PROJECT ASSESSMENT DRAFT REPORT

DEVELOPMENT OF THE QUEENSLAND - NSW INTERCONNECTOR

31 March 2014

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Executive Summary

This Project Assessment Draft Report (PADR) has been prepared by TransGrid and Powerlink in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4 and the Australian Energy Regulator's (AER) guidelines for application of the Regulatory Investment Test for Transmission (RIT-T).

The existing Queensland - NSW interconnector (QNI) has been operating since 2001. Its original maximum transfer capacity was 300 MW to 350 MW in both directions. This has been increased progressively through a series of incremental augmentations and additional extensive testing to a present maximum transfer capacity of 700 MW from NSW to Queensland and 1200 MW from Queensland to NSW.

QNI is nonetheless constrained on occasions for both northwards and southward flows, and the number of hours of constraint has increased in the northern direction in recent years. TransGrid and Powerlink have been conducting studies for a number of years to assess market benefits from uprating the interconnector or reducing the constraints on its operation by other means.

TransGrid and Powerlink commenced the first stage of the current RIT-T consultation process with the release of a Project Specification Consultation Report (PSCR) in June 2012.[1] Submissions to the PSCR closed on 30 November 2012.

To provide an added degree of robustness to the studies being undertaken, TransGrid and Powerlink published the "QNI Upgrade Competition Benefits Methodology Consultation Paper" in April 2013. Although not a requirement under the NER, the paper consulted with interested parties and sought feedback on the assumptions to be used and the approach to be followed in the assessment of the competition benefits associated with the augmentation options for this RIT-T.

As a result of the time required to undertake this additional consultation step, TransGrid and Powerlink sought an extension of time to the publication date of the PADR until 31 March 2014 in accordance with clause 5.16.4(j) of the NER. The AER provided such written consent on 29 November 2013.

This PADR represents the second stage of the formal consultation process set out in the NER in relation to the application of the RIT-T for the further development of QNI capacity. It contains the results of the planning studies and cost-benefit analysis of credible options.

Submissions to the PSCR were received from ten parties; AEMO, CS Energy, Department of Development, Infrastructure and Planning, Energex, EPURON (White Rock wind farm), NGF, Origin Energy, Stanwell Corporation, Private generators (AGL, Alinta, Energy Brix, GDF Suez Energy, InterGen, NRG Gladstone), and Wind Prospect (Sapphire wind farm). The submissions did not propose any potential non-network options.

The feedback received from stakeholders as a result of the above consultations has been used to further refine the options being considered, and the analysis conducted for this RIT-T assessment.

The RIT-T cost-benefit analysis contained in this PADR has not identified a preferred *credible* option. Consequently, TransGrid and Powerlink consider it prudent to recommend the 'do nothing' option as the preferred option.

1 TransGrid and Powerlink, Project Specification Consultation Report – Development of the Queensland-NSW Interconnector, available at: http://www.transgrid.com.au/network/consultations/Documents/PROJECT%20SPECIFICATION%20CONSULTATION%20REPORT%20QNI%20UPGRADE.pdf

Credible options included in the assessment

Table 1 details the six options that have been included as credible options in the RIT-T analysis.

Table 1 Credible Options

Option	Description	Cost ($m 2013/14)
Option 0	Uprating of the Northern NSW 330 kV lines	46.5
Option 1a	50% Series Compensation. This option involves the installation of thyristor controlled series capacitors across the Bulli Creek to Dumaresq and the Dumaresq to Armidale 330 kV circuits.	179.5
Option 1b	50% Series Compensation + 2nd Armidale Static VAr Compensator (SVC). This option involves the installation of thyristor controlled series compensation across the Bulli Creek to Dumaresq and Dumaresq to Armidale 330 kV circuits as described in Option 1a together with a SVC at Armidale Substation.	222.0
Option 1c	30% Series Compensation. This option involves the installation of thyristor controlled series capacitors only on the Dumaresq – Bulli Creek circuits. Option 1c avoids series compensation of the Armidale – Dumaresq circuits, making it lower cost for wind farms to connect to that double circuit line should they choose to do so in future.	130.0
Option 2a	2nd Armidale SVC. This option involves the installation of a second SVC at Armidale 330 kV Substation.	53.5
Option 2b	New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth substations. This option involves installation of +350 MVAr / -100 MVAr SVC at Tamworth and Dumaresq substations. Shunt capacitors are also installed at Dumaresq, Armidale and Tamworth substations.	176.2

Note: Options 1a, 1b and 2a were included in the PSCR published in June 2012.
Options 1c and 2b were identified in response to feedback received after publication of PSCR.
Option 0 has been introduced since the release of the PSCR and represents a relatively low cost option of uprating the existing Northern NSW 330 kV lines.

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. The notional interconnector capabilities provided by these options are detailed in Chapter 3.

In addition to the options above, TransGrid and Powerlink considered a further six options. These options are defined in Table 2 together with their respective cost. For these options TransGrid and Powerlink undertook a more limited market modelling exercise as part of a ‘first pass assessment’. These analyses indicated that none of these options have a positive net market benefit, and as such were not considered further.

Table 2 Details for options subject to first pass assessment

Option	Description	Cost ($m 2013/14)	*Reason* (see chapter 3)
Option 3	Protection System Upgrade	2.1	Low increase in transfer capability, negative net market benefit
Option 4a	Second HVAC interconnector at 330 kV	1,300	Negative net market benefit
Option 4b	New Armidale – Bulli Creek HVAC interconnector at 330 kV	560	Negative net market benefit
Option 4c	Second HVAC Interconnector at 500 kV	2,300	Negative net market benefit
Option 5	High Voltage Direct Current (HVDC) Back to Back Converter Station	445	Negative net market benefit
Option 6	Braking resistor	8.1	Limited increase in transfer capability northward, no increase southward, negative net market benefit

Scenarios considered

Given the long-term nature of the investments being considered, the outcome of the analysis must be tested against a range of potential futures. The RIT-T requires that future uncertainty be taken into account by testing the market benefits of the credible options across a number of reasonable scenarios.

The reasonable scenarios adopted for this RIT-T are based on scenarios developed by AEMO for its 2012 NTNDP. These scenarios reflect different levels of economic growth, industrial energy demand, rooftop PV penetration, energy efficiency and small non-scheduled generation. The AEMO core scenarios adopted for this RIT-T assessment include its 'Planning", 'Fast World Recovery' and 'Slow Rate of Change' scenarios.[2] However, the electricity demand projections associated with each of these scenarios have been updated to align with AEMO's latest demand forecasts published in the November 2013 National Electricity Forecasting Report (NEFR).

In addition to the variables identified above, the potential market benefits that can be realised from a QNI upgrade depends on the future fuel costs, in particular gas prices. Higher gas price projections which result in gas fuelled generating plant within the Queensland region being less competitive relative to lower cost black and brown coal within the southern states significantly affects the power transfers on QNI. To test the sensitivity of market benefits to this key gas price assumption a scenario with a lower gas price projection was included.

Various wind generation proponents have also made connection enquiries to TransGrid for connection of wind generation near the mid-point of the Armidale to Dumaresq line. The connection costs for these wind farm developments will depend on which option is adopted for increasing the capacity of QNI. To capture this impact, a scenario that models a 300 MW wind farm in northern NSW has been included.

[2] Section 5.4 of 2012 National Transmission Network Development Plan http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan

Therefore, the following five scenarios, that reflect a broad range of different assumptions in relation to growth in electricity demand, the future carbon price (if any), future wind generation and future gas prices, were considered in undertaking the RIT-T analysis presented in this PADR:

- Scenario 1: Planning.
- Scenario 2: Fast World Recovery.
- Scenario 3: Slow Rate of Change.
- Scenario 4: Planning with low gas prices.
- Scenario 5: Planning with northern NSW 300 MW wind generation.

RIT-T results

Table 3 below summarises the net market benefit in Net Present Value (NPV) terms for each credible option under each scenario. The table also shows the corresponding ranking (from 1 to 6 in order of descending net market benefit) of each option, for each scenario.

In summary:

- under the Planning scenario, the Present Value (PV) of net benefits of Options 1a, 1c and 2b are effectively ranked equal first;
- under the Fast World Recovery scenario, the PV of net benefits of Options 1a and 2b are effectively ranked equal first;
- under the Slow Rate of Change scenario, all credible options have a negative net market benefit, except Option 0 which is found to be marginally positive[3];
- under the Planning scenario with low gas prices, all credible options have a negative net market benefit; and
- under the Planning scenario with 300 MW wind generation in northern NSW, Option 0 is ranked first.

The main category of market benefits associated with increasing the transfer capability across QNI are related to reductions in the cost of supply from generators. Increasing QNI capability allows generating plant with a relatively high cost of fuel to be displaced with lower cost sources. The level of fuel cost savings differ between the scenarios. The quantum of benefits depend on factors such as the relativity of load and energy growth between the regions on each side of the interconnector, projected gas prices, and transfer capability of QNI and the continued operation, or otherwise, of Redbank Power Station.

The current market simulation studies carried out for each of the scenarios forecast increasing levels of utilisation and congestion across QNI in the northerly direction. The increased level of utilisation of QNI in the northerly direction is a result, in part, of projected increases in wind generation development within the southern regions to meet the LRET, and subdued load and energy growth within the southern states.

The market benefits associated with changes in generator fuel consumption are found to greatly reduce under scenarios assuming a low growth in electricity demand (scenario 3) and a lower than forecast gas price (scenario 4). Under these two scenarios all options investigated are found to have a negative net market benefit with the exception of option 0 under scenario 3, which is found to be marginally positive. As a consequence, all of the options are ranked less than the ‘do nothing’ option, and cannot be expected to result in an overall net benefit to the market in these scenarios.

3 The market benefits associated with Option 0 are related considerably to assumptions on the continued operation of Redbank power station.

Table 3 Net Market Benefit and Ranking of Each Credible Option, Under Each Scenario (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Uprate the Northern NSW 330 kV lines	13.0	5th	-13.1	6th	**2.4**	**1st**	-11.0	2nd	**53.7**	**1st**
1a: 50% Series Compensation	50.5	**=1st**	**43.6**	**=1st**	-32.5	4th	-30.4	4th	-32.3	4th
1b: 50% Series Compensation + 2nd Armidale SVC	31.4	4th	23.3	4th	-47.7	6th	-43.3	6th	-48.4	5th
1c: 30% Series Compensation	51.6	**=1st**	34.7	3rd	-16.5	3rd	-22.9	3rd	43.4	2nd
2a: 2nd Armidale SVC	1.7	6th	-3.1	5th	-7.9	2nd	**-6.2**	**1st**	-4.1	6th
2b: New SVCs at Dumaresq and Tamworth and capacitor banks	53.5	**=1st**	**48.3**	**=1st**	-34.7	5th	-34.6	5th	21.4	3rd

Robustness of the rankings

The sensitivity of the RIT-T outcome to differences in the probability assigned to the different scenarios has been tested. The preferred option(s) has been found to be critically dependent on the assigned scenario weightings.

The RIT-T assessment also identified four important factors which influence the market benefits of credible options:

1. future gas prices in Queensland;
2. the possible retirement of Redbank Power Station;
3. the development of wind farms in northern NSW; and
4. load growth.

TransGrid and Powerlink also tested the robustness of the net market benefits and ranking of options to a number of other factors, including:

(a) the exclusion of competition benefits;
(b) a reduction in QNI capacity provided by the option;
(c) an increase and decrease in the cost of the credible options; and
(d) differences in the discount rate used in the NPV assessment.

The results of all this analysis shows that the ranking of credible options is inconsistent across the scenarios. Further, many credible options have negative net market benefits under a number of scenarios and hence rank below the 'do nothing' option. Therefore, there is no preferred credible option.

Therefore, it is the view of TransGrid and Powerlink that there is too much uncertainty around these factors and that it is prudent to not recommend a preferred credible option but to continue to monitor developments in these key input assumptions.

Next steps

TransGrid and Powerlink intend to publish the Project Assessment Conclusions Report (PACR) for this RIT-T as soon as practicable after the end of the consultation period on this PADR.[4] TransGrid and Powerlink envisage that the range of scenarios considered and the outcomes of this assessment will remain valid within that timeframe and the analysis will not have to be redone. However, any information raised in submissions to this PADR will be taken into account in the PACR for this RIT-T process as well in any future RIT-T assessment undertaken for upgrading QNI power transfer capability.

In addition, TransGrid and Powerlink will continue to investigate the feasibility of any non-network option proposed or otherwise identified and encourage interested parties to make submissions regarding possible non-network solutions. Information contained in any submissions received on non-network options will also be taken into account as part of the PACR for this RIT-T process as well as part of any later RIT-T assessment undertaken for QNI.

TransGrid and Powerlink invite submissions on this PADR from Registered Participants, AEMO and interested parties.

In particular, TransGrid and Powerlink seek additional feedback responding to the following issues:

- Does this PADR provide enough information and or detail to enable stakeholders to effectively provide a response?
- Are the explanations in this PADR sufficiently clear?
- Is the logic provided in the conclusions within this PADR sufficiently robust?
- Any other relevant feedback.

Submissions in relation to this PADR should be emailed to regulatory.consultation@transgrid.com.au and/or networkassessments@powerlink.com.au. The closing date for submissions is **Monday 2 June 2014**.

Submissions will be published on the TransGrid and Powerlink websites.

[4] NER, 5.16.4 (r) & (t)

1. Introduction

1.1. Overview

This Project Assessment Draft Report (PADR) has been prepared by TransGrid and Powerlink in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4 and the Australian Energy Regulator's (AER) guidelines for application of the Regulatory Investment Test for Transmission (RIT-T).

The first stage of the current RIT-T consultation process was the release of the Project Specification Consultation Report (PSCR) in June 2012.[5]

The PADR represents the second stage of the formal consultation process set out in the NER in relation to the application of the RIT-T for the further development of Queensland - NSW Interconnector (QNI) capacity, via an increase in the existing transfer capability of QNI or the reduction of constraints in its operation by various means. These developments are referred to as the 'QNI upgrade' in this PADR.The formal RIT-T consultation process follows the earlier published descriptions of limitations affecting the capacity of QNI by both TransGrid and Powerlink in their Transmission Annual Planning Reports (TAPRs)[6]. AEMO's previous National Transmission Network Development Plans (NTNDP), their National Transmission Statement (NTS) in 2009 and their Annual National Transmission Statement (ANTS) in 2008 also contained descriptions of these limitations. With the exception of the 2012 and 2013 NTNDP, these earlier AEMO reports showed potential market benefits from upgrading QNI under some market development scenarios.

The structure of this PADR is as follows:

- Section 2 describes the identified need, the existing supply arrangements, the limitations on the network and the nature of the interconnector loading.
- Section 3 outlines the credible options included in the full RIT-T analysis. It also describes the additional options included as part of the 'first pass' assessment, which were found not to have a positive net market benefit.
- Section 4 details the submissions received in response to the PSCR. In addition, this section discusses submissions received in response to the additional consultation conducted in relation to the methodology used to quantify competition benefits.
- Section 5 describes the methodology adopted for both the market modelling used to assess the market benefits and the financial analysis used to determine the results of the RIT-T. The scenarios adopted and their weightings used for the assessment are also discussed.
- Section 6 provides more detail on the assessment process and the quantification of option costs and market benefits.
- Section 7 sets out the results of the net present value analysis.
- Section 8 presents the overall conclusion of this report.

Additional appendices to this PADR provide further information in relation to the assumptions adopted for the RIT-T assessment, the detailed results of the assessment and responses to submissions received.

1.2. Background to the RIT-T

The purpose, principles and procedures of the RIT-T are set out in NER clauses 5.16.1 – 5.16.4. These provisions were put in place following the Australian Energy Market Commission's (AEMC) national transmission planning arrangements review in 2008.[7]

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

5 TransGrid and Powerlink, Project Specification Consultation Report – Development of the Queensland-NSW Interconnector, http://www.transgrid.com.au/network/consultations/Documents/PROJECT%20SPECIFICATION%20CONSULTATION%20REPORT%20QNI%20UPGRADE.pdf

6 Previously called Annual Planning Reports (APRs).

7 AEMC, National transmission planning arrangements, Final report to MCE, 2008.

reliability standards.[8] The RIT-T replaced the Regulatory Test, 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:

1. Publishing a PSCR.
2. Publishing a PADR.[9]
3. Publishing 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 sections 5 and 6 and Appendices C and D).

Importantly, the RIT-T assessment is an assessment of the *relative* costs and benefits[10] of alternative options, in order to identify the option which maximises net economic benefits relative to a 'do nothing' option. 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. Nature of regulatory consultation documents

Clause 5.16.4 (a) of the NER requires the proponent (in this case TransGrid and Powerlink) to consult with all Registered Participants, AEMO and interested parties. As these parties are all associated with the NEM, the regulatory consultation documents assume an understanding of the operation of the NEM and of the nature and behaviour of transmission systems.

While the NER specify the "matters" which need to be addressed in regulatory consultation documents, they are silent on the amount of detail that should be provided. Similarly, the AER's "Application Guidelines" provide little or no guidance on the appropriate level of detail. This is understandable as it is not possible to determine in advance, the level of detail that may be appropriate in any particular circumstance.

To manage this uncertainty, TransGrid has adopted a "process improvement" approach whereby comments and submissions received in response to consultation documents are used to inform the nature and amount of information included in future consultation documents.

The intention of this is to provide the level of detail required by Registered Participants, AEMO and interested parties to allow them to make informed comments and submissions.

When additional information is requested, TransGrid generally holds discussions with the relevant party to determine what additional information is required. This enables TransGrid to tailor the additional information provided to the specific needs of that party.

TransGrid believes that this approach is well suited to the RIT-T consultation process, which generally involves two consultation documents and a conclusions document, and therefore provides two opportunities for comments/submissions.

A less targeted, approach which would rely less on comments/submissions by providing additional information initially, was considered but not adopted as:

- It would not be certain that the exact information required would be provided; and
- There is a greater risk that the information required by particular parties may be "obscured" by other information that is not relevant to them.

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8 AER, Regulatory Investment Test for Transmission, Issues Paper, September 2008, p. 1.

9 Under certain circumstances a transmission network service provider (TNSP) may claim exemption from preparation of a PADR (see: NER, 5.16.4(y)-(z)).

10 Note that different categories of market benefit may be positive or negative, for each option assessed.

Submissions and/or comments on TransGrid's approach are welcome. Please refer to the following Section for contact details.

1.4. Submissions

TransGrid and Powerlink welcome submissions on this PADR.

