FUTURE CONGESTION PATTERNS & NETWORK AUGMENTATION

Report on Assignment A: Transmission Development Framework Scenarios

25 June 2009

Final Report

IES
Intelligent Energy Systems

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Executive Summary

Background

This report presents the methodology, results and assumptions of the modelling undertaken by Intelligent Energy Systems (IES) in Assignment A of the Future Congestion Patterns & Network Augmentation Scenario Studies.

The aim of modelling studies was to provide insight into whether the existing frameworks, with the introduction of the CPRS and expanded RET, will provide network and generation businesses appropriate operational and investment incentives and locational signals in the new environment within which congestion may be more material

Assignment A specified that the following scenarios be modelled based on normal commercial entry and exit decisions and behaviour of generators:

- Transmission is developed to only meet mandatory obligation and the RET target (based on normal commercial entry and exit decisions and behaviour of generators);
- Transmission is developed according to the current framework (based on normal commercial entry and exit decisions and behaviour of generators);
- Transmission and generation development are co-optimised.

It was agreed with the AEMC that that all cases should be based on a central planning approach that optimises generator entry and exit within the framework of the scenario to allow for a common basis for comparison of the first two cases with the co-optimised case.

The assumptions that IES and ROAM Consulting (ROAM) were to use were agreed with the AEMC at a meeting on 30th March 2009. Since ROAM and IES had both been commissioned to undertake Assignment A, it was agreed that IES and ROAM would utilise common assumptions where possible. This included the interconnector upgrade options and costs. There was no discussion on the options and costs to address intra-regional transmission line congestion.

Assumptions

All the assumptions were obtained from public documents where available. The key assumptions were obtained from: the 2008 NEMMCO SOO and 2009 NTS Consultation Issue Paper, the 2009 ACIL TASMAN report to NEMMCO on “Fuel Resource, New Entry and Generation Costs in the NEM”, and the Australian Treasury paper “Australia’s Low Pollution Future: The Economics of Climate Change Mitigation”, October 2008.

Scenario Development

After consideration of the issues involved, IES translated the AEMC’s scenarios into the following modelling:

- ***Scenario 1: Non-responsive transmission*** – generation entry and exit is optimised based on a forward curve for carbon permit prices and the requirements for the RET using the existing transmission system with committed expansions. Generator entry is based on existing transmission capacity. Transmission is only developed to ensure demand is supplied and the RET satisfied.
- ***Scenario 2: Current regime working effectively*** – generation entry and exit are optimised based on a forward curve for carbon permit prices and the requirement for the RET. Generators enter on the assumption that any intra-regional transmission constraints will be addressed under the regulatory test where mandatory obligations, as they pertain to the reliability limb of the test, incorporate current TNSP planning criteria. Interconnection is developed as would likely be done under the Regulatory Test.
- ***Scenario 3: Co-optimising central planner*** – generation entry and exit *and transmission expansion* is co-optimised with transmission upgrade options based on a forward curve for carbon permit prices and the requirements for the RET.

Limitations of the Modelling

Before commencing the modelling a number of limitations were identified. The main ones were as follows:

- All the modelling assumed that the transmission system was only in the system normal state. This meant that the degree of congestion and the value of transmission upgrades were underestimated as the most severe cases of market congestion occur when one or more key components of the transmission system are unavailable;
- The modelling did not assume any change to the current regional reserve criteria associated with interconnector options modelled. This meant that there may have been some economic value to some interconnector upgrades not included in the modelling undertaken;
- While the modelling was based on realistic generator bidding behaviour it did not include potential gaming strategies that could be employed in the presence of an increased number of intra-regional constraints;
- There was very limited data on potential network upgrade options. This meant that a proper co-optimisation of intra-regional network upgrades and generation was not possible;
- Because the modelling only used 50% probability of exceedence peak demands and it is during very high demand periods (sometimes considerably higher the 50% probability of exceedence peak demands) that network capacity is fully utilised, the modelling may have understated the required amount and value of transmission upgrades.

The Modelling Approach

IES used two models in this study. The first was the IES Integrated Energy Market Model (referred to as the MARKAL model as it is based on the MARKAL modelling framework) and the second was the IES simulation model PROPHET.

MARKAL was used to obtain the optimised level of interconnection development and the optimised entry of generators as assumed in the scenarios. The IES PROPHET model was used to model the NEM in detail and the constraints that occur on the transmission system under the assumptions used.

Results of the Modelling

The key results of the modelling were

- The level of congestion observed;
- The interconnection and intraregional transmission lines developed;
- The differences in the level and location of renewable generation and non-renewable generation;
- The difference in dispatch costs.

Line Constraints

To analyse the level of congestion in the network, both the hours that lines were constrained and the amounts by which they were constrained were considered. This was done by relaxing all the intra-regional transmission line limits in the simulation model and determining the MWh of flows that exceeded each line's rating. We have called this "uncarried" energy. Uncarried energy can be thought of as the energy that would have been transmitted had the line been able to support flows greater than allowed by its rating. In the report uncarried energy is presented for individual lines and also as a total over all lines.

Figure 1-1 below shows the amount of uncarried energy per year for each scenario before line upgrades were carried out according to a criterion of limiting uncarried energy to 10,000 MWh per year. As expected, Scenario 2 (unconstrained generator development) leads to the highest amount of uncarried energy before line upgrades. In this scenario the level of uncarried GWh increases significantly over the period 2014 to 2017 after which it decreases slightly. This rapid change is probably due to the substantial increase in carbon emissions costs from 1st July 2014 due to a change from a 5% target to a 15% target. Scenarios 1 and 3 show similar levels of uncarried energy indicating that optimising generator / transmission development involves utilising the existing network to near its fullest.

The sensitivity of congestion expressed as uncarried energy to line rating was also analysed. This was done by increasing the rating of all lines by a multiplier. This is shown in Figure 1-2 for the year 2020, which shows uncarried energy versus the multiplier used to increase all line ratings.

Figure 1-1 Total amount of uncarried GWh per year

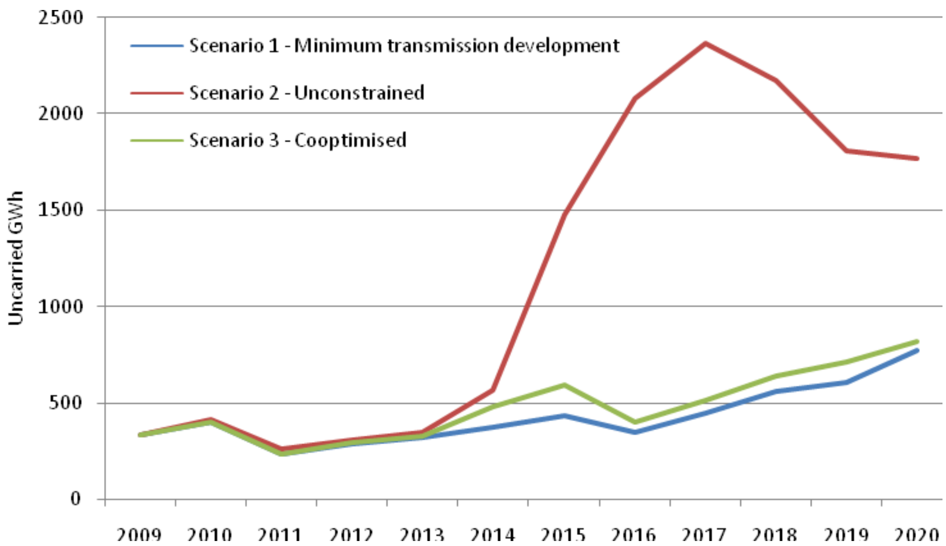
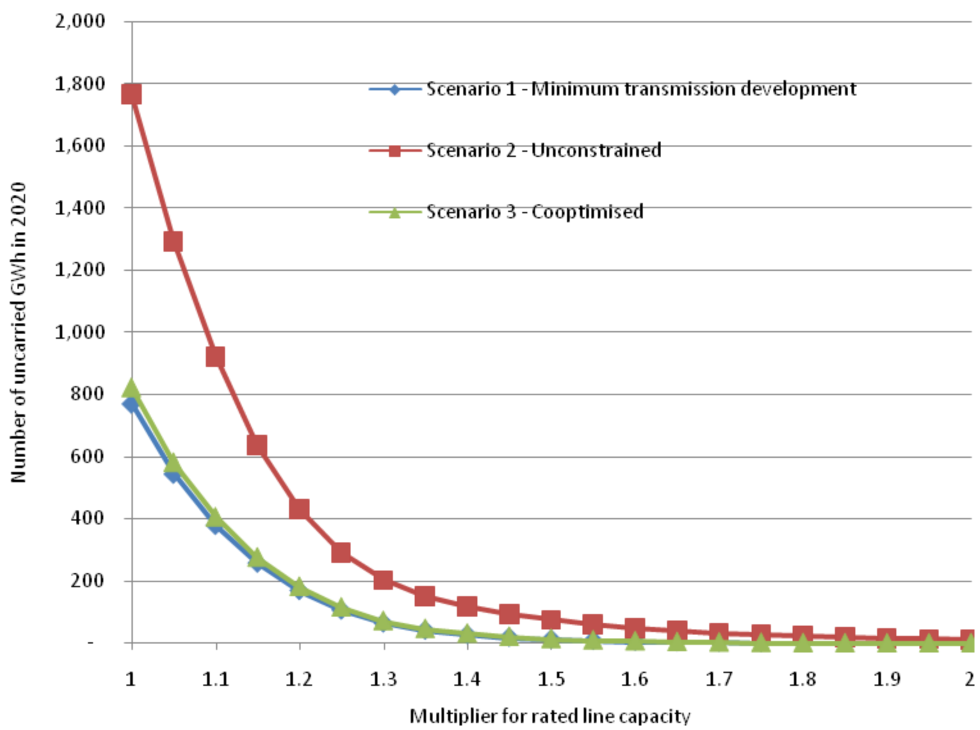


Figure 1-2 Total number of uncarried GWh in 2020 where constraint threshold increases from rated line capacity to 2x rated line capacity

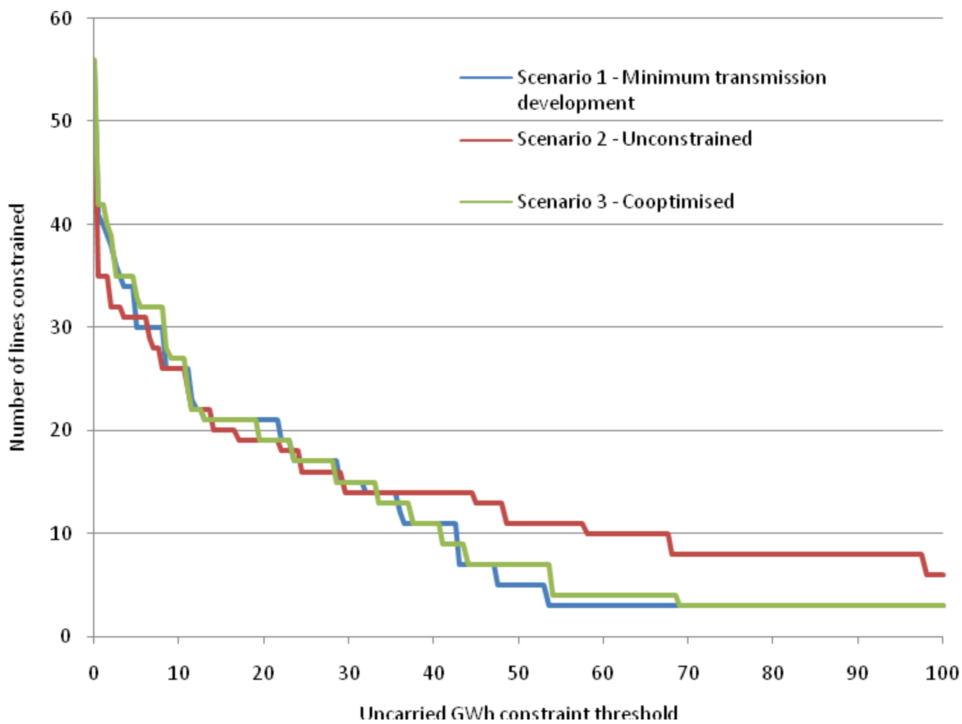


Lines Developed

Line upgrades were carried out based on the criterion of uncarried energy on that line being greater than 10,000 MWh for more than two years running. Lines were then upgraded in 300MW increments. Some lines required multiple upgrades to satisfy the 10,000MWh threshold. Furthermore, to account for build and planning times, no lines were upgraded before 2011. This criterion resulted in 23 upgrades of 300MW over 19 lines being developed in Scenario 2 and 21 upgrades of 300MW over 19 lines being developed in Scenario 3. The absence of any real cost data led IES to assume upgrade costs of $30M for a 300 MW upgrade. This gives costs of $690M and $630M for transmission line upgrades for Scenarios 2 and 3 respectively.

The number of lines to upgrade clearly depends on the criterion used. The figure below shows for each scenario the number of lines that had flows at or greater than a defined level of uncarried GWh. Here we see how Scenario 2 (unconstrained generator development) leads to similar numbers of constrained lines at lower levels of constraint but significantly greater levels of constrained lines at higher constraint limits.

Figure 1-3 Number of constrained lines versus increasing constraint limits in terms of uncarried energy in year 2020



Economic Costs

The table below shows a summary of the economic costs (generator dispatch costs, generator and transmission capital costs, interconnector upgrade costs and costs of unserved energy) for the three scenarios modelled. This showed the total costs to be very close between the scenarios.

Table 1-1 Summary of Generator Capital and Dispatch Costs

Scenario 1

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	25,921	1,151	-	-	8	27,080
Qld	20,896	1,382	-	-	18	22,296
SA	4,918	1,322	-	-	-	6,239
Tas	610	552	-	-	11	1,173
Vic	15,805	1,938	-	-	38	17,781
Total	**68,149**	**6,345**	**-**	**-**	**75**	**74,569**

Scenario 2

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	26,033	1,058	-	10	54	27,155
Qld	21,003	1,211	-	10	37	22,260
SA	5,011	1,467	75	-	-	6,553
Tas	463	437	40	-	7	947
Vic	15,690	1,848	96	-	2	17,636
Total	**68,200**	**6,021**	**211**	**20**	**100**	**74,551**

Scenario 3

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	26,057	1,123	-	10	15	27,205
Qld	20,833	1,163	-	10	46	22,052
SA	4,993	1,320	70	-	-	6,384
Tas	638	553	39	-	4	1,234
Vic	15,703	1,867	72	-	16	17,659
Total	**68,224**	**6,028**	**182**	**20**	**81**	**74,533**

We observe that the study constraint of having renewable generation equal the RET target profile in all three scenarios acted as a driver to have similar NPV costs in the three scenarios. This meant that the total generation level from renewables and nonrenewables would be the same in all scenarios except for changes in transmission losses. Changes in capital investment would be the prime difference in costs. Thus changes in transmisison line constraint hours and development patterns may be the key metric in the studies presented.

Conclusions

The modelling has demonstrated that there could be material differences in the location and development of transmission for each of the scenarios.

In particular, if new entry generation locates without regard to intraregional constraints then this study suggests that the result could be a significant increase in transmission congestion, and correspondingly the level of transmission development needed.

Here we note that although the differences in the present values of total costs between the scenarios are not very high relative to the total costs, this does not mean that different regimes of locational pricing for generators would not result in significantly different economic costs.

This potential discrepancy between assessed NPV costs and potential economic impacts arises from the fact that the modelling undertaken had a number of limitations and assumptions. In particular, these were the assumptions of central planning optimisation as opposed market driven entry combined with a network charging regime, assumptions of system normal conditions and average weather conditions, and that network extension costs were not included.

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1 Introduction

Intelligent Energy Systems (IES) were engaged by the Australian Energy Market Commission (AEMC) to perform modelling studies to assist the AEMC in preparing its 2nd Interim Report for its Review of Energy Market Frameworks in light of Climate Change policies. This report presents the results and conclusions from IES's modelling studies.

1.1 Background

The stated purposes of the modelling studies included:

- investigating the relative economic costs of different models of locational entry and exit of generation and network investment response in the National Electricity Market (NEM) following the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (expanded RET); and
- undertaking case studies of network augmentations responding to congestion arising from generation locational decisions.

The aim of modelling studies was to provide insight into whether the existing frameworks, with the introduction of the CPRS and expanded RET, will provide network and generation businesses appropriate operational and investment incentives and locational signals in the new environment within which congestion may be more material.

The modelling tasks are:

- Assignment A: future congestion patterns and network flows;
- Assignment B: case studies of network augmentation responding to congestion; and
- Assignment C: possible extension of work in assignments A and B.

This report concerns the modelling and analysis undertaken for Assignment A. As requested by the AEMC, the report has been written to be concise and with a non-technical readership in mind. Detailed technical descriptions are confined to the appendices.

1.2 Process To-Date

The AEMC engaged both IES and ROAM Consulting (ROAM) to undertake Assignment A. The expressed reason for this was to obtain results from two different models and modelling methodologies to ensure that any conclusions from this work were likely to be robust.

To ensure that any difference in the modelling results of IES and ROAM could be understood, it was requested that where possible, the assumptions used in the modelling should align. IES sent a draft assumptions document (dated 24th March 2009) to the AEMC that outlined the issues important to the study, gave a broad overview of the proposed approach to be used and the reasons for the proposed approach, and listed the key assumptions proposed to be used in the modelling. ROAM also produced an assumptions document that was sent to the AEMC. The ROAM and IES assumptions documents were forwarded by the AEMC to IES and ROAM for review.

Following this the AEMC held a meeting (on 30th March 2009) with IES, ROAM and interested participants on the modelling assumptions and approaches to be used. It was agreed at the meeting that the prime purpose of modelling was to test the framework in relation to:

- whether the existing framework with the introduction of the CPRS and expanded RET will provide network and generation businesses appropriate operational and investment incentives and locational signals in the new environment within which congestion may be more material; and
- how close to economically optimal are the resulting market outcomes.

During the course of discussions, it was agreed and noted that the primary purpose of the modelling was to test the current framework for how the transmission system would expand and new generation would enter the market against some hypothesised alternative models. The aim of the exercise was not to model or forecast prices nor emulate the modelling undertaken for the Regulatory Test for specific potential transmission upgrades. The aim was to provide insight into how the power system may develop under (a) the current regulatory arrangements for transmission and (b) generator decisions about investment locations within this framework, compared to other possible frameworks in light of the substantial changes that will occur with the introduction of the RET and CPRS. As a consequence of this approach a number of assumptions were agreed on the basis of them being more suitable for testing the existing framework rather than being the most likely scenario.

Following the meeting of 30th March 2009 an updated assumptions document was developed by IES (dated 22 April 2009) and sent to the AEMC. The agreed assumptions at that meeting and detailed approach to be used were also presented in that assumptions document.

On 12th May, IES discussed our draft report with the AEMC's reviewer, Dr Grant Read and the following day presented our report and initial findings to the AEMC's Commissioners. Since then, IES has refined some of the modelling and revised the report based on comments from Grant Read's review, the meeting with the Commissioners and the AEMC's written comments.

1.3 Terms of Reference – Assignment A

The AEMC's Terms of Reference were as follows.

For Assignment A the consultant is to model a range of credible scenarios for the NEM that reflect different models of locational entry and exit for generators and different transmission investment scenarios. The range of scenarios is to include:

a. "**Non-responsive transmission**" – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will be limited to the bare minimum consistent with meeting mandatory obligations. The level of transmission investment in this case would reflect the bare minimum required to continue meeting NEM demand and the expanded RET targets. The scope of this investment would be subject to discussion with the AEMC;

b. "**Current regime working effectively**" – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will respond consistent with delivering mandatory and discretionary investment consistent with the National Electricity Rules (NER). The level of transmission investment in this case would reflect both reliability and market benefits driven investments to continue meeting NEM demand and the expanded RET targets. This case reflects the investment decisions that can be made under the current framework; and

c. "**Co-optimising central planner"** – a "socially optimal" generation and network investment case that reflects co-optimised investment decisions by generation and transmission businesses from a central-planning perspective. The decision to locate takes account of excess network capacity and the supply-demand balance. This would assume perfect foresight by the central planner and the objective of minimising the total costs of delivering energy services to customers over the analysis period, with some allowance for on-going benefits beyond 2020.

The modelling should:

- determine the likely congestion patterns and network flow outcomes arising under the range of scenarios; and
- measure and compare the change in dispatch costs and network investment costs under the different scenarios.

The consultant is to provide a report that:

- develops the modelling assumptions and a range of credible scenarios of future generation and demand for each region under the CPRS during the period July 2010 to July 2020 with the AEMC;
- advises on the likely changes in the location of generation in each region resulting from the changing generation mix under the CPRS;

- advises on the likely location decisions of renewable generation under the expanded RET;
- discusses how the operation and dispatch of increased renewable generation (under the expanded RET) and the changing generation plant mix (under CPRS) influences the patterns of congestion compared to the current patterns;
- models the likely inter-regional and intra-regional network flows under each credible scenario;
- identifies and measures the resulting congestion under each scenario;
- identifies areas where congestion could be persistent and material, if efficient network developments cannot be achieved; and
- provides a commentary and observations about how to improve the current incentives that inform generation entry and exit decisions and network investment decisions, where the dispatch and network investment costs under the different scenarios differ substantively.

1.4 A Note on Data Sources

It was agreed that to the extent possible all data should be sourced from public domain publications.

The main data sources used in the modelling were:

- NEMMCO, 2008 Statement of Opportunities, 30 Oct 2008;
- NEMMCO, 2009 NTS Consultation: Issue Paper, 16 Feb 2009;
- ACIL TASMAN, Fuel Resource, New Entry and Generation Costs in the NEM (draft) and spreadsheet dataset, published in NEMMCO website, 25 Feb 2009;
- Australian Treasury, Australia's Low Pollution Future: The Economics of Climate Change Mitigation, October 2008.

Other sources are cited when information from them was used.

1.5 Dollars Used

All dollars used, unless otherwise stated, are real 2009/10 Australian dollars.

1.6 Outline of the Report

The structure of the report is as follows:

- Chapter 2 discusses NEM regulatory frameworks specified in the three scenarios and the approach to representing these in the modelled cases;

- Chapter 3 discusses the approach to modelling the transmission network, the network model used and future augmentations to the transmission network;
- Chapter 4 then discusses the issues of how generators would enter the market under the three scenarios and proposes a common principle for all the scenarios;
- Chapter 5 describes the two models used in the modelling undertaken (MARKAL and PROPHET);
- Chapter 6 presents how the scenarios were modelled using these models;
- Chapter 7 presents the key assumptions to the study in relation to the modelling of wind generation and the inclusion of CPRS;
- Chapter 8 next overviews the assumptions used in respect to demand, generator behaviour and government policies. These are important to the way the market will out turn;
- Chapter 9 notes limitations to the modelling undertaken and the implications of this;
- Chapter 10 then present respectively the modelling results for the three scenarios modelled;
- In order to assist in understanding the results obtained, Chapter 11 specifically examines the economics of interconnector upgrades;
- The report concludes with Chapter 12 that compares the modelling results of the three scenarios, summarises the finding and discusses the results obtained.

2 Modelling the Regulatory Frameworks

2.1 Introduction

For Assignment A the consultant was to model a range of credible scenarios for the NEM that reflect different models of locational entry and exit for generators and different transmission investment scenarios. The Terms of Reference required the consultant to model a range of scenarios, specifically:

1. “Non-responsive transmission”;
2. “Current regime working effectively”; and
3. “Co-optimising central planner”

Each of the three modelling scenarios requires that a different regime for transmission development be employed. Since the project timing was very tight it was important to determine some reasonable approaches to modelling the transmission and generation investment scenarios. When considering the approaches to use for the modelling IES was aware of the potential confounding effect that mixing central planning approaches and market based entry could have on the results. For instance under a scenario where there are no material transmission constraints a central planning approach to generator entry can result in quite a different generation development program to what could occur with market based entry where there are generation portfolios with some degree of market power. Thus in order to avoid introducing another source of variation into the inferences about the three regimes by mixing central planning and market based new entry IES tried to accommodate all within a central planning approach. Thus for all three scenarios, generator entry and retirements were modelled through central planning optimisations, albeit, with different network constraints/limitations.

The treatment of the methodology used for generator entry is discussed in Chapter 4. The methodology used for transmission development required interpretation of the different transmission investment regimes and development of a modelling approach to emulate these regimes. This chapter presents the issues and approached used in this regard.

2.2 Transmission Developments

In terms of new generation developments or changed dispatch patterns, transmission developments can be roughly classified into four areas:

1. development of connection assets;
2. extension of the shared network to connect multiple generators;

3. augmentations of the existing shared transmission system to give access to the regional reference node (this could be radial lines or elements of the meshed network); and

4. augmentations of the existing network or new interconnectors to allow greater power flow between NEM regions.

In the modelling studies which IES has undertaken to investigate the current regulatory framework we have not addressed the first two areas to any extent. The first area was dealt with via the capital costs used for different projects having some estimate of shallow connection costs incorporated into them. Consequently, for some power station sites where there may be a considerable distance to connect to the shared network, the connection costs were underestimated. Similarly, for situations that could require extensions of the shared network to connect multiple generators, the costs of these network extensions were not dealt with. The implications of these two simplifications regarding connection costs and shared network extension costs are as follows. Firstly, in areas where extensive connection or extension assets are required the costs of developing this generation will be underestimated. In terms of making inferences about how the three regimes compare, it probably does not have much impact though it certainly could make a material difference regarding the location of generators and the transmission lines that would be upgraded. On the other hand if the modelling were focussed on looking at how various network charging regimes could impact on generator locations then this omission could have considerable impact.

In the case of the third area, although not really explicitly specified by the AEMC in the Terms of Reference, IES has attempted to investigate this area to some extent but this has been limited by the lack of general network cost information for a large number of potential network upgrades and the ability to obtain this information from TNSPs in the short time frames of this project. The last area, interconnector augmentations, has been dealt with in the modelling studies.

2.3 The Regulatory Test

The regulatory test is an analysis tool used by transmission and distribution businesses in the National Electricity Market (NEM) to assess the efficiency of network investment. TNSPs use the test as the basis for determining whether potential network investments should proceed. There are two limbs of the test: the reliability limb and the market benefits limb. The reliability limb is used for reliability driven augmentations which are based on service obligations. The market benefits limb is used for any investment not assessed under the reliability limb. The Regulatory Test states that

"An option satisfies the regulatory test if:

(a) in the event the option is necessitated principally to meet the service standards linked to the technical requirements of schedule 5.1 of the

Rules or in *applicable regulatory instruments* - the option minimises the present value of the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios*;

(b) in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the present value of the *market benefit* less the present value of *costs*."[1]

2.3.1 Market Benefit

The Regulatory Test defines the market benefit as:

"(3) *Market benefit* means the present value of the total benefit of an option (or an *alternative option*) to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of *reasonable scenarios*. For clarity, *market benefit* does not include the transfer of surplus between consumers and producers, nor does it include the *costs* defined in paragraph 2.

(4) In determining the *market benefit*, the analysis may include the present value of the following benefits:

(a) changes in fuel consumption arising through different generation dispatch;

(b) changes in voluntary load curtailment;

(c) changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers;

(d) changes in costs caused through:

(i) differences in the timing of new plant;

(ii) differences in capital costs;

(iii) differences in the operational and maintenance costs; and

(iv) differences in the timing of transmission investments;

(e) changes in transmission losses;

(f) changes in ancillary services costs;

(g) competition benefits being net changes in market benefit arising from the impact of the option on participant bidding behaviour; and

(h) other benefits that are determined to be relevant to the case concerned.

(5) Where the analysis separately identifies the magnitude or quantum of any *competition benefits* (either as a proportion or a component of the total *market benefit*) the analysis must make clear the methodology used to estimate it.

[1] The Australian Energy Regulator 'Final Decision regarding the Regulatory Test version 3 & Application Guidelines' November 2007

(6) The *market benefit* of an option will only include *competition benefits* where the *network service provider* responsible for undertaking the analysis of the option determines that it is appropriate, in all the circumstances, to take *competition benefits* into account.

(7) In determining the *market benefit*, the analysis must not double-count *competition benefits* where they have already been accounted for in other elements of the *market benefit."*

2.3.2 Sunk versus Variable Costs and Network Investment

The calculation of the market benefit in the regulatory test can change considerably depending on whether an investment is sunk or committed versus not yet committed. A network upgrade can go from having costs exceeding the market benefits to the other way around depending on whether some investments are treated as committed or not. This is more likely to occur for intra-regional upgrades than for inter-regional upgrades. For instance, if there is a committed remote generation project on the end of a radial transmission line then the cheapest option for a TNSP to meet a regional reliability criteria or local reliability criteria may be to just upgrade the radial transmission line. However, the combined cost of the remote generator and the transmission upgrade may not have been the lowest cost option. A more expensive local generator and no network upgrade may have been cheaper but because the remote generation project was committed then the economic comparison that the TNSP would look at is just the cost of the upgrade of the radial line versus the more expensive local generator. On the other hand, since each region requires sufficient generation within the region to satisfy reliability and security criteria, considering any inter-regional reserve sharing, sunk generation investments don't always have quite the same impact on interconnector upgrades as they do for intra-regional network upgrades. Interconnectors tend to have more of an ebb and flow of power, so often these sunk generation investments mainly result in dispatch cost benefits in an adjacent region rather than significant generation investment cost savings.

In terms of renewable generation, network upgrades that enable access to the regional reference node are likely to satisfy the Regulatory Test if power stations such as wind farms are committed developments because under a CPRS regime the dispatch costs of the renewable generator may be near zero and the generation that it reduces is likely to be thermal generation which may have a dispatch cost of around $50/MWh if the cost of carbon emissions is included. Further the value of Renewable Energy Certificates should also be included in the analysis[2]. The shortfall penalty for the expanded national RET is expected to

[2] In version 2 of the Regulatory Test, the total cost of an option (or an alternative option) included the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution (including greenhouse gas abatement). It stated that an environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost. In version 3 of the Regulatory test, this explicit mention of environmental laws and taxes has been simplified to the cost of complying with laws, regulations and applicable administrative requirements in relation to the option.

be $65 nominal. Therefore, it is possible that the REC value could add another $30/MWh[3] of benefit bringing the dispatch cost saving to around $80/MWh. Under this scenario many quite substantial transmission upgrades may have net benefits. Following this to its logical conclusion, if renewable generators were to commit and connect to the shared network then using the Regulatory Test could result in transmission following renewable generation. This transmission investment model for intra-regional augmentations is picked up in Scenario 2.

On the other hand if deep connection costs are charged then much of the renewable generation developments will then be determined by the capacity in the existing network. In the NEM there is a view held by some which argues that Clause 5.4A of the NER that details access arrangements relating to transmission networks essentially requires new generators to pay deep connection costs. Clause 5.4A states that TNSPs:

- must negotiate in good faith with a connection applicant;
- must take reasonable steps to provide access arrangements consistent with the connection application;
- must take into account the amount of power transfer capability being provided to existing generators under existing access agreements;
- in relation to the three points above, must consider potential augmentations and extensions required to be undertaken on all affected shared infrastructure; and
- calculate the charges to be paid by the connection applicant concerning connection and as a consequence of required augmentations and extensions.

The deep connection costs model for transmission investment is roughly approximated in Scenario 1.

2.4 Discussion of Scenarios

This section discusses the approach to represent the regulatory frameworks specified in the three scenarios in the modelled cases.

2.4.1 Scenario 1: Non-responsive Transmission

Scenario 1 is based on meeting the RET and implementation of the CPRS but with zero transmission augmentation or if this is not possible then just the minimum transmission augmentation necessary to meet the NEM demand and the expanded RET target. Here we note that meeting NEM demand can be done at different levels of security, and consequently this required a consideration of what are the mandatory requirements.

[3] The $30 per REC price is just for illustration. The modelling undertaken to determine new entry generation does not use an explicit REC price but uses a constraint that the amount of renewable generation has to be sufficient to met the renewable energy target each year. These constraints will imply different REC prices for each year.

Each of the respective state transmission planning bodies develops and uses slightly different planning criteria for the development of intra-regional transmission assets. These criteria form the basis of what could be considered as the minimum mandatory obligations. The understood criteria are described in the table below.

