benefit under OFA (and co-optimised).

This assessment must be carefully interpreted taking into consideration the timing of capital expenditure over the 18-year outlook, and for that reason the findings have been reported on as NPV’s elsewhere in this report.

6.4.2) Transmission Cost Sensitivity

The cost of transmission upgrades is of importance in evaluating the benefits of optional firm access. Therefore, sensitivities have also been conducted which investigate the effect of the cost of intra-regional transmission augmentations on total system costs. As discussed in Section 3.3), the outcomes detailed so far in the report have all been based on an assumed unit cost of transmission of $2,000/MW/km. ROAM has analysed the impact of increasing or decreasing this cost to $3,000/MW/km and $1,000/MW/km respectively. The outcomes of these studies are provided in Table 6.8[43].

Table 6.8 – Total System Costs – Transmission Cost Sensitivity ($m) (Scenario 2)

Scenario		Generation Costs	Transmission Costs	Total System Costs
RIT-T	$1,000/MW/km	118,513	223	118,736
	$2,000/MW/km	**118,614**	**278**	**118,892**
	$3,000/MW/km	118,724	273	118,997
Co-optimised	$1,000/MW/km	118,550	153	118,703
	$2,000/MW/km	**118,673**	**146**	**118,819**
	$3,000/MW/km	118,782	87	118,870
Firm Access	$1,000/MW/km	118,604	142	118,746
	$2,000/MW/km	**118,702**	**163**	**118,865**
	$3,000/MW/km	118,764	171	118,935

From these results it can be seen that the total cost of transmission in the planning study is not directly proportional to the transmission capital cost. Under the RIT-T method, the LTIRP is less likely to install transmission if the cost of transmission increases. When subject to a higher cost, any investment in transmission must produce a higher level of economic value. An increase in the cost of transmission reduces the transmission build and increases congestion and therefore results in a higher cost of generation.

[43] The generation costs presented in this Table 6.5 are those resulting from the LTIRP studies, whereas those presented in Table 6.3 and 6.5 previously include variable cost modelling from the 2-4-C studies.

For both the co-optimised and the firm access planning approaches, the LTIRP is able to choose generation locations that may be of higher cost but require less transmission investment. Accordingly, generation investment is more likely to occur in zones that reduce the need for additional transmission investment.

The higher unit cost of transmission has a material impact on the relativity of costs of the planning scenarios. A higher unit transmission cost increases the inefficiencies embodied in the RIT-T methodology when compared with the co-optimised approach. In the low unit transmission cost scenario, the difference between the RIT-T and the co-optimised approach is minimal. The firm access package actually represents in an increase in total system costs over the RIT-T method. It follows that the high transmission cost sensitivity increases the benefits of a co-optimised approach to generation and transmission planning.

6.5) *Assessing Willingness to Contract*

An assessment of the willingness to contract has been completed for a low utilisation OCGT. The net revenue expectation (defined here as pool revenue plus cap contract settlement plus congestion settlement [if applicable]) has been assessed for an OCGT generator located in the SWNSW zone which has purchased firm access vs one which has not purchased firm access. The net revenue is assessed for each of these generators for various levels of contract sales. The notional annual cap contract premium for a $300/MWh cap has been set at $11.96/MWh. This value reflects an assessment of the value at risk in the pool price forecast from the modelling. 100 Monte Carlo simulations have been completed for each of the H10 and H50 load profiles under Scenario 2.

The key observations from this assessment are as follows:

- Comparing the firm and non-firm uncontracted raw pool revenue spread:
    - Under H10 demand conditions it is clear that a firm generator receives a higher average pool revenue compared with a non-firm generator. This is due to the firm generator never missing out on market price due to network congestion. What is perhaps not an intuitive outcome is that the firm generator also experiences a more volatile pool revenue with the volatility more weighted to the upside. However, the firm generator always receives the extreme pool price events, which is why the firm generator has a higher average revenue expectation.

   - The same general observation is true for the H50 demand expectation. The pool revenue expectation is much lower in the H50 case compared with the H10 case.
- Comparing the firm and non-firm fully contracted net revenue spread:
   - Under H10 demand expectations the outcome presents a lower average net revenue compared to the uncontracted pool revenue. This is purely an outcome of the elected $11.96/MWh cap premium. A higher or lower premium will increase or reduce the average net revenue expectation. This absolute outcome is not the focus of this assessment. The focus is how contracting affects the net revenue certainty. What the assessment clearly shows is that contracting to 100% of capacity results in a much narrower spread of net revenue expectation. This is true both within any year and also over the 5-years of modelled outcomes presented. Not surprisingly, contracting increases revenue certainty. The absolute revenue risk/reward is a function of the expectation of pool revenue and the contract premium the generator is able to attract. That final point is not a focus of this analysis. Again, an important observation is that the firm generator receives a higher average revenue compared with the non-firm generator.
   - Under H50 demand conditions a firm generator will have a higher average net revenue expectation compared with a non-firm generator. A further important observation is that the contracted net revenue is much more closely aligned for the H10 and H50 outcomes. Again this supports the revenue certainty principle. Again the firm generator in fact maintains a greater volatility in expected net revenue compared with the non-firm generator, due to the upside price volatility.

Overall observations comparing the firm vs non-firm generator are:

- the standard deviation of revenue expectation decreases as the level of contracting increases.
- a firm generator has a higher average net revenue expectation compared with a non-firm generator under all levels of contracting.
- as highlighted in the charts and discussion above, the firm generator maintains a higher standard deviation of revenue expectations under all levels of contracting, although it is towards the upside.

This demonstrates that generator market revenue is likely to be enhanced for firm generators under Package 4 compared with Package 1 as they will achieve income from market price volatility whenever they are available. This in turn suggests that Package 4 may increase the willingness of firm generators to enter into contracts as they will have a higher confidence of access to the market price and thus lower risk of facing a short position.

