South Australia – Victoria (Heywood) Interconnector Upgrade

RIT-T: Project Assessment Draft Report

September 2012

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electricity transmission

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Executive summary

This Project Assessment Draft Report (PADR) has been prepared by ElectraNet and the Australian Energy Market Operator (AEMO) for consultation in accordance with the requirements of the Regulatory Investment Test – Transmission (RIT-T) process set out in the National Electricity Rules (NER). The PADR is the second public consultation stage of the RIT-T process.

The PADR recommends a preferred option for investment to increase the transfer capability of the South Australia to Victorian (Heywood) Interconnector to deliver a net market benefit through significant reductions in generation dispatch costs over the longer term.

The preferred option to install a third transformer and 500 kV bus tie at Heywood in Victoria, series compensation on 275 kV transmission lines in South Australia, and 132 kV network reconfiguration works in South Australia is expected to increase interconnector capability by about 40% in both directions. This would enable increased wind energy exports from South Australia and also increase imports of lower cost generation into South Australia, particularly at times of peak demand.

The estimated commissioning date for this option is July 2016. The total capital cost of the option is estimated at $107.7m ($2011/12, equating to $79.8m in present value terms) with net market benefits of more than $190 million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

Identified need

The Heywood Interconnector is located between the South East (South Australia) and Heywood (Victoria) substations. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, with the addition of significant amounts of wind generation in South Australia, the interconnector is also being used to export power from South Australia.

The 'identified need' for the proposed investment is an increase in the sum of producer and consumer surplus, i.e. an increase in net market benefit.

Two main limitations currently affecting the Heywood interconnector have been identified. The first involves thermal capabilities and voltage stability limitations in south-east South Australia. The second is the transformer capacity at Heywood. Alleviating both these limitations would increase the import and export capability of the interconnection. ElectraNet and AEMO consider that increasing the capability of the interconnection will achieve an overall increase in net market benefit in the National Electricity Market (NEM). This is demonstrated in the analysis presented in this PADR.

Credible options included in the assessment

The following nine options have been included as potential credible options in the RIT-T analysis:

- Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus a 100 MVar capacitor at South East substation and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). Estimated commissioning date of July 2016.
- Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). Estimated commissioning date of July 2016.
- Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a.
- Option 2b – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1b.
- Option 3 - Construct a new Krongart-Heywood 500 kV interconnector and associated 275 kV works between Krongart and Tungkillo (South Australia). Staged works, with estimated commissioning dates of July 2025 and July 2030.
- Option 4 – Option 1a minus 3rd 500/275 kV transformer at Heywood.
- Option 5 – Five-year, 200 MW demand management (DM) program beginning in 2013 plus Option 1b, deferred by two years (so estimated commissioning date of July 2018).
- Option 6a – Control scheme applying to specific wind generation in South Australia and the South East substation, and a 500 kV bus tie at Heywood. Estimated commissioning date of July 2015.
- Option 6b – Control scheme applying to specific wind generation in South Australia and the South East substation (estimated commissioning date July 2015) plus Option 1b, minus the 3rd 500/275 kV transformer at Heywood (estimated commissioning date of July 2016).

Many of the options above involve different combinations of particular investment components. Table 1 provides an overview of the investment components included in each option. The preferred option, 1b, has been highlighted.

Table 1: Overview of the option components

Option	Service Date	3rd Heywood Tx	3rd South East Tx	Heywood bus tie	Control Schemes	DM	132kV works	Series Comp	100 MVar Capacitor
Option 1a	July 2016	✓		✓			✓		✓
Option 1b	July 2016	✓		✓			✓	✓	
Option 2a	July 2016	✓	✓	✓			✓		✓
Option 2b	July 2016	✓	✓	✓			✓	✓	
Option 3	See description in text								
Option 4	July 2016			✓			✓		✓
Option 5	July 2018[a]	✓		✓		✓	✓	✓	
Option 6a	July 2015			✓	✓				
Option 6b	July 2016[a]			✓	✓		✓	✓	

[a] The dates shown are for the network component, not the DM and control scheme components.

Apart from Option 3, in all cases these options relate to works within existing substation boundaries and do not involve new line works.

Options 5, 6a and 6b all include a non-network component, reflecting non-network options identified in submissions to the PSCR. For Option 5 and Option 6b the non-network component has been considered together with a network component, as preliminary screening identified that these combinations would have a greater net market benefit than the non-network component alone.

The notional (maximum theoretical) interconnector capabilities provided by these options are shown in Table 2 below, with the preferred option highlighted. The interconnector transfer capability achieved at any point in time will be subject to network and local conditions such as the level of demand, and generation dispatch outcomes. The limits shown for Options 6a and 6b would be under high wind output in south east South Australia. Without additional wind farms in the south east of South Australia, the notional limit for Option 6b would be 570 MW.

Table 2: Notional interconnector limits for options (MW)

Option	Description	Notional limit (MW)		Change from current (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	3rd Heywood transformer + 100 MVar capacitor + 132 kV works	550	550	90	90
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	650	650	190	190
Option 2a	Option 1a + 3rd South East transformer	550	550	90	90
Option 2b	Option 1b + 3rd South East transformer	650	650	190	190
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVar capacitor	460	460	-	-
Option 5	200 MW DM + Option 1b	650	650	190	190
Option 6a	Control schemes + 500 kV bus tie	550	460	90	-
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	570 / 690	460	110-230	-

Scenarios analysed

ElectraNet and AEMO have adopted the following four reasonable future scenarios in undertaking the RIT-T analysis presented in this PADR (the weight applied to each scenario is shown in brackets):

- **Scenario 1**: Central scenario (29%).
- **Scenario 2**: Low scenario (13%).
- **Scenario 3**: High scenario (17%).
- **Scenario 4**: Revised central scenario (41%).

These scenarios reflect a wide range of variations in assumptions in relation to those variables that may materially affect the relative assessment of options under the RIT-T.

ElectraNet and AEMO note that there have been a number of recent major announcements which could be expected to have a material impact on the outcome of this RIT-T assessment. In particular these include BHP Billiton's announcement of the deferral of the expansion of its Olympic Dam mine and the Federal Government's announcements of the removal of the floor price under the carbon trading scheme and the cessation of negotiations with coal-fired generators under the Contract for Closure Program. The impact of these announcements is captured under the assumptions adopted for the reasonable scenarios for this RIT-T analysis.

Sensitivities conducted in relation to the weightings applied to each of the scenarios indicate that the RIT-T outcome is robust to a wide-range of alternative weightings.

Market benefits

The assessment conducted under this RIT-T has involved detailed market modelling using a market dispatch model (Prophet), combined with the development of alternative generation expansion plans (utilising the PLEXOS software).

The results of the net present value (NPV) assessment highlight that the key categories of market benefit for this RIT-T are changes in fuel consumption and changes in generation investment costs. Changes in network losses and involuntary load shedding (unserved energy) form only a very minor part of the market benefit calculated for any of the nine options.

This result holds across all four scenarios modelled. The pattern of market benefits vary over time, across scenarios, and between options (particularly between Option 3 (new Krongart 500 kV interconnector) and the other options). However in all cases market benefits are driven by enabling an increase in output from lower operating cost and low emission generation sources, displacing output from higher operating cost and/or higher emission generation sources.

The precise nature of the change in generation dispatch varies with the reasonable scenario considered. Under scenarios 1, 2 and 3, the majority of the options result in an *increase* in investment in low operating cost and low emission generation (i.e. an overall market cost), the cost of which is off-set by the resulting reductions in dispatch costs. In scenario 4 this additional generation investment does not occur to the same extent due to lower demand and fewer coal-fired plant retirements. [1]

Table 3 summarises the net market benefit in NPV terms for each credible option. The net market benefit for each option (the present value (PV) market benefits minus the PV cost) reflects the weighted net market benefit across the four reasonable scenarios considered. The table also shows the corresponding ranking of each option under the RIT-T, with the options ranked from 1 to 9 in order of descending net market benefit. Option 1b, the preferred option, has been highlighted.

[1] AEMO and ElectraNet note that an assumption of fewer retirements of coal-fired plant is consistent with the Federal Government's recent announcement that it has ceased negotiations with coal-fired generators on the Contract for Closure Program.

Table 3: Net market benefit for each credible option (PV, $m)

Option	Description	Costs	Market benefit	Net market benefit	Ranking under RIT-T
Option 1a	3rd Heywood transformer + 100 MVar capacitor + 132 kV works	57.8	222.2	164.4	4
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	79.8	270.5	190.8	=1
Option 2a	Option 1a + 3rd South East transformer	70.7	227.5	156.9	6
Option 2b	Option 1b + 3rd South East transformer	92.7	270.4	177.7	3
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	212.2	303.0	90.8	8
Option 4	132 kV works + 100 MVar capacitor	30.6	155.6	124.9	7
Option 5	200 MW DM + Option 1b	147.1	304.1	156.9	5
Option 6a	Control schemes + 500 kV bus tie	17.6	18.5	0.9	9
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	64.1	253.1	189.0	=1

Table 3 shows that all of the credible options considered have a positive net market benefit. As a consequence, all of the options are ranked higher than the 'do nothing' option,[2] and could be expected to deliver an overall net benefit to the market.

The results show that:

- Option 6a (Stand-alone control schemes + bus tie) is a clear outlier in terms of net market benefit, with an overall net market benefit orders of magnitude below that of the other credible options.

[2] The base case is equivalent to 'doing nothing', and represents the system as-is. Market benefits are calculated by comparing the option results with the base case.

- The higher costs of Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works) are not outweighed by substantially higher benefits, compared to the other options; resulting in the overall net market benefit for this option being materially below that of other options.
- The lower costs for Option 1a (which includes a 100 MVar capacitor) do not offset the lower market benefits of this option, compared with Option 1b (which include series compensation); resulting in Option 1a having a lower net market benefit than Option 1b.
- The incremental costs of adding the 3rd transformer at South East substation under Options 2a and 2b are not offset by the additional market benefits.
- There are additional net benefits with including the 3rd Heywood transformer (Options 1a and 1b) compared with only undertaking the 132 kV works in South Australia and installing a 100 MVar capacitor (Option 4).
- The additional market benefit associated with including a DM component (Option 5) is outweighed by the higher cost of that option compared with the network component alone.

It is also clear from Table 3 that Option 1b (3rd Heywood transformer + series compensation + 132 kV works) and Option 6b (Control schemes + Option 1b, minus 3rd Heywood transformer) have the highest net market benefit, but cannot be materially distinguished on the basis of net market benefit alone.

The impact of the control schemes is to expand the export capacity from South Australia at lower cost than under the 3rd Heywood transformer. Option 1b therefore has greater market benefits under those scenarios in which there is substantial investment in renewable generation in South Australia, i.e. the high and low scenarios. In contrast, adding a 3rd transformer at Heywood increases both the import and export capability of the interconnector. Option 1b therefore enables additional exports from South Australia, albeit at a lower level than is facilitated by the control schemes, whilst also enabling increased imports of lower cost generation into South Australia.

The difference in net market benefit between Option 6b and Option 1b is only \$1.8m, or 0.95%. Moreover the relative ranking of these two options is sensitive to relatively small changes in key input assumptions. The net market benefit between Option 6b and Option 1b is therefore essentially the same.

ElectraNet and AEMO note that there are several core investment elements which are common across both of these options, namely:

- Reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- 275 kV series compensation in South Australia.
- The installation of a bus tie at Heywood.

These investment components therefore clearly form part of the preferred option.

The question is therefore whether this ‘core' network component should be coupled with a 3rd transformer at Heywood (Option 1b) or control schemes at Heywood and South East (Option 6b).

ElectraNet and AEMO note that there are a number of risks associated with selecting the control scheme component in preference to adding a 3rd transformer at Heywood:

- There is substantial uncertainty in relation to the commercial feasibility of the control schemes, as issues relating to liabilities and associated indemnities would need to be worked through. It is anticipated that significant further work would be required, with an uncertain outcome, since initial investigation of commercial issues for the PADR indicates that the commercial issues are not straightforward.
- The issue of technical feasibility would need to be subject to further detailed investigation, particularly in relation to issues of wider system security and the overload ratings of the Heywood transformers.
- The RIT-T assessment has included benefits associated with additional wind generation locating at Krongart and participating in the control scheme. However there is currently no application from new wind generators to connect at Krongart, and so this portion of the market benefit remains speculative.
- The costs of the control scheme component are relatively uncertain, including the assumption of zero participation fees for existing and new generators.
- Adding a 3rd transformer at Heywood would have the added benefit of reducing the risks associated with a prolonged outage of one of the existing transformers, compared with the alternative of adopting the control schemes. Although the probability of a transformer outage is low, if a catastrophic failure of one of the Heywood transformers did occur (for example, due to a failure in the transformer tank) then the replacement time would be in the order of two years. During this period, the interconnector limits would become 460 MW (each way) if there was a third Heywood transformer in place (Option 1b). However, if the control schemes were to be adopted instead (Option 6b), the interconnector limits would fall to approximately 250 MW (South Australia to Victoria) and 210 MW (Victoria to South Australia).

In light of the additional risks associated with the control schemes, ElectraNet and AEMO have determined that the 3rd Heywood transformer should be selected in preference to the control schemes, as the additional component of the preferred option. The 3rd Heywood transformer is a lower risk investment that performs equally as well as the control schemes in the assessment of net market benefits.

Preferred option

The preferred option for investment is Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). This option satisfies the RIT-T. The estimated commissioning date for this option is July 2016. The total capital cost of this option is estimated at $107.7m (2011/12$).

Submissions and next steps

ElectraNet and AEMO welcome written submissions on this PADR. Submissions are due on or before 26 October 2012.

Submissions should be emailed to consultation@electranet.com.au and Planning@aemo.com.au. Submissions will be published on the ElectraNet and AEMO websites.

ElectraNet and AEMO also intend to hold a public forum in relation to this PADR in on 27 September 2012.

ElectraNet and AEMO will consider submissions in preparing the Project Assessment Conclusions Report, which represents the final step in the RIT-T process for this investment.

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Appendix E – NPV and Generation Data – See separate spreadsheet.

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1 Introduction

1.1 Overview

This Project Assessment Draft Report (PADR) has been prepared by ElectraNet and the Australian Energy Market Operator (AEMO) in accordance with the requirements of the National Electricity Rules (NER) clause 5.6.6.

The PADR represents the second stage of the formal consultation process set out in the NER in relation to the application of the Regulatory Investment Test – Transmission (RIT-T) for the South Australia–Victoria (Heywood) Interconnector upgrade. The first stage was the release of the Project Specification Consultation Report (PSCR) in October 2011.[3] This formal consultation process follows the earlier South Australian Interconnector Feasibility Study (Joint Feasibility Study) published in February 2011[4] and AEMO's 2010 National Transmission Network Development Plan (NTNDP), which indicated the possibility of net market benefits from increasing the capacity of the existing 275 kV interconnector between South Australia and Victoria.

This PADR:

- Describes the identified need which ElectraNet and AEMO are seeking to address, namely an increase in overall net market benefit.
- Describes the credible options that ElectraNet and AEMO consider may address the identified need.
- Summarises and provides commentary on the submissions received on the earlier PSCR.
- Provides a quantification of costs and classes of material market benefit for each of the credible options, together with an outline of the methodologies adopted by ElectraNet and AEMO in undertaking this quantification.
- Provides the results of the net present value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements.
- Identifies the preferred option for investment by ElectraNet and AEMO.

Appendices to this PADR provide further information in relation to the assumptions adopted for the RIT-T assessment and the results of the assessment.

1.2 Background to the RIT-T

The purpose, principles and procedures of the RIT-T are set out in NER clauses 5.6.5B – 5.6.6. These provisions were put in place following the Australian Energy Market Commission's (AEMC) national transmission planning arrangements review in 2008.[5]

The purpose of the RIT-T is to rank various transmission investment options and identify the option which maximises net economic benefits and, where applicable, meets the relevant jurisdictional or

[3] AEMO - ElectraNet, South Australia – Victoria (Heywood) Interconnnector Upgrade RIT-T: Project Specification Consultation Report, October 2011 http://www.electranet.com.au/network/regulatory-investment-test/rit-t-consultation-reports/sa-vic-interconnec ion-upgrade/.

[4] ElectraNet-AEMO Joint Feasibility Study http://www.aemo.com.au/planning/saifs.html.

[5] AEMC, National transmission planning arrangements, Final report to MCE, 2008.

NER-based reliability standards.[6] The RIT-T replaced the regulatory test for transmission investments and removed the distinction in the regulatory test between reliability driven projects and projects motivated by the delivery of market benefits, acting as a single framework for assessing all transmission investments.

The RIT-T process involves three primary steps, namely:

- Producing a Project Specification Consultation Report (PSCR).
- Producing a Project Assessment Draft Report (PADR).[7]
- Producing a Project Assessment Conclusions Report (PACR).

As part of the PADR and the PACR, the transmission network service provider (TNSP) must present the results of the RIT-T analysis. This analysis is based on quantification of various categories of costs and benefits arising in the National Electricity Market (NEM). Both positive and negative market impacts are included as part of this assessment.

Consistent with the NER, this PADR provides a detailed description of the assumptions underlying the RIT-T assessment (see section 5 and Appendices C and D). Importantly, the RIT-T assessment is an assessment of the *relative* costs and benefits[8] of alternative options, in order to identify the option which maximises net economic benefits.

The materiality of the assumptions underlying the quantification of the costs and benefits is therefore dependent on the extent to which changes in those assumptions are expected to affect the relative ranking of the options under the RIT-T. Variations in assumptions which result in a change in the value of the net market benefit calculated for a particular option, but leave the relative net benefit of that option unchanged relative to alternative options are not material for the RIT-T assessment.

1.3 Submissions

ElectraNet and AEMO welcome written submissions on this PADR.

Submissions are due on or before 26 October 2012.

Submissions should be emailed to consultation@electranet.com.au or Planning@aemo.com.au. Submissions will be published on the ElectraNet and AEMO websites.

[6] AER, Regulatory investment test for transmission, Issues Paper, September 2008, p. 1.

[7] Under certain circumstances a transmission network service provider (TNSP) may claim exemption from preparation of a PADR (see: NER, 5.6.6(y)-(z)).

[8] Note that different categories of market benefit may be positive or nega ive, for each option assessed.

Further details in relation to this project can be obtained from:

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ElectraNet and AEMO also intend to hold a public forum in relation to this PADR on 27 September 2012.

ElectraNet and AEMO will consider submissions in preparing the PACR, which represents the final step in the RIT-T process for this investment.

2 Identified need

2.1 Background

The Heywood Interconnector is located between the South East (South Australia) and Heywood (Victoria) substations. This interconnector was constructed in 1988. It features a 500 kV to 275 kV transformation at Heywood and 275 kV lines from Heywood to South East. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, with the addition of significant amounts of wind generation in South Australia, the interconnector is now also being used to export power from South Australia.

In February 2011, ElectraNet and AEMO published the Joint Feasibility Study. The purpose of the study was to assess the potential economic benefits from increasing the transfer capacity between South Australia and the rest of the National Electricity Market (NEM). An increase in interconnector capacity would provide South Australia with increased access to reliable, lower cost thermal generation from the rest of the NEM, particularly at peak times, and also enable further development of South Australia's renewable generation resources.

The study found that:

- There is potential for augmenting transmission capacity between South Australia and the rest of the NEM.
- An incremental upgrade to the existing interconnector showed the largest net economic benefit.

ElectraNet and AEMO have now extended the analysis conducted in the Joint Feasibility Study by undertaking a formal RIT-T assessment of potential options for augmenting the capacity of the interconnector. The PSCR in relation to this RIT-T application was published in October 2011.

2.2 Summary of the identified need

The 'identified need' for the proposed investment is an increase in the sum of producer and consumer surplus, i.e. an increase in net market benefit. ElectraNet and AEMO believe that reducing existing constraints and augmenting the capability of the Heywood Interconnector capability will achieve this.

Consideration has been given in particular to:

- Increasing the thermal and voltage stability limits in south-east South Australia.[9]
- Increasing the transformer capacity at Heywood.

The Heywood Interconnector has a maximum short-term capacity rating of ±460 MW due to the N-1[10] rating of the two 500/275 kV transformers at the Heywood substation in Victoria.

However the actual power transfer capability is often restricted due to constraints including voltage limits or thermal limits that vary under different operating conditions.

[9] Previous studies by ElectraNet and AEMO which assessed the increase of the South Australian Oscillatory Export limit from 420 MW to 580 MW were also extended to examine the works required to increase this limit to 870 MW. These studies concluded that this increased level of export can be achieved, but will require the retuning of the power system stabilisers on the Para SVCs.

[10] N-1 loading is the loading following the loss of the most critical network element.

AEMO's Constraint Reports for 2011 and 2010[11] show that:

- The power transfer capability from Victoria to South Australia is frequently restricted by voltage stability limits in south-east South Australia, particularly during high demand conditions and when there is high generation in south-east South Australia (bound for 1027 hours in 2011 and 542 hours in 2010).
- The power transfer capability from South Australia to Victoria is frequently restricted by the thermal capability of the South East 275/132 kV transformers in South Australia (bound for 195 hours in 2011 and 204 hours in 2010).

The 275 kV transmission lines between the Heywood and South East substations are rated up to about 45% higher than the presently limiting transformer section of the interconnector flow path. The existing transformer capacity limitation affects the extent to which power can flow across the interconnector. Specifically it affects the amount of generation from other regions in the NEM which can be used to meet peak demand conditions in South Australia. It also restricts the amount of wind generation which can be exported from South Australia at times of high wind output and low South Australian demand. South Australia is recognised as having one of the best wind resources in the NEM, as well as having the potential for the future development of large-scale geothermal generation.

The expansion of the Heywood Interconnector has been previously discussed in:

- AEMO's 2010 NTNDP.[12]
- AEMO–ElectraNet's Joint Interconnector Feasibility Study.
- Annual Planning Reports (APR) in both South Australia[13] and Victoria.[14]
- The South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T PSCR.

Expanding the transfer capacity of the Heywood Interconnector would relieve the current limitations, and would increase both the import and export capability of the interconnection. The PSCR noted that this has the potential to result in an increase in several classes of market benefit, in particular:

- Reduced total dispatch costs (including fuel costs), resulting from:
  - An increase in imports of lower cost thermal generation from Victoria and elsewhere in the NEM into South Australia, during periods of low wind generation output in South Australia, especially during peak load periods.
  - An increase in low fuel cost and low emission exports of wind generation from South Australia at times of high wind generation output, displacing higher cost thermal generation elsewhere in the NEM.
- Reduced generation investment costs, resulting from:
  - The deferral of generation investment to meet peak demand (particularly in South Australia), due to the increased ability to share generation resources across the interconnector.

[11] http://www.aemo.com.au/electricityops/0200-0006.html

[12] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan

[13] http://www.electranet.com.au/network/transmission-planning/annual-planning-report/

[14] http://www.aemo.com.au/planning/VAPR2011/vapr html

3 Credible options included in the RIT-T analysis

The following nine options have been included as potential credible options in the RIT-T analysis:

- Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus a 100 MVar capacitor at South East substation and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a.
- Option 2b – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1b.
- Option 3 - Construct a new Krongart-Heywood 500 kV interconnector and associated 275 kV works between Krongart and Tungkillo (South Australia).
- Option 4 – Option 1a minus 3rd 500/275 kV transformer at Heywood.
- Option 5 – Five-year, 200 MW demand management program beginning in 2013 plus Option 1b, deferred by two years.
- Option 6a – Control scheme applying to specific wind generation in South Australia and the South East substation and 500 kV bus tie.
- Option 6b – Control scheme applying to specific wind generation in South Australia and the South East substation plus Option 1b, minus the 3rd 500/275 kV transformer at Heywood.

Table 3-1 provides an overview of which components are included in each option.

Table 3-1: Overview of the option components

Option	Service Date	3rd Heywood Tx	3rd South East Tx	Heywood bus tie	Control Schemes	DM	132kV works	Series Comp	100 MVar Capacitor
Option 1a	July 2016	✓		✓			✓		✓
Option 1b	July 2016	✓		✓			✓	✓	
Option 2a	July 2016	✓	✓	✓			✓		✓
Option 2b	July 2016	✓	✓	✓			✓	✓	
Option 3	See option description in section 3.1								
Option 4	July 2016			✓			✓		✓
Option 5	July 2018[a]	✓		✓		✓	✓	✓	
Option 6a	July 2015			✓	✓				
Option 6b	July 2016[a]			✓	✓		✓	✓	

[a] The dates shown are for the network component, not the DM and control scheme components.

With the exception of Option 3 (new Krongart-Heywood 500 kV interconnector), all of these options relate to works within existing substation boundaries and do not involve new line works.

The notional (maximum theoretical) interconnector capabilities provided by these options are shown in Table 3-2 below. The interconnector transfer capability achieved at any point in time will be subject to network and local conditions such as the level of demand, and generation dispatch outcomes. The limits shown for Options 6a and 6b would be under high wind output in south east South Australia. Without additional wind farms in the south east of South Australia, the notional limit for Option 6b would be 570 MW.

Table 3-2: Notional interconnector limits for options (MW)

Option	Description	Notional limit (MW)		Change from current (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	3rd Heywood transformer + 100 MVar capacitor + 132 kV works	550	550	90	90
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	650	650	190	190
Option 2a	Option 1a + 3rd South East transformer	550	550	90	90
Option 2b	Option 1b + 3rd South East transformer	650	650	190	190
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVar capacitor	460	460	-	-
Option 5	200 MW DM + Option 1b	650	650	190	190
Option 6a	Control schemes + 500 kV bus tie	550	460	90	-
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	570 / 690	460	110-230	-

3.1 Description of the credible network options assessed

This section provides a description of each of the credible network options assessed in the RIT-T, including:

- The technical characteristics of the option.
- The estimated construction timetable and commissioning date.
- The estimated capital and operating & maintenance costs.

The impact on selected existing network constraints of each option is provided in Appendix D, Table D-4. Some of these network options have been discussed at a high level in AEMO's 2010 and 2011 NTNDP[15] and in ElectraNet's 2012 Annual Planning Report.[16]

Section 3.2 provides the equivalent description of each of the credible non-network options assessed in the RIT-T.

[15] AEMO, 2011 NTNDP, section 2.2.4; AEMO, 2010 NTNDP, section 4.6.3.

[16] http://www.electranet.com.au/network/transmission-planning/annual-planning-report/.

Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus a 100 MVar capacitor at South East substation and reconfiguration of 132 kV network

Option 1a maximises the use of spare capacity available on the Heywood–South East transmission line, by augmenting the existing capacity of the Heywood transformers. Option 1a is depicted in Figure 3.1.

Option 1a includes the installation of a 3rd 370 MVA 500/275 kV transformer and associated works at Heywood, together with the installation of a 100 MVar capacitor at South East substation to provide the reactive support required to support the higher interconnector capacity.