Table 2-1 State Transmission Planning Criteria

State	Transmission Planning Criteria
South Australia	Cater for any one line out of service and the worst generator combination at time of 10% POE demand level
Victoria	Probabilistic assessment of unserved energy across conceivable power system conditions
Tasmania	Cater for no credible contingency event interrupting more than 25 MW of load and no single asset failure interrupting more than 850 MW or, in any event, cause a system black
New South Wales	Cater for any one line out of service and the worst generator combination at time of 10% POE demand level
Queensland	Cater for any one line out of service and the worst generator unit for that line outage at time of 10% POE demand level

As can be seen, except for Victoria the criteria are more stringent than would be established through a probabilistic assessment. This is because for each potential transmission line outage, the probability of this occurring at the same time as both the worst generator unit outage and 10% Probability of Exceedence (POE)[4] maximum demand is extremely low. This deterministic criterion can be thought of as saying that should the 10% POE demand level occur, the power system will be secure against the forced outage of any one transmission line with any one generator unit out of service.

In interpreting the meaning of minimal mandatory obligations in the description of Scenario 1 we note that application of the TNSP planning criteria would closely lead to the level of investment (in intra-regional transmission) as would occur under the regulatory test. However any less than this would lead to a less secure transmission system.

To differentiate the level of transmission development in Scenario 1 from that of Scenario 2, it was assumed in Scenario 1 that transmission would only be developed to maintain the power system within the established reliability level and to ensure that the RET target was met. In adopting this approach it was recognised that this could understate the level of transmission that would be developed under the current planning provisions of the TNSPs.

2.4.2 Scenario 2: Current Regime Working Effectively

Scenario 2 is based on the application of the (current) Regulatory Test to both intra-regional and inter-regional transmission development, noting that this

[4] The 10% POE is a demand level that has a probability of being exceeded once every 10 years.

requires the application of the reliability and market limbs of the Regulatory Test to potential intra-regional transmission upgrades, and the market limb to inter-regional transmission upgrades.

The treatment of the regulatory test (as modelled in Scenario 2) is discussed below, first for intra-regional transmission and then for inter-regional transmission.

2.4.2.1 Intra-regional Transmission

As noted above, intra-regional transmission development now requires both the reliability and market benefits limbs of the regulatory test be applied. The impact of this is that market benefits are now accounted for in the comparison of the relative economics of alternative intra-regional transmission projects. We note that given the stringent nature of the planning criteria used in most states, the overriding driver to intra-regional transmission development is most likely to remain the reliability limb of the regulatory test.

The previous section discussed the interpretation of mandatory obligations and the requirement to continuing meeting NEM demand. For the purposes of Scenario 1 we took the view of relaxing the TNSP planning criteria in order to have a minimum transmission development case. However we noted that this would produce less transmission enhancements than would occur under the reliability limb of the regulatory test based on current TNSP planning criteria.

For Scenario 2 the treatment of intra-regional transmission upgrades that would occur under the Regulatory Test was taken to be that based on the current TNSP planning criteria.

To emulate this in the modelling, the approach used was to upgrade the appropriate transmission lines in order to maintain transmission line constraints to an acceptable level. Both the hours that lines were constrained and the amounts by which they were constrained were considered. This was done by relaxing all the intra-regional transmission line limits in the simulation model and determining the MWh of flows that exceeded each line's rating. We have called this uncarried energy. Uncarried energy can be thought of as the energy that would have been transmitted had the line been able to support flows greater than allowed by its rating.

The lines chosen to be upgraded were those that had 10,000MWh of uncarried energy per annum for two years running. This criterion was chosen for the following reasons[5]:

- 10,000 MWh per year represents an average flow over rating of about 1 MW over all hours, 22 MW over 5% of hours, or 114 MW over 1% of hours. From experience this was considered the level at which congestion would become a problem requiring augmentation;

[5] In using an arbitrary criterion it was understood that this might understate or overstate the level of augmentation required. However no other approach was possible within the time of the study.

- The requirement to have two consecutive years was to ensure that the congestion observed was sustained.

Lines were upgraded in 300MW increments. Some lines required multiple upgrades to satisfy the 10,000MWh threshold. Furthermore, to account for build and planning times, no lines were upgraded before 2011. In this scenario we are implicitly assuming that transmission follows generation within a region.

2.4.2.2 Inter-regional Transmission Development

The application of the Regulatory Test to inter-regional transmission development is quite different to that of intra-regional transmission in that it is based solely on the market benefits limb of the Regulatory Test. The market benefits limb is an economic test as it considers the total economics of the network upgrade on the market (i.e. changes to: capital costs for generation and transmission, dispatch costs, unserved energy and ancillary services).

If we assume that the inter-regional network upgrade options being chosen by the TNSPs were the best of all the alternative options on the basis of the market benefits test then the interconnector upgrades being chosen would correspond to a central planning economic optimisation.

2.4.3 Scenario 3: Co-optimising Central Planner

The scenario of the co-optimising central planner was difficult to model fully. To properly undertake this requires that the optimization accounts for generation investment, transmission investment as it impacts market benefits and transmission investment as it impacts required reliability standards. Here we note that interconnector economics only requires a consideration of market benefits.

Further, while information on options and costs was available for four interconnector upgrade scenarios this was not the case for intra-regional network developments. The reason for this is that many of these options are only in the conceptual stage and there was insufficient time to obtain information from the TNSP's to develop what might be useable data. This meant using very indicative and generic assumptions in relation to upgrade options and costs.

We modelled an approximation to this scenario in the following manner. We first co-optimised interconnection and generation on the assumptions that there were no intraregional constraints that would significantly impact market benefits. Then based on this optimal level of interconnection, we optimised generation entry accounting for intra-regional constraints. Intraregional transmission was then upgraded based on uncarried energy as in Scenario 2.

While it is recognized that this approach falls short of a co-optimised solution, it does move towards that from the scenario of current arrangements.

3 Modelling the Transmission System

This chapter presents an overview of the transmission system model used in the modelling undertaken. This includes potential new transmission projects and the agreed interconnector upgrades to be used in the modelling. Also, this chapter briefly discusses the general issue of modelling transmission constraints and the approach used by IES.

3.1 Modelling Transmission Constraints

As one of the key aims of this project's modelling and analysis was to consider the relationship between generator investments, network congestion and network investment, this required a reasonably detailed model of the NEM's transmission system.

There were two main choices as to how the network would be modelled, these being:

- to use a NEM regional model combined with the use of generic constraints[6] such as the ANTS constraints used by NEMMCO or
- to develop and using an explicit network model[7].

IES adopted the second approach of developing and using an explicit network model. The reason for this were the advantages that had been observed in previous modelling assignments[8] undertaken by IES where the transmission system had been modelled via an explicit transmission model that had a reduced number of nodes (compared to the actual transmission system) and transmission lines[9].

One of the main advantages of using an explicit model of the transmission system compared to using only generic constraints is that it adapts well to considerable changes in dispatch patterns and local demand patterns. The reason for this is that many constraints in the network are based on thermal limits and what were originally complex generic constraints can often degenerate into relatively simple bounds or constraints on flows in a zonal network model[10].

Importantly the transmission model needs to properly represent the security constraints that the market operates under. These security constraints are often referred to as N-1 constraints as they limit power flows on transmission lines such that if any one of the N elements of the transmission system or any one

[6] Generic constraints are equations that are written to represent transmission flow limits without the actual flows being modelled. These equations put limits on generation levels that would otherwise result in flows being about the established limits.

[7] By an explicit model is meant a model of nodes and lines where the actual flows are modelled.

[8] Such as that undertaken for Powerlink and Transgrid in 2007 for the application of the regulatory test for QNI upgrades.

[9] This can be thought of as a simplified zonal model, an example of this being the zonal model of Queensland that Powerlink present in their annual planning statement.

[10] The same is the case for many voltage and stability constraints, and when this is not the case these limits are often only marginally more constraining than thermal limits which in turn can often be modelled in terms of simple network flows

generator is forced out of service (i.e. breaks down) then the power system would remain within all short term power flow limits. In the reduced network model that was used to model the NEM, individual lines in this model usually represent two or more physical lines. The flow bounds on these lines in the model represents the maximum security constrained flow for the sum of the physical lines which make up the single line in the model. However, in some situations this approach was not adequate, particularly in highly meshed areas of the transmission system. Thus, in addition, some generic constraints were included to limit the flow on a group of transmission lines and possibly, generator outputs on a selection of generators.

3.2 Development of the Transmission Model Used

The transmission model used was based on that developed for the purposes of a study being conducted by the NGF. The development of the network model involved:

- Obtaining and testing network models of the Queensland and NSW transmission systems that had originally been developed by Powerlink and TransGrid but updated for the AEMC study;
- Obtaining models from the respective TNSPs for the South Australian, Victoria and Tasmanian transmission systems and testing these models;
- Incorporating these models into both the IES MARKAL and IES PROPHET models;
- Addressing a number of identified issues including the modelling of losses, network topology, constraint limits and mathematical solution issues when there were negative nodal prices and non physical losses caused by constraints occurring in a loop (spring washer effect)[11].

3.3 The Transmission System Modelled

A broad description of the transmission system model developed and used in the study is as follows:

- 93 nodes;
- 130 lines between these nodes;
- Power flow losses modelled on each line;
- Security constraints incorporated that involving flows on multiple transmission lines;

[11] In modelling transmission systems solutions can appear that are not possible in reality. An example of this in the MARKAL model is the mathematical solution choosing to have power flows that increase losses for the purpose of increasing generation in order to satisfy the level of RECs required. Such solutions are termed non-physical and need to be removed from the solution.

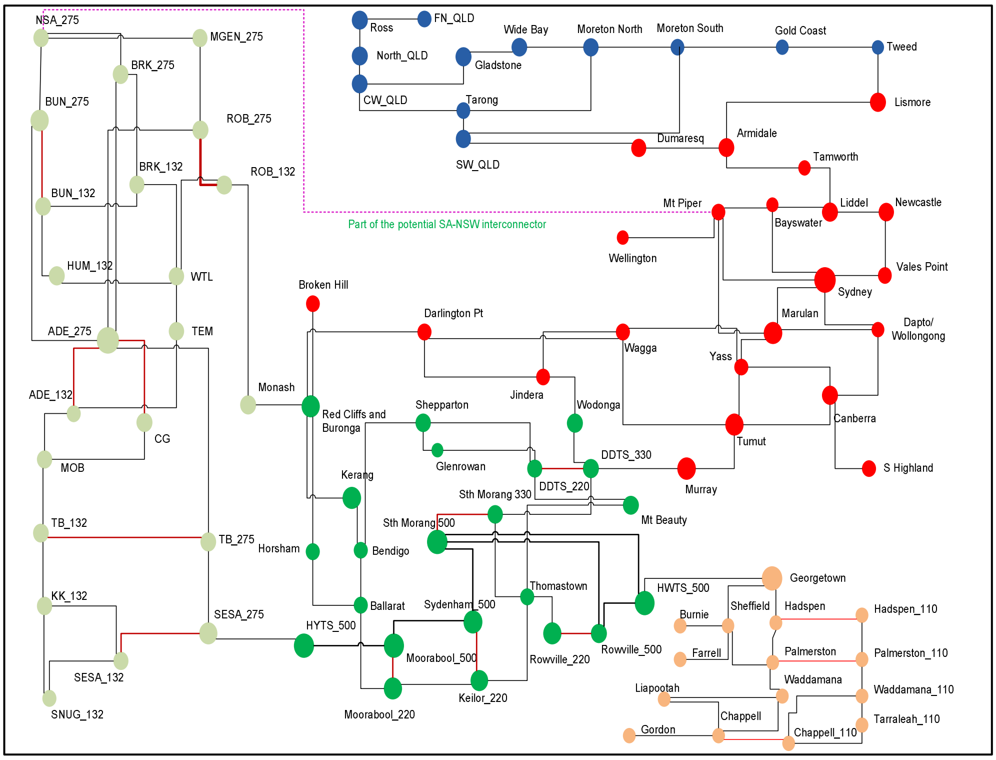
- Inter-regional constraints are inherent in the network model (there are no hypothetical transmission lines going from one reference node to another reference node);
- Customer loads are modelled on all the nodes that have customer loads.

The network topology of this model is shown Figure 3-1 below. The nodes in the different NEM regions are represented by different colours.

As previously noted, network constraints are modelled through simple limits on the transmission lines shown above and by equations (generic constraints) that place flow limits on groups of transmission lines. An example of a generic constraint is the limit on the flow across the three transmission lines that cross the NSW – Vic border. There were 290 so called generic constraints used in the transmission model used.

Additional details on the transmission model used are presented in Appendix 1 The Full Transmission Model.

Figure 3-1 NEM Network Topology



3.4 Network Augmentations

The NEMMCO SOO provides three categories of network augmentation, these being:

- Committed projects;

- Routine augmentations; and
- Conceptual augmentations.

The committed projects that are listed in Table 9.1 of the NEMMCO 2008 SOO were included in the modelling. Routine augmentations as listed in Table 9.2 of the NEMMCO 2008 SOO were also included in the modelling when required to meet system standards.

Conceptual augmentations pertain to potential transmission line upgrades. These are listed in Table 9.3 of the NEMMCO 2008 SOO. These upgrades were not included in the modelling unless they were required. A review of these potential augmentations shows that unlike generation, upgrades are very line specific and until detailed studies are done, the costs and capacity upgrades are at best very tentative or unknown.

It was agreed with the AEMC that interconnector upgrade options and costs be common for the modelling undertaken by IES and ROAM. These agreed upgrade options and associated costs are shown below in Table 3-1.

Table 3-1 Interconnector Upgrade Options

Upgrade Path	**Capacity Increase**	**Capital Cost estimate ($millions)**
Northern SA to Melb (upgrade existing lines)	400MW bidirectional	$400M
Melb to SWNSW (upgrade existing lines)	400MW bidirectional	$247M
Northern NSW to SW Qld (upgrade existing lines)	400MW bidirectional	$220M
Adelaide to NCEN (new transmission line in addition to removing constraints Northern SA to Adelaide and Adelaide to South East SA)	2000MW bidirectional	$2,300M (estimate only)

Of note is that when one of these options is required to be incorporated in the constraint modelling it requires that upgrades to a number of specific transmission lines be undertaken.

4 Modelling Generator Development

Chapter 2 discussed the approach to representing the various regulatory frameworks in the modelling. This chapter discusses and presents the IES's approach to modelling generator entry and exit and transmission augmentations for the three scenarios.

4.1 Generator Entry Criterion

4.1.1 Economic Criteria

At the AEMC meeting and in IES's proposal it was noted that the three cases as described in the Terms of Reference may not clearly illustrate the impact of the different regulatory arrangements being modelled in each scenario. This is because the scenarios change both the manner in which generation enters the market and the manner in which transmission is developed. The differences in generator development are that Scenarios 1 and 2 have profit maximising entry whereas Scenario 3 is based on a central planning deterministic cost minimisation.

To properly identify the impact of the different regulatory arrangements being modelled (i.e. minimum transmission development, current framework, and co-optimised) it was agreed and considered more appropriate to have generation development done on the same basis in all the modelled cases. That is, there would not be a mixture of market based new entry and centrally planned new entry across the scenarios. It was agreed to have for all scenarios, generators enter and retire on the same basis as in Scenario 3, i.e. all scenarios would use a central planning optimisation, albeit with different things being optimised and held fixed, rather than any market based new entry. It was also noted that the profit maximising behaviour and market based entry would be better addressed in further work where a few case studies of particular situations could be developed to see how different transmission development frameworks affect entry and exit of generators in the market.

4.1.2 Locational Issues

As noted in section 2.3.2 there is an issue of how the Regulatory Test might extend and augment the network to new generators, particularly remote renewable generators and who pays for these augmentations. How this is done and the perceptions of how it will be done in the future will affect the locational decisions of new entry generators, particularly wind and geothermal generators that may be required to locate in remote areas. These generators investment and locational decisions will be substantially affected by the following questions.

- The "who pays" question for shared extension assets is particularly important to wind generators that are likely to require such assets to connect to the main grid. If wind generators are required to pay for these assets then this would impact the economics of potential sites;

- There is debate over the access rights of the incumbent generators who have a view that any reduction in the level of access brought about by new entrants (either renewable or non renewable generators) should be addressed by the new entrant, either through funding congestion on the shared network (to the local reference node) or through compensation.

The treatment of these issues was relevant to the three cases that were modelled:

- Scenario 1 (non responsive transmission development) was taken to represent the situation where transmission is not developed to support increased congestion on the shared network other than to ensure demand is met and the RET is satisfied. Consequently in this scenario generators were taken to have a preference to locate in areas that have existing transmission capacity.
- Scenario 2 (current arrangements) was developed on the basis that customers pay for congestion on the shared network. This meant that generators locate within regions on the assumption that transmission would be developed to address any congestion that may arise, and that the level of access would remain at near historical levels.
- Scenario 3 (co-optimised development) meant that generation and transmission were developed in such a manner that total cost was minimised.

In all scenarios, the modelling assumed that extension transmission assets are built as required to connect the selected generation projects into the existing grid. Costs of the extension assets were generally not considered in the optimisations as there was little or no data available on the cost of extension assets for the various potential new generator projects (particularly wind) that were modelled. From a modelling perspective this means that the cost of new entry generators includes only transmission connection costs not any extension assets. The implications of this simplification regarding shared network extension costs are as follows. Firstly, in areas where substantial extension assets are required the costs of this generation will be underestimated. In terms of making inferences about how the three regimes compare it probably does not have much impact though it certainly could make considerable difference regarding the location of generators and the transmission lines that would be upgraded. On the other hand if the modelling were focussed on looking at how various network charging regimes could impact on generator locations then this omission could have considerable impact.

5 Overview of the Market Models

IES used two models in this study. The first was the IES Integrated Energy Market Model (referred to as the MARKAL model as it is based on the MARKAL modelling framework) and the second was the IES simulation model PROPHET. These are described in turn below.

5.1 The IES MARKAL Model

The IES MARKAL Integrated Energy Model is a mixed integer linear programming optimisation model of the power and gas systems. The gas system was not modelled for this study. The model was used primarily to determine generation entry and retirements and interconnector upgrades. To do this the model optimises generator dispatch to meet demand for a number of points on the annual load duration curve, and new investments and retirements of generation and transmission. For this study the model was upgraded to include a detailed network model of the NEM which used a DC load flow model to approximate the AC transmission network.

Two forms of the IES MARKAL model were used in the modelling undertaken. These were as follows

- The Regional MARKAL Model – the transmission model used here only incorporated interconnectors between the NEM regions (i.e. it was based on the NEM regional transmission model but without all of the generic constraints);
- The Full Network MARKAL Model – the transmission model used here was the full transmission model developed for this study and was the same as that used in the PROPHET model. An overview of the transmission model used can be found in Chapter 3.

In the cases modelled, MARKAL was used to obtain the optimised entry and exit of generation and the optimised level of interconnection development.

A description of the IES MARKAL model is presented in Appendix 2.

As the MARKAL model is essentially a central planning model it only models generator bidding behaviour as though every generator offered its capacity at marginal cost. It does not model half hourly generation dispatches, the variability of loads over time nor the impact of generator random outages. Thus the MARKAL modelling was only used as a “first pass” at modelling the system to determine the new generator and transmission entry such that system developed at least cost and the RET targets were satisfied. The detailed market modelling was done using the PROPHET market simulation model.

5.2 The IES PROPHET Model

The IES PROPHET Model is a detailed market simulation model of the NEM. The key features of PROPHET are as follows:

- As a market simulation model, PROPHET operates through clearing the market each settlement period based on generator price/volume offers, demand side bids, and customer loads. The modelling was based on simulating each half hour period;
- PROPHET is a Monte Carlo simulation which can model random events such as generator unit outages;
- PROPHET represents each generator unit in terms of variable and fixed costs, forced outage profile, maintained maintenance, auxiliary load, generator price offers, location on the transmission system and transmission losses, maximum capacity, ramp rates etc;
- PROPHET represents generator companies in terms of the generating units they own, their trading strategies, contracts etc;
- PROPHET simulate generator profit maximising behaviour in a way similar to how generators operate and rebid in the NEM;
- PROPHET represents the transmission system in terms of nodes, lines, losses, limits;
- PROPHET represents retailers in terms of wholesale load purchases, load variability, etc;
- PROPHET represents the NEM Market rules – VoLL, energy market, ancillary services market, etc.;

PROPHET was used in all the cases to model the NEM in detail and to identify the constraints that occur on the transmission system under the assumptions used. From these model runs the level of transmission development required under the different criteria was obtained.

6 Approach to the Modelling

This chapter presents the modelling approach and process for each of the three scenarios modelled.

6.1 Description of Modelled cases

As discussed in Section 4.1.1, all cases were based on a central planning approach that optimises generator entry and exit within the framework of the scenario to allow for a common basis for comparison of the first two cases with the co-optimised case.

With this modified description of the cases being modelled, the specification of the three cases modelled by IES was as follows:

- ***Scenario 1 - Non-responsive transmission*** – generation entry and exit is optimised based on a forward curve for carbon permit prices and the requirement for the RET using the existing transmission system with committed expansions. Generator entry follows existing transmission capacity. Transmission is only developed to ensure demand is supplied and the RET is satisfied.
- ***Scenario 2 - Current regime working effectively*** – generation entry and exit is optimised based on a forward curve for carbon permit prices and the requirement for the RET. Generators enter on the assumption that any intra-regional transmission constraints will be addressed under the Regulatory Test where mandatory obligations (as they pertain to the reliability limb of the test) incorporate current TNSP planning criteria. Interconnection is developed as would likely be done under the Regulatory Test.
- ***Scenario 3 - Co-optimising central planner*** – generation entry and exit and transmission expansion is co-optimised based on a forward curve for carbon permit prices and the requirements for the RET.

In undertaking the modelling, it was also recognised and agreed that the modelling would assume that the transmission system is always in a system normal state. (It was noted that this would underestimate congestion and underestimate the value of some transmission upgrades.)

As discussed earlier it should be noted that all three scenarios approximated generator entry based on a central planning optimisation. Market based new entry was not modelled for scenarios 1 and 2 to ensure that there was not a potentially erroneous comparison made with scenario 3 of the co-optimised central planning optimisation of both generation and transmission. If there had been a mix of market based entry and central planning then if profit maximising market based entry in scenario 1 had been compared with central planning co-optimisation in scenario 3, it would not have been possible to determine whether any difference was occurring due to the restricted network expansion versus the co-optimised generation and network expansion or whether it was largely due to central planning versus market based new entry. If market based new entry were to be used then each of the three scenarios would need to have been reformulated in terms of network / locational charging regimes for generators combined with network expansion arrangements. However some insight into generator network charging regimes can be gleaned as follows.

Scenario 1 of no network augmentations could be thought of as a rough proxy for deep network connection charges as generators choose to locate at locations of existing network capacity. Scenario 2 could be thought of as a proxy for no generator network charges other than shallow connection costs as generators do not take into consideration existing network capacity when locating. Scenario 3 might be thought of as somewhat in between these.

Consequently, the three regimes as IES has modelled them will give:

- a fair comparison of how the network and generator entry and retirements would develop in terms of locations, assuming an efficient market, in response to different regimes for network expansion;
- insight into how different generator locational pricing regimes may affect market based generator entry and exit in terms of location; and
- only modest insight into the relative economic benefits of different generator network charging regimes.

6.2 Modelling the Cases

In order that the modelling process is clear, this section lays out the step by step process used that was used in the three cases modelled.

6.2.1 Scenario 1 – Non-responsive transmission

The steps involved in modelling Scenario 1 were as follows:

- The Full Network MARKAL model was used to determine the optimal level of generator development on the assumption of no transmission development except committed projects.
- The generator entry and retirement schedule was imported into the PROPHET model from which was obtained the level of renewable energy generation, load not supplied, and transmission constraints. Transmission lines were only upgraded to ensure that the level of renewable energy generation satisfied the RET target and load was supplied. The actual modelling required no lines to be upgraded.

6.2.2 Scenario 2 – Current Arrangements

For Scenario 2 the modelling approach implicitly assumed that intra-regional transmission upgrades would be determined by the location choices of generators and growth in demands; that is transmission would follow generation and loads.

To represent the application of the regulatory test for interconnectors, the Regional MARKAL model was used to optimise the four agreed interconnection development options based on a regional transmission model (the Regional MARKAL central planning model optimises generation entry and exit and inter-connector upgrades based on a regional transmission model that does not consider intra-regional constraints). This had the advantages of:

- Closely duplicating the economic assessment process that occurs under the market benefits limb of the regulatory test;
- Incorporating the relative economic comparisons of interconnection upgrades and timings as would occur through some level of coordinated interconnector transmission planning.

The steps involved in modelling Scenario 2 were as follows:

- The Regional MARKAL model was used to co-optimise generator and interconnector developments (this implicitly ignores intra-regional constraints);
- The interconnector upgrades, generator entry and retirement schedule was imported into the PROPHET model from which was obtained the level of renewable energy generation, load not supplied and transmission constraints. Transmission lines were upgraded to remove transmission constraints using the 10,000 MWh of uncarried energy criteria discussed in Section 2.4.2.1 and to ensure that the level of renewable energy generation satisfied the RET target and that load was supplied. The actual modelling required no line upgrades to meet the RET.

As will be discussed in the next chapter, generator entry and exit was optimised on the basis of a full transmission model with all intra-regional network constraints being relaxed.

6.2.3 Scenario 3 – Co-optimised Development

As discussed in Section 2.4.3, the scenario of the co-optimising central planner was difficult to model fully. To do this two approaches were investigated, these being

- Approach 1: co-optimisation of generation and interconnectors whilst maintaining the rest of the transmission system fixed, and upgrading transmission links based on a criteria of hours constrained; and
- Approach 2: co-optimisation of generation, interconnectors and the intra-regional network elements using a rough estimate for intra-regional network upgrade costs.

While Approach 2 was the preferred method, the study used Approach 1 due to the lack of data available to support a sensible application of the co-optimisation.

The steps involved in modelling Scenario 3 for the two approaches were as follows:

Approach 1

- The Regional MARKAL Model was used to co-optimise generators and interconnectors.
- Using this optimised interconnector upgrades, the Full Network MARKAL Model was used to develop the optimal generation entry and exit schedule on the assumption that the rest of the transmission system is fixed;
- Upgrades to the transmission system and the generator entry and retirement schedule were imported into the PROPHET model from which was obtained the level of renewable energy generation, load not supplied and transmission constraints. If required, transmission lines were upgraded to remove transmission constraints using the 10,000 MWh of uncarried energy criteria discussed in section 2.4.2.1 and to ensure that the level of renewable energy generation satisfied the RET target and that load was supplied.

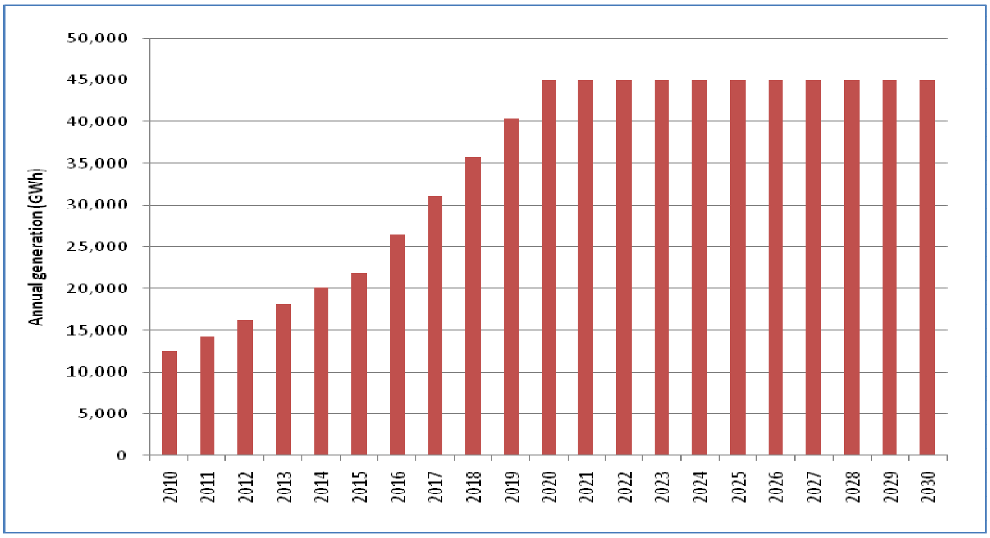
7 Renewable Energy and CPRS Assumptions

This chapter presents the assumptions and treatment of renewable generator entry and the Carbon Pollution Reduction Scheme. It covers the assumed renewable target profile, an overview of the make-up and costs of renewable generation by location and type, and the dynamics of entry.

7.1 Renewable Energy Target

The renewable energy target from the government's expanded national Renewable Energy Target scheme as announced 30 April 2009 was assumed in this study. The target is shown in the Figure 7-1 below.

Figure 7-1 Renewable Energy Target



7.2 Renewable Generation

A database of renewable projects has been created by IES using both publicly available information and information provided by the CEC, NGF and ORER. This database covers existing, committed, planned, proposed and generic renewable energy projects in Australia, along with capital costs, operating and maintenance costs, capacity factors, earliest available dates etc. Over 120,000 annual GWh of renewable generation is included in the database, of which 11,500 annual GWh is from existing and committed projects. Estimated capacity factors for projects were generally sourced from information provided by proponents on their websites, planning documents or other published information. Where this was no available, capacity factors for plant in nearby locations were used as a basis for an estimated capacity factor. In the case of wind turbines, these estimated capacity factors were adjusted for the size of the proposed wind turbine as the larger turbines tend to give rise to slightly higher capacity factors due to technological improvements and increased turbine hub heights.

Table 7-1 below presents the total possible renewable generation (GWh) by energy source above the renewable energy baselines (closely corresponding to REC production) and status in the IES renewable database. The status of projects is classified as committed, uncommitted or generic. We have defined these terms as follows:

- Committed plant – known plant which are already existing or have a definite commitment to proceed. In this case, project costs are assumed to be sunk and are not considered in the study;
- Uncommitted plant – actual projects which have been identified but have no commitment to proceed; and
- Generic plant – projects which have been added to the database where IES believes the potential of an energy source in a given region is not fully captured by the known committed or uncommitted plant. These projects represent the unknown renewable projects that are likely to materialise in the future.

Table 7-1 Breakdown of projects in IES renewable projects database by energy source and classification (GWh)

Energy source	Committed		Uncommitted		Generic		TOTAL
	Embedded	Grid-connected	Embedded	Grid-connected	Embedded	Grid-connected	
Bagasse	331	739	37	854	-	-	1,961
Black liquor	136	36	31	1,183	-	-	1,386
Crop waste	1	-	-	-	-	-	1
Food waste	9	-	105	-	-	-	114
Geothermal	62	-	42	46,291	-	12,067	58,462
Hydro	208	1,764	32	381	-	-	2,385
Landfill gas	370	123	-	-	-	-	493
Municipal waste	-	-	197	403	-	-	600
Photovoltaic	1	270	18	128	-	-	417
Sewage gas	45	-	-	-	-	-	45
Small Generation Units	13	-	-	-	-	-	13
Solar - generic projects	-	-	-	70,080	-	-	70,080
Solar - known projects	18	-	35	1,601	-	-	1,654
Solar Water Heater	1,366	-	-	-	-	-	1,366
Wave	-	-	-	265	-	-	265
Wind	157	5,826	469	39,207	-	2,102	47,761

Wood waste	107	-	846	3,401	-	-	4,354
TOTAL	**2,823**	**8,759**	**1,812**	**163,794**	**0**	**14,169**	**191,357**

For the purposes of this study, projects with a capacity less than 20MW were considered to be embedded and were not explicitly modelled. (Embedded generation projects were considered economic and assumed to enter if they had a levelised cost equal to or less than $110/MWh. A cost of $110/MWh was chosen as this was considered to represent the cost level above which such projects may not proceed). This left a maximum possible annual generation of over 186,000 GWh from committed and potential (uncommitted or generic) grid-connected projects. Table 15-9 in Appendix 3 shows the capacity of plant per region and type explicitly modelled in this study.