Figure 6.14 – Net revenue uncontracted OCGT H10 demand

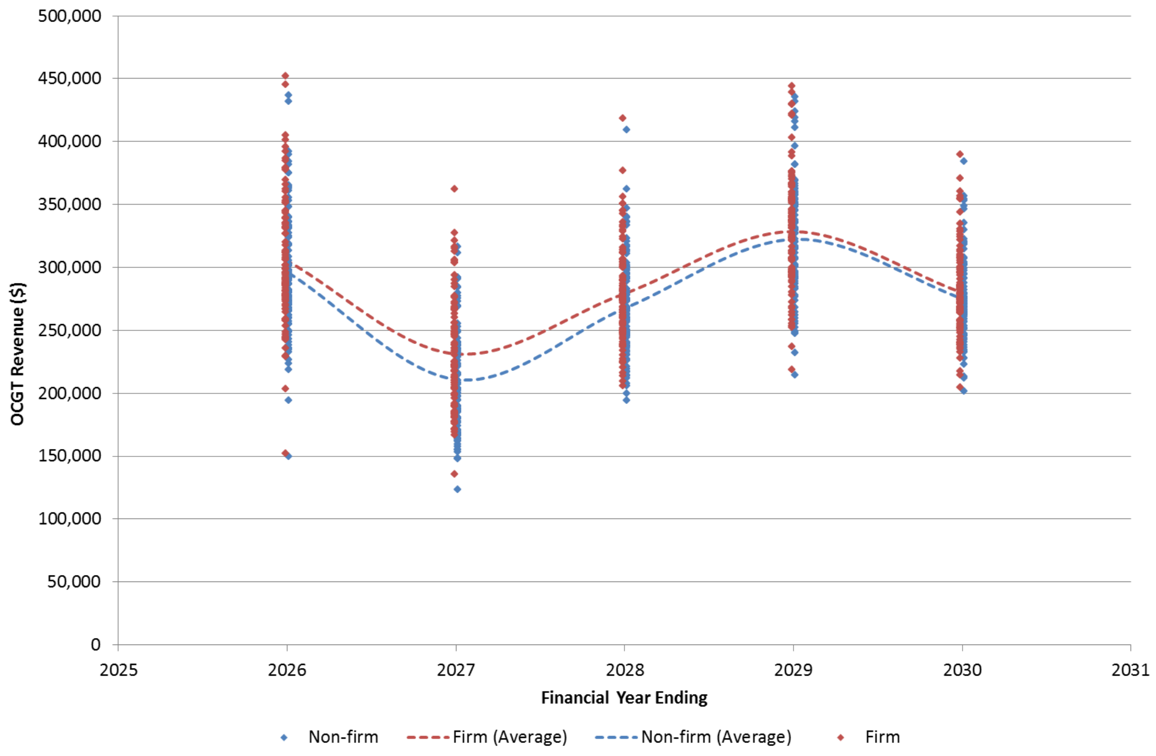


Figure 6.15 – Net revenue uncontracted OCGT H50 demand

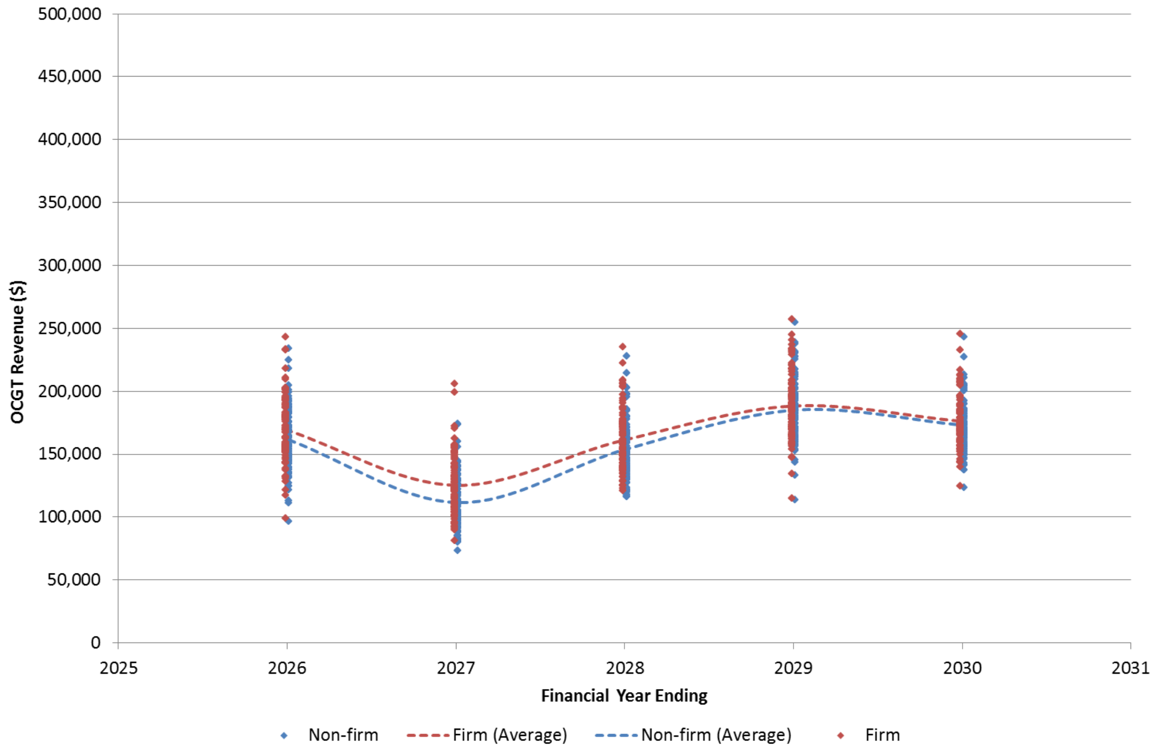


Figure 6.16 – Net revenue fully contracted OCGT H10 demand

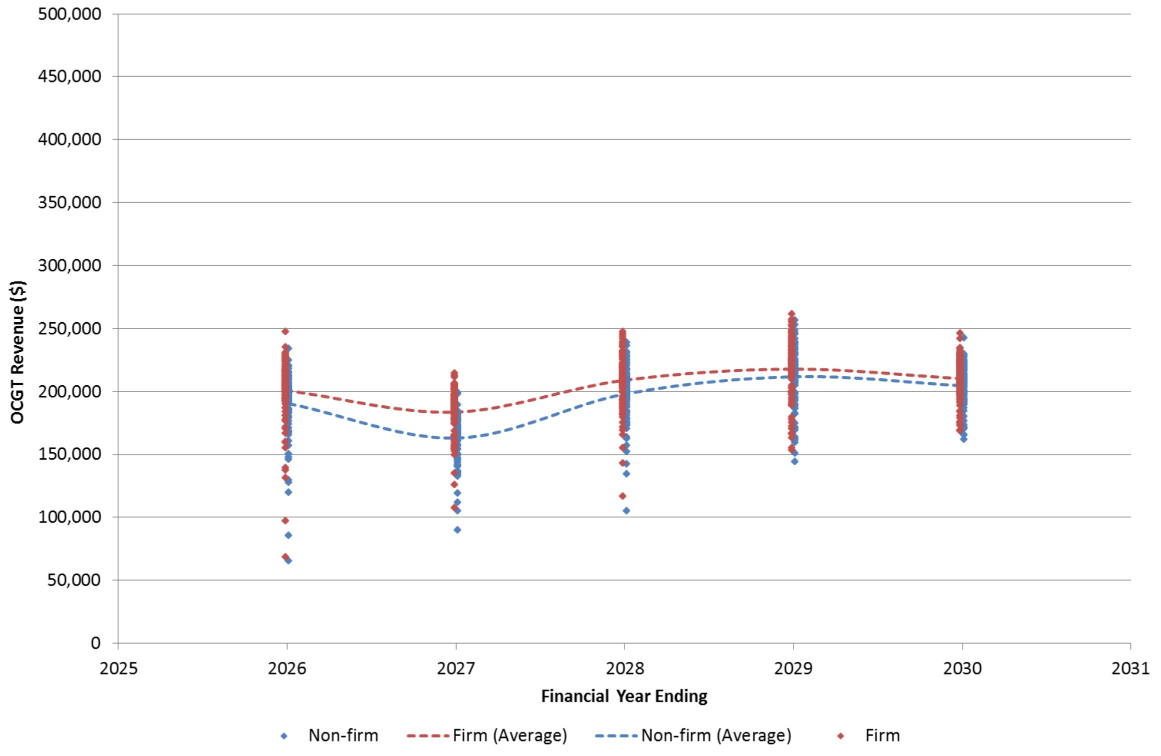
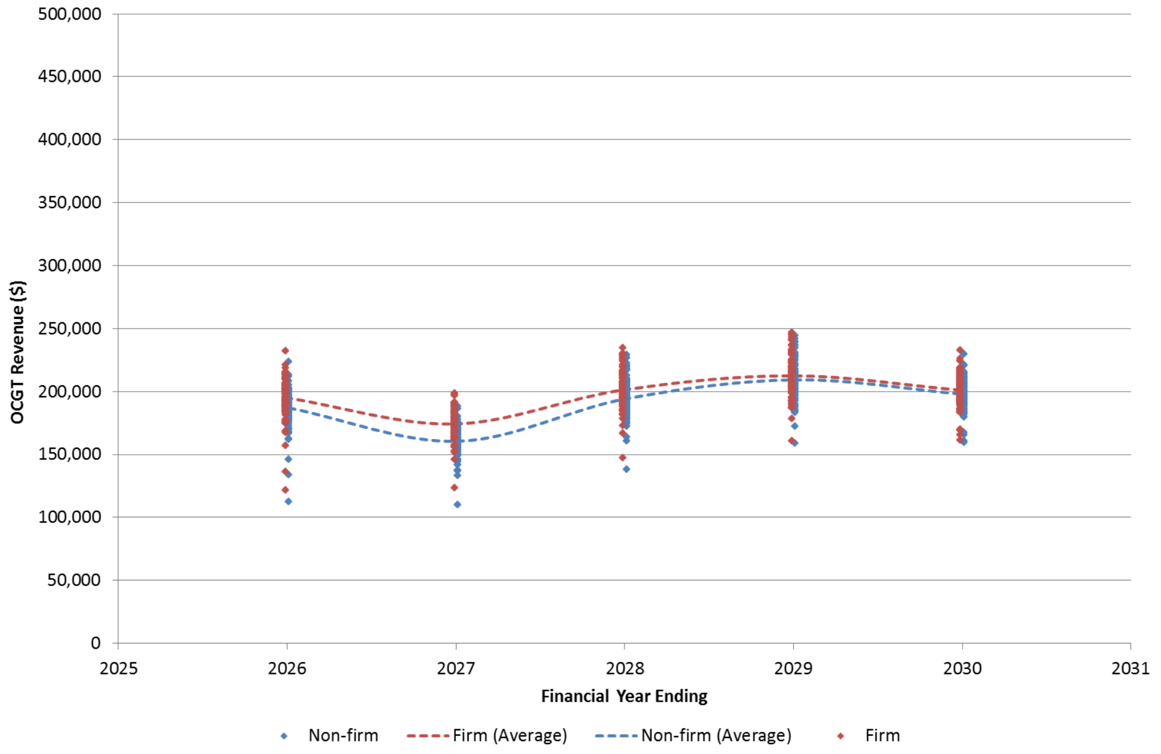


Figure 6.17 – Net revenue fully contracted OCGT H50 demand

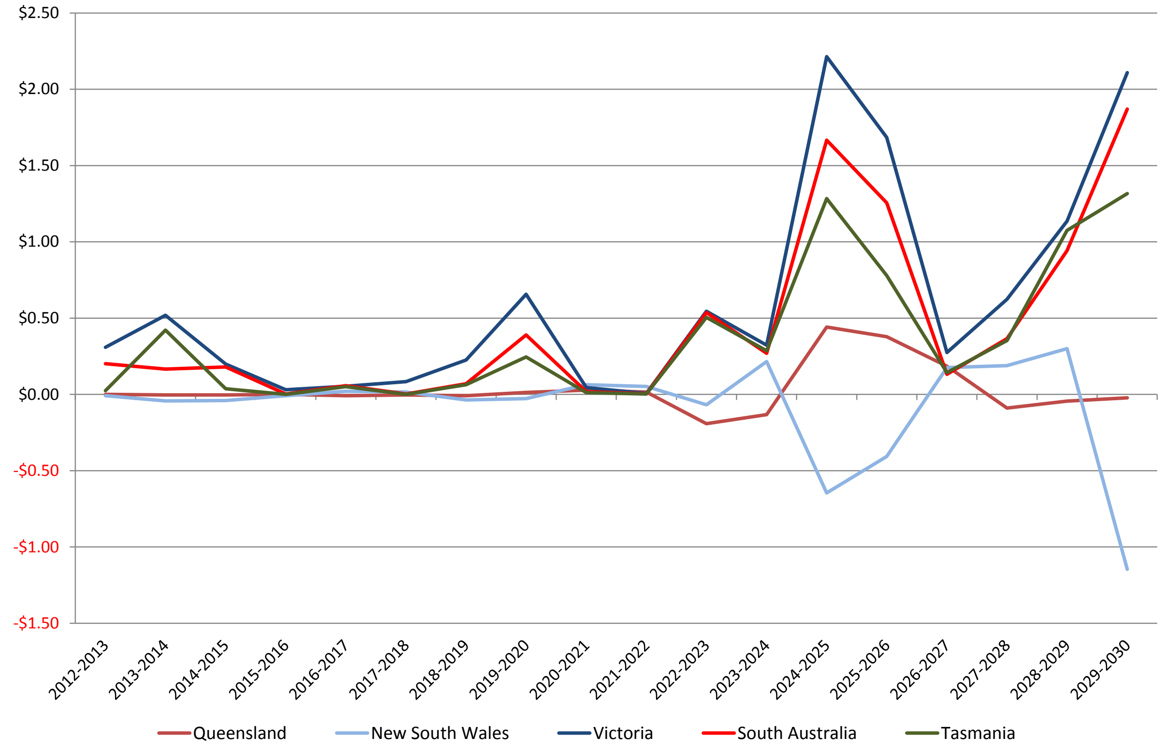


6.6) *Impact of Alternative Packages on Wholesale and Retail Prices*

The quantitative assessment of the alternative packages has not revealed any significant impacts on total system supply cost.