TransGrid and Powerlink intend to publish the PACR for this RIT-T as soon as practicable after the end of the consultation period on this PADR.[11] TransGrid and Powerlink envisage that the range of scenarios considered and the outcomes of this assessment will remain valid within that timeframe and the analysis will not have to be redone. However, any information raised in submissions to this PADR will be taken into account in the PACR as part of this RIT-T process as well in any future RIT-T assessment undertaken for upgrading the capability of QNI.

In addition, TransGrid and Powerlink will continue to investigate the feasibility of any potential non-network option proposed or otherwise identified, and encourage interested parties to make submissions regarding possible non-network solutions. Information contained in any submissions received on non-network options will also be taken into account as part of the PACR as part of this RIT-T process as well as part of any later RIT-T assessment undertaken for QNI.

In particular, TransGrid and Powerlink seek additional feedback responding to the following issues:

- Does this PADR provide enough information and or detail to enable stakeholders to effectively provide a response?
- Are the explanations in this PADR sufficiently clear?
- Is the logic provided in the conclusions within this PADR sufficiently robust?
- Any other relevant feedback.

Submissions are due on or before Monday 2nd June 2014.

Submissions should be emailed to regulatory.consultation@transgrid.com.au and/or networkassessments@powerlink.com.au. Submissions will be published on the TransGrid and Powerlink websites.

[11] NER, 5.16.4 (r) & (t)

2. Identified need

2.1. Background

The existing Queensland - NSW interconnector (QNI) has been operating since 2001.

Since the commissioning of QNI, TransGrid, Powerlink and AEMO (previously NEMMCO) have undertaken system tests and the tuning of control systems to gradually improve its capability. The original maximum transfer capacity was 300 to 350 MW in both directions. This has been progressively increased following extensive system tests, limit equation revisions and a series of incremental augmentations, to the present maximum transfer capacity of 700 MW north from NSW to Queensland and 1200 MW south from Queensland to NSW.[12]

Since QNI was commissioned, there have also been a number of studies to assess the technical and economic viability of increasing the power transfer capability in both directions.

In 2003, TransGrid and Powerlink undertook a pre-feasibility investigation of the market benefits of various upgrade options under the Australian Competition and Consumer Commission (ACCC) Regulatory Test (later replaced by the RIT-T). The results of this study were published in March 2004. A copy of the report is available on TransGrid's and Powerlink's websites. The main conclusion from this study was that no major upgrade of QNI could be justified at that time. The study showed that only a very low cost intra-regional augmentation to enhance the NSW import capability was expected to have a positive net market benefit.

In February 2007 TransGrid published a Final Report on the regulatory consultation with respect to relieving a limitation on the southward flow of power on QNI due to the thermal rating of the Armidale – Kempsey 132 kV No. 965 line.[13] A copy of the Final Report is available on TransGrid's website. The Final Report concluded that the installation of a phase shifting transformer at Armidale to control power flows on the No. 965 line satisfied the market benefits limb of the Regulatory Test. These works have now been completed.

Following significant market developments, including the Kogan Creek coal fired generator in Queensland and the Tallawarra, Uranquinty and Colongra gas fired power stations in NSW, Powerlink and TransGrid undertook further detailed investigations of the potential market benefits associated with an upgrade of QNI capacity, leading to the publication of an Interim Report for Market Consultation in March 2008. The Final Report on the results of this investigation, including responses to submissions, was published in October 2008. A copy of the Final Report is available on TransGrid's and Powerlink's websites. This report concluded that, in the absence of any large changes in forecast load growth and generation developments, an augmentation to the interconnector capacity of up to nominally 300-400 MW would not have a positive net market benefit until around 2015/16. Therefore, the report concluded that it would be premature for TransGrid and Powerlink to recommend any augmentation option at that time.

Since the 2008 TransGrid and Powerlink report, there have been a number of network, generation and load developments. These have warranted a reassessment of potential net market benefits which could result from an increase in transfer capability across QNI. In general, these changes are:

- Various generation and large load developments in NSW and Queensland (in particular renewable wind generation and Liquefied Natural Gas (LNG) and coal developments) as well as NEM-wide reductions in forecast load and energy consumption; and
- Routine revision of the limit equations defining the transfer capability across the Queensland to NSW interconnector

In addition, there have been changes to the NER which have introduced the Regulatory Investment Test for Transmission (RIT-T) to replace the Regulatory Test. As a result TransGrid and Powerlink have commenced the re-evaluation of the potential to upgrade the transfer capacity of QNI by applying the RIT-T methodology, taking into account the changes to the network, generation and load that have occurred since publication of the 2008 report.

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12 The actual capacity at any point in time depends on factors such as load levels and generation dispatch. Consequently it will vary depending on actual conditions. The maximum capacity has been taken to be the small signal (oscillatory) stability limits.

13 This investment was separate to the investments considered as part of the earlier 2003 study into enhancing the capacity of QNI.

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, compared to the base case of no investment.

2.2.1. The nature of limitations on the network

The transfer capacity of QNI is frequently fully utilised, leading to network constraints between NSW and Queensland. Currently, the transfer capability across QNI is limited by voltage control, transient stability, oscillatory stability and line thermal rating considerations. The capability of the network at any time is dependent on a number of power system conditions, including the loads and generation patterns.

Whilst the 330 kV interconnecting lines may have a relatively high thermal rating, the power transfer capability of QNI is governed by the capability of the supporting transmission systems in NSW and Queensland, as well as power system conditions across the whole interconnected NEM grid. These supporting systems, in particular the transmission lines from Liddell to Armidale, can, and do at times limit the capability for power transfer from NSW to Queensland.

At present QNI transfer capability in the southerly direction is mostly limited by the following constraints:

- Transient stability associated with transmission faults in Queensland;
- Transient stability associated with the trip of a smelter potline load in Queensland;
- Transient stability associated with transmission faults in the Hunter Valley (New South Wales);
- Transient stability associated with a fault on the Hazelwood to South Morang 500 kV transmission line in Victoria;
- Thermal capacity of the 330 kV transmission network between Armidale and Liddell in New South Wales; and the
- Oscillatory stability upper limit of 1,200 MW[14].

In the northerly direction, QNI transfer capability is limited by the following constraints:-

- Transient and voltage stability associated with transmission line faults in New South Wales;
- Transient stability and voltage stability associated with loss of the largest generating unit in Queensland;
- Thermal capacity of the 330 kV and 132 kV transmission network within northern New South Wales; and the
- Oscillatory stability upper limit of 700 MW.

The number of hours that QNI flows have been constrained by year since 2004 is shown in Table 4. These periods include occurrences with planned network outages required for maintenance activities.

Table 4 Historical QNI Constraint Times (Hours)

Direction	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Northerly Direction	33	23	34	389	262	352	365	296	492	868
Southerly Direction	346	1,084	2,063	513	881	577	2,135	900	1,191	79

The above constraints and the assumptions made in defining the identified need were discussed in detail in Section 2.4 of the earlier PSCR.

14 The small signal oscillatory limit in the southerly direction has recently been increased from 1078MW to 1200MW (conditional on the availability of dynamic power monitoring equipment).

2.2.2. Key sources of potential market benefit

TransGrid and Powerlink have identified that upgrading the power transfer capability across QNI has the potential to provide market benefits. The primary source of potential market benefits is related to reductions in the cost of supply from generators. Increasing QNI capability allows generating plant with a relatively high cost of fuel to be displaced with lower cost sources. Other sources of market benefits include reduction in forecast levels of unserved energy by facilitating increased sharing of generation reserves between regions, and competition benefits.

TransGrid and Powerlink note that AEMO's NTNDP for 2010, 2011 and for 2012, their NTS in 2009 and their ANTS in 2008 also contained descriptions of the limitations on QNI capacity. With the exception of the 2012 and 2013 NTNDP, AEMO's reports have shown potential net market benefits from upgrading QNI under some market development scenarios.

AEMO's 2012 NTNDP did not identify a net market benefit associated with a major transmission augmentation to QNI interconnector capacity, under least cost modelling for AEMO's planning scenario. In addition, the 2013 NTNDP stated that the modelling undertaken has not identified any requirement for major investment in interconnector augmentations following the completion of the Heywood augmentation between Victoria and South Australia.

Powerlink and TransGrid note there are some differences between the assessment contained within this report and the analysis carried out by AEMO as part of the NTNDP. This report contains an analysis of market benefits across a wider range of potential future market developments and network upgrade options, which may lead to different conclusions under some scenarios. The market studies contained within this report also focus on examining market benefits using realistic bidding behaviour models and include an assessment of competition benefits. In addition, Powerlink and TransGrid have observed some differences in forecast generation retirement outcomes between these studies and the NTNDP, which may potentially lead to different outcomes under some of the scenarios.

2.3. Joint planning

As discussed above, TransGrid and Powerlink have periodically reviewed whether upgrading the capacity of QNI might deliver net market benefits. Section 2.1 above describes that co-operation and the previous work conducted in relation to the potential for expansion of QNI interconnector capacity.

TransGrid and Powerlink have carried out joint annual planning reviews as required by Clause 5.12.1 (b) of the NER. As required by Clause 5.14.1(d)(4) they have identified that the limitations described in Section 2.2 may give rise to potential benefits associated with augmentations of network capacity and have carried out joint planning to determine potential options for these augmentations.

3. Options for augmenting QNI capacity

This section discusses the credible options included in the RIT-T analysis. Clause 5.16.4 (b)(5) of the NER requires TransGrid and Powerlink in applying the RIT-T to consider all options that could reasonably be classified as credible options, including network options and non-network options. The absence of a proponent does not exclude an investment from being considered a credible option.[15] Credible options must be both commercially and technically feasible.

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

- **Option 0** – Uprating of the Northern NSW 330 kV transmission lines.
- **Option 1a** – 50% Series Compensation. This option involves the installation of thyristor controlled series capacitors across the Bulli Creek to Dumaresq and the Dumaresq to Armidale 330 kV circuits.
- **Option 1b** – 50% Series Compensation with second Armidale SVC. This option involves the installation of series compensation across the Bulli Creek to Dumaresq and the Dumaresq to Armidale 330 kV circuits as described in Option 1a together with a second SVC at Armidale 330 kV Substation.
- **Option 1c** – 30% Series Compensation. Series capacitor compensation is installed only on the Dumaresq – Bulli Creek circuits. Option 1c does not involve series compensation of the Armidale – Dumaresq circuits, thus making it easier for wind farms generation to connect to that double circuit line should they choose to do so.
- **Option 2a** – Second Armidale SVC. This option involves the installation of a second SVC at Armidale 330 kV Substation.
- **Option 2b** – New SVCs at Dumaresq and Tamworth and Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth substations. This option involves installation of +350 MVAr / -100 MVAr SVCs at Tamworth and Dumaresq 330 kV substations. Shunt capacitors are also installed at Dumaresq, Armidale and Tamworth 330 kV substations.

Option 1a, 1b and 2a were included in the PSCR published in June 2012. Options 1c and 2b were identified in response to feedback received after publication of the PSCR and make it easier for wind farms generation to connect to the Armidale – Dumaresq line should they choose to do so. Option 0 has been introduced since the release of the PSCR and represents a relatively low cost option of uprating the existing Northern NSW 330 kV lines.

The interconnector transfer capability achieved at any point in time will be subject to several factors, including the level of demand, generation dispatch, status and availability of transmission equipment, and network and ambient operating conditions. The notional interconnector capabilities provided by these options are shown in Table 5.

The notional interconnector capabilities tabled for each of the upgrade options take into consideration thermal, voltage, transient and oscillatory limitations. With respect to thermal limitations these have been quantified at time of summer daytime peak load and hot ambient conditions. This explains the identical limits for options 1a and 1b. At more favourable ambient and load conditions the transfer capability of QNI reverts to stability limitations. During these times the addition of the Armidale SVC (option 1b) delivers incremental transfer capability compared to option 1a.

In the northward direction the thermal limitations occur on the Liddell – Tamworth line following the loss of the Liddell – Muswellbrook line. The notional northward thermal limits are therefore dependent on the availability and dispatch of generation in NSW further north than this limiting circuit (e.g. Redbank Power Station). The notional northward thermal limits have been defined assuming that this power station is in service.

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15 NER 5.15.2(d).

Table 5 Notional Interconnector Limits for credible options (MW)

Option	Description	Notional Limit		Change from Current	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
Option 0	Uprating of the Northern NSW 330 kV lines	540	1200	230[16]	0
Option 1a	50% Series Compensation	770	1445	230	245
Option 1b	50% Series Compensation with Second Armidale SVC	770	1445	230	245
Option 1c	30% Series Compensation	752	1371	212	171
Option 2a	Second Armidale SVC	540	1257	78[17]	57
Option 2b	New SVCs at Tamworth and Dumaresq and shunt capacitor banks	770	1394	230	194

3.1. Description of the credible network options assessed

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

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

3.1.1. Option 0 – Uprating the Northern NSW 330 kV lines

This option involves the uprating of lines 83, 84 and 88 (which are the Liddell to Tamworth via Muswellbrook circuits), and reconfiguration of the Tamworth 330 kV Switchyard.

The network configuration does not change under Option 0 and so no network diagram has been included in this PADR.

TransGrid would be the proponent of this option.

Technical Characteristics

The technical characteristics of this option include:

- The uprating of the following lines from the existing design operating temperature of 85 ^{o}C to a higher design temperature of 120^{o}C,
  - 83, Liddell – Muswellbrook 330 kV transmission line;
  - 88, Muswellbrook – Tamworth 330 kV transmission line; and
  - 84, Liddell – Tamworth 330 kV transmission line.
- The Tamworth 330 kV substation reconfiguration.

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16 The notional limit is set by line thermal ratings and transient stability. Uprating of the Northern NSW 330 kV lines would improve the thermal limit by 230 MW in the northerly direction. The thermal transfer limit in the southerly direction would remain unchanged as it is limited by the other sections of the QNI corridor. Uprating the northern NSW 330 kV lines would have no impact on voltage and transient stability limitations in either direction.

This means that depending on actual system conditions, transient stability may limit the improvement to less than 230 MW.

17 The notional limit in the northward direction is set by summer day line thermal ratings. The second Armidale SVC would improve the transient stability limit by 78 MW in the northerly direction while the thermal transfer limit would remain unchanged. The increased stability limit could be utilised during periods of more favourable ambient conditions when the thermal limits are greater.

Impact on Transfer Capability

The notional limit for northward flow is 540 MW due to the transient stability following the trip of the Kogan Creek generator; while the notional limit for southward flow is 1200 MW due to transient stability following a two-phase-to-ground fault on one circuit of the Armidale – Dumaresq line.

In the northward direction, thermal limitations also occur on the Liddell – Tamworth line following the loss of the Liddell – Muswellbrook line. Uprating of the northern NSW 330 kV lines (circuits 83, 84 and 88) increases the summer day, thermal capability from 540 MW to 770 MW. During more favourable winter evening conditions the thermal capability increases from 728 MW to 960 MW.

Option 0 does not impact on any transient, voltage or oscillatory limits in a northerly or southerly direction.

Construction Timetable and Anticipated Costs

It is expected that it would take around 47 months to complete this project. Details of the economic timing results for this option can be found in section 6.2 below.

The estimated capital cost of this option is $46.5 million. This reflects the following breakdown:

- 83, 84, 88 line uprating – $35.5m
- Tamworth 330 kV reconfiguration – $11m

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was not discussed in the NTNDP for 2010, 2011, 2012 or 2013.

3.1.2. Option 1a – 50% Series Compensation

This option involves the installation of thyristor controlled series capacitors across the Bulli Creek to Dumaresq and the Dumaresq to Armidale 330 kV circuits, shunt connected capacitor banks at Armidale, the uprating of lines 83, 84 and 88 (the Liddell to Tamworth via Muswellbrook circuits), and Tamworth 330 kV Switchyard reconfiguration. 50% of the reactance of the 330 kV transmission circuits between the Bulli Creek to Dumaresq and the Dumaresq to Armidale substations would be compensated using series capacitors installed at TransGrid's Dumaresq Substation. The upgraded network is shown in Figure 3-1.

As a result of series capacitors being installed on the QNI interconnector, there is a potential for sub-synchronous resonance to occur with some nearby thermal generators, or any wind farm generators that may be developed nearby in the future. In order to counteract sub-synchronous resonance, the series compensation option must have a component of the series capacitance controlled by thyristors in series with a fixed capacitor component. This is known as Thyristor Controlled Series Compensation (TCSC), and in the proposed scheme half of the series capacitors would be controlled by thyristors[18]. An indicative arrangement of the TCSC was provided in the PSCR.