In relation to the development of the above tables we note that the amount of potential investment for certain renewable technologies was limited in line with proven developments. In particular:

- Geothermal plant was assumed to be limited to 1000MW of capacity by 2020. This was an assumption agreed to by IES and Roam at the 30th March meeting with the AEMC and is in line with what IES considers to be a reasonable expectation for this technology;
- Biomass plant (bagasse, municipal waste, wood waste, food waste, landfill gas etc.) are limited by fuel availability. In this study, only known committed and potential projects were included in the assumptions listed above;
- Wave energy technology is still in very early stages of development. A few known projects in the form of small pilot plant were included in this modelling. Costs published for these plant are as given in Table 7-2. However as significant investment in wave energy was considered to be unlikely within the modelling period, no generic plant were included in the modelling;
- A small number of known small solar projects were included in the modelling. These projects have published costs as given in Table 7-2. However IES considers these costs as unrepresentative of generic solar plant in Australia. For this reason, generic solar plant was included in the database with significantly higher costs.

7.2.1 Renewable project costs

Project information for the IES renewable database has been collected over a number of years from numerous public and private sources. To account for movements in project prices over this time, project costs were scaled from those originally entered into the database to achieve values in line with IES's understanding of current cost levels.

The levelised costs that a project proponent would use were calculated assuming a 50/50 debt-equity ratio resulting in a project rate of 10.93%. An economic lifetime of 20 years was assumed. Table 7-2 below shows the average fixed and variable costs assumed by type for energy sources that had uncommitted or generic projects. The levelised cost incorporates the capital expenditure and variable O&M costs as well as an expected plant capacity factor.

We note that there are significant uncertainties in relation to renewable generation costs and the relativities of these costs. However the assumed limitations on the various technologies meant that wind generation would be the most significant technology used in the studies undertaken.

Table 7-2 Average project costs and capacity factors for potential grid-connected renewable plant by type (real $2009)

Energy source	Average fixed cost ($/MWh)	Average variable cost ($/MWh)	Average levelised cost ($/MWh)	Average Capacity Factor
Bagasse	49.29	30	79.29	52%
Geothermal	70.2	12.8	83.00	95%
Municipal_waste	55.65	25	80.65	77%
PV	166.83	1	167.83	20%
Solar - generic projects	153.00	1	154.00	40%
Solar - known projects	84.84	1	85.84	40%
Wave	93.68	10	103.68	39%
Wind	123.87	1	124.87	34%
Wood_waste	39.24	50	89.24	75%

7.2.2 Timing of Renewable Generator Investments

Previous IES modelling has shown that renewable generation investment is likely to follow the renewable energy target if the combination of energy prices and the RET shortfall charge is high enough and the target has a flat trajectory in the later years of the scheme[12].

Lower energy prices or RET shortfall charge would lead to the amount of renewable generation developed being less than the legislated target. The uncertainty in relation to the profile of renewable generator development was discussed at the 30 March meeting with the AEMC and it was agreed that the assumption be made that renewable generator entry would match the target

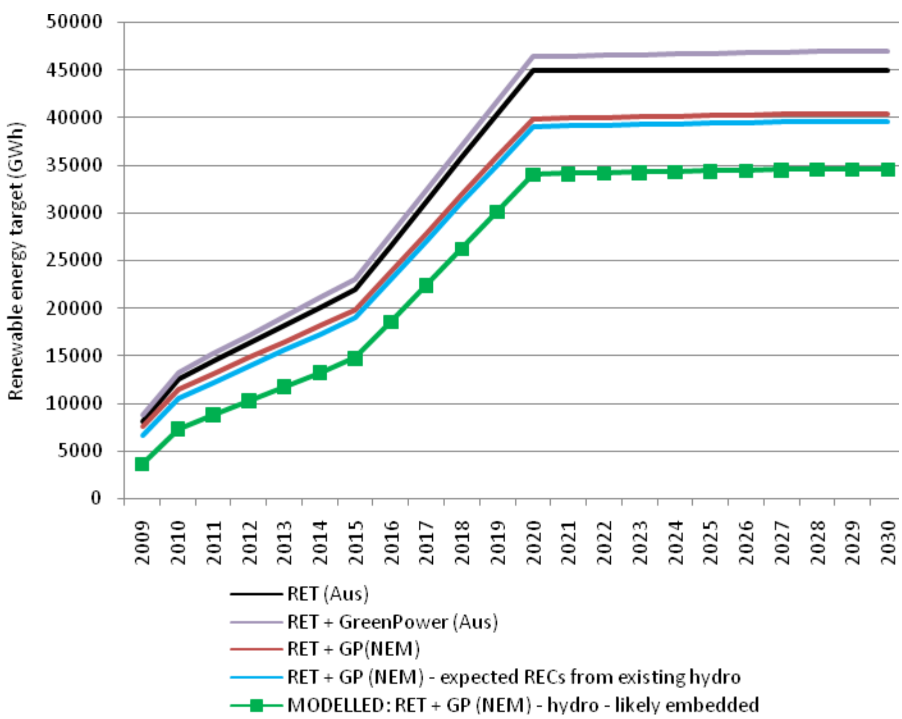
[12] Note that this is not true for targets with decreasing trajectories in the later years (for example, the draft expanded national RET legislation announced December 2008 which proposed a decreasing target from 2025-2030). As banking and "borrowing" are permitted under the RET rules, the amount of generation required to fulfil the scheme obligations is less than the maximum target level if the target reduces towards the end of the scheme. Moreover, depending on project costs and forward electricity prices, a declining target may result in projects being committed well ahead of the target and the surplus of renewable energy certificates (RECs) banked for use later in the scheme, further reducing the final level of renewable generation.

profile[13]. The reason for this was that while this may understate the level of renewable generation in the early years, it would result in additional investment over the period of the study. This would likely be associated with increased stress on the transmission system towards the end of the study period.

7.2.3 Renewable Energy Level to be Modelled

As the modelling of renewable energy projects considered only non-embedded projects in the NEM, the target level for these projects had to be developed. This was based on (1) the amount of embedded renewable generation assumed in the modelling (projects smaller than 20MW were considered embedded) (2) the small increase in RECs demand brought about by the GreenPower scheme (3) the proportion of REC demand in the NEM compared to the whole of Australia (agreed at 86% at the 30 March meeting). Having developed this the following were deducted to obtain the REC demand on the projects modelled – (1) forecast production of RECs by existing hydro sources assuming reservoir inflows at 90% of long term average over the study period (2) REC generation from committed embedded projects (these were assumed to be projects of less than 20MW with levelised costs less than $110/MWh) and (3) expected solar water heater installations. This is shown in Figure 7-2 below. This target was used in all the modelling carried out for this study.

Figure 7-2 Modelled renewable energy target



[13] This meant that the IES renewable energy model would not be used in the establishment of the timing of renewable generator investment.

7.3 Wind Generation Variability

Historic 5-minute data for generation from eight wind farms across South Eastern Australia was obtained and correlations between the wind farms examined. These correlations may be found in Table 7-3. From this it can be seen that the correlation between the generation of two wind farms is extremely dependent on the location of the two farms. In order to properly account for the impact of wind on transmission, it is therefore necessary to capture this relationship in the modelling.

Historic half-hour data from Lake Bonney 2 wind farm was used to create wind traces for all wind farms included in the modelling. This historic generation was scaled to match the energy and capacity of each plant. The scaled generation trace was then shifted in time to obtain correlations similar to those shown in Table 7-3. Correlations between neighbouring regions (for instance, South Australia - Victoria, Victoria - New South Wales, etc.) were considered to be particularly important, with particular attention paid to attaining realistic values for these pairs. For pairs of states for which historical correlations in generation was unavailable, target correlations were chosen taking into account geographical location and distance between states.

Correlations for multiple wind farms at the same node were assumed to be 1.0. That is, other than scaling associated with different capacities and capacity factors, all wind farms at any one node generate identically. The final correlations between wind generation used in this modelling are given in Table 7-4.

Table 7-3 Historical Correlation between Winds Farms

		SA Canunda	SA Cathedral Rocks	SA Lake Bonney	SA Starfish Hills	SA Wattle Pt	TAS Woolnorth	VIC Challicum Hills	VIC Yambuk
SA	Canunda	1.000	0.416	0.918	0.543	0.489	0.272	0.535	0.639
SA	Cathedral Rocks		1.000	0.414	0.528	0.472	0.115	0.302	0.252
SA	Lake Bonney			1.000	0.507	0.476	0.262	0.503	0.608
SA	Starfish Hills				1.000	0.695	0.114	0.454	0.338
SA	Wattle Pt					1.000	0.156	0.493	0.376
TAS	Woolnorth						1.000	0.225	0.338
VIC	Challicum Hills							1.000	0.533
VIC	Yambuk								1.000

Capacities and capacity factors for wind farms were sourced from public and private data and agreed upon in consultation with the AEMC and ROAM. A list of wind farms modelled in this project with corresponding capacities and capacity factors can be found in Appendix 3.

Table 7-4 Correlations between modelled Wind Farms

	NSW	QLD	SA	TAS	VIC
NSW	0.86	0.46	0.65	0.18	0.30
QLD		n/a	0.31	0.09	0.18
SA			0.74	0.28	0.56
TAS				0.90	0.61
VIC					0.65

7.4 Carbon Pollution Reduction Scheme

The proposed Carbon Pollution Reduction Scheme (CPRS) is assumed to commence from 1 July 2010 onwards. Although the introduction of the CPRS by this date may be considered unlikely, it was agreed that since the purpose of the modelling is to test the NEM transmission development framework to increased congestion issues, a commencement date of 1 July 2010 should be assumed.

The carbon permit prices to be used was agreed to be that reported in the October 2008 Treasury modelling as follows:

- The permit prices under the CPRS 5% trajectory until 2015; and
- The permit prices under the CPRS 15% trajectory after 2015.

The permit prices were provided by the AEMC and are presented in the Table 7-5 below. The Treasury prices which were in 2005 dollars have been converted to 2009/10 dollars using an agreed factor of 1.1367.

Table 7-5 Carbon Emissions Permit Price in 2009-10$/tCO2-e

Year	CPRS Trajectory	Permit price $/Tonne
2010/11	CPRS 5%	23.19
2011/12	CPRS 5%	23.98
2012/13	CPRS 5%	25.92
2013/14	CPRS 5%	27.85
2014/15	CPRS 15%	45.24
2015/16	CPRS 15%	47.63
2016/17	CPRS 15%	49.90
2017/18	CPRS 15%	52.29
2018/19	CPRS 15%	54.56
2019/20	CPRS 15%	56.72

Source: Derived from Australian Treasury, Australia's Low Pollution Future: The Economics of Climate Change Mitigation, October 2008 (Chart 6.3 and Table 6.1)

8 NEM Data Assumptions

This chapter presents the key assumptions regarding NEM data to be used in the modelling, other than those previously discussed. This chapter addresses customer demand levels, generator bidding behaviour and government policies. The detailed assumptions can be found in Appendix 3.

8.1 Demand Assumptions

8.1.1 Regional Demand

The demand growths used in the modelling were sourced from the NEMMCO 2008 Statement of Opportunities (SOO). The demand scenario used was the Energy and Maximum Demand Projection in the Medium Economic Growth Scenario (for scheduled generation). For years not covered by this (past 2018/19), demand projections were extrapolated at the average rate of load growth for the last five years.

The scheduled energy and maximum demand projections used in this study were sourced from the 2008 NEMMCO SOO. As this study explicitly modelled grid-connected renewable plant, a majority of which is non-scheduled, it was necessary to increase the modelled demand by the expected generation from this sector. Estimates of non-scheduled grid-connected biomass, wind, hydro and other renewable generation were obtained from the NIEIR publication prepared for NEMMCO “Projections of non-scheduled and exempted generation in the National Electricity Market, 2007-08 to 2019-20”.

Half hourly demand traces (MW) were produced by scaling the 2006-07 half-hourly demand by the projected energy and maximum demand levels calculated as described above. The demand traces were based on actual load shapes for each NEM region used in the network model to ensure that demand variability was captured.

For the purposes of this study, renewable plant with an installed capacity of less than 20MW were considered to be embedded. Generation from such plant was therefore assumed to be outside of the projected generation levels published in the NIEIR report and was not explicitly modelled.

8.1.2 Nodal Demands

The use of a 93 node transmission model requires that regional load be allocated to nodal loads. Further, since the regional load forecasts include transmission losses associated with intra-regional flows these had to be removed as IES was explicitly modelling these losses on each transmission line with the detailed transmission model. Consequently, the NEMMCO load forecasts were reduced by the level of losses explicitly modelled when using the detailed transmission network model.

Disaggregating the regional loads into nodal loads was done through information provided by the respective TNSP. In some cases this was based on historical nodal or zonal half hourly loads and in other cases IES was provided with factors to split the regional loads into nodal loads. Either way, the half hourly nodal loads for the simulations were effectively created by disaggregating the half hourly regional loads with half hourly allocation factors, which for some regions could be constant over time. This information remains confidential to the respective TNSPs.

Table 13-3 in Appendix 1 presents a list of nodes with demand attached.

8.1.3 Demand Response

The 2008 NEMMCO SOO says that the load forecast include an allowance for the increased cost of electricity due to the introduction of an emissions trading scheme. Given this, no additional reduction in demand was assumed.

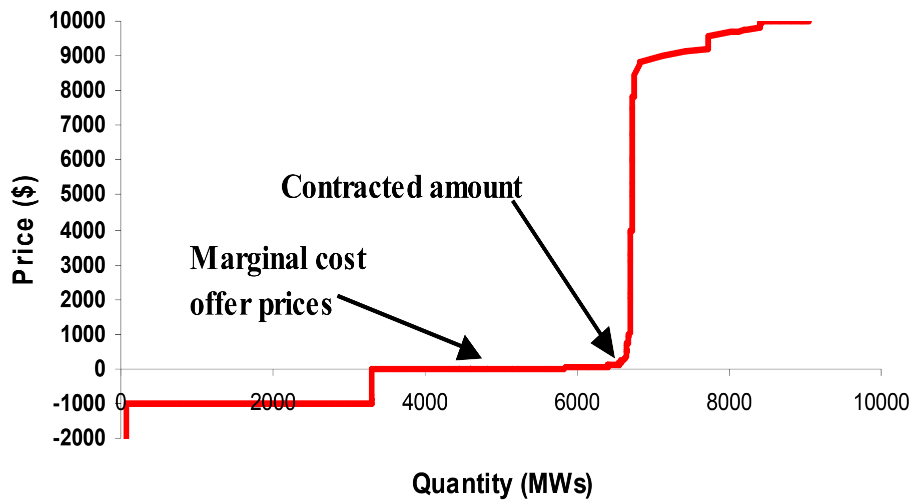
8.2 Generator behaviour

Equally as important as renewable generation levels and loads at the different locations is the level and variability of existing generation, in particular brown coal, black coal, gas generation and hydro. The key issue here is the manner the existing generators offer their generation into the market, often referred to as generator bidding behaviour.

The approach to generator bidding was to model the dynamics of the market as observed. This was done through developing assumptions about the levels of contracts sold by generators on a portfolio basis and having generator portfolios behave in a manner consistent with their respective contract positions. Further, in the PROPHET modelling the supply curves offered by generators dynamically respond to changes in the market such as level of demand and planned and forced outages. This included portfolio generators adjusting their individual plant offers to maintain their overall portfolio offer to cover their contract positions in the presence of outages of one of their generator units.

The shape of the generator offer curves used in the modelling is shown in the figure below. This shows the typical bid shape displayed in electricity pool markets which has generators bidding at near SRMC to their contract obligations and higher prices after this.

Figure 8-1 Typical Generator Bid Profile Used in the Modelling



8.3 Government Policies

8.3.1 Queensland Gas Scheme

The Queensland Gas Scheme is assumed to be in operation for the whole modelling period but not materially affecting the location of generators because the CPRS creates a situation whereby there market delivers more than enough gas generation to meet the Queensland Gas Scheme's requirements.

8.3.2 NSW Greenhouse Gas Reduction Scheme

It is assumed that the NSW Greenhouse Gas Reduction Scheme (GGAS) will cease its operation at the start of the CPRS from 1 July 2010.

9 Limitations of Modelling

There are a number of limitations to the modelling undertaken in this study. These are as follows.

9.1 Modelling the transmission system only in the system normal state

As agreed with the AEMC all the modelling undertaken assumes the transmission system is in a system normal state. In practice however much of the time there are one or more elements of the transmission system out for planned or unplanned maintenance, upgrades etc, and many of the most severe cases of market congestion occur under these conditions, that is when one or more key components of the transmission system are unavailable due to forced or planned outages. Thus modelling the market assuming the transmission system is always in a system normal state will underestimate congestion levels and the impact of congestion, and thus will underestimate the value of transmission upgrades.

9.2 Reserve levels in regions

NEMMCO establish reserve levels in each region based on reliability modelling studies that establish the level of generation capacity required to be installed to satisfy the reliability criteria having no more than of 0.002% of unserved energy. Such studies account for among other things the reliability of generator units and the probability distribution of demand including the correlation of demands between regions. The demands used also incorporate the 10% POE demands.

These studies are also used to determine the change / reduction in the level of generation required if an interconnector were to be increased. A decrease in the level of generation required due to an increase in interconnection would be expressed as a reduction in the level of reserve required in one or more regions. Here it is noted that a rule of thumb for the optimum level of interconnection between regions is the level of demand diversity between regions at time of maximum demand plus the size of the largest unit. This means that increasing interconnection may not result in a comparable change in the level of regional generating reserve required.

Without such modelling being undertaken, the modelling studies undertaken for this report assumed that the interconnector options being considered did not impact the regional reserve criteria. This meant that the total level of generation that would be required to be developed in the NEM would likely be close between all the interconnector options being considered. In making this assuming it was recognised that there may be some economic value not being included in the modelling undertaken. This assumption was reflected in the MARKAL planning model which was used to optimise new entry generation and transmission through maintaining the level of required reserve in each region unchanged all interconnector options. If the reserve constraint was binding in all scenarios then the level of generation required would be the same.

9.3 Variation in system security outcomes

The approach to the scenarios noted that there was less intra-regional transmission developed for Scenarios 1 and 3 compared to Scenario 2. In these scenarios it was not possible to account for the differences in regional security resulting from these differences or to value any differences in this regard.

This was because the modelling was undertaken using system normal network configurations. New generation and network were developed to ensure that reserve margins were met. Identified constrained lines were upgraded based on a criterion of uncarried energy (potential flows above rating). However, there is no guarantee that the intra-regional networks over time would meet the individual TNSP planning requirements in terms of system security.

9.4 Generator bidding behaviour

The scenario design noted that the basis of generation entry was done on an optimised basis to have a level of consistency between the three scenarios modelled. The modelling showed that this did allow for a better comparison of the impact of the different regulatory frameworks being modelled. This was done using the MARKAL model which also determines new entrant generation implicitly assuming strict merit order dispatch (i.e. short run marginal cost bidding).

The market modelling undertaken using the simulation model PROPHET was undertaken to model reasonable and realistic generator bidding behaviour. However the modelling did not investigate potential gaming strategies that could be employed in the presence of an increased number of intra-regional constraints.

9.5 Generator locational decisions

As generator entry was undertaken on an optimised basis it was not the intention to include how network charging might influence generator location decisions. However this was indirectly picked up in the modelling via the three scenarios.

Scenario 1 of no network augmentations could be thought of as a rough proxy for deep network connection charges as generators choose to locate at locations of existing network capacity. Scenario 2 could be thought of as a proxy for no generator network charges other than shallow connection costs as generators do not take into consideration existing network capacity when locating. Scenario 3 might be thought of as somewhat in between these.

9.6 Network upgrade options and costs

As previously discussed in Section 6.2, the information on potential network options is conceptual only and there was not sufficient time available to obtain network upgrade options and cost information from the TNSPs. This meant that a proper co-optimisation of intra-regional network upgrades and generation was not possible. This also raises another issue. As there are no concrete options and costs for most of the potential upgrade options there are basic limitations on undertaking any reasonable a priori co-optimisation of network and generation development.

9.7 Demands that stress the network

As agreed the modelling only used 50% probability of exceedence peak demands. As a result the modelling did not include periods of very high demands such as 10% probability of exceedence peak demands and the associated weather conditions such as very hot days that result in transmission network thermal ratings being significantly reduced. It is during these periods that much of the value of the "marginal capacity" of the network is derived. Consequently, the modelling may have understated the required level and value of transmission upgrades.

9.8 Ancillary services

The modelling did not consider issues of frequency control, inertia etc that may place practical limitations on the amount of wind that the system could absorb as a whole or on a zonal/regional basis. In particular, the impact of these issues at times of very low load.

9.9 Tasmanian wind projects

We finally note that there are probably more potential wind developments in Tasmania than we have identified in the database of projects used for the modelling. This would have the result of understating issues in Tasmania and overstating issues on the mainland, particularly SA and Victoria. However while this may be a material issue in Tasmania, this would not be expected to be material to the mainland states.

10 Modelling Results

This chapter presents the results of the modelling of the three scenarios modelled.

10.1 Description of the Model Outputs

The modelling results for each scenario show the development (and retirement) of generation and transmission assets and associated cost, the use of these assets in terms of dispatch costs for generators and flow metrics for transmission lines and associated upgrades and costs, and overall NPV for each scenario.

The specific outputs shown for each scenario are:

- Cumulative generator entry and annual generator retirement schedule;
- Transmission lines with most hours of constraint and the number of transmission lines that exceed a defined constraint threshold level;
- Total NPV of generator and transmission development and generator production costs;
- Graphs of generator dispatch costs and capital development costs;
- Network diagrams showing the locational profile of new entry generation (renewable and non renewable) and transmission lines with constraints greater then the specified threshold.

10.1.1 Note of NPV Calculations

The calculation of NPV required a number of assumptions to be made in relation to costs and discount rate. These were as follows:

- Cost of unserved energy (USE) = $12,500/MWh;
- Costs of transmission line upgrade (except interconnectors) was $30 Million per line for a 300 MW upgrade (this equates to $100,000/MW);
- Economic life of generation investment = 30 years;
- Economic life of transmission investment = 40 years;
- Discount rate of 8% (this was the rate used in the 2008 NEMMCO ANTS);
- Annual total cost was defined as the sum of the following:
    - dispatch costs,
    - new entry capital costs,
    - transmission costs,
    - interconnector upgrade costs, and
    - cost of unserved energy (USE).

10.2 Scenario 1 – Non-responsive Transmission

To recap from Section 3.4, Scenario 1 had the central planning model (incorporating the full network model) optimise generation entry and exit (based on a forward curve for a carbon emissions price and the requirement for the RET) using the existing transmission system with committed expansions. The optimised generator development schedule was then transferred to PROPHET where intra-regional constraints were identified and a minimal amount of additional transmission augmentations were undertaken to ensure load was supplied and the RET target met. The modelling required no network upgrades.

The key modelling results from the MARKAL run were the generator development schedule.

10.2.1 Generation Development

Figure 10-1 show the accumulated amount of new entry that has entered the NEM for each year by fuel type and capacity for Scenario 1. The breakdown of new entry by region can be found in Appendix 4.

Figure 10-1 Scenario 1 Cumulative Generator New Entry

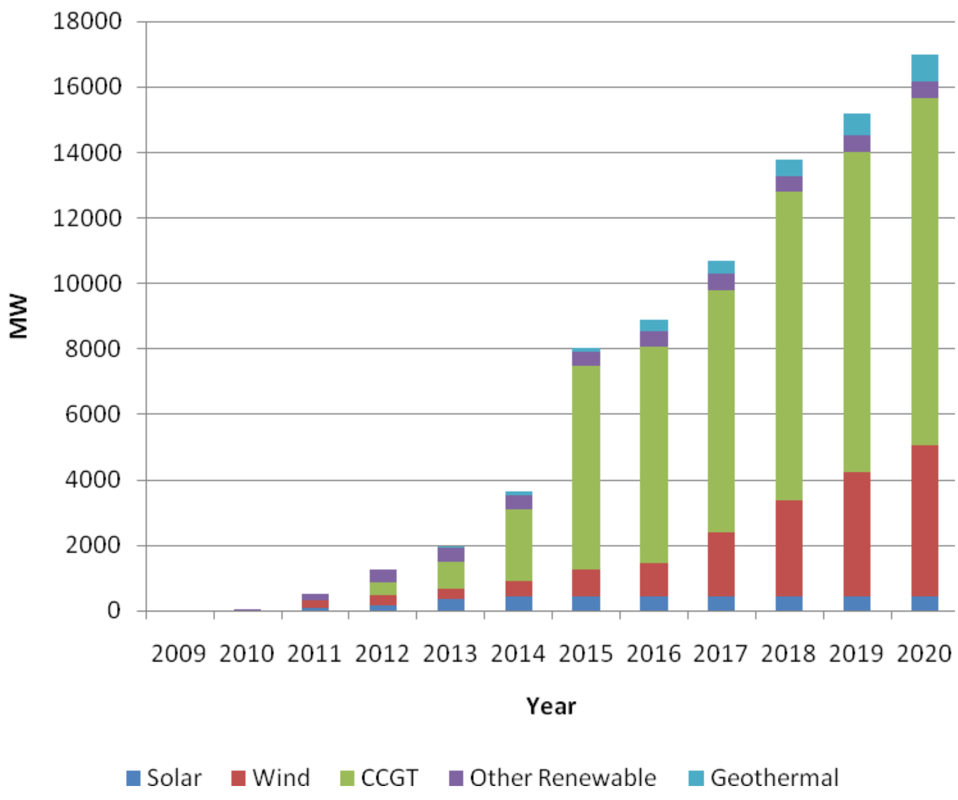


Table 10-1 lists the coal-fired generation retired in each year by region for Scenario 1. Only coal plant was retired in the modelling.

Table 10-1 Scenario 1 Retirements (MW)

Region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
NSW	650	0	0	600	0	0	525	525	0	1050	3350
QLD	947	0	0	0	0	0	0	280	280	840	2347
SA	240	0	0	0	0	0	0	0	0	0	240
TAS	0	0	0	0	0	0	0	0	0	0	0
VIC	0	0	0	148	3087	0	154	0	0	520	3909

10.2.2 Network Constraints and Line Upgrades

No line upgrades were necessary to meet the renewable energy target. As discussed earlier, reliability was satisfied by adding extra generation where necessary.

Figure 10-2 below shows the lines which were constrained the most over the entire period and the number of hours constrained.

Figure 10-2 Scenario 1: Most Constrained lines (total hours over modelling period)

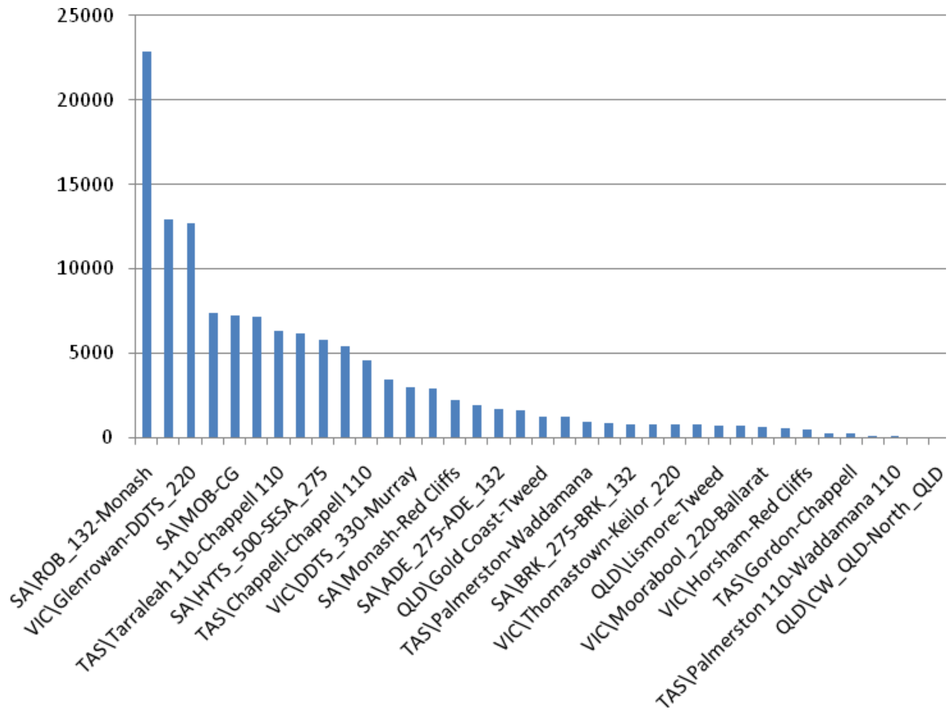
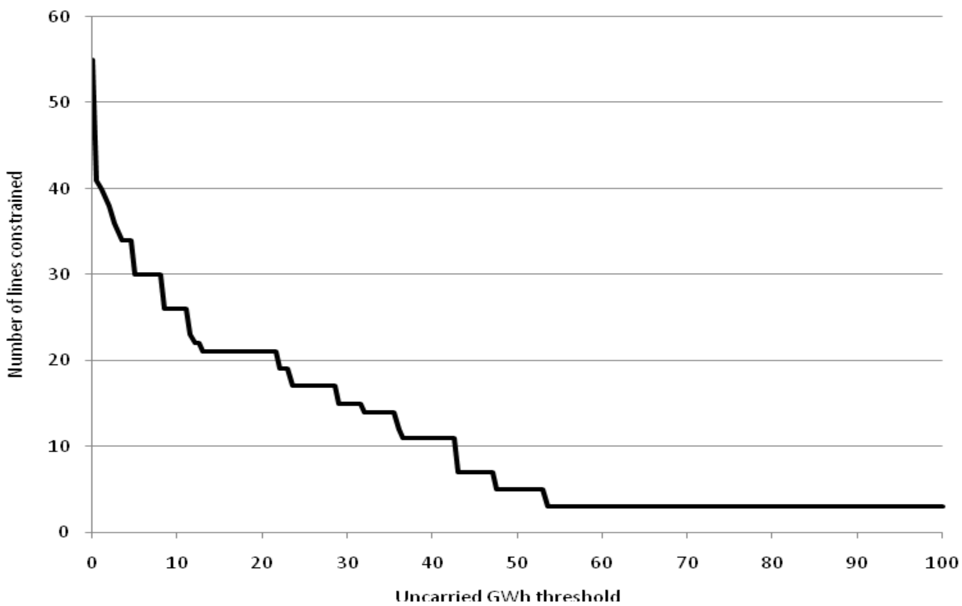


Figure 10-3 shows the number of lines constrained versus the threshold used for uncarried energy. In other words, it shows the number of lines versus the level of line uncarried GWh. We introduce the word Threshold on the graphs to indicate that the criterion for upgrading lines was based on uncarried energy being greater than a threshold level of uncarried energy.

Figure 10-3 Scenario 1 Number of Lines constrained versus Uncarried GWh Threshold



10.2.3 Market outcomes

Table 10-2 below shows the Net Present Values for dispatch, capital and transmission costs for each region. A breakdown of costs by year can be found in Appendix 4 (Section 16.2).

Table 10-2 Scenario 1: NPVs

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	25,921	1,151	-	-	8	27,080
Qld	20,896	1,382	-	-	18	22,296
SA	4,918	1,322	-	-	-	6,239
Tas	610	552	-	-	11	1,173
Vic	15,805	1,938	-	-	38	17,781
Total	**68,149**	**6,345**	**-**	**-**	**75**	**74,569**

Figure 10-4 below shows the annual dispatch costs for each region. Dispatch costs comprise of fuel, emissions and variable operating and maintenance costs.

Figure 10-4 Scenario 1: Annual Dispatch Costs ($m)

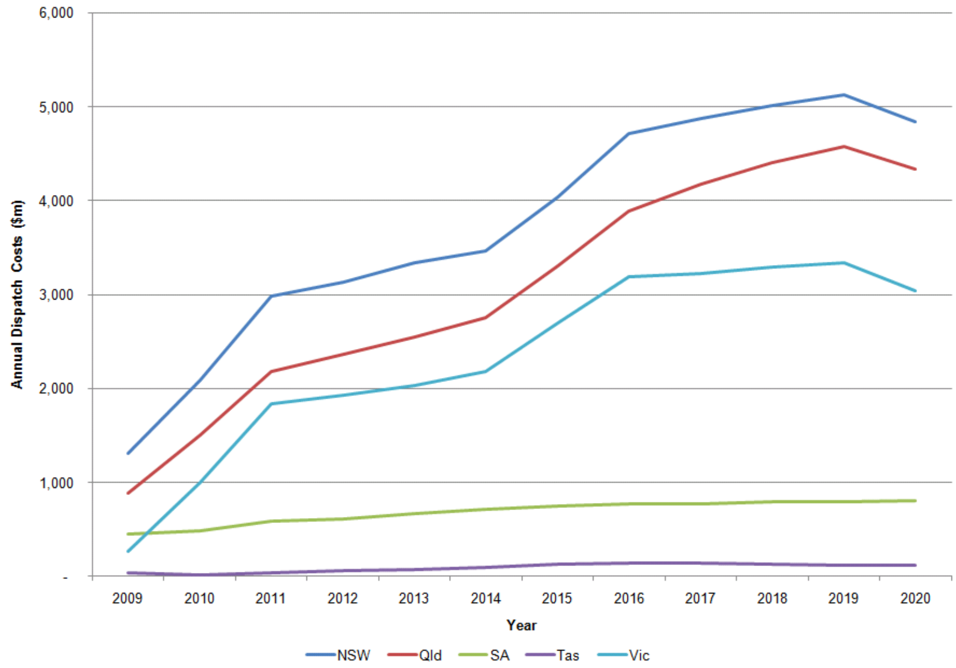


Figure 10-5 below shows the Annual Capital Costs for each region. This is an annualised amount equivalent to the cost of new entry generation.