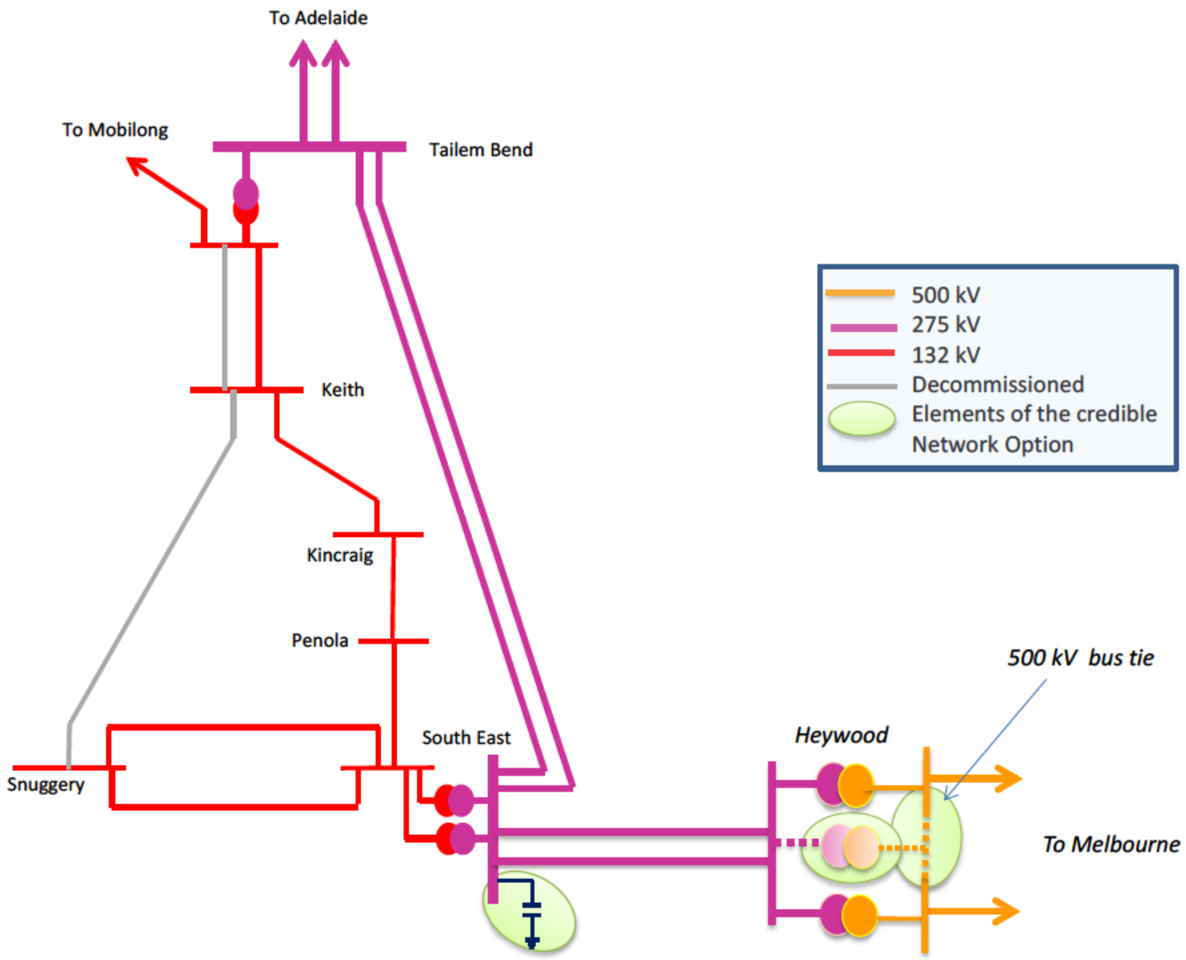
The option also includes some network reconfiguration of the existing 132 kV lines between Snuggery–Keith and Keith–Tailem Bend in South Australia, which currently cause some of the existing thermal limitations on the Heywood transfer capacity. The current lines were built in the 1960s and are in poor condition and also close to the end of their technical life. This option would include a full decommissioning of these lines and network reconfiguration to optimise the interconnector capability along with additional reactive support on the 132 kV system to support local voltages. The reactive support that will be required on the 132 kV system includes two 15 MVar 132 kV capacitors at Keith/Penola substations and one 15 MVar capacitor at Blanche substation. The Blanche capacitor is an advancement of a proposed project by 2 years.

The estimated capital cost of this option is $78.0m. This cost is comprised of:

- 3rd 370 MVA 500/275 kV transformer and bus tie at Heywood: $45.0m.
- Installation of a 100 MVar capacitor: $4.4m.
- Reconfiguration and decommissioning of 132 kV network: $28.6m.

Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable is up to three years, with a commissioning date of July 2016.

Figure 3-1: Option 1a - Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus a 100 MVar capacitor at South East substation and 132 kV works



Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus series compensation of 275 kV lines and reconfiguration of 132 kV network

Option 1b is depicted in Figure 3.2. This option is the same as Option 1a, but with series compensation of the Tailem Bend to South East 275 kV lines at Black Range to provide reactive support, rather than a capacitor at South East substation. Option 1a is depicted in Figure 3.1.

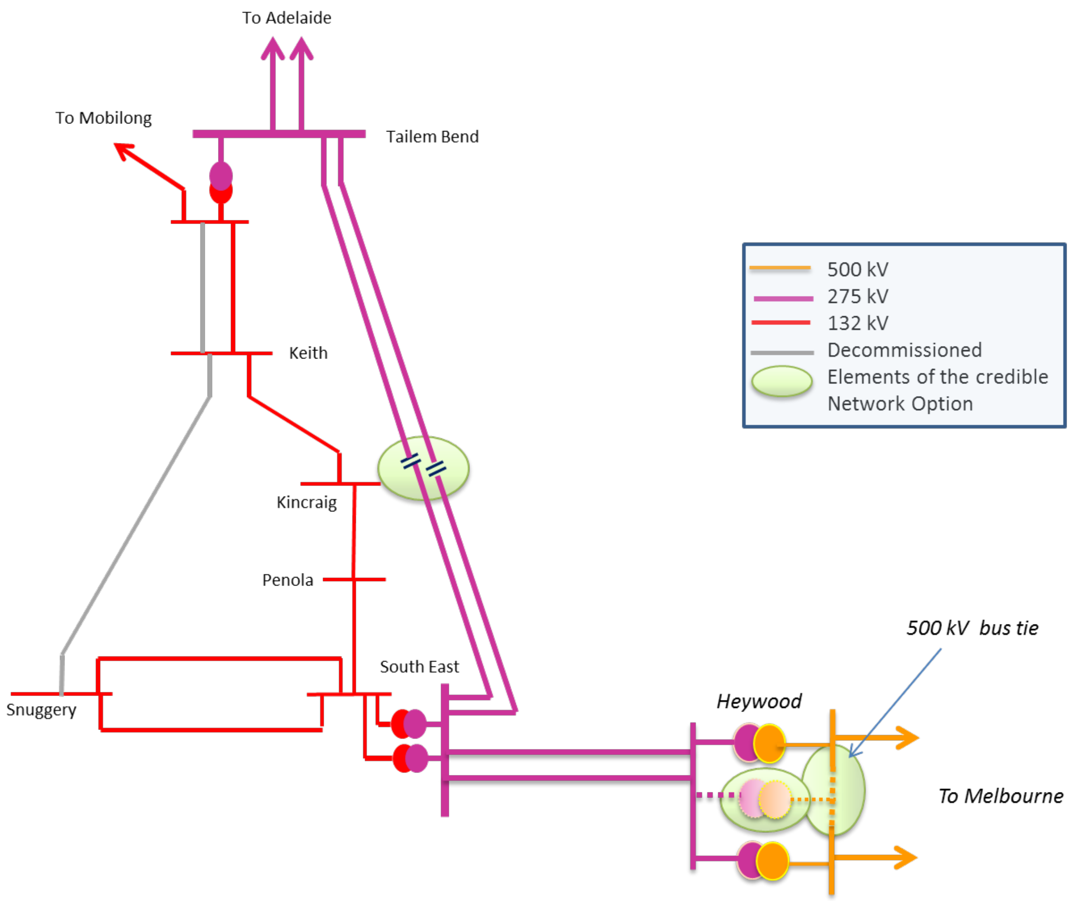
The option also includes network reconfiguration of the existing 132 kV lines between Snuggery–Keith and Keith–Tailem Bend along with additional reactive support on the 132 kV system to support local voltages, as discussed above for Option 1a.

The estimated capital cost of this option is $107.7m. This cost is comprised of:

- 3rd 370 MVA 500/275 kV transformer and bus tie at Heywood: $45.0m.
- 275 kV series compensation: $34.1m.
- Reconfiguration and decommissioning of 132 kV network: $28.6m.

Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable is up to three years, with a potential commissioning date of July 2016.

Figure 3-2: Option 1b - Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus series compensation of 275 kV lines and 132 kV works



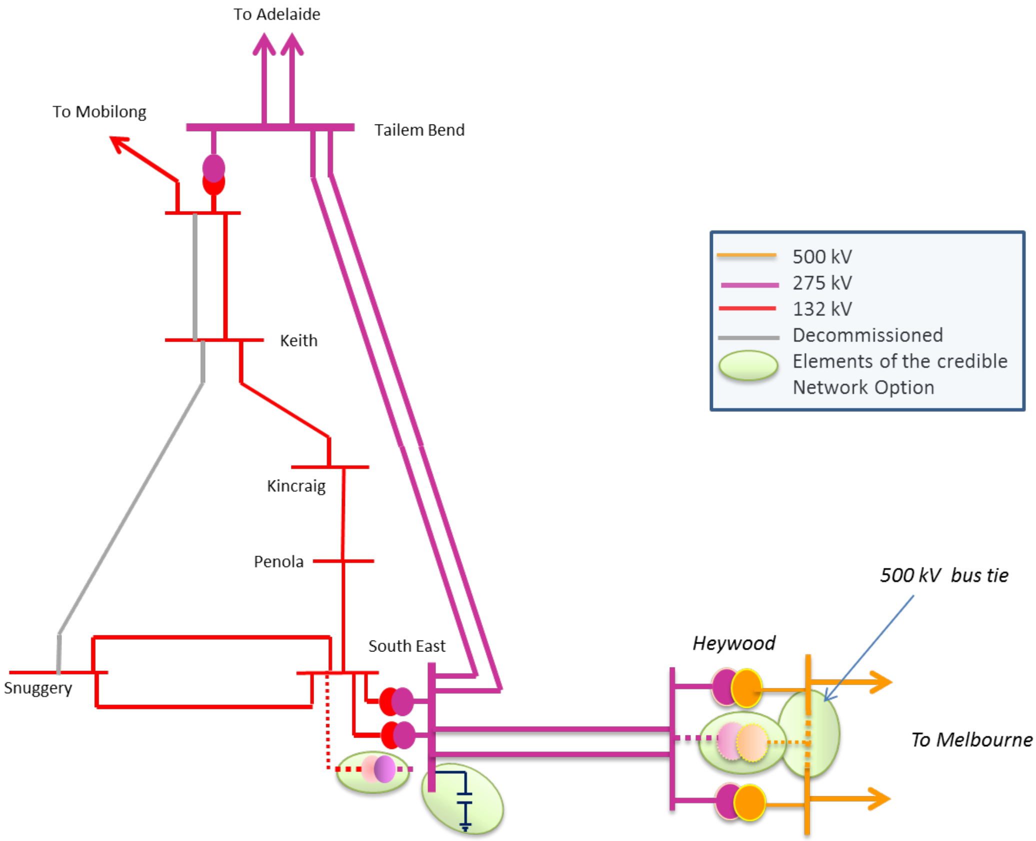
Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a

The existing capacity of the transformers at South East substation causes restrictions to exports from South Australia as well as constraints to wind generation in the South East region, and is forecast to limit imports into South Australia in the future.[17]

ElectraNet and AEMO have therefore also considered the net market benefit associated with adding a 3rd 160 MVA 275/132kV transformer at South East substation, in addition to the works included under Option 1a. ElectraNet and AEMO note that the inclusion of a 3rd transformer at South East substation as part of the network options being considered was requested in the submission to the PSCR by the private generators.[18]

This option is depicted in Figure 3.3 below.

Figure 3-3: Option 2a - Installation of a 3rd 160 MVA 275/132 kV transformer at South East plus Option 1a



The estimated capital cost of the 3rd transformer at South East and associated works is $17.4m. The total capital cost of this option is therefore $95.4m. Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable remains three years, with a commissioning date of July 2016.

17 AEMO, 2011 NTNDP.

18 See section 4 2

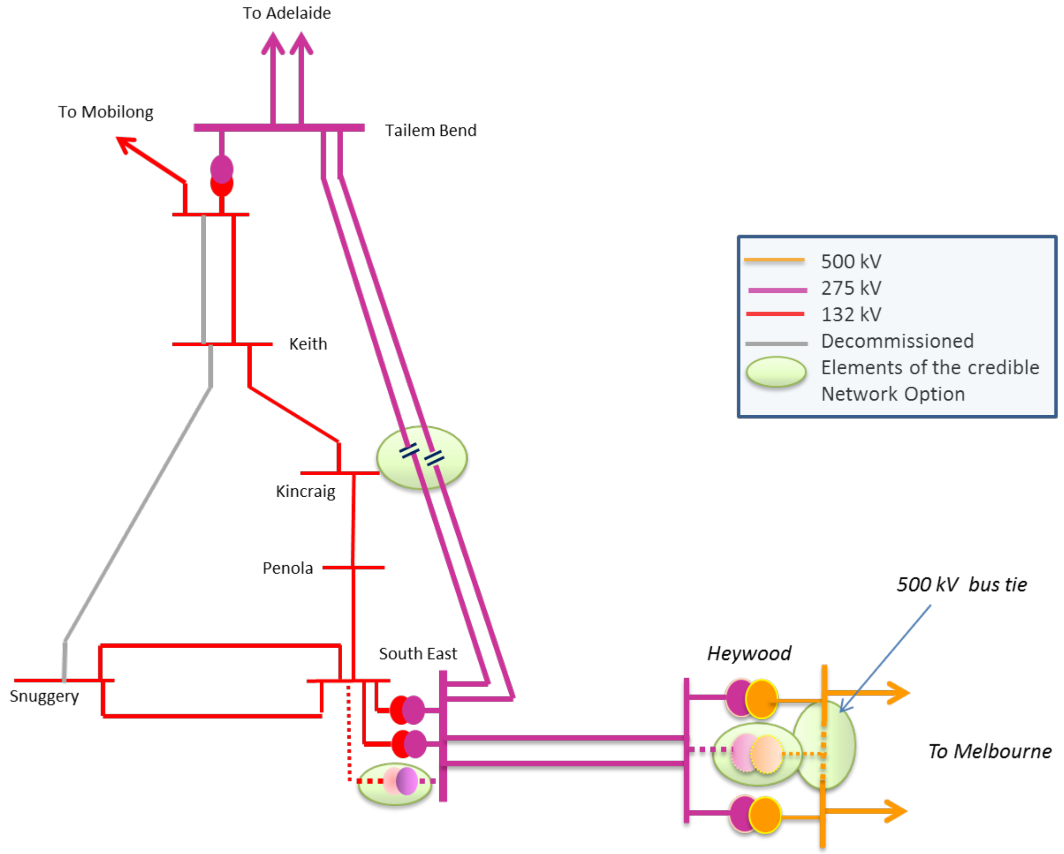
Option 2b - Construction of a 3rd 160 MVA 275/132kV transformer at South East plus Option 1b

Option 2b includes a 3rd 160 MVA 275/132 kV transformer at South East substation, together with the works set out under Option 1b. This option is shown in Figure 3.4.

The estimated capital cost of the 3rd transformer at South East and associated works is $17.4m. The total capital cost of option is therefore $125.1m. Annual operating costs have been estimated at 2% of this capital cost.

The estimated construction timetable is again three years, with a commissioning date of July 2016.

Figure 3-4: Option 2b - Installation of a 3rd 160 MVA 275/132 kV transformer at South East plus Option 1b



Option 3 – New Krongart–Heywood 500 kV interconnector and associated 275 kV works

This is a greenfield option which would provide a much higher Heywood Interconnector capacity (about 2,000 MW additional capacity). This is the lowest cost of all the high-capacity interconnector options considered previously in studies such as AEMO's 2010 NTNDP and the AEMO-ElectraNet Joint Feasibility Study. While the estimated cost of this option is higher than that of Options 1a and 1b discussed above, the higher capacity may potentially provide greater net market benefits than those other options. ElectraNet and AEMO have therefore considered it prudent to evaluate this as a separate option under the RIT-T.

The scope of this option includes both a new Krongart-Heywood 500 kV interconnector, as well as associated works on the 275 kV network between Krongart and Tungkillo.

The estimated capital cost of this option is dependent on the assumed timing and staging of development. By initially operating the new interconnector at 275 kV, some substation and transformer costs can be deferred.

Specifically, works on the interconnector and the associated works on the 275 kV network in South Australia could be staged as follows:

- Stage 1: Establish a new 275 kV switching station at Krongart and build a 500 kV double circuit line from Krongart to Heywood (initially operated at 275 kV), plus 500/275 kV transformers at Heywood and stringing a 3rd circuit between Tailem Bend and Tungkillo.
- Stage 2: Create a 500 kV switchyard at Krongart, add 500/275 kV transformers at Krongart and re-connect the Heywood end line termination to the 500 kV side of the Heywood substation, plus add a new double circuit line from Krongart to Tailem Bend.

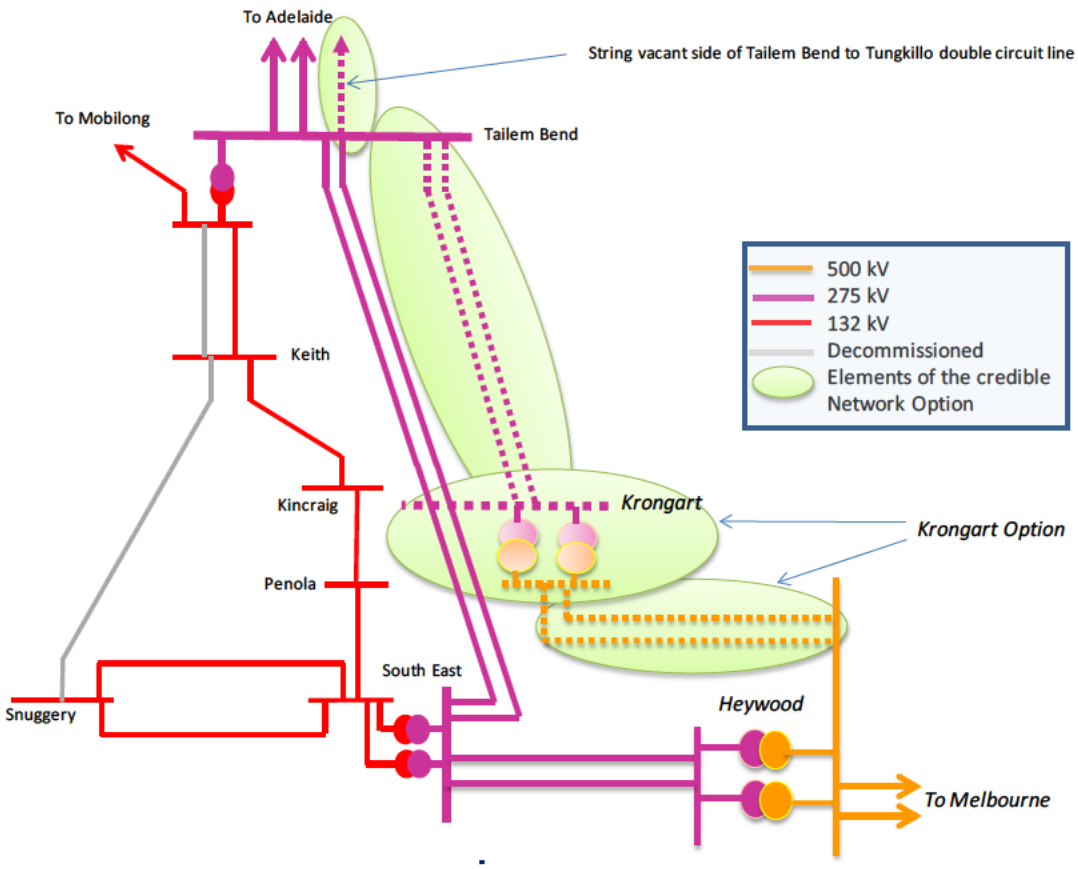
On the basis of the staged development set out above, the total estimated capital cost of this option is $888.8m:

- Krongart Stage 1 works: $417.3m
  - $368.0m for the Heywood and Krongart works.
  - $49.3m for Tailem Bend – Tungkillo 275 kV works.
- Krongart Stage 2 works: $471.5m
  - $164.5m for upgrades to 500 kV.
  - $307.0m for Tailem Bend – Krongart 275 kV works.

Annual operating costs have been estimated at 2% of this capital cost.

The estimated construction timetable is 7–10 years, with a commissioning date of July 2025 for Stage 1 and the 275 kV works, and July 2030 for Stage 2. These estimated commissioning dates are based on the optimal timings identified by the earlier Joint Feasibility Study.

Figure 3-5: Option 3 – New Krongart-Heywood 500 kV Interconnector and associated 275 kV works



Option 4 – Option 1a minus 3rd Heywood transformer

Submissions on the PSCR from the group of private generators and Alinta raised a concern about the need for the Heywood transformer augmentation, if the existing 460 MW capacity of the Heywood interconnector is maintained on a firmer basis, by addressing network congestion issues in South Australia.

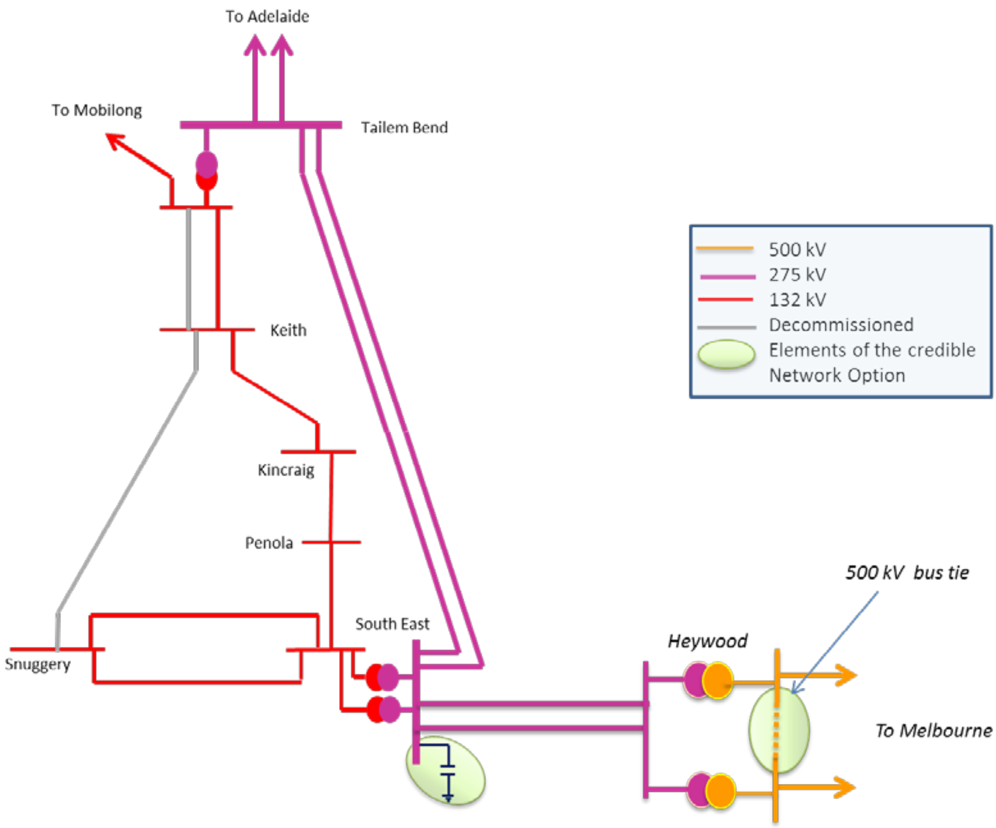
ElectraNet and AEMO have considered as an additional credible network option an option which includes works to address constraints on the 132 kV network in South Australia but does not include installation of a 3rd 500/275 kV transformer at Heywood.

Specifically Option 4 covers the same works included in Option 1a, minus the 3rd 500/275 kV transformer at Heywood. That is, the decommissioning of the Keith-Snuggery and Keith-Tailem Bend 132 kV lines, together with the installation of a 100 MVar capacitor. In addition, a 500kV bus tie at Heywood would still be required to address thermal and voltage issues on the Victorian side of the network, even without a 3rd transformer at Heywood. The 3rd transformer at South East has not been included in this option, as the results from the market modelling analysis show that inclusion of the 3rd South East transformer (i.e. Option 2a) does not increase the overall net market benefit compared with Option 1a.

This option is depicted in Figure 3.6. The estimated capital cost of this option is $40.6m.

The estimated construction timetable would be three years, with a commissioning date of July 2016.

Figure 3-6: Option 4 – 132 kV Works between Snuggery-Keith and Keith-Tailem Bend plus 100 MVar capacitor and a 500 kV bus tie at Heywood



3.2 Description of the credible non-network options assessed

ElectraNet and AEMO have included three options which have a non-network component as part of the credible options considered for this RIT-T. These non-network components reflect specific options raised in submissions to the PSCR. ElectraNet and AEMO note that for the purposes of discussion in this PADR, the automatic control schemes have been considered to be 'non-network options', as although these control schemes would be owned by the relevant TNSPs, the control scheme component does not include network augmentation.

For two of these options, the non-network component has been considered together with a network component, as preliminary screening identified that these combinations would have a greater net market benefit than the non-network component alone.

Option 5 – Five-year, 200 MW demand management program plus Option 1b, deferred by two years

EnerNOC[19] identified in a submission to the PSCR that it would be a proponent for a demand management (DM) option, and requested that a DM option be considered in the RIT-T assessment. In its initial submission EnerNOC noted that a DM option could be either temporary or permanent, and

[19] EnerNOC Australia Pty Ltd.

could either be considered on a stand-alone basis, or used to defer an eventual network augmentation.

In a second submission, EnerNOC proposed to provide up to 200 MW of firm demand response capacity, which they guarantee would be available during the contracted period, to be agreed with ElectraNet. EnerNOC proposed a five year (60 month) contract period in relation to this capability, with contract costs to be based on both a per MW availability fee and a per MWh dispatch fee. EnerNOC would accept financial penalties for failing to provide firm capacity availability by established milestone dates and for failing to deliver contracted capacity during dispatches.

For the purposes of the RIT-T assessment, ElectraNet and AEMO have modelled this option as representing 200 MW of DM capability, available for five years from July 2013. ElectraNet and AEMO have adopted an indicative cost of $120,000/MW/annum for the availability fee and $750/MWh for the dispatch fee, based on cost estimates suggested by EnerNOC, in order to establish an indicative cost for the DM component. ElectraNet and AEMO note that the option proposed by EnerNOC is at this stage a proposal, rather than a firm offer. Therefore both the MW DM capability and the costs would need to be subject to further verification and agreement before this option could be implemented.

ElectraNet and AEMO have combined this DM component with a deferred augmentation of the Heywood Interconnector capacity. Initial screening work indicated that in combination these investments are likely to have a greater net market benefit than the DM component alone. In order to establish the combination of DM and network augmentation likely to yield the highest net market benefit, the network component reflects the network option which has been found to have the highest net market benefit, considered on a stand-alone basis, i.e. Option 1b. The commissioning date for this network investment is deferred until July 2018, two years after the commissioning date for the network component considered on a stand-alone basis.

Option 6a – Control schemes applying to specific wind generation in South Australia and South East substation and 500 kV bus tie

The second non-network option included in the RIT-T analysis comprises automatic control schemes, which would trip specific participating wind generation in south east South Australia to manage thermal limitations of the South East transformers, the South East to Heywood lines and the Heywood transformers, following an N-1 event, in order to provide an increased South Australia to Victoria export capability. This option has been considered both on a stand-alone basis (Option 6a) and also combined with network investment (Option 6b – discussed below). Although the market benefits of stand-alone control schemes may be expected to be lower than where such schemes are coupled with network augmentation, a stand-alone option would also have a substantially lower cost, and therefore has the potential overall to have a greater net market benefit.

The commissioning date for this option is assumed to be July 2015.

In its submission to the PSCR, Infigen Energy proposed the use of advanced control schemes for wind generation in south-east South Australia and south-west Victoria.[20] Infigen suggested that such control schemes could be similar in principle to the Basslink Network Control Special Protection scheme, which has been successfully applied in Tasmania to maximise transport of energy to Victoria

[20] Infigen Energy, South-Australia- Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Specification Consulta ion Report, 30 January 2012.

via Basslink. Several other submissions to the PSCR noted that they considered Infigen's proposed scheme to be a potentially credible non-network option, worthy of further consideration.[21]

ElectraNet and AEMO note that Infigen's submission contained a high level control scheme concept, but with limited detail. Given the interest expressed in the control scheme concept by stakeholders, ElectraNet and AEMO engaged independent consultants (David Strong & Associates (DSA)) to provide an initial, high-level review of whether a control scheme of the type suggested by Infigen may be technically feasible and, if so, to provide an indication of the costs of such an option, in order for it to be considered as part of the RIT-T analysis. The DSA report is being released alongside this PADR. It should be noted that DSA's review does not include detailed testing or specific contractual discussions. It also does not include the detailed power system studies that would be necessary in order to confirm that the scheme will not cause any system security risks/issues. SP AusNet has also reviewed the control scheme proposal and provided updated costs for the assets required in the Victorian region.