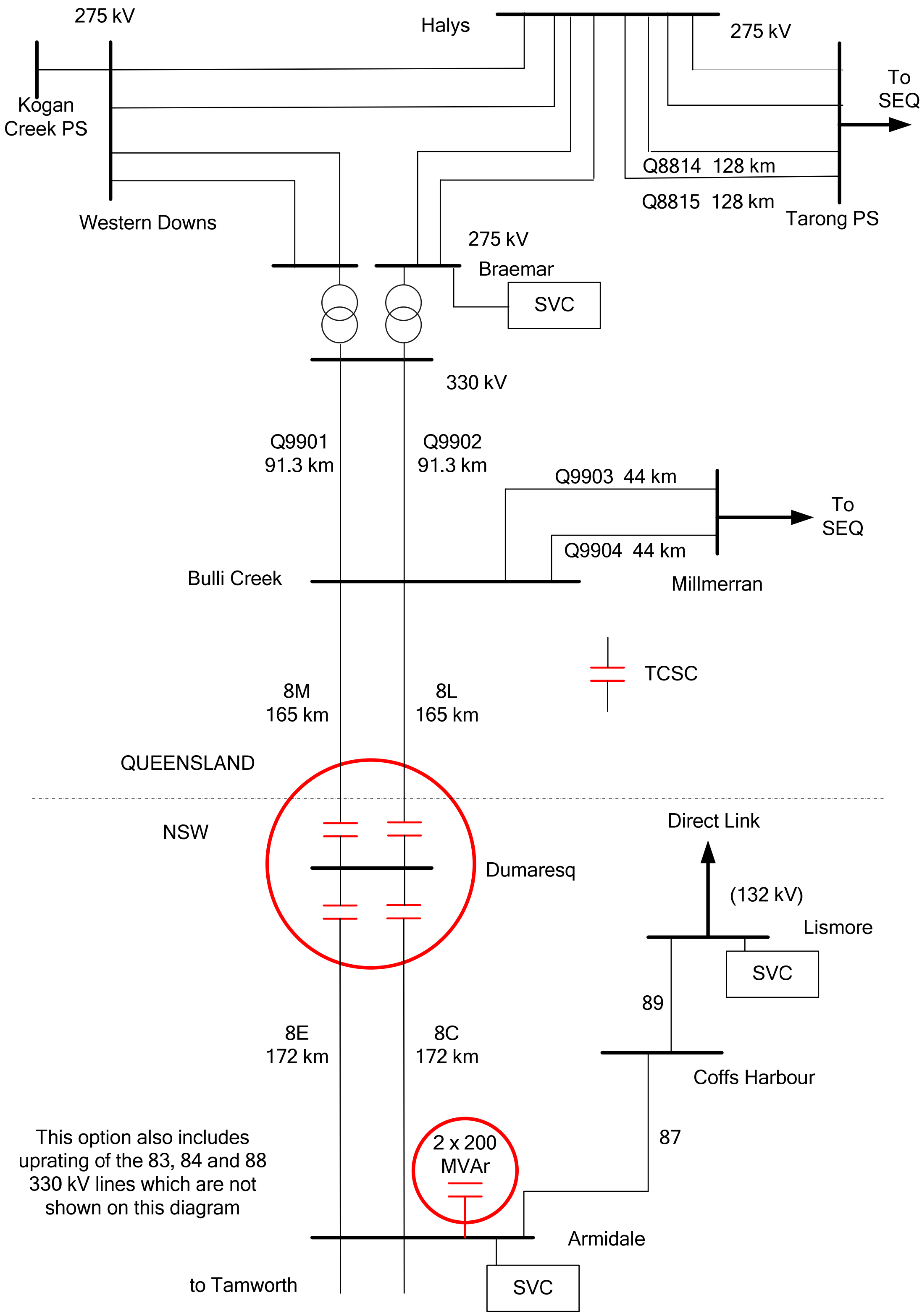
The series capacitors reduce the effective reactance across the compensated transmission lines which subsequently brings the two systems electrically closer together, thereby improving both transient and voltage stability. However, series compensation would not increase QNI limits set by the thermal ratings of the circuits. It is evident from analysis undertaken by TransGrid and Powerlink that the stability limit increase in both directions with 50% compensation would encroach on the thermal ratings of QNI.

The level of compensation proposed recognises that for flows in the northerly direction, the benefits of high levels of compensation could not be realised due to line thermal ratings becoming limiting. Therefore, the full benefits of this option can only be captured by uprating lines 83, 84 and 88. These works are included as part of the cost of this option. This approach is consistent with submissions to the PSCR which highlighted that TransGrid and Powerlink should also include the cost of addressing any intra-regional constraints required by an option.

TransGrid would be the proponent of this option.

[18] D.K. Geddey, L.C.Xu, D.J. Conroy, "Upgrade Options for the Queensland to NSW Interconnector (QNI)", TransGrid, SCB4 Colloquium, Australia, October 2011

Figure 3-1: Option 1a - Series Compensation



Technical Characteristics

The technical characteristics of this option include:

- The installation of four thyristor controlled series capacitors at Dumaresq 330 kV Switching Station, one in each of the Dumaresq to Bulli Creek 330 kV transmissions circuits (8L and 8M) and the Dumaresq to Armidale 330 kV transmission circuits (8E and 8C). The series capacitors would compensate 50% of the reactance of each of these transmission circuits;
- The installation of associated 330 kV switchgear and connections at Dumaresq Substation;
- Extension of the existing Dumaresq switchyard bench to accommodate the four TCSC units and associated switchgear and connections;
- Diverting the existing transmission lines to allow connection to the TCSC units;
- The uprating of the following lines to 120°C operating temperature,
  - 83, Liddell – Muswellbrook 330 kV transmission line;
  - 88, Muswellbrook – Tamworth 330 kV transmission line; and
  - 84, Liddell – Tamworth 330 kV transmission line.
- The installation of 2 x 200 MVAr, 330 kV shunt capacitor banks at Armidale 330/132 kV Substation;
- 330 kV Tamworth Switchyard reconfiguration; and
- Associated relay protection and control system works.

Impact on Transfer Capability

The notional limit for northward flow is 770 MW due to thermal limitations following an outage of the Liddell – Muswellbrook line during hot ambient summer conditions and peak load. The notional limit for southward flow is 1445 MW due to thermal limitations following an outage of an Armidale – Dumaresq circuit.

In the northward direction, the thermal limitation occurs on the Liddell – Tamworth Line following the loss of the Liddell – Muswellbrook line. Following the thermal upgrade of circuits 83, 84 and 88 the summer day, thermal capability increases from 540 MW to 770 MW. During more favourable winter evening conditions the thermal capability increases from 728 MW to 960 MW. In the southward direction, the thermal limitation occurs on one of the Armidale – Dumaresq circuits following the loss of the parallel circuit. The summer day thermal capability is 1445 MW.

The series capacitors reduce the effective reactance across the transmission lines and therefore improve the notional northerly transient stability limit from 540 MW to 922 MW. During hot ambient summer day conditions the improved transient stability limit in a northerly direction would exceed the thermal capability. However, during winter evening conditions, the improved transient stability limit would still be lower than the corresponding thermal capability.

Construction Timetable and Anticipated Costs

It is expected that it would take around 45 months to complete this option (excluding connection of any wind generation). Details of the economic timing results for this option can be found in section 6.2 below.

The estimated capital cost of this option is $179.5 million. This reflects the following breakdown:

- 4 x TCSCs – $123m
- 83, 84, 88 line uprating – $35.5m
- Capacitor banks at Armidale – $10m
- Tamworth 330 kV reconfiguration – $11m

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was discussed in AEMO's 2010 NTNDP. At that time AEMO's market modelling indicated that this option would deliver net market benefits in five out of the ten NTNDP scenarios.

In the 2012 and 2013 NTNDP, AEMO did not conclude that a QNI interconnector upgrade would have a positive net market benefit. However, TransGrid and Powerlink have assessed this project under a wider range of scenarios and economic modelling approaches, which has resulted in different outcomes under some sensitivities and scenarios.

3.1.3. Option 1b – 50% Series Compensation with Second Armidale SVC

This option involves the installation of thyristor controlled series capacitors across the Bulli Creek to Dumaresq and the Dumaresq to Armidale 330 kV circuits, shunt connected capacitor banks and a second SVC installed at Armidale, the uprating of lines 83, 84 and 88 (which are the Liddell to Tamworth via Muswellbrook circuits), and Tamworth 330 kV substation reconfiguration. 50% of the reactance of the 330 kV transmission circuits between Bulli Creek to Armidale substations (i.e. Dumaresq to Armidale and Dumaresq to Bulli Creek) would be compensated using series capacitors installed at Dumaresq Substation. The upgraded network is shown in Figure 3-2.

There is a potential for sub-synchronous resonance to occur with some nearby thermal generators or any wind farm generators that may be developed nearby in the future. Mitigating potential sub-synchronous resonance requires a component of the series capacitance to be controlled by thyristors. As for option 1a half of the series capacitors would be controlled by thyristors.

Capturing the full benefits of this option again requires uprating of the lines 83, 84 and 88. These works are therefore included as part of the costs of this option. This approach is consistent with submissions to the PSCR which highlighted that TransGrid and Powerlink should also include the cost of addressing any intra-regional constraints required by an option.

The SVC would be installed at a new Armidale 330 kV switchyard near the existing Armidale 330/132 kV Substation. The optimal location of the SVC would be identified as part of the detailed design and analysis process.

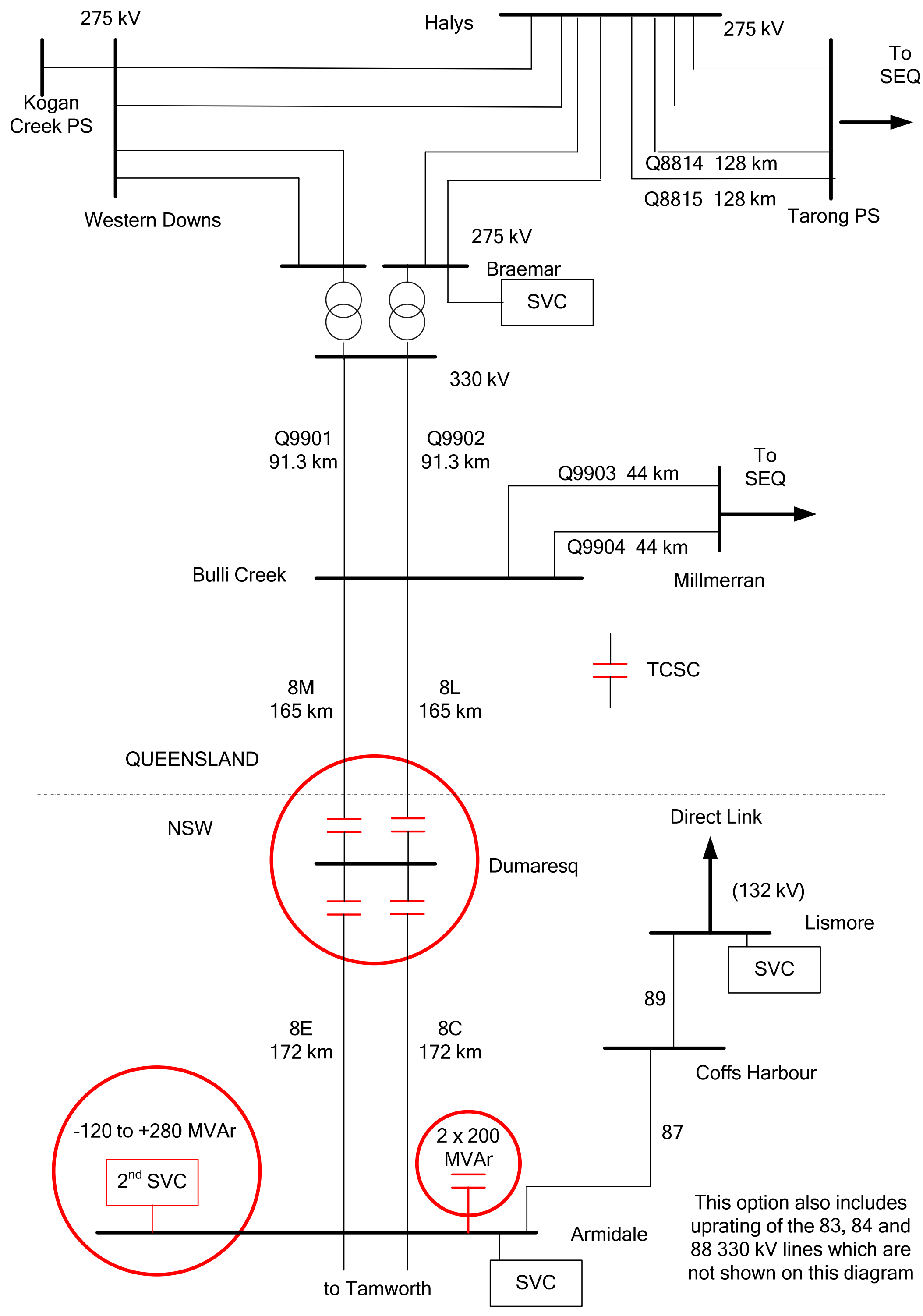
TransGrid would be the proponent of this option.

<u>Technical Characteristics</u>

The technical characteristics of this option would include:

- The installation of four thyristor controlled series capacitors at Dumaresq 330 kV Switching Station, one in each of the Dumaresq to Bulli Creek 330 kV transmissions circuits (8L and 8M) and the Dumaresq to Armidale 330 kV transmission circuits (8E and 8C). The series capacitors would compensate 50% of the reactance of each of the transmission circuits;
- The installation of associated 330 kV switchgear and connections at Dumaresq Substation;
- Extension of the existing Dumaresq switchyard bench to accommodate the four TCSC units and associated switchgear and connections;
- Diverting the existing transmission lines to allow connection to the TCSC units;
- The installation of one SVC with a range of -120 MVAr inductive to +280 MVAr capacitive at nominal voltage and connected to the 330 kV busbar at the new Armidale 330 kV switchyard;
- The installation of one 330 kV switchbay (with a 50 kA short-circuit rating) for connection of the SVC to the 330 kV bus at the site,
- The uprating of the following lines to 120°C operating temperature,
  - 83, Liddell – Muswellbrook 330 kV transmission line;
  - 88, Muswellbrook – Tamworth 330 kV transmission line;
  - 84, Liddell – Tamworth 330 kV transmission line;
- The installation of 2 x 200 MVAr, 330 kV shunt capacitor banks at Armidale 330/132 kV Substation;
- 330 kV Tamworth Switchyard reconfiguration; and
- Associated relay protection and control system works.

Figure 3-2: Option 1b – Series Compensation with Second Armidale SVC



Impact on Transfer Capability

The notional limit for northward flow is 770 MW due to thermal limitations following an outage of the Liddell – Muswellbrook line during hot ambient summer conditions and peak load. The notional limit for southward flow is 1445 MW due to thermal limitations following an outage of an Armidale – Dumaresq circuit.

In the northward direction, the thermal limitation occurs on the Liddell – Tamworth Line following the loss of the Liddell – Muswellbrook line. Following the thermal upgrade of circuits 83, 84 and 88 the summer day, thermal capability increases from 540 MW to 770 MW. During more favourable winter evening conditions the thermal capability increases from 728 MW to 960 MW. In the southward direction, the thermal limitation occurs on one of the Armidale – Dumaresq circuits following the loss of the parallel circuit. The summer day thermal capability is 1445 MW.

The series capacitors reduce the effective reactance across the transmission lines and therefore improve the transient, voltage and oscillatory limits. The addition of the second SVC at Armidale also improves these stability limitations. The series and shunt compensation components of this option increase the notional northerly stability limit from 540 MW to 1012 MW. The improved stability limit in the northward direction exceeds the thermal capability both during hot summer day ambient conditions and during winter evening conditions. Therefore, the thermal capability would constrain the maximum secure power transfer in both directions.

Construction Timetable and Anticipated Costs

It is expected that it would take around 55 months to complete this option. Details of the economic timing results for this option can be found in section 6.2 below.[19]

The estimated capital cost of this option is $222 million. This reflects the following breakdown:

- 4 x TCSCs – $123m
- Second SVC at Armidale 330 kV – $42.5m
- 83, 84, 88 line uprating – $35.5m
- Capacitor banks at Armidale – $10m
- Tamworth 330 kV reconfiguration – $11m

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

The addition of the SVC to the series compensation option was not discussed within the NTNDP for 2010, 2011, 2012 or 2013.

3.1.4. Option 1c – 30% Series Compensation

This option involves the installation of thyristor controlled series capacitors across the Bulli Creek to Dumaresq (northern leg only) 330 kV circuits, shunt connected capacitor banks at Armidale Substation, the uprating of lines 83, 84 and 88, and 330 kV Tamworth Switchyard substation reconfiguration. An equivalent 30% of the reactance of the 330 kV transmission lines between Bulli Creek and Armidale would be compensated using series capacitors installed at Dumaresq Substation. The upgraded network is shown in Figure 3-3.

As a result of series capacitors being installed on the QNI interconnector, there is a potential for sub-synchronous resonance to occur with some nearby thermal generators or any wind farm generators that may be developed nearby in the future. As for options 1a and 1b, TCSC is proposed to counteract any potential sub-synchronous resonance.

The series capacitors reduce the effective reactance across the transmission lines which subsequently bring the two systems electrically closer together, thereby improving both transient and voltage stability. Capturing the full benefits of this option again requires uprating lines 83, 84 and 88. These works are therefore included as part of the cost of this option. This approach is consistent with submissions to the PSCR which highlighted that TransGrid and Powerlink should also include the cost of addressing any intra-regional constraints required by an option.

This option has been introduced as a potential option after the publication of the PSCR to assess whether lower levels of series compensation (with associated lower costs) would deliver higher net market benefits

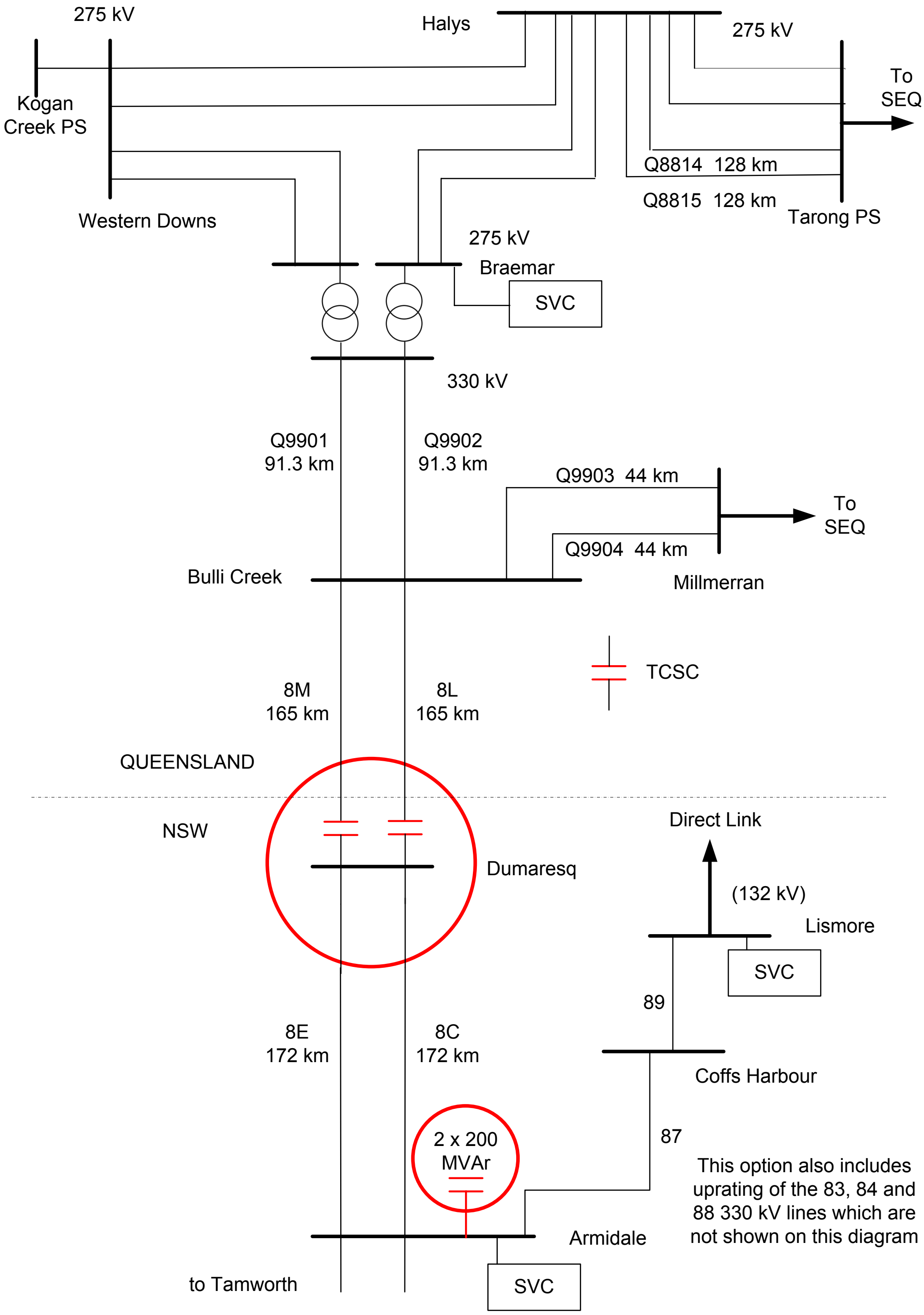
[19] This lead time excludes connection works for any potential wind generation development.

compared to the installation of series compensation across both 330 kV line sections between Armidale and Bulli Creek substations.