Figure 10-5 Scenario 1: Annual Capital Costs ($m)

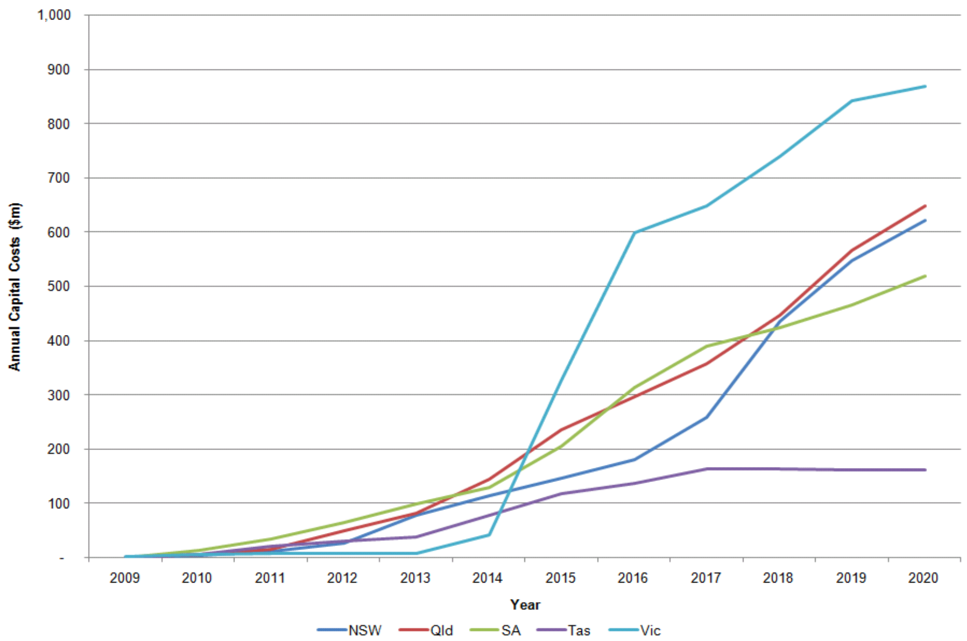


Figure 10-6 below shows the Annual Total Costs for each region.

Figure 10-6 Scenario 1: Annual Total Costs ($m)

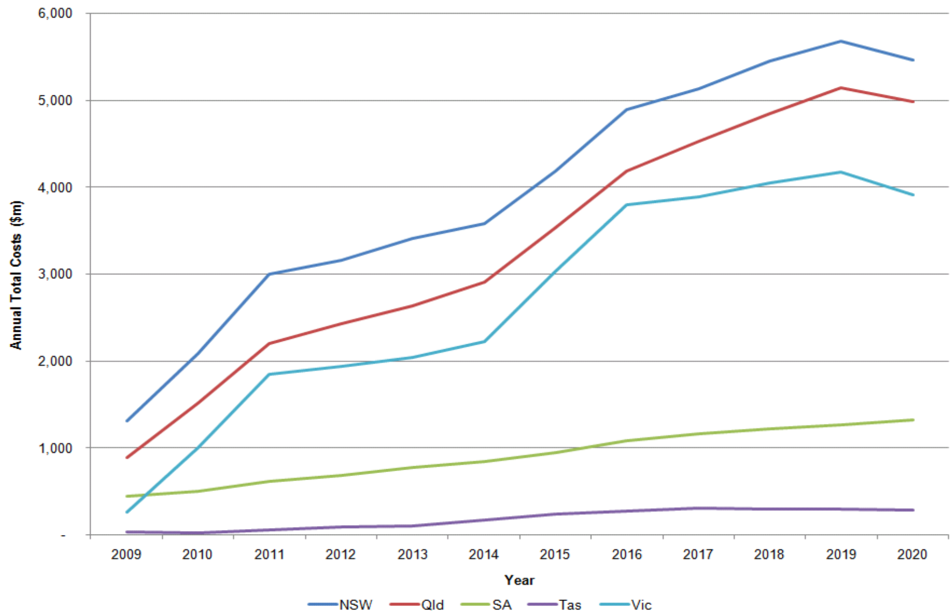
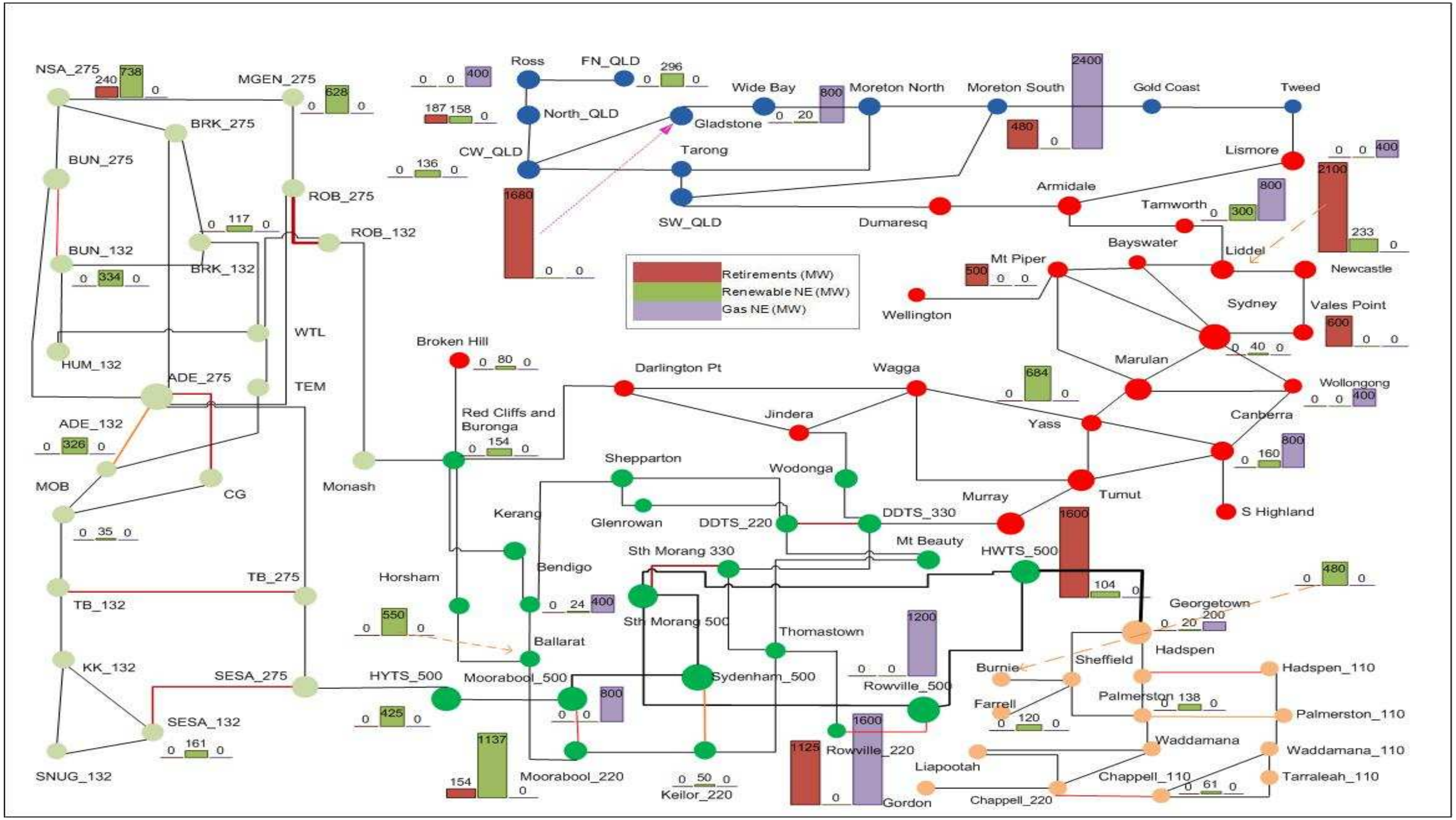


Figure 10-7 on the next page displays the transmission system, location and amounts of generation and exit of generation for Scenario 1.

Figure 10-7 Scenario 1: Network Diagram with New Entry/Retirements



10.3 Scenario 2 - Current Arrangements

As previously noted, modelling of the current arrangements was a challenging task as this involves interpreting the outcomes of applications of the Regulatory Test for both inter and intra-regional transmission.

The approach used was described in Section 6.2.2 of this report. This outlined the use of the Regional MARKAL model to first develop an optimised interconnector upgrade schedule and generator investment and retirement schedule (representing the application of the market limb of the regulatory test), and input of the results of this modelling to PROPHET to investigate the level of intra-regional transmission constraints. Identified intra-regional transmission constraints were addressed through the addition of appropriate new transmission capacity (representing the application of the reliability and market limb of the regulatory test).

10.3.1 Generation Development

Figure 10-8 show the accumulated amount of new entry that has entered each year by fuel type and capacity for Scenario 2. The breakdown of new entry by region can be found in Appendix 4.

Figure 10-8 Scenario 2 Cumulative Generator New Entry

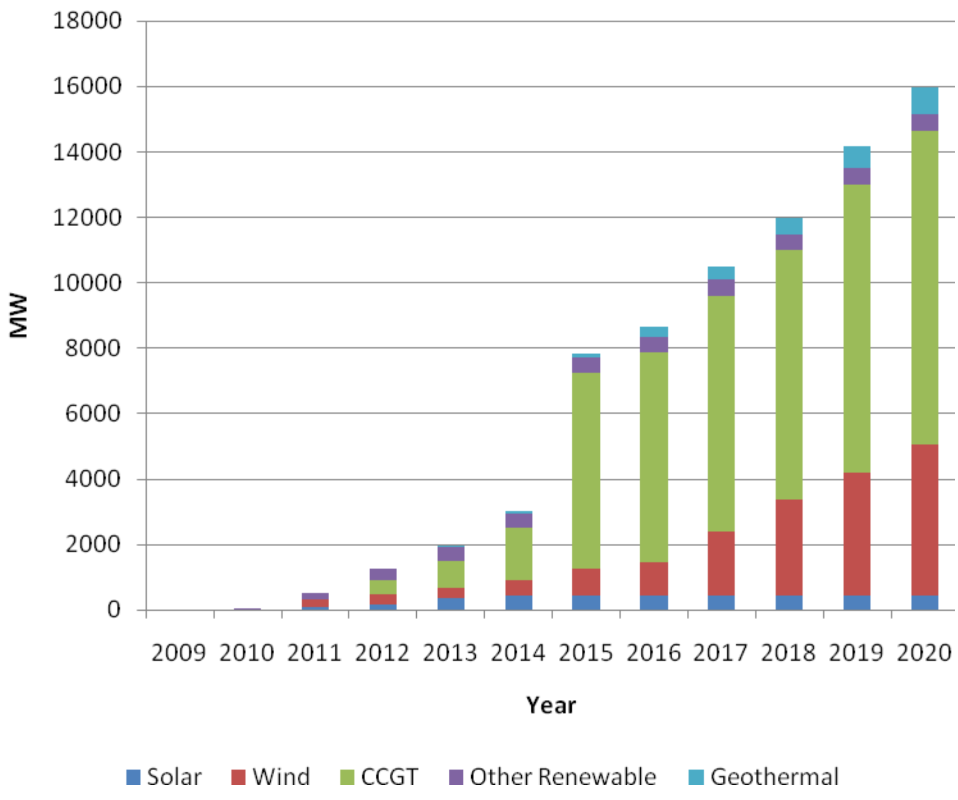


Table 10-3 lists the coal-fired generation retired in each year by region for scenario 2. Only coal plant was retired in the modelling.

Table 10-3 Scenario 2 Retirements (MW)

Region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
NSW	500	0	0	600	150	1050	0	0	0	1050	3350
QLD	947	0	0	0	0	0	280	280	560	280	2347
SA	240	0	0	0	0	0	0	0	0	0	240
TAS	0	0	0	0	0	0	0	0	0	0	0
VIC	148	0	0	0	3087	0	154	0	0	520	3909

10.3.2 Interconnection Development

QNI was upgraded by 400MW in July 2018.

10.3.3 Network Constraints and Upgrades

Figure 10-9 below shows the cumulative number of 300 MW line upgrades by year.

Figure 10-9 Scenario 2: Number of line upgrades by year

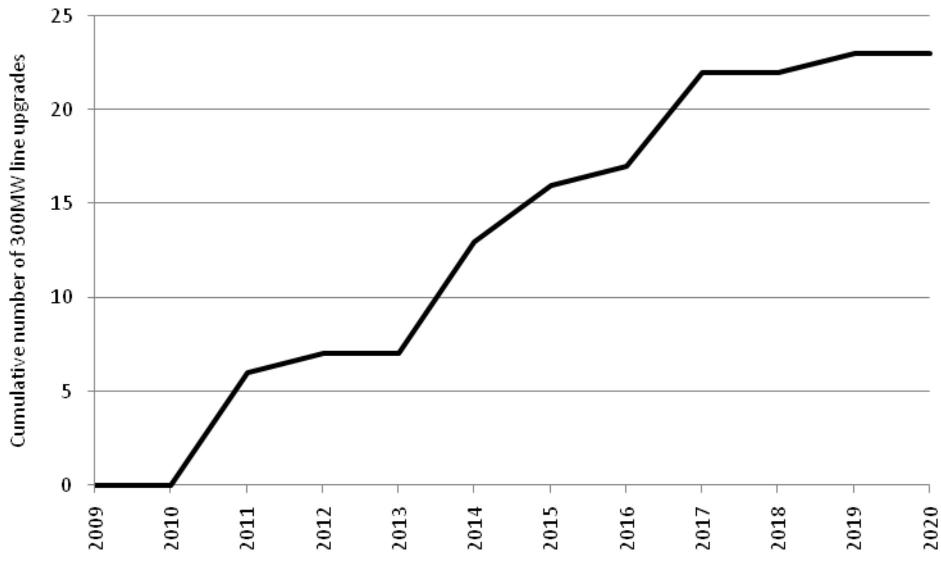


Figure 10-10 below shows the lines which were constrained the most over the entire period and the number of hours constrained.

Figure 10-10 Scenario 2: Most Constrained lines (total hours over modelling period)

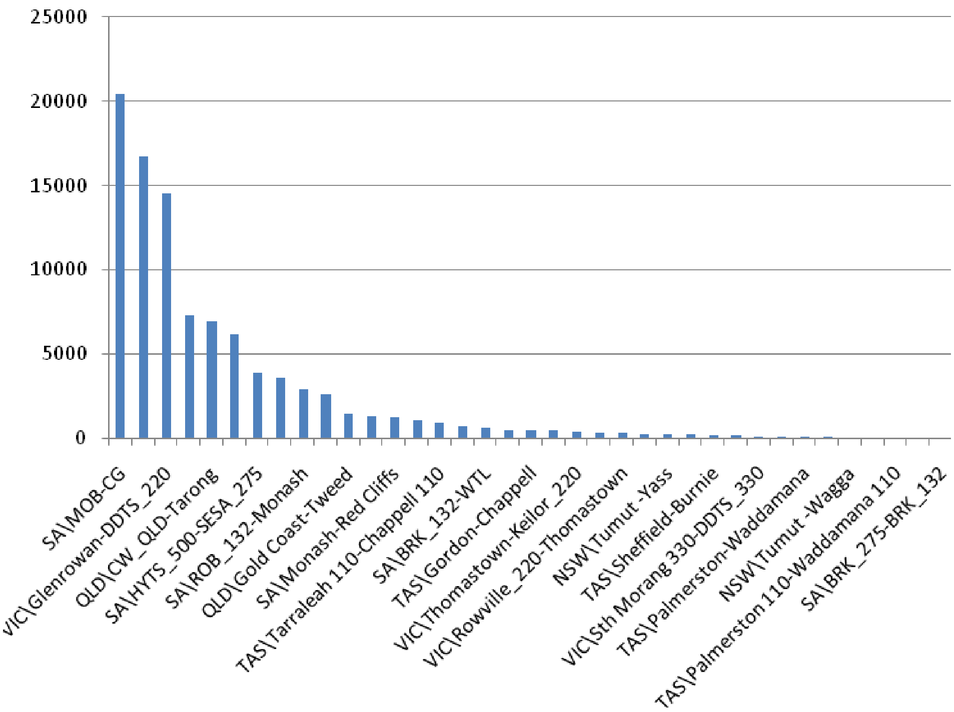
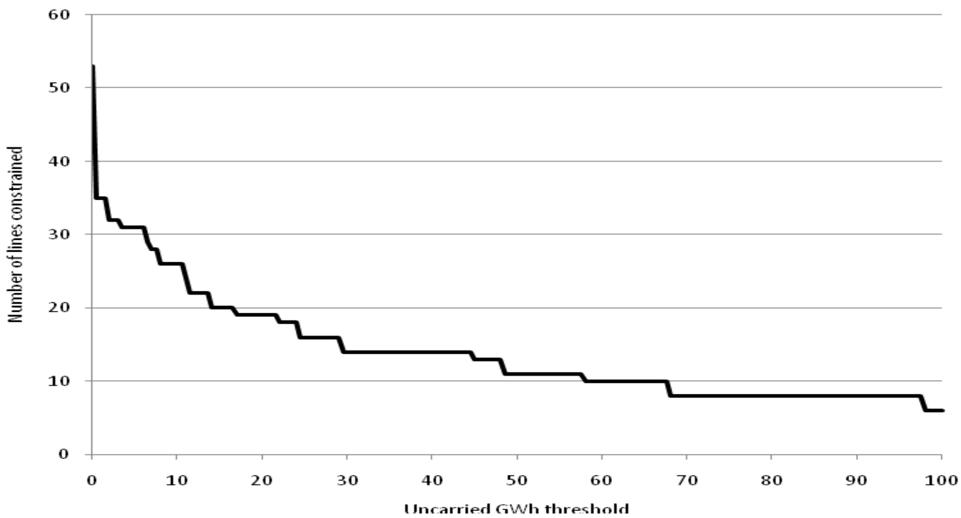


Figure 10-11 shows the number of lines constrained as the constraint threshold increases.

Figure 10-11 Scenario 2: Number of Lines constrained Vs Uncarried GWh Threshold



10.3.4 Market outcomes

Table 10-4 below shows the Net Present Values for dispatch, capital and transmission costs for each region. A breakdown of costs by year can be found in Appendix 4 (Section 16.2).

Table 10-4 Scenario 2: NPVs

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	26,033	1,058	-	10	54	27,155
Qld	21,003	1,211	-	10	37	22,260
SA	5,011	1,467	75	-	-	6,553
Tas	463	437	40	-	7	947
Vic	15,690	1,848	96	-	2	17,636
Total	**68,200**	**6,021**	**211**	**20**	**100**	**74,551**

Figure 10-12 below shows the Annual dispatch Costs for each region. Dispatch Costs comprise of fuel, emissions and variable operating and maintenance.

Figure 10-12 Scenario 2: Annual Dispatch Costs ($m)

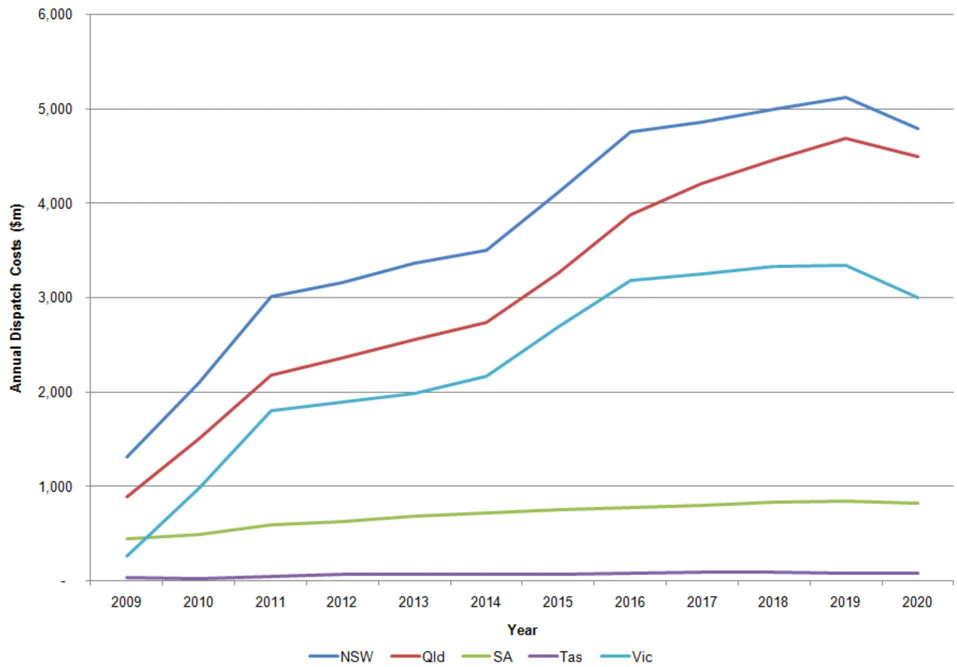


Figure 10-13 below shows the Annual Capital Costs for each region. This is an annualised amount new entry generators pay.

Figure 10-13 Scenario 2: Annual Capital Costs ($m)

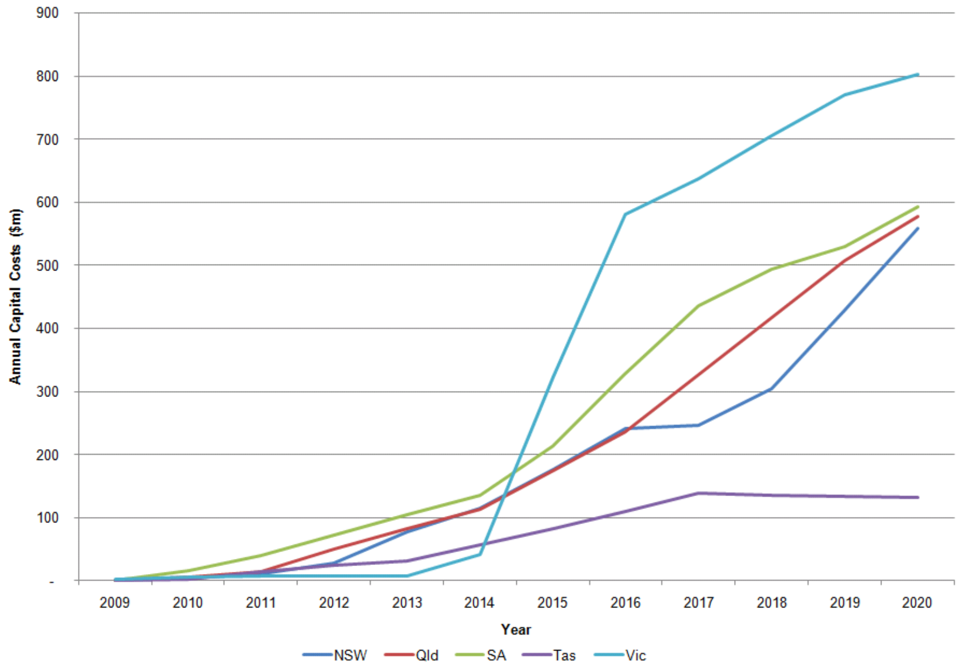


Figure 10-14 below shows the Annual Transmission Costs for each region. Note that the NSW curve is invisible on the graph as it is hidden by the Qld curve.

Figure 10-14 Scenario 2: Annual Transmission Costs ($m)

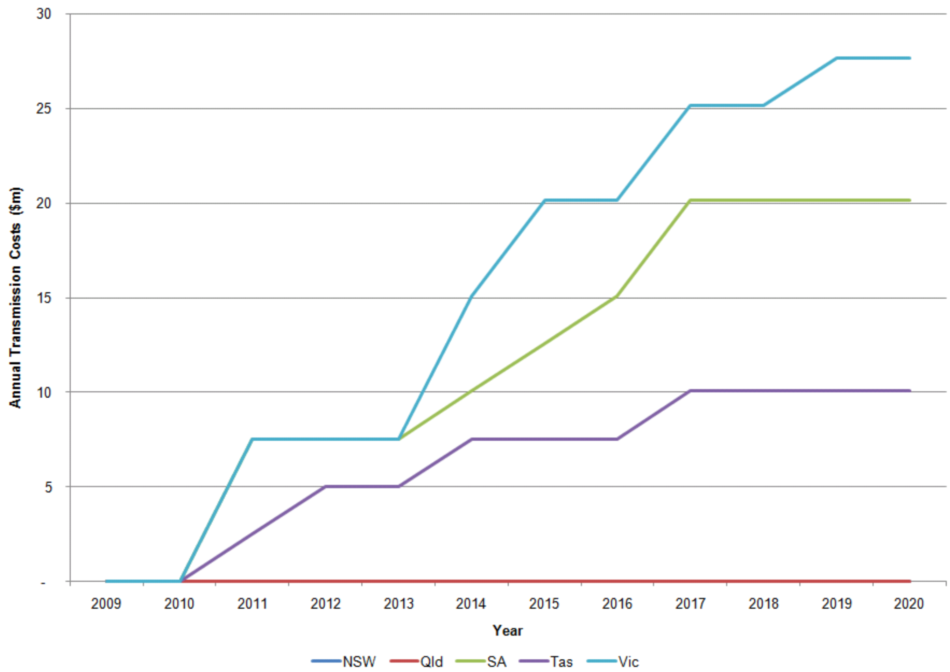


Figure 10-15 below shows the Annual Total Costs for each region.

Figure 10-15 Scenario 2: Annual Total Costs ($m)

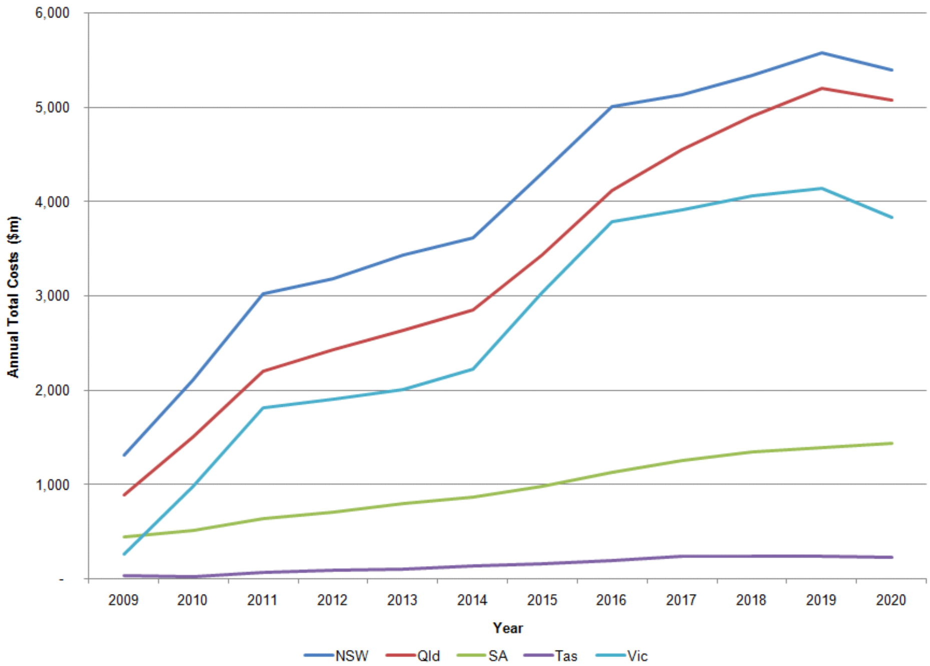


Figure 10-16 and Figure 10-17 on the next page display the transmission system, location and amounts of new and retiring generation and line upgrades.

Figure 10-16 Scenario 2: Network Diagram with New Entry/Retirements

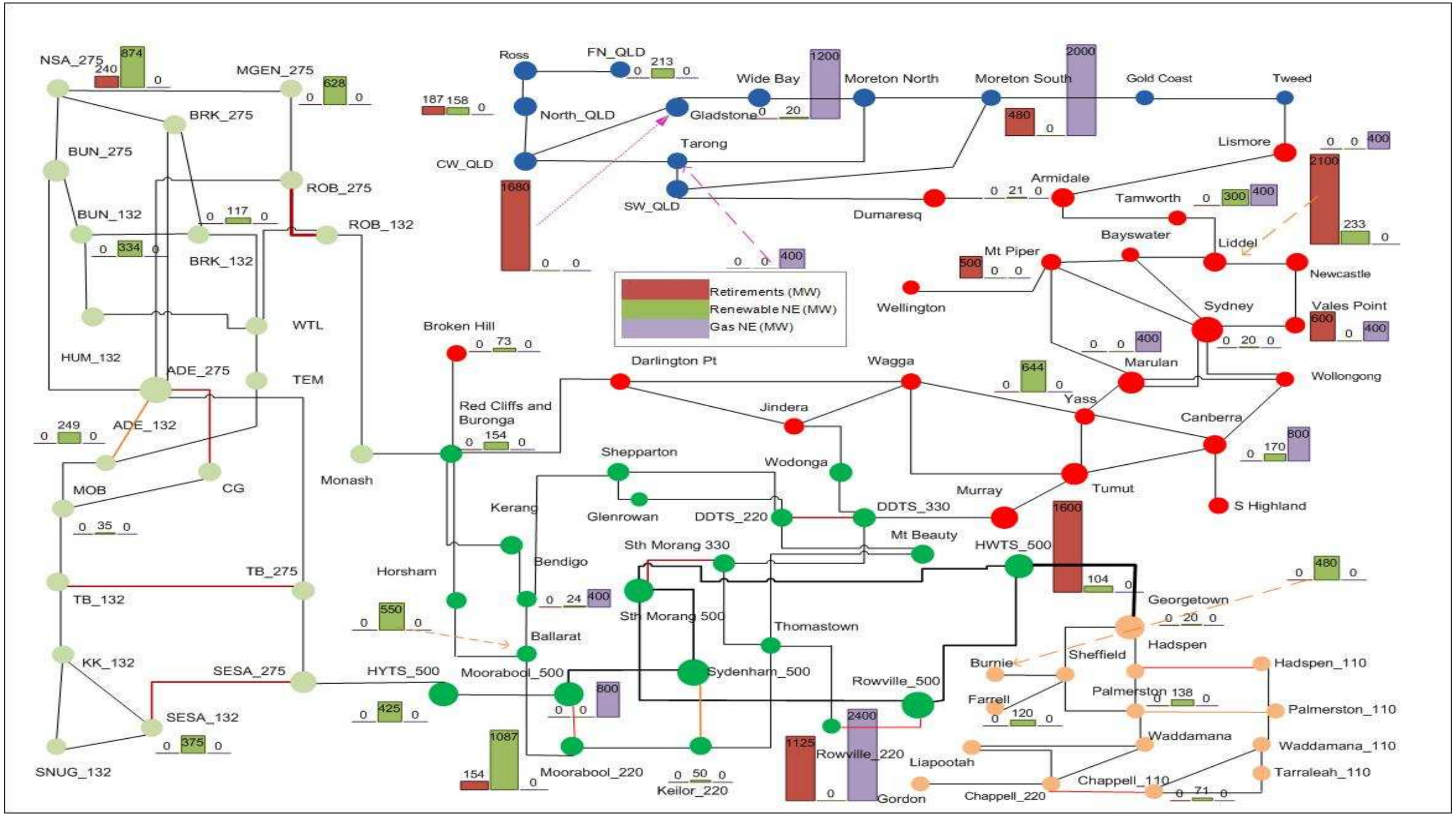
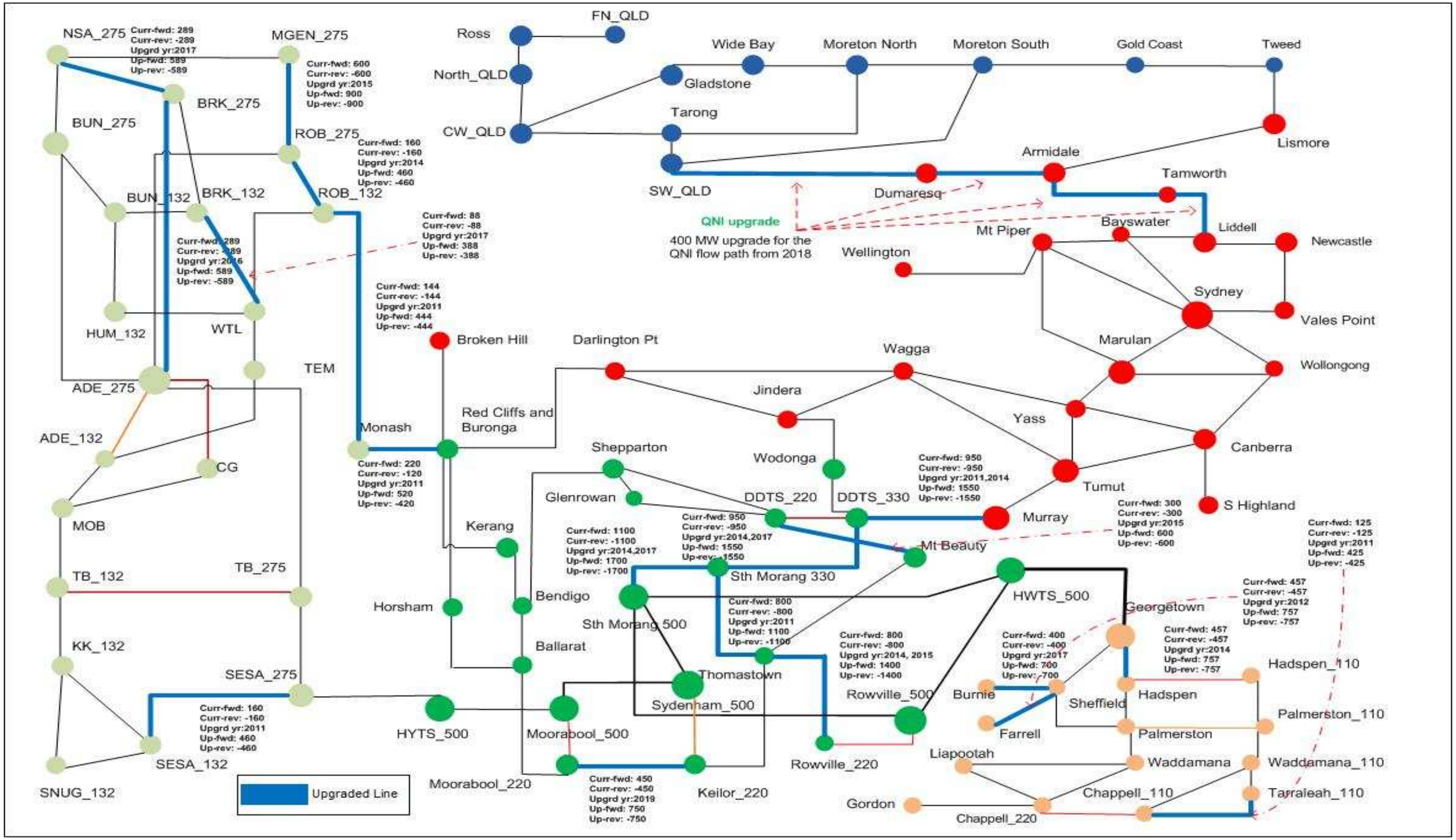


Figure 10-17 Scenario 2: Network Diagram with link upgrades



10.4 Scenario 3 - Optimal Development

Modelling the co-optimised full transmission system and generation development presented the greatest modelling and data assumptions challenge of the study.