Infigen had proposed that the control scheme could apply to its Lake Bonney wind farms, as well as any new wind generators in both south-east South Australia and south-west Victoria. However AEMO notes that the line ratings for the 500 kV part of the network are higher than that had been assumed by Infigen, and as a consequence the scope of the control scheme would be more appropriately limited to wind farms in South Australia, and in particular the Lake Bonney wind farms and new wind farms connecting in the vicinity of Krongart in South Australia.

In addition, DSA recommended that a separate control scheme be put in place between the Lake Bonney wind farms and South East substation, in order to address the South East substation 275/132 kV transformer constraint.

The Heywood control scheme would enable the existing Heywood interconnector to be operated closer to its full capacity under system normal conditions, as the control scheme would provide the means of addressing overloads following a contingency event. Specifically, the control scheme would enable the wind generators who participate in the scheme to be tripped following a contingency event, in order to prevent overloading of any of the remaining transmission lines or transformers. This would potentially enable the interconnector to be operated to a higher capacity at times when the participating wind generators are operating while exporting power from South Australia. Any extra capacity that can be gained will be linked to the output of participating generators at any given time. The control scheme will not provide any benefit in terms of enhancing the capacity for importing power into South Australia.

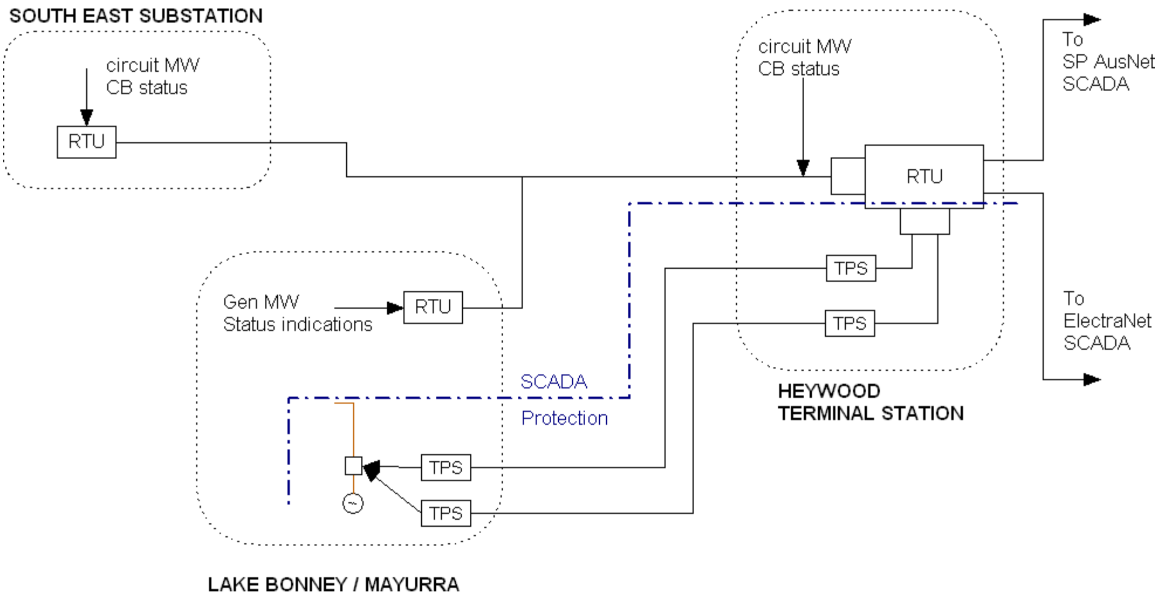
For the purposes of including the control schemes in the RIT-T analysis, ElectraNet and AEMO have assumed that:

- A control scheme would apply to Infigen's Lake Bonney windfarms (Heywood control scheme).
- A separate control scheme would be put in place between the Lake Bonney wind farms and South East substation (South East control scheme).
- New wind generators connecting in the vicinity of Krongart would be incorporated within the Heywood control scheme only.

The control schemes are depicted in Figure 3-7 and Figure 3-8.

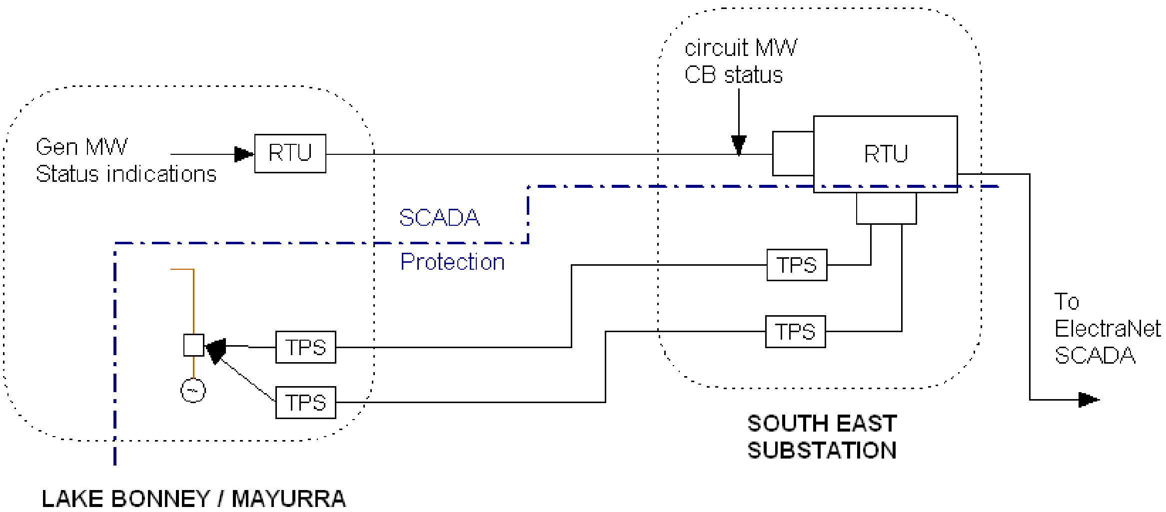
[21] See section 4.3.

Figure 3-7: Heywood control scheme design concept



Source: David Strong and Associates

Figure 3-8: South East control scheme design concept



Source: David Strong and Associates

Under the NER a credible option needs to be technically and commercially feasible.[22]

DSA has concluded that implementing the proposed control schemes is technically feasible. However, ElectraNet and AEMO note that this conclusion relates to the feasibility of implementing the scheme between the network business and the generators subject to the scheme. DSA's assessment did not include a review of the implications for wider aspects of system security, which would also be an important component in establishing the technical feasibility of the control scheme option, and would

[22] NER, 5.6.5D(a)(2).

require further detailed studies. This is discussed further below in relation to the overload rating for the Heywood transformers.

The DSA report noted that since the majority of the assets to be protected by the control scheme for the wind generators are in Victoria, SP AusNet would be the logical owner of the Heywood control scheme. DSA therefore recommended that AEMO (as the provider of prescribed transmission services in Victoria) contract with SP AusNet for the implementation and ownership of the Heywood control scheme. However DSA noted that it would also be possible for AEMO to put the project out to tender.

DSA highlight that the provision of the Heywood control scheme would require the following agreements:

- Control scheme implementation and ownership (AEMO-SP AusNet).
- Communication service provision (SP AusNet – ElectraNet).
- Generator tripping services agreement (AEMO - generators).
- Generator control scheme participation agreements (SP AusNet – generators).
- Site occupancy license of lease agreements (various).

In relation to the South East control scheme, ElectraNet would have responsibility for ensuring that the requisite arrangements were established, and would be the owner of the assets.

A detailed discussion between all relevant parties on the contractual arrangements has not occurred as part of the consideration of the control scheme option to date. However from initial discussions, ElectraNet and AEMO consider that there is a substantial degree of uncertainty in relation to the commercial feasibility of the proposed control scheme, as it gives rise to potential liability issues and may require generators to indemnify the relevant TNSPs. Detailed consideration and discussion of the contractual arrangements would be a key next step in developing this option to the point where it could be implemented.

ElectraNet and AEMO have undertaken initial discussions with SP AusNet, and would like to record their appreciation for SP AusNet's cooperation and input into consideration of the control scheme option for this RIT-T. The discussions with SP AusNet have focused on technical feasibility rather than specific contractual and commercial issues and have highlighted the criticality of the transformers at Heywood to the operation, safety and stability of the Victorian transmission network. Notwithstanding this criticality, SP AusNet has indicated that it would consider operating the transformers at Heywood outside of the current operating envelope, subject to addressing all risks resulting from this operating mode. Specifically, SP AusNet is able to provide a 1.5 second MVA rating as highlighted in the DSA report, subject to specific calculations being performed and verified.

Under normal circumstances, when ordering a new transformer any abnormal overload requirement would be part of the tender specification and factored into the design. This has not occurred for the Heywood transformers. In addition, the Heywood transformers have a tertiary winding that supplies a load connection to a third party, which SP AusNet must guarantee and which needs to be given full consideration when analysing the overload rating of the transformers. There would therefore need to be further consideration of the technical feasibility of operating the Heywood transformers in the manner that would be required under the control scheme. SP AusNet has indicated that it would be able to provide ElectraNet and AEMO with a list of the calculations that would be required in this regard.

Notwithstanding that that there are questions in relation to both the technical and commercial feasibility of the control schemes, ElectraNet and AEMO have incorporated this option in the RIT-T analysis reported in this PADR, in order to assess whether such control schemes would be likely to have higher net market benefits than the other credible options identified. The issues relating to technical and commercial feasibility would need to be subject to further examination if this option were to be taken forward as the preferred option for implementation.

The capital costs of the control schemes included in this RIT-T have been based on the estimate provided by DSA and SPAusNet as follows:

- Heywood control scheme: $12.0m.[23]
- South East control scheme: $1.0m.
- Additional cost of adding in new wind generation at Krongart to Heywood control scheme: $1.0m.

On-going operating costs have been estimated by DSA at $1.5m for each control scheme (being a total of $3.0m).This cost has not been included in the RIT-T analysis. Annual operating costs have been estimated at 2% of the capital cost consistent with the other options.

The above capital cost estimate includes the costs of communication links at Heywood. ElectraNet has proposed that a communications capability be put in place for other network operational purposes as part of its current submission to the Australian Energy Regulator (AER). If the AER approves this expenditure as part of prescribed transmission services, then it would no longer to be incorporated as part of the costs of the control scheme.[24] However ElectraNet and AEMO also note that SP AusNet has recommended that two geographically diverse telecommunication paths are implemented between Heywood and South East substations. This would add a further $7m to the capital cost. This additional cost has not been included in the RIT-T assessment.

In addition, it is possible that there would be costs associated with generator participation in the schemes. In initial discussions, Infigen has noted that it would not require payment for the participation of its Lake Bonney windfarm in the control scheme. For the purposes of the RIT-T analysis, ElectraNet and AEMO have therefore assumed no generator participation costs. However, ElectraNet and AEMO note that owners of new wind generation connecting at Krongart may require payment to participate in the scheme.

In addition, a 500kV bus tie at Heywood would still be required to address thermal and voltage issues on the Victorian side of the network under this option. The capital cost of the bus tie is estimated at $7.6m.

DSA and SP AusNet have both estimated that the control scheme would take two years to implement. The commissioning date for this option is therefore assumed to be July 2015.

[23] An indicative estimate received from SP AusNet was at the upper end of the DSA estimate accuracy (+-30%). For the purposes of this RIT-T assessment the DSA estimates were adjusted upward by approximately 25%. A number of costs are common to the two control schemes, and have therefore been incorporated only into the cost of the Heywood control scheme. In particular the full cost of the digital radio ($4.5m) is reflected in the costs for the Heywood control scheme.

[24] The AER's Draft Determination for ElectraNet is due by the end of Novemebr 2012, with the Final Determination due by 30 April 2013.

Option 6b – Control scheme applying to specific wind generation in South Australia and South East substation plus Option 1b minus the 3rd Heywood transformer

The control schemes discussed above (i.e. Option 6a) have also been considered in combination with the network augmentation found to have the highest net market benefit, specifically Option 1b.

The 3rd transformer at Heywood has however been excluded from this option, as the installation of the control scheme represents an alternative means of managing the transformer capacity limitation at Heywood.

The cost of this option is:

- control schemes: $12.0m for the control scheme, plus on-going costs of $3.0m per annum (see description as part of the earlier discussion of Option 6a).
- network component: $70.3m.

The expected commissioning date for the control scheme part of this option remains July 2015, whilst the commissioning date for the network component is July 2016, in line with the commissioning date for Option 1b considered on a stand-alone basis.

3.3 Credible options eliminated from the PSCR

There were two non-network options mentioned in the PSCR which have not been taken forward into the RIT-T modelling at this PADR stage.

The PSCR included demand management as a possible non-network option, and noted that at that stage ElectraNet and AEMO intended to model a demand-shifting response of a similar scale to the capacity of the smaller network options (i.e. 650 MW).

As discussed above, ElectraNet and AEMO received a proposal from EnerNOC in response to the PSCR which set out a specific demand management option, for which EnerNOC wishes to be identified as a proponent. ElectraNet and AEMO have therefore evaluated this specific demand management proposal as part of the RIT-T analysis, in preference to evaluating a more generic demand management option for which no proponent has been identified.

The PSCR also mentioned utility scale storage as a possible non-network option. ElectraNet and AEMO noted in the PSCR that they were not in a position to suggest the technical characteristics of a storage solution that could compete with the network alternatives being considered for the Heywood Interconnector, or to estimate the total cost. ElectraNet and AEMO sought submissions on these topics. No submissions were received which supported further consideration of a utility scale storage solution. Origin Energy commented in its submission that it considers that significant utility scale energy storage is unlikely to be economic in the near term. Infigen Energy noted that it believed that other more credible and beneficial non-network options exist to meet the identified need. Similarly, the submission from the private generators suggested that Infigen’s control scheme proposal is far more credible as a non-network option. As a consequence, utility scale storage has not been considered further as a credible non-network option for this RIT-T.

4 Submissions to the Project Specification Consultation Report

ElectraNet and AEMO received six submissions[25] to the PSCR, from:

- Origin Energy.
- Alinta.
- Private Generators (AGL Energy, Alinta Energy, Energy Brix, International Power GDF-Suez, Origin Energy, TRUenergy).
- EnerNOC.
- Infigen.
- The National Generators Forum (NGF).[26]

The key issues raised in these submissions are discussed in this section. In addition, specific issues raised in submissions are also discussed in the relevant sections throughout this PADR.

4.1 Importance of interconnector capacity

The submission from the private generators noted that interconnector limits have a profound impact on market operation. The decrease in the Heywood Interconnector capacity has reduced both the reserve margin available to South Australia from other NEM regions and South Australia's ability to access lower cost interstate power. The generators further noted that from a commercial perspective this undermines confidence in inter-regional trading, as parties are not able to effectively manage basis risk. This in turn reduces contract liquidity and overall competition in the market. The generators are therefore supportive of the process ElectraNet and AEMO are pursuing to evaluate possible enhancements of interconnector capacity.

4.2 Alleviation of South Australia intra-state network constraints

Alinta Energy and the private generators expressed the view in their submissions that action to address thermal and voltage stability limits in south-east South Australia is justified independent of any Heywood interconnector upgrade.

Alinta suggested that AEMO and ElectraNet evaluate intra-regional issues affecting South Australia separate to the case for various interconnector options. Alinta also commented that the progression of works to maintain the existing capacity of the Heywood Interconnector remains critical going forward.

[25] PSCR submissions can be accessed at: http://www.aemo.com.au/en/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

[26] ElectraNet and AEMO note that the submission from the NGF was received one month after the closing date for submissions. Given he lateness of the submission, limited additional work has been able to be undertaken in response. However, ElectraNet and AEMO consider that the issues raised by he NGF are adequately addressed in this PADR.

The private generators further noted that they would be against a proposal that would improve capability between Heywood substation in Victoria and South East substation in South Australia but leave the 'upstream' issues in and around south-east South Australia unresolved. They would prefer that the option to add a 3rd 275/132 kV transformer at South East be included as part of the network options evaluated, rather than being left to a sensitivity study.

ElectraNet and AEMO note that the credible network options set out in section 3 include re-configuration of the 132 kV network between Snuggery–Keith and Keith–Tailem Bend, which currently cause some of the existing thermal limitations on Heywood transfer capacity, as well as reactive power compensation which will alleviate voltage/stability constraints.

ElectraNet and AEMO have also investigated the market benefits which may be expected as a result of intra-regional investment in South Australia to address constraints around the south-east, not coupled with a 3rd transformer being installed at Heywood. An option which includes re-configuration of the 132 kV network and installation of a 100 MVar capacitor, but does not include a 3rd transformer at Heywood has been included as a credible option in the RIT-T analysis (Option 4).

ElectraNet and AEMO further note that consideration of other investments to address particular intra-regional constraints (outside of the scope of this RIT-T assessment) would still need to be subject to a separate RIT-T assessment. This would include investments to address network limitations in and around the Robertstown transformer which may impact the Murraylink interconnector capacity. The issue of network limitations around Robertstown was raised in Alinta's submission, but is considered outside the purview of this current RIT-T.

4.3 Non-network options

Two additional non-network options were proposed in response to the PSCR:

- A DM option, proposed by EnerNOC and for which EnerNOC has identified itself as a proponent.
- A control scheme for wind generators in south-east South Australia and south-west Victoria, proposed by Infigen to increase South Australia to Victoria export capability.

EnerNOC requested some additional details in relation to the characteristics that a DM option would need to meet, in order to enable it to estimate the details of its DM proposal and the cost of that option. This information was provided to EnerNOC and also posted on AEMO and ElectraNet's websites in order to be accessible to all interested parties.

Both of the non-network options proposed in submissions have been subject to further specific assessment and evaluation, and have been included as a component of potential credible options in the RIT-T analysis. These options are discussed further in section 3.2.

Alinta and the private generators expressed support for consideration of as many technically feasible options as possible, within reason, in the RIT-T, including the control scheme proposed by Infigen. The private generators note that this option is far more credible as a non-network option compared to the two non-network options set out in the PSCR (demand management and utility scale storage). ElectraNet and AEMO note that they have considered a substantial number of potential alternative credible options as part of this RIT-T process.

4.4 Market benefits included in the RIT-T assessment

In its submission, EnerNOC referred to a number of categories of market benefits which may be associated with a DM option. These include fuel cost benefits associated with both the avoidance of the dispatch of high cost generation in South Australia as a result of peak demand reduction, and an increase in curtailable load that can increase its demand to better utilise available wind generation in South Australia. EnerNOC also notes that there may be capital expenditure deferral benefits (both generation and network capital expenditure), and competition benefits associated with a DM option, as a non-network option can be highly competitive to a non-network solution. ElectraNet and AEMO note that each of these categories of market benefit has been considered as part of the assessment of the DM option under the RIT-T, where they have been assessed as material.

In addition, EnerNOC refers to the following benefits from a DM option:

- A downward pressure on energy prices for the entire market.
- The increased time made available for a major augmentation.
- Improvement in reliability and security.
- Reduction in greenhouse gas emissions.

In relation to these four categories of benefit, ElectraNet and AEMO note that all but the first benefit has been included in the assessment of the DM option (i.e. Option 5) under the RIT-T. The RIT-T does not take into account changes in NEM prices as a category of market benefit, since this represents a transfer between producers and consumers, rather than an overall net benefit to the market.

In relation to the other categories of benefit, the modelling has included the impact on unserved energy (USE) associated with the DM option (i.e. the improvement in reliability and security), as well as the impact on greenhouse gas emissions (since generator short run marginal cost (SRMC) has been calculated inclusive of the associated carbon emission level for that generator and the assumed carbon price[27]). The DM option assessed has also considered the lower cost (in present value terms) associated with a deferral of the time at which a network augmentation is undertaken, as this option explicitly includes a two year deferral of network augmentation.

[27] This is consistent with the AER RIT-T Application Guidelines in relation to the inclusion of the carbon price in the RIT-T analysis. See AER, RIT-T Applica ion Guidelines, June 2010 p. 21-25.

4.5 RIT-T analysis to be sufficiently transparent and robust

The submission received from the NGF highlighted its view of the importance of the analysis by AEMO and ElectraNet being rigorous and robust, as well as sufficiently transparent to facilitate detailed analysis by third parties.

In particular the NGF highlighted a number of assumptions which it considered should be made transparent in the PADR, such as those made about wind farm output in South Australia at times of peak demand, any assumptions made in relation to the Federal Government's Contract for Closure (CFC) Program, the minimum generation levels assumed for South Australian generators and the additional generating capacity assumed in the 2011 Electricity Statement of Opportunities to be required in both South Australia and Victoria by 2014/15.

Infigen commented in relation to the network options included in the PSCR that it is important that the costs of each option are provided at suitable granularity to allow detailed feedback by industry participants and/or third party engineering review. Infigen also noted that the assumption of what the new entrant wind energy price will be at the time of commissioning the proposed additions would be a materially significant assumption, and could be influenced by the rapid pace of change in the industry and the entrance of new, cheaper manufacturers of wind turbines. Infigen also commented that network connection costs for wind generators would be greater for 500 kV sites in Victoria relative to 275 kV connected sites in south-east South Australia, and suggested that actual connection costs for advanced wind farms be used, using nominal 132 kV circuits.

ElectraNet and AEMO note that the NER requires the PADR to include a detailed description of the methodologies used in quantifying each class of material market benefit and cost.[28] The NER also require the PADR to contain the results of a net present value (NPV) analysis of each credible option and accompanying explanatory statement regarding the results.[29] Key assumptions adopted for the market modelling component of the RIT-T assessment are discussed in section 5 of this PADR. The results of the NPV analysis for all credible options are presented and discussed in section 6.3 of this PADR. Greater detail in relation to both the assumptions adopted in the analysis and the NPV results are contained in Appendices C, D and E.[30]

In addition, ElectraNet and AEMO note that the main cost estimates for the network component of the credible options has been subject to independent review by external engineering consultants, as discussed in section 6.1.

ElectraNet and AEMO further note that the RIT-T assessment is one which compares the relative ranking of alternative options against each other, and against the option of no investment. Assumptions are material to the extent that they affect this *relative* ranking, rather than simply where they affect the value calculated for the net market benefit. ElectraNet and AEMO have conducted a number of sensitivity tests as part of the modelling assessment, in order to gauge the importance of particular assumptions in affecting the rankings between the different options. The results of this analysis is discussed in section 6.3.

[28] NER 5.6.6(k)(4).

[29] NER 5.6.6(k)(7).

[30] Please note that Appendix E is a separate spreadsheet available on the ElectraNet and AEMO websites.

5 Description of methodology

This section provides a summary of the methodology adopted for the RIT-T assessment, including a description of the approach used for the market dispatch modelling, a description of the reasonable scenarios considered and a summary of key assumptions.

Section 6 provides a further description of the approach adopted to quantifying each of the material categories of market benefits.

5.1 Analysis period

The RIT-T analysis has been undertaken over a period from 2013/14 to 2054/55.

Specifically, the market modelling discussed in section 5.3 below has been undertaken for the period 2013/14 to 2039/40. The period selected for the market modelling was sufficiently long to cover ten years following the end of the Large-scale Renewable Energy Target (LRET) scheme. ElectraNet and AEMO consider that this is important in order to reflect the impact of each network option on the NEM, once the specific LRET driver for increased investment in renewable generation has been removed.

However ElectraNet and AEMO do not consider that an extension of the period for the market modelling beyond 2039/40 is either credible or warranted.[31] Instead, in order to capture the 'end-effects' associated with the life of the network assets extending beyond 2039/40, the market benefits calculated for the final five years of the modelling period (i.e. 2035/36 to 2039/40) have been averaged, and this average value has been assumed to be indicative of the annual market benefit that would continue to arise under that credible option in the future. This annual average value of the market benefit has been assumed to apply for a further 15 years, following the end of the modelling period, in calculating the overall net market benefit associated with that option, together with the annualised cost of that option.

The approach of adopting an extended analysis period, based on the continuation of an assumed end-value, is one which has commonly been adopted in other similar assessments.[32]

5.2 Discount rate

A discount rate of 10% (real, pre-tax) has been adopted in undertaking the NPV analysis, for all credible options. This discount rate represents a reasonable commercial discount rate, appropriate for the analysis of a private enterprise investment in the electricity sector, as required by the RIT-T.[33]

ElectraNet and AEMO have tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 6.13%, as reflective of

[31] ElectraNet and AEMO note that the expansion plan modelling was conducted out to 2045, in order to minimise distor ions in modelled generator planting decisions in the final years of the main modelling period.

[32] See for example: Powerlink and TransGrid, Final Report – Queensland/New South Wales Interconnector upgrade, 24 July 2008.

[33] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 14, p. 6.

the regulatory weighted average cost of capital (WACC) [34] and an upper bound discount rate of 13%. The sensitivity of the RIT-T results to the discount rate assumption is discussed further in section 6.3.

5.3 Market modelling

The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant.[35] ElectraNet and AEMO consider that a market dispatch modelling methodology is relevant for this RIT-T application, and as a consequence have adopted this approach in order to calculate the market benefits associated with the credible options included in the RIT-T analysis.

The RIT-T requires many of the categories of market benefit to be calculated by comparing the 'state of the world' in the base case (where no action is undertaken by ElectraNet or AEMO) with the 'state of the world' with each of the credible options in place. The 'state of the world' is essentially a description of the NEM outcomes expected in each case,[36] and includes the type, quantity and timing of future generation investment as well as the market dispatch outcomes over the assessment period. The approach to calculating market benefits by comparing the states of the world 'with' and 'without' each credible option is depicted in Figure 5-1.

In the case of this RIT-T assessment, the complexity of the impact of each of the credible options on the operation of and outcomes in the NEM is such that the relevant comparison between the states of the world with and without each of the options can only be estimated using market dispatch modelling.

In addition, the uncertainty associated with future NEM development and therefore the future 'state of the world' is addressed under the RIT-T by considering a number of 'reasonable scenarios' (discussed further in section 5.4).

Figure 5-2 provides an overview of the modelling approach adopted by ElectraNet and AEMO for this RIT-T assessment. The following sub-sections provide a further description of the specific models used for this assessment.

[34] This is the lower bound scenario for he discount rate, specified in the RIT-T paragraph (15)(g). The estimate of the regulatory WACC (real, pre-tax) that would apply to ElectraNet is based on the AER's April 2012 final determination for Powerlink. http://www.aer.gov.au/node/7945.

[35] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 11, p. 6.

[36] The AER describes the 'state of the world' in its RIT-T Application Guidelines as being a detailed description of all of the relevant market supply and demand characteristics and conditions likely to prevail if a credible option proceeds or in the base case, if the credible op ion does not proceed (AER, RIT-T Application Guidelines, June 2010, p. 15).