Under this option, the 330 kV line between Armidale and Dumaresq is not compensated, thus enabling the connection of wind generation near the mid-point of the Armidale to Dumaresq circuit section at a lower cost in the future. This difference in connection cost for a potential wind farm generator is considered as a market benefit under those scenarios which include development of wind farm generation within this location.

TransGrid would be the proponent of this option.

Figure 3-3: Option 1c - Series Compensation



Technical Characteristics

The scope of works for this option would include:

- The installation of two thyristor controlled series capacitors at Dumaresq 330 kV Switching Station; one in each of the Dumaresq to Bulli Creek 330 kV transmissions circuits (8L and 8M). The series capacitors would compensate 60% of the reactance of each of the circuits (or an equivalent 30% between Armidale and Bulli Creek);
- The installation of associated 330 kV switchgear and connections at Dumaresq;
- Extension of the existing switchyard bench to accommodate the two TCSC units and new 330 kV line bays;
- Diverting the existing transmission lines to allow connection to the TCSC units;
- The uprating of the following lines to 120°C operating temperature,
    - 83, Liddell – Muswellbrook 330 kV transmission line;
    - 88, Muswellbrook – Tamworth 330 kV transmission line;
    - 84, Liddell – Tamworth 330 kV transmission line;
- The installation of 2 x 200 MVAr, 330 kV shunt capacitor banks at Armidale 330/132 kV Substation;
- 330 kV Tamworth Switchyard reconfiguration; and
- Associated relay protection and control system works.

Impact on Transfer Capability

The notional limit for northward flow is 752 MW due to the transient stability following the trip of Kogan Creek generator. The notional limit for southward flow is 1371 MW due to the transient stability following a two-phase-to ground fault on an Armidale – Dumaresq circuit. As for Options 1a and 1b, 30% series compensation reduces the effective reactance across the transmission lines which improves transient, voltage and oscillatory stability.

The thermal uprating of lines 83, 84 and 88 increase the thermal capability from 540 MW to 770 MW during hot ambient sum day conditions and during more favourable winter evening conditions from 728 MW to 960 MW. These thermal limits exceed the notional stability limitations. Therefore, for Option 1c the notional maximum secure power transfer capability is limited by transient stability.

Construction Timetable and Anticipated Costs

It is expected that it would take around 45 months to complete this option. Details of the economic timing results for this option can be found in section 6.2 below.

The estimated capital cost of this option is $130 million. This reflects the following breakdown:

- 2 x TCSCs – $73.5m
- 83, 84, 88 line uprating – $35.5m
- Capacitor banks at Armidale – $10m
- Tamworth 330 kV reconfiguration – $11m

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option has not been discussed in AEMO's NTNDP for 2010, 2011, 2012 or 2013.

3.1.5. Option 2a – Second Armidale SVC

This option involves the installation of a second SVC at Armidale 330 kV Substation. The upgraded network is shown in Figure 3-4.

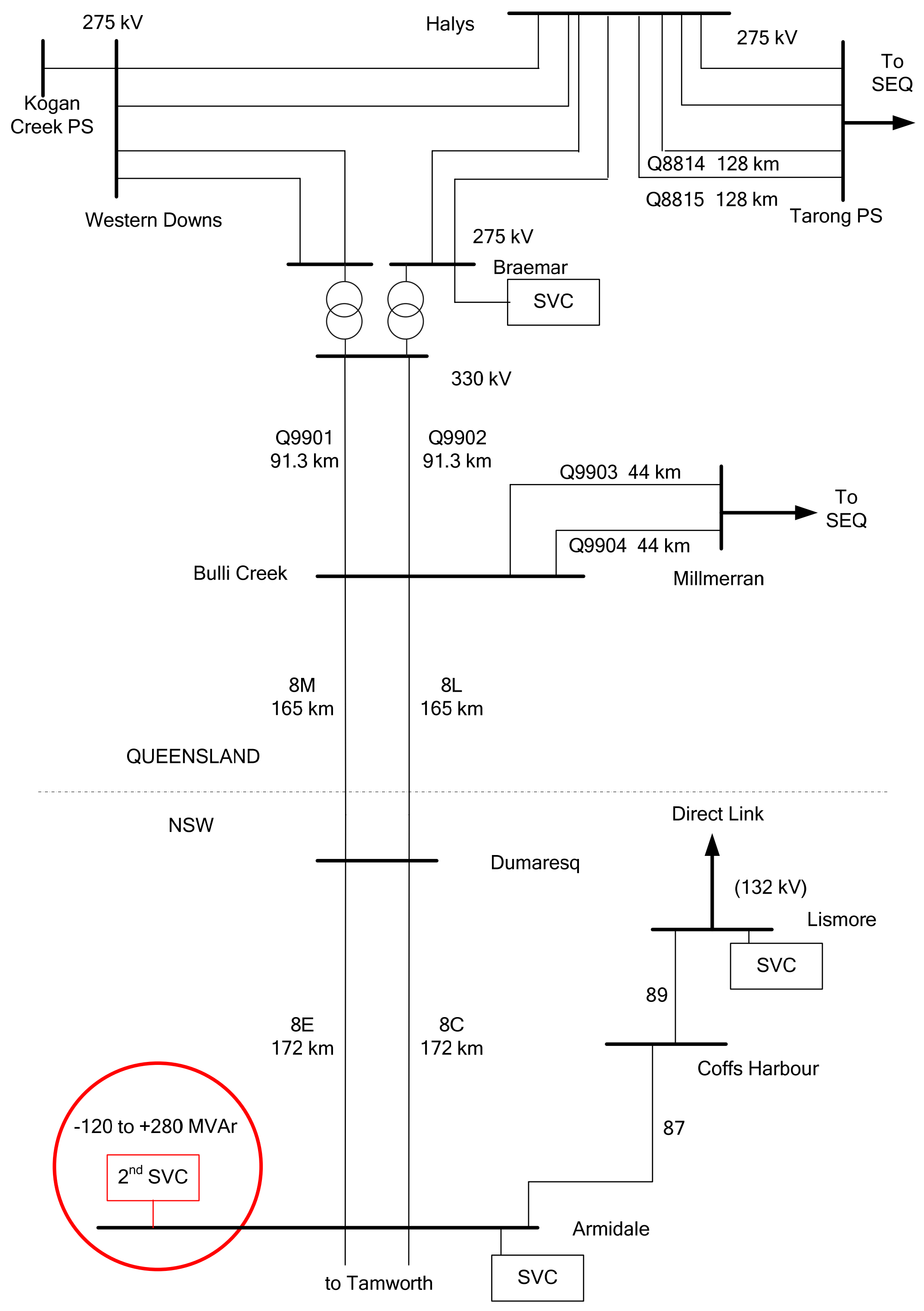
The SVC would be installed at a new Armidale 330 kV switchyard near the existing Armidale 330/132 kV Substation. The optimal location of the SVC would be identified as part of the detailed design and analysis process.

The addition of the second SVC at Armidale would increase the level of dynamic reactive reserves within the northern NSW network. This would enable an increase in the level of northerly and southerly QNI transfer capability.

The installation of an SVC would not increase the line thermal rating limitations in the system.

TransGrid would be the proponent of this option.

Figure 3-4: Option 2a – Second Armidale SVC



Technical Characteristics

The scope of this option would include the following:

- The installation of one SVC with a range of -120 MVAr inductive to +280 MVAr capacitive at nominal voltage and connected to the new 330 kV busbar at Armidale;
- The installation of one 330 kV switch bay (with a 50 kA short-circuit rating) for connection of the SVC to the 330 kV bus; and
- Tamworth 330 kV Switchyard reconfiguration.

Impact on Transfer Capability

The notional limit for northward flow is 540 MW due to thermal limits following an outage of the Liddell – Muswellbrook line during hot ambient summer conditions. The notional limit for southward flow is 1257 MW due to transient stability following a two-phase-to ground fault on an Armidale – Dumaresq circuit.

The addition of the second SVC at Armidale increases the level of dynamic reactive reserves, which increases the transfer capability based on stability criteria. The notional northward transient stability limit increases from 540 MW to 618 MW, an increase of 78 MW. Therefore, the northerly transient stability limits may permit greater northward QNI flow during more favourable ambient conditions than hot summer peak days.

Construction Timetable and Anticipated Costs

It is expected that it would take around 45 months to complete this option with the establishment of a new Armidale 330 kV switch bay for connecting the second SVC. Details of the economic timing results for this option can be found in section 6.2 below.

The estimated capital cost of this option is $53.5 million. This reflects the following breakdown:

- Second SVC at Armidale 330 kV – $42.5m
- Tamworth 330 kV reconfiguration – $11m

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option is discussed in AEMO's 2010 NTNDP. At that time AEMO's market modelling indicated that this option would deliver net market benefits in five out of the ten NTNDP scenarios.

In the 2012 and 2013 NTNDP, AEMO did not conclude that a QNI interconnector upgrade would have a positive market benefit. However, TransGrid and Powerlink have assessed this option under a wider range of scenarios and modelling approaches, which has led to different outcomes under some cases.

3.1.6. Option 2b – New SVCs at Tamworth and Dumaresq and shunt capacitor banks

This option been introduced as a result of submissions received in response to the PSCR. Submissions received raised a number of issues including the possibility of large scale wind generation in northern NSW. Those generators may be connected to the Armidale – Dumaresq double circuit 330 kV line. This option would facilitate the later connection of wind generation at a lower cost, should such development occur.

This option involves the installation of a two additional SVCs at Tamworth and Dumaresq 330 kV substations, provision of additional 330 kV shunt connected capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substations, the uprating of lines 83, 84 and 88 (Liddell to Tamworth via Muswellbrook circuits), and the Tamworth 330 kV Switchyard reconfiguration.

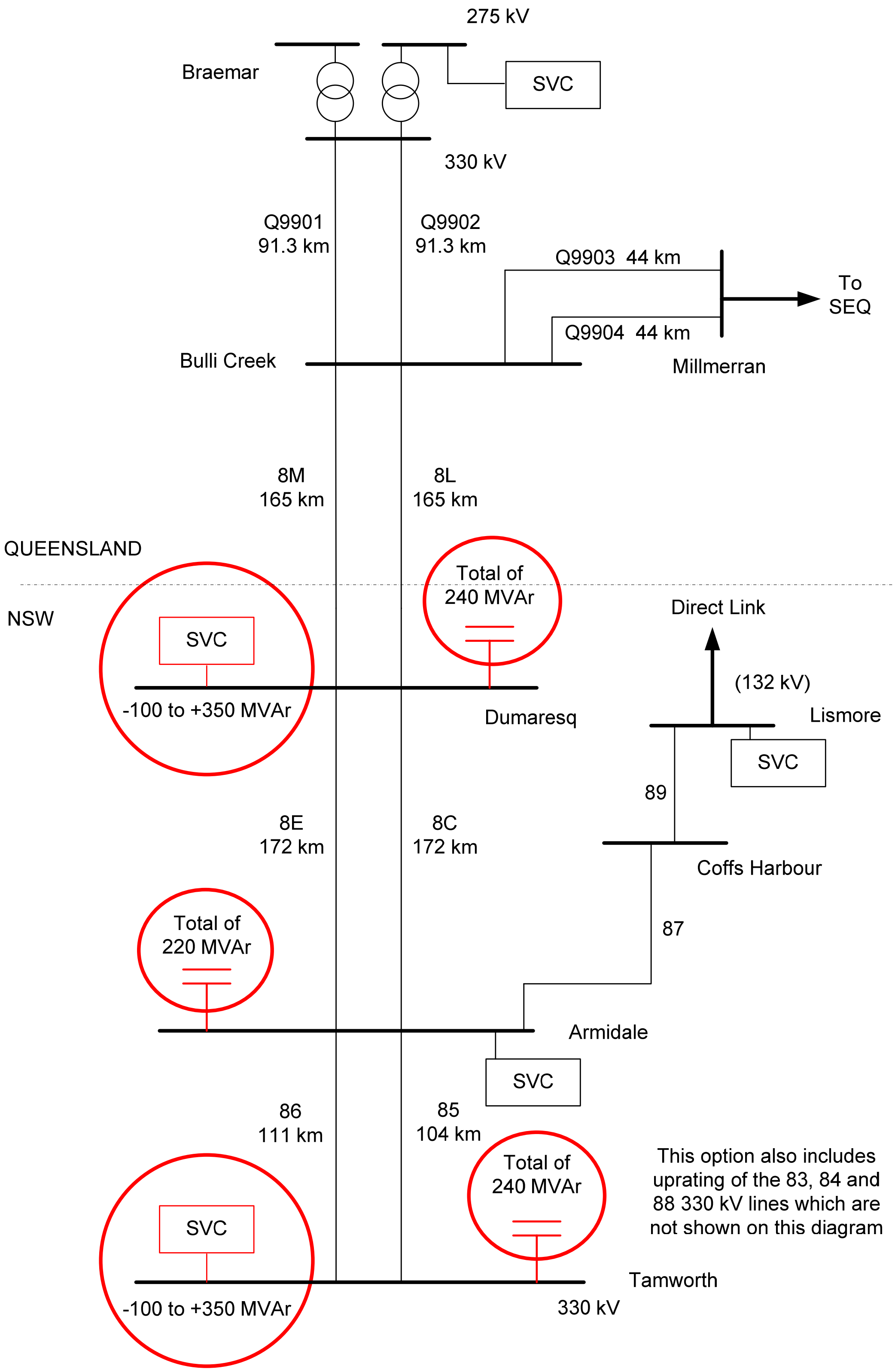
The addition of new SVCs at Tamworth and Dumaresq would increase the level of dynamic reactive reserves within the northern NSW network. This would enable an increase in the level of northerly and southerly QNI transfer capability.

The installation of new SVCs would not increase the line thermal rating limitations in the system.

Capturing the full benefits of this option requires uprating of the lines 83, 84 and 88. These works are therefore included as part of the cost of this option.

TransGrid would be the proponent of this option, which is shown in Figure 3-5.

Figure 3-5: Option 2b – New SVCs at Tamworth and Dumaresq and capacitors



Technical Characteristics

The scope of this option would include the following:

- The installation of a SVC at each of Tamworth and Dumaresq substations with a range of -100 MVAr inductive to +350 MVAr capacitive at nominal voltage and connected to the respective 330 kV busbars;
- The installation of two 330 kV switchbays (with a 50 kA short-circuit rating) for connection of the SVC to the 330 kV bus at the nominated sites;
- The uprating of the following lines to 120°C operating temperature,
  - 83, Liddell – Muswellbrook 330 kV transmission line;
  - 88, Muswellbrook – Tamworth 330 kV transmission line; and
  - 84, Liddell – Tamworth 330 kV transmission line.
- 330 kV Tamworth Switchyard reconfiguration;
- Shunt connected capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substations as detailed below.

Site	**Capacitors (MVAr)**	**Total MVAr**
Tamworth 330 kV Substation	2 x 60 + 120	240
Armidale 330 kV Substation	2 x 50 + 120	220
Dumaresq 330 kV Substation	2 x 120	240

- Associated relay protection and control system works.

Impact on Transfer Capability

The notional limit for northward flow is 770 MW due to thermal limitations following an outage of the Liddell – Muswellbrook line during hot ambient summer conditions and peak load. The notional limit for southward flow is 1394 MW due to transient stability following a two-phase-to ground fault on an Armidale – Dumaresq circuit.

In the northward direction, the thermal limitation occurs on the Liddell – Tamworth Line following the loss of the Liddell – Muswellbrook line. Following the thermal upgrade of circuits 83, 84 and 88 the summer day, thermal capability increases from 540 MW to 770 MW. During more favourable winter evening conditions the thermal capability increases from 728 MW to 960 MW. In the southward direction, the thermal limitation occurs on one of the Armidale – Dumaresq circuits following the loss of the parallel circuit. The summer day thermal capability is 1445 MW.

The addition of new SVCs at Tamworth and Dumaresq increase the level of dynamic reactive reserves and therefore improve the northward transient stability limit from 540 MW to 917 MW. During summer days, the improved transient stability limit exceeds the thermal capability in a northerly direction. However, during more favourable winter evening conditions, the improved transient stability limit would still be lower than the thermal capability.

Construction Timetable and Anticipated Costs

It is expected that it would take around 44 months to complete this option. Details of the economic timing results for this option can be found in section 6.2 below.

The estimated capital cost of this option is $176.2 million. This reflects the following breakdown:

- New SVCs at Tamworth and Dumaresq 330 kV substation, Capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substation and Armidale, Dumaresq substation reconfiguration - $129.7M
- Tamworth 330 kV substation reconfiguration – $11M
- 83, 84, 88 line uprating – $35.5M

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was not discussed in AEMO's NTNDP for 2010, 2011, 2012 or 2013.

3.2. Additional network options subject to first pass assessment

When undertaking this RIT-T assessment, TransGrid and Powerlink examined the economic viability of additional QNI upgrade options under a more limited set of market development scenarios, to determine whether some of the options could be ruled out from further study. This 'first pass assessment' involved carrying out market simulations using realistic bidding behaviour under the Fast World Recovery scenario. Powerlink and TransGrid are of the view that if an upgrade option is not economic under the Fast World Recovery scenario, which incorporates high economic growth, it is unlikely to be economic under the other scenarios (with lower levels of economic growth), and therefore uneconomic overall.