The approached used was described in Section 3.4 of this report. This outlined the use of the Regional and Full Network MARKAL models to first develop an optimised interconnector upgrade schedule and generator investment and retirement schedule (representing the application of the market limb of the regulatory test), and input of the results of this modelling to PROPHET to investigate the level of intra-regional transmission constraints. Identified intra-regional transmission constraints were addressed through the addition of appropriate new transmission capacity (representing the application of the reliability and market limb of the regulatory test).

10.4.1 Generation Development

Figure 10-18 show the accumulated amount of new entry that has entered the NEM for each year by fuel type and capacity for Scenario 3. The breakdown of new entry by region can be found in Appendix 4.

Figure 10-18 Scenario 3 Cumulative Generator New Entry

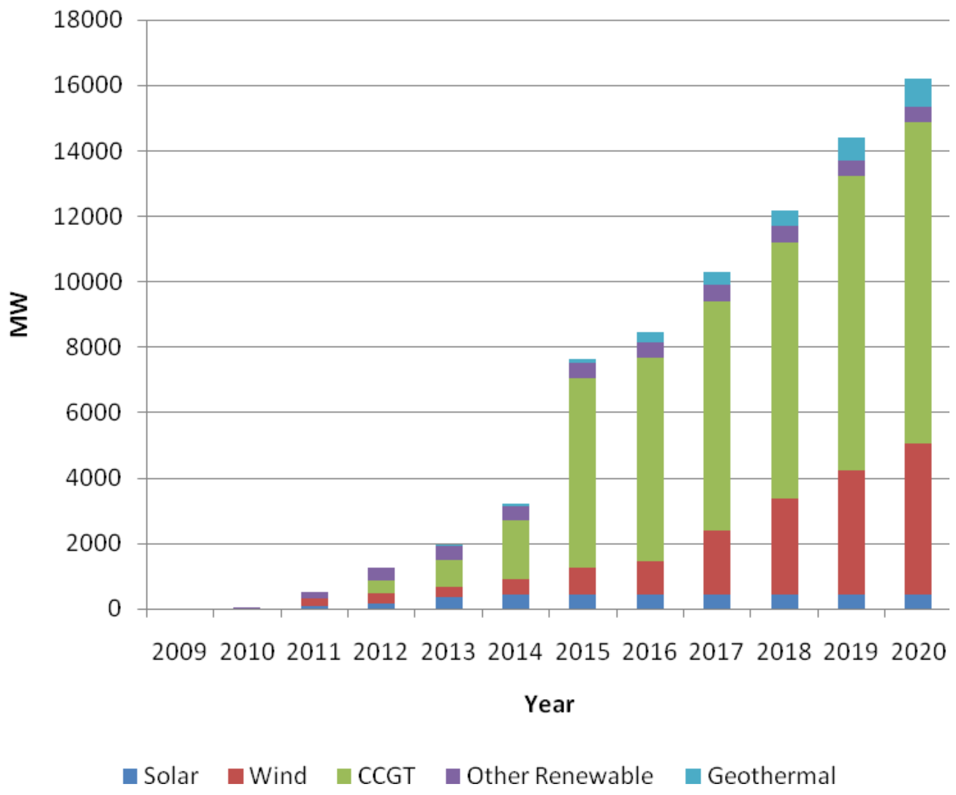


Table 10-5 lists the coal-fired generation retired in each year by region for scenario 3. Only coal plant was retired in the modelling.

Table 10-5 Scenario 3 Retirements (MW)

Region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
NSW	650	0	0	600	0	0	525	525	0	1050	3350
QLD	947	0	0	0	0	0	0	280	560	560	2347
SA	240	0	0	0	0	0	0	0	0	0	240
TAS	0	0	0	0	0	0	0	0	0	0	0
VIC	0	0	0	148	3087	0	0	154	0	520	3909

10.4.2 Interconnection Development

QNI was upgraded by 400MW in July 2018.

10.4.3 Network Constraints

Figure 10-19 below shows the cumulative number of 300 MW line upgrades by year.

Figure 10-19 Scenario 3: Number of line upgrades by year

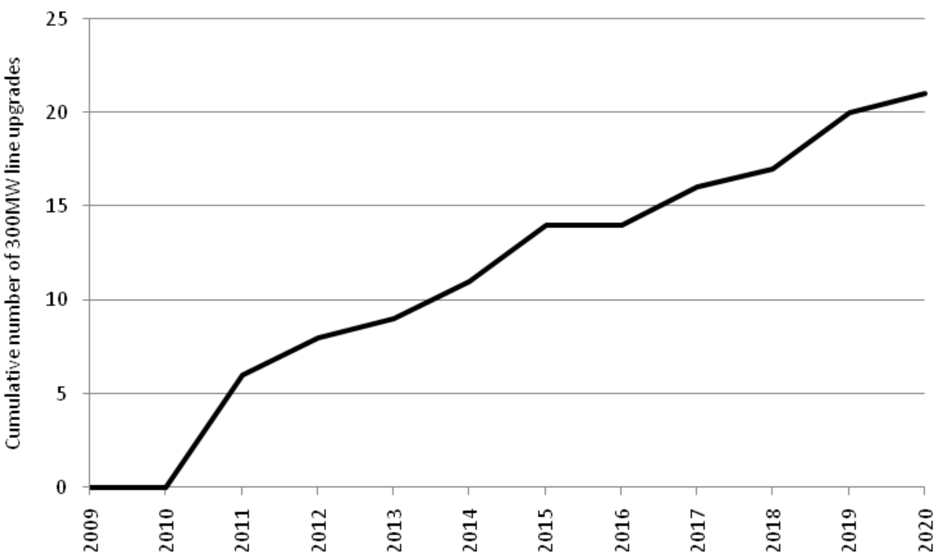


Figure 10-20 below shows the lines which were constrained the most over the entire period and the number of hours constrained.

Figure 10-20 Scenario 3: Most Constraining line (total hours over modelling period)

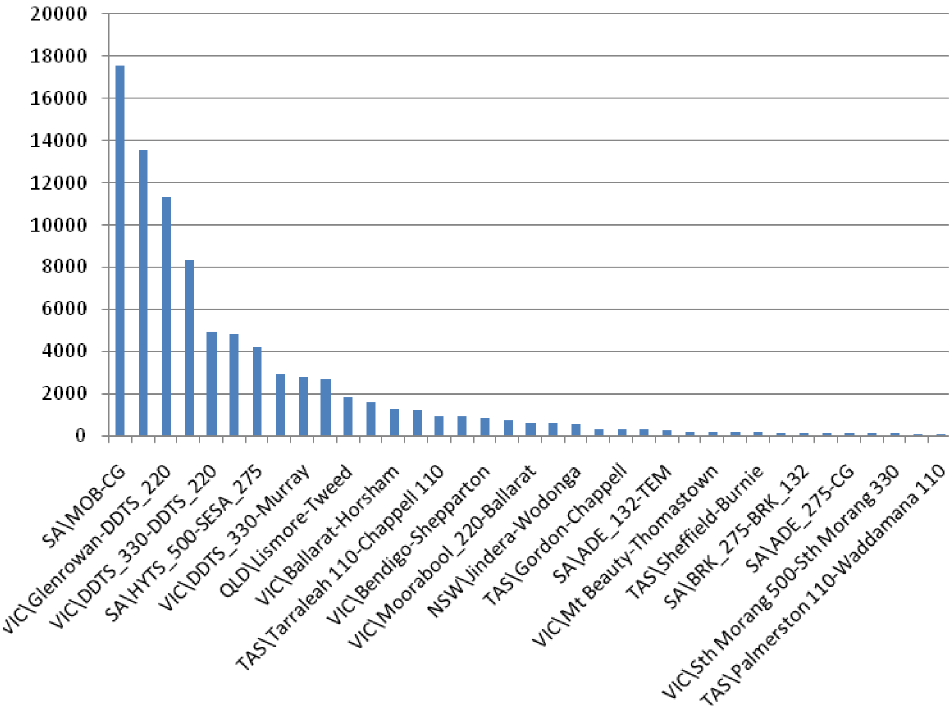
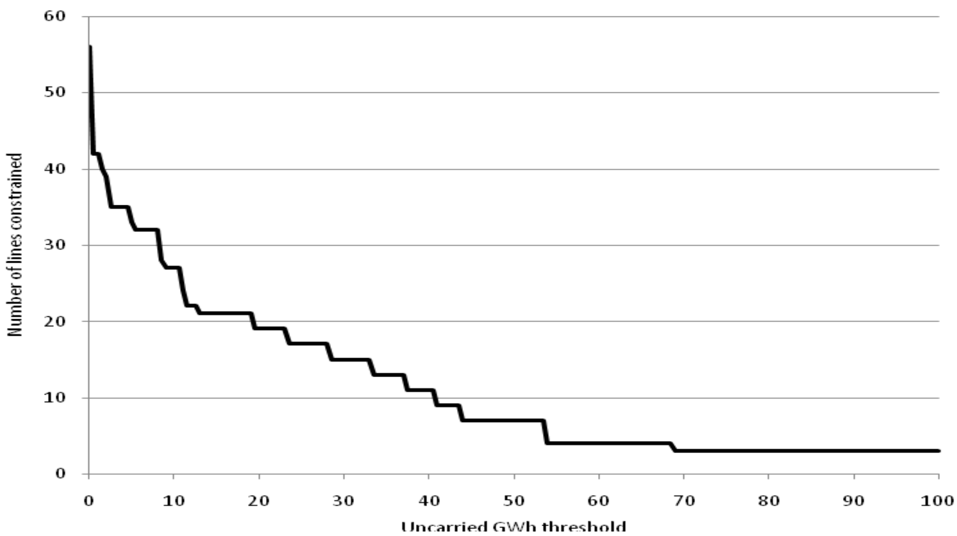


Figure 10-21 shows the number of lines constrained as the constraint threshold increases.

Figure 10-21 Scenario 3: Number constrained lines Vs Uncarried Constraint Threshold



10.4.4 Market outcomes

Table 10-6 below shows the Net Present Values for dispatch, capital and transmission costs for each region. A breakdown of costs by year can be found in Appendix 4 (Section 16.2).

Table 10-6 Scenario 3: NPVs

	Dispatch Costs ($m)	Capital Costs ($m)	Transmission Costs ($m)	Interconnector Upgrade Costs ($m)	Unserved Energy Costs ($m)	Total Costs ($m)
NSW	26,057	1,123	-	10	15	27,205
Qld	20,833	1,163	-	10	46	22,052
SA	4,993	1,320	70	-	-	6,384
Tas	638	553	39	-	4	1,234
Vic	15,703	1,867	72	-	16	17,659
Total	**68,224**	**6,028**	**182**	**20**	**81**	**74,533**

Figure 10-22 below shows the annual dispatch costs for each region. Dispatch costs comprise of fuel, emissions and variable operating and maintenance.

Figure 10-22 Scenario 3: Annual Dispatch Costs ($m)

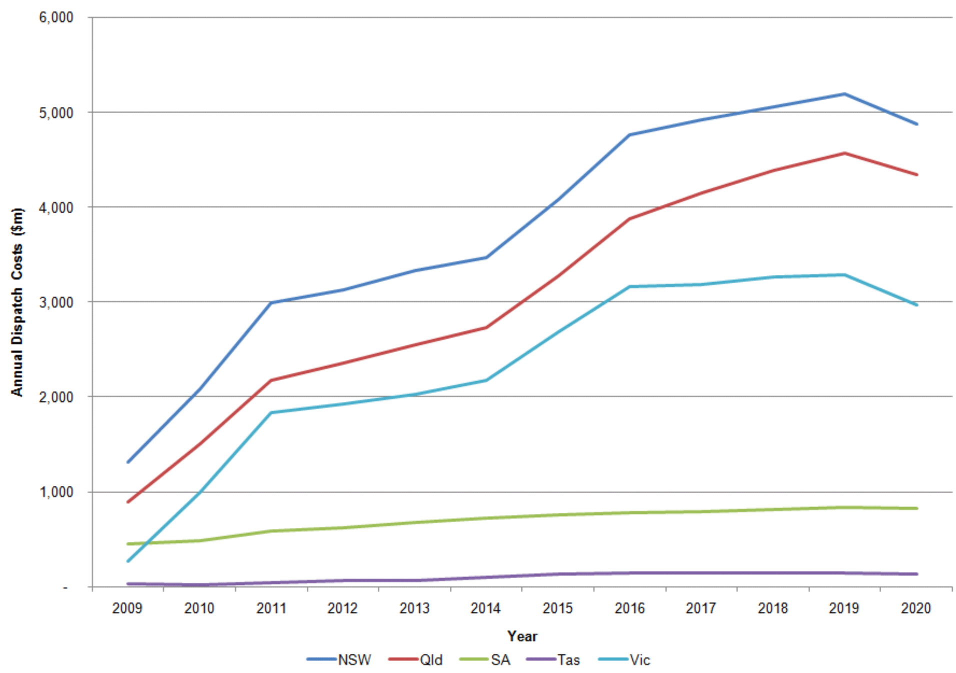


Figure 10-23 below shows the Annual Capital Costs for each region. This is an annualised amount new entry generators pay.

Figure 10-23 Scenario 3: Annual Capital Costs ($m)

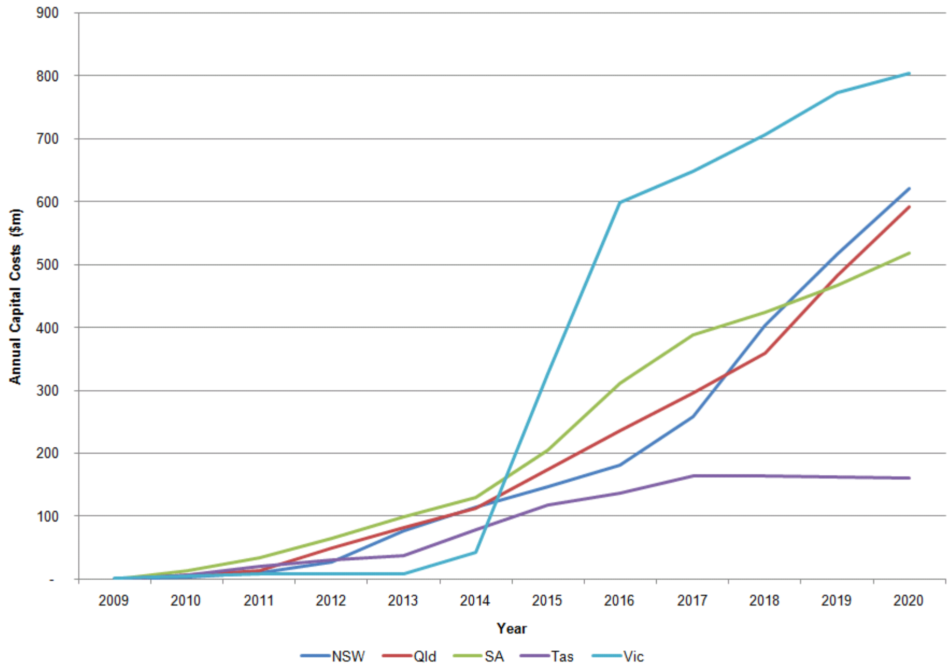


Figure 10-24 below shows the Annual Transmission Costs for each region. Note that the NSW curve is invisible on the graph as it is hidden by the Qld curve.

Figure 10-24 Scenario 3: Annual Transmission Costs ($m)

Figure 10-25 below shows the Annual Total Costs for each region.

Figure 10-25 Scenario 3: Annual Total Costs ($m)

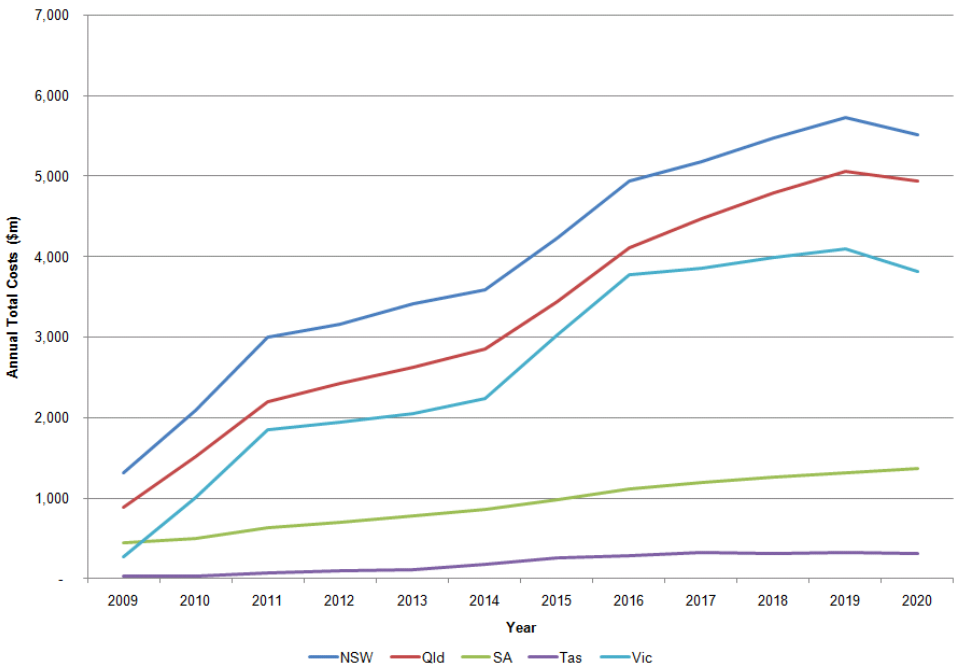


Figure 10-26 Scenario 3: Network Diagram with New Entry/Retirements

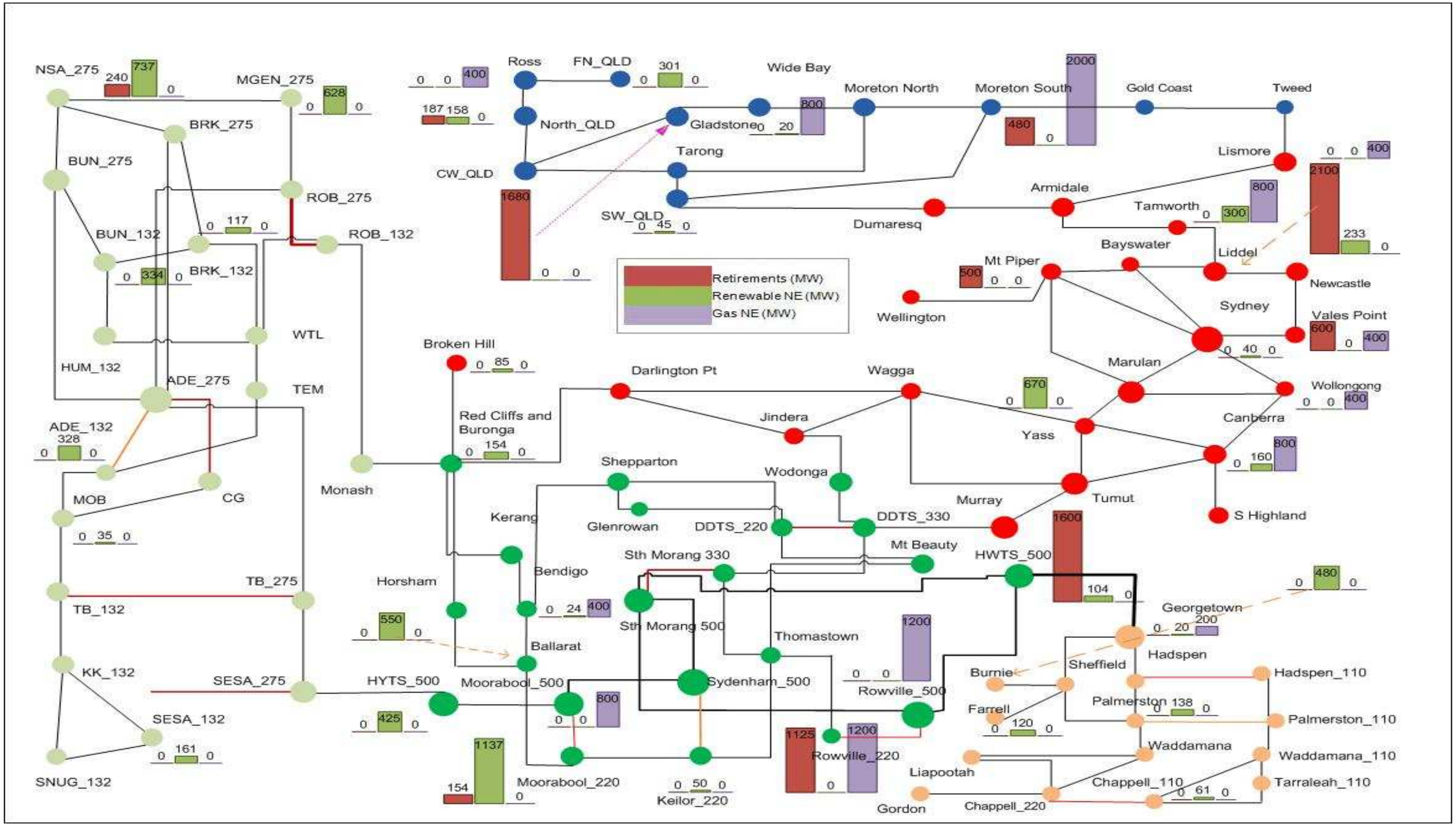
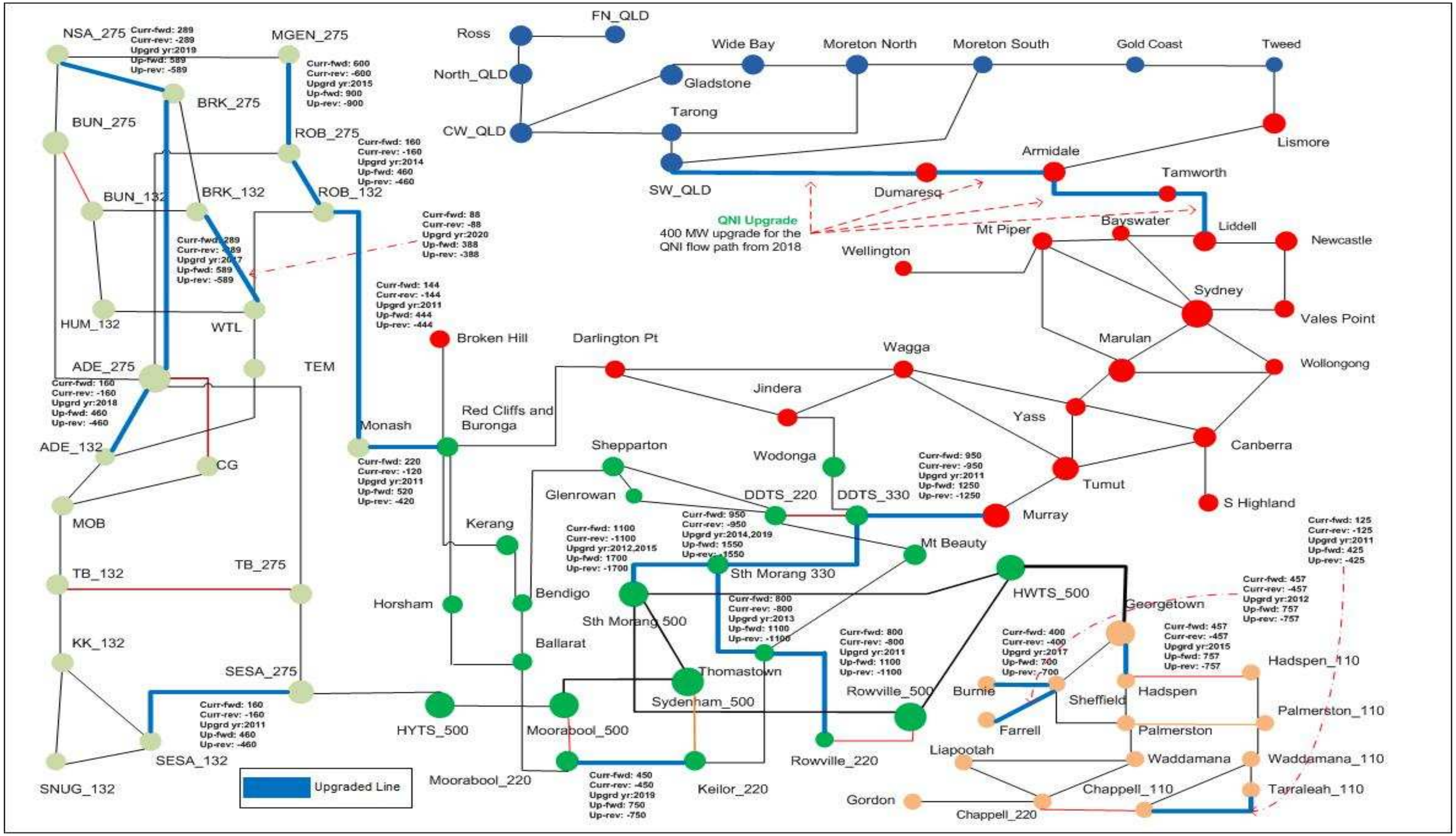


Figure 10-27 Scenario 3: Network Diagram with Link Upgrades



11 Interconnector Upgrade Economics

The modelling undertaken for the three scenarios had only the New South Wales to Queensland (QNI) interconnector being upgraded. However this does not tell us how close the other interconnectors are to being economic or under what circumstances they would be.

To investigate this, a sensitivity analysis was undertaken using the Regional MARKAL model with the aim of assessing how economic the other interconnectors are and under what conditionals they would warrant upgrading.

The sensitivities modelled and the resultant interconnector upgrade options that were economic are shown in the table overleaf. Also shown are the level of geothermal generation that entered the market in SA, the date Northern Power Station retires, and the level of wind developed in SA and Victoria by 2020/21. For comparison the results of Scenario 2 (current arrangements) are included as Number 0.

The results show the following:

- The QNI upgrade is robust to the sensitivities modelled;
- Vic – NSW is never upgraded;
- The SA – Vic interconnector upgrade is contingent on a substantial level of renewable generation being developed in SA;
- The SA - Vic interconnector was also economic under conditions of either increased carbon permit prices or significantly reduced development costs;
- Of note was that including a reserve benefits equal to 50% of the capacity provided by the SA – Vic interconnector upgrade options did not result in this interconnector being developed;
- The 2000 MW SA - NSW interconnector required that more than 2000 MW of geothermal in SA be committed. Of note is that the modelling had geothermal ramp up from 2017 and that geothermal capacity is limited to 1000 MW prior to 2020.

These results indicate that the result of QNI being the only interconnector upgraded during the study period (of the options considered) in the scenarios modelled appears as a robust outcome under the general assumptions of the study.

Table 11-1 Sensitivity Descriptions and Results

No	Sensitivity Scenario Description	Interconnectors that are developed and the year of entry	Level of SA Geothermal in 2020-21 (MW)	Northern Power Station Retirement Date	Level of SA Wind in 2020-21 (GWh)	Level of Vic Wind in 2020-21 (GWh)
0	Agreed Assumptions	QNI - 2018/19	800	-	6631	5751
1	All SA geothermal enters in earliest possible year	QNI - 2017/18, SA/NSW - 2020/21	3803	2018/19	3467	2075
2	All SA geothermal enters in earliest possible year except Olympic Dam (i.e. 1000MW less in 2020/21)	QNI - 2017/18, SA/NSW - 2020/21	2803	2018/19	3468	2074
3	VIC/SA link costs reduced to by 55% ($400M -> $180M)	QNI - 2018/19	800	-	7285	5751
4	VIC/SA link costs reduced to 40% original ($400M -> $160M)	QNI - 2018/19, VIC/SA - 2020/21	800	-	6631	5751
5	CRPS Prices at 15% target for all years	QNI - 2017/18	800	-	6533	6976
6	CPRS prices at 15% target CPRS + $10 for all years	QNI - 2013/14, VIC/SA - 2020/21	800	-	6503	5751
7	SA wind costs 20% cheaper	QNI - 2017/18 VIC/SA - 2018/19	508	-	10697	4219
8	VIC wind CF reduced by 30% (SA wind CF higher than in Vic)	QNI - 2017/18	800	-	6919	901
9	Reserve benefits included at 50% of the upgrade capacity	QNI - 2014/15	800	-	6503	5644

12 Discussion of Modelling Results

This chapter presents a brief review and comparison of the modelling results obtained for the three scenarios modelled and makes some conclusions regarding the scenarios. This is undertaken by considering the changes in transmission congestion and development, changes in generation development and retirement, and the consequent changes in total cost.