The impact of disorderly bidding on pool prices can be seen in Figure 6.18. This figure shows the increase in time weighted annual average pool price that resulted from the implementation of disorderly bidding and therefore provides a comparison between Package 1 and Package 2. This analysis is for the Scenario 2 set of input assumptions. It is evident from the pool price outcomes that when combined with the energy base, the potential wealth transfer towards consumers which results from removing disorderly bidding is potentially of a greater magnitude than the impact of disorderly bidding on system costs.

Figure 6.18 – Pool Price Increase from Disorderly Bidding (Scenario 2)



Qualitatively, under the proposed Package 4 mechanism generation will be exposed to the cost of transmission. On the other hand the transmission development cost will be relieved from the transmission service provider to a large degree (apart from reliability driven transmission requirements). The outcome will be that transmission costs will be reflected in the wholesale energy market, rather than through TUoS.

Exposing renewable generators to the cost of transmission may also have potential implications for meeting the RET and the price of the LGC market that supports the RET. However, higher market prices reflecting the cost of transmission in the generation sector should balance the higher total cost of renewable generation and therefore lead to similar LGC market prices.

7) Conclusions

7.1) Assessment of disorderly bidding

The potential productive efficiency gains from removing the incentives for disorderly bidding have been found to be similar in the forecasting to that in the backcasting. The modelling has shown that the potential for system conditions which lead to disorderly bidding behavior may increase over time due to increased development of intermittent wind generation and periods of network congestion. Furthermore the potential cost of disorderly bidding may increase as a result of carbon pricing increasing the cost of fossil fuel plant, combined with fossil fuel plant displacing very low marginal cost renewable wind (and solar) generation during disorderly bidding periods. Despite these factors, the observed cost increase resulting from disorderly bidding should remain small compared with total system costs.

The historical assessment of disorderly bidding supports the general observations of market participants that such events are primarily triggered by non-system normal transmission events. Accordingly, the behavior of generation and the operation of settlements under the OFA model will be critically important during these periods.

7.2) Long term forecast modelling

The LTIRP modelling suggests that the implementation of the OFA Package 4 does not significantly improve the allocative or dynamic efficiency of the system in meeting demand. This is despite the fact that the co-optimisation of transmission and generation results in considerable differences in generation and transmission development when compared to the current RIT-T approach. These differences do not result in a material change in economic cost due to numerous factors:

1. The margins in locational decisions are relatively small. That is, the additional cost of locating generation away from the lowest cost zone to avoid congestion is not dissimilar in magnitude to the additional transmission cost avoided. Therefore, a substantial change in the location of generation (such as that observed between SWQ and SEQ) may have only a minor impact on efficiency.
2. Wind power makes up the majority of new entrant generation. The locational decision making of wind generation is observed to be relatively independent of the planning approach. Wind generation generally locates in zones that provide the highest capacity factors. The energy able to be produced by the wind farm has a more dominant impact on wind farm locational incentives that transmission concerns.

3. The relatively low cost of transmission as a whole when compared to generation costs.

7.3) Summary

This modelling has focused on quantifying the potential changes in the productive, allocative and dynamic efficiencies of the development and operation of the NEM under the proposed Package 1, Package 2 and Package 4 transmission frameworks. The modelling has shown that the overall system costs are very similar under all frameworks due to the widespread availability of energy resources throughout the NEM and the cost structures of fuel transport, transmission and generation in the NEM jurisdiction.

It is acknowledged that operational and financial risk in the NEM is associated with market price outcomes. Although such outcomes may be considered a wealth transfer it is ultimately the price that consumers pay for electricity that is of key importance. We therefore recommend that this quantitative assessment be expanded to investigate in more depth market price implications and risk management costs for the generation sector.

Appendix A) The LTIRP model

The LTIRP software has been designed specifically to meet the challenges of generation and transmission development co-optimisation problems. It uses linear programming techniques (or Mixed Integer Programming if desired, as discussed below) to determine the least cost economic expansion plan by minimising the cost of serving the energy demanded for each year. Other key features include:

- The model aggregates a number of half hourly periods into each load block, with weightings assigned to each load block such that an accurate representation of the load duration curve is modelled. This is explained further below.
- Includes the capability to limit:
  - Fuel availability (particularly important for energy limited generators such as hydro plant)
  - Build rates of generation technologies
  - Availability dates for generation technologies
  - RET and carbon emissions targets
  - Banking and borrowing of RECs
- Other features include:
  - Full accounting of existing generation plant
  - Carbon pricing
  - Fuel supply and demand price curves
  - Economic, age and capacity factor based retirements

A.1) Model limitations

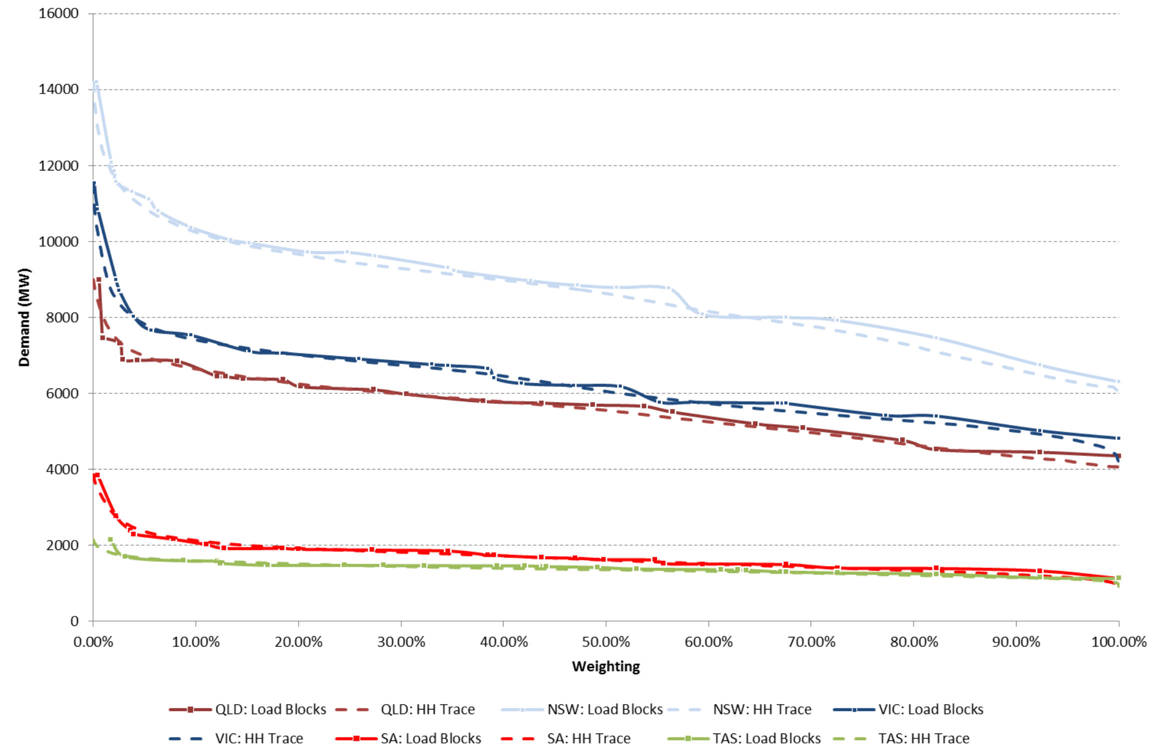
ROAM's LTIRP model is the most sophisticated of its kind available. However, like all models of this nature it has limitations. The most important limitations are:

Not time sequential

This model utilises "load blocks", which are determined based upon the load duration curve. Each load block is simulated only once, and the results from each load block are weighted according to the load duration curve to produce realistic annual outcomes. This approach significantly reduces the amount of simulation time required, allowing a much larger number of variable parameters to be co-optimised. However, it is not time sequential in nature, and this means that certain features of the market are captured through averaging methods. For example, generator forced outages are captured as a reduction in availability spread across all load blocks (generator scheduled outages are included via annual maximum capacity factors for each station such that maintenance can be scheduled during the most appropriate load blocks).

The model uses a discrete number of load blocks per year to represent each region's load duration curve simultaneously. The figure below demonstrate the accuracy of the methodology applied, with minimal difference between the load duration curves derived from the load blocks, and the full half hourly load trace.

Figure A.1 – Load Block versus Half Hourly Trace Comparison



If desired, ROAM also utilises an alternative Integrated Resource Planning (IRP) model that is time sequential. However, this model has much longer simulation times, which will increase the cost of this study. For this reason most consultants offer non time sequential models.