Figure 5-1: Market benefits are calculated by comparing outcomes in different states of the world

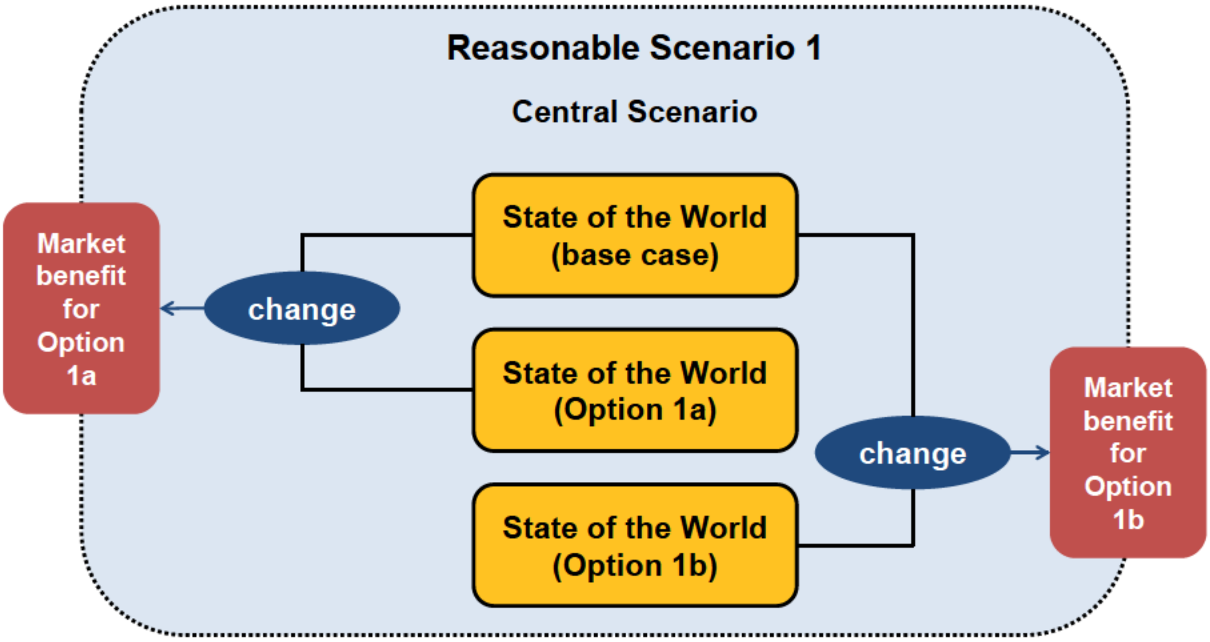
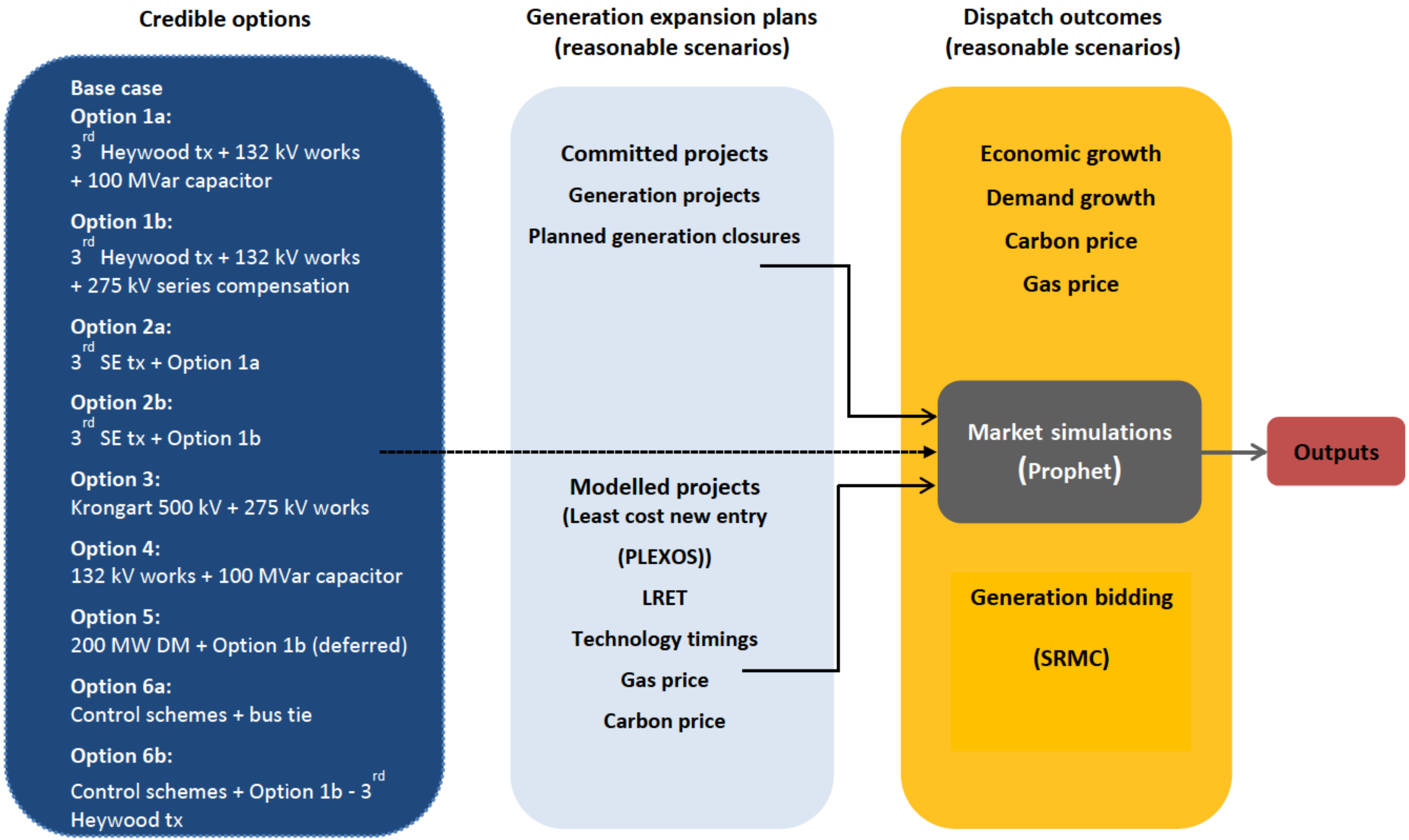


Figure 5-2: Approach to calculating market benefits



5.3.1 Generation expansion plans: modelled projects

ElectraNet and AEMO have modelled the generation expansion plans under each of the four reasonable scenarios considered in this RIT-T assessment.[37]

Committed generation projects are based on those projects identified by AEMO in the 2011 Electricity Statement of Opportunities (ESOO) as 'committed'. The generation expansion plans also reflect assumptions about potential future generation retirements, including the expected closure of some high-emission generators as part of the Federal Government's Clean Energy Package, which are varied across the reasonable scenarios considered in the RIT-T. Further details in relation to the specific assumptions made about committed generation projects and generator retirements are set out in section 5.5.

The generation expansion plans also include modelled generation projects, which have been derived by ElectraNet and AEMO using a model (Long Term (LT) Plan) developed utilising the PLEXOS software.[38] Consequently, these modelled projects were developed on a least-cost basis, consistent with the requirement of the RIT-T.[39] The expansion plan model adopts a number of build limits in order to ensure that the modelled generation build profile is realistic. It also adopts the same new entrant cost assumptions for different generation technologies as used in the NTNDP.[40] In modelling the expansion plan, ElectraNet and AEMO have assumed that the LRET is met. It has therefore been taken as a 'hard constraint' in the modelling. The model also reflects assumptions about the timing of availability of new technologies (including geothermal), which are varied across the reasonable scenarios considered in the RIT-T (see section 5.4).

Generation expansion plans have been modelled for the base case for each scenario, and for each credible option (with the exception of Option 6a (stand-alone control schemes) which was considered to be of such a small scale that it would not affect wider generator investment decisions in the NEM). Modelling of the expansion plans for Options 1a, 1b, 2a, 2b, 4 and 6b highlighted the sensitivity of the expansion plans to the detailed specification of various network constraints. AEMO and ElectraNet consider that differences in the expansion plans under these options reflect these sensitivities, rather than fundamental differences in how the options would in reality impact generation investment decisions. As a consequence the same expansion plans have been adopted for these six options in the RIT-T analysis. ElectraNet and AEMO do not consider that this approach will materially affect the outcome of the RIT-T. A different expansion plan has been modelled for Option 3 (new Krongart-Heywood 275 kV interconnector + 275 kV works), for scenarios 1, 2 and 3. The greater capacity of this option means that it would be expected to influence generation investment decisions in a different way to the smaller capacity options. The results of the modelling also show that the overall market benefit of Option 3 is increased, if this expansion plan is used. For scenario 4, although a different expansion plan was again modelled for Option 3, overall market benefits were found to be higher if the expansion plan for the smaller scale options was used (i.e. the expansion plan for Options 1a, 1b,

[37] AEMO notes that the least cost expansion plans developed for this RIT-T are not directly comparable with the forecasts of future generation requirements presented in the ESOO. In particular the ESOO projections consider only a single period of demand per year and do not allow for any uncommitted retirement of plant.

[38] ElectraNet and AEMO have not identified any 'anticipated' genera ion projects which are expected to materially impact the results.

[39] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 21, pp. 8-9.

[40] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan-Consultation. These costs have been escalated by CPI to June 2011 dollars.

2a, 2b, 4 and 6b).[41] The smaller-scale expansion plan was therefore used for Option 3 under scenario 4.

In the case of Option 5 (DM + deferred Option 1a), under scenarios 1 (central), 2 (low) and 3 (high) the modelling has assumed the deferral of 200 MW of OCGT plant in South Australia as a consequence of the introduction of the DM capability, in addition to the impact of the network augmentation component of that option on the underlying generation expansion plan. ElectraNet and AEMO note that further market modelling would need to be undertaken in order to determine whether in reality all of this 200 MW of OCGT investment would be deferred; however this is considered a reasonable assumption for the purposes of this PADR. Under scenario 4 (revised central), the amount of additional OCGT plant built in South Australia in the base case (i.e. without any option in place) is below 200 MW, which reduces the amount of generation investment deferral which can be achieved by the DM capability. Under scenario 4, the generation deferral associated with DM falls to zero for the first three years of the program, followed by a two year deferral of 87 MW of OCGT plant in South Australia. The costs of the DM program are still assumed to be the same as in the other scenarios, as the DM program would need to be robust to all scenario outcomes.[42]

5.3.2 Market dispatch model

In order to calculate dispatch outcomes in the relevant 'state of the world', ElectraNet and AEMO have undertaken market simulations using a market model which incorporates generation dispatch and market clearing processes to replicate the operation of the NEM. The model used for this RIT-T is the Prophet model.[43]

The market dispatch modelling methodology adopted is consistent with the further requirement in the RIT-T that the model must incorporate both:

- A realistic treatment of plant characteristics, including for example minimum generation levels and variable operating costs.
- A realistic treatment of the network constraints and losses.

The modelling uses the NTNDP database with a full set of NEMDE pre-dispatch system normal constraints so that all intra-regional constraints are captured. The assumptions used in the modelling also capture minimum load assumptions for generators which are in general consistent with those used in the NTNDP.[44]

The Prophet model has been run using load and wind traces from 2009/10 and based on an assumption of SRMC bidding behaviour of generators.

[41] This is considered to be due to differences between the assumptions and level of granularity used in the PLEXOS and Prophet modelling, leading PLEXOS to select an expansion plan which on the basis of the Prophet modelling does not appear to be optimal for Option 3 in this scenario.

[42] It may be possible to stagger the introduction of the DM program over several years. However in this case the benefits assumed under scenarios 1 (central), 2 (low) and 3 (high) would also be staggered.

[43] The Prophet model was one of the models used by AEMO for its analysis in relation to the 2010 NTNDP.

[44] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan-Consultation. Appendix D highlights where the assumptions adopted differ from those used in the NTNDP.

5.4 Description of reasonable scenarios

The RIT-T analysis needs to incorporate a number of different reasonable scenarios, which are used to estimate market benefits. The RIT-T states that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. The choice of reasonable scenarios must reflect any variables or parameters that:[45]

- Are likely to affect the ranking of the credible options, where the identified need is reliability corrective action.
- Are likely to affect the ranking of the credible options, or the sign of the net economic benefits of any of the credible options, for all other identified needs.

ElectraNet and AEMO have adopted the following four scenarios in undertaking the RIT-T analysis presented in this PADR:

- Scenario 1: Central scenario.
- Scenario 2: Low scenario.
- Scenario 3: High scenario.
- Scenario 4: Revised central scenario.

These four scenarios reflect a broad range of different assumptions in relation to factors such as growth in electricity demand, the future carbon price and future gas prices, which were considered to have the potential to affect the market modelling outcomes under this RIT-T.

The first three scenarios adopted for this RIT-T largely reflect scenarios developed by AEMO for the 2010 and 2011 NTNDP, with some of the parameters updated where relevant to reflect more recent information.[46] ElectraNet and AEMO have also made a number of modifications to the NTNDP scenarios, where these are considered to make them 'fit for purpose', given the situation being assessed under this RIT-T. Specifically, scenario 1 represents central values of each of the relevant parameters, largely based on the 2010 and 2011 NTNDP. Scenario 2 reflects parameters that would be associated with a slower rate of economic development than in scenario 1, such as lower electricity demand and low domestic gas prices. Scenario 3 reflects parameters associated with a faster rate of economic development, such as higher electricity demand (including additional mining loads on the Eyre Peninsula and at Olympic Dam[47] in South Australia) and high domestic gas prices.

Scenario 4 is based on the medium demand forecasts from AEMO's 2012 National Electricity forecasting Report (NEFR),[48] which are lower than the 2010 forecasts used for the 2010 NTNDP, together with a low carbon price assumption. Ensuring adequate consideration in the RIT-T of scenarios reflecting low economic growth and a low carbon price has been raised informally by some stakeholders.

[45] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 16, p. 7.

[46] For instance, scenario 3 used core Treasury carbon pricing, and scenario 4 used the low carbon pricing in the Prophet modelling to ensure consistency with announcements on carbon price at the time these assumptions were made.

[47] BHP Billiton's recent media announcement not to progress the Olympic Dam expansion occured too late to be reflected in the modelling for this RIT-T, without delaying publication of the PADR. However ElectraNet and AEMO note that the 'high' scenario (scenario 3) has been given a relatively low weighting in determining the overall net benefit of each option in the RIT-T. A further reduction in the weighting of the high scenario to reflect BHP Billiton's announcement would not change he ranking of the preferred option under the RIT-T, as discussed in section 6.3.2.

[48] http://www.aemo.com.au/en/Electricity/Forecasting.

The modelling of both generation expansion plans and dispatch outcomes in the base case (i.e. with none of the credible options in place) and for each credible option has been undertaken for each of the four reasonable scenarios.

The parameters adopted under each of these scenarios are summarised in Table 5.1.

In particular:

- **Scenario 1 (the 'central' scenario**) is equivalent to the 'Decentralised World' scenario used in AEMO's 2010 NTNDP, updated to reflect the most recent core Treasury carbon price and updated assumptions about earliest timings for new technology.
- **Scenario 2 (the 'low' scenario)** is equivalent to the 'Independent Climate Action' scenario used in AEMO's 2010 NTNDP, updated to reflect the most recent high Treasury carbon price and updated assumptions about timings for new technology. This scenario incorporates a high carbon price, as one of the contributors to the low overall rate of economic growth. The 'low' scenario used in this RIT-T is modified from the NTNDP scenario in that a low gas price has been assumed for the RIT-T scenario, based on the low gas price assumption in the NTNDP 'Uncertain World' scenario.
- **Scenario 3 (the 'high' scenario)** is equivalent to the 'Uncertain World' scenario used in AEMO's 2010 NTNDP, modified to reflect increased electricity demand in South Australia due to increased mining activity in the Eyre Peninsula and the expansion of Olympic Dam, and updated to reflect the most recent core Treasury carbon price and updated assumptions about timings for new technology. The 'high' scenario used in this RIT-T is modified from the NTNDP scenario in that a high gas price has been assumed for the RIT-T scenario, based on the high gas price assumption in the NTNDP 'Fast Rate of Change' scenario.
- **Scenario 4 (the 'revised central' scenario)** includes the recent 2012 demand assumptions contained in AEMO's 2012 NEFR. The 2012 NEFR also includes a higher penetration of solar PV, which changes the demand profile. Scenario 4 also includes a lower carbon price assumption than in the other three scenarios, specifically three years of a fixed carbon price and the legislated carbon floor continuing beyond 2017.[49] This recognises the continuing evolution in expectations around the level of future carbon prices, with many commentators pointing to carbon prices being below the core Federal Treasury forecasts. Scenario 4 assumes moderate adoption of demand-side technologies, consistent with the 2012 NEFR. Scenario 4 also uses the 2012 NTNDP wind contribution to peak demand assumptions, since the shift of new generation from NSW to South Australia was considered relevant to the RIT-T. The other scenario parameters are as per scenario 1.

[49] ElectraNet and AEMO note the Federal Government's announcement on 28 August 2012 that it intends to remove the floor price under the Carbon Price scheme. This could mean that future carbon prices fall below the level assumed in his scenario.

Table 5-1: Summary of parameters under each reasonable scenario

	Scenario 1: Central Scenario	Scenario 2: Low Scenario	Scenario 3: High Scenario	Scenario 4: Revised Central Scenario
Economic growth	Medium	Low	High	2012 NEFR Medium
Demand growth	Medium	Low	High plus Eyre Peninsula and Olympic Dam	2012 NEFR Medium
Carbon price	Core Treasury price	High Treasury price	Core Treasury price	Low carbon price[50]
Technology timings and cost	Central view of timings for new technologies	Timings delayed 2 years (compared with central view)	Timing brought forward by 2 years (compared with central view)	Central view of timings for new technologies
Gas prices	Business as usual: medium published gas prices as per 2010 NTNDP	Surplus domestic supply: low domestic prices	High international demand: high domestic prices	Business as usual: medium published gas prices as per 2010 NTNDP
Wind contribution to peak demand	2011 NTNDP	2011 NTNDP	2011 NTNDP	2012 NTNDP[51]
Demand-side technologies (Electric vehicles; scale storage)	Low adoption	No adoption	High adoption	2012 NTNDP moderate adoption
LRET	Hard target (moderate uptake of greenpower)	Hard target (low uptake of greenpower)	Hard target (moderate uptake of greenpower)	Hard target (moderate uptake of greenpower)

Appendix C provides a more detailed summary of the specific assumptions made in relation to each of the parameters included in the RIT-T scenarios.

ElectraNet and AEMO note that the scenarios used in the RIT-T assessment differ from those used in the earlier Joint Feasibility Study. The scenarios used in the Joint Feasibility Study were intended to capture those scenarios which were likely to represent the most favourable conditions for additional interconnection. In contrast, the RIT-T scenarios are intended to capture a reasonable range of outcomes for those factors which may materially affect the level of market benefits resulting from the options being considered.

ElectraNet and AEMO note that, inevitably, there will be a continuing evolution of expectations around future developments, particularly in heavily policy-related areas such as the future level of carbon price. However, it is also important to recognise that the scenarios adopted in this RIT-T cover a 50 year assessment period, and so must be reflective of a plausible range of long-term expectations. The inclusion of additional scenarios in the RIT-T analysis has a material impact on the time and

[50] See Appendix C, Section C.2.

[51] See Appendix C, Section C.5.

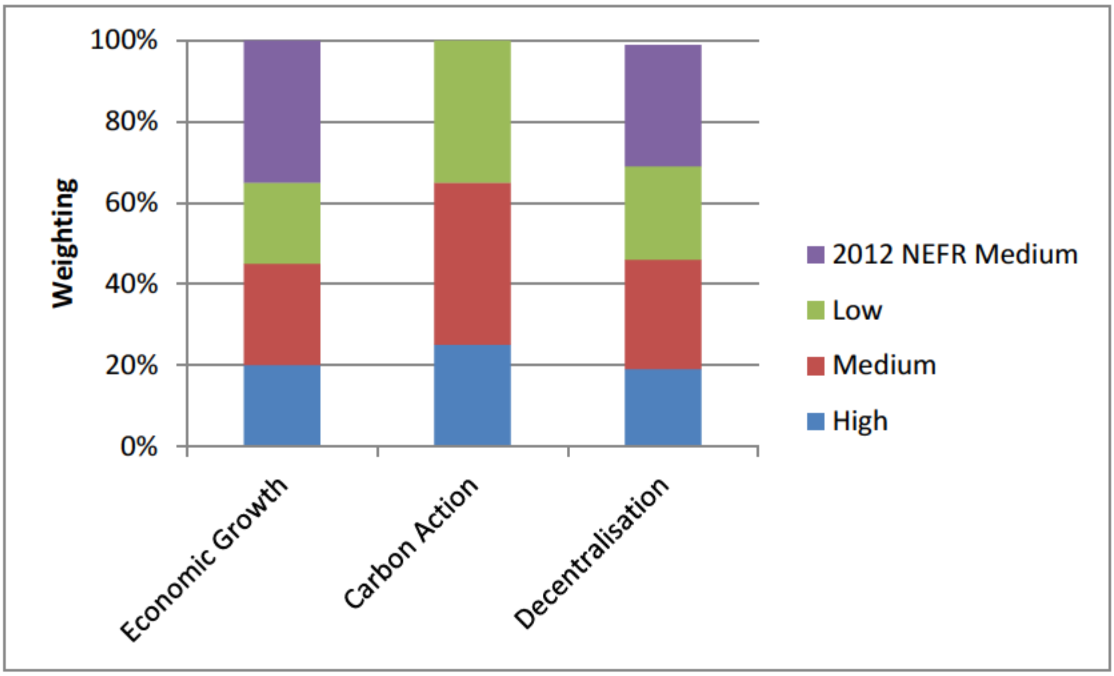
resources required to undertake the market modelling, where the parameters varied impact generation investment and dispatch outcomes. ElectraNet and AEMO are confident that for this RIT-T assessment the four scenarios considered reflect a reasonably broad range of assumptions in relation to the key parameters that are likely to materially impact the outcome of the analysis.

5.4.1 Weights applied to each scenario

ElectraNet and AEMO acknowledge that the weights applied to the various reasonable scenarios is reliant on making an assessment of the likelihood of different future paths for factors such as the carbon price, economic growth and future gas prices.

The scenario weights adopted in this RIT-T have been derived by firstly considering the likelihood that the assumptions used in the scenario definitions would be achieved for: future economic growth; the extent of action taken to address carbon emissions; and the degree of decentralisation of generation. These scenario parameters represent the underlying drivers of many of the assumptions. Each of these parameters was assigned a probability against the scenario assignments so that the probabilities summed to 100% as shown in Figure 5-3.

Figure 5-3: Weightings of scenario parameters



The scenario drivers have then been 'mapped' onto the reasonable scenarios used in this RIT-T (the scenario definition in Table 5-1 determined which of these weightings were combined to derive the scenario weighting). Table 5-2 presents the mapping of scenario drivers to each scenario.

Table 5-2: Mapping of Scenario Drivers to the RIT-T Scenarios

	Scenario			
Scenario Parameters	**Central**	**Low**	**High**	**Revised Central**
Economic growth	Medium	Low	High	2012 NEFR Medium
Carbon Action	Medium	High	Medium	Low
Decentralisation	Medium	Low	High	2012 NEFR Medium

Mapping the assumptions in relation to whether the scenario drivers are high, medium or low (Table 5-2) with the probabilities assigned to each scenario driver (Figure 5-3) results in the weightings for the four RIT-T reasonable scenarios adopted for this PADR set out in Table 5-3.

Table 5-3: Weightings for RIT-T reasonable scenarios

	RIT-T Reasonable scenarios			
	Central	**Low**	**High**	**Revised Central**
Scenario weightings	29%	13%	17%	41%

5.5 Assumptions on committed new generator entry and forced closures

The generation expansion plans developed for the RIT-T reflect the following committed new generation entrants, as identified by AEMO in the 2011 ESOO. In relation to South Australia and Victoria, these generators include:

- 566 MW new OCGT entry in Melbourne from 2011/12 (Mortlake Stage 1).
- 67 MW new wind in Victoria from 2011/12 (Oakland Hills).
- 420 MW new wind in Victoria from January 2013 (Macarthur Wind Farm).

In addition, the following assumptions have been made in relation to the closure/conversion of generating plant for the market modelling under scenarios 1, 2 and 3, using inputs and results from the 2011 NTNDP:

- Hazelwood: retirement of two units (400 MW) in each of 2016/17, 2017/18, 2018/19 and 2019/20.[52]
- Playford assumed to convert to 258 MW OCGT in 2012/13 in scenarios 1, 2 and 3.

In scenario 4, no assumption about forced closures of generation has been made, as well as no assumption in relation to the conversion of Playford. Rather, the model is allowed to choose the retirement date for both Hazelwood and Playford.[53]

[52] The assumed retirement timings were based on 2011 NTNDP sensitivity modelling.

5.6 Classes of market benefits not expected to be material

In the PSCR ElectraNet and AEMO noted that the following classes of market benefit are unlikely to be material for this RIT-T analysis:

- Changes in ancillary services costs.
- Option value.

Origin Energy agreed in its submission to the PSCR that changes in ancillary services costs and option value are not material for this RIT-T assessment. ElectraNet and AEMO note that no submissions to the PSCR disputed the identification of these two categories of market benefit as being not material for this RIT-T assessment.

In addition to these categories, ElectraNet and AEMO have also identified that changes in penalties paid or payable for not meeting the LRET and changes in unrelated transmission investment are not material categories of market benefit for the purposes of this RIT-T assessment.

The reasons for these assessments are set out below.

Changes in ancillary services costs

The cost of Frequency Control Ancillary Services (FCAS) may rise as a result of increased wind generation associated with the network options. However, the cost of frequency control services is not likely to be material in the selection of the preferred option.[54]

FCAS costs are typically less than 1% of the total electricity market costs. Further, the inclusion of all, or some, of the FCAS markets as part of the market modelling under the RIT-T would lead to substantial increase in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given that changes in FCAS costs will not have a role in determining the preferred option.

There is no expected change to the costs of Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.

Option value

ElectraNet and AEMO note the AER's view that option value is likely to arise in situations where the following three conditions are all met:

- There is uncertainty regarding future outcomes.
- The information that is available in the future is likely to change.
- The credible options considered by the TNSP are sufficiently flexible to respond to that change.[55]

ElectraNet and AEMO also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T.

[53] ElectraNet and AEMO note that in this scenario he model decides to retire Playford in July 2015.

[54] NER 5.6.6(c)(6)(iii).

[55] AER, Final Regulatory Investment Test for Transmission Application Guidelines, June 2010, p. 39 and p. 75.

For this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis would require a significant modelling assessment, which would be disproportionate to any additional option value benefit that may be identified. ElectraNet and AEMO have not therefore estimated any additional option value market benefit for this RIT-T assessment.

Penalties for not meeting the LRET

One of the categories of market benefit identified under the RIT-T is 'the negative of any penalty paid or payable for not meeting the LRET'.

As noted earlier, one of the assumptions that has been made in conducting this RIT-T assessment is that the LRET target is met. As such it is a 'hard target'. As a consequence, there are no market benefits (or market costs) in relation to changes in the penalties paid for not meeting the LRET as a result of any of the credible options.

Differences in the timing of unrelated transmission investment

ElectraNet and AEMO have not identified any unrelated transmission investment which would be affected by the credible options being assessed under this RIT-T. This is therefore not a material category of market benefit for this RIT-T.

6 Detailed option assessment

This section sets out the results of the NPV analysis for each of the credible options discussed in section 3.

The NER requires that the PADR set out a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the results of the NPV analysis, and accompanying explanatory statement regarding the results. This section therefore discusses how each of the costs and material categories of market benefits have been calculated, before presenting and discussing the results of that analysis across all of the credible options.

6.1 Quantification of costs for each credible option

The total capital costs for each credible option are set out in Table 6-1. The present value of these costs are set out in Table 6-3 in section 6.3.2.

The capital costs for the network options have been developed by ElectraNet and SP AusNet. ElectraNet's cost estimates have been based on a range of factors including historical data from actual projects and ElectraNet's substation and line design manuals. ElectraNet's cost estimates have also been subject to review by external engineering consultants. SP AusNet's cost estimates have been based on in-house estimation. Operating costs for the network options have been assumed to be 2% of the capital costs.

The indicative cost of the DM component of Option 5 has been based on estimates provided by EnerNOC, which has confirmed that they would like to be identified as a proponent for this option. In addition to the total availability fee of $120m (i.e. $24m a year for a five year program), there would also be a dispatch fee estimated at around $750/MWh.

The capital cost of the control schemes included in Options 6a and 6b has been estimated by independent consultants (DSA). These costs were adjusted based on an indicative estimate received from SP AusNet. No costs have been included to reflect either operating costs of the control scheme or participation fees that may be required by generators.