The first pass assessment concluded that several credible network options were not considered to be economically viable, and as such have not been considered further. TransGrid and Powerlink consider that this assessment incorporates a level of analysis that is proportionate to the scale and likely impact of each of the credible options being considered, consistent with clause 5.16.1(c)(2) of the NER.

Further discussion on these network options is provided below. The detailed results of this first pass assessment, including net market benefits, are provided in Appendix F.

3.2.1. Option 3 – Protection System Upgrade

The transfer capability across QNI can be limited by a series of transient stability and voltage control limitations following transmission and generator contingencies. This option involves the upgrade of protection relays and replacement of circuit breakers to reduce the fault clearance times for critical contingencies. For these contingencies this option facilitates higher power transfers across QNI by reducing the level of disturbance to the power system.

This option was included in the PSCR. However, since that time, TransGrid and Powerlink have conducted further detailed power systems modelling into the effectiveness of this option in maintaining power system stability. These studies indicate that while upgrading the protection system may be effective in addressing the disturbance for a number of transmission contingencies, the option was not effective in mitigating the disturbances for other critical contingencies which set the QNI limits for a significant proportion of the time.

TransGrid would be the proponent of this option.

Technical Characteristics

This option would involve a combination of protection relay upgrades and circuit breaker replacements to reduce the fault clearance times. These would be applied to the following lines:

- Liddell – Tamworth 330 kV No.84 line;
- Liddell – Muswellbrook 330 kV No.83 line; and
- Liddell – Newcastle 330 kV No.81 line.

The scope of work associated with the Liddell – Newcastle 330 kV No. 81 line is:

- Replace the Newcastle Circuit Breaker 812a (NNSNEW1L2); and
- Replace the No.1 Protections at both ends of the line.

The scope of work associated with the Liddell – Muswellbrook No. 83 line is:

- Replace the Muswellbrook Circuit Breaker 832a (NNSMRK1aC);
- Replace the Muswellbrook Circuit Breaker 832b (NNSMRK1bC); and
- Protection changes.

The resulting change to the export limits under a range of generator and system operating conditions for faults at Liddell are shown in Table 6.

Table 6 Notional Interconnector Limits for Option 3

Option	Description	NSW to QLD Notional Limit (MW)		NSW to QLD Change from Current (MW)	
		Fast Clearing Times on TL Liddell - Muswellbrook	Fast Clearing Times on TL Liddell - Tamworth	Fast Clearing Times on TL Liddell - Muswellbrook	Fast Clearing Times on TL Liddell - Tamworth
Option 3	Protection System Upgrade	538	1200	7	6

<u>Construction Timetable and Anticipated Costs</u>

This option involves lower capital cost and construction lead times than some of the other options, but results in lower increases to transfer capacity across QNI. It is expected that it would take around one and one half years to complete this option.

The estimated capital cost of this option is $2.1 million.

Given that this option involves replacement of existing equipment, it is expected that there would be little (if any) change to annual operation and maintenance costs.

<u>National Transmission Network Development Plan</u>

This option was not discussed in the 2010, 2011 nor the 2012 NTNDPs.

<u>Reasons for Not Pursuing</u>

This option does not improve the stability limits for contingencies that have been found to set the QNI transfer capability for a significant proportion of the time. Furthermore, for the transmission contingencies which this option is effective in addressing, the corresponding increase in transfer capability is relatively low.

The first pass assessment confirmed that this option is not expected to be economic, with net market benefits being negative (-$1.0m) under the Fast World Recovery scenario. This option is not expected to be economic under the other scenarios, since there is not expected to be a material change to the critical contingencies which set the transfer capability across QNI for a large proportion of the time. Accordingly, this option has not been considered further.

3.2.2. Option 4a – Second High Voltage Alternating Current (HVAC) Interconnector at 330 kV

This option would involve the construction of an additional 330 kV double circuit transmission line and intermediate switching stations between Bayswater and Western Downs substations.

TransGrid and Powerlink would be the proponents of this option.

<u>Technical Characteristics</u>

The scope of work associated with the construction of a second 330 kV HVAC double circuit transmission line between Bayswater and Western Downs substations is:

- Establish three new switching stations, one in the Narrabri/Gunnedah area, one west of Armidale and one west of Dumaresq;
- Construct four double circuit 330 kV transmission lines:
  - From Bayswater to the new 330 kV switching station in the Narrabri/Gunnedah area;
  - From the Narrabri/Gunnedah site to the new switching station west of Armidale;
  - From the site west of Armidale to the new switching station west of Dumaresq;
  - From the site west of Dumaresq to Bulli Creek; and
  - From Bulli Creek to Western Downs.
- Construct three single circuit 330 kV transmission lines:
  - From the new Narrabri/Gunnedah site to the new Tamworth 330 kV Switching Station;
  - From the new site west of Armidale to the new Armidale 330 kV Switching Station;
  - From the new site west of Dumaresq to the existing Dumaresq 330 kV Switching Station.

- Augment the existing substations/switching stations at Bayswater, Tamworth (New), Armidale (New), Dumaresq, Bulli Creek and Western Downs to accommodate the additional transmission line connections.

The intermediate switching stations would be located to enable connections to be made to the existing 330 kV switchyards at Tamworth, Armidale and Dumaresq.

It is possible that the additional transmission lines may consist of new lines largely along the routes of one or both of the existing single circuit 330 kV lines between Liddell and Tamworth, and between Tamworth and Armidale. The end result would be additional 330 kV circuits between Liddell and Armidale via Tamworth.

The notional interconnector capabilities provided by this option are shown in Table 7.

Table 7 Notional Interconnector Limits for Option 4A

Option	Description	Notional Limit (MW)		Change from Current (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
Option 4a	Second HVAC interconnector at 330 kV	1347	2041	807	841

Construction Timetable and Anticipated Costs

This option involves a significantly higher capital cost and longer construction lead times than some of the other options, but results in substantive increases to the transfer capability across QNI. It is expected that it would take around 43 months to complete this option.

The estimated capital cost of this option is $1,300 million.

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was discussed in AEMO's 2010 NTNDP.

Reasons for Not Pursuing

The first pass assessment indicated that this upgrade option is not expected to deliver any positive net market benefits, since the high capital cost of the project outweighs potential market benefits associated with increases in transfer capability. Specifically, this option was found to have estimated net market benefits of -$943m under the Fast World Recovery scenario. Therefore, this option has not been considered further.

3.2.3. Option 4b – New Armidale – Bulli Creek High Voltage Alternating Current (HVAC) Interconnector at 330 kV

This option involves the construction of an additional 330 kV double circuit transmission line between a new Armidale 330 kV switchyard and Dumaresq, and Dumaresq and Bulli Creek and the uprating of lines 83, 84 and 88 (the Liddell to Tamworth via Muswellbrook circuits).

TransGrid and Powerlink would be the proponents of this option.

Technical Characteristics

The scope of work associated with the construction of a second Armidale – Bulli Creek via Dumaresq 330 kV HVAC double circuit transmission line is:

- Construct two double circuit 330 kV transmission lines:
  - From the new Armidale to existing Dumaresq switching station;
  - From Dumaresq to Bulli Creek.
- The uprating of the following lines to 120^{o}C operating temperature,
  - 83, Liddell – Muswellbrook 330 kV transmission line;
  - 88, Muswellbrook – Tamworth 330 kV transmission line;
  - 84, Liddell – Tamworth 330 kV transmission line; and
- Augment the existing substations and/or switching stations at Armidale (new), Dumaresq and Bulli Creek to accommodate the additional transmission line connections.

The resulting change to the QNI limits this option provides would would be less than those for the option 4a.

The notional interconnector capabilities provided by this option are shown in Table 8.

Table 8 Notional Interconnector Limits for Option 4B

Option	Description	Notional Limit (MW)		Change from Current (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
Option 4b	New Armidale – Bulli Creek HVAC interconnector at 330 kV	770	1593	230	393

Construction Timetable and Anticipated Costs

This option involves a significantly higher capital cost and longer construction lead times than some of the other options. It is expected that it would take around 43 months to complete this project.

The estimated capital cost of this option is $560 million.

Annual operation and maintenance costs are anticipated to be around 2% of the capital costs.

National Transmission Network Development Plan

This option has not been directly discussed in AEMO's NTNDP.

Reasons for Not Pursuing

As with option 4a, the first pass assessment indicated that this upgrade option is not expected to deliver positive net market benefits, since the high capital cost of the project outweighs potential market benefits associated with increases in transfer capability. Specifically, this option was found to have estimated net market benefits of -$224m under the Fast World Recovery scenario. Therefore, this option has not been considered further.

3.2.4. Option 4c – Second High Voltage Alternating Current (HVAC) Interconnector at 500 kV

This option involves the construction of an additional 500 kV double circuit transmission line and intermediate switching stations between Bayswater and Western Downs substations.

TransGrid and Powerlink would be the proponents of this option.

Technical Characteristics

The scope of work associated with the installation of the proposed 500 kV interconnector includes:

- The construction of three new 500/330 kV substations at:
  - A site west of Dumaresq;
  - A site west of Armidale; and
  - A site in the Gunnedah/Narrabri area.
- The construction of double circuit 500 kV transmission lines with a total route length of approximately 700 km;
- The construction of single circuit 330 kV transmission lines with a total route length of approximately 235 km;
- Augmentations to Dumaresq 330 kV switching station, new Armidale 330 kV switching station, and new Tamworth 330 kV switching station to accommodate the 330 kV single circuit transmission line connections to the new 500/330 kV substations.
- Augmentations to Bulli Creek Substation to establish a 500 kV switchyard and 500/330 kV transformer.
- Augmentations to Western Downs Substation in Queensland to convert the existing 275 kV switching station to a 500/275 kV substation and connect the 500 kV transmission line.
- Augmentations to Bayswater 500/330 kV substation in northern NSW to accommodate the double circuit 500 kV transmission line connections.

The intermediate substations are likely to be located in the Gunnedah/Narrabri area, Armidale area, Dumaresq area and at Bulli Creek to enable connections to be made to the existing 330 kV switchyards at Tamworth, Armidale, Dumaresq and Bulli Creek.

The notional interconnector capabilities provided by this option are shown in Table 9.

Table 9 Notional Interconnector Limits for Option 4C

Option	Description	Notional Limit (MW)		Change from Current (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
Option 4C	Second HVAC Interconnector at 500 kV	1243	2041	703	841

Construction Timetable and Anticipated Costs

This option involves the highest capital cost and longer construction lead times of all of the options, but results in the highest levels of increase to transfer capability across QNI. It is expected that it would take around 80 months to complete this option.

The estimated capital cost is $2,300 million.

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was discussed as part of the NEMLink project covered in the 2010 NTNDP. It was not discussed in subsequent NTNDPs.

Reasons for Not Pursuing

As with option 4a, the first pass assessment indicated that this upgrade option is not expected to deliver positive net market benefits, since the high capital cost of the project outweighs potential market benefits associated with increases in transfer capability. Specifically, this option was found to have estimated net market benefits of -$1,912m under the Fast World Recovery scenario. Therefore, this option has not been considered further.

3.2.5. Option 5 – High Voltage Direct Current (HVDC) Back to Back Converter Station

This option would involve the installation of a 1,500 MW HVDC back to back asynchronous link located in the interconnected network between Bulli Creek Substation in Queensland and Dumaresq Substation in NSW, together with supporting works. This option isolates the alternating current systems of the Queensland and the southern state transmission networks.

TransGrid and Powerlink would be the proponents of this option.

Technical Characteristics

In order to ensure reliability of service and to provide a firm transfer capability around 1,500 MW, a scheme incorporating 5 x 350 MW HVDC back-to-back converters operating in parallel would be required for this option.

The scope of the works for this option includes the following:

- Development of a HVDC back-to-back scheme north of the existing Dumaresq 330 kV switching station;
- The northern terminals of the HVDC scheme to be connected to the re-routed end of the Dumaresq to Bulli Creek lines No.8L and 8M;
- The uprating of the following lines to 120^{o}C operating temperature,
    - 83, Liddell – Muswellbrook 330 kV transmission line;
    - 88, Muswellbrook – Tamworth 330 kV transmission line;
    - 84, Liddell – Tamworth 330 kV transmission line;
- 330 kV Tamworth Switchyard reconfiguration; and
- Associated relay protection and control system works.

An assessment was made of the power system characteristics of the high voltage transmission system within northern NSW. The assessment found that the strength of the power system (evaluated through calculation of short circuit ratios) was not sufficient to support conventional HVDC switching technology.

The calculated short circuit ratio for the high voltage transmission system at the proposed location for the HVDC back to back converter stations is shown in Table 9 below. In general, short circuit ratios less than 2 would indicate the need for HVDC converter technology based on self-commutating switching devices (such as insulated gate bipolar transistors).

ABB and Siemens offer HVDC systems incorporating self-commutating switching devices under the trade names “HVDC Light” and “HVDC Plus” respectively. The cost of these systems, however, is generally higher than those using conventional thyristor valve switching.

Table 10 Short Circuit Ratio at Dumaresq

System Condition	North Flow		South Flow	
	NSW End SCR	QLD End SCR	NSW End SCR	QLD End SCR
System Intact	1.2	2.0	1.2	2.0
N-1	0.9	1.2	0.8	1.2

The cost of the HVDC option within this report has been based on converter stations which incorporate self-commutating IGBT switching technology.

Construction Timetable and Anticipated Costs

It is expected that it would take around 35 months to complete this option.

The estimated capital cost of this option is $445 million.

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option was discussed in the 2010 NTNDP.

Reasons for Not Pursuing

The first pass assessment indicated that this upgrade option is not expected to deliver positive net market benefits, since the high capital cost of the project outweighs potential market benefits associated with increases in transfer capability. Specifically, this option was found to have estimated net market benefits of -$147m under the Fast World Recovery scenario. Therefore, this option has not been considered further.

3.2.6. Option 6 – Hunter Valley NSW Braking Resistor

This option would involve the installation of a 500 MW braking resistor connected to either the Liddell or Bayswater Power Station 330 kV busbar to improve the NSW to Queensland transfer over QNI. The braking resistor at either of these locations would not provide any improvement to the Queensland to NSW transfer capability.

TransGrid would be the proponent of this option.

Technical Characteristics

This option would involve the installation of control, communication and switching systems to control a 500 MW 330 kV braking resistor.

The scope of work associated with the installation of the braking resistor for this option includes:

- Construction of the two circuit breaker switch-bay;
- Erection, test and commissioning of the 500 MW braking resister; and
- Commissioning the 330 kV switch-bay.

The resulting change to the export limits under a range of generator and system operating conditions for faults at Liddell are shown in Table 11.

Table 11 Notional Interconnector Limits for Option 6

Option	Description	NSW to QLD Notional Limit (MW)		NSW to QLD Change from Current (MW)	
		2LL-G Fault on Liddell - Muswellbrook	2LL-G Fault on Liddell - Tamworth	2LL-G Fault on Liddell - Muswellbrook	2LL-G Fault on Liddell - Tamworth
Option 6	Braking resistor	572	1259	32	59

Construction Timetable and Anticipated Costs

It is expected that it would take around 20 months to complete this option.

The estimated capital cost of this option is $8.1 million.

Annual operation and maintenance costs are anticipated to be around 2% of the capital cost.

National Transmission Network Development Plan

This option has not been discussed in any of AEMO's NTNDPs.

Reasons for Not Pursuing

The Hunter Valley braking resistor option does not improve the transfer capability across QNI for limitations set by either voltage stability or thermal rating considerations. Furthermore, this project is only effective in improving transient stability limits associated with faults occurring in the Hunter Valley (e.g. Liddell). These limitations do not set the northerly transfer capability across QNI for a significant proportion of the time. Therefore, this project provides limited benefits in increasing the transfer capability of QNI in the northerly direction, and does not provide any benefit in increasing the transfer capability across QNI in the southerly direction.

The first pass assessment confirmed that this upgrade option is not expected to deliver positive net market benefits. Specifically, this option was found to have estimated net market benefits of -$7m under the Fast World Recovery scenario. In addition to being marginally negative, these estimated net market benefits are an order of magnitude lower than the other credible options examined within this report (for the same market development scenario), and so this project is unlikely to be ranked above these other options. Therefore, this option has not been considered further.

3.3. Non-network options

3.3.1. Overview

The PSCR set out the technical characteristics that a non-network option would be required to deliver in order to meet the identified need.

A non-network option could take one of the following forms and provide benefits to the NEM.

(a) An option which would not allow increasing the power transfer capability over QNI above the current limits, but yet alter generation and/or demand balance between NSW and Queensland.

(b) An option which would allow increasing the power transfer over QNI above the current limits, and thereby facilitate and improve electricity trading between NSW and Queensland.

Non-network options which would not require increasing the power transfer over QNI, but yet facilitate and improve electricity trading between NSW and Queensland include:

- Load reduction at peak load times, in either Queensland or NSW;
- The shifting of load to alternative time periods, in either Queensland or NSW;
- Energy storage that uses any surplus of low cost generation to be released at appropriate times, in either Queensland or NSW; or
- Pre-emptive load reduction to reduce the loading on QNI at constraining times.

Non network options which would allow increasing the power transfer over QNI above the current limits, and thereby facilitate and improve electricity trading between NSW and Queensland include:

- Post-contingent load reduction and generator tripping to counteract the stability limitations on QNI. These actions would need to be high speed (within one second of a contingency).

A non-network option in the above form would have different levels of impact on the respective QNI thermal, voltage stability, transient stability limit and small signal stability limit.

None of the submissions received in response to the PSCR identified any potential non-network options.

3.3.2. Additional investigation of a load shedding option

TransGrid and Powerlink have examined the possibility of a non-network option to increase the transfer capability across the Queensland to NSW interconnector. The non-network service could potentially increase the power transfer capabilities across QNI if pre-determined actions in response to generator or transmission contingencies were in place to mitigate the impacts of the contingency following the event.

For example, a critical contingency which determines that maximum transfer across QNI in the northerly direction for a significant proportion of time is a trip of the largest generator within the Queensland region. If a pre-determined response following this critical contingency was in place and armed to respond to this event, it may be possible that higher pre-contingent QNI flows could occur. In the case of a generator contingency, a pre-determined response might be the trip of a large load within the Queensland region in a very short time following the critical contingency.