Intermittent generation

Due to the non-time sequential nature of the LTIRP model (and all similar models) the modelling of intermittent generation is a key challenge. Many previous modelling studies have assumed a constant average output from intermittent generators in all load blocks. This greatly over estimates the contribution of intermittent generation to reliability. ROAM's approach, by contrast, is as follows:

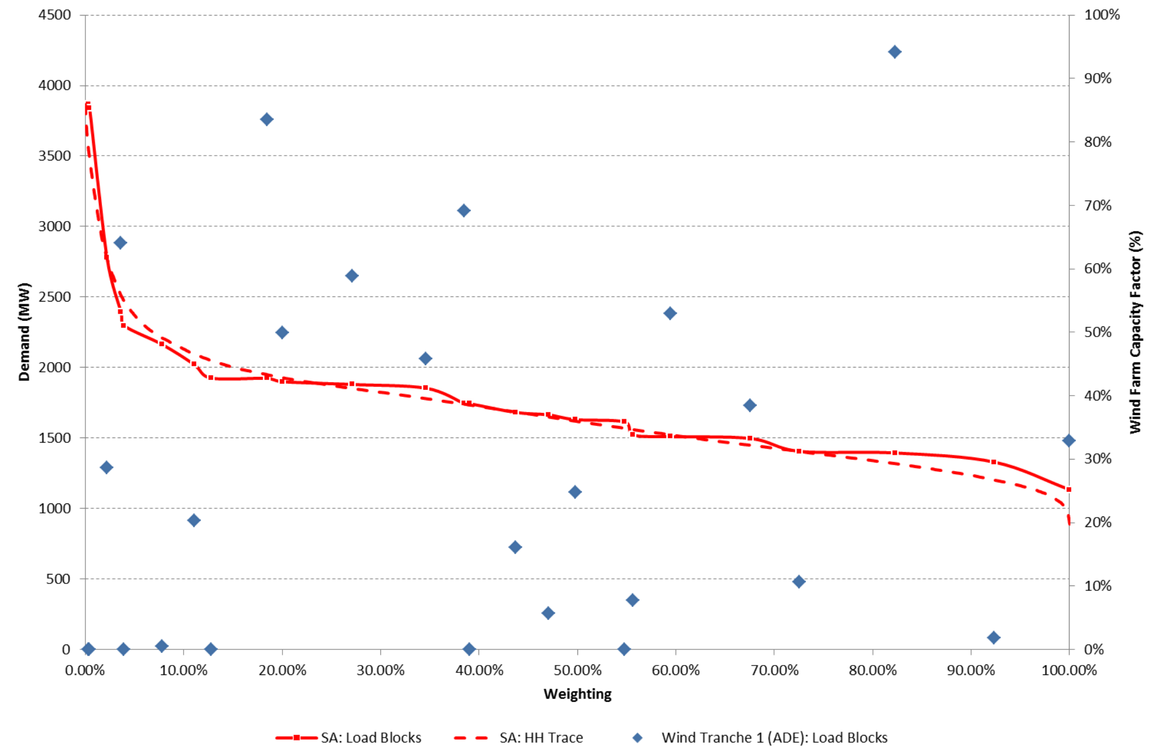
1. Determine load blocks from the load duration curve.
2. Determine the generation duration curve for wind farms in each NTNDP zone.

3. Use the previously defined load blocks to split up the intermittent generation duration curve into equivalently weighted blocks. These are forced to be in a different order to the load blocks to ensure diversity (and ensure that the model doesn't always have high wind at times of high demand and low wind at times of low demand).
4. The wind is considered to contribute these varying amounts in each load block. This means that wind contributes a large quantity of energy in some load blocks, and very little in other blocks, and the weighting of periods is determined from actual wind farm output data. This forces the model to include sufficient other firm capacity when it is economical to do so (to avoid the cost of unserved energy in periods where there is no contribution from wind).

This methodology effectively captures the intermittency of wind and its impacts upon market and network operation. It is a large improvement over previous modelling approaches that utilise a constant output from intermittent generators.

Solar farms are modelled with a similar approach to capture the intermittency of solar technologies. An example of the production from wind farms in each load block versus the load duration curve is shown in the figure below.

Figure A.2 – Load Block versus Half Hourly Trace Comparison



Zonal network model

This modelling will capture network augmentations between the nominated zones, but will not capture network augmentation within these zones.

Non-integer solutions

For this study ROAM proposes to use a linear programming approach. This will allow incremental upgrade of the network (installation of small pieces). Often the network is augmented in response to a new generator or other market development, in which case interconnector augmentations will enter in realistic capacities. However, in some cases small increments can be installed in each year, which is not realistic. This can be addressed through the application of additional constraints in a follow-up iteration.

ROAM can also operate the LTIRP model in an integer fashion (using Mixed Integer Programming), allowing only whole interconnectors to be installed. However, with large numbers of variable parameters this can take a large amount of simulation time, and may not solve within an acceptable time. This limitation applies to all models of this nature. For this reason, ROAM recommends the linear programming approach, with further iterations if required, and/or with possible use of the Mixed Integer Programming approach (if it can be solved within a reasonable timeframe).

A.2) APPLYING THE LTIRP TO FORECAST PACKAGE 1 & 2 – CONTINUATION OF THE RIT-T PLANNING APPROACH

To model Package 1, the LTIRP has been run without any intra-regional transmission limitations. The main driver for generators in locational decisions is therefore to locate in regions and within zones according to the costs of supply, including capital and O&M costs, and availability and price of fuel supply. In other words; this models generators making the assumption that access will be available through transmission building out intra-regional constraints according to the RIT-T and will therefore not be subject to significant congestion. The data on costs of supply has been accessed from the 2012 NTNDP dataset. Inter-regional transmission for Package 1 has been developed on a least cost basis by the LTIRP, by co-optimising inter-regional transmission and regional generation to provide the least cost development.

In the market as the Rules presently apply, TNSPs react to the development of new generation remote from the regional reference node by building out the constraints that result at the intra-regional level through application of the RIT-T. This approach is not necessarily the same as delivering the 'least cost' combination of generation and inter-and intra-region transmission as, under an open access regime consistent with Package 1, generators do not absorb the cost of transmission upgrades in their development program, but instead expect intra-regional constraints to be built out in time to avoid significant congestion. From their business perspective, TNSPs see where generation is being built and apply the RIT-T to alleviate intra-regional transmission congestion where it can be economically justified.

The inter-zonal flows in the LTIRP resulting from the generation development and retirement pattern modelled by the first LTIRP case have then been further modelled to determine the timing and scale of transmission augmentations needed to support the generation developed in the model, acknowledging that some optimal level of congestion is likely to remain. This analysis has been performed using a systematic method which approximates the existing RIT-T procedure, in accordance with the following quantitative methodology.

In order to replicate the RIT-T process, ROAM has developed an alternative LTIRP model that determines market benefit and reliability driven intra-regional transmission upgrades. In this model, the generation and inter-regional interconnector development determined by the first stage of the LTIRP is used as input. The transmission capacity between zones and the DC load flow approximation are then used by the model to determine the flows, and therefore the level of congestion, observed on flowpaths between zones. The RIT-T process can therefore observe the congestion on each flowpath and will develop intra-regional transmission which provides a net economic benefit to the market. The LTIRP inherently computes the least cost outcome for the NEM, consistent with meeting the reliability standard, through the application of the Market Price Cap to any unserved energy resulting from generation and transmission capacity limitations at the grid level.

To determine transmission investments that meet the RIT-T criteria, the LTIRP weighs the benefits of the investment against the costs. The cost of intra-regional transmission upgrades is very difficult to determine as each case is unique depending on circumstances such as the voltage of the system, the series of transmission lines which consist the intra-zonal transfer, the terrain which the transmission traverses, the availability of easements etc. ROAM has therefore assumed a unit cost of $2000/MW/km for intra-regional transmission augmentation. The distances have been calculated as the distance between representative points in the transmission network in each zone.

This modelling incorporates the development of load, both regionally (using AEMO demand and energy targets) and within regions. The location of load within a region does impact on transmission flows on congestion and is reflected in the demand coefficients of ROAM's constraint equations. ROAM has used data from numerous sources to incorporate the impacts of significant load developments on the division of load in peak and off-peak periods between zones. These impacts are incorporated into both the LTIRP congestion modelling and the development of demand coefficients for ROAM's set of thermal constraint equations.

The final outcome of this stage is a listing of size and timing of intra-regional transmission development, based on the estimated relationship between capacity and cost for each intra-regional flowpath. The LTIRP results have been analysed and have been found to allow some optimum level of congestion to occur if the generator cost differences between the zones are insufficient to justify the cost of the transmission investment required.

The resulting series of intra-regional transmission upgrades is then used to develop the alleviation of thermal constraint equations over the period of the study. For the purposes of constraint equations, any transmission investment increases the capacity of the transmission lines but does not impact on the relative flows between lines. Therefore, a transmission augmentation on a given flowpath is effectively a proportional uprating of each transmission line chosen to represent the flowpath.

A.3) APPLYING THE LTIRP TO FORECAST PACKAGE 4 – OPTIONAL FIRM ACCESS PLANNING APPROACH

To model Package 4 the LTIRP has been configured to assess the impact of optional financial firm access on the development of generation and transmission. The AEMC has developed the principle of the Firm Access Standard (FAS) whereby the transmission network must be sufficient to meet both reliability criteria and allow for firm access generation to be dispatched in system normal conditions. ROAM's LTIRP has been altered to meet these criteria by enforcing additional constraints on the capacity of each transmission path between zones. These constraints are dependent on a number of assumptions related to demand, support generation (that is, generation which alleviates congestion on the flowpath) and the level of firm access generation (and firm access held by interconnectors) in each zone.

ROAM's firm access constraints are developed on the assumption that the transmission network must be capable of dispatching 100% of all firm access generation at any time.

Therefore support generation is assumed to not contribute to any alleviation of congestion. Similarly, the firm access constraints must hold for any observable level of regional demand.

A key feature of the AEMC FAS is that the market benefits aspect of the RIT-T will no longer be applicable. ROAM has restricted the transmission built above the level of firm access to ensure that the LTIRP outcomes are consistent with this principle.

A generator that is situated at a remote node and chooses to purchase firm access to the reference node must procure access to each transmission flowpath between it and the reference node, proportional to its use of each flowpath.

The LTIRP would then calculate the appropriate level of firm access for each new entrant and each generator type by deciding the size and timing of firm access generators versus non-firm access generators.

Appendix B) Constraint Equation Formulation using The Constraint Equation Development Tool

B.1) Methodology

The objective of a thermal constraint equation is to prevent overloading of any transmission element during both system normal operation and following any single credible contingency (post contingent). A constraint equation is made up of terms on the left-hand side (LHS) and right-hand side (RHS) of the equation such that the sum of terms on the LHS is less than (or sometimes greater than) or equal to the sum of terms on the RHS.

The elements within a thermal constraint equation can be categorised into one of the following four categories:

- Generator coefficients;
- Interconnector coefficients;
- Demand coefficients; and
- Constant term.