Table 6-1: Costs of each credible option (2011/12 $m)

	Components	Component costs	Total capital cost ($m)
Option 1a	3rd 500/275 kV Heywood transformer and 500 kV bus tie	$45.0m	$78.0m
	Reconfiguration of 132 kV network	$28.6m	
	Installation of 100 MVar capacitor	$4.4m	
Option 1b	3rd 500/275 kV Heywood transformer and 500 kV bus tie	$45.0m	$107.7m
	Reconfiguration of 132 kV network	$28.6m	
	Series compensation of the Tailem Bend to South East 275 kV double circuit lines at Black Range	$34.1m	
Option 2a	Works as per Option 1a	$78.0m	$95.4m
	3rd transformer at South East and associated works	$17.4m	
Option 2b	Works as per Option 1b	$107.7m	$125.1m
	3rd transformer at South East and associated works	$17.4m	
Option 3	**Krongart Stage 1 Works:** New switching station at Krongart	$417.3m	$888.8m
	New 500 kV double circuit line from Krongart to Heywood (operated at 275 kV)		
	500/275 kV transformers at Heywood		
	275 kV works Tailem Bend to Tungkillo		
	Krongart Stage 2 works: Create a 500 kV switchyard at Krongart	$471.5m	
	500/275 kV transformers at Krongart		
	Re-connect the Heywood end line termination to the 500 kV side of the Heywood substation		
	275 kV works Tailem Bend - Krongart		
Option 4	500 kV bus tie	$7.6m	$40.6m
	Reconfiguration of 132 kV network	$28.6m	
	Installation of 100 MVar capacitor	$4.4m	

Option 5	200 MW DM	$120.0m (availability fee)	$227.7m
	Option 1b	$107.7m	
Option 6a	Heywood control scheme (Lake Bonney wind farms)	$12.0m	$21.6m
	South East control scheme	$1.0m	
	Adding additional wind generation at Krongart	$1.0m	
	500 kV bus tie	$7.6m	
Option 6b	Heywood control scheme (Lake Bonney wind farms)	$12.0m	$84.3m
	South East control scheme	$1.0m	
	Adding additional wind generation at Krongart	$1.0m	
	Option 1b minus 3rd 500/275 kV Heywood transformer	$70.3m	

6.2 Quantification of classes of material market benefit for each credible option

The purpose of the RIT-T is to identify the credible option that maximises the present value of the net economic benefits to all those who produce, consume and transport electricity in the market.[56]

To measure the increase in net market benefit, ElectraNet and AEMO have analysed the classes of market benefit required for consideration under paragraph 5 of the RIT-T, with the exception of those categories which are not considered material for this RIT-T assessment (see section 5.6).

The remaining classes of market benefit which have been quantified for this assessment are:

- Changes in generator fuel consumption arising through different patterns of generation dispatch (including changes in carbon costs).
- Changes in voluntary load curtailment.
- Changes in involuntary load shedding.
- Changes in costs for parties, other than the TNSP.
- Changes in network losses.

There have been no additional categories of market benefit identified as relevant for this RIT-T assessment, outside of those specified in the RIT-T itself.[57]

As noted earlier, many of the material categories of market benefit for this RIT-T are calculated by comparing the 'state of the world' in the base case (where no action is undertaken by ElectraNet or AEMO) with the 'state of the world' with each of the credible options in place.

Competition benefits have not been included in the results reported in section 6.3. Studies undertaken by ElectraNet indicate that, for this particular RIT-T assessment, the magnitude of competition

[56] NER 5.6.5B (b).

[57] RIT-T para (5)(k).

benefits is expected to be low and would not materially affect the RIT-T outcome. Key findings from ElectraNet's analysis of competition benefits are discussed in section 6.4.

6.2.1 Changes in fuel consumption

ElectraNet and AEMO have calculated the fuel consumption costs (including the costs associated with the carbon price) and the variable operating costs arising under the base case, for each of the scenarios considered in the RIT-T analysis. Fuel costs (including carbon costs) and variable operating costs have been calculated on the basis of the generator dispatch pattern resulting from the Prophet dispatch market modelling, taking into account the difference in generation expansion plans associated with each of the different credible options.

For each scenario, the fuel consumption cost (including emissions costs) and variable operating cost estimated under the base case has then been compared with the fuel consumption cost and variable operating cost predicted by Prophet if each of the credible options were in place. For example, using the Prophet model ElectraNet and AEMO have calculated the fuel consumption costs and variable operating cost under scenario 1 (central scenario) for the base case and then taken the difference between this cost and the fuel consumption costs estimated by Prophet under scenario 1 if Option 1a is in place (i.e. the 3rd transformer at Heywood + 100 MVar capacitor + 132 kV works). A positive difference represents a *reduction* in fuel costs resulting from the credible option (a market benefit), whilst a negative difference represents an *increase* in fuel costs resulting from the credible option (a market cost).

The differences in dispatch costs have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.2 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load, once pool prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.[58]

The Prophet modelling incorporates voluntary load curtailment as part of its suite of dispatch options. As a consequence, the market benefit associated with changes in voluntary load curtailment is already reflected in the difference in dispatch cost outcomes discussed under section 6.2.1.

ElectraNet and AEMO note that the level of voluntary load curtailment currently present in the NEM is limited.

6.2.3 Changes in involuntary load shedding

Raising the import capacity of the Heywood Interconnector increases the generation supply availability from Victoria to meet demand in South Australia. This will provide greater reliability for South Australia by reducing the potential for supply shortages and the consequent risk of involuntary

[58] It is also noted that the frequency of high price periods will be limited in the SRMC analysis, and therefore voluntary load curtailment is likely to be underestimated. However, this is not expected to have a material impact on results.

load shedding. At the same time, increasing the export capability from South Australia provides greater reliability for the Victorian region.

ElectraNet and AEMO have quantified the impact of changes in involuntary load shedding associated with the implementation of each credible option via the Prophet market modelling. Specifically, the Prophet modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to the estimated level of USE. The VCR adopted for this RIT-T analysis varies for each jurisdiction, and reflects the regional VCR estimates presented in AEMO's 2012 National Value of Customer Reliability study.[59]

The differences in USE have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.4 Changes in costs for other parties

Changes in costs to other parties reflects the differences in the value of generation investment between the base case 'state of the world' and the 'state of the world' arising from the implementation of each of the credible options.

Differences in generation investment can relate to the type, timing and quantity of generation investment between the base case (in which no action is undertaken by ElectraNet and AEMO) and each credible option. In particular, differences in generator capital and fixed costs between the base case and with the credible option in place could arise due to:

- A deferral of the need to build new generation investment, arising from an increased ability to share generation resources across the expanded interconnector capacity (for the network options), or a reduction in peak demand (for the DM option).
- A difference in the type of generation investment, given the change in market opportunities represented by the expanded interconnector capacity, and/or modified demand conditions (for the DM option). In particular, expansion of the interconnector may provide increased opportunities to invest in generation technologies with high capital costs but low fuel cost and low emission generation, such as wind and geothermal.
- Changes in the location of new wind generation prior to 2020 to meet the LRET target, to higher-efficiency wind locations, resulting in an overall decrease in the MW of wind generation required.

The generation expansion plan in the base case and under each option[60] for each scenario has been derived on the basis of the PLEXOS modelling described earlier (section 5.3.1). The exception is for the DM component of Option 5, where an assumption of a five year deferral of 200 MW of OCGT investment in South Australia compared with the base case has been made in scenarios 1, 2 and 3, and a two year deferral of 87 MW of OCGT in South Australia in scenario 4.

[59] AEMO, January 2012, National Value of Customer Reliability, p. 4. for example, the VCR applied for South Australia is $44,300/MWh whilst that for Victoria is $57,290/MWh.

[60] As noted earlier, Option 6a (stand-alone control scheme) is not expected to impact generation investment decisions, due to its relatively small scale, and so there is no impact on the base case expansion plan for this option.

Differences between the base expansion plan and the expansion plan resulting with the credible option in place have then been identified, and the difference in capital costs and fixed operating costs under the two expansion paths has been calculated. A positive difference between the generation capital costs in the base case and the generation capital costs with the credible option represents a *reduction* in overall capital costs resulting from the credible option (i.e. a market benefit), whilst a negative difference represents an *increase* in capital costs resulting from the credible option (i.e. a market cost). The differences in generator capital and fixed operating costs have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.5 Changes in network losses

The market modelling undertaken by ElectraNet and AEMO has taken into account the change in network losses that may be expected to occur as a result of the implementation of any of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

An increase in network losses represents a negative market benefit (i.e. a market cost), whilst a reduction in losses represent a positive market benefit.

The market benefits of the change in losses have been quantified by a direct calculation of the likely MWh impact on losses in each trading interval for each year of the modelling horizon. Specifically, losses on the interconnectors have been modelled explicitly based on loss equations from the NTNDP, with the Heywood equations updated to take into account the proposed augmentations. Intra-regional losses have been modelled using the generator marginal loss factors for 2011/12. These MWh figures for losses have then been multiplied by the value of those losses, as measured by the Pool Price applicable in each trading period, taken from the Prophet dispatch modelling.

The differences in network losses have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.3 Net Present Value results

This section summarises the results of the net present value (NPV) analysis. Appendix E sets out the full NPV results for each of the credible options, under each of the three scenarios. The full NPV analysis shows separately the costs for each option, and each class of material market benefit.

6.3.1 Gross market benefits

Table 6.2 summarises the gross market benefit, in NPV terms, for each of the nine credible options included in the RIT-T analysis. The gross market benefit is the sum of each of the individual categories of material market benefit (both positive and negative), as quantified on the basis of the approach set out in the preceding section.

As discussed earlier, the gross market benefit of each option has been calculated for four reasonable scenarios. The results for each option under each scenario have then been weighted together in order to derive the overall market benefit for each option.

A detailed breakdown of the gross market benefit for each credible option, under each scenario is provided in Appendix E. The remainder of this section discusses some high-level observations in relation to the key drivers of market benefits for each option, and how these differ between the individual scenarios.

Key categories of market benefit

A review of the results of the gross market benefit quantification highlights that the two main categories of market benefit which are material for this RIT-T are changes in fuel consumption and changes in costs for other parties (i.e. changes in generator investment costs). Losses and changes in involuntary load shedding (unserved energy) form only a very minor part of the total gross market benefit calculated for any of the nine options.

This conclusion holds across all four of the reasonable scenarios. In general terms, the market benefit associated with each of the options arises from the ability of that option to facilitate the increased output of lower operating cost generation (including emissions costs), across the NEM as a whole.

The precise pattern of market benefits, and the relative breakdown between changes in fuel consumption and changes in generator investment costs differs across scenarios. The most notable difference is that under the revised central scenario (scenario 4) changes in fuel costs form a higher proportion of the overall market benefit of each option, compared to the other three scenarios where changes in generation investment costs (and notably an *increase* in those costs) are also significant.

The one outlier in terms of the nine credible options considered is Option 6a (the stand-alone control scheme option). The market benefits for this option predominantly relate to changes in fuel costs since the expansion plan used for this option is no different from the base case, so there are no changes in generator investment costs. Whilst this option has a positive market benefit, the size of that benefit is orders of magnitude different to the other options included in the assessment. Appendix E provides the detailed breakdown of the market benefits for this option. However given that it is a clear outlier, Option 6a is not discussed further in this section.

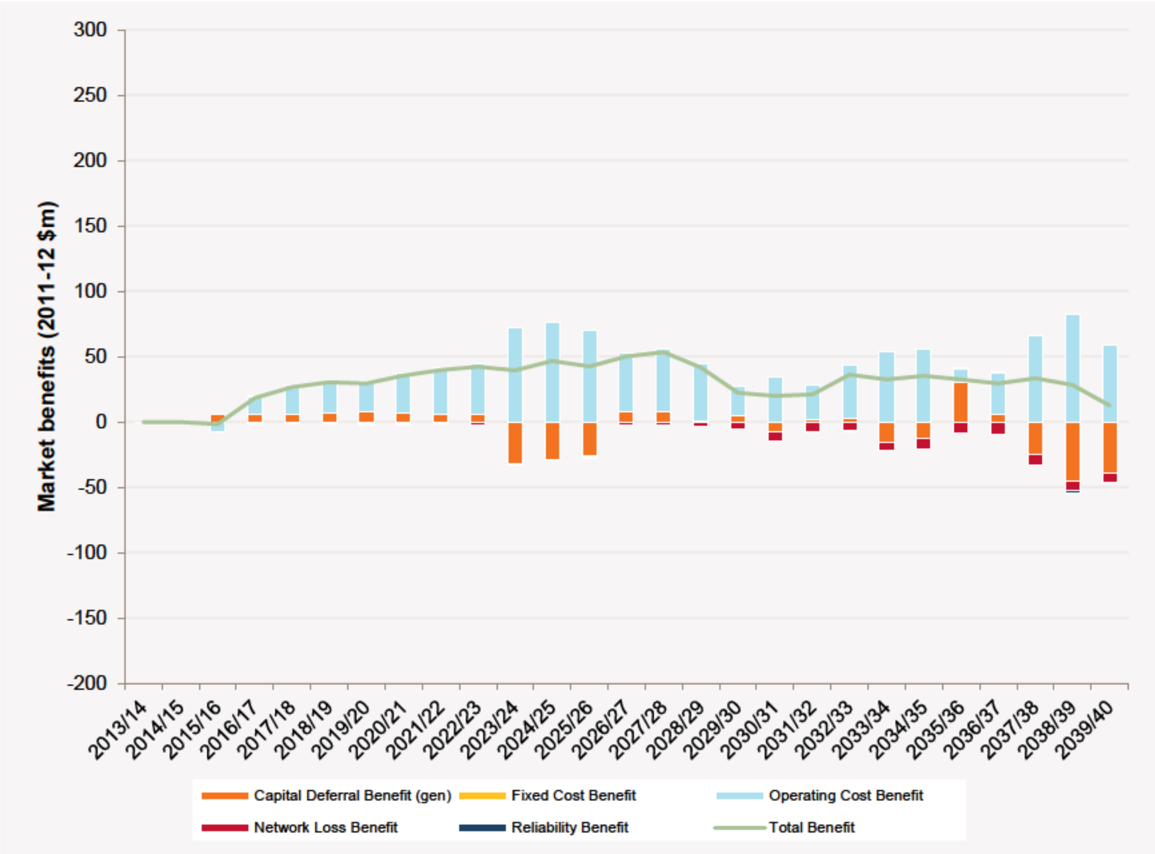
Table 6-2: Gross market benefit for each credible option (NPV, $m)

		Scenario 1: Central Scenario	Scenario 2: Low Scenario	Scenario 3: High Scenario	Scenario 4: Revised Central Scenario	Market Benefit (weighted)
Scenario weights		29%	13%	17%	41%	
Option 1a	3rd Heywood transformer + 100 MVar capacitor + 132 kV works	144.6	308.8	264.5	232.0	222.2
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	199.1	340.8	306.2	284.0	270.5
Option 2a	Option 1a + 3rd South East transformer	151.6	308.7	272.7	236.8	227.5
Option 2b	Option 1b + 3rd South East transformer	199.2	340.5	304.9	284.2	270.4
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	290.8	444.7	350.0	247.2	303.0
Option 4	132 kV works + 100 MVar capacitor	85.9	176.6	173.4	190.8	155.6
Option 5	200 MW DM + Option 1b	261.5	411.7	372.6	271.6	304.1
Option 6a	Control schemes + 500 kV bus tie	19.9	48.8	8.5	12.1	18.5
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	176.0	342.9	295.4	261.6	253.1

Figure 6-1 shows the breakdown of gross market benefits for Option 1b (3rd Heywood transformer + 100 MVar capacitor + 132 kV works), under scenario 1 (central scenario). It is clear from the figure that the main positive category of market benefit for this option under this scenario is the reduction in generator operating costs (which comprise mainly fuel and carbon costs) resulting from the implementation of the option. In the earlier years of the assessment period, and in some subsequent years, there is also a limited benefit in terms of reduced generation investment costs. However, from

2023/24 onwards, generation investment costs in several years actual *increase* as a result of implementation of the option, indicating additional investment in capital-intensive generation in order to realise dispatch cost benefits.

Figure 6-1: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) – gross market benefits (central scenario) (2011/12 $m)



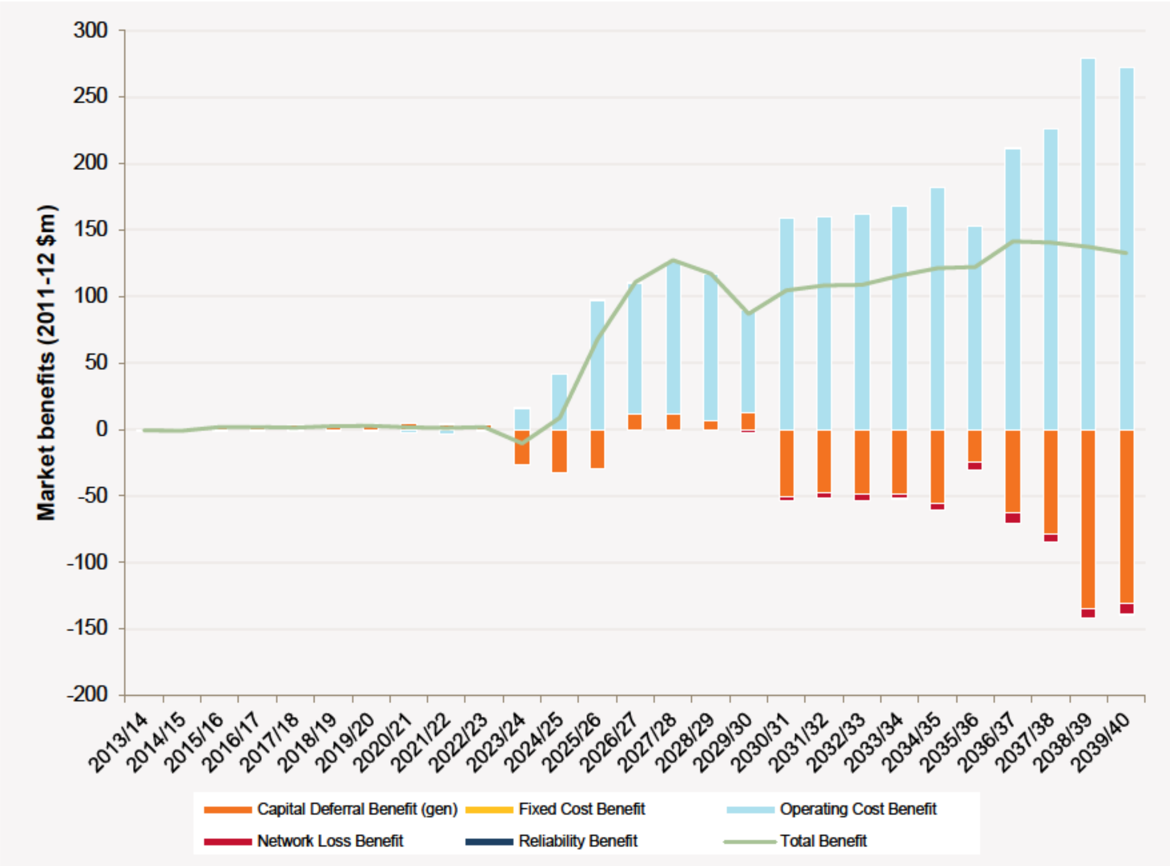
The overall pattern and breakdown of gross market benefits under the central scenario is very similar for Options 1a, 2a, 2b, 4, 5 and 6b. However the following differences are worth noting:

- The magnitude of the differences in fuel costs and generator investment is slightly lower for Option 1a compared with Option 1b. This is because Option 1a (which includes the capacitor) results in lower voltage stability limits over the interconnector (for both flow directions) compared with Option 1b (which include series compensation). These voltage stability limits begin to become significant during the later years of the assessment period for Victoria to South Australia flows, limiting flows below those which are possible under Option 1b.
- The options which include the 3rd South East transformer (i.e. Options 2a and 2b) have only slightly higher overall gross market benefits than the corresponding options without the South East transformer (i.e. Options 1a and 1b). The re-arrangement of the 132 kV network leads to higher flows on the parallel 275 kV network compared to the base case, which in turn results in lower parallel flow through the South East transformers due to interconnector flows, and reduces the scope for market benefits.

- Option 4, which does not include the 3rd Heywood transformer, has a lower overall magnitude of market benefits due to the lower interconnector limits (+/- 460MW) without the transformer.
- Option 5 has the additional capital deferral benefit associated with the 5-year DM program deferring the need for 200 MW of new OCGT plant in South Australia.

The pattern of market benefits is different for Option 3 (new Krongart – Heywood 500 kV interconnector + 275 kV works). Under the central scenario, this option shows benefits occurring later than for the other options, but being of a greater magnitude. However, the key benefit categories remain operating cost savings and generation capital deferral, with the latter representing a negative benefit in most years (i.e. an increased cost of generation investment following the augmentation).

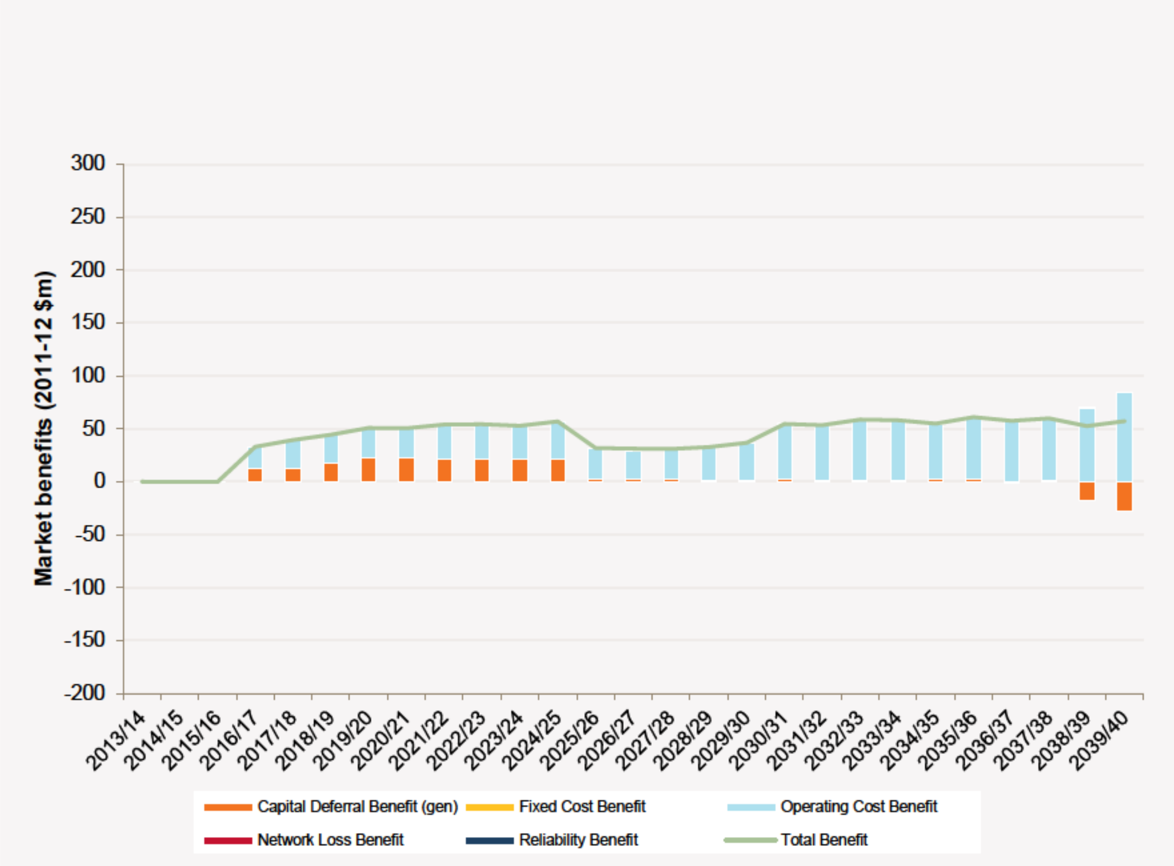
Figure 6-2: Option 3 (New Krongart 500 kV interconnector + 275kV works) – gross market benefits (central scenario) (2011/12 $m)



The pattern and breakdown of market benefits for scenario 2 (low scenario) and scenario 3 (high scenario) are similar to that for the central scenario. In scenario 2, which has a higher carbon price, there is a greater degree of additional investment in low operating cost and low emission generation, in order to realise dispatch cost benefits.

Scenario 4 (revised central scenario) shows a slightly different breakdown of benefits, in that fuel cost benefits are realised without additional generation investment until much later in the period, due to low demand forecasts and fewer coal-fired generator retirements. Figure 6-3 shows the breakdown of market benefits for Option 1b under scenario 4.

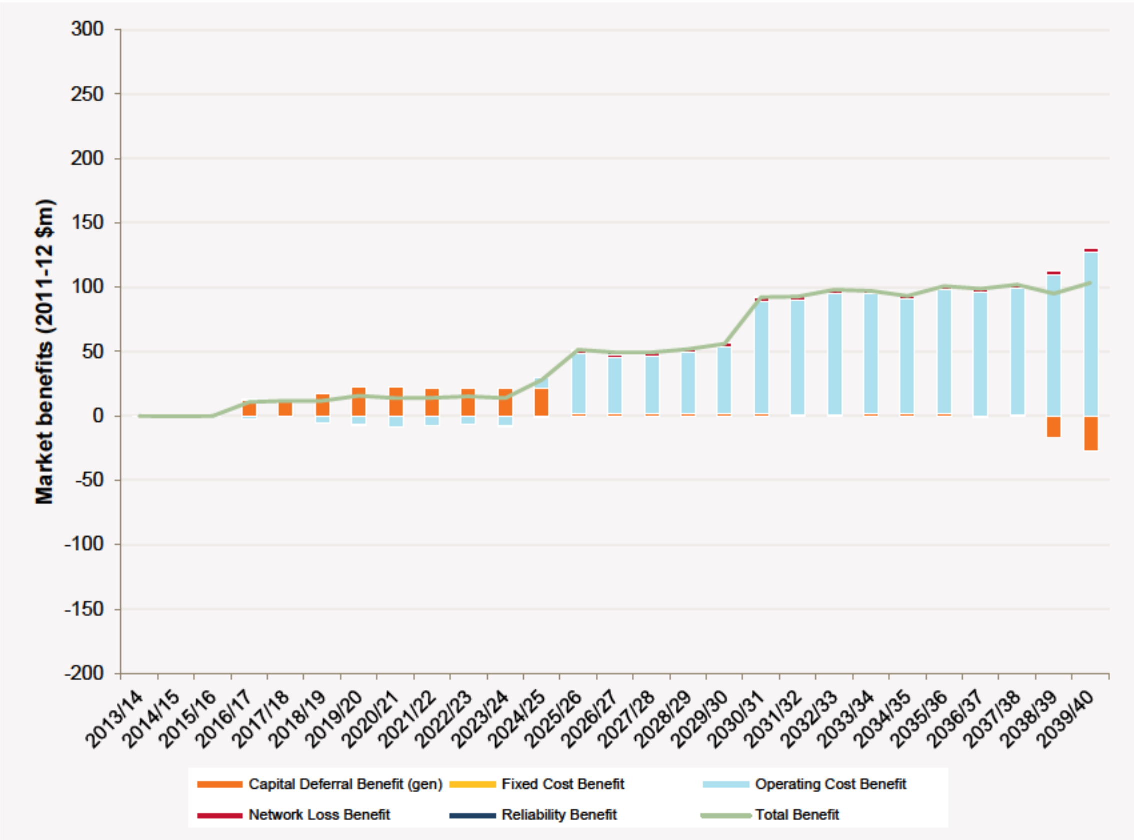
Figure 6-3: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) – gross market benefits (revised central scenario) (2011/12 $m)



This breakdown remains similar for Options 1a, 2a, 2b, 4, 5 and 6b under this scenario, subject to the relativities discussed earlier.

The breakdown of benefits for Option 3 (new Krongart 500 kV interconnector) is also somewhat different under scenario 4, as shown in Figure 6-4. Again, under this scenario substantial benefits in relation to fuel consumption are achieved, without a corresponding increase in the level of investment in low operating cost generation. This reflects an increase in imports into South Australia, as lower operating cost generation outside of South Australia is substituted for higher operating cost generation in South Australia.

Figure 6-4: Option 3 (New Krongart 500 kV interconnector + 275kV works) – gross market benefits (revised central scenario) (2011/12 $m)



Changes in fuel costs

The change in fuel costs represents the biggest category of positive market benefit associated with each of the options. This is the case across all of the options and for each of the scenarios considered, although the underlying changes in fuel costs differ between scenarios. A detailed breakdown of the impact of each option on generation output for each jurisdiction, under each scenario, is provided in Appendix E.

Changes in fuel costs reflect the change in generation dispatch which is facilitated by each of the credible options, compared to the base case in each scenario. Differences between scenarios reflect the impact of the different assumptions between scenarios (such as the assumed carbon price, which will directly affect the relative costs of different generation sources). It will also reflect different base case generation expansion plans associated with the different scenarios. For example, in scenario 1 (central scenario), substantial additional generation (particularly wind generation) is assumed in the base case generation expansion plan, compared with scenario 4 (revised central scenario).