In the case of the largest Queensland generator contingency above, power system studies undertaken by Powerlink and TransGrid have indicated that a load in the order of 400 MW would need to be tripped very quickly following the critical contingency event to allow transfers across QNI to be increased to levels commensurate with the 50% series compensation option, i.e., Option 1a.

The arming and activation of the non-network service would need to be performed through dedicated control and signalling systems, which would need to be protection grade. These works would be undertaken by the relevant network service providers (envisaged to be Powerlink and TransGrid).

Arming of the service

The outputs of market simulations run by TransGrid and Powerlink were examined to determine if a pattern or trend could be determined as to the most likely times the non-network service would need to be armed. It was found that northerly transfers across QNI could potentially bind due to a number of factors, including:

- generator outages;
- relative load demand levels between Queensland and the southern regions;
- availability and dispatch of renewable generation (in particular wind generation within the southern states); and
- thermal ratings and network conditions which can vary depending on the time of day and year.

In essence, there were no consistent patterns or trends to indicate when northerly transfers across QNI were most likely to bind, and hence when a potential non-network scheme would need to be armed. Furthermore, the market simulations indicated that the service could need to be armed at some point during the day for a large proportion of the year, to maximise the benefits of the scheme.

Under some scenarios, the market simulation studies have forecast that occurrences of QNI binding in the northerly direction by the early 2020s could be significant. Under these scenarios, the non-network service would ideally need to be armed for a significant proportion of the time.

Activation of the non-network service

The non-network service would need to be activated upon the onset of the critical contingency event. Post-contingent load reduction to counteract the stability limitations on QNI would need to be within one second of a large generator tripping contingency.

TransGrid and Powerlink have examined historical records of the critical generator and transmission outage events, and can provide this information to assist potential non-network service providers if requested.

Small signal (oscillatory) stability limit analysis

Oscillatory stability could potentially limit transfers across QNI. The existing oscillatory stability limits across QNI are 1200 MW and 700 MW in a southerly and northerly direction respectively.[20] Analysis to

[20] The actual capacity at any point in time depends on factors such as load levels and generation patterns. Consequently it will vary depending on actual conditions. The maximum capacity has been taken to be the small signal (oscillatory) stability limits.

investigate whether these oscillatory limits can be increased is ongoing. Early indications are that any possible non-network options would need to be considered on a case by case basis and until relevant analysis is complete the existing small signal stability limits would be preserved as non-network options do not employ any additional stability improving equipment (such as TCSCs or SVCs). The effectiveness of load shedding options in increasing the QNI transfer level may therefore be limited by the small signal stability of QNI.

As noted above, none of the submissions received in response to the PSCR raised potential non-network options that should be included in the RIT-T analysis. In addition, there are a number of issues that would likely need to be resolved if load shedding were to be implemented at the scale discussed above. These include the complexity of the schemes (which would need to be secure, fast acting and protection based) and the risks associated with its operation.

As a consequence, non-network options involving load shedding or load shifting have not been incorporated as credible options in the RIT-T analysis. If a non-network offer is forthcoming then detailed power system and market benefit analysis would need to be undertaken to assess its technical and commercial feasibility.

Summary of characteristics

The key characteristics required of a non-network are outlined in the table below.

Table 12 Characteristics of a Non-Network Option

Arming of the non-network service	The non-network service would need to be armed at times when transfers across QNI in the northerly direction would be otherwise constrained. The service may need to be armed most days throughout the year and possibly for a significant proportion of the time to maximise the market benefits of the scheme.
Activation of the non-network service	The non-network service would need to be activated upon the onset of the critical contingency event. TransGrid and Powerlink have examined historical records of the critical generator and transmission outage events, and can provide this information to assist potential non-network service providers. Post-contingent load reduction and generator tripping to counteract the stability limitations on QNI would need to be high speed (within one second of a contingency).
Restoration of load following activation of the service	Load can be restored within 30 minutes if there is spare generation capacity otherwise it could take an hour or longer.
Schedule of critical contingencies	The activation of the service may need to be carried out in response to a number of critical contingencies which could set the transfer capability across QNI from time to time, including trip of a large generator within the Queensland region or the occurrence of transmission line faults within NSW.
Location of non-network service	In Queensland region.
Magnitude of load trip	In the order of 400 MW. Conditional on proponent’s proposal. Further analysis would be conducted on a case by case basis.

4. Submissions received

TransGrid and Powerlink received ten submissions in response to both the PSCR and the separate consultation paper issues in relation to the methodology for calculating competition benefits, from:

- AEMO
- Private generators
- CS Energy
- Queensland Department of State Development, Infrastructure and Planning (DSDIP)
- Energex
- Epuron – White Rock Wind Farm
- National Generators Forum (NGF)
- Origin Energy
- Stanwell
- Wind Prospect

The issues raised in these submissions are discussed below, and are also set out in Appendix G. In addition, specific issues raised in submissions are also discussed in the relevant sections throughout this PADR. Each of the submissions has also been published on Powerlink's and/or TransGrid's websites.

4.1. Assumptions surrounding demand forecasts and carbon prices

The private generators submission noted that the identified need for increased QNI capacity as described in the PSCR is based on the 2010 NTNDP scenarios and demand forecasts. Specifically, the submission noted that there has been a substantial reduction in actual demand and forecast demand since these forecasts were made and that it is important that any analysis of potential market benefits from increasing QNI capacity uses the most recent forecast data. Epuron stated in its submission that the recent reductions in demand in the NEM are likely to materially change the justification for each of the QNI upgrade options.

TransGrid and Powerlink agree that the analysis should draw on the most contemporary demand forecasts available at the time the analysis is being undertaken. The market simulations discussed in this PADR use the most recent energy and demand forecasts published by AEMO and Jurisdictional Planning Bodies in November 2013, which are consistent with the demand traces used in the 2013 NTNDP. The modelling for this PADR therefore incorporates the latest demand traces provided for the 2013 NTNDP. There have been significant changes in these traces to include the new baseload CSG compression loads in Queensland and the significant reduction in baseload electricity consumption in other states, particularly the Kurri Kurri aluminium smelter in NSW, and the reduction in manufacturing activity more broadly. This is consistent with the NGF submission that supported the use of the 2013 AEMO demand and energy forecasts in the PADR modelling. In addition, the analysis has also been undertaken under a scenario with lower demand growth (the 'Slow Rate of Change scenario'), in order to test the sensitivity of the RIT-T outcome to further reductions in future load growth forecasts.

The private generators submission outlines the possibility that the economy and the NEM could be moving into a period of low demand, low growth and low carbon prices. The submission suggests that sensitivities around these economic parameters are likely to demonstrate that a large-scale upgrade is not warranted at this point in time. TransGrid and Powerlink are aware of this possible future state of the world and note that the RIT-T requires that credible options be assessed against a range of realistic scenarios, or future states of the world. The scenarios examined for this PADR include one with a zero carbon price and low electricity demand (i.e. the 'Slow Rate of Change' scenario), as well as scenarios with more robust economic growth and demand forecasts. Given the long-lived nature of the investments being considered, it is important that the outcome of the RIT-T is robust to a range of potential future economic outcomes. The scenarios included as part of this RIT-T, and the weightings given to each scenario, are discussion in detail in section 5.3.1 below.

The private generators submission also states that, while it is important to review previous QNI power flows and constraint performance, the extent to which historical performance is a predictor of the future needs to be carefully assessed. TransGrid and Powerlink agree with this and note that the modelling for this PADR is not based on extrapolation of past performance as a predictor of future needs. The modelling instead incorporates forecast demand and energy within each region of the NEM, and utilises market modelling of generator dispatch to meet that future demand.

4.2. Concerns regarding the need for investment at this point in time

AEMO's submission noted that the NTNDP 2012 studies indicate the economic timing for QNI investment has been extended by 10 to 15 years into the future. AEMO therefore does not see an economic or system reliability justification for action at this time.

As discussed in section 5, the modelling undertaken for this PADR has assessed the market benefits across a wider range of network upgrade options and market development scenarios. This may lead to different outcomes under some cases.

The private generators submission noted that, while it appears unlikely that any large-scale upgrade is required at this point in time, the PCSR suggests that at least one low-cost no-regrets option should proceed regardless of the study outcomes. The submission noted that at a cost of $5 million, with a two year payback, option 3 appears to be an initiative that can be initiated without recourse to a RIT-T process.

TransGrid and Powerlink assume that the two year 'payback' for option 3 referenced is taken from section 3.4 of the PSCR, which is instead the estimated time to implement the option, not an estimated payback period. Notwithstanding this point, the NER require that the RIT-T be applied when the estimated cost of the most expensive option which is technically and economically feasible has an estimated capital cost in excess of the threshold (currently $5 million). There are a number of feasible options for this RIT-T that are estimated to cost in excess of the $5 million threshold. Option 3 has been subject to a first pass market benefits assessment, and was found to not have a positive net market benefit. One of the reasons this option was not considered economic is that the project does not address the critical contingencies which determine the transfer capability across QNI for a large proportion of the time.

The NGF submission expressed concern that the costs of options investigated may be understated. Specifically, the submission suggested that TNSPs tend to 'under cost' planning proposals in order to achieve regulatory approvals and observe large cost increases during the construction phase. NGF sought a binding and enforceable guarantee that actual costs will not exceed nominal costs by more than 10 per cent. The CS Energy submission questioned the reliability of results if uncertainty in costs remains in the range +/- 25%, as for the previous QNI upgrade study.

TransGrid and Powerlink note that there are inevitably uncertainties in the costing of options, particularly at the earlier stages of the development process. The RIT-T requires sensitivity testing of a range of the input parameters, including the costs of credible options. TransGrid and Powerlink have undertaken a number of sensitivity tests on the costs of the options (as outlined in section 7.4.3 below). In addition, TransGrid and Powerlink 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 (provided that that value remains positive).

Origin submitted that a QNI upgrade would deliver the following benefits:

- least overall cost energy to the NEM;
- improve economic investment in the NEM;
- unlock additional competition benefits; and
- potentially increase reliability of supply in the NEM.

TransGrid and Powerlink agree with Origin that a QNI upgrade could deliver market benefits of the type identified. The RIT-T requires TransGrid and Powerlink to assess the net market benefits to all those who generate, transmit, distribute and consume electricity in the NEM.

4.3. Greater transparency and detail in the assessment

Stanwell submitted that the PADR should include detailed information on the financial modelling associated with each option, including costs and timing of new generation developments, generator bidding behaviour, derivation of competition benefits, and intra-regional transmission developments and impacts for intra-regional transmission congestion. More detailed information on these aspects of the assessment are included as part of this PADR.

NGF submitted that the PADR should include data regarding voluntary load shedding and quantum of benefits identified as a separate item. TransGrid and Powerlink note that the input data to voluntary load shedding was sourced from the 2012 AEMO NTNDP. As noted in section 6.3.5, the market benefits associated with changes in voluntary load shedding have been included within the changes in generator fuel consumption market benefit, and are not a major portion of this benefit.

CS Energy submitted that the RIT-T should consider whether there will be any difference in fuel costs and prices if marginal generators, whose fuel cost is set by international markets through LNG or coal export, are pricing on the opportunity cost of selling gas or coal back into the international markets. TransGrid and Powerlink note that the market simulations discussed in this PADR use the fuel costs published by AEMO as part of the 2012 NTNDP, which are based on assumptions that fuel prices will be set by reference to world market levels.

CS Energy also submitted that marginal network losses are already reflected in regional reference prices (RRPs) and that, if changes in network losses are then included the RIT-T, there may be double counting of any market benefit associated with network losses. TransGrid and Powerlink note that in all market simulations, including the 'do nothing' case, network losses are captured in the total cost of production. Network losses are not determined or valued using the RRP.

4.4. Intra-regional constraints

The private generators submission states that it understands that most, if not all of the options discussed in the PSCR would alleviate the stability constraints but that it is not clear that any of the options would alleviate the FCAS constraints. The submission states that if this is true, then it would appear that even if QNI were upgraded, a substantial amount of constrained operation may remain due to FCAS constraints.

TransGrid and Powerlink note that FCAS constraints occur on QNI when one of the two circuits from Bulli Creek - Dumaresq - Armidale - Tamworth is out of service for maintenance or following a fault, or when AEMO declares the trip of both circuits to be a credible contingency. This is due to the need to secure FCAS services to cover the event of severing the interconnection and Queensland operating as an electrical island, separate from the rest of the NEM. Options which include additional circuits in parallel with the existing QNI circuits (i.e., options 4(a), 4(b) and 4(c)) would alleviate these FCAS constraints. The results of the first pass assessment undertaken by TransGrid and Powerlink discussed in section 3.2 (presented in full in Appendix F of this PADR) shows that these options have a high cost relative to the additional market benefit they provide.

The private generators submission also states that a more substantive review of intra-regional constraints would be more beneficial at this point in time, given the uncertainty regarding demand and the need for a large scale upgrade of the interconnector. The submission uses the uncertainty around the 855/871 constraint, and ongoing congestion arising from Calvale/Wurdong in Queensland and the 330 kV network connections from Liddell to Tamworth in Northern New South Wales as an example of a constraint that should be considered ahead of any large scale interconnector upgrade. Powerlink is able to advise that two new 275 kV transmission circuits between Calvale and Stanwell were commissioned in late 2013, which are anticipated to relieve congestion associated across feeders 855/871. Where appropriate the uprating of the following lines has been included in the options being considered in this PADR:

- Line 84 – Liddell to Tamworth;
- Line 83 – Liddell to Muswellbrook; and
- Line 88 – Muswellbrook to Tamworth.

The NGF submitted that the PADR should include the impact on intra-regional congestion for each option and information on any additional transmission upgrades required for the RIT-T options to provide the nominal upgrade. The submission outlined the concern that some options, such as option 4a, would lead to increased intra-regional congestion between the generation centre and the RRN, significantly reducing the nominal benefits of the options.

TransGrid and Powerlink have included the costs of investments needed to relieve intra-regional constraints where relevant, as part of the cost of the option for augmenting the capacity of QNI. Specifically, options 1a, 1b, 1c and 2b include the cost of uprating lines 83, 84 and 88, which may otherwise be the limiting factors when upgrading the transfer capability across QNI. In addition, options 4b and 5 included in the first pass assessment (outlined in section 3.2.3 above) also includes investments to address intra-regional constraints.

4.5. Capacity of credible options

The NGF submission states that the PSCR is not clear on whether the credible options are cumulative or if a higher cost option may only deliver a partial increase in capacity above one of the lower cost upgrade options. TransGrid and Powerlink note that each option is assessed as a complete, stand-alone option with any capacity increase being the increase from the current capacity. Further, the costs are the estimated costs for all works necessary to provide that capacity increase across QNI.

The NGF submission also outlined a concern that historical QNI capacity outcomes have been less than the nominal capacity and enquired as to what guarantees will be provided that the nominal capacity of the proposed upgrade will actually be achieved. TransGrid and Powerlink note that the actual capacity of QNI at any time depends on a wide range of power system conditions, including generator dispatch outcomes. For instance, when the trip of Kogan Creek (as the largest generator in the Queensland Region), is the most limiting factor for QNI northward flow, any increase in Kogan Creek dispatch will result in a corresponding decrease in QNI capacity. Further, as part of the co-optimisation of constraints AEMO may include QNI as a controllable term on the LHS of other network constraints. If those other network constraints become binding the capacity of QNI may be adjusted to allow those other constraints to be satisfied.

Notwithstanding the above, TransGrid and Powerlink have assessed the sensitivity to lower levels of assumed additional capacity associated with the QNI upgrade options, to examine the robustness of potential market benefits. This is discussed further in section 7.4.2.

4.6. New entrant generators

The Wind Prospect submission proposes that this RIT-T consider the development of a new switching station along the Armidale to Dumaresq 330 kV line which can facilitate the connection of renewable energy projects and result in the following:

- lower cost of energy due to shared connection assets for generation projects;
- improved network impedance with SVCs installed at the new switching station and Armidale; and
- improved switching and protection capabilities on circuits 8C and 8E.

Epuron submitted that there are a number of potential technical solutions that would enable wind farm connection to proceed without impeding any future upgrade of QNI, should the economic justification of an upgrade be confirmed.

TransGrid and Powerlink note that the RIT-T assessment within this PADR includes a scenario of significant wind farm development at a point between Armidale and Dumaresq. Under this scenario the series capacitor options have had their costs and resultant changes in QNI capability adjusted to reflect the different network development.

The NGF submission requests that the PADR include a complete list of all proposed new generation builds including sub-regional specific location and commissioning date. TransGrid and Powerlink note that these data have been included at an appropriate level of detail in Appendix D.

CS Energy submitted that the RIT-T needs to consider only real capacity that must rely on NEM spot revenue to be paid, rather than capacity required under the reliability standards as specified in the ESOO. TransGrid and Powerlink note that the RIT-T requires that market development modelling, such as new entrant generators, be undertaken on a least cost basis, including meeting any minimum reserve requirements. Market driven modelling may also be undertaken, where appropriate, but as a complement to the least cost modelling, not as a substitute. The question of least-cost modelling versus market driven modelling was explicitly considered by the AER when developing the RIT-T.

4.7. Application of the RIT-T

CS Energy submitted that it agrees with statements made by AGL to the Productivity Commission that the RIT-T is not competitively neutral in that it overvalues the benefit of an interconnector by not accounting for market risk. CS Energy stated that the RIT-T can include avoided costs for reserve capacity when generators receive no such payments for reserve capacity in the NEM. TransGrid and Powerlink note that they are required to apply the RIT-T as published by the AER. Under the RIT-T market benefits must include the benefit of changes in costs for parties, other than the TNSPs, due to the difference in timing of new plant, unless it can be demonstrated that the benefit would not materially affect the outcome, or the cost and resources required to model the benefit is disproportionate to the scale, size and potential benefits of the credible options being considered. The RIT-T also requires that market development modelling be undertaken on a least cost basis, including meeting any minimum reserve requirements.

CS Energy state that under static assumptions the difference in supply costs in each region has to be significant to justify an interconnector upgrade and that such differences have not been evident across the major interconnections in the NEM since inception. TransGrid and Powerlink note this market observation but also note that the modelling undertaken for this PADR is not based on such static assumptions.

CS Energy also submitted that under dynamic conditions, increasing transfer capacity is coupled with investment in generators within the exporting region to service incremental demand in the importing region. CS Energy state that one way of easing the investment hurdle would be to assume persistent oversupply in one region so that the importing region's long run costs of investing in a generator would be compared with the exporting region's short-run costs (fuel) and the interconnector cost. TransGrid and Powerlink note that a persistent oversupply of generation has not been assumed in any part of the NEM. The capital and operating costs of all new entrant generators are included in the economic assessment.