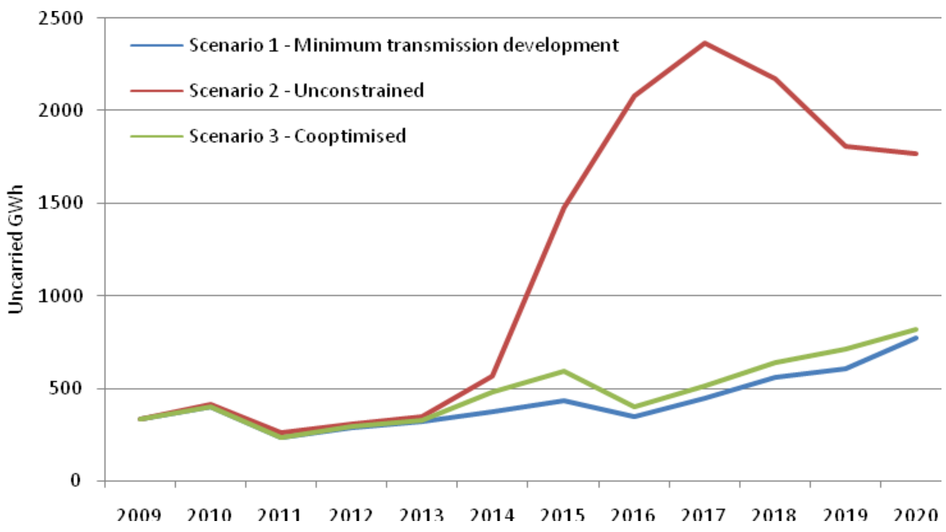
Most of the discussion focuses on the differences between scenario 1 and 2 as these are the most different scenarios and scenario 3 tends to be some where between these two.

12.1.1 Scenario differences in transmission constraints

In terms of the degree to which the three scenarios modelled required transmission upgrades there were two key statistics taken from the modelling undertaken. These were the degree to which there is network congestion prior to transmission upgrades and the number of lines deemed as requiring upgrades.

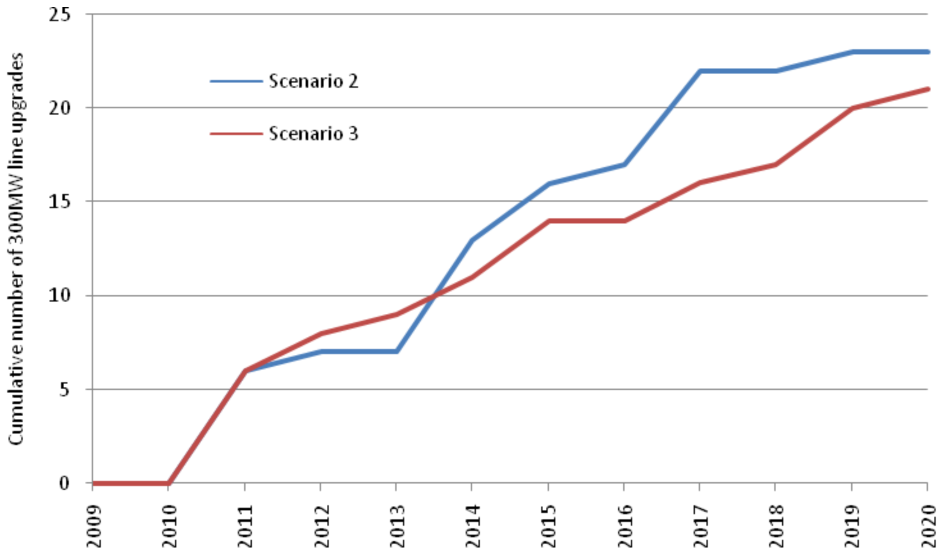
The first of these (the degree to which there is network congestion prior to transmission upgrades) was captured by the amount of 'uncarried' energy produced during the process of determining line upgrades, and this is presented in Figure 12-4 below. The results are consistent with expectations – if generation enters without consideration of transmission capability then one can expect higher levels of transmission congestion.

Figure 12-1 Total amount of uncarried energy per year before line upgrades



The second of these is presented in Figure 12-2 which presents the cumulative number of line upgrades for scenarios 2 and 3. Scenario 1 did not have any line upgrades.

Figure 12-2 Cumulative number of line upgraded by year (Scenarios 1 and 2)

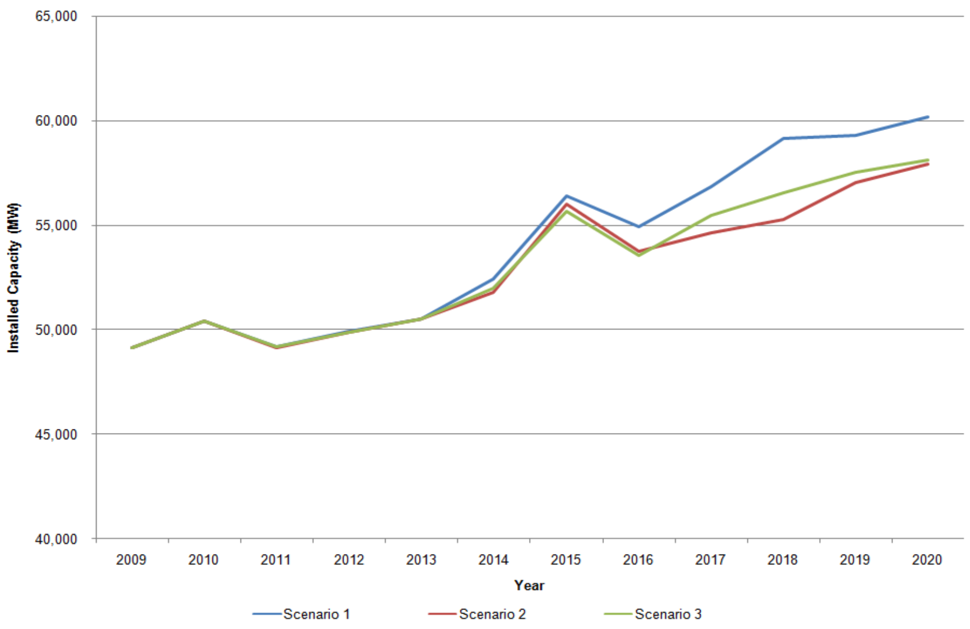


The higher level of transmission development in Scenario 2 over Scenario 3 is also to be expected, due to the limited trade-off of generator versus transmission development in Scenario 2.

12.1.2 Scenario differences in Generator new entry and retirements

Figure 12-3 below shows the total installed capacity for each of the scenarios. Compared to scenario 2, scenario 1 has slightly more new renewable generation in 2020 because it has not been able to fully exploit the cheapest project options due to the constraint of using only the existing network along with committed network upgrades. This has resulted in 214 MW less generation in south east South Australia (node SESA_132) and 136 MW less generation in northern South Australia (NSA_275). This generation has been replaced by increased generation in Central West QLD (136 MW), Far North QLD (82 MW), Adelaide 132 (77 MW), Moorabool 220 (50 MW) and Yass (40 MW). Scenario 1 and 3 were very similar except for swapping about 45 MW from Central West QLD to South West QLD in scenario 3. In the case of thermal generation, compared to scenario 2, scenario 1 has about 1000 MW extra new generation in 2020. In the case of scenario 1 compared to scenario 2 regarding the new entrant thermal generation, there was a reduction of 400 MW of generation at each of the nodes: Marulan, Vales Point, Tarong and Wide Bay and an increase of 400 MW of generation at each of the nodes: Rowville, Newcastle, Tamworth, Wollongong, Moreton South and Ross and 200 MW at Georgetown.

Figure 12-3 Total Installed Capacity (MW)



The table below shows the capacity retired each year for the three scenarios.

Figure 12-4 Retirements by year (expressed as MW)

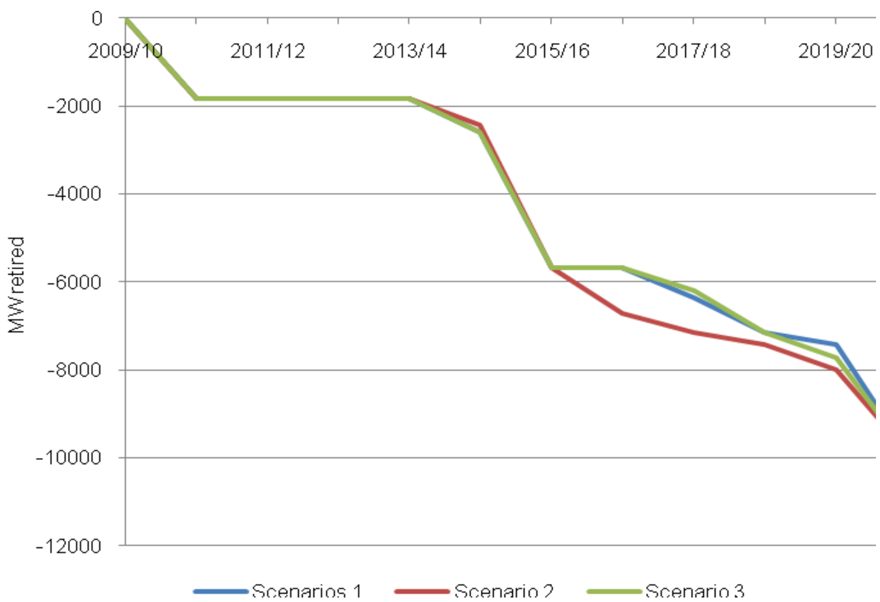
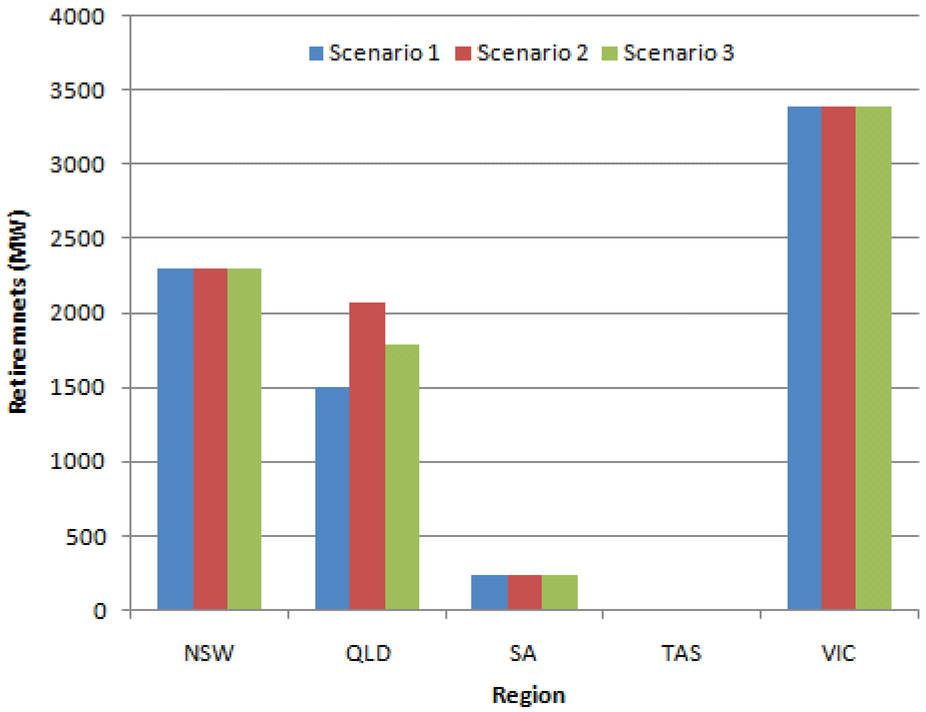


Figure 12-5 below shows the total capacity retired during the modelled period by region for each scenario.

Figure 12-5 Total Capacity Retired by Region All Scenarios



12.1.3 Scenario differences in economic costs

Table 12-1 below shows the Net Present Value of the total cost for each of the three scenarios. However it should be noted that the intra-regional network upgrade costs are only roughly factored in due to limited information and system security and reliability issues are also not fully incorporated.

Table 12-1 Summary of Scenario NPV's ($m)

Cost type ($M)	Scenario 1	Scenario 2	Scenario 3
USE cost	74.819	100.057	80.592
Dispatch Costs	68,149.236	68,199.616	68,223.675
Capital Costs	6,344.810	6,021.292	6,027.877
Interconnector costs	-	19.512	19.512
Transmission Costs	-	210.794	181.712
Total Costs ($)	74,568.866	74,551.271	74,533.369

What is interesting to note is that the differences in total costs between the three scenarios are relatively small. The co-optimised Scenario 3 is the cheapest, then Scenario 2 (transmission following generation) is the next most expensive (costing $17.9 million more) and finally scenario 1 (no network upgrades) costs the most (being $35.5 million more expensive than scenario 3).

If only generation dispatch costs and investment costs are looked at then Scenario 2 is the cheapest followed by scenario 3 and then Scenario 1.

Table 12-2 provides a breakdown of the NPV costs by region.

Table 12-2 Total cost NPV's ($m)

	Scenario 1	Scenario 2	Scenario 3
NSW	27,080	27,155	27,205
Qld	22,296	22,260	22,052
SA	6,239	6,553	6,384
Tas	1,173	947	1,234
Vic	17,781	17,636	17,659
Total	74,569	74,551	74,533

We observe that the study constraint of having renewable generation equal the target profile in all three scenarios acted as a driver to have similar NPV costs in the three scenarios. This meant that the total generation level from renewables and nonrenewables would be the same in all scenarios except for changes in transmission losses. Changes in capital investment would be the prime difference in costs. Thus changes in transmisison line constraint hours and development patterns may be the key metric in the studies presented.

12.1.4 Conclusions

The modelling has demonstrated that there could be material differences in the location and development of both generation and transmission for each of the scenarios.

In particular, if new entry generation locates without regard to intraregional constraints then this study suggests that the result could be a significant increase in transmission congestion, and a significant increase in the level of transmission development needed. This is brought about by generators locating in locations that have lower generator development costs but overall higher costs when transmission is considered. This suggests that the current arrangements as embodied in scenario 2 may lead to materially more congestion and consequent transmission development than other arrangements which provide generators with locational prices.

Here we note that although the differences in the present values of total costs between the scenarios are not very high relative to the total costs, this does not mean that different regimes of locational pricing for generators would not result in significantly different economic costs.

This potential discrepancy between assessed NPV costs and potential economic impacts arises from the fact that the modelling undertaken had a number of limitations and assumptions. In particular, these were the assumptions of central planning optimisation as opposed market driven entry combined with a network charging regime, assumptions of system normal conditions and average weather conditions, and that network extension costs were not included.

13 Appendix 1 The Full Transmission Model

This note presents the sources of network data used in this study and description of modelling of the NEM network such as generic constraints, nodal demand, and line losses.

13.1 Network data source

The transmission model used was that developed for the purposes of a study being conducted by the NGF. This model was developed as follows:

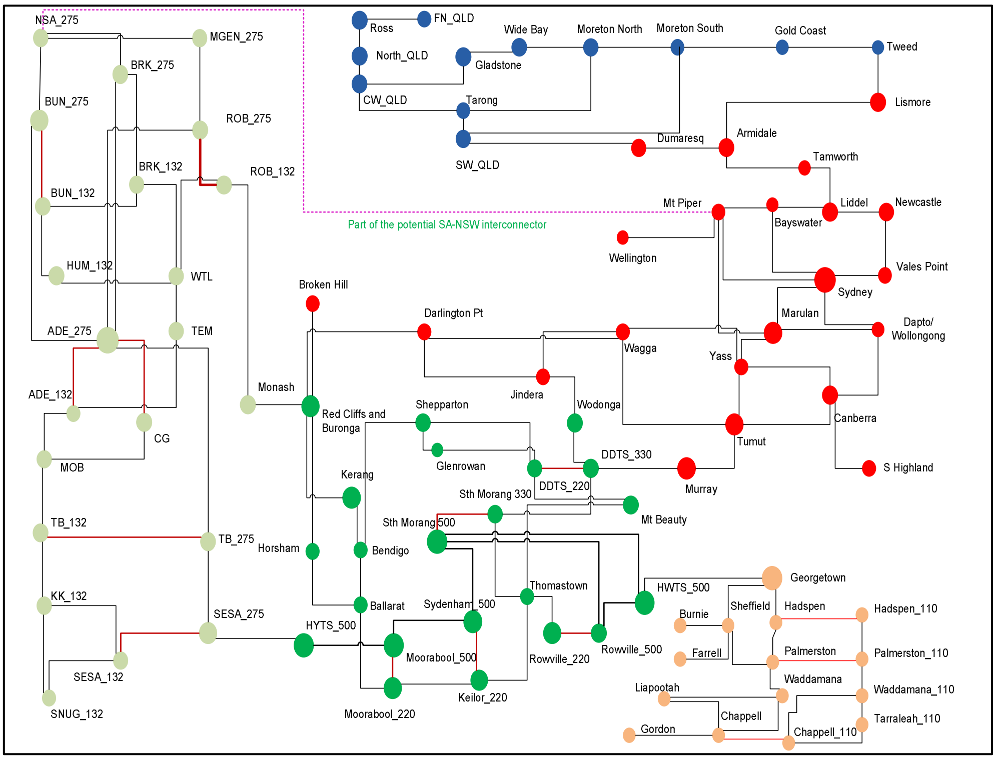
- An existing model of the Queensland and New South Wales transmission systems that had been developed by Powerlink and TransGrid in conjunction with IES in a previous modelling study was obtained and tested;
- For South Australia a model was used that was developed by the South Australian Electricity Supply Industry Planning Council (ESIPC) in a study being conducted by the NGF. This model was tested and adjustments made for the purposes of this study;
- For Victoria a model was used that had been developed by VENCorp in a study being conducted by the NGF. This model was tested and adjustments made for the purposes of this study;
- For Tasmania a model was used that had been developed by Transend in a study being conducted by the NGF. This model was tested and adjustments made for the purposes of this study,

The confidentiality of the network model constraints prevented the detailed on the line parameters from being published.

13.2 Network diagram

Figure 13-1 shows the network topology of the NEM. There are 93 nodes and 130 links including transformers.

Figure 13-1 NEM Electricity Network Topology



The tables below show the names of nodes modelled in the transmission system.

Table 13-1 List of Nodes in the Transmission Network Modelled

QLD		TAS	
Node	**Name**	**Node**	**Name**
CW_QLD	Central West QLD	Burnie	Burnie
FN_QLD	Far North QLD	Chappell 110	Chappell 110
Gladstone	Gladstone	Chappell 220	Chappell 220
Gold Coast	Gold Coast	Farrell	Farrell
Moreton North	Moreton North	Georgetown	George Town
Moreton South	Moreton South	Gordon	Gordon
North_QLD	North QLD	Hadspen 110	Hadspen 110
Ross	Ross	Hadspen	Hadspen
SW_QLD	South West QLD	Liapootah	Liapootah
Tarong	Tarong	Palmerston 110	Palmerston 110
Tweed	Tweed	Palmerston 220	Palmerston 220
Wide Bay	Wide Bay	Sheffield	Sheffield
		Tarraleah 110	Tarraleah 110
		Waddamana 110	Waddamana 110
		Waddamana 220	Waddamana 220

NSW		SA		VIC	
Node	Name	Node	Name	Node	Name
Armidale	Armidale	ADE_132	Adelaide 132	Ballarat	Ballarat
Bayswater	Bayswater	ADE_275	Adelaide 275	Bendigo	Bendigo
Broken Hill	Broken Hill	BRK_132	Brinkworth 132	DDTS_220	Dederang 220
Canberra	Canberra	BRK_275	Brinkworth 275	DDTS_330	Dederang 330
Darlington Pt	Darlington Pt	BUN_132	Bungama 132	Glenrowan	Glenrowan
Dumaresq	Dumaresq	BUN_275	Bungama 275	Horsham	Horsham
Highland (Cooma)	Highland (Cooma)	CG	Cherry Gardens	HWTS_500	Hazelwood 500
Jindera	Jindera	HUM_132	Hummocks 132	HYTS_500	Heywood 500
Liddell	Liddell	KK_132	Keith Kincraig 132	Keilor_220	Keilor 220
Lismore	Lismore	MGEN_275	MGEN 275	Kerang	Kerang
Marulan	Marulan	MOB	Mobilong	Moorabool_220	Moorabool 220
Mt Piper	Mt Piper	Monash	Monash	Moorabool_500	Moorabool 500
Newcastle	Newcastle	NSA_275	North SA 275	Mt Beauty	Mt Beauty
Sydney	Sydney	ROB_132	Robertstown 132	Murray	Murray
Tamworth	Tamworth	ROB_275	Robertstown 275	Red Cliffs	Red Cliffs
Tumut	Tumut	SESA_132	South East SA 132	Rowville_220	Rowville 220
Vales Point	Vales Point	SESA_275	South East SA 275	Rowville_500	Rowville 500
Wagga	Wagga	SNUG_132	Snuggery 132	Shepparton	Shepparton
Wellington	Wellington	TB_132	Tailem Bend 132	Sth Morang 330	South Morang 330
Wollongong	Wollongong	TB_275	Tailem Bend 275	Sth Morang 500	South Morang 500
Yass	Yass	TEM	Templers	Sydenham_500	Sydenham 500
		WTL	Waterloo	Thomastown	Thomastown
				Wodonga	Wodonga

13.3 Generic constraints

There are two types of network constraints modelled. The simple bound constraint for individual links limits the power flow on the link due to its thermal rating. The other type of constraints is called generic constraints in this study, which manages contingency events. These constraints can be either on a cut-set (group of links), single link or on generation of a single or a group of plant.

There are 290 generic constraints implemented in the modelling for a particular scenario in any year, covering NEM inter-regional constraints, and intra-regional constraints in NSW and QLD. Some constraints manage the same contingency events, but in different time periods such as daytime or night in winter, summer, spring or autumn

The table overleaf summarises generic constraints and the relevant contingency events that the constraints manage. Each dot point in the table under Contingency is referred to a contingency event and forms a generic constraint accordingly.

Table 13-2 Generic Constraints and Related Contingency Events

No	Single or Cut-set Links	Contingency	Region
1	CW_QLD-North_QLD	• Townsville GT contingency	QLD
2	HYTS_275-SESA_275 (Heywood link)	• Out=Nil; Vic-SA South Australian import Stability limit; fully co-optimised. • Outage = Nil, limit Vic to SA to avoid transient instability for fault and trip of a Moorabool to Heywood 500 kV line with automatic allowance for Heywood bus tie status based on Heywood 275 kV capacitor bank status • Prior Outage = Nil. Mannum to Mannum pump 2 line OL for one Northern PS trip. Fb CoOp. • Prior Outage = Nil. Prevent Keith - Tailem Bend OL for South East - Tailem Bend trip. Fb CoOp. • Prior Outage = Nil. Prevent Mt Gambier - Blanche OL for South East - Tailem Bend trip. Fb CoOp. • Out = Nil; South East generation & Vic-SA limit to avoid Snuggery - Keith line OL (continuous rating). System normal. • Prior Outage = Nil. Mannum to Mannum pump 2 line OL for one Northern PS trip. Fb CoOp. • Victoria to SA on VicSA upper transfer limit of 460 MW	VIC, SA
3	Monash-Red Cliffs (Murraylink)	• Outage=Nil, limit SA to Vic on Murraylink to avoid overloading North West Bend to Robertstown #1 132kV line • Out=Nil, SA-V on ML, load on Waterloo - MWP4, Robt Tx 1 cont • Outage=Nil, limit SA to Vic on Murraylink to avoid overloading a Robertstown 275/132kV transformer on trip of the other Robertstown 275/132kV transformer • Outage=Nil, limit SA to Vic on Murraylink avoid overloading Para to Roseworthy 132kV line on loss of either Robertstown 275/132kV transformer or Mintaro to Waterloo 132kV line • SA to Vic on ML upper transfer limit of 220 MW • Outage = Nil, limit Vic to SA on Murraylink to avoid pre-contingent overloading of the Bendigo to Fosterville to Shepparton 220 kV line with VFRB Murraylink control scheme armed	VIC, SA
4	HWTS_500-Georgetown (Basslink)	• Out = Nil, Basslink importing only, avoid transient instability for fault and trip of the Palmerston to Sheffield line • Outage = Nil, Basslink in service, avoid overloading the Palmerston to Sheffield 220kV line (flow to North) for loss of a Sheffield to Georgetown 220kV line, feedback equation, swamp if Basslink exporting • Outage = Nil, Basslink in service, avoid overloading the Palmerston to Sheffield 220kV line (flow to South) for loss of a Sheffield to Georgetown 220kV line, feedback equation, swamp if Basslink exporting • Outage = Nil, Basslink in service, limit Tasmanian generation to avoid pre-contingent and post-contingent overloading the Palmerston to Hadspen No.1 220kV line, feedback equation • Outage = Nil, Basslink in service, limit Tasmanian generation to avoid pre-contingent and post-contingent overloading the Hadspen to Georgetown No.1 220kV line, feedback equation • Outage = Nil, Basslink in service, limit Tasmanian generation to avoid pre-contingent and post-contingent overloading the Sheffield to Georgetown No.1 220kV line, feedback equation • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Palmerston to Hadspen 220kV line (flow to North) for trip of the other Palmerston to Hadspen 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Palmerston to Hadspen 220kV line (flow to North) for trip of a Sheffield to Georgetown 220kV line with	VIC, TAS

		no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Palmerston to Hadspen 220kV line (flow to South) for trip of the other Palmerston to Hadspen 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Palmerston to Hadspen 220kV line (flow to South) for trip of a Sheffield to Georgetown 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Hadspen to Georgetown 220kV line (flow to North) for trip of the other Hadspen to Georgetown 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Hadspen to Georgetown 220kV line (flow to North) for trip of a Sheffield to Georgetown 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Hadspen to Georgetown 220kV line (flow to South) for trip of the other Hadspen to Georgetown 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Hadspen to Georgetown 220kV line (flow to South) for trip of a Sheffield to Georgetown 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Sheffield to Georgetown 220kV line (flow to North) for trip of the other Sheffield to Georgetown line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Sheffield to Georgetown 220kV line (flow to North) for trip of the Palmerston to Sheffield 220kV line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Sheffield to Georgetown 220kV line (flow to South) for trip of the other Sheffield to Georgetown line with no SPS action • Outage = Nil, Basslink not exporting, limit Tasmanian generation to avoid post-contingent overloading either Sheffield to Georgetown 220kV line (flow to South) for trip of the Palmerston to Sheffield 220kV line with no SPS action • Basslink export hard limit	
5	Liddell-Tamworth	• Outage=Nil, limit QNI and Directlink to avoid overloading (15 min rating) of Armidale to Tamworth (86) 330kV line on loss of other Armidale to Tamworth (85)	NSW
6	Dumaresq-SW_QLD (QNI)	• Transient stability, Fault on one Bayswater to Liddell Line • avoid overloading Bulli Creek to Dumaresq on the trip of the other • avoid transient instability on 2L-G fault at Bulli Creek • Outage = Nil, Qld to NSW on QNI Transient Stability Limit, Fault on Liddell to Newcastle (81) 330kV line	NSW, QLD
7	QLD\Lismore-Tweed (DirectLink)		NSW, QLD
8	DDTS_330-Murray	• Outage= Nil, NSW to Qld Transient Stability Limit for: Vic to Snowy flows of 1000 to 1170 MW, 7 or less units in service at Bayswater and Liddell • Discretionary Snowy to Vic transfer limit of 1900 MW • Outage = Lower Tumut to Upper Tumut 330kV line, limit Snowy to Vic to avoid voltage collapse for trip of the largest Vic generating unit (500 MW)	NSW, VIC
9	Tamworth-Armidale	• Avoid overloading on Tamworth to Armidale on Armidale to Tamworth trip	NSW
10	NSW\Tumut -Canberra	• loss of Canberra to Upper Tumut	NSW

	NSW\Tumut –Wagga NSW\Tumut -Yass	• loss of Lower Tumut to Yass • loss of Canberra to Yass • loss of Upper Tumut to Canberra • Avoiding overloading on Murray to Upper Tumut (NIL Trip) • Avoiding overloading on Murray to Lower Tumut (NIL Trip) • Avoiding overloading on Upper Tumut-> Murray (NIL Trip) • Avoiding overloading on Lower Tumut to Murray (NIL Trip) • Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 1200 to 1270 MW, 7 or less units in service at Bayswater and Liddell • NSW-Snowy Export Limit 1150 MW	
11	SA\Monash-Red Cliffs NSW\Tumut -Canberra NSW\Tumut -Wagga NSW\Tumut -Yass	• loss of Jindera to Wagga • loss of Jindera to Wodonga	NSW, VIC, SA
12	VIC\DDTS_330-Murray NSW\Tumut -Canberra NSW\Tumut -Wagga NSW\Tumut -Yass	• loss of Murray to Lower Tumut • loss of Murray to Upper Tumut • loss of Murray to Lower Tumut • loss of Murray to Upper Tumut	NSW, VIC
13	QLD\Dumaresq-SW_QLD QLD\Lismore-Tweed	• avoid overloading on Liddell->Tomago on Liddell-Newcastle(81) • avoid overloading on Vales Pt->Munmorah on loss of Sydney North to Vales Pt • Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 0 to 1000 MW, V-SA positive, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 0 to 1000 MW, V-SA negative, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 0 to 1200 MW, 7 or less units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: Vic to Snowy flows of 0 to 500 MW, V-SA positive, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for, Vic to Snowy flows of 0 to 500 MW, V-SA negative, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: Vic to Snowy flows of 0 to 500 MW, 7 or less units in service at Bayswater and Liddell • Outage= Nil, avoid Voltage Collapse on loss of Liddell to Muswellbrook (83) 330kV line (one for each direction) • Outage = Nil, NSW to Qld Transient Stability for a trip of a Callide C unit • Outage = Nil, NSW to Qld Transient Stability Limit for trip of a Kogan Creek unit • Outage=Nil, avoid Voltage Collapse on loss of largest Qld Generator • Outage = Nil, NSW to Qld Transient Stability for a trip of a Millmerran unit, for 1 unit online at Millmerran • Outage = Nil, NSW to Qld Transient Stability Limit for trip of a Tarong North unit	NSW, QLD
14	NSW\Tumut -Canberra NSW\Tumut -Wagga NSW\Tumut -Yass QLD\Dumaresq-SW_QLD QLD\Lismore-Tweed	• Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 1000 to 1200 MW, V-SA positive, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: NSW to Snowy flows of 1000 to 1200 MW, V-SA negative, 8 units in service at Bayswater and Liddell	NSW, QLD

15	VIC\DDTS_330-Murray QLD\Dumaresq-SW_QLD QLD\Lismore-Tweed	• Outage= Nil, NSW to Qld Transient Stability Limit for:Vic to Snowy flows of 500 to 1000 MW, V-SA positive, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for:Vic to Snowy flows of 1000 to 1170 MW, V-SA positive, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for:Vic to Snowy flows of 500 to 1000 MW, V-SA negative, 8 units in service at Bayswater and Liddell • Outage= Nil, NSW to Qld Transient Stability Limit for: Vic to Snowy flows of 500 to 1000 MW, 7 or less units in service at Bayswater and Liddell	NSW, QLD, VIC
16	VIC\DDTS_330-Murray QLD\Dumaresq-SW_QLD QLD\Lismore-Tweed SA\HYTS_275-SESA_275	• Outage= Nil, NSW to Qld Transient Stability Limit for:Vic to Snowy flows of 1000 to 1170 MW, V-SA negative, 8 units in service at Bayswater and Liddell	NSW, QLD, SA, VIC
17	SA\HYTS_275-SESA_275 SA\Monash-Red Cliffs VIC\DDTS_330-Murray QLD\Dumaresq-SW_QLD VIC\HWTS_500-Georgetown (Basslink)	• Outage = Nil, Basslink import from Tas, limit Vic interconnectors, NSW to Qld on QNI and Vic generation to avoid transient instability for fault and trip of a Hazelwood to Sth Morang 500kV line, radial mode at Hazelwood • Outage = Nil, Basslink export to Tas, limit Vic interconnectors, NSW to Qld on QNI and Vic generation to avoid transient instability for fault and trip of a Hazelwood to Sth Morang 500kV line, radial mode at Hazelwood	NSW, QLD, SA, TAS, VIC
18	SA\Monash-Red Cliffs SA\HYTS_275-SESA_275	• Eff = 07/03/2003 ; RHS = 420 ; Op = "<=" ; Wt = 20	SA, VIC
19	SA\Monash-Red Cliffs VIC\DDTS_330-Murray	• Outage = Nil, limit Snowy to Vic to avoid exceeding the continuous rating of the No.1 Dederang 330/220kV transformer with the DBUSS-Transformer control scheme armed	NSW, SA, VIC
20	SA\HYTS_275-SESA_275 NSW\Tumut -Canberra NSW\Tumut -Wagga NSW\Tumut -Yass	• NSW-Snowy Transient Export Limit	NSW, SA, VIC
21	QLD\CW_QLD-Tarong QLD\Gladstone-Wide Bay	• Gladstone Margin • Calvale Margin	QLD
22	QLD\Tarong-Moreton North QLD\SW_QLD-Moreton South QLD\Lismore-Tweed	• Swanbank E Contingency • Woolooga-Palmwoods Contingency • Calvale-Tarong Contingency • Tarong-Blackwall Contingency • Wivenhoe Contingency	NSW, QLD
23	QLD\Moreton South-Gold Coast QLD\Lismore-Tweed	• Swanbank-Mudgeeraba contingency	NSW, QLD
24	QLD\SW_QLD-Tarong QLD\SW_QLD-Moreton South		QLD

13.4 Nodal demands

Table 13-3 lists the nodes with demand attached.