There are other components which may form part of a generic constraint equation, such as terms relating to generator or capacitor bank status. However, they are not required for this work since we are only interested in thermal constraint equations, which do not depend on non-linear terms.

Generator Coefficients

Generator coefficients in a constraint equation are Power Transfer Distribution Factors (PTDFs) associated with generators within the network. The PTDF for transmission element connecting bus j to bus k with respect to a generator at bus m is a sensitivity measure of the power flow on the transmission element, expressed in terms of a percentage distribution of an incremental power injection at bus m.

The coefficient for a generator connected at bus m can be calculated by differentiating the power flow across a monitored element connecting bus j to bus k with respect to the power injection at bus m. That is,

$$PTDF_{m,j\to k} = \frac{dF_{j\to k}}{dP_m}$$

where P_m is the power injection at bus m and $F_{j\to k}$ is the power flow across the monitored element from bus j to bus k. An underlying assumption that is inherently applied is that the Regional Reference Node (location of the slack bus) will absorb any incremental injection at bus m. Therefore, the PTDFs can be viewed as the contribution of a small amount of power injection at bus m on the power flow across element connecting bus j to bus k to supply a small increase in demand at the Regional Reference Node.

Generator coefficients defined this way will be dependent purely on the system network topology and the location of the Regional Reference Node. They will not be influenced by the regional demand or generation dispatch across the system.

ROAM's constraint equation development tool computes PTDFs in DC solution mode, which assumes zero transmission losses. ROAM understands that this is the methodology employed by AEMO in determining dispatch constraint equations. Therefore, there is no inconsistency in obtaining the generator coefficients for constraint equations between ROAM and AEMO.

Interconnector Coefficients

As for the calculation of generator coefficients outlined in the previous section, interconnector coefficients are PTDFs associated with power injection at the regional boundary buses. That is, the coefficient for an interconnector at the regional boundary bus n for a monitored element connecting bus j to bus k is defined as,

$$PTDF(INTER)_{n,j\to k} = \frac{dF_{j\to k}}{dP(INTER)_n}$$

where $P(INTER)_n$ is the interconnector power injection (positive for importing power and negative for exporting power) from neighbouring regions into bus n.

Demand Coefficients

Demand coefficients correspond to the contribution of regional demand towards the power flow on a monitored network element. To calculate the demand coefficient for a monitored network element connecting bus j to bus k, we calculate the derivative of the power flow from bus j to bus k with respect to the regional *as generated* demand (as delivered demand plus system losses and auxiliary loads). That is,

$$\text{Demand Coefficient}_{j\to k} = \frac{dF_{j\to k}}{d\ \text{Demand}}$$

This value can be approximated accurately by scaling the regional demand up by a small amount (less than 1%) and dividing the difference in power flow by the difference in regional demand. That is,

$$\text{Demand Coefficient}_{j\to k} = \frac{F'_{j\to k} - F_{j\to k}}{\text{Demand}' - \text{Demand}} = \frac{\Delta F_{j\to k}}{\Delta\text{Demand}}$$

where $F'_{j\to k}$ is the observed flow associated with the scaled demand and Demand' is the scaled up demand.

The methodology described above assumes that the change in the regional demand is balanced by power injection at the Regional Reference Node. Furthermore, since the demand is scaled up in proportion to the existing demand distribution, different demand distributions from different system operating states will result in different demand coefficients. Therefore, some consideration is required to decide upon the most adequate demand coefficient for a particular constraint.

ROAM computes demand coefficients using AC power flow and the full Newton solution method. ROAM understands that this is consistent with AEMO's methodology.

Constant Term

The constant term corresponds predominantly to the thermal line rating (in MW) of the monitored element, with an additional offset referred to as the *constant-ex-rating* value. That is,

$$\text{Constant Term} = \text{Rating}_{\text{MW}} + \text{Constant-ex-rating}$$

Thermal line ratings are typically given in MVA. To convert MVA ratings to MW ratings, ROAM assumes a power factor (PF) of 0.95 and equates the MW ratings as,

$$\text{Thermal Rating}_{MW} = PF \times \text{Thermal Rating}_{MVA}$$

The *constant-ex-rating* value is required in addition to the thermal rating to take account of the difference in power flow between AC and DC solutions (since generator coefficients are calculated based in DC load flow) and the contribution (equivalent PTDF) of all other generators with small coefficients which are not explicitly included in the constraint equation. This value is computed as the difference between the calculated flow across the monitored element based on generator and demand coefficients obtained and the actual AC power flow solution. For a system with *M* generator connection points and *N* interconnector boundaries, the *constant-ex-rating* value for the monitored element connecting bus j to bus k is calculated as,

$$\begin{aligned} \textit{constant-ex-rating}_{j\to k} = & \sum_{m=1}^{M} PTDF_{m,j\to k} \cdot GEN_m \\ & + \sum_{n=1}^{N} PTDF(INTER)_{n,j\to k} \cdot P(INTER)_n \\ & + \text{Demand Coefficient}_{j\to k} \cdot \text{Demand} - F_{j\to k} \end{aligned}$$

B.2) Formulation of a Constraint Equation

Having defined all of the key elements, a constraint equation is formulated with generation and interconnector terms on the LHS and constant and demand terms on the RHS as,

$$\begin{aligned} \sum_{m=1}^{M} PTDF_{m,j\to k} \cdot GEN_m \quad & \leq \quad \text{Thermal Limit'}_{MW} + \text{Constant-ex-rating}_{j\to k} \\ + \sum_{n=1}^{N} PTDF(INTER)_{n,j\to k} \cdot P(INTER)_n \quad & \quad\quad - \text{Demand Coefficient}_{j\to k} \cdot \text{Demand} \end{aligned}$$

Further to this, AEMO has specified that in cases where the coefficient of a term on the LHS is relatively small then the risk of NEMDE choosing sub-optimal dispatch decisions may exist. To avoid such situations the following rule has been adopted[44]:

[44] AEMO: Constraint Formulation Guidelines, version 10, 6 July 2010.

LHS Terms shall not have coefficients less than 0.07. This can be achieved as follows.

1. Scale the constraint equation such that all coefficients for LHS terms are not less than 0.07 provided that the absolute value of largest coefficient of any LHS term does not then exceed 1.0. This is to ensure that the effective violation penalties of network constraint equations grade adequately with other constraints in the dispatch algorithm; and
2. If after scaling terms with such small coefficients remain, transfer these terms to the RHS.

B.3) SELECTION OF BRANCHES FOR CONSTRAINT EQUATION EVALUATION

The zonal configuration has been developed based on an assessment of the NEM transmission network. Most of the zonal arrangement selected is in alignment with the NTNDP zones defined by AEMO. ROAM has developed constraint equations based on the N-1 security envelope for the set of lines that cross the zonal boundaries.

Table B.1 – Inter-zonal transmission elements selected for constraint equations development

Zones	From Bus	To Bus	Circuit
NQ to CQ	4BOU275A	4NEB_S1	1
NQ to CQ	4NEB_S1	4BRD275A	1
NQ to CQ	4NEB_S1	4BRD275A	2
NQ to CQ	4NEB_S1	4BRD275A	3
NQ to CQ	4DYS_S1	4PKD132A	1
CQ to SEQ	4GIN275A	4GLD175A	1
CQ to SEQ	4GIN275A	4GLD175A	2
CQ to SEQ	4GIN275A	4WUR275A	1
CQ to SWQ	4HALYS	4CVL275A	1
CQ to SWQ	4HALYS	4CVL275A	2
SWQ to SEQ	4MID330E	4GBK_S1	1
SWQ to SEQ	4MID330E	4GBK_S1	2
SWQ to SEQ	4POS110A	4MID110B	1
SWQ to SEQ	4TNG275A	4BLK_S1	1
SWQ to SEQ	4TNG275A	4BLK_S1	2
SWQ to SEQ	4MTE275A	4TNG275A	1
SWQ to SEQ	4MTE275A	4TNG275A	2
SWQ to SEQ	4SPN275A	4TNG275A	1
SWQ to NNSW	Interconnectors are limited by intra-regional zonal limitations		

Zones	From Bus	To Bus	Circuit
SEQ to NNSW	Interconnectors are limited by intra-regional zonal limitations		
NNSW to HUNTER	2LPS330A	2TAM330A	1
NNSW to HUNTER	2MRK330A	2TAM330A	1
NNSW to HUNTER	2KEM132B	2PMQ132G	1
HUNTER to SYD	2EPS500A	2KCR500A	1
HUNTER to SYD	2EPS500A	2KCR500A	2
HUNTER to SYD	2SYN330A	2VPS330A	1
HUNTER to SYD	2MNP330A	2TGH330B	1
HUNTER to SYD	2SYW_S1	2VYD330A	1
HUNTER to SYD	2SYW_S1	2MNP330A	1
HUNTER to SYD	2SYW_S1	2RGV330A	1
HUNTER to SYD	2SYW_S1	2BAY330A	1
HUNTER to CENTRAL	2BAY500A	2MPS500A	1
HUNTER to CENTRAL	2BAY500A	2WOL500A	1
CENTRAL to SYD	2SYS330A	2WWP330A	1
CENTRAL to SYD	2ING330A	2WWP330A	1
STHRN to CENTRAL	2BAN500A	2MPS500A	1
STHRN to CENTRAL	2BAN500A	2MPS500A	2
STHRN to SYD	2SYW_S1	2BAN330A	1
STHRN to SYD	2DPT330A	2SYS330A	1
STHRN to SYD	2KCR330A	2MAC330A	1
CAN to STHRN	2BAN330A	2CRW330A	1
CAN to STHRN	2MRN330A	2YAS330A	1
CAN to STHRN	2MRN330A	2YAS330A	2
CAN to STHRN	2CAP330A	2KVP330A	1
SWNSW to CAN	2CAN330A	2UTP330A	1
SWNSW to CAN	2UTP330A	2YAS330A	1
SWNSW to CAN	2LTP330A	2YAS330A	1
SWNSW to CAN	2CAN330A	2LTP330A	1
SWNSW to CAN	2YAS132A	2MRU132A	1
SWNSW to CAN	2YAS132A	2WAW132A	1
SWNSW to CAN	2YAS132A	2BUK132A	1
SWNSW to NVIC	Interconnectors are limited by intra-regional zonal limitations		
SWNSW to CVIC	Interconnectors are limited by intra-regional zonal limitations		
NVIC to MEL	3DED330A	3SOU330B	2
NVIC to MEL	3DED330A	3SOU330C	1
NVIC to MEL	3EPS220A	3THO220B	1
NVIC to CVIC	3FOS220A	3SHE220A	1
LV to MEL	3HAZ500A	3SOU500A	1
LV to MEL	3HAZ500A	3SOU500A	2
LV to MEL	3HAZ500A	3ROV500A	1
LV to MEL	3CRA500A	3HAZ500A	1