CS Energy submitted that an alternative would be if there were extremely bullish assumptions on demand growth, thus bringing forward investment cost of supply from generators. TransGrid and Powerlink note that the reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand projection associated with each of these scenarios has however been updated to reflect the latest demand forecasts developed by AEMO, as published in its November 2013 NEFR update.

4.8. Separate identification of competition benefits

The submission made by CS Energy states that competition benefits should be specified separately and all assumptions disclosed publicly. The NGF submission also stated that if competition benefits are claimed, the PADR should include the bid structure for all generators and the quantum of competition benefits identified as a separate item.

TransGrid and Powerlink note that in response to feedback received on the PSCR, a separate consultation document was published that outlined the methodology for assessing competition benefits in April 2013, which set out particulars on the methodology and key assumptions to be adopted when assessing competition benefits.

Although it is not required under the RIT-T, TransGrid and Powerlink have provided the results of the RIT-T modelling in a way which separately identifies the amount due to competition benefits, in response to the request in submissions.

4.9. Submissions received in response to the competition benefits methodology consultation

One of the classes of market benefits that could potentially be material in assessing the market benefits attributable to an increase in QNI capability are competition benefits. A number of submissions received in response to the PSCR requested more clarity and transparency on the assessment of market benefits, including the assumptions and methodology that will be used to quantify competition benefits.

In response to feedback received on the PSCR, TransGrid and Powerlink published a separate consultation document, Methodology for Assessing Competition Benefits, in April 2013. That document set out further particulars on the methodology and key assumptions to be adopted when assessing competition benefits.

In particular the consultation document proposed to adopt the methodology developed by Frontier Economics for the ACCC in 2004.

Submissions were received from the following:

- Frontier Economics (Frontier)
- Snowy Hydro (Snowy)
- AEMO
- Roam Consulting (Roam)

Submissions from Frontier, Snowy and Roam all supported the inclusion of competition benefits in the assessment of market benefits attributable to an upgrade of QNI. The Roam submission highlighted the potential computational complexity in the proposed approach.

The submission from AEMO, while not discounting the potential for competition benefits, noted that a number of previous assessments internationally had shown negative competition benefits.

The Frontier submission raised concerns about whether the Supply Side Equilibrium framework implemented in the Prophet software was the appropriate framework for modelling dynamic bidding behaviours by generators. In particular, Frontier queried whether the framework was able to take into account the impacts of other participants' behaviour on the bidding behaviour of any given participant, as specified in the RIT-T Guidelines.

TransGrid and Powerlink have confirmed with IES, the developer of the Prophet software that the framework implemented in the software to model dynamic bidding behaviour by generators meets the requirements of the RIT-T and the RIT-T Guidelines.

5. Description of the methodology

This section describes the assumptions and methodologies carried out in relation to the market modelling and financial analysis of the credible network options.

5.1. Financial analysis assumptions – analysis period, discount rate

The RIT-T analysis has been undertaken over a fifty year period.

The market modelling discussed in section 5.2 below has been undertaken across a twenty year period. The market benefits calculated for the final three years of the modelling period have then been averaged, and this average value has been assumed to apply for a further thirty years following the end of the modelling period.

The approach of adopting an extended analysis period, based on the continuation of an assumed end-value, is one which has been adopted in other similar assessments.[21] TransGrid and Powerlink believe that this is a reasonable approach, given the long-lived nature of the investments associated with the QNI upgrade.

A discount rate of 10% (real, pre-tax) has been adopted in undertaking the NPV analysis for the credible network 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.[22] However, TransGrid and Powerlink have tested the sensitivity of the results to changes in this discount rate assumption, specifically to the adoption of a lower bound discount rate of 6.28% as reflective of the regulatory weighted average cost of capital (WACC)[23] 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 7.4.4.

5.2. Market modelling

Where a proposed network augmentation is expected to have an impact on dispatch of generation, the RIT-T makes provision to the method that must be used to quantify the different classes of market benefits. Paragraph (11) of the RIT-T states that:

> (11) In estimating the magnitude of market benefits, a market dispatch modelling methodology must be used and must incorporate:
>
> (a) a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and
>
> (b) a realistic treatment of the network constraints and losses.

A commercially available market modelling software package, PROPHET, has been used by Powerlink and TransGrid in quantifying the market benefits of QNI upgrade. The market benefits have been assessed using a two stage process as follows:

> Stage 1: Develop a program of generation development (and potential retirements) to meet minimum reserve levels on a least cost expansion basis.
>
> Stage 2: Perform time sequential monte-carlo market simulations using the generation new entry obtained from the least cost modelling to quantify the market benefits.

Figure 5.1 below illustrates the relationships between the different modelling methodologies, and the flow of input and output information from the two stage simulation approach.

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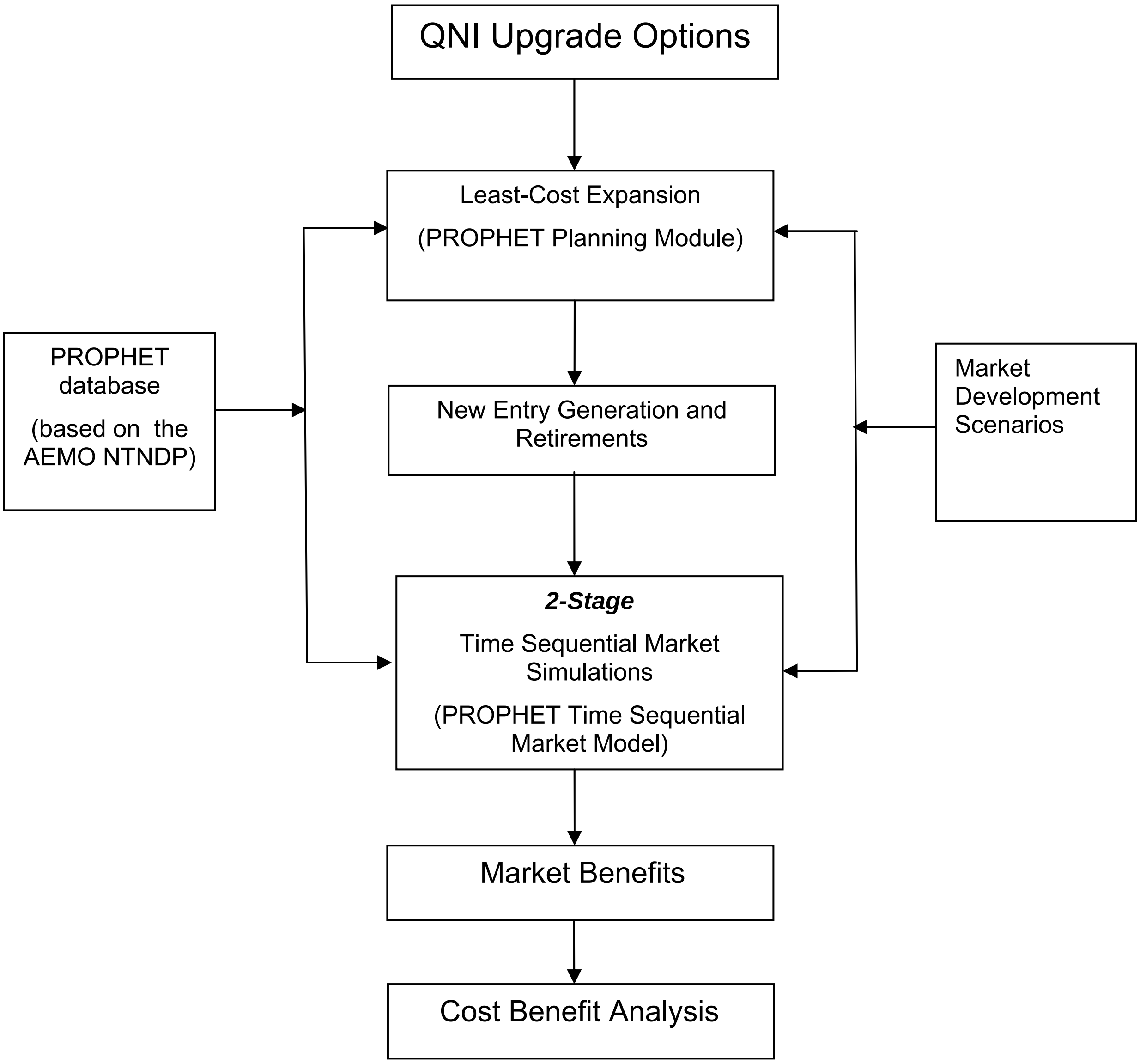
[21] See for example: ElectraNet and AEMO, South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Draft Report, September 2012; Powerlink and TransGrid, Final Report – Queensland/New South Wales Interconnector upgrade, 24 July 2008.

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

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

Figure 5-1: Overview of modelling methodologies



5.2.1 Overview of market modelling

The market simulations performed as part of this RIT-T assessment have been carried out using the commercially available market modelling software PROPHET. The software incorporates a stochastic simulation model intended to replicate the chronological operation of the Australian National Electricity Market (NEM). The market simulation package is capable of replicating rules and trading arrangements within the NEM, and the software has been demonstrated to produce an acceptable degree of accuracy when benchmarking actual market data and outcomes.

The PROPHET database contains information on the various components of the NEM, including network topology, regional demand, intra-regional loss equations, hydro and fuel resources, renewable energy and carbon emissions. Information related to the financial market for electricity trading required to replicate strategic bidding behaviour of generators has also been incorporated within the model.

As part of its role as National Transmission Planner, AEMO has made available in the public domain the PROPHET database used as part of their planning responsibilities and activities. The database contains input data required to undertake market studies encompassing a period of 20 years into the future. This database is used by AEMO to perform market simulation studies as part of the NTNDP.

The QNI upgrade studies have used the AEMO PROPHET database as the basis for input data to the market simulation model. As a consequence, the input data and modelling assumptions used for this RIT-T are broadly consistent with those used by AEMO for the 2012 NTNDP. More recent demand forecasts contained in AEMO's November 2013 NEFR Update have been included. A number of updates to input data, including changes to carbon price trajectories, have also been included.

5.2.1.1. Backcasting

A verification study was performed on the 2012 PROPHET database to verify the simulated results for consistency with recent history. From the results of the verification study, particularly when looking at the total Snowy generation over a period of 20 years into the future, it was observed that the total annual energy significantly exceeds the long term average historical figure. In addition, the maximum flow across the notional Snowy to NSW cut-set (using an appropriate measure) was lower than historically observed figures on a number of simulated years.

In order to ensure that the database is suitable to use for QNI upgrade studies, TransGrid and Powerlink considered it necessary to perform a backcasting study. Backcasting involved simulating the market operation of the most recent historical year and comparing the simulated results with actual market dispatch outcomes. For hydro plant, the focus was on their long term average energy capabilities that take into account the variability of water inflows.

A number of performance indicators were utilised to obtain a direct comparison between the simulated results and historical outcomes. These were based on the following:

- Price duration curves;
- Interconnector Flow duration curves;
- Interconnector total energy transferred;
- Interconnector time constrained

The backcasting process generally involved running the study then comparing the results to historical outcomes using the above performance indicators. This is an iterative process where the appropriate input data is adjusted to bring the simulated results as close as possible to historical outcomes. The final set of input parameters was selected when the simulated outcomes showed no significant change when adjusting each parameter.

5.2.1.2. Least-cost expansion approach

The least-cost planning approach is a technique used for making rational decisions about investments in infrastructure projects. The technique is based on cost-benefit analysis of individual projects but also examines the costs and benefits for all alternatives and treats them on equal footing. System planners make assessments of future generation requirements based on projected load growth, and also plan to augment the transmission networks to ensure acceptable reliability of supply to all points of utilisation at the least possible cost.

The most common approach is through the use of mathematical models such as linear programming (LP) which are able to represent the power system by a large set of linear equations. It is necessary to restrict decision variables to be integer constraints, i.e. discrete unit sizes. However, this can lead to a large amount of time to obtain an optimal solution of the objective function. It is possible to simplify or relax the integer constraint problem without loss of accuracy by using a mixed integer linear programming (MILP) approach. In this case, integer constraints are replaced with "continuous variables", where new generation capacity can take on any value.

A MILP model can be used to produce an optimised least cost generation to satisfy generation reserve requirements given a range of input parameters and constraints. Existing and candidate new entry generators can be provided as an input to the model, and from these a selection can be made by the linear programming optimiser.

For the QNI upgrade study, a least-cost software model called the Planning Module was used to determine new entry generation requirements for each of the scenarios considered, and also for each of the QNI upgrade options. The Planning Module is a sub-set of the PROPHET electricity market model used to perform the hourly time sequential simulations.

5.2.1.3. Generation retirement

Powerlink and TransGrid have noted that findings published as part of the 2013 NTNDP contain considerable levels of retirement of black and brown coal fired generation within the NSW and Victorian regions[24].

TransGrid and Powerlink sought the assistance of ROAM Consulting to provide advice on the modelling of generation development and retirement. ROAM have advised that closure of a coal fired power station could result in significant costs relating to the removal of physical infrastructure, site rehabilitation and redeployment of staff, and that a cost to reflect these factors would be reasonable to incorporate within least cost expansion models.

As part of assistance provided to Powerlink and TransGrid, ROAM conducted a series of sensitivity studies to assess the impact of retirement costs on the level of forecast black and brown coal fired generation within the NEM. ROAM indicated that a cost of around $250,000/MW might be reflective of expenses involved with closing and rehabilitating a coal fired power station site. The sensitivity studies performed by ROAM were carried out using their least cost expansion model, and incorporated salient assumptions utilised by AEMO within their 2013 NTNDP.

The ROAM least cost expansion modelling found that including a cost of retirement in the order of $250,000/MW could impact on the level of forecast retirements. This reduces the level of retirement, since generating units which were not economic during the ramping up phase of renewable energy could be financially incentivised to absorb fixed costs until profitability returned. The least cost modelling performed by ROAM found coal fired retirements in the order of 1.2 GW by 2020 under the Planning scenario. This level of retirement is lower than the levels forecast by AEMO within the 2013 NTNDP.

TransGrid and Powerlink have utilised the generator retirements findings from the ROAM modelling within the QNI upgrade market studies.

5.3. Description of reasonable scenarios

Given the long-term nature of the investments being considered, the outcomes of the RIT-T analysis must be tested against a range of potential futures. The RIT-T requires that future uncertainty be taken into account by testing the market benefits of the credible options across a number of reasonable scenarios.

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: [25]

- 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.

The reasonable scenarios adopted for this RIT-T are based on scenarios developed by AEMO, in conjunction with the Department of Resources, Energy and Tourism (DRET)[26] and in consultation with the Stakeholder Reference Group (SRG), for its 2012 NTNDP. These scenarios reflect different levels of economic growth, industrial energy demand, rooftop PV penetration, energy efficiency and small non-scheduled generation. The AEMO core scenarios adopted for this RIT-T assessment include its 'Planning', 'Fast World Recovery' and 'Slow Rate of Change' scenarios.[27] However, the electricity demand projections associated with each of these scenarios have been updated to align with AEMO's latest

[24] Under the Planning scenario, modelling for the NTNDP shows around 3.7 GW of coal fired retirement by 2016/17 within the NSW and Victorian regions.

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

[26] Now the Department of Industry (DOI).

[27] Section 5.4 of 2012 National Transmission Network Development Plan http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan

demand forecasts published in the November 2013 National Electricity Forecasting Report (NEFR) Update.

In addition to the variables identified above, the potential market benefits that can be realised from a QNI upgrade depends on the future fuel costs, in particular gas prices. Higher gas price projections which result in gas fuelled generating plant within the Queensland region being less competitive relative to lower cost black and brown coal within the southern states significantly affects the power transfers on QNI. To test the sensitivity of market benefits to this key assumption a scenario with a lower gas price projection was included.

Various wind generation proponents have also made connection enquiries to TransGrid for connection of wind generation near the mid-point of the Armidale to Dumaresq line. The connection costs for these wind farm developments will depend on which option is adopted for increasing the capacity of QNI. To capture this impact, a scenario that models a 300 MW wind farm in northern NSW has been included.

Therefore, the following five scenarios, that reflect a broad range of different assumptions in relation to growth in electricity demand, carbon price (if any), wind generation and gas price projections, were considered in undertaking the RIT-T analysis presented in this PADR:

- Scenario 1: Planning.
- Scenario 2: Fast World Recovery (FWR).
- Scenario 3: Slow Rate of Change (SRC).
- Scenario 4: Planning with low gas prices.
- Scenario 5: Planning with northern NSW 300 MW wind generation.

A summary of key parameters forming part of each scenario are provided in Table 12 below.

Table 13 Key Parameters under the Reasonable Scenarios

	Scenario 1: Planning	Scenario 2: Fast world recovery	Scenario 3: Slow rate of change	Scenario 4: Planning with reduced gas prices	Scenario 5: Planning with northern NSW 300 MW wind
Economic growth	Medium	High	Low	Medium	Medium
Demand growth	Medium	High	Low	Medium	Medium
Gas price	2012 NTNDP	2012 NTNDP	2012 NTNDP	Reduced[28]	2012 NTNDP
Commodity prices	Medium	High	Low	Medium	Medium
Population growth	Medium	High	Low	Medium	Medium
Renewable Energy Targets	Remains	Remains	Remains	Remains	Remains
Distributed generation penetration	Moderate	Strong	Weak	Moderate	Moderate
Carbon price	Core	Core	Zero	Core	Core
Carbon reduction targets (below 2000 levels)	5% by 2020 80% by 2050	5% by 2020 80% by 2050	Zero by 2020 80% by 2050	5% by 2020 80% by 2050	5% by 2020 80% by 2050
Wind generation	2013 NTNDP	2013 NTNDP	2013 NTNDP	2013 NTNDP	2013 NTNDP with 300 MW wind development near QNI*

** The level of wind development under this scenario is the same as the other scenarios. The key difference is that 300MW of wind has been assumed to connect to the midpoint of the Armidale – Dumaresq line.*

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.

5.3.1 Weighting applied to each scenario

TransGrid and Powerlink note that the weighting 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, wind developments, economic growth and future gas prices.

The sensitivity of the RIT-T outcome to differences in the weights applied to the different scenarios has been carried out. The sensitivity study has found that the RIT-T outcome is sensitive to the weighting placed on each scenario. This is further discussed in section 7.3.