Table 13-3 Nodes with Demand

NSW	QLD	SA	TAS	VIC
Lismore	FN_QLD	SESA_132	Burnie	Moorabool_220
Armidale	Ross	SNUG_132	Farrell	Keilor_220
Tamworth	North_QLD	KK_132	Sheffield	Thomastown
Liddell	CW_QLD	TB_132	Georgetown	Rowville_220
Mt Piper	Gladstone	MOB	Hadspen	HWTS_500
Wellington	Wide Bay	ADE_275	Palmerston_110	Ballarat
Newcastle	SW_QLD	TEM	Liapootah	Bendigo
Central Coast	Moreton North	WTL	Tarraleah_110	Horsham
Sydney	Moreton South	HUM_132	Chappell_110	Red Cliffs
Wollongong	Gold Coast	BUN_132		Kerang
Marulan	Tarong	BRK_132		Shepparton
Yass	Tweed	Monash		Glenrowan
Canberra		NSA_275		Mt Beauty
Wagga				Wodonga
Broken Hill				
Darlington Pt				
South Highland				
Jindera				

13.5 Locations of existing generators

This section presents the locations of existing conventional and some wind power stations.

Table 13-4 Locations of NSW Existing Conventional Generators

Node	Generators
Bayswater	Bayswater; HVGTS
Liddell	Liddell; Redbank
Marulan	Marulan
Mt Piper	Mt Piper; Smithfield; Wallerawang
Murray	Guthega; Hume NSW; Murray; Shoalhaven
Tumut	Blowering;Tumut3;Upptumut
Vales Point	Colongra; Eraring GT; Eraring; Munmorah; Vales Pt
Wagga	Uranquinty
Wollongong	Bamarang; Tallawarra

Banarang gas turbine was classified as a publicly announced project by Delta Electricity and is located near Nowra.

Table 13-5 Locations of QLD Existing Conventional Generators

Node	Generator
CW_QLD	Barcaldine; Callide C3;Callide C4; CallideA; CallideB; Stanwell;
FN_QLD	Barron Gorge; Kareeya
Gladstone	Gladstone; Gladstone PPA; Yarwun
Gold Coast	DryCreek
Moreton South	SwanbankB; SwanbankE; Wivenhoe
North_QLD	Collinsville; Mackay GT
Ross	Mt Stuart; Yabulu
SW_QLD	Braemar Stage 2; Braemar Stage 3; Braemar; Darling Downs; Kogan Creek; Millmerran PP;
Tarong	Condamine; Oakey; Roma GT; Tarong; TNPS1

Table 13-6 Locations of SA Existing Generators

Node	Generator
ADE_275	Osborne; Quarantine; Dry Ck; Pelican Point; Torrens A; Torrens B
BUN_132	Snowtown WF; Clements Gap WF
HUM_132	Wattle Pt WF
MGEN_275	Brown Hill WF; Hallet GT
MOB	Angaston
NSA_275	Northern PS; Playford B; Port Lincoln; Cathedral Rocks WF; Mt Millar WF; Northern; Playford
SESA_132	Ladbroke Grove
SNUG_132	Lake Bonney WF; Snuggery
TB_132	Starfish Hill WF

Table 13-7 Locations of TAS Existing Generators

Node	Generator
Burnie	Woolnorth Studland Bay, Woolnorth Wind Farm
Farrell	Bastyan, John Butters, Mackintosh, Reece 1, Reece 2, Tribute
Georgetown	Bell Bay 1, Bell Bay 2, BellBayThree1, BellBayThree2, BellBayThree3
Gordon	Gordon
Hadspen	Trevallyn
Liapootah	LI_WY_CA, Meadowbank
Palmerston 110	Poatina 110, Poatina 220
Sheffield	Cethana, Devils Gate, Fisher, LEM_WIL, Paloona
Tarraleah 110	Tarraleah, Tungatinah

Table 13-8 Locations of VIC Existing Generators

Node	Generator
Ballarat	Mt Mercer WF; Waubra WF
HWTS_500	Bairnsdale; Hazelwood; Jeeralang A; Jeeralang B; Loy Yang A; Loy Yang B; Morwell; Valley Power; Yallourn W1
HYTS_275	Portland WF
Keilor_220	Newport
Moorabool_220	Anglesea; Laverton North
Moorabool_500	Mortlake
Mt Beauty	Bogong; Dartmouth; Eildon; HumeV; McKay; West Kiewa
Rowville_220	Yallourn W2-4

13.6 Transmission Upgrade Options

Transmission upgrade options were agreed for interconnectors. This information was taken from the 2008 NEMMCO SOO and is shown in the table below. It is assumed that the potential interconnector between ADE and NCEN includes augmentating ADE_SESA, NSA_ADE plus a new line between the nodes NSA_275 (SA) and Mt piper (NSW), as shown in Figure 13-1.

Table 13-9 Interconnector Options and Costs

Upgrade Path	Capacity Increase	Flow paths augmented	Capital Cost estimate ($millions)
NSA to MEL (upgrade)	400MW bidirectional	NSA_ADE, ADE_SESA, SESA_MEL	$400m (includes all conceptual augmentations [39,40,41] on p 9-13 of the SOO ANTS)
MEL to SWNSW (upgrade)	400MW bidirectional	MEL_NVIC, NVIC_SWNSW	$247m (includes all options on p 8-17 in the SOO [Fig 8.6] for VICTORIA – NEW SOUTH WALES)
NNS to SWQ (upgrade)	400MW bidirectional	NCEN_NNS, NNS_SWQ	$220m (Option 1 on p 8-17 in the SOO for NEW SOUTH WALES – QUEENSLAND plus $100m for 300km of 330kV line between Liddell and Armidale)
ADE to NCEN (new)	2000MW bidirectional	New flow path ADE_NCEN plus remove constraints between NSA_ADE, ADE_SESA	$2,300m (estimate received by ROAM Consulting on 27th April as “strictly indicative only”

There was very little information available on transmission upgrade options within regions (to address intraregional transmission constraints and even less information on costs. A list of conceptual options from the 2008 NEMMCO SOO was developed and is shown in the table below. Each of these options would influence transmission losses (through possible changes in resistance) and the flow paths (through possible changes in reactance).

Table 13-10 Conceptual Transmission Upgrade Options from the 2008 NEMMCO SOO

SOO Reference	Brief description
1	Concept 1:QNI Series Cap addition
2	Concept 2: Armidale SVC
3	Concept 3:System Protection Scheme
4	Concept 4: DC link
5	Concept5:330 kV dc Bulli Ck - Bayswater
6	Replace one Armidale – Tamworth 330 kV by SC hicap line
7	Replace one Armidale – Tamworth 330 kV by DC hicap line
8	Liddell-Tamworth new line (assume same as existing)
9	Uprate Muswellbrook- Liddell
10	New Hunter – Eraring 500kV replaces existing 330 kV
11	Hunter Valley braking resistor
12	HVDC link SA to NSW
13	For NSW – Vic transfer: 4th Dederang 330/220 transformer
14	For Vic export: Second SMTS 500/330 kV transformer, Line thermal uprate
15	For Vic Export: As for 14 above plus Dederang SVC (see 23)
16	For NSW export: Compensate Lower Tumut – Wagga- Jindera (assume 50%), plus capacitors and controls Pre-requisites are 13 above and network services
17	(a) Cut Rowville – Thomastown at Sth Morang and uprate Dederang – Sth Morang lines (b) Plus: 3rd Sth Morang 330/220 tfr (c) Plus: Series comp Wodonga- Dederang (assume 60%) (d) Plus: Uprate Eildon-T-town & 25% series compensate (e) Plus phase angle regulate Bendigo Shepparton (f) upgrade Wagga –Jindera-Wodonga lines Re-requisites are 13, 16, 32, 35 Note: Although bundled these are separable into NSW export and Vic export
18	3rd transformer at Heywood plus double circuit 275 kV Heywood to SE (assume 1 cct strung) plus 3rd SESA 275/132 kV transformer Plus SESA SVC; Pre-requisites 19, 40
19	Loy Yang Braking resistor
20	Bendigo to Shepparton phase angle regulator
21	Duplicate Basslink Plus new G-town- Farrell 220 kV Plus new G-town Chappell 220 kV (assume all SC)
22	Palmerston- Sheffield replace one line (assume bigger conductors)
23	For Vic export: Dederang SVC
24	Concept 1: Calvale-Tarong Series Comp (assume 60%)
25	Concept 2: New 275 kV dc inland (assume Calvale – Tarong)
26	Concept 3:New 275 kV dc coastal (assume Gladstone –Moreton Nth
27	Concept 4: CQ to SQ 500 kV line (assume Central West – Tarong and operate at 275 kV initially?)
28	Halys- Blackwall uprate from 275 kV operation to 500 kV
29	Greenbank –Mudgerabah replace SC line by DC
30	Bannaby- Sydney 500 kV line replaces 330 kV (may soon be committed)
31	Wagga to Darlington Pt 330 kV line

32	Raise operating voltage of Darlington Pt- Buronga 220 to 275 kV
33	Add new Yass- Bannaby 500 kV line (assume single cct new route)
34	Uprate various line thermal constraint upgrade Tumut –Yass/Canberra
35	New Yass – Wagga 330 kV (assume new route)
36	New System protection scheme
37	Yass – Marulan and Yass – Bannaby uprating
38	Hazelwood extra transformer
39	Break parallel between 275 kV and 132 kV Adelaide to SE
40	New dc 275 kV SESA – Tailem Bend - Tunkillo
41	New Riverland 275kV Monash - Robertstown

As there was insufficient time to develop the options noted above, for the purposes of the modelling the following assumptions were made in relation to intraregional transmission augmentation. This was that is a line were to be upgraded to would be a 300 MW increase at a cost of $30M.

14 Appendix 2 The IES MARKAL Model

In its broadest representation, MARKAL is a multi-time period model of an energy system that allows technology and policy options to be analysed in a consistent manner. It can be structured at any desired level such as for a state or region, country or group of countries. The model is normally applied to cover all energy sectors and include both supply and demand side options. But it can be equally applied to just a sub-set of the energy system.

The primary fuel resource is presented to MARKAL as a cost per gigajoule for different types of fuel. Limits can be placed on either the annual or cumulative availability of fuels over the study period in which case an "opportunity" cost as determined within the model will apply if the resource limit is reached. Different cost categories for fuels can be specified if required to represent a supply curve. A delivery cost may also apply to fuel delivered to a power station. Delivery infrastructure such as gas pipelines can be incorporated into a fuel delivery cost or modelled explicitly to compete with other options in the model on a least cost basis for implementation.

One of the strengths of MARKAL is that it is generally a straight-forward matter to incorporate different policy options in the model. For example, applying a renewable portfolio standard (RPS) simply involves an equation to be specified that ensures the required portion of relevant electricity demand be supplied from renewable sources. The model would meet this in a least-cost manner from the range of technologies presented to it. Immediate output includes:

- Increase in total system cost;
- Impact on electricity prices;
- Green certificate price;
- Investments in renewable and other technologies;
- Resource use; and
- Environmental emissions.

14.1 The representation of the NEM

For this study MARKAL represented the NEM only. MARKAL was structured to represent the NEM in fine detail including separate representation for individual power stations. The model used annual time-steps based on financial years. All costs were expressed in real 2009/10 dollars.

The description here is presented in terms of the physical representation of the power system and the operation of the NEM.

14.1.1 Physical Power System

14.1.1.1 Loads

MARKAL represented the electricity load by dividing the year into an arbitrary number of slices in which load is assumed constant. The load was represented as a load duration curve (LDC) which was divided into 9 slices to obtain a reasonable step-wise approximation to the continuous curve, which then subdivided into 6 wind regimes to account for the variability of wind as presented in Section 7.3.

14.1.1.2 Power Stations

MARKAL represented individual power stations. Power stations were grouped by the type of fuel used such as black coal, natural gas, distillate etc.

As no oligopoly behaviour is modelled, portfolio structure is not relevant in this model. Each power station had data on fixed cost, variable operating cost, heat rate, emissions rate.

The model includes existing plant capacity along with their scheduled retirement. New plant that are regarded as firmly committed are entered as definite additions in MARKAL.

Potential new entry power stations are specified in terms of the capital and operating costs and the other factors noted above. These enter the market in order to satisfy the energy and reserve capacity requirements (constraints) discussed below.

A constraint on capacity factor of operation can be included.

14.1.1.3 Transmission

Two forms of the IES MARKAL model were used in the modelling undertaken. These were as follows

- The Regional MARKAL Model – the transmission model used here only incorporated interconnectors between the NEM regions (i.e. it was based on the NEM regional transmission model);
- The Full Network MARKAL Model – the transmission model used here was the full transmission model developed for this study and was the same as that used in the PROPHET model. The transmission model used incorporated the DC load flow constraints and the generic constraints used.

Because losses vary with flow, all transmission lines and interconnectors, with the exception of Terranora and Basslink, have been defined in the model in segments (up to 10 segments each way). Each segment has a loss factor associated with it and this more accurately captures the increase in losses with flow.

14.1.2 Market Operation

MARKAL operates to provide the electricity demand at least cost from the available plant and to build additional capacity as required to meet increasing load or to replace plant that are retired.

It also conforms to any constraints that are placed on the system or technologies therein. The electricity balance equations in MARKAL, along with an additional equation ensuring sufficient capacity is installed to meet peak load plus reserve, produce a set of electricity prices that can be interpreted as outcomes from a competitive market.

As with a competitive market, the marginal plant sets the electricity price in each time slice such that all capital, operating and fuel costs are recovered over a year.

In summary, the model implicitly uses LRMC for capacity expansion and SRMC for dispatch. However, it should be noted that *no attempt is made to model the bidding behaviour of generators in this process*, but nonetheless the outcome in pricing and dispatch should mirror actual outcomes under conditions that are reasonably competitive.

The operating constraints in MARKAL are as follows:

- Energy Balance: Each load segment and for each region, the total generation in that region + net imports + losses = the regional load
- Transmission: Power flows between regions must be within the limits of the interconnectors/transmission lines
- Reserve margin: Each year there must be sufficient installed capacity to satisfy the reserve margin in each region. Regional reserve margin accounts for inter-regional support (which is assumed constant)
- RECs: the total level of renewable generation must be must be greater than or equal to the requirement in that year
- QGS: the total level of gas generation in QLD must be at above the requirement
- CPRS: two modes of modelling:
  - with defined permit price - production costs reflect permit prices
  - with cap on emissions - the level of emissions must be within that defined by the scheme (which was not used in this study)

The model can be operated to only allow generator units to enter and leave as a whole or to allow these to enter and leave in part (which is clearly not realistic). All existing coal-fired generators are assumed to remain in service unless they become uneconomic on the spot market, in which case they are retired. The definition of uneconomic is when a generator unit is not covering its costs, i.e. the NPV of its revenue less costs is negative.

15 Appendix 3 Generator Assumptions

15.1 Existing Generation

15.1.1 Generator Capacities

The station capacities used are "*as generated*". Data were sourced from the NEMMCO "2008 Statement of Opportunities for the NEM" (SOO).

15.1.2 Station Emissions Factors

The station emissions factors used are "*as sent out*". The emissions factors and emissions intensities are from the ACIL Tasman report[14] on "Fuel resource, new entry and generation costs in the NEM", 13 Feb 2009.

15.1.3 Station Heat Rates

These were obtained from the ACIL Tasman "Fuel resource, new entry and generation costs in the NEM", 13 Feb 2009. They are also provided "*as sent out*".

15.1.4 Intra-regional Loss Factors

The Intra-regional loss factors were obtained from NEMMCOs "List of Regional Boundaries Marginal Loss Factors for the 2008/09 Financial Year"[15]. For new generators the average loss factor for existing generators in the same state was used.

15.1.5 Generator Loss Factors

A loss factor of 0.995 was assumed for all generators for losses between a generator and the node it is connected to.

15.1.6 Forced Outage Levels

Minimum output levels, planned and forced outage rates are sourced from NEMMCO "2009 NTS Consultation: Issues Paper"[16]. The forced outage rates are given in Table 15-1.

Table 15-1 Forced Outage Rates by Technology

	Full Forced Outage Rate (FFOR)	Partial Forced Outage Rate (PFOR)	Equivalent Forced Outage Rate (EFOR)	Partial Derating
Black Coal	2.64%	5.81%	3.84%	20.77%
Brown Coal	3.25%	14.13%	4.36%	7.82%
CCGT	4.24%	0.67%	4.63%	57.24%

[14] ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 February 2009. Available: http://www.nemmco.com.au/psplanning/nts.html
[15] NEMMCO, List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year, 18 November 2008. Available: http://www.nemmco.com.au/psplanning/172-0066.html
[16] NEMMCO, 2009 NTS Consultation: Issues Paper, 16 February 2009. Available: http://www.nemmco.com.au/psplanning/nts.html

	Full Forced Outage Rate (FFOR)	Partial Forced Outage Rate (PFOR)	Equivalent Forced Outage Rate (EFOR)	Partial Derating
OCGT	27.88%	0.00%	27.88%	28.00%
Gas Other	2.14%	2.15%	2.43%	13.33%
Hydro	3.54%	2.88%	4.44%	31.17%

Source: NEMMCO, 2009 NTS Consultation: Issue Paper, Page 63

The average number of hours that a plant of a given technology can switch from one state to another is given in Table 15-2.

Table 15-2 Transition Time between States

	Available to Partially Available	Available to Unavailable	Partially Available to Available	Partially Available to Unavailable	Unavailable to Available	Unavailable to Partially Available
Black Coal	253	1715	16	943	54	238
Brown Coal	37	852	6	224	37	45
CCGT	1991	391	14	153	17	1195
OCGT	3.90E+04	7.40E+01	0	7.20E+09	29	2.40E+09
Gas Other	6252	592	131	1.30E+10	13	1957
Hydro	9.50E+04	394	3670	9100	15	29215

Source: NEMMCO, 2009 NTS Consultation: Issue Paper, Page 63

15.1.7 Planned Outage levels

Planned outage levels are provided as a number of days per year. Planned outages are assumed not to occur between November and March inclusive.

Table 15-3 shows the planned outage in each NEM region by the service type of an existing plant.

Table 15-3 Planned Outage (Days per Year) – Existing Plant

Region	Baseload	Intermediate	Hydro	Peaking
QLD	16	30	17	6
NSW	28	16	15	5
VIC	19	26	15	3
SA	28	16		4
TAS	16		17	4

Source: NEMMCO, 2009 NTS Consultation: Issue Paper, February 2009, Page 64.

Table 15-4 shows the planned outage by technology applied to all NEM regions.

Table 15-4 Planned Outage (Days per Year) – New Entry

Technology	Days per Year
Black Coal	16
Brown Coal	19
CCGT	16
OCGT	4

Source: NEMMCO, 2009 NTS Consultation: Issue Paper, February 2009, Page 64.

15.1.8 Variable Operating and Maintenance Costs (VOM)

Variable Operating and Maintenance costs were obtained from ACIL Tasman "Fuel resource, new entry and generation costs in the NEM", 13 Feb 2009.

15.1.9 Fixed Operating and Maintenance Costs (FOM)

Fixed O&M costs for existing generators were obtained from ACIL Tasman "Fuel resource, new entry and generation costs in the NEM", 13 Feb 2009.

15.2 Hydro Generation

Table 15-5 lists the assumed monthly inflows to electric hydro storages in GWh. These do not necessarily correspond to actual historic inflows but are the assumed values which NEMMCO uses for its modelling.

Table 15-5 Monthly Inflow to Hydro Storages in GWh

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Blowering	-	-	-	-	-	-	-	-	6	25	31	34
Eucumbene	328	330	100	329	434	750	749	434	435	434	154	293
Fitzroy Falls	-	-	-	-	-	-	-	-	-	-	-	-
Guthega	5	2	0	1	4	7	9	15	21	34	25	14
Koombooloomba	16	21	23	17	22	40	36	73	63	51	36	44
Kuranda Weir	31	25	29	17	29	27	17	13	30	19	16	13
Split Yard Creek	-	-	-	-	-	-	-	-	-	-	-	-
TASLongTerm	72	62	81	185	270	308	374	391	343	274	180	132
TASMidTerm	138	113	136	305	433	464	563	558	497	408	293	216
TASRunofRiver	123	103	117	193	258	292	341	341	300	263	207	166

Source: NEMMCO, 2009 NTS Consultation: Issue Paper, Page 62

15.3 New Generation (Non-Renewable)

15.3.1 Supply Developments

The committed new entry projects are shown below in Table 15-6 and are given as per the NEMMCO 2008 SOO. Tamar is currently under construction and is included even though it is classified as an advanced proposal rather than committed project in 2008 SOO.

Table 15-6 Committed New Plant

Commit Date	Region	Plant	Capacity (MW)
1/07/2009	Qld	Braemar OCGT	519
1/12/2009	NSW	Colongra OCGT	668
1/12/2009	Qld	Mt Stuart OCGT	127
1/07/2009	Qld	Condamine CCGT	138
1/07/2010	Qld	Darling Downs CCGT	621
1/07/2009	Tas	Tamar CCGT	207

1/07/2009	Tas	Tamar OCGT	58
1/12/2008	SA	Quarantine	123
1/12/2008	NSW	Uranquinty OCGT	664
1/07/2010	Qld	Yarwun CoGen	169
1/01/2010	Vic	Bogong (Hydro)	140
1/01/2011	Vic	Mortlake 1 CCGT	550

Source: Based on NEMMCO, 2008 State of Opportunities

15.3.2 Market New Entry Capital Costs

All non-renewable generators that entered the market were assumed to be either CCGT or OCGT plant. New entry capital costs are obtained from ACIL Tasman "Fuel resource, new entry and generation costs in the NEM", 13 Feb 2009. From the above report, the size of CCGTs is assumed to be 400 MW (200MW in South Australia and Tasmania), and the size of an OCGT is assumed to be 100 MW. The capital costs are given in Table 15-7.

Table 15-7 Capital Cost of New Entry in (Real 2009-10$/kW)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
CCGT (WC)	1,314	1,224	1,222	1,200	1,185	1,181	1,177	1,173	1,168	1,164	1,159	1,154
OCGT	985	918	916	900	888	886	883	880	876	873	869	866
Geothermal (HDR)	5,330	5,369	5,300	5,232	5,165	5,099	5,034	4,969	4,905	4,842	4,780	4,719

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Annualised costs including capital (assuming an economic life of 30 years), fixed O&M and tax are given in Table 15-8.

Table 15-8 Annualised Cost of New Entry in Real $/kW/year Installed

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
CCGT (WC)	168	159	158	156	155	154	154	153	153	152	152	151
OCGT	113	106	106	104	103	103	102	102	102	101	101	101
Geothermal (HDR)	626	630	623	615	608	600	593	586	579	572	565	558

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

15.4 Renewable Generators

Table 15-9 presents the capacity of committed and potential (uncommitted and generic) renewable plant by type and region explicitly modelled in this study. As discussed in Section7.2.3, renewable plant smaller than 20MW were assumed to be embedded and therefore not explicitly treated in the modelling.

Table 15-9 Capacity of committed and potential renewable plant by type and region explicitly modelled in this study (MW)

Energy source	NSW	QLD	SA	TAS	VIC	TOTAL
Bagasse	60	357	-	-	-	417
Black liquor	-	-	-	-	24	24
Geothermal	220	900	3,803	-	-	4,923
Hydro	3941	669	54	2254	501	7,419
Landfill gas	48	-	-	-	-	48
Municipal waste	20	-	20	-	20	60
PV	73	-	-	-	154	227
Solar - generic projects	5,000	5,000	5,000	-	5,000	20,000
Solar - known projects	383	-	74	-	-	457
Wave	-	-	50	-	27	77
Wind	2,972	1,010	4,302	1,238	4,625	14,147
Wood waste	40	80	65	97	30	312
TOTAL	12,757	8,016	13,368	3,589	10,381	48,111

15.4.1 Wind farm capacity factors

As wind generation was the marginal new renewable energy source (due to both cost and potential capacity available) it was important that the assumptions regarding the wind generation were realistic.

The following table lists the wind project modelled in this study with the following information:

- Project name;
- Earliest date that the project could commence operation;
- Status of the project;
- Capacity (MW); and
- The capacity factor of operation.

Table 15-10 Wind Farm Projects

Name	Earliest possible date of operation	Status	Capacity (MW)	Capacity factor
Toora Wind Farm (VIC)	2002	Existing/Committed	21	30.3%
Woolnorth Wind Farm (TAS)	2002	Existing/Committed	64.75	39.8%
Challicum Hills Wind Farm (VIC)	2003	Existing/Committed	52.5	29.9%
Starfish Hill Wind Farm (SA)	2003	Existing/Committed	34	30.9%
Canunda Wind Farm (SA)	2004	Existing/Committed	46	31.7%
Lake Bonney Wind Farm Stage 1 (SA)	2004	Existing/Committed	80.5	26.7%
Cathedral Rocks Wind Farm (SA)	2005	Existing/Committed	66	32.0%
Wattle Point Wind farm (SA)	2005	Existing/Committed	91	32.0%
Mt Millar Wind Farm (SA)	2006	Existing/Committed	70	32.0%
Yambuk Wind Farm (VIC)	2006	Existing/Committed	30	33.4%
Woolnorth Studland Bay (TAS)	2007	Existing/Committed	75	45.7%
Cape Bridgewater - Portland Stage II (VIC)	2008	Existing/Committed	58	37.0%
Conroys Gap Wind Farm (NSW)	2008	Existing/Committed	30	33.0%
Lake Bonney Stage II (SA)	2008	Existing/Committed	159.5	34.0%
Bald Hills (1 and 2) (VIC)	2008	Potential	104	36.8%
Baynton (VIC)	2008	Potential	200	31.0%
Ben Lomond (NSW)	2008	Potential	150	32.0%
Crookwell II (NSW)	2008	Potential	110	30.6%
Crows Nest (QLD)	2008	Potential	150	32.0%
Drysdale (VIC)	2008	Potential	29.9	33.0%
Lincoln Gap (SA)	2008	Potential	118	32.0%
Troubridge Point (SA)	2008	Potential	30	35.0%
Worlds End (SA)	2008	Potential	180	32.0%
Cape Nelson - Portland Stage III (VIC)	2009	Existing/Committed	44	37.0%
Capital Wind Farm (NSW)	2009	Existing/Committed	132.3	35.0%
Hallett Wind Farm (Brown Hill Range) (SA)	2009	Existing/Committed	94.5	41.0%
Snowtown Stage I (SA)	2009	Existing/Committed	94	38.1%
Waubra Wind Farm (VIC)	2009	Existing/Committed	192	35.0%
Barn Hill (Red Hill) (SA)	2009	Potential	123	33.0%
Cape Jaffa (SA)	2009	Potential	150	37.0%
Cullerin Range Wind Farm (NSW)	2009	Potential	30	36.1%
Evandale (NSW)	2009	Potential	30	32.0%
Green Point (SA)	2009	Potential	44	30.0%
Gunning (NSW)	2009	Potential	62	31.3%
Hawkesdale (VIC)	2009	Potential	62	29.7%
High Road (QLD)	2009	Potential	40	30.0%
Highfields (NSW)	2009	Potential	21	35.0%

Lake George (SA)	2009	Potential	120	33.0%
Lexton (VIC)	2009	Potential	38	35.0%
Mount Gellibrand (VIC)	2009	Potential	232	36.8%
Mt Mercer (VIC)	2009	Potential	131.2	34.4%
Musselroe (TAS)	2009	Potential	138	24.8%
Myponga/Sellicks Hill (SA)	2009	Potential	35	36.5%
Naroghid (VIC)	2009	Potential	44	34.8%
Ryan Corner (VIC)	2009	Potential	136	30.0%
Sheringa Beach (SA)	2009	Potential	100	36.0%
Silverton Stage 1 (NSW)	2009	Potential	150	33.0%
Snowtown II and III (Barunga) (SA)	2009	Potential	240	36.5%
Snowy Plains Wind Farm (NSW)	2009	Potential	28	32.9%
Southern Highlands (NSW)	2009	Potential	30	30.0%
Taralga (NSW)	2009	Potential	186	34.0%
Tungketta Hill I (SA)	2009	Potential	55	36.0%
Tungketta Hill II (SA)	2009	Potential	65	36.0%
Uley Basin (SA)	2009	Potential	160	34.0%
Waterloo (SA)	2009	Potential	117	37.0%
Woodlawn (NSW)	2009	Potential	50	32.0%
Hallett Hill (SA)	2010	Existing/Committed	71.4	39.0%
North Brown Hill (Hallett project) (SA)	2010	Existing/Committed	132	39.0%
Australia Plain (SA)	2010	Potential	150	33.0%
Cape Sir William Grant & Cape Nelson North - Portland Stage IV (VIC)	2010	Potential	81	37.0%
Collaby Hill (SA)	2010	Potential	120	32.0%
Crowlands Wind Farm (VIC)	2010	Potential	165	28.5%
Glen Innes (NSW)	2010	Potential	55	32.0%
Kongorong (SA)	2010	Potential	30	30.0%
Lal Lal (VIC)	2010	Potential	140	32.6%
Macarthur Wind Farm (VIC)	2010	Potential	330	32.0%
Mackay (QLD)	2010	Potential	20	30.0%
Monaro (NSW)	2010	Potential	100	32.0%
Mortons Lane (VIC)	2010	Potential	29.9	33.0%
Nirranda (VIC)	2010	Potential	50	33.0%
Oberon (NSW)	2010	Potential	40	29.0%
Paling Yards (NSW)	2010	Potential	100	33.0%
Silverton Stage 2 (NSW)	2010	Potential	300	33.0%
South Eastern (SA)	2010	Potential	80	34.0%
Southern Highlands 2 (NSW)	2010	Potential	21	30.0%
Waokwine (SA)	2010	Potential	100	29.0%
Weymouth (Hill) (SA)	2010	Potential	20	32.0%
Woolsthorpe (VIC)	2010	Potential	40	32.0%
Woorndoo (VIC)	2010	Potential	26	33.0%
Winchelsea (VIC)	2011	Existing/Committed	28	35.5%

Allendale Wind Farm (SA)	2011	Potential	150	35.0%
Ararat Wind Farm (VIC)	2011	Potential	228	34.2%
Archer Point (stage 1 and 2 138MW each) (QLD)	2011	Potential	276	33.0%
Berrybank (VIC)	2011	Potential	255	35.0%
Bluff Range Wind Farm (Hallett Project) (SA)	2011	Potential	50	38.0%
Box Hill (NSW)	2011	Potential	20	32.0%
Bunyan (Cooma) (NSW)	2011	Potential	150	32.0%
Clements Gap Wind Farm (SA)	2011	Potential	57	34.0%
Collector (NSW)	2011	Potential	150	29.0%
Coopers Gap Wind Farm (QLD)	2011	Potential	300	34.6%
Darlington (VIC)	2011	Potential	450	35.0%
Dollar (VIC)	2011	Potential	79	32.0%
Granville Harbour (TAS)	2011	Potential	40	39.0%
Gullen Range Wind Farm (NSW)	2011	Potential	278	35.0%
Gulnare Wind Farm (SA)	2011	Potential	175	39.1%
Heemskirk (TAS)	2011	Potential	160	41.0%
Jims Plains (TAS)	2011	Potential	60	41.0%
Kemmiss Hill Road, Yankalilla (SA)	2011	Potential	30	32.0%
Kulpara (SA)	2011	Potential	100	32.0%
Kyoto Energy Park (NSW)	2011	Potential	99	34.0%
Laslett (SA)	2011	Potential	150	37.0%
Mortlake 1 (VIC)	2011	Potential	150	32.0%
Mortlake 2 (VIC)	2011	Potential	150	32.0%
Mount Bryan (Hallett Project) (SA)	2011	Potential	80	40.0%
Oaklands Hill Wind Farm (VIC)	2011	Potential	63	35.4%
Rock Flat Creek (NSW)	2011	Potential	100	29.0%
Sidonia Hills (VIC)	2011	Potential	68	35.0%
Silverton Stage 3 (NSW)	2011	Potential	550	33.0%
Stockyard Hill (VIC)	2011	Potential	564	30.0%
Tuki (VIC)	2011	Potential	38	30.0%
Vincent North Wind Farm (SA)	2011	Potential	59.4	26.9%
Welshpool, Gippsland (VIC)	2011	Potential	36	32.0%
Willogoleche Hill (Hallett Project) (SA)	2011	Potential	42	38.0%
Windy Hill II (QLD)	2011	Potential	24	30.0%
Berrimal (VIC)	2012	Potential	24	32.0%
Newfield (VIC)	2012	Potential	22.5	33.0%
Rosedale (VIC)	2012	Potential	45	35.0%
SA Project (SA)	2012	Potential	450	37.0%
White Rock Ridge, Robbins Island (TAS)	2012	Potential	100	40.0%
Yaloak Wind Farm (VIC)	2012	Potential	115.5	32.0%
Robertstown (SA)	2013	Potential	96	31.7%

15.5 Fuel Costs

This section presents fuel price assumptions used in the study. The fuel cost is from the fuel and generation costs report[17] prepared by ACIL Tasman for NEMMCO.