Figure 6-5 and Figure 6-6 show the changes in the source of generation output that arise from Option 1b, compared to the base case, for the central scenario. Specifically Figure 6-5 highlights the five sources of generation which have the largest increases[61] in output (in GWh) together with the remaining overall increase in generation output across all other remaining generation sources. Figure 6-6 presents the same breakdown, but in relation to the main sources of decreases in generation.

[61] Where he increase is measured by adding the annual GWh changes over he modelling period.

Figure 6-5: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) - top five increases in NEM generator dispatch (GWh), central scenario

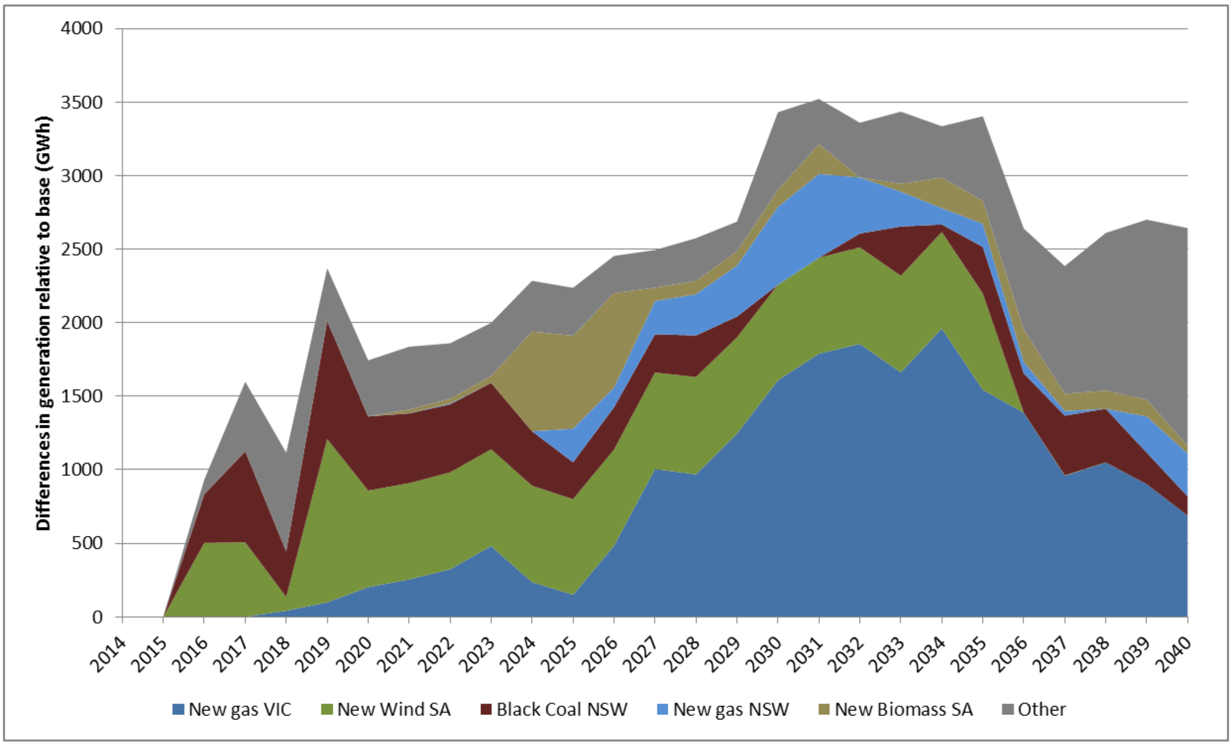
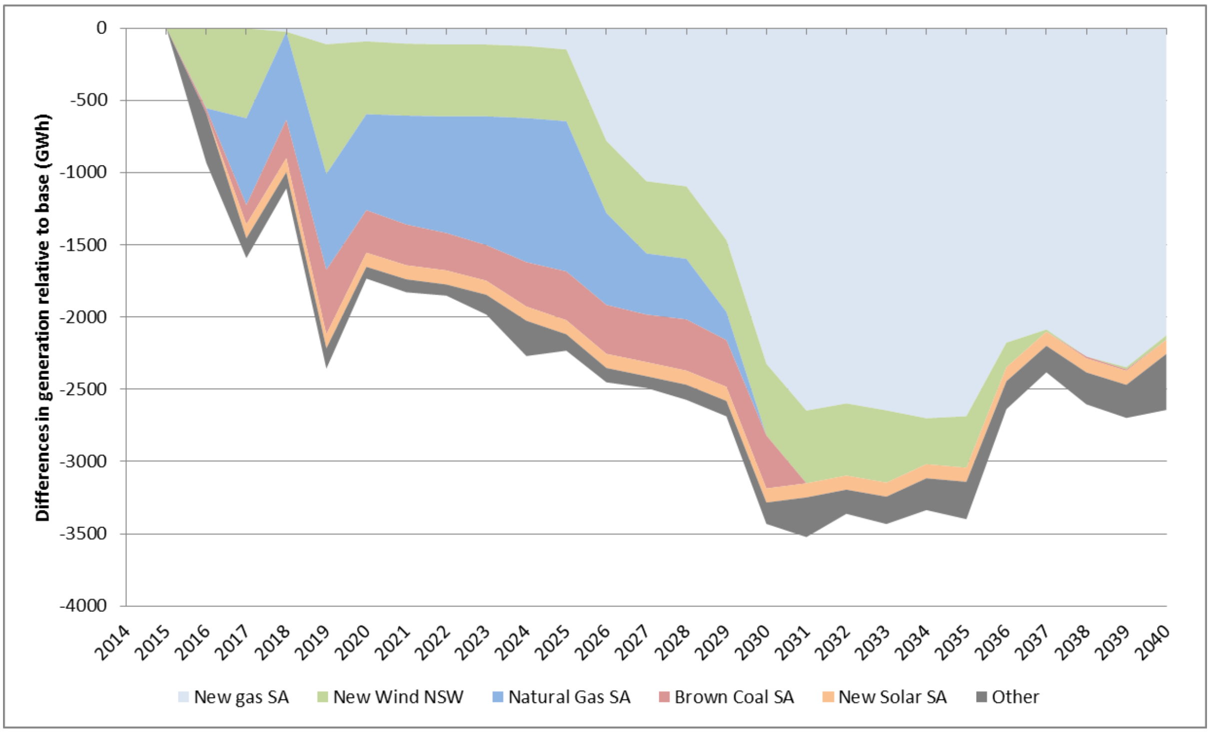


Figure 6-6: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) - top five decreases in NEM generator dispatch (GWh), central scenario



From the figures it is clear that a key impact of Option 1b under the central scenario is the increase it enables in the output of new wind generation in South Australia from 2015 and, later in the period, the increase in the output of new gas-fired generation in Victoria. Increases in these sources of generation displace higher fuel cost generation from new and existing gas-fired generators in South Australia, and from new wind generation in NSW, which would otherwise have occurred in the base case. The fuel cost benefit for Option 1a reflects the differences in generation operating cost (including carbon costs) associated with this changed pattern of dispatch.

A similar change in dispatch patterns is evident for the majority of other options in this scenario. The pattern of redispatch under Option 3 (new Krongart – Heywood 500 kV interconnector + 275 kV works) is slightly different in that it shows increased output of new gas generation in Victoria, together with new geothermal generation in South Australia, predominantly displacing the output of new gas plant in South Australia. The changes in generation output under Option 3 are shown in Figure 6-7 and Figure 6-8.

Under the revised central scenario (scenario 4), the dispatch of generation resulting in lower fuel costs (including emission costs) remains the key component of market benefit under each of the options. However, the specific changes in generation redispatch differ to that under the central scenario. Figure 6-9 and Figure 6-10 show the top five changes in the source of generation output (in GWh) that arise from Option 1b (3rd Heywood Transformer + series compensation + 132kV works), compared to the base case, for the revised central scenario.

The figures show that under the revised central scenario (scenario 4) a key impact of Option 1b is the increase it enables in the output of new biomass generation in South Australia, displacing the need to build OCGTs in South Australia to meet reserve requirements. With an increase in biomass investment in South Australia, less biomass is required to be built in NSW to meet the LRET, and NSW biomass generation is replaced by existing black coal generation in New South Wales. To a lesser extent, there is also increased output of existing wind generation in South Australia. Increases in these sources of generation displace higher fuel cost generation from new and existing gas-fired generation in South Australia, which would otherwise have occurred in the base case. Again, this revised dispatch pattern reflects a lower overall dispatch cost (including carbon cost).

In relation to the remaining scenarios:

- Under the low scenario (scenario 2), Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) results in an increase in the output of new geothermal generation in South Australia together with new gas generation in Queensland. These increases displace new gas-fired generation in South Australia and New South Wales, and new solar generation in South Australia.
- Under the high scenario (scenario 3), Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) results in an increase in new wind generation in South Australia, in addition to new geothermal generation in South Australia and new gas generation in Victoria. These increases predominantly displace generation which would otherwise have been provided from new gas-fired generation in South Australia.

As noted earlier, the differences in generation redispatch between the central, revised central, high and low scenarios reflects differences in the modelled expansion plans and input assumptions between scenarios. What is consistent across all scenarios is that market benefits are being driven by the increased dispatch of low operating cost and low emission generation sources.

Figure 6-7: Option 3 (New Krongart 500 kV interconnector + 275kV works) - top five increases in NEM generator dispatch (GWh), central scenario

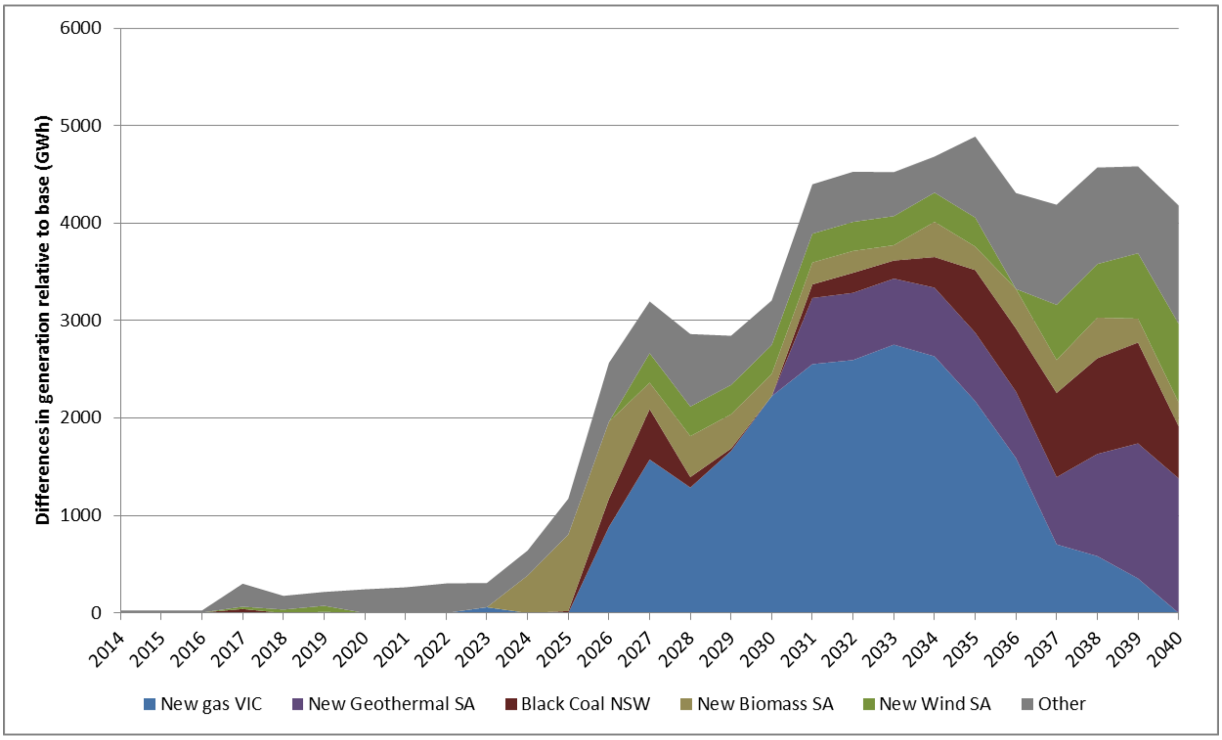


Figure 6-8: Option 3 (New Krongart 500 kV interconnector + 275kV works) - top five decreases in NEM generator dispatch (GWh), central scenario

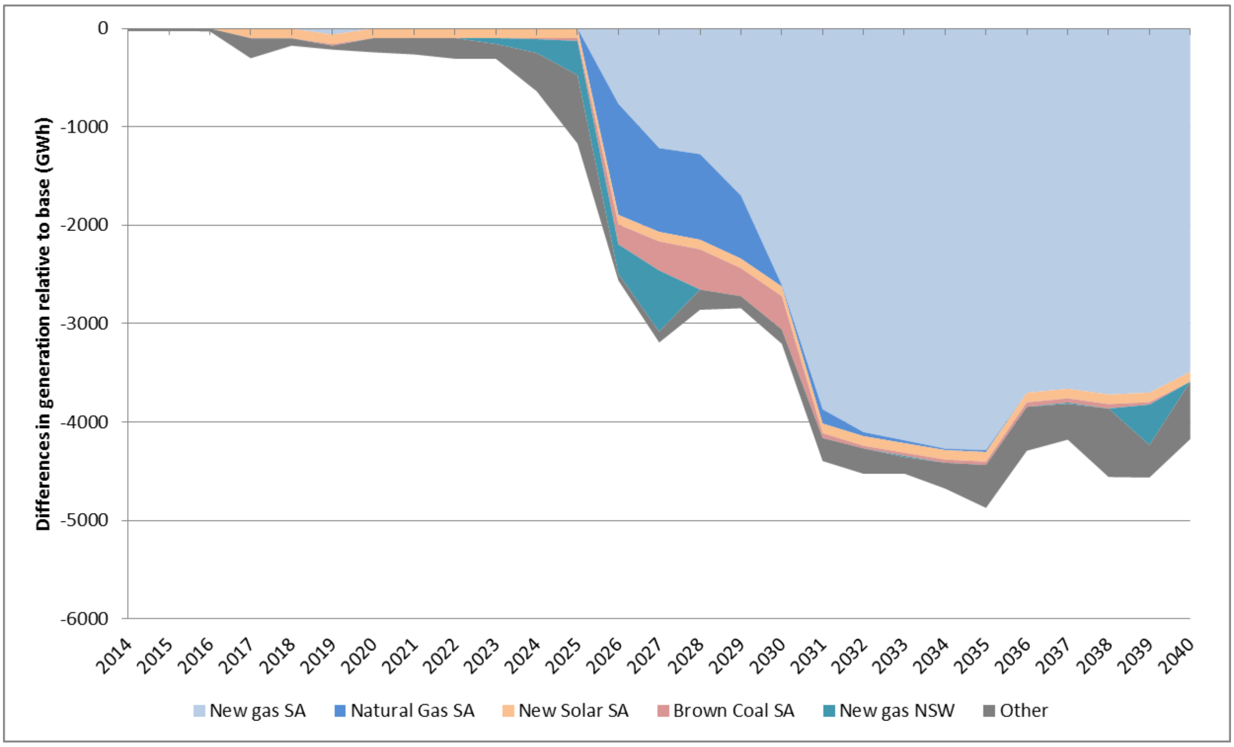


Figure 6-9: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) - top five increases in NEM generator dispatch (GWh), revised central scenario

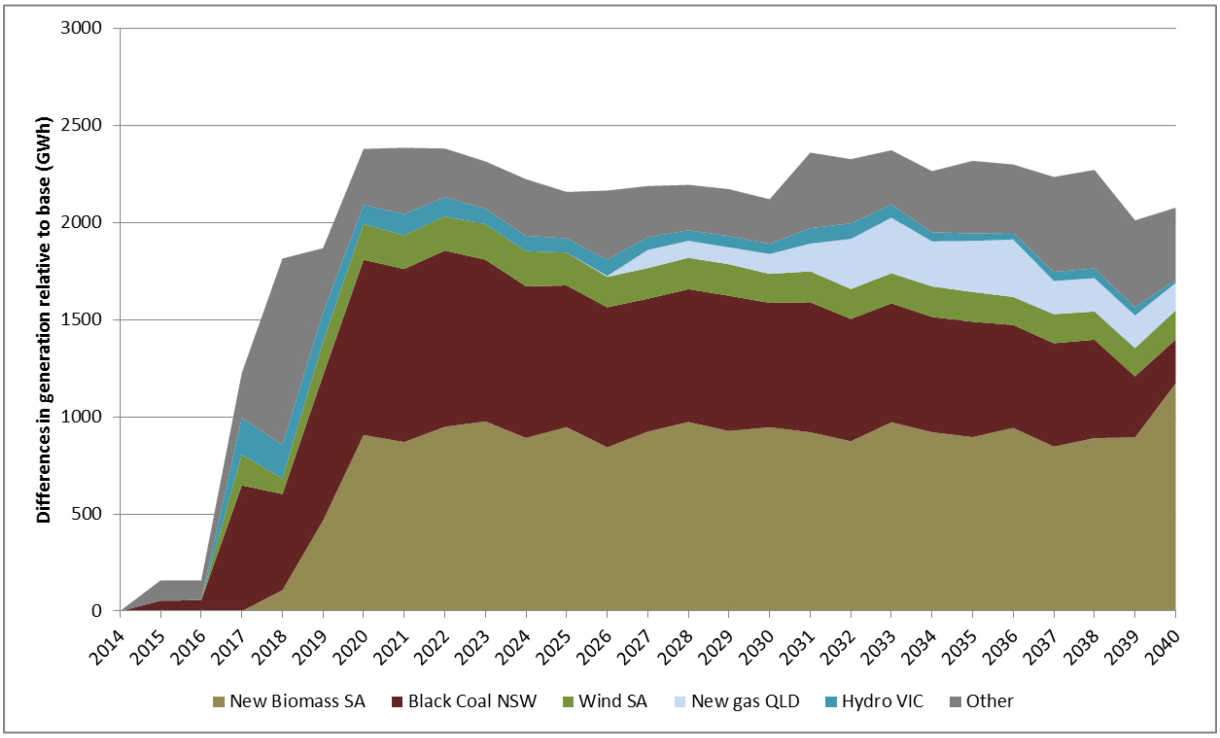
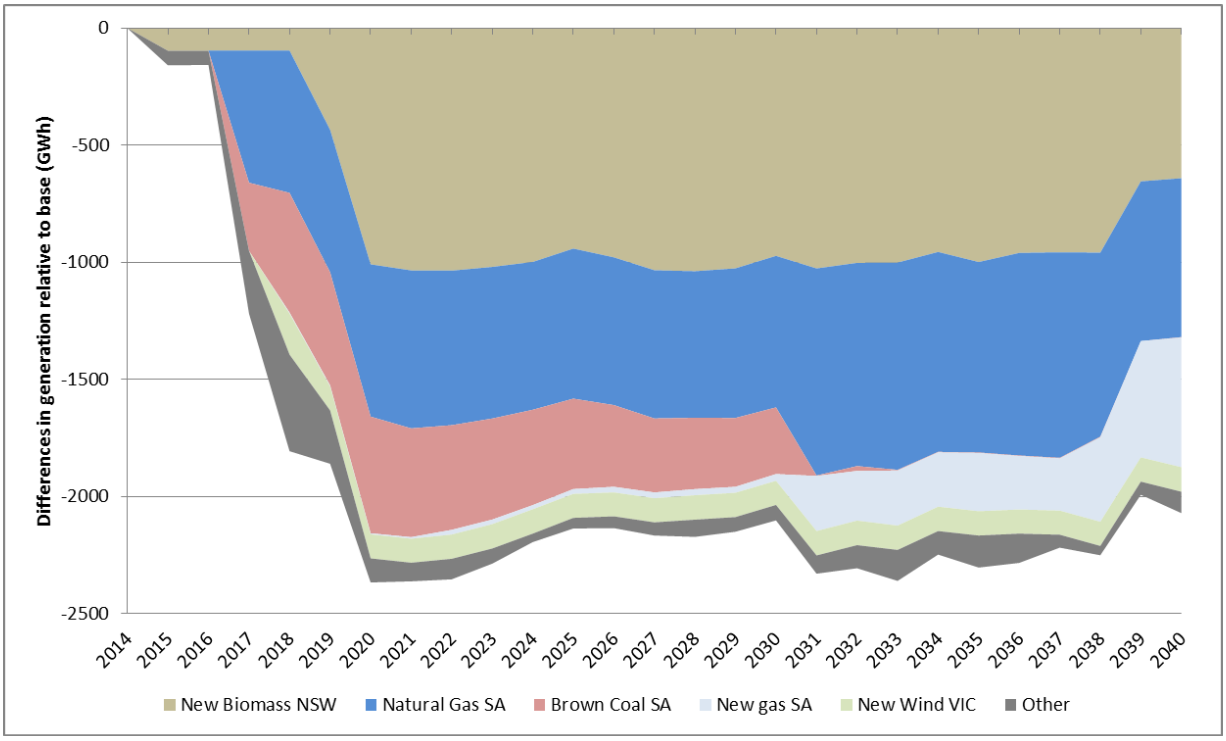


Figure 6-10: Option 1b (3rd Heywood Transformer + series compensation + 132kV works) - top five decreases in NEM generator dispatch (GWh), revised central scenario



Changes in generation investment

It is evident from the preceding discussion that for scenarios 1 (central scenario), 2 (low scenario) and 3 (high scenario), a substantial proportion of the change in fuel costs resulting from the different credible options is related to changes in the output of new (modelled) generation, as well as existing generation. The modelling results indicate that the different credible options considered each, to varying extents, enable additional investment in low fuel cost sources of generation, compared with the base case. This includes (but it not limited to), new gas-fired generation in Victoria displacing new gas-fired generation in South Australia and new wind generation in South Australia displacing wind generation in NSW.

The impact on gross market benefit of the change in generation investment pattern will depend on the relative costs of the additional generation, compared to the generation displaced. The modelling results highlight that for scenarios 1 (central scenario), 2 (low scenario) and 3 (high scenario) there is an overall increase in the cost of generation investment under each option, compared to the base case, representing a negative market benefit. However, this negative benefit is outweighed by the positive market benefit resulting from the overall reduction in dispatch costs resulting from the increased presence of low-cost generating sources (discussed above). This impact does not occur to the same extent under scenario 4 (revised central scenario) due to the relatively low demand growth and fewer coal-fired generation retirements.

A detailed breakdown of the change in generation investment by jurisdiction is provided in Appendix E, across all scenarios.

As an illustration, Figure 6-11 and Figure 6-12 summarise the five largest changes in the type of generation investment across the NEM as a whole (cumulative MW over the overall assessment period) under the central scenario for Options 1a,1b, 2a, 2b, 4 and 6b.[62] For Option 5 (200 MW DM + Option 1b) an additional impact of the deferral of 200 MW of OCGT investment in South Australia by five years from 2013/14 has also been assumed under the central scenario.

Figure 6-13 and Figure 6-14 show the equivalent key changes in the generation expansion plan associated with Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works), under the central scenario.

[62] As discussed in section 5.3.1, the impact of these six options on the generation expansion plan was found to be materially identical, and so the same expansion plan was adopted across all of these options.

Figure 6-11: Options 1a, 1b, 2a, 2b, 4 and 6b - top five increases in NEM generation investment (MW), central scenario

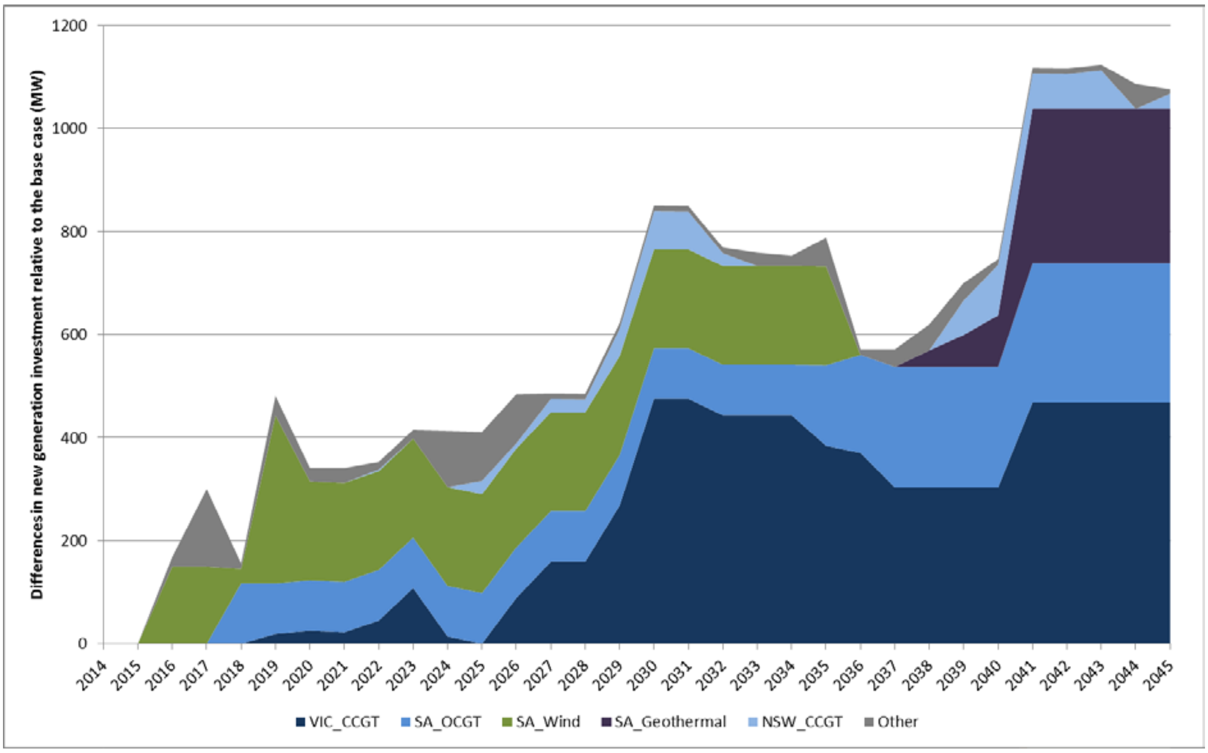


Figure 6-12: Options 1a, 1b, 2a, 2b, 4 and 6b - top five decreases in NEM generation investment (MW), central scenario

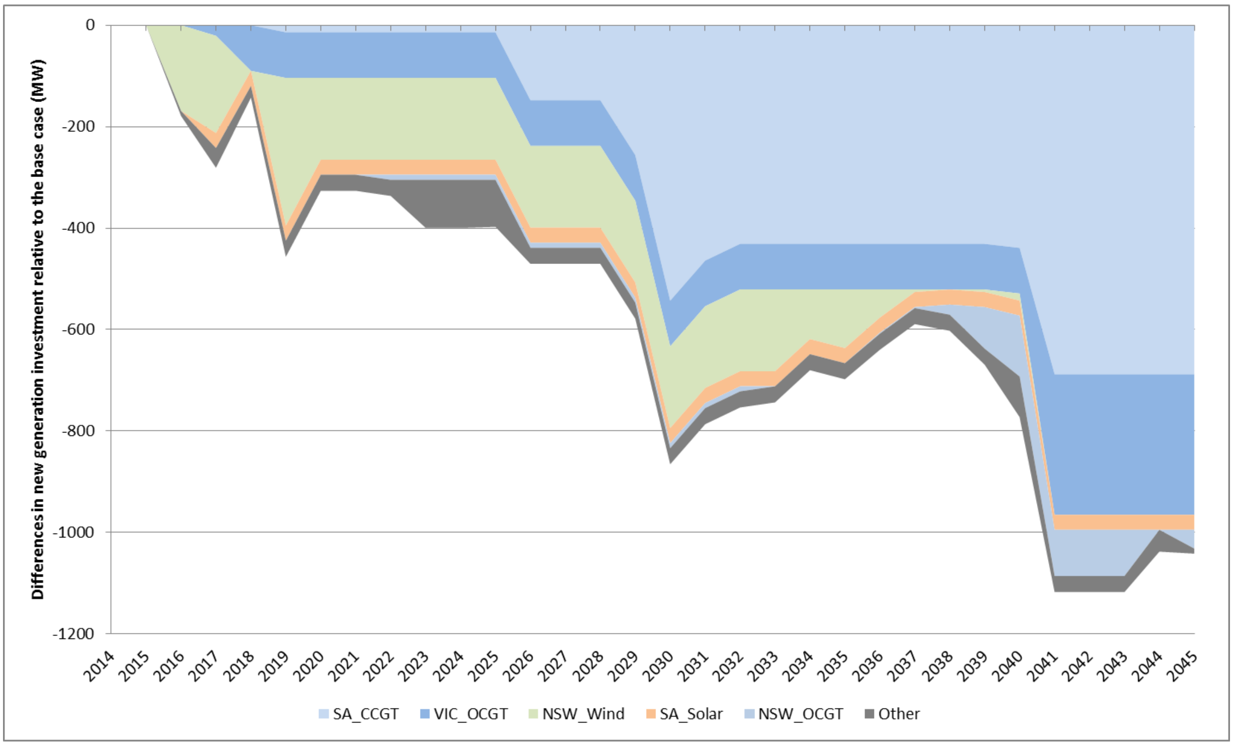


Figure 6-13: Option 3 (New Krongart-Heywood 500 kV interconnector + 275 kV works) - top five increases in NEM generation investment (MW), central scenario