Zones	From Bus	To Bus	Circuit
LV to MEL	3HWP220C	3ROW220A	1
LV to MEL	3HWP220C	3ROW220A	2
LV to MEL	3ROW220A	3YPS220A	1
LV to MEL	3ROW220B	3YPS220A	2
LV to MEL	3ROW220B	3YPS220A	3
LV to MEL	3ROW220B	3YPS220A	4
MEL to WVIC	3MOO500A	3MRT500A	1
MEL to WVIC	3MOO500A	3MRT500A	2
MEL to CVIC	3BAL220A	3MOO220A	1
MEL to CVIC	3BAL220A	3MOO220A	2
MEL to CVIC	3BAL220A	3TER220A	1
MEL to SESA	Interconnectors are limited by intra-regional zonal limitations		
CVIC to NSA	Interconnectors are limited by intra-regional zonal limitations		
SESA to ADE	5TUN275A	5TAL275A	1
SESA to ADE	5CHG275A	5TAL275A	1
SESA to ADE	5MOB132A	5TAL132A	1
ADE to NSA	5BUN275A	5PAR275C	1
ADE to NSA	5PAR275C	5TMP275B	1
ADE to NSA	5ROS132A	5PAR132A	1
ADE to NSA	5ROB275A	5PAR275C	1
ADE to NSA	5ROB275A	5TUN275A	1
NSA to FNSA	5DAV275B	5BUN275A	1
NSA to FNSA	5DAV275B	5BRK275A	1
NSA to FNSA	5DAV275B	5CAN275A	1
NSA to FNSA	5DAV275B	5BEL275A	1
LV to Tas	Interconnectors are limited by intra-regional zonal limitations		

Appendix C) Zonal model, distances between zones and existing limits

The zonal representation of the NEM developed by ROAM is presented in the series of charts below. The distances between zones, as shown, are applied within the LTIRP modelling to determine capital cost for network augmentation. The existing limits between zones are also shown.