The scope and time provided for the study did not allow any consideration be given to the gas pipeline system and the impact this would have to the timing and location of new gas generators. Locational fuel issues were managed through the use of ACIL's gas costs that are provided for different locations. We note that these gas prices assumed that the gas prices would approach export parity prices.

15.5.1 Coal Prices

15.5.1.1 Coal Prices for Existing Plant by Region

Coal prices for existing plant are given by region in the tables below and price is in real 2009-10 $/GJ. Table 15-11 gives prices for New South Wales power Stations, Table 15-12 for Victorian and South Australian stations and Table 15-13 gives Queensland coal prices for existing stations (note that Swanbank E is scheduled to retire in 2012/13).

Table 15-11 Projection of Marginal Coal Prices into NSW Power Stations ($/GJ)

	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2009-10	1.29	1.72	1.75	1.80	1.01
2010-11	1.24	1.71	1.73	1.78	1.01
2011-12	1.22	1.71	1.72	1.77	1.01
2012-13	1.31	1.70	1.71	1.75	1.00
2013-14	1.31	1.68	1.69	1.67	1.00
2014-15	1.30	1.73	1.68	1.39	1.00
2015-16	1.29	1.71	1.67	1.37	1.00
2016-17	1.29	1.70	1.65	1.35	0.99
2017-18	1.28	1.71	1.64	1.33	0.99
2018-19	1.27	1.69	1.63	1.31	0.99
2019-20	1.27	1.67	1.61	1.29	0.99
2020-21	1.26	1.65	1.65	1.27	0.98

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

[17] ACIL TASMAN: Fuel resource, new entry and generation costs in the NEM", 13 February 2009

Table 15-12 Projection of Marginal Cost of Brown Coal into Victorian and South Australian Power Stations ($/GJ)

	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2009-10	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2010-11	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2011-12	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2012-13	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2013-14	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2014-15	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2015-16	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2016-17	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2017-18	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2018-19	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2019-20	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52
2020-21	0.10	0.08	0.37	0.08	0.39	0.59	1.52	1.52

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-13 Projection of Marginal Coal Prices into Queensland Power Stations ($/GJ)

	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2009-10	1.57	1.40	1.01	2.20	1.32	2.10	0.85	0.75
2010-11	1.56	1.39	1.00	2.19	1.32	2.10	0.85	0.75
2011-12	1.56	1.39	1.00	2.19	1.31	2.09	0.85	0.75
2012-13	1.55	1.39	1.00	2.18	1.31	2.09	0.84	0.75
2013-14	1.55	1.38	1.00	2.17	1.31	2.08	0.84	0.74
2014-15	1.55	1.38	0.99	2.17	1.30	2.08	0.84	0.74
2015-16	1.54	1.38	0.99	2.16	1.30	2.07	0.84	0.74
2016-17	1.54	1.37	0.99	2.16	1.30	2.06	0.84	0.74
2017-18	1.53	1.37	0.99	2.15	1.29	2.06	0.83	0.74
2018-19	1.53	1.37	0.98	2.15	1.29	2.05	0.83	0.73
2019-20	1.53	1.36	0.98	2.14	1.29	2.05	0.83	0.73
2020-21	1.52	1.36	0.98	2.14	1.28	2.04	0.83	0.73

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

15.5.1.2 Coal prices for new entrant plant

Coal prices for new entrant plant are shown in Table 15-14.

Table 15-14 Projection of new entrant coal prices by zone ($/GJ)

	Black Coal NQ	Black Coal CQ	Black Coal SWQ	Black Coal NNS	Black Coal NCEN	Black Coal SWNSW	Brown Coal LV
2009-10	1.84	1.41	1.47	1.54	1.3	1.06	0.57
2010-11	1.84	1.39	1.46	1.52	1.28	1.06	0.57
2011-12	1.84	1.37	1.45	1.5	1.26	1.06	0.57
2012-13	1.84	1.35	1.44	1.48	1.25	1.06	0.57
2013-14	1.84	1.33	1.43	1.46	1.23	1.06	0.56
2014-15	1.83	1.3	1.41	1.44	1.22	1.06	0.56
2015-16	1.83	1.28	1.4	1.42	1.2	1.06	0.56
2016-17	1.83	1.26	1.39	1.4	1.19	1.06	0.56
2017-18	1.83	1.24	1.38	1.39	1.17	1.06	0.56
2018-19	1.83	1.22	1.37	1.37	1.16	1.06	0.56
2019-20	1.83	1.2	1.37	1.35	1.14	1.06	0.56
2020-21	1.83	1.19	1.36	1.33	1.13	1.06	0.55

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

15.5.2 Gas Prices

15.5.2.1 Gas prices for existing gas fired power plant

Gas costs for existing power stations by regions are shown in Table 15-15 to Table 15-19,Table 15-20 shows the gas cost for two proposed power stations in an advanced stage. Prices are given in real 2009-10 $/GJ.

Table 15-15 Gas Price for NSW Existing Gas Power Stations ($/GJ)

	Colongra	Smithfield	Tallawarra	Uranquinty
2009-10	7.42	4.19	3.80	6.22
2010-11	7.09	4.18	3.80	6.28
2011-12	7.05	4.18	3.79	6.32
2012-13	7.02	4.17	3.79	6.29
2013-14	7.03	4.16	3.78	6.30
2014-15	7.06	4.16	3.78	6.32
2015-16	7.07	5.61	3.77	6.33
2016-17	7.08	5.64	3.77	6.34
2017-18	7.16	5.74	3.76	6.40
2018-19	7.26	5.94	3.76	6.49
2019-20	7.38	6.02	3.75	6.59
2020-21	7.37	6.02	3.75	6.58

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-16 Gas Price for QLD Existing Gas Power Stations ($/GJ)

	Barcaldine	Braemar	Braemar 2	Condamine	Darling Downs	Oakey	Swanbank E	Roma	Townsville	Yarwun
2009-10	6.67	2.67	2.89	0.95	3.42	4.24	3.53	4.70	4.05	3.55
2010-11	6.64	2.67	2.89	0.95	3.42	4.23	3.43	4.69	4.04	3.57
2011-12	6.62	2.67	2.89	0.95	3.42	4.22	3.44	4.20	4.03	3.55
2012-13	6.60	2.67	2.89	0.95	3.42	4.21	3.44	4.22	4.02	3.53
2013-14	6.58	2.67	2.89	0.95	3.42	4.20	3.44	4.38	4.02	3.52
2014-15	8.27	2.67	2.89	0.95	3.42	6.02	3.45	4.39	4.01	3.50
2015-16	8.28	2.67	2.89	0.95	3.42	6.05	4.21	4.41	4.00	3.52
2016-17	8.30	3.33	2.89	0.95	3.42	6.08	4.23	4.44	3.99	3.50
2017-18	8.67	4.15	2.89	0.95	3.42	6.46	4.24	4.74	3.98	3.49
2018-19	8.70	4.17	2.89	0.95	3.42	6.51	4.26	4.78	3.97	3.47
2019-20	8.75	4.21	2.89	0.95	3.42	6.57	4.27	4.83	5.59	3.45
2020-21	8.74	4.21	2.89	0.95	3.42	6.57	4.54	4.83	5.60	3.47

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-17 Gas Price for VIC Existing Gas Power Stations ($/GJ)

	Bairnsdale	Jeeralang	Laverton North	Mortlake OCGT	Newport	Somerton	Valley Power
2009-10	4.29	3.88	4.11	5.00	4.08	4.12	3.87
2010-11	4.29	3.88	4.11	5.00	4.08	4.12	3.87
2011-12	4.29	3.88	4.11	5.02	4.08	4.11	3.87
2012-13	4.29	4.47	4.69	5.05	4.66	4.70	4.46
2013-14	4.89	4.49	4.71	5.34	4.69	4.72	4.48
2014-15	4.91	4.51	4.73	5.36	4.71	4.74	4.50
2015-16	5.22	4.82	5.04	5.67	5.01	5.05	4.81
2016-17	5.25	4.85	5.07	5.70	5.04	5.08	4.84
2017-18	5.35	4.95	5.17	5.80	5.14	5.18	4.94
2018-19	5.55	5.16	5.38	6.01	5.35	5.38	5.15
2019-20	5.64	5.24	5.46	6.10	5.44	5.47	5.24
2020-21	5.63	5.24	5.46	6.10	5.44	5.47	5.24

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-18 Gas Price for SA Existing Gas Power Stations ($/GJ)

	Torrens Island	Pelican Point	Ladbroke Grove	Osborne	Quarantine	Mintaro	Dry Creek	Hallett
2009-10	4.04	3.98	5.05	4.14	5.98	6.61	4.72	6.61
2010-11	4.03	3.97	5.04	4.13	5.97	6.61	4.71	6.61
2011-12	4.02	3.96	5.06	4.12	5.99	6.63	4.70	6.63
2012-13	4.02	3.95	5.09	4.11	6.02	6.67	4.68	6.67
2013-14	4.01	5.75	5.37	4.10	6.33	7.02	7.19	7.02
2014-15	4.00	5.77	5.39	5.77	6.35	7.05	7.21	7.05
2015-16	3.99	6.07	5.70	6.07	6.68	7.43	7.59	7.43
2016-17	3.98	6.09	5.73	6.09	6.70	7.46	7.62	7.46
2017-18	6.19	6.19	5.83	6.19	6.81	7.59	7.74	7.59
2018-19	6.39	6.39	6.03	6.39	7.03	7.85	7.99	7.85
2019-20	6.47	6.47	6.12	6.47	7.12	7.95	8.09	7.95
2020-21	6.47	6.47	6.11	6.47	7.12	7.95	8.09	7.95

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-19 Gas Price for TAS Existing Gas Power Stations ($/GJ)

	Bell Bay	Bell Bay Three	Tamar Valley
2009-10	5.52	5.52	5.52
2010-11	5.52	5.52	5.52
2011-12	5.54	5.54	5.54
2012-13	5.56	5.56	5.56
2013-14	5.58	5.58	5.58
2014-15	5.61	5.61	5.61
2015-16	5.91	5.91	5.91
2016-17	5.94	5.94	5.94
2017-18	6.05	6.05	6.05
2018-19	6.25	6.25	6.25
2019-20	6.34	6.34	6.34
2020-21	6.34	6.34	6.34

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

Table 15-20 Gas Price for Power Stations Proposed (Advanced Stage) ($/GJ)

	Mortlake 2	Spring Gully
2009-10	4.58	0.80
2010-11	4.58	0.80
2011-12	4.60	0.80
2012-13	4.63	0.80
2013-14	4.92	0.80
2014-15	4.94	0.80
2015-16	5.25	0.80
2016-17	5.28	0.80
2017-18	5.38	0.80
2018-19	5.59	0.80
2019-20	5.68	0.80
2020-21	5.68	0.80

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

15.5.2.2 Gas prices for new entry gas fired power plant

The delivered gas cost for new entry CCGT power stations in the 16 NEM zones are shown in Table 15-21. A graph of gas costs for new generators for a representative selection of locations is shown below.

Figure 15-1 Delivered Gas Price for New Entry CCGTs ($/GJ)

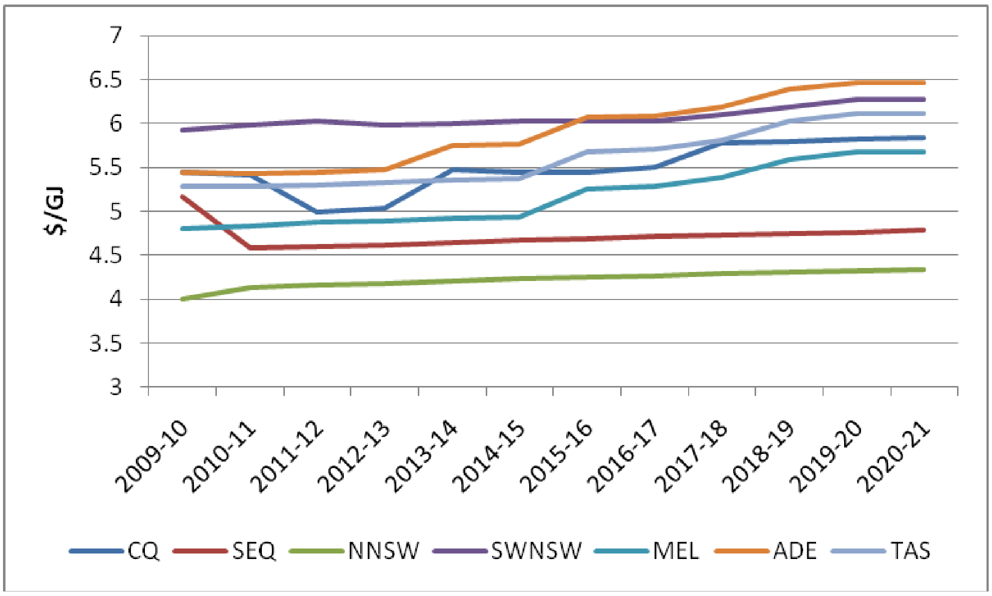


Table 15-21 Delivered Gas Price for New Entry CCGTs ($/GJ)

	NQ	CQ	SEQ	SWQ	NNSW	NCEN	SW NSW	CAN	NVIC	LV	MEL	CVIC	NSA	ADE	SESA	TAS
2009-10	5.37	5.44	5.17	4.70	4.00	5.81	5.92	5.46	5.32	4.46	4.81	4.58	5.65	5.44	5.05	5.28
2010-11	5.34	5.41	4.58	4.69	4.14	5.54	5.98	5.31	5.35	4.47	4.83	4.58	5.64	5.43	5.04	5.28
2011-12	5.04	5.00	4.60	4.20	4.16	5.50	6.02	5.23	5.41	4.50	4.87	4.60	5.66	5.44	5.06	5.30
2012-13	5.49	5.04	4.62	4.22	4.18	5.48	5.99	5.25	5.43	4.52	4.89	4.63	5.68	5.47	5.09	5.33
2013-14	5.50	5.47	4.65	4.38	4.21	5.49	6.00	5.27	5.45	4.54	4.92	4.92	5.96	5.75	5.37	5.35
2014-15	5.52	5.45	4.67	4.39	4.23	5.51	6.02	5.29	5.48	4.56	4.94	4.94	5.98	5.77	5.39	5.37
2015-16	5.54	5.45	4.69	4.41	4.25	5.52	6.03	5.30	5.78	4.87	5.25	5.25	6.28	6.07	5.70	5.68
2016-17	5.55	5.50	4.71	4.44	4.27	5.53	6.03	5.31	5.81	4.90	5.28	5.28	6.30	6.09	5.73	5.71
2017-18	5.56	5.78	4.73	4.74	4.29	5.60	6.10	5.38	5.92	5.01	5.38	5.38	6.40	6.19	5.83	5.81
2018-19	5.57	5.79	4.75	4.78	4.31	5.68	6.18	5.47	6.12	5.21	5.59	5.59	6.60	6.39	6.03	6.02
2019-20	5.59	5.82	4.76	4.83	4.32	5.78	6.27	5.56	6.21	5.30	5.68	5.68	6.68	6.47	6.11	6.11
2020-21	5.60	5.84	4.79	4.83	4.34	5.78	6.27	5.56	6.21	5.30	5.68	5.68	6.67	6.47	6.11	6.11

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

The delivered gas cost for new entry OCGT power stations in the 16 NEM zones are shown in Table 15-22.

Table 15-22 Delivered Gas Price for New Entry OCGTs ($/GJ)

	NQ	CQ	SEQ	SWQ	NNSW	NCEN	SW NSW	CAN	NVIC	LV	MEL	CVIC	NSA	ADE	SESA	TAS
2009-10	6.72	6.80	6.46	5.87	4.99	7.27	7.40	6.82	6.65	5.58	6.01	5.72	7.07	6.79	6.31	6.60
2010-11	6.68	6.77	5.72	5.87	5.17	6.93	7.48	6.64	6.69	5.58	6.03	5.72	7.05	6.78	6.30	6.60
2011-12	6.29	6.26	5.75	5.25	5.20	6.88	7.52	6.54	6.76	5.62	6.09	5.75	7.07	6.80	6.32	6.63
2012-13	6.86	6.30	5.78	5.28	5.23	6.85	7.48	6.57	6.79	5.65	6.12	5.79	7.11	6.84	6.36	6.66
2013-14	6.88	6.83	5.81	5.47	5.26	6.87	7.50	6.59	6.82	5.68	6.15	6.15	7.45	7.19	6.72	6.69
2014-15	6.90	6.82	5.84	5.49	5.29	6.89	7.52	6.61	6.84	5.71	6.18	6.18	7.47	7.21	6.74	6.71
2015-16	6.92	6.82	5.87	5.51	5.32	6.91	7.53	6.63	7.23	6.09	6.56	6.56	7.85	7.59	7.12	7.10
2016-17	6.93	6.87	5.89	5.55	5.34	6.92	7.54	6.64	7.27	6.13	6.60	6.60	7.88	7.62	7.16	7.14
2017-18	6.95	7.22	5.91	5.93	5.36	7.00	7.62	6.72	7.40	6.26	6.73	6.73	8.00	7.74	7.28	7.27
2018-19	6.96	7.24	5.93	5.97	5.38	7.10	7.72	6.83	7.65	6.52	6.99	6.99	8.25	7.99	7.54	7.52
2019-20	6.99	7.28	5.95	6.04	5.40	7.22	7.84	6.95	7.76	6.63	7.10	7.10	8.35	8.09	7.64	7.63
2020-21	7.00	7.30	5.98	6.04	5.43	7.22	7.83	6.95	7.76	6.63	7.10	7.10	8.34	8.08	7.64	7.63

Source: ACIL TASMAN, Fuel resource, new entry and generation costs in the NEM, 13 Feb 2009

16 Appendix 4 Detailed Modelling Results

16.1 New Entry by Region

16.1.1 Scenario 1

Table 16-1 Scenario 1 New Entry (MW) NSW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	33	196	104	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	30	301	162	204
CCGT	0	0	0	0	400	0	400	0	400	800	0	800
Other Renewable	0	0	0	20	0	0	0	10	10	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	90	110	0

Table 16-2 Scenario 1 New Entry (MW) QLD

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	155
CCGT	0	0	0	400	0	800	400	400	400	800	400	0
Other Renewable	0	0	128	55	20	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	69

Table 16-3 Scenario 1 New Entry (MW) SA

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	24	0	0	0	0	0	0	0	0
Wind	0	0	152	63	0	9	192	34	323	312	24	4
CCGT	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	50	39	6	0	0	0	0	0	0
Geothermal	0	0	0	0	50	50	0	220	90	0	57	98

Table 16-4 Scenario 1 New Entry (MW) TAS

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	53	66	0	94	179	121	166	59	0	0
CCGT	0	0	0	0	0	200	0	0	0	0	0	0
Other Renewable	0	0	24	34	0	4	10	10	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

Table 16-5 Scenario 1 New Entry (MW) VIC

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	49	406	326	644	474
CCGT	0	0	0	0	0	400	3200	0	0	400	0	0
Other Renewable	0	18	39	0	0	0	20	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

16.1.2 Scenario 2

Table 16-6 Scenario 2 New Entry (MW) NSW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	33	196	104	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	30	55	412	220
CCGT	0	0	0	0	400	0	800	0	0	0	400	800
Other Renewable	0	0	0	20	0	0	0	0	10	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	104	96

Table 16-7 Scenario 2 New Entry (MW) QLD

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0
CCGT	0	0	0	400	0	400	400	400	800	400	800	0
Other Renewable	0	0	128	55	20	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

Table 16-8 Scenario 2 New Entry (MW) SA

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	24	0	0	0	0	0	0	0	0
Wind	0	0	199	63	0	9	191	67	434	248	40	0
CCGT	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	50	39	6	0	0	0	0	0	0
Geothermal	0	0	0	0	50	50	0	220	90	90	63	70

Table 16-9 Scenario 2 New Entry (MW) TAS

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	8	66	0	94	180	134	256	0	0	0
CCGT	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	24	34	0	4	10	20	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

Table 16-10 Scenario 2 New Entry (MW) VIC

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	203	695	372	611
CCGT	0	0	0	0	0	400	3200	0	0	0	0	0
Other Renewable	0	18	39	0	0	0	20	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

16.1.3 Scenario 3

Table 16-11 Scenario 3 New Entry (MW) NSW

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	33	196	104	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	30	302	160	209
CCGT	0	0	0	0	400	0	400	0	400	400	400	800
Other Renewable	0	0	0	20	0	0	0	10	10	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	90	110	0

Table 16-12 Scenario 3 New Entry (MW) QLD

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	47	169
CCGT	0	0	0	400	0	400	400	400	400	400	800	0
Other Renewable	0	0	128	55	20	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	71

Table 16-13 Scenario 3 New Entry (MW) SA

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	50	24	0	0	0	0	0	0	0	0
Wind	0	0	152	63	0	9	191	34	308	327	29	2
CCGT	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	50	39	6	0	0	0	0	0	0
Geothermal	0	0	0	0	50	50	0	220	90	0	57	96

Table 16-14 Scenario 3 New Entry (MW) TAS

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	53	66	0	94	180	120	181	44	0	0
CCGT	0	0	0	0	0	200	0	0	0	0	0	0
Other Renewable	0	0	24	34	0	4	10	10	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

Table 16-15 Scenario 3 New Entry (MW) VIC

Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	50	405	326	596	459
CCGT	0	0	0	0	0	400	3200	0	0	0	0	0
Other Renewable	0	18	39	0	0	0	20	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0

16.2 Economic Costs by Region

16.2.1 Scenario 1

Table 16-16 Scenario 1: Dispatch Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,088	2,989	3,131	3,337	3,463	4,037	4,716	4,874	5,016	5,129	4,841
Qld	889	1,505	2,183	2,367	2,550	2,754	3,301	3,893	4,173	4,400	4,578	4,332
SA	446	489	582	615	672	712	746	769	771	793	799	802
Tas	34	18	41	60	67	98	127	137	143	132	123	118
Vic	263	998	1,837	1,928	2,030	2,180	2,696	3,191	3,228	3,295	3,334	3,037
Total	**2,946**	**5,097**	**7,634**	**8,101**	**8,656**	**9,206**	**10,906**	**12,706**	**13,189**	**13,636**	**13,963**	**13,129**

Table 16-17 Scenario 1: Capital Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	3	10	27	77	114	146	181	258	435	547	621
Qld	-	6	14	50	82	144	235	297	357	447	566	647
SA	-	13	34	65	99	129	205	313	389	424	466	518
Tas	-	6	20	31	38	78	117	136	163	163	162	161
Vic	1	5	8	8	8	42	327	599	649	740	842	868
Total	**1**	**35**	**87**	**181**	**304**	**508**	**1,031**	**1,526**	**1,816**	**2,210**	**2,584**	**2,815**

Table 16-18 Scenario 1: Transmission Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	-	-	-
Qld	-	-	-	-	-	-	-	-	-	-	-	-
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	-	-	-
Vic	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 16-19 Scenario 1: Interconnector Upgrade Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	-	-	-
Qld	-	-	-	-	-	-	-	-	-	-	-	-
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	-	-	-
Vic	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 16-20 Scenario 1: USE Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	1	-	4	-	-	-	6	4	4
Qld	1	-	-	13	-	10	-	-	-	-	-	1
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	1	3	13	9
Vic	-	-	-	2	8	1	12	11	10	17	3	10
Total	**1**	**-**	**-**	**16**	**8**	**14**	**12**	**11**	**11**	**25**	**19**	**23**

Table 16-21 Scenario 1: Total Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,091	3,000	3,158	3,414	3,581	4,183	4,896	5,132	5,456	5,680	5,466
Qld	890	1,511	2,198	2,430	2,632	2,907	3,536	4,190	4,530	4,848	5,145	4,980
SA	446	502	617	680	771	841	951	1,082	1,161	1,217	1,266	1,320
Tas	34	24	62	91	105	176	244	274	306	299	298	287
Vic	265	1,004	1,845	1,938	2,046	2,223	3,035	3,802	3,887	4,051	4,179	3,915
Total	**2,949**	**5,132**	**7,721**	**8,297**	**8,967**	**9,728**	**11,950**	**14,243**	**15,016**	**15,871**	**16,566**	**15,968**

16.2.2 Scenario 2

Table 16-22 Scenario 2: Dispatch Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,100	3,013	3,155	3,360	3,498	4,120	4,760	4,857	4,991	5,117	4,788
Qld	889	1,504	2,182	2,365	2,551	2,731	3,260	3,880	4,204	4,464	4,687	4,490
SA	446	491	589	622	681	723	757	780	799	829	840	821
Tas	34	19	45	63	70	72	71	80	91	90	83	81
Vic	263	979	1,798	1,888	1,987	2,161	2,688	3,182	3,245	3,326	3,344	3,000
Total	**2,946**	**5,093**	**7,627**	**8,093**	**8,649**	**9,186**	**10,897**	**12,682**	**13,197**	**13,701**	**14,071**	**13,180**

Table 16-23 Scenario 2: Capital Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	3	10	27	77	114	176	240	246	305	430	558
Qld	-	6	14	50	82	112	174	235	326	417	507	578
SA	-	17	40	72	105	135	214	329	436	493	530	592
Tas	-	3	14	24	31	56	82	109	139	135	134	132
Vic	1	5	8	8	8	42	323	580	637	706	771	803
Total	**1**	**34**	**87**	**180**	**303**	**461**	**969**	**1,494**	**1,784**	**2,055**	**2,371**	**2,664**

Table 16-24 Scenario 2: Transmission Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	-	-	-
Qld	-	-	-	-	-	-	-	-	-	-	-	-
SA	-	-	8	8	8	10	13	15	20	20	20	20
Tas	-	-	3	5	5	8	8	8	10	10	10	10
Vic	-	-	8	8	8	15	20	20	25	25	28	28
Total	**-**	**-**	**18**	**20**	**20**	**33**	**40**	**43**	**55**	**55**	**58**	**58**

Table 16-25 Scenario 2: interconnector Upgrade Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	5	9	9
Qld	-	-	-	-	-	-	-	-	-	5	9	9
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	0	0	0
Vic	-	-	-	-	-	-	-	-	-	0	0	0
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**9**	**18**	**18**

Table 16-26 Scenario 2: USE Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	6	24	32	18	42
Qld	1	-	-	15	-	4	1	-	21	21	-	3
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	5	9	1
Vic	-	-	-	-	2	-	-	-	-	1	-	-
Total	**1**	**-**	**-**	**15**	**2**	**4**	**1**	**6**	**45**	**59**	**26**	**46**

Table 16-27 Scenario 2: Total Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,104	3,023	3,182	3,437	3,613	4,297	5,007	5,127	5,332	5,573	5,397
Qld	890	1,510	2,196	2,430	2,632	2,847	3,435	4,116	4,551	4,906	5,203	5,080
SA	446	507	637	702	794	869	983	1,124	1,255	1,343	1,391	1,433
Tas	34	22	62	92	107	136	161	197	241	239	236	225
Vic	265	985	1,814	1,904	2,005	2,219	3,032	3,782	3,908	4,058	4,142	3,831
Total	**2,949**	**5,127**	**7,732**	**8,309**	**8,975**	**9,684**	**11,908**	**14,225**	**15,081**	**15,879**	**16,545**	**15,966**

16.2.3 Scenario 3

Table 16-28 Scenario 3: Dispatch Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,088	2,989	3,129	3,336	3,474	4,078	4,762	4,920	5,054	5,192	4,878
Qld	889	1,503	2,180	2,362	2,547	2,730	3,272	3,875	4,154	4,393	4,573	4,340
SA	446	489	586	620	678	720	761	784	788	815	832	828
Tas	34	18	41	59	66	100	132	142	148	144	140	134
Vic	263	999	1,837	1,928	2,027	2,181	2,690	3,162	3,191	3,260	3,290	2,969
Total	**2,946**	**5,097**	**7,633**	**8,098**	**8,653**	**9,205**	**10,932**	**12,724**	**13,201**	**13,665**	**14,027**	**13,150**

Table 16-29 Scenario 3: Capital Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	3	10	27	77	114	146	181	258	404	517	621
Qld	-	6	14	50	82	112	174	235	295	358	482	591
SA	-	13	34	65	99	129	205	312	388	424	466	518
Tas	-	6	20	31	38	78	117	137	164	163	162	161
Vic	1	5	8	8	8	42	327	599	649	706	774	803
Total	**1**	**35**	**87**	**181**	**304**	**477**	**970**	**1,465**	**1,755**	**2,057**	**2,401**	**2,694**

Table 16-30 Scenario 3: Transmission Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	-	-	-
Qld	-	-	-	-	-	-	-	-	-	-	-	-
SA	-	-	8	8	8	10	13	13	15	18	20	23
Tas	-	-	3	5	5	5	8	8	10	10	10	10
Vic	-	-	5	8	10	13	15	15	15	15	20	20
Total	**-**	**-**	**15**	**20**	**23**	**28**	**35**	**35**	**40**	**43**	**50**	**53**

Table 16-31 Scenario 3: interconnector Upgrade Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	-	-	-	-	-	-	5	9	9
Qld	-	-	-	-	-	-	-	-	-	5	9	9
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	0	0	0
Vic	-	-	-	-	-	-	-	-	-	0	0	0
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**9**	**18**	**18**

Table 16-32 Scenario 3: USE Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	-	-	-	1	-	3	-	-	-	9	10	9
Qld	1	-	-	16	-	4	1	3	21	37	1	2
SA	-	-	-	-	-	-	-	-	-	-	-	-
Tas	-	-	-	-	-	-	-	-	-	1	8	0
Vic	-	-	-	2	1	-	-	-	1	5	8	19
Total	**1**	**-**	**-**	**18**	**1**	**7**	**1**	**3**	**22**	**52**	**27**	**31**

Table 16-33 Scenario 3: Total Costs ($m)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NSW	1,314	2,091	2,999	3,157	3,413	3,592	4,224	4,943	5,178	5,472	5,728	5,517
Qld	890	1,509	2,194	2,428	2,629	2,846	3,447	4,113	4,470	4,793	5,065	4,942
SA	446	503	627	693	784	859	978	1,109	1,191	1,257	1,318	1,369
Tas	34	24	64	95	109	184	257	287	322	318	321	305
Vic	265	1,004	1,851	1,945	2,045	2,235	3,032	3,776	3,856	3,986	4,092	3,812
Total	**2,949**	**5,131**	**7,735**	**8,317**	**8,981**	**9,717**	**11,938**	**14,227**	**15,019**	**15,826**	**16,524**	**15,945**