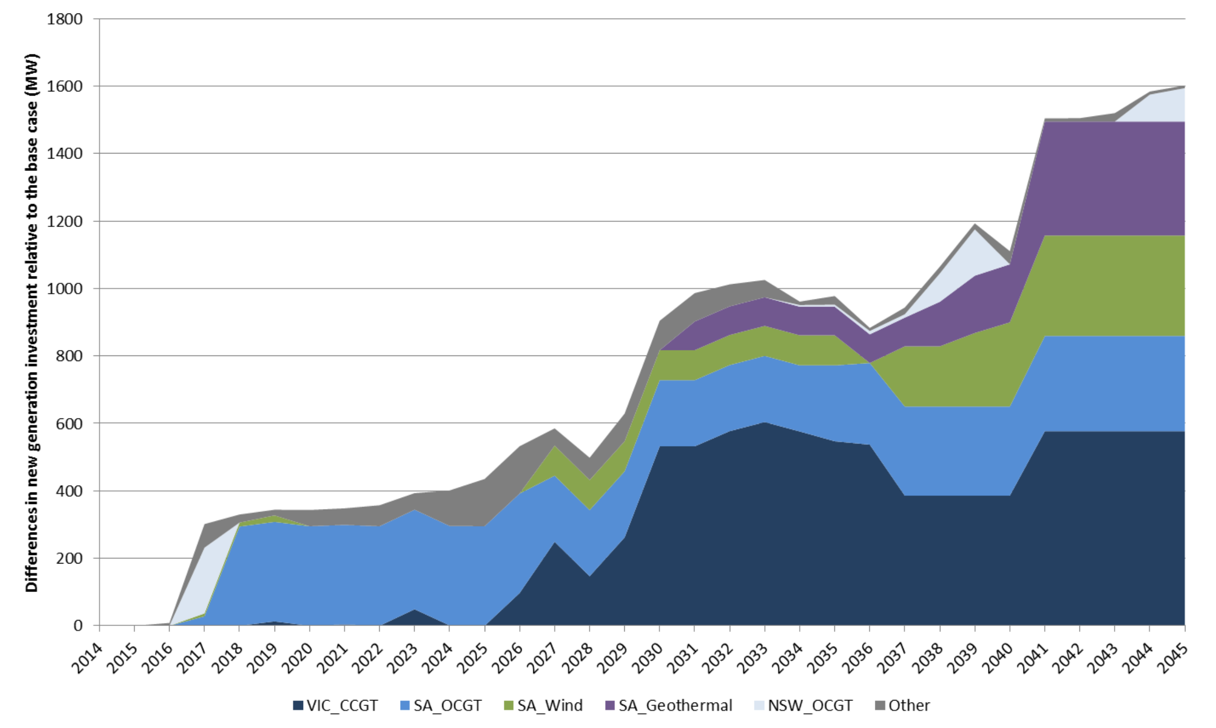
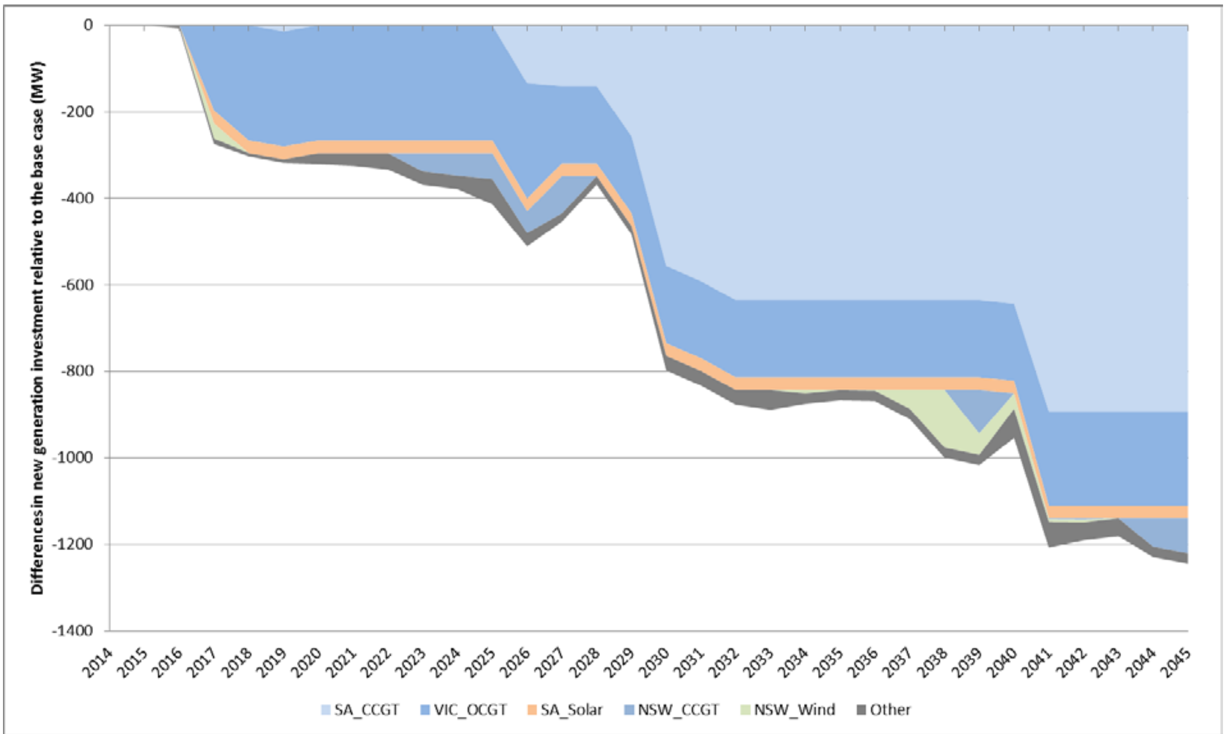


Figure 6-14: Option 3 (New Krongart-Heywood 500 kV interconnector + 275 kV works) - top five increases in NEM generation investment (MW), central scenario



6.3.2 Net market benefits

Table 6.3 summarises the net market benefit in NPV terms for each credible option. The net market benefit is the gross market benefit, weighted across all scenarios (as set out in Table 6.2), minus the costs of each option, all in present value terms.

The table also shows the corresponding ranking of each option under the RIT-T, with the options ranked from 1 to 9 in order of descending net market benefit.

Table 6-3: Net market benefit for each credible option (PV, $m)

		Costs	Market benefit	Net market benefit	Ranking under RIT-T
Option 1a	3rd Heywood transformer + 100 MVar capacitor + 132 kV works	57.8	222.2	164.4	4
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	79.8	270.5	190.8	=1
Option 2a	Option 1a + 3rd South East transformer	70.7	227.5	156.9	6
Option 2b	Option 1b + 3rd South East transformer	92.7	270.4	177.7	3
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	212.2	303.0	90.8	8
Option 4	132 kV works + 100 MVar capacitor	30.6	155.6	124.9	7
Option 5	200 MW DM + Option 1b	147.1	304.1	156.9	5
Option 6a	Control schemes + 500 kV bus tie	17.6	18.5	0.9	9
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	64.1	253.1	189.0	=1

Table 6.3 shows that all of the credible option considered have a positive net market benefit. As a consequence, all of the options are ranked higher than the 'do nothing' option, and could be expected to result in an overall net benefit to the market.

Option 6a (Stand-alone control schemes + bus tie) is a clear outlier in terms of net market benefit, with an overall net market benefit orders of magnitude below other credible options. Even with the control scheme in place, which can theoretically increase the thermal limits for the interconnector flows to 690 MW from South Australia to Victoria with future generation added at Krongart (up to 570 MW with existing generation), voltage stability issues would limit this to less than 550 MW. Without the 132 kV network re-arrangements or increased reactive compensation, interconnector flows were found to be frequently limited by other 132 kV network limitations not covered by the control scheme, which in turn limits the benefits associated with this stand-alone option. Further, flows from Victoria to South Australia are not improved in any way under the stand-alone control scheme option, compared to the 'do nothing' option.

It is also evident from the results that the higher costs of Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works) are not outweighed by substantially higher benefits, compared to the other options, resulting in the overall net market benefit for this option being materially below that of other options. Similarly, the results show that the lower costs for Option 1a (which includes a 100 MVar capacitor) do not offset the lower market benefits of this option, compared with Option 1b (which include series compensation), resulting in Option 1a having a lower net market benefit than Option 1b.

The RIT-T assessment also shows that the incremental costs of adding the 3rd transformer at South East substation under Options 2a and 2b are not offset by the additional market benefits. As noted earlier, the re-arrangement of the 132 kV network leads to higher flows on the parallel 275 kV network compared to the base case. This results in lower parallel flow through the South East transformers due to interconnector flows, which reduces the potential scope for additional market benefits from adding the 3rd transformer at South East. Although there are additional benefits available from installing a 3rd transformer under Option 2a, the cost of this transformer was found to outweigh these benefits. However ElectraNet notes that a 3rd transformer at South East is likely to be needed at some point in the future (in the mid-2020s) in order to address reliability concerns. It would therefore be subject to a separate RIT-T at that time.

The results also demonstrate that there are additional net benefits with including the 3rd Heywood transformer (i.e. Options 1a and 1b) compared with only undertaking the 132 kV works in South Australia and installing a 100 MVar capacitor (i.e. Option 4). The assessment also shows that the additional market benefit associated with including a DM component (i.e. Option 5) is outweighed by the higher cost of that option compared with the network component alone.

Notwithstanding the above conclusions, it is also clear from Table 6.3 that Option 1b (3rd Heywood transformer + series compensation + 132 kV works) and Option 6b (Control schemes + Option 1b minus 3rd Heywood transformer) have the highest net market benefit, but cannot be materially distinguished on this basis alone. Although Option 1b has the greatest net market benefit, the difference between this option and Option 6b is only $1.8m, or 0.95%.

As noted earlier, ElectraNet and AEMO have performed a series of sensitivity tests in relation to these results. Given the closeness of the results, the relative ranking of Options 1b and 6b are sensitive to changes in the discount rate applied, and changes in the assumed network capital costs. However the ranking of the other options relative to Options 1b and 6b are not sensitive to these changes, and in no case were these latter options found to have a higher net market benefit than Options 1b and 6b (see Table 6-4).

Table 6-4: Sensitivity to different discount rates and network capital cost assumptions ($m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
If 6% discount rate applied	328.4	381.9	314.1	358.2	206.4	243.2	338.2	9.2	381.9
If 13% discount rate applied	106.0	122.8	101.1	113.9	53.3	82.1	94.3	(1.3)	120.7
If network capital cost estimates increased by 10%	158.6	182.8	149.8	168.5	69.6	121.9	149.7	0.3	183.8
If network capital cost estimates decreased by 10%	170.2	198.8	163.9	187.0	112.0	128.0	164.1	1.5	194.3

The relative ranking of Options 1b and 6b is also dependent on the scenario weightings adopted. If higher weights are given to the high and low scenarios, this increases the weighted market benefit of Option 6b, relative to Option 1b. However, even if the weights of the high and low scenario were increased to 25% each,[63] Option 6b would only have a net market benefit 1.0% higher than Option 1b. ElectraNet and AEMO consider such high weights for the high and low scenarios to be unrealistic, particularly in the light of the recent announcements in relation to the deferral of the expansion of BHP Billiton's Olympic Dam project and the removal of the floor price under the carbon trading scheme.

BHP Billiton's announcement that it has deferred the expansion of its Olympic Dam project would potentially support applying a lower weight to the high scenario in the RIT-T. The Federal Government's announcement of the removal of the floor price under the carbon trading scheme would potentially support applying a higher weight to the revised central scenario, which is the scenario which incorporates the lowest carbon price assumption. If the weighting of the high scenario is decreased to reflect the Olympic Dam announcement, concurrent with increasing the weighting on the revised central scenario to reflect the Federal Government's announcement of the removal of the floor price under the carbon trading scheme, Option 1b would have a 1.5% higher net market benefit than Option 6b.

Table 6-5 shows the difference in the NPV of net market benefit and the relative ranking of Options 1b and 6b under the discount rate sensitivities and alternative scenario weightings. ElectraNet and AEMO note that sensitivities conducted in relation to the weightings applied to each of the scenarios indicates that the RIT-T outcome is robust to a wide-range of alternative weightings.

[63] This calculation assumes that the weights assumed for the other scenarios are also changed to 25% for scenario 1 (central scenario) and 25% for scenario 4 (revised central scenario.

Table 6-5: Sensitivity to different scenario weightings ($m)

	Net market benefit ($m)		Scenario weighting			
	Option 1b	Option 6b	Central	Low	High	Revised Central
Using current scenario weightings	190.9	189.2	29%	13%	17%	41%
50% combined weighting of high and low scenarios	202.8	204.9	25%	25%	25%	25%
High scenario decreased and revised central scenario increased	187.7	184.8	30%	13%	7%	50%

ElectraNet and AEMO have performed further analysis in relation to Options 1b and 6b, to investigate whether adoption of a different reference year for the load traces used in the dispatch modelling[64] would materially affect the relative net market benefits of these two options. This analysis showed that adopting a different reference year does not help to distinguish between the two options. Similarly, studies conducted by ElectraNet in relation to the potential competition benefits associated with these options (discussed in section 6.4) also indicated that the quantification of competition benefits would not provide a robust basis on which to distinguish between these options.

In light of these results, ElectraNet and AEMO consider that the net market benefit of Option 1b and Option 6b are essentially equal.

ElectraNet and AEMO note that there are core investment elements which are common to both Option 1b and Option 6b, namely reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia), 275 kV series compensation in South Australia and the installation of a bus tie at Heywood. These investment components therefore clearly form part of the preferred option.

The question is therefore whether this ‘core’ network component should be coupled with a 3rd transformer at Heywood (i.e. Option 1b) or network control schemes (i.e. Option 6b).

In relation to Option 6b, ElectraNet and AEMO note that the inclusion of series compensation and 132 kV re-arrangements as part of this option overcomes the voltage and thermal limitations discussed above in relation to the stand-alone control scheme option (i.e. Option 6a), to allow the control scheme to fully utilise the non-firm ratings of the Heywood transformers and South East to Heywood lines. The series compensation also improves the voltage stability limits for Victoria to South Australia when compared to the base case. Although still limited to 460 MW Victoria to South Australia, this full 460 MW is able to be better utilised, so realising benefits for additional flows in this direction.

The impact of the control schemes is to expand the export capacity from South Australia at lower cost than under the 3rd Heywood transformer. It therefore has greater market benefits under those scenarios in which there is substantial investment in renewable generation (particularly geothermal generation) in South Australia, i.e. the high and low scenarios. In contrast, adding a 3rd transformer at Heywood increases both the import and export capability of the interconnector. It therefore enables

64 As set out in section 5.3.2, the Prophet model has been run using load traces from 2009/10. Sensi ivity of the results for Options 1a and 6b to the adoption of load traces for 2005/6 and 2007/8 were also conducted, as noted above.

additional exports from South Australia, albeit at a lower level that is facilitated by the control schemes, whilst also enabling increased imports of lower cost generation into South Australia.

ElectraNet and AEMO note that there are a number of risks associated with selecting the control scheme component of Option 6b in preference to adding a 3rd transformer at Heywood, several of which were discussed in section 3.2. In particular:

- There is substantial uncertainty in relation to the commercial feasibility of the control schemes, as issues relating to liabilities and associated indemnities would need to be worked through. It is anticipated that significant further work would be required, with an uncertain outcome, since initial investigation of commercial issues for the PADR indicates that the commercial issues are not straightforward.
- The issue of technical feasibility would need to be subject to further detailed investigation, particularly in relation to issues of wider system security and the overload ratings of the Heywood transformers.
- The RIT-T assessment has included benefits associated with additional wind generation locating at Krongart and participating in the control scheme. However there is currently no application from new wind generators to connect at Krongart, and so this portion of the market benefit remains speculative.
- The costs of the control scheme component are relatively uncertain, including the assumption of zero participation fees for generators.
- Adding a 3rd transformer at Heywood would have the added benefit of reducing the risks associated with a prolonged outage of one of the existing transformers, compared with the alternative of adopting the control schemes. Although the probability of a transformer outage is low, if a catastrophic failure of one of the Heywood transformers did occur (for example, due to a failure in the transformer tank) then the replacement time would be in the order of two years. During this period, the interconnector limits would become 460 MW (each way) if there was a third Heywood transformer in place (i.e. Option 1b). However, if the control schemes were to be adopted instead (i.e. Option 6b), the interconnector limits would fall to approximately 250 MW (South Australia to Victoria) and 210 MW (Victoria to South Australia).

In the light of the risks associated with selecting the control scheme component in preference to adding a 3rd transformer at Heywood, ElectraNet and AEMO have determined that the preferred option for investment is Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).

ElectraNet and AEMO consider that this is a prudent decision, taking into account the RIT-T assessment and the additional risks associated with Option 6b. The transformer is a lower risk option that performs equally as well in the assessment of market benefits and satisfies the RIT-T.

6.4 Competition benefits

Competition benefits are defined in the RIT-T as 'net changes in market benefit arising from the impact of the credible option on participant bidding behaviour'. [65]

A lack of competition between generators can lead to one or more of the following outcomes:

- Non-optimal dispatch: cheap generation may be withheld, and replaced by more expensive peaking generation.
- Reduced consumption: higher electricity prices as a result of non-competitive outcomes lead to less consumption and therefore lower utility for electricity consumers, whether residential or commercial/industrial.
- Over investment in generation: inflated prices may bring forward unnecessary investments in generation that would have been uneconomic under a competitive market.

Where a credible option results in changes in participant bidding behaviour, market benefits can arise as a result of improvements in each of the above areas.

Changes in bidding behaviour can also lead to substantial wealth transfers between market participants. However wealth transfers between participants in the NEM are not counted as a market benefit under the RIT-T.

There are substantial challenges with quantifying competition benefits, as it requires assumptions about current and future generator contracting levels, future ownership of generating plant and the price elasticity of demand for electricity. The results are likely to be sensitive to these assumptions and any comprehensive study would need to cover a wide range of sensitivities, reflecting a range of possible futures, in order to derive a robust value. In addition, the complexity of the modelling requires approximate methods to be used, which leads to an uncertainty band around the results.

Due to the complexity of the modelling, quantifying competition benefits is therefore likely to be disproportionate to the scale, size and potential benefits of each credible option considered in the RIT-T analysis, unless competition benefits are expected to be significant and to materially affect the outcome of the RIT-T assessment.[66]

6.4.1 Competition benefit studies

ElectraNet and AEMO have explored a limited number of futures in order to test the likely magnitude of the competition benefits that may be associated with the credible options considered in relation to this RIT-T. This modelling has focussed on estimations of the consumer surplus benefits attributable to changes in consumption.

[65] AER (2010): *Regulatory Investment Test for Transmission*, June 2010, para (5)(h).

[66] The RIT-T requires a TNSP to calculate all classes of market benefits in a RIT-T assessment, unless it can provide reasons why a particular class of market benefit is not likely to materially affect the RIT-T outcome, or where the estimated cost of undertaking the analysis the quantify the market benefit is likely to be disproportionate to the scale, size and potential benefits of each credible option considered in the analysis (NER 5.6.5B(c)(6). For he purposes of the RIT-T, a class of market benefits is judged to be material if it would alter the ranking of alternative options or if it would change he sign of the preferred option's net benefit.

The studies used the Nash-Cournot algorithm in Energy Exemplar's PLEXOS modelling software. Extensive testing was undertaken to ensure that the results from the PLEXOS model were comparable with the outputs from AEMO's Prophet model.

ElectraNet made the following assumptions as part of its initial quantification of competition benefits:

- The Price Elasticity of Demand (PED) estimates published by AEMO in its 2012 NEFR were used. The price elasticity published in this report applies to retail electricity prices. ElectraNet scaled these values by forty per cent to reflect the contribution of the spot price to the retail price. [67]
- New entrant generation was assumed to be unattached to any existing portfolio. The implication of this assumption is that competition benefits will reduce over time. As a consequence, ElectraNet has focussed on the first 10 years of the proposed augmentation's life.
- Generation contracting levels have been assumed to be at 90 per cent.

An idealised network model was used which incorporates nominal interconnector limits between the regions but does not enforce the full range of network constraints on dispatch. Testing comparing this idealised model to the outcomes from AEMO's Prophet model indicated that use of the idealised model did not significantly affect results.

Competition benefits were tested only for the central scenario. Given that there was no prior expectation that a particular scenario would drive any more or less competitive outcomes, use of the central scenario was considered appropriate for this exercise.

The studies performed have shown that the magnitude of competition benefits associated with the credible options considered in this RIT-T is very low. Competitive bidding under the Nash-Cournot algorithm led to higher prices when compared to SRMC pricing. These higher prices in turn led to a reduction in consumption. With the credible options in place, prices were lower, and consumption higher. However, the change in the regions expected to be most influenced by the augmentation (Victoria and South Australia) were small, and hence changes in consumption and consumer surplus in these regions were also small. Price impacts did extend beyond these regions; however these were found to be smaller again. Further, changes in consumption were found to be volatile over the years, demonstrating a high level of variability in outcomes.

ElectraNet and AEMO note that the finding that competition benefits are relatively small in the context of this RIT-T is unsurprising. NERA [68] suggests the two following conditions as necessary for competition benefits to arise:

1. There must exist non-competitive bidding strategies in at least one of the relevant spot markets (or, to the extent that intra-regional transmission constraints exist, in some subsets of that spot market) which result in prices being above marginal cost for a sustained period; and

[67] That the values in the AEMO report are comparable to the PED values published by Monash University for South Australia.

[68] NERA (2011): *Assessing Competition Benefits under the RIT-T*, May 2011

2. there must be some change in either the outcome of the non-competitive bidding strategy or in the bidding strategy itself as a result of the option being considered, such that spot market prices fall closer to marginal costs.

In relation to the first condition, the AEMC's draft determination on market power in the NEM[69] has studied evidence in relation to the extent of sustained market power in the NEM. Referring to several consultant's reports, the AEMC concludes that:

> *In consideration of the lack of evidence from NERA's analysis supporting the existence of substantial generator market power, and the lack of firm evidence from CEG's analysis supporting the existence of significant barriers to entry, the Commission considers that there are insufficient grounds to conclude the existence of substantial market power and to assume the likely future exercise of substantial market power by generators in the NEM.*

This suggests the competition benefits, if any, are likely to be moderate at best for many RIT-T assessments.

The second condition requires that the options considered in the RIT-T must be able to affect the outcome of generator bidding behaviour. This suggests that competition benefits are more likely to occur for larger upgrades. Incremental upgrades may have no significant impact on the ability of generators to exercise market power, meaning that competition benefits are likely to be more limited for such upgrades. In the case of this RIT-T, many of the credible options represent incremental upgrades of capacity. The exception is Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works), but even for this option ElectraNet's analysis indicates that the extent of market benefits is of an order of magnitude that would not affect the ranking of this option against the other credible options.

Given the findings from the competition benefit studies, ElectraNet and AEMO have concluded that competition benefits are not material for this RIT-T, and that the quantification required would be disproportionate to the expected level of such benefits. Of the two top-ranked options from the analysis excluding competition benefits, Option 1b (which includes the 3rd Heywood transformer) would be expected to have greater competition benefits than Option 6b (which includes the control schemes), as Option 1b increases the capacity of the interconnector in both directions. However, both of the two top-ranked options relate to relatively small incremental increases in capacity, and therefore the magnitude of competition benefits associated with these options would be relatively low. The significant uncertainty band surrounding any quantification of competition benefits, coupled with this relatively low magnitude, therefore means that it would not be reasonable to distinguish between the two options on this basis alone.

[69] AEMC (2012): *Draft Rule Determination - Potential Generator Market Power in the NEM*, June 2012

7 Proposed preferred option

The previous section has presented the results of the NPV analysis conducted for this RIT-T assessment.

The NER requires the PADR to include the identification of the preferred option under the RIT-T.[70] This should be the option with the greatest net market benefit and which is therefore expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The RIT-T analysis (discussed in section 6.3.2) indicates that Option 1b (3rd Heywood transformer + 275 kV series compensation + 132 kV works) and Option 6b (Control schemes plus Option 1b, minus 3rd Heywood transformer) have the same net market benefit, and are ranked substantially ahead of all other credible options.

ElectraNet and AEMO note that there are core investment elements which are common to both Option 1b and Option 6b, namely reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia), 275 kV series compensation in South Australia and the installation of a bus tie at Heywood.

There are a number of additional risks associated with selecting the control scheme component in addition to the above core elements in preference to adding a 3rd transformer at Heywood, as discussed in section 6.3.2. In light of these risks, ElectraNet and AEMO have determined that the 3rd Heywood transformer should be selected in preference to the control schemes, as the additional component of the preferred option.

The preferred option for investment is therefore Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). This option has a positive net market benefit and satisfies the RIT-T.

The estimated commissioning date for this option is July 2016. The total capital cost of the option is estimated at $107.7m ($2011/12, equating to $79.8m in present value terms) with net market benefits of more than $190 million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

The technical characteristics of this option have been set out in section 3. In compliance with the NER provisions,[71] ElectraNet and AEMO note that this option is likely to have a material inter-regional impact between South Australia and Victoria only.

[70] NER 5.6.6 (c)(8).

[71] NER 5.6.6(k)(9)(iii).

Appendix A – Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clauses 5.6.6(k) of the NER version 42.

NER clause	Summary of requirements	Relevant section in PADR
5.6.6 (k)	A Transmission Network Service Provider must prepare a project assessment consultation report, which must include:	
	• a description of each credible option assessed;	3
	• a summary of, and commentary on, the submissions to the *Project Specification Consultation Report*;	4
	• a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each *credible option*;	3 6.1 6.2 Appdx E
	• a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 6.2
	• the reasons why the TNSP has determined that a class or classes of market benefit are not material, where relevant;	5.6
	• the identification of any class of market benefit estimated to arise outside the TNSP's region and quantification of the aggregate value of such market benefit;	6.2.1 6.2.2 6.2.3 6.2.4
	• the results of an NPV analysis of the net market benefit of each *credible option* and accompanying explanatory statements regarding the results;	6.3 Appdx E
5.6.6 (k)	• the identification of the proposed *preferred option* and a statement that the *preferred option* satisfies the RIT-T: - details of the technical characteristics - the estimated construction timetable and commissioning date - if the option is likely to have a material inter-regional network impact; and - an augmentation technical report (if the TNSP has received such a report from AEMO).	7

Appendix B – Definitions

All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

A comprehensive list of applicable regulatory instruments is provided in the NER.