Figure C.1 – Queensland Zonal Model

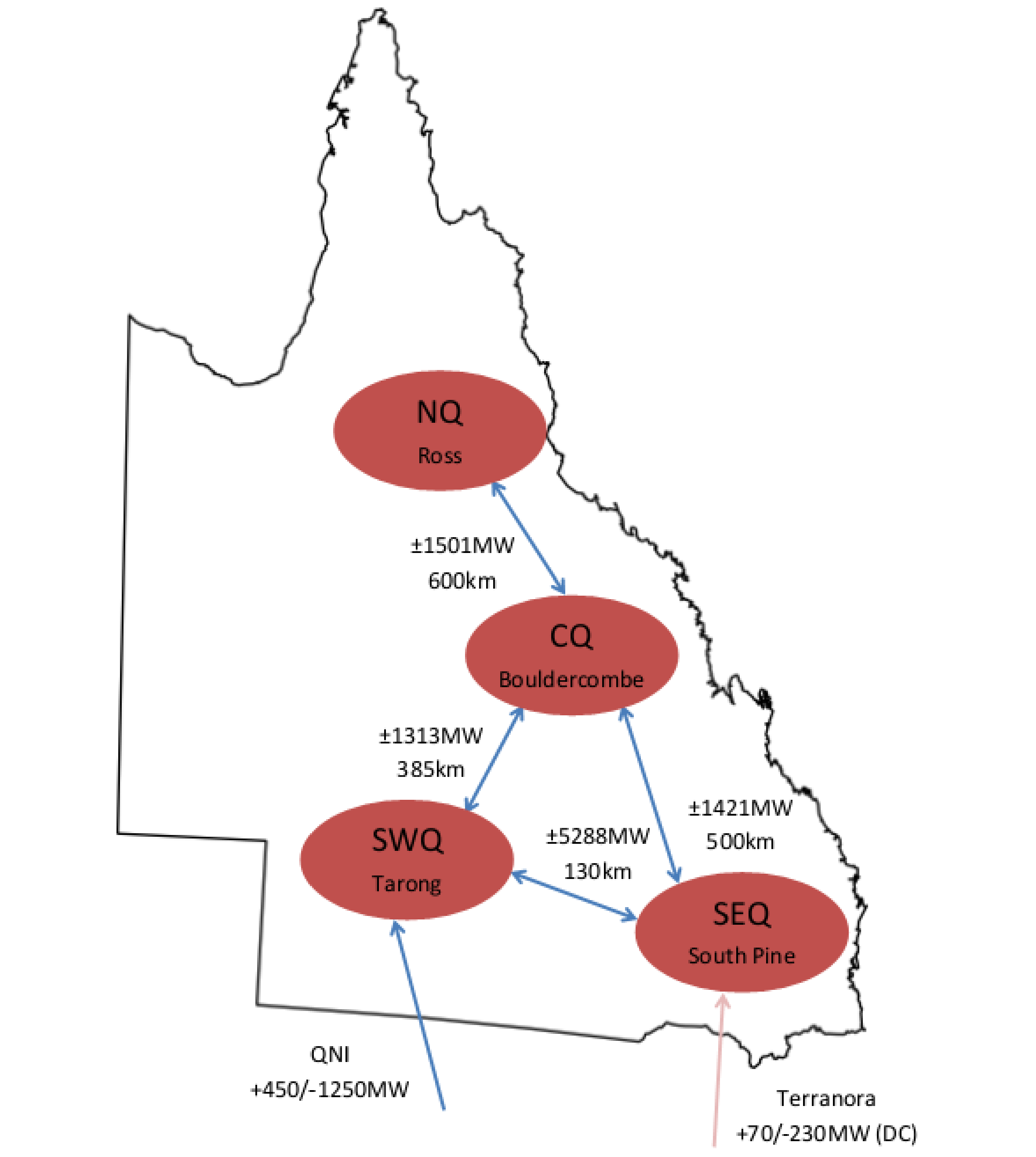


Figure C.2 – New South Wales Zonal Model

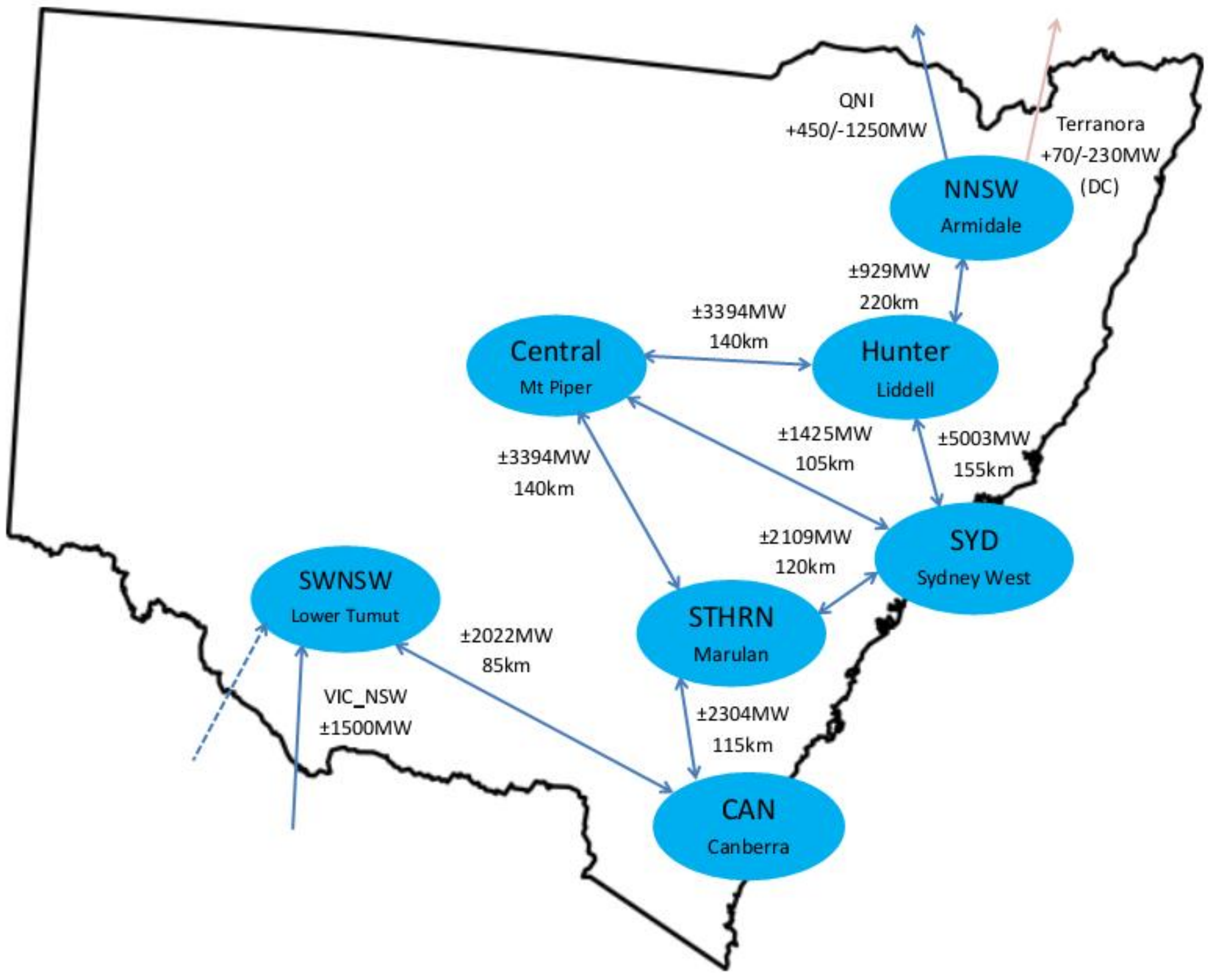


Figure C.3 – Victoria Zonal Model

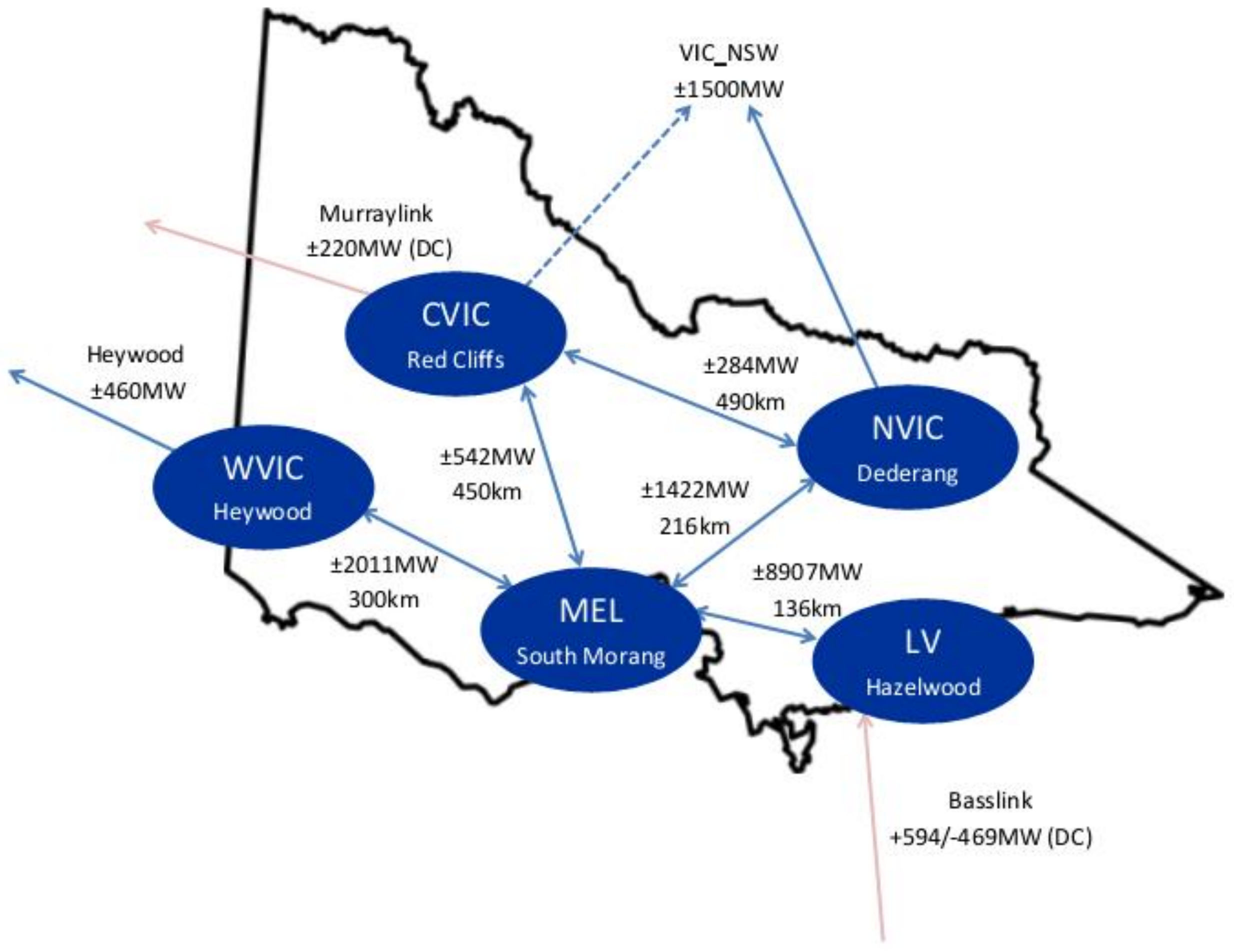
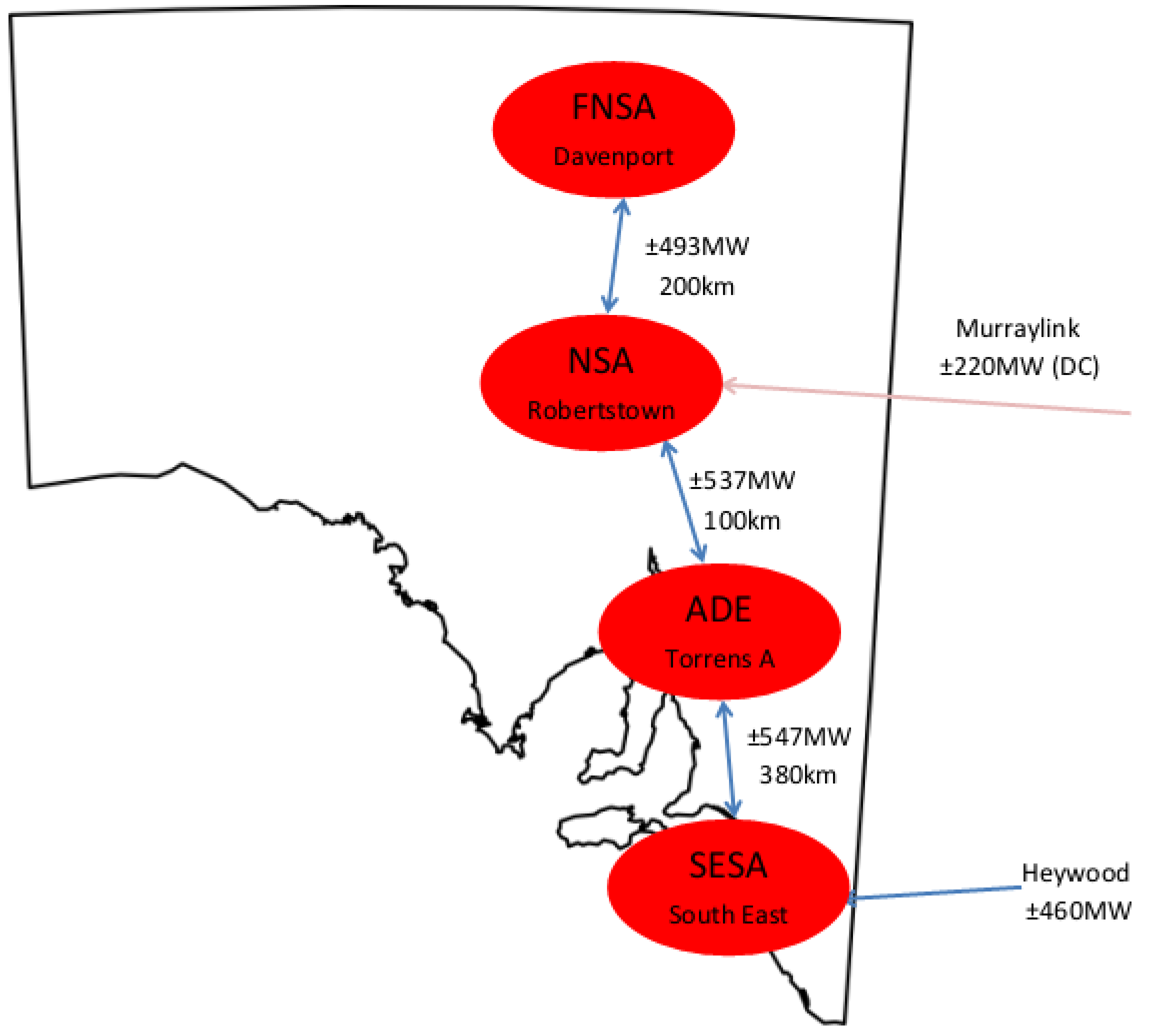


Figure C.4 – South Australia Zonal Model



Appendix D) QP Bids and Disorderly Bidding Methodology

D.1) Generator Bidding Strategies

The bidding strategies of generators can be one of the most influential on modelling outcomes, and care must be taken to ensure that generators are modelled appropriately given technical and economic considerations. ROAM uses historical analysis to determine the bidding strategies for existing generators in the modelling period.

ROAM's historical analysis uses quadratic programming techniques to determine a set of bid profiles which accurately results in the least distortion of modelled dispatch by considering the generation at each of the units in the NEM versus the price in the relevant region in various time sets. The bid profiles produced will then accurately capture average time of day bidding as well as other bidding nuances which occur in various price bands. The methodology is further explained in the paper "Calculation of Minimum Reserve Levels for the Australian National Electricity Market" by Richard Bean and Ben Vanderwaal, presented at 17th Power Systems Computation Conference in Stockholm in 2011.[45]

The "QPBids" utility can be configured to analyse any subset of the year. Typically, ROAM calculates bids by time of day, with at least four time slices: 7 am to 10 pm / 10 pm to 7 am, and weekdays / weekends. The utility is flexible, and this may be re-examined to allow for increased differentiation for other seasonal or monthly periods, or time of day slices.

By assessing historical performance when constructing the bids using the QPBids tool, ROAM effectively captures the contract and hedging positions of existing generation portfolios, although the model does not provide for dynamic adjustment of bids during periods of outage or other events which may result in supply shortfall against contractual levels.

D.2) Generator Trading

2-4-C is typically configured with market generator trading behaviour consistent with observed recent historic trends and performance in the market. The trading behaviour is

[45] http://www.pscc-central.org/uploads/tx_ethpublications/fp249.pdf

developed by analysing generator performance against the full history of generator bid offers into the market over the previous twelve month period. The QP Bids optimisation is employed to establish a common trading behaviour which delivers a ‘back-cast’ for the period using the 2-4-C model which is consistent with history. The trading behaviour is then projected into the future.

Modifications to the baseline trading behaviour for future assessment are made based on:

- Increased competition from new entry generation;
- Changes in underlying fuel prices, O&M and other costs;
- Changes in carbon pricing.

The 2-4-C database is also maintained with the data set of underlying costs for generators as published by ACIL Tasman, EPRI and AEMO from time to time and pure SRMC bidding and LRMC bidding options are available for application in this investigation.

D.3) Implementation of race-to-floor Disorderly Bidding

The 2-4-C model implements a form of dynamic race-to-floor bidding behaviour. In this mode each period is first assessed in a pre-dispatch solution and a number of subsequent re-solves until no further rebidding occurs. The general implementation is as follows:

1. At the end of each pre-dispatch interval each unit checks to see if it has been constrained off. It does this by checking its expected dispatch based on its current availability, bid offers and the pool price compared with its actual dispatch level. If it has been constrained off then the unit prepares a new bid by moving its entire capacity into a market floor price bid offer, taking its loss factor into account. This is done simultaneously for all units.
2. If any units wanted to rebid then the interval is resolved with the new bids.
3. The solution is checked again;
    a. each unit that didn’t race to floor checks if it now wants to race-to-floor
    b. each unit that did race-to-floor checks to see if it is now dispatched at more than it would have with its original bid, had it not been constrained off (indicating that rebidding everything at the floor was ‘too much’) – if it did, the unit changes to a mix between half its capacity at the floor and half in the original price bands (taking the lowest price bands first).
4. If any units wanted to rebid then the interval is resolved with the new bids.
5. The solution is checked again;

a. Any units that want to race to floor and have not previously can race-to-floor
b. any units that did race to floor and want to back off to the 'halfway' bid can make that move
c. a unit that raced to floor and backed off in the previous period can either keep the halfway bid or go back to normal bids – it cannot race-to-floor again.

This process of checking and resolving in steps 2-5 continues until no units want to change their bid anymore, or no units can change their bid anymore because they have already made a change previously.

Appendix E) Historical development of intraconnectors

The purpose of the LTIRP modelling has been to develop a least cost plan of combined generation and transmission development to reliably supply the NEM demand over a 20 year (or more) period ahead. The LTIRP modelling has been conducted for several different forecast demand and energy profiles based on regional forecasts.

The LTIRP input has included, as a starting point, the present generation plant in the NEM, with associated generating capacity, availability and energy production capability. Thus, the starting point is that the NEM is modelled to faithfully represent the present situation, including interconnector and intraconnector flows.

One of the key observations from the modelling is that the NEM seems to be well supplied with intra-regional transmission in overall terms and that relatively little expansion in transmission is indicated on a least cost basis over the next decade, but that building of new transmission will need to accelerate after that.

ROAM has therefore conducted an additional LTIRP investigation to assist in understanding how the existing intra-regional transmission capacity is utilised. For this study we have made the assumption that the generation plant in the NEM is as it presently is developed, and in its present locations. We have furthermore assumed that future generation development will be in accordance with a continuation of the RIT-T planning approach, where generators can locate wherever they choose within a region without reference to transmission costs. We have also assumed that interconnector capacity is at present levels, but is allowed to develop in the future on least cost principles.

The difference from the simulations presented in the main report is that we have assumed that no intra-regional lines exist at the start of the study, and that the LTIRP develops these from the first year, and continues to develop them in each subsequent year on least cost principles, as needed to reliably meet the demand and energy in the NEM.

Table E.1 shows the resulting optimum development plan in the first year (2013), and in 2021 and 2030. ROAM has available the year-by-year plan, but has summarised the outcomes for the three milestone years for the purpose of this discussion. We also show, for comparison, ROAM's assessment of intra-regional capacities of the existing transmission system.

The first column shows the estimated 'firm transmission' capacity available in the current system. The subsequent columns show the firm transmission capacity developed in the

LTIRP from a zero starting point (first value) and the difference between this and the estimate of existing transmission capacity (second value). The highlighting shows where the zero starting point LTIRP transmission capacity exceeds the existing transmission capacity. This suggests that some 1,100MW additional transmission capacity is required by 2021 and almost 5,300MW by 2030 (assessed as the sum of the positive difference values).

Table E.1 – Transmission flow path upgrades with LTIRP outcomes from zero transmission starting point (with differences in capacity)

Transmission flow path	Existing system capacity	LTIRP outcome with zero transmission starting point		
		Installed by 2013	Installed by 2021	Installed by 2030
CQ to NQ	1501	32%	63%	72%
SEQ to CQ	1421	36%	68%	78%
SEQ to SWQ	5288	81%	95%	116%
SWQ to CQ	1313	5%	39%	42%
HUNTER to NNSW	929	32%	132%	140%
HUNTER to CENTRAL	3394	36%	35%	35%
SYD to HUNTER	5033	87%	95%	96%
SYD to CENTRAL	1425	91%	101%	112%
STHRN to SYD	2109	70%	91%	131%
STHRN to CENTRAL	3394	36%	38%	40%
CAN to STHRN	2304	21%	54%	105%
SWNSW to CAN	2022	60%	104%	165%
MEL to NVIC	1422	75%	116%	194%
CVIC to NVIC	284	106%	131%	131%
MEL to CVIC	542	60%	77%	77%
MEL to WVIC	2011	7%	72%	98%
LV to MEL	8907	74%	83%	83%
SESA to ADE	547	57%	75%	76%
ADE to NSA	537	74%	174%	178%
NSA to FNSA	493	51%	58%	72%

For all intra-regional flow paths bar one (CVIC to NVIC), the LTIRP outcome has a lower level of intra-connector capacity than the existing system at the present time. By 2021, there are several major interconnector flow paths which are likely to need augmentation in the NSW, Victorian and South Australian regions. Shortfalls are up to several hundred megawatts. By 2020, approximately half the intra-connectors will need augmentations, including into Sydney, Melbourne, Brisbane and Adelaide.

On the other hand there are several intra-regional flow paths that show evidence of significant overbuilding. There are reasons for each of these, which will be considered on a case by case basis.

In the case of CQ-NQ, the capacity of this section was duplicated from two 275kV lines to four 275kV lines over the last several years. This is due to a RIT-T investigation, which showed that the two existing lines, which were built in the 1970's, could no longer support the generation in NQ and provide reliable supply.

In the case of SEQ-CQ and SWQ-CQ, the SEQ-CQ lines were built when southern Queensland was almost entirely reliant on Gladstone power station to provide reliable supply from the early 1980's. In the early 2000's, the SWQ-CQ lines were built together with the 900 MW Callide C power station to provide additional power into South East Queensland. This was before there was any significant development of the Surat Basin, which has now become a major gas and coal hub. Hence usage of the these lines has tapered off as demand has grown in CQ to service major aluminium refining and smelting and expansion of coal mining in the Bowen Basin.

The SEQ-SWQ path was established when Tarong power station was built in the early 1980's. However, it has recently been expanded to accommodate:

- Interconnector flows from QNI since the start of the market
- Millmerran, Kogan Creek, Tarong North, Darling Downs, and Braemar power stations, which have added more than 3000 MW of generation to that location
- It is anticipated that this will continue to grow in importance in supplying South East Queensland and further development will be needed before 2021, based on the LTIRP modelling.

The lines between HUNTER and NNSW were originally developed to supply NNSW from the Hunter Valley. At that time, and up to the year 2000, the grid was very weak in the vicinity of the Queensland – NSW border, and parts of NSW were supplied from Queensland, while parts of Queensland were supplied by NSW, in order to achieve savings. There was no synchronous connection between Queensland and NSW until 2001, when QNI was built. Hence the HUNTER to NNSW lines appear to have spare capacity but this is solely because the LTIRP has optimised supply, taking into account flows from Queensland which were not previously possible.

HUNTER to CENTRAL and STHRN to CENTRAL were originally built as a ring around Sydney at 330 kV. In recent years, these lines have been uprated to 500 kV, which has more than doubled their capacity. The reasons for this uprating are the subject of reports by TransGrid. Should the NEM be strengthened in accordance with the principles of the proposed NEMLink, then this corridor will form a key part. However, the LTIRP is tending to indicate that these are relatively underutilised compared with the radial lines into Sydney, which are of lower voltage.

All lines into Sydney from the North, West and South are relatively highly utilised at their present ratings, to supply the major load area of Sydney. At least one of these corridors is likely to need uprating by 2021, with the LTIRP favouring the lines from the west, but more detailed planning may show advantages for one of the other corridors. Further upgrading will be needed in the following decade. Hence it is likely that further development of 500 kV transmission into Sydney will be needed within that time frame.

At present, flows between SWNSW and Sydney tend to be in the south west direction. Hence there is apparent spare capacity in this section. However, by 2021, the section between SWNSW and CAN (Canberra) will be insufficient, and by 2030, all sections between SWNSW and SYD will need major reinforcement, mainly due to projected wind developments.

In Victoria, the major 500 kV intra-connector between Latrobe Valley and Melbourne shows spare capacity. However, it has been identified that this intra-connector is subject to overloading in the event of a line outage, in which case the security of the system will not be able to be maintained without restricting generation. The Moorabool-Heywood/Alcoa Portland 500 kV lines were constructed in 1980 to supply the Portland aluminium smelter. The MEL to WVIC lines in the table show this apparent overcapacity, which is a reflection of recent generation development in the WVIC area, following the development of major gas and wind generation. The LTIRP predicts that it will become heavily utilised again with the next decade.

The MEL to NVIC corridor which transfers power to and from the Snowy will need augmentation by 2021, again because of the development of wind generation in Victoria and South Australia, which will be exported to NSW.

In South Australia, the lines between NSA and ADE, which are being heavily developed to accommodate new wind farms, are likely to need uprating in the next decade. Other South Australian intra-connectors may need uprating, in particular the SESA to ADE lines, in association with any interconnector upgrades.