Applicable regulatory instruments	
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible under clause 5.6.5D(a)(2) of the Electricity Rules if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options. This is taken to be synonymous with 'economically feasible'. Costs are the present value of the direct costs of a credible option.
Credible option	A credible option is an option (or group of options) that: address the identified need; is (or are) commercially and technically feasible; and can be implemented in sufficient time to meet the identified need.
Economically feasible	An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this general guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost. This is taken to be synonymous with 'commercially feasible'.
Identified need	The reason why the Transmission Network Service Provider proposes that a particular investment be undertaken in respect of its transmission network.
Market benefit	Market benefit must be: (a) the present value of the benefits of a credible option calculated by: (i) comparing, for each relevant reasonable scenario:

Applicable regulatory instruments	
	(A) the state of the world with the credible option in place to (B) the state of the world in the base case, **And** (ii) weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. (b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.
Net economic benefit	Net economic benefit equals the market benefit less costs.
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).
Reasonable scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Appendix C – Reasonable scenario assumptions

This appendix provides further information in relation to key parameters incorporated in the reasonable scenarios adopted for the RIT-T analysis and discussed in section 5.4 of this report.

C.1 Electricity demand projections

Demand projections used in the 2010 NTNDP scenarios were based on the 2009 ESOO projections.

For this RIT-T, new load profiles have been grown using the 2009/10 base year, and the following ESOO 2011 demand projections:

- Scenario 1 – based on 2011 ESOO medium economic growth demand projections.
- Scenario 2 – based on 2011 ESOO low economic growth demand projections.
- Scenario 3 – based on 2011 ESOO high economic growth demand projections.

Varying assumptions around electric vehicle uptake and the potential for additional new step-loads in South Australia (Olympic Dam/Eyre peninsula) have then been imposed on these base demand forecasts, as discussed below.

For scenario 4, the electricity demand projections are based on the medium forecasts in the 2012 NEFR.

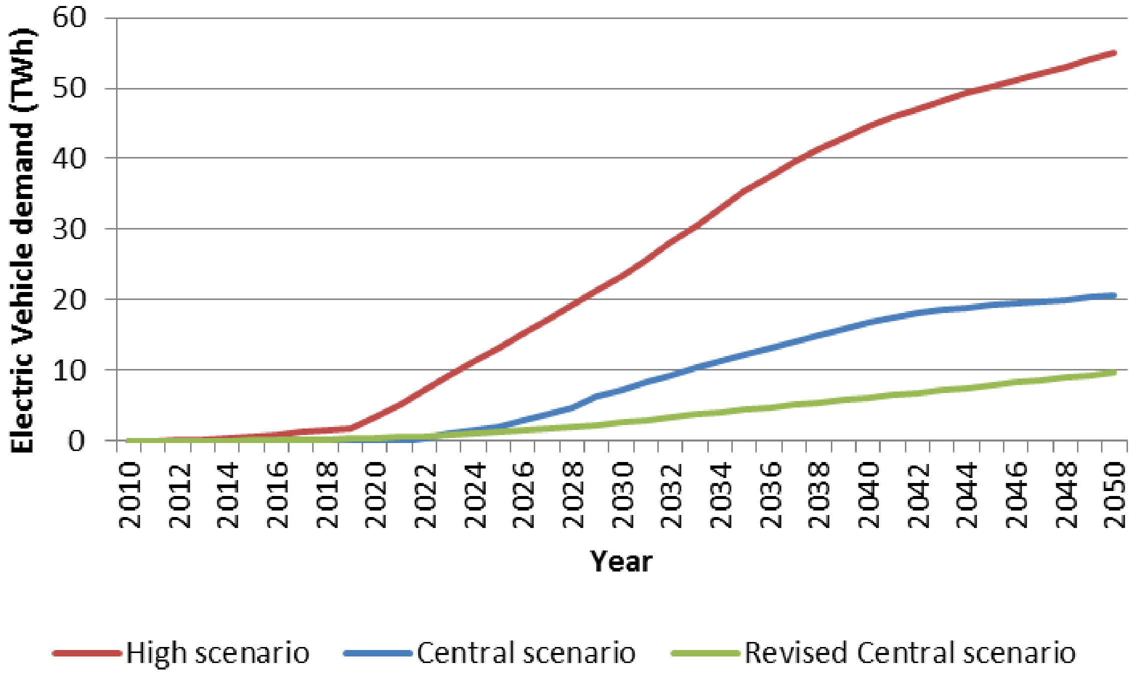
Electric vehicles

New electric vehicle assumptions have recently been derived by CSIRO for AEMO for the five NTNDP scenarios.

The electric vehicle demand projections for the central and high scenarios are summarised in Figure C-1 below. In the low scenario, no electric vehicle uptake is assumed.

For the revised central scenario, a moderate adoption of electric vehicle uptake has been assumed, consistent with the 2012 NEFR.

Figure C-1: Proposed electric vehicle uptake per scenario



Additional Eyre Peninsula/Olympic Dam demand

The ‘high scenario’ also reflects additional electricity demand in South Australia as a result of developments at Olympic Dam and on the Eyre Peninsula.

Specifically, assumptions have been made in relation to the expected increase in mining load on the Eyre Peninsula, based on connection enquiries which ElectraNet has received to date. Whilst the precise details of these connection enquiries are confidential, for the purposes of this RIT-T ElectraNet and AEMO have made the following indicative assumptions in relation to the mining and supporting loads:

- 192 MW, 1 July 2015.
- 180 MW, 1 July 2016.

In addition, the high scenario assumes an expansion of the existing Olympic Dam mine. While recent announcements indicate that this expansion is unlikely in the short term, under a scenario with high economic growth, it may still be a plausible option.

Currently Olympic Dam uses 125 MW, supplied by a 275 kV line from Davenport. A 132 kV transmission line from Pimba is used for stand-by capacity.[72]

Operational post expansion loads are expected to increase by approximately 641 MW in South Australia. The table below presents data from BHP Billiton included in the Environmental Impact Statement, highlighting types of loads, location, energy and maximum demand forecasts. In

[72] Olympic Dam Environmental Impact Assessment Section 5.8.1 page 156.

addition there is a 250 MW cogen facility that is expected to grow at the same rate as the loads below.

Table C-1: BHP Billiton energy and demand forecasts

Description	Location	Maximum demand	Annual energy	Load factor
Open pit mine	Open pit mine	95	283	34%
New concentrator	Flat	300	2365	90%
New hydrometallurgical	Flat	40	315	90%
Expanded smelter	Flat	3	24	91%
Expanded refinery	Flat	12	95	90%
New on-site admin	Variable	4	18	51%
Acid plant	Flat	42	331	90%
Process infrastructure	Flat	20	158	90%
TOTAL ON-SITE		**516**		
Desalination plant	Flat	35	245	80%
Water supply pipeline	Flat	22	154	80%
Transmission losses	Removed	7	61	99%
Pimba intermodal	Variable	3	16	61%
Port – Darwin	Removed	5	26	59%
Port – Outer Harbour	Variable	5	26	59%
Land facility	Variable	2	11	63%
Airport	Variable	1	4	46%
Roxby Downs	Variable	42	184	50%
Hiltaba Village	Variable	8	35	50%
TOTAL OFF-SITE		**130**		

These loads have been grouped into three categories: flat loads, variable loads and the open pit mine. This information has been summarised as follows in figures 2 for maximum demand. This summary has been used to simplify the above data to assist in identifying the relevant load shapes for fitting.

Table C-2: Load characteristics to be modelled

Summary	Capacity	Energy	Load Factor
Flat	474	3687	89%
Cogeneration facility*	(250)	(2,081)	95%
TOTAL	224	1,607	
Variable	65	294	52%
Open pit mine	95	283	34%
NET	384	2,184	

* Cogeneration assumptions are presented in Table C-3 below.

Modelling of the 224 MW flat load additions have been based on the load shapes at Olympic Dam. Specifically Olympic Dam West 275 kV and 132 kV transformers 1 and 2 (S179) have been chosen. This is a flat load profile with a load factor that is 84 per cent, which is close to the 89 per cent across the flat loads.

The 65 MW variable loads are scattered over a wide geographical area leading to the potential for local weather effects. It is noted that most variable loads are centred on Roxby Downs. There is no comparable load shape currently at Roxby Downs. Further, some of the loads represent different electrical usage patterns. Loads with the same usage characteristics (such as time of day) are not known and are unlikely to lead to sufficient value in separating the credible options to develop.

The load at Playford has been selected as the best proxy. It has similar load factor characteristics to BHP Billiton's forecasts at 44 per cent. It is likely to experience weather effects similar to Roxby Downs. It is, however, much smaller than the loads being modelled.

There is not a load shape that reasonably fits with the load characteristics of the open pit mine, with a large maximum demand of 95 MW but a relatively low load factor of 34 per cent. A load trace that matches these characteristics is still under development.

The timing of this load is subject to three stages as identified in the Olympic Dam EIS. These steps occur at year 6, 9 and 11 representing the mine reaching 20, 40 and 60 million tonnes of ore per annum. The cogeneration unit is assumed to grow at the same rates as the loads. Year 1 is taken as starting on 1 July 2012. Table C-3 presents the timing and size of the additional loads.

Table C-3: Timing of energy and demand increases

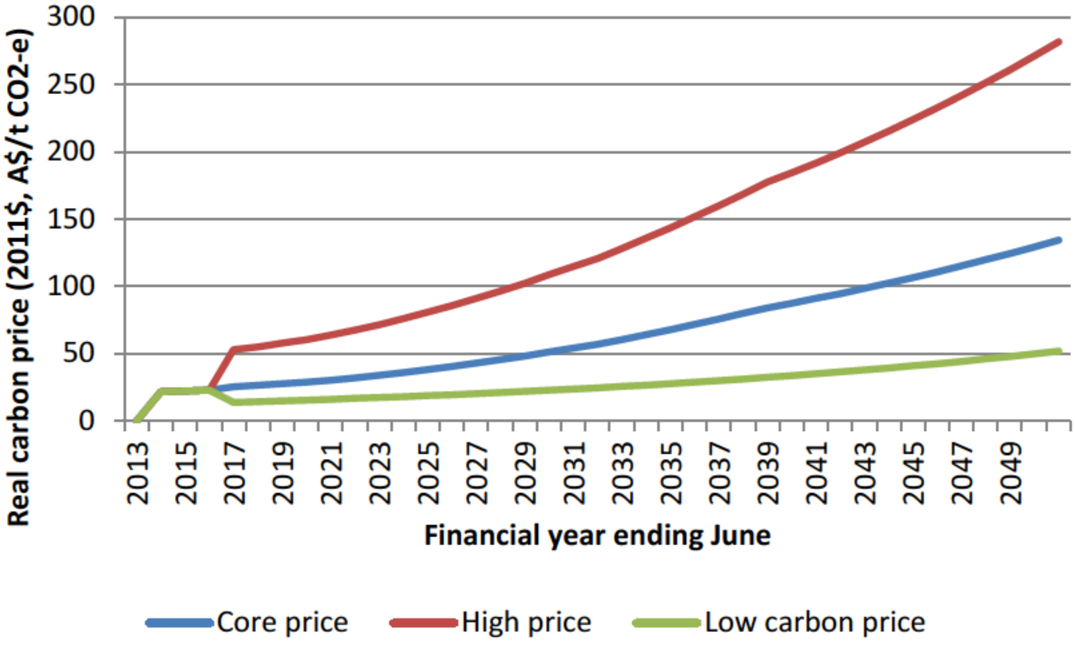
Timing	2018		2021		2023	
Percentage	33%		66%		100%	
	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)
Flat	74	530	148	1,060	224	1,607
Variable	21	97	43	194	65	294
Open pit mine	31	93	63	187	95	283
Total	**126**	**720**	**254**	**1,441**	**384**	**2,184**

C.2 Carbon price

The carbon price assumed in the Prophet modelling for each scenario is consistent with Federal Government's Clean Energy Policy, as shown in Figure C-2 below.

The figure also shows the 'carbon floor' price path included in the fourth scenario (Revised central scenario). The carbon floor price path reflects three years of a fixed carbon price, and the current legislated carbon floor continuing beyond 2017 (assumed to be $15/tonne rising annually at 4%).

Figure C-2: Carbon prices assumed



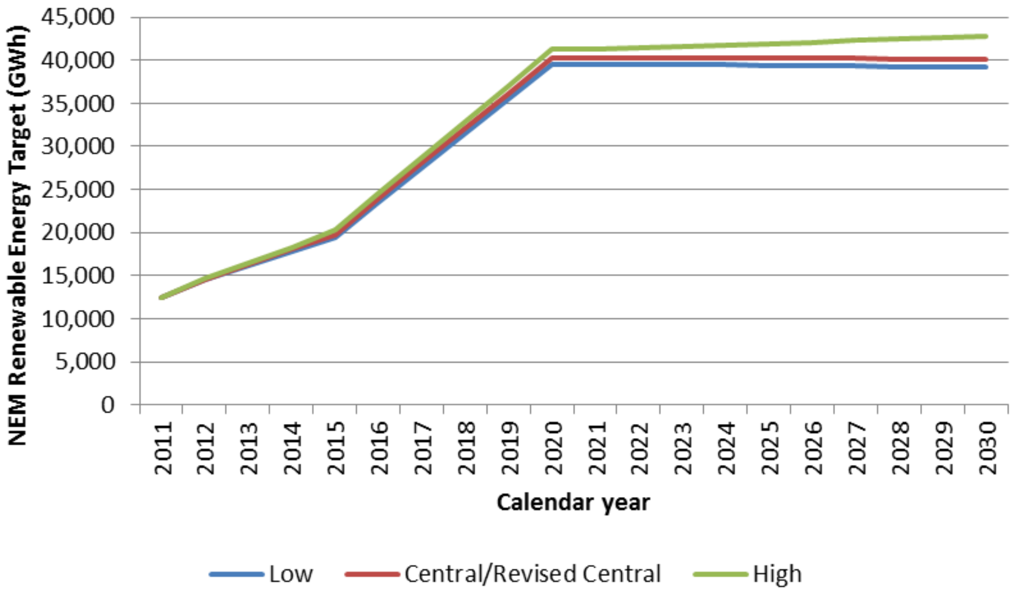
Source: Clean Energy Policy, http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp

C.3 Renewable Energy Target

For the purpose of the RIT-T analysis, the percentage of the national LRET apportioned to the NEM has been based on the ratio of NEM energy relative to the total energy consumption in Australia which, in 2009/10, was 0.89.[73] Therefore, the assumed NEM share of the LRET is 89%.

The NEM equivalent renewable energy target consists of a portion of the national large-scale renewable energy target (LRET), projections of GreenPower sales, and commitments from desalination plant in South Australia and New South Wales to purchase energy from renewable generation sources. This target differs slightly for each of the Heywood RIT-T scenarios, as shown in Figure C-3, with the main difference being attributed to variations in projections of GreenPower sales. The target for scenario 1 (central) and scenario 4 (revised central) are the same. In scenario 4, the renewable energy target also includes commitments from the Olympic Dam desalination plant to purchase energy from renewable generation sources.

Figure C-3: NEM renewable energy target assumed for each scenario.



[73] ABARE: "Australian Energy Statistics - Energy update 2011". 2009/10 reflects the most recent information available at the time at which the modelling for this RIT-T was undertaken.

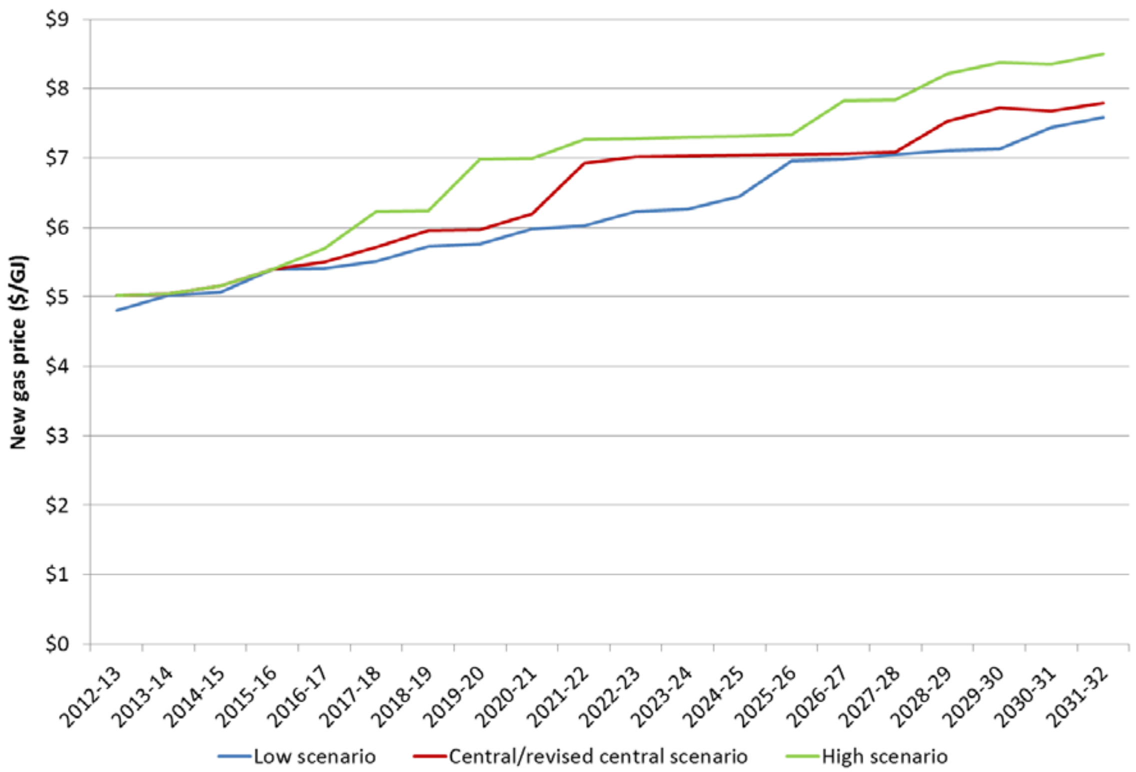
C.4 Gas prices

The following NTNDP scenarios have been used for the fuel price assumptions:

- Scenario 1 (central scenario) and Scenario 4 (revised central scenario) – using gas and coal prices from the Decentralised World.
- Scenario 2 (low scenario) – using gas and coal prices from Uncertain World.
- Scenario 3 (high scenario) – using gas and coal prices from Fast Rate of Change.

To demonstrate the range of gas prices covered in these three scenarios, Figure C-4 shows the gas prices assumed for new CCGT plant locating in central Victoria.

Figure C-4: New gas prices for new central Victorian CCGT



C.5 Technology timings and contribution of wind to peak demand

The following assumptions reflect the 'central view' of the availability of new technologies. In some cases these reflect updated assumptions from those used in the 2010 NTNDP:

- Based on the Worley Parsons technology assumptions draft report prepared for AEMO for the 2012 NTNDP,[74] the first year available for geothermal construction in South Australia is 2015, with a five year construction period. Therefore, the earliest date for geothermal generation in South Australia is assumed to be July 2020.

[74] The draft report was the most recent report available at the time at which the modeling for this RIT-T assessment was being undertaken. http://www.aemo.com.au/en/Electricity/Planning/2012-National-Transmission-Network-Development-Plan-Consultation

- For Victoria, given that the projects are not as far advanced in this region, it is assumed that nothing of scale is constructed prior to the commissioning of the first units in South Australia. Therefore, the earliest date for geothermal generation in Victoria and all other states is July 2025.
- 200 MW annual geothermal build limit per State, as per Worley Parson's draft report.
- Earliest date of operation for carbon capture and storage (CCS) technologies is assumed to be 1 July 2024, based on the draft Worley Parson's report.
- Size of new CCGTs reduced from 700 MW per unit to 250 MW per unit in South Australia and Tasmania and to 350 MW per unit in the other regions.
- CCS cost and efficiency parameters have been revised, and Victorian IGCC with CCS is now included as an option for consideration in the study.
  - Limit solar thermal new entry in the first round of the Solar Flagship Program to 400 MW total, and only allow units to be built in NSW and Queensland. Relax this limit to 1,000 MW and allow other states to participate in the second round of funding from 1 July 2016.

For scenarios 1, 2 and 3, the assumptions made in relation to the contribution of wind generation to peak demand are consistent with the 2011 NTNDP assumptions.

In scenario 4 the 2012 NTNDP assumptions have been used, which reflect an increased contribution. Preliminary analysis in the 2012 NTNDP has shown that, using the new peak contribution factors, there is a shift of new wind generation investment from NSW to South Australia. Since this may impact on the RIT-T outcome, it was decided to use these new figures in market modelling runs for scenario 4.

Appendix D – Modelling inputs

This appendix provides additional information in relation to some of the assumptions used in the market modelling described in section 5.3. In general, inputs have come from the 2010 NTNDP. This appendix documents those assumptions that have diverged from the 2010 NTNDP assumptions.

D.1 Base years

Wind and demand profiles for the long term simulation are using profiles based on the 2009/10 financial year. Wind output is scaled so that the average capacity factor per tranche is equal to the ACIL Tasman assumptions provided for the 2010 NTNDP.

The 2009/10 wind profiles lie close to the average capacity factor for all wind bubbles over the range 2002/03 to 2009/10 and are hence the most suitable for the expansion plan.

To test the sensitivity of market benefits to base profile used, for the two preferred options time sequential runs have also used 2005/06 profiles and 2007/08 profiles with equal weighting across the three base years. These profiles have also been scaled, using the same scalars as for the 2009/10 profiles. The three years experienced a range of demand conditions with respect to peak demand across the south east of Australia. The 2009/10 year has relatively high NSW and SA demand at time of Victorian peak demand. The 2005/06 year has relatively low SA and NSW demand at time of Victorian peak demand, and the 2007/08 year falls somewhere in the middle with high SA demand but relatively low NSW demand at time of Victorian peak demand. Additionally all three years are relatively recent, maintaining as close as reasonable relationship with current demand patterns.

D.2 Probability of exceedance (POE)

Demand traces have included both 50 POE and 10 POE peak demand conditions with weightings of 69.6 per cent and 30.4 per cent respectively.[75]

[75] The 2010 NTNDP consultation paper, appendix B, details these weightings (p. 5): http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/0418-0004%20pdf ashx They are also repeated in the 2012 NTNDP consultation methodology and assumptions paper (p.10): http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/2418-0002%20pdf ashx

D.3 Minimum generation levels

Some minimum generation levels have been reduced from the 2010 NTNDP. The table below identifies only those assumptions that have changed.

Table D-1: Minimum generation levels (variations from 2010 NTNDP)

Station	Capacity (MW)	Minimum generation assumed in RIT-T (MW)
Yallourn 1	350	216
Yallourn 2	350	216
Yallourn 3	350	228
Yallourn 4	350	228
Loy Yang B1	500	262.5
Loy Yang B2	500	262.5
Anglesea	150	79
Loy Yang A1	560	435
Loy Yang A2	500	397.5
Loy Yang A3	560	435
Loy Yang A4	560	435
Northern 1	273	60
Northern 2	273	60

D.4 New entry costs

The market modelling uses cost assumptions for all generators as per the ACIL Tasman data for:

- Capital costs.
- Fuel costs.
- Fixed operating and maintenance costs.
- Variable operating and maintenance costs.

Connection costs for wind generation were based on the assumptions used in the 2010 NTNDP. Two alternative sets of connection costs were also developed: one set assuming that the same size generator connects at all voltages and the other set assuming that larger generators connect at the higher voltage. Sensitivity tests indicated that the resulting changes in the modelled planting schedules relatively small, and that the 2010 NTNDP assumptions were therefore fit for purpose.

D.5 Network modelling

The following assumptions have been made in relation to network developments which may impact flows over the Heywood interconnector:

Murraylink:

- A new Ballarat-Moorabool 220 kV line upgrade occurs in 2016/17 (RIT-T currently in progress).
- The existing Ballarat-Bendigo 220 kV line is uprated in 2016/17 (RIT-T currently in progress).
- New 275 kV supply to Riverland area in SA in 2025/26 (as per ElectraNet APR).

Heywood:

- New Moorabool-Mortlake/Heywood 500 kV line when new generation along line exceeds 2500 MW (as per NTNDP and VAPR).

The following tables provide a summary of ratings of selected circuits, a description of impacted constraints and the impact of selected existing constraints.

Table D-2:Summary of ratings of selected circuits

Element	Continuous rating (MVA)	Post contingent rating (MVA)	Notes
Heywood 500/275 kV transformers	370	525	Post contingent reactive flows require a 460 MW limit for these transformers
Heywood-South East 275 kV lines	591-675 503-644	 591-772	Seasonal ratings for South Australian side Temperature dependant rating for Victorian side
South East-Tailem Bend 275 kV lines	591-675	-	Seasonal ratings
Tailem Bend - Keith No 1 132kV line	60-97	-	Seasonal ratings
Tailem Bend - Keith No 2 132kV line	178-221	-	Seasonal ratings
Keith – Snuggery 132kV line	60-97	97*	Seasonal ratings
South East 275/132 kV transformers	160	-	
Heywood-Moorabool/Mortlake 500 kV lines	2,043	-	Protection limit

* Some of the line ratings on the South Australian side are design ratings and would require plant and protection upgrades to get to the ratings shown above.

Table D-3: Description of selected impacted constraints

Constraint	Description
S:V_580	Combined limit Murraylink and Heywood for export from South Australia to Victoria due to oscillatory stability
S>V_NIL_HYTX_HYTX	Thermal limit due to the rating of the Heywood 500/275 kV transformer for flow South Australia to Victoria
V>S_460	Thermal limit due to the rating of the Heywood 500/275 kV transformer for flow Victoria to South Australia
S>>V_NIL_SETX_SETX	Thermal limit due to the rating of the South East 275 kV transformer for flow South Australia to Victoria
V^^S_NIL_MAXG_AUTO	Voltage stability limit to cater for a trip of the largest generator in the South Australia region, limits flow for flow Victoria to South Australia
V>>S_NIL_NIL_SGKHC	Thermal limit due to the rating of the Snuggery-Keith 132 kV line for flow Victoria to South Australia
V>>S_NIL_KHTB1_KHTB2	Thermal limit due to the rating of the Keith-Tailem Bend 132 kV line for flow Victoria to South Australia
V::N_NILQx_BL_R V::N_NILVx_BL_R	Victorian Export Transient stability limit for a South Morang to Hazelwood 500 kV line fault

Table D-4: Impact on selected existing constraints

	Constraint							
	Option 1a 132 kV works, Heywood tx[c], 100 MVar capacitor	Option 1b 132 kV works, Heywood tx, series compensation	Option 2a 132 kV works, Heywood tx, 100 MVar capacitor, SE tx	Option 2b 132 kV works, Heywood tx, series compensation, SE tx	Option 3 Krongart 500 kV circuits	Option 4 132 kV works, 100 MVar capacitor	Option 6a Control scheme only	Option 6b 132 kV works, series compensation, control scheme
S:V_580[a]	Remove.	Remove.	Remove.	Remove.	Remove.	Remove.	Remove.	Remove.
S>V_NIL_HYTX_HYTX	+460[d].	+460.	+460.	+460.	+1940	No change [e]	+ 0 to 230[b]	+ 0 to 230
V>S_460	Remove.[d]	Remove.	Remove.	Remove.	+1940	No change.[e]	No change.[e]	No change.[e]
S>>V_NIL_SETX_SETX	+ 5 to 20	+ 15 to 30	+165 to 180	+175 to 190	Remove.	+5 to 20	+ 0 to 140	+ 15 to 140
V^^S_NIL_MAXG_AUTO	+130	+350	+130	+350	Remove.	+130	No change.	+350
V>>S_NIL_NIL_SGKHC	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_KHTB1_KHTB2	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V::N_NILQx_BL_R V::N_NILVx_BL_R	No change.	No change.	No change.	No change.	No change.	No change.	No change.	No change.

a. Previous studies by ElectraNet and AEMO which assessed the increase of the South Australian Oscillatory Export limit from 420 MW to 580 MW were extended to examine the works required to increase this limit to 870 MW. These studies concluded that this increased level of export can be achieved, but will require the retuning of the power system stabilisers on the Para SVCs.

b. Dependant on genera ion available for tripping.

c. tx = transformer.

d. Heywood –South East 275 kV line ratings will limit flows prior to the transformers with 3 installed.

e. Heywood 500 kV bustie overcomes uneven loadings that can currently occur for these transformers.

f. New thermal constraints still required for remaining Keith-Tailem Bend and Keith to South East 132 kV lines.

Note: Indicative changes shown. Constraints reformulated for the market modelling so actual increases are dependant on system conditions.