[28] The projection of gas price under this scenario has been taken as two thirds of the gas price within the Planning scenario.

5.4. Methodology for evaluating 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'.*[129]

The RIT-T requires a TNSP to calculate competition benefits in a RIT-T assessment, unless it can provide reasons why these benefits are 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.[30] For the 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 the sign of the preferred option's net benefit.

The AER has provided clear guidance that competition benefits are automatically included where realistic bidding assumptions are adopted as part of the market dispatch modelling undertaken for the RIT-T assessment.[31] However several submissions to the earlier PADR requested that TransGrid and Powerlink show competition benefits separately in conducting this RIT-T. Given the calculation of competition benefits has not been a major component of RIT-T assessments to date, TransGrid and Powerlink have adopted an approach which allows competition benefits to be shown as a separate line item in the RIT-T assessment.

In order to take account of competition benefits, it is necessary for the dispatch modelling to be undertaken on the following basis:

1) assuming a realistic bidding strategy and the level of market power assumed in the base case (i.e., no credible option in place);

2) assuming either the same realistic bidding strategy or an alternative strategy (where the credible option is expected to change the bidding strategy adopted), and the level of market power assumed with the credible option in place.

The AER RIT-T Guidelines state that the AER does not wish to prescribe the methodology for determining realistic bidding behaviour other than to suggest that it should: [32]

- be based on a credible theory as to how participants are likely to behave in the wholesale spot market over the modelling period; and
- take into account the impacts of other participants' behaviour on the bidding behaviour of any given participant.

In April 2013, Powerlink and TransGrid published a consultation paper outlining the methodology and input data assumptions proposed to be used to quantify competition benefits for this RIT-T assessment. The methodology used to quantify competition benefits within this RIT-T process has been based on the approach outlined within that consultation paper.

TransGrid and Powerlink have also assessed the net market benefits of the QNI upgrade options if competition benefits were not included. These results are discussed further in section 7.4.1, and also presented in Appendix E.

5.5. Benefits that are not material for this RIT-T assessment

TransGrid and Powerlink consider that the following classes of market benefits are not likely to be material for this RIT-T assessment.

The first two of these categories of benefit were identified in the PSCR as not likely to be material for this RIT-T analysis. None of the submissions to the PSCR raised concerns in relation to these categories not being incorporated in the RIT-T analysis.

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29 AER, (2010), Regulatory Investment Test for Transmission, June 2010, Paragraph 5(h), p. 4.

30 NER 5.16.1(c)(6).

31 AER, *Final Regulatory Investment Test for Transmission Application Guidelines,* June 2010, version 1, section A.8: competition benefits, p.70.

32 AER, (2010), *Regulatory Investment Test for Transmission Application Guidelines*, June 2010, p. 72.

5.5.1. Changes in ancillary services costs

The cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following an augmentation to QNI.

FCAS costs are relatively small compared to the total market costs, and the cost of FCAS is not likely to be material in the selection of the preferred option.

The inclusion of FCAS in the market modelling would require a significant modelling assessment, which would be disproportionate for this specific RIT-T assessment, as it would be unlikely to change the ranking of the credible options. TransGrid and Powerlink therefore do not propose to estimate the impact on FCAS costs for this RIT-T assessment.

There are presently no Network Control Ancillary Services arrangements provided by generators near to QNI or related to QNI. It is therefore unlikely that NSCAS costs would be affected as a result of any of the options considered. TransGrid and Powerlink have not therefore estimated the impact on NSCAS costs for this RIT-T assessment.

5.5.2. Option value

TransGrid and Powerlink note the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered are sufficiently flexible to respond to that change.

TransGrid and Powerlink 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.

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

5.5.3. 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'.

One of the assumptions that have been made in conducting this RIT-T assessment is that the LRET target is met. 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.

6. Detailed option assessment

This section sets out the basis for establishing the cost estimates and a detailed description of the methodologies used to quantify each class of material market benefit as required by the NER. The next section 7 then utilises these costs and benefits for the NPV analysis of the options and presents the findings.

6.1. Quantification of costs for each credible option

The capital costs for the network options have been developed by TransGrid and Powerlink utilising each party's standard costing processes. TransGrid's and Powerlink's cost estimating procedures are based on a database and system built up over time using historical and current data from competitively tendered projects. The process also takes into account current commodity prices and exchange rates. The cost estimates are made to a +/- 25% tolerance. This is consistent to the level of accuracy required for the PADR stage as this is at the conceptual stage of the project development and is prior to the detail design and Environmental Impact Assessment processes undertaken as the project progresses.

The sensitivity of the NPV ranking has been tested against a number of factors including cost estimate variations which assumes the cost of each option varied by 25%. These findings are discussed in section 7.4.3 below.

TransGrid and Powerlink note that factors that affect costs across all options in a similar manner will not affect the relative NPVs of the options considered. As a consequence, such cost changes are unlikely to affect the outcome of the RIT-T. The exception is where the change in costs would make the overall net market benefit of the preferred option negative, as in this case the option would then be ranked below the 'do nothing' base case.

An estimate of the annual operation and maintenance cost of 2% of the capital cost has been used. This is consistent with good engineering practise, and reflects the approach adopted for other RIT-T assessments.[33] This assumption is also consistent with the Grid Australia RIT-T Handbook.[34]

33 See for example: ElectraNet and AEMO, South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Draft Report, September 2012; and ElectraNet, South Australia – Lower Eyre Peninsula Reinforcement, RIT-T: Project Assessment Draft Report, January 2013

34 Grid Australia, RIT-T Cost Benefit Analysis Handbook, November 2011 p. 62

Table 14 Estimated capital costs of each credible option ($m 2013/14)

Option	Components	Estimated Total Capital Cost
Option 0: Northern NSW 330 kV Line Uprating	83, 84, 88 line uprating – $35.5m Tamworth 330 kV reconfiguration – $11M	46.5
Option 1a: 50% Series Compensation	4 x TCSCs – $123M 83, 84, 88 line uprating – $35.5M Capacitor banks at Armidale – $10M Tamworth 330 kV reconfiguration – $11M	179.5
Option 1b: 50% Series Compensation + 2nd Armidale SVC	4 x TCSCs – $123M Second SVC at Armidale 330 kV – $42.5M 83, 84, 88 line uprating – $35.5M Capacitor banks at Armidale – $10M Tamworth 330 kV reconfiguration – $11M	222.0
Option 1c: 30% Series Compensation	2 x TCSCs – $73.5M 83, 84, 88 line uprating – $35.5M Capacitor banks at Armidale – $10M Tamworth 330 kV reconfiguration – $11M	130.0
Option 2a: 2nd Armidale SVC	Second SVC at Armidale 330 kV – $42.5M Tamworth 330 kV reconfiguration – $11M	53.5
Option 2b: SVCs at Dumaresq and Tamworth	New SVCs at Tamworth and Dumaresq 330 kV substation, Capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substation and Armidale, Dumaresq substation reconfiguration - $129.7M Tamworth 330 kV substation reconfiguration – $11M 83, 84, 88 line uprating – $35.5M	176.2

6.2. Timing of the credible options

The economic timing of each option was determined based on the results of the market modelling for the Planning scenario. The timing was taken to be the first year in which the gross market benefits (including competition benefits) exceeded the annualised capital cost of that option.

The economic timing for each of the credible options is shown in Table 15 below.

Table 15 Economic timing of credible options

Option	Timing
Option 0	2022
Option 1a	2023
Option 1b	2024
Option 1c	2022
Option 2a	2034
Option 2b	2023

For completeness, the economic timing for each of the credible options for the two other scenarios showing prospective outcomes is shown in Table 16.

Table 16 Economic timing of credible options

Option	Scenario 2 FWR Timing	Scenario 5 Planning with Wind Timing
Option 0	Not economic	2018
Option 1a	2017	2025
Option 1b	2017	2025
Option 1c	2018	2023
Option 2a	2018	Not economic
Option 2b	2017	2024

6.3. Quantification of classes of material market benefits for each credible option

In order to measure the increase in net market benefit, TransGrid and Powerlink have analysed the market benefits required to be considered by the RIT-T. The market benefits considered not to be material have been identified in section 5.5 of this PADR.

The classes of market benefit that are considered material and have been quantified and considered for this assessment are:

- Reduction in the cost of supply from generators;
- Other party cost changes;
- Changes in network losses;
- Changes in involuntary and voluntary load shedding;
- Differences in the timing of network investment; and
- Competition benefits.

Each of these is discussed in more detail in the sections below.

6.3.1. Changes in generator fuel consumption

Increased power flow capacity between NSW and Queensland is expected to improve the sharing of generation between Queensland and the rest of the NEM. As discussed in section 2.4.1 of the PSCR, peak demand in Queensland and NSW are not coincident. Improved sharing of generation capacity is expected to reduce the overall cost of dispatch by reducing fuel costs and variable operation and maintenance costs.

Changes in dispatch costs have been estimated via the market modelling. This market benefit is driven primarily by differences in generator fuel costs but also includes changes in variable operating costs and carbon costs (under scenarios where a carbon price is assumed). The scenarios selected for the RIT-T assessment reflect different carbon price projections (including a zero price projection), as well as different fuel costs (in particular assumed gas prices).

The change in dispatch costs is quantified using the change in generator dispatch patterns arising from the market modelling. The results for each option under a particular scenario modelled are compared to the base case and the resulting difference in fuel costs compared to costs for the base case give rise to a positive difference or a negative difference representing a market benefit or a market cost. Changes in dispatch costs have been estimated on the basis of realistic bidding, but excluding the additional impact of the option on competition, which has instead been incorporated within the estimating of competition benefits.

The market simulations are forecasting increasing levels of QNI transfers in the northerly direction, primarily as a result of increasing gas prices, which is resulting in gas fired generation not being as competitive as lower priced coal fired plant, and wind generation in the southern states. The displacement of higher priced gas fired generation within the Queensland region with lower priced generation within the southern states is one of the primary sources of dispatch cost savings.

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

6.3.2. Changes in costs for parties other than TransGrid and Powerlink, due to differences in the timing of new plant, capital and operation and maintenance costs

Increased power flow capacity between NSW and Queensland could potentially affect the pattern of future generation development in the NEM, and may defer the need for investment in new generating plant. A reduced need for new investment in generating plant, or a deferral of generation investment, would represent a market benefit.

TransGrid and Powerlink have examined whether an upgrade of QNI could potentially result in capital deferral of generation plant as a result of improved reserve sharing between Queensland and NSW. The assessment of capital deferral was carried out using the least cost expansion methodology assuming existing levels of reserve margins. The analysis indicated that no material deferral of generation capacity was evident for the short-listed QNI upgrade options.

6.3.3. Changes in network losses

Any change in network losses may be material in the assessment of the upgrade options.

Increasing the transfer capability of QNI is expected to increase power flows across the interconnector, and hence increase network losses. The development of transmission lines between NSW and Queensland may reduce overall losses across the interconnection. However, as discussed in section 3.2 above, these options (i.e., option 4a, 4b and 4c) have not been included as credible options as part of this report.

Power flows in the supporting networks in NSW and Queensland would also change, depending on the particular option adopted, which would have a further impact on losses. Losses may increase or decrease in these supporting networks depending on the pattern of generation dispatch and the level of load. Any overall increase in network losses would represent a negative market benefit.

Changes in network losses are captured in the market modelling used in the assessment of the options as part of the overall change in generation dispatch costs. Changes in network losses are therefore reported as part of the dispatch cost market benefit.

The difference in losses has been calculated across the NEM as a whole, and therefore also reflects market benefits that arise outside of NSW and Queensland.

6.3.4. Changes in involuntary load shedding

An increase in interconnection capacity between NSW and Queensland would enhance the ability to meet high loads across the NEM, increasing supply reliability and reducing the potential for supply shortages under conditions of generation outages. This would reduce the risk of involuntary load shedding giving rise to market benefits.

TransGrid and Powerlink have estimated reductions of expected unserved energy resulting from an increase in transfer capability across QNI using time sequential monte-carlo simulation techniques. The cost of unserved energy has been calculated by applying a cost of reliability to this level of unserved energy. The cost of reliability, also referred to as the Value of Customer Reliability (VCR), has been assumed to be $60,000/MWh for the purposes of this RIT-T assessment.

The difference in USE has been calculated across the NEM as a whole, and therefore also reflects market benefits that arise outside of NSW and Queensland.

6.3.5. Changes in voluntary load shedding

The interconnector upgrade may have a material impact on pool prices. Customers can agree to reduce their load once pool prices reach a certain threshold and receive a payment for doing so. Hence there may be changes to voluntary load curtailment should an option be implemented that affects pool price outcomes. AEMO provides information on voluntary load curtailment and these have been incorporated within the market modelling.

The market models in effect represent demand side participation as an additional generator that may be dispatched, and have been implemented in the market models as scheduled loads. The changes in voluntary load shedding are therefore reflected within the overall dispatch outcomes. The market benefits associated with changes in voluntary load shedding make up a minor portion of this market benefit and so have not been shown separately.

The difference in voluntary load shedding has been calculated across the NEM as a whole, and therefore also reflects market benefits that arise outside of NSW and Queensland.

6.3.6. Differences in the timing of expenditure

Transmission investments can affect the timing and/or cost of other transmission investments for unrelated identified needs.

At the PSCR stage, TransGrid and Powerlink indicated that this category of market benefit may not be material, but that it would be reviewed prior to the PADR. On review, some of the options being considered could impact the timing or cost of unrelated transmission investments. Specifically, the costs associated with possible future wind farms connections in the area would vary depending on the QNI upgrade option chosen.

TransGrid is aware of various wind proponents interested in the connection of wind generation in the region near the mid-point of the Armidale to Dumaresq 330 kV line. The potential wind capacity that may be developed in this region ranges from approximately 150 MW to 800 MW.

The costs associated with the connection of wind generation at this location would be impacted by the specific investment option undertaken to augment the capacity of QNI. In particular, once series capacitors have been installed within a transmission line, new connections cannot be made to the mid-point of the transmission circuits without either partially or fully disabling (i.e. removing) the compensation or relocating some of the compensation devices. Where investment options involving series compensation proceed, wind generation developments would be required to connect back to the transmission system at either Armidale or Dumaresq substations. The connection costs under this case would be higher, since the connection route back to Dumaresq or Armidale substations would be longer than a corresponding mid-point connection location.

As discussed in section 5.3 above, in order to capture the impact of changes in transmission expenditure between the different credible network options for the case where a new wind farm development proceeds, an additional wind scenario (i.e., scenario 5) has been included within this RIT-T assessment. Specifically, under this scenario 300 MW of wind generation is assumed to develop near the mid-point of the Armidale to Dumaresq line. The 300 MW wind scenario reflects connection enquiries received by TransGrid.

Under this scenario, network costs associated with the development of wind generation for each of the upgrade option cases (as well as the base case) as summarised in Table 17 below. It is clear from the table that for some options (specifically options 1a and 1b), the costs for connection of a potential wind farm are significantly higher than the other options. The difference in connection costs between these options is considered a market benefit, and has been included within the RIT-T economic assessment.

Table 17 Scope of Works and Associated Costs for Wind Connection ($m, 2013/14)

Option	Scope of works for wind connection	Total Capital Cost
Base Case	- A 330 kV switchyard with a breaker and a half arrangement for a possible wind farm connection at the mid-point on the Armidale to Dumaresq 330 kV transmission line; and - Switchgear and required equipment to make the connections at the new mid-point 330 kV Switching Station.	$53
Option 0 – Northern NSW 330 kV line uprating	- A 330 kV switchyard with a breaker and a half arrangement for a possible wind farm connection at the mid-point on the Armidale to Dumaresq 330 kV transmission line; and - Switchgear and required equipment to make the connections at the new mid-point 330 kV Switching Station.	$53
Option 1a – 50% Series Compensation	- A single circuit 330 kV transmission line of approximately 85 km length from the wind farms (near the mid-point of the Armidale to Dumaresq 330 kV line) to Dumaresq 330 kV Switching Station; and - Switchgear and required equipment to make the connections at Dumaresq 330 kV Switching Station.	$150
Option 1b – 50% Series Compensation with Second Armidale SVC	- A single circuit 330 kV transmission line of approximately 85 km length from the wind farms (near the mid-point of the Armidale to Dumaresq 330 kV line) to Dumaresq 330 kV Switching Station; and - Switchgear and required equipment to make the connections at Dumaresq 330 kV Switching Station.	$150
Option 1c – 30% Series Compensation	- A 330 kV switchyard with a breaker and a half arrangement for a possible wind farm connection at the mid-point on the Armidale to Dumaresq 330 kV transmission line; and - Switchgear and required equipment to make the connections at the new mid-point 330 kV Switching Station.	$53
Option 2a – 2nd Armidale SVC	- A 330 kV switchyard with a breaker and a half arrangement for a possible wind farm connection at the mid-point on the Armidale to Dumaresq 330 kV transmission line; and - Switchgear and required equipment to make the connections at the new mid-point 330 kV Switching Station.	$53
Option 2b – New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	- A 330 kV Switching Station with a breaker and a half arrangement for a possible wind farm connection near the mid-point on the Armidale to Dumaresq 330 kV transmission line; and - Switchgear and required equipment to make the connections at the new 330 kV Switching Station.	$53

6.3.7. Competition benefits

Increased capacity of QNI has the potential to increase competition between generators across the NEM at times where the interconnector may be constrained. Increased competition may affect the pattern of generation dispatch over and above the change associated with the displacement of higher cost generation with lower cost generation as a result of the increased capacity of the interconnector. An increase in competition between generators may represent a further market benefit associated with an upgrade.

The analysis of competition benefits and description of how they have been calculated are described in section 5.4 of this PADR. Additionally TransGrid and Powerlink conducted a competition benefit methodology consultation in April 2013 entitled *QNI Upgrade Competition Benefits Methodology Consultation Notice*. Information relating to this consultation process is available in TransGrid's and Powerlink's websites.

The RIT-T does not require competition benefits to be quantified separately. However, TransGrid and Powerlink have decided to quantify this benefit separately in response to requests in submissions.

The differences in competition benefits have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of NSW and Queensland.

7. Net present value results

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

7.1. Gross market benefits

Table 18 below summarises the gross market benefit, in NPV terms, for each of the six credible options included in the RIT-T analysis across all reasonable scenarios. The gross market benefit is the sum of each of the individual categories of material market benefit (both positive and negative) quantified on the basis of the approach set out in the preceding section.

The market benefits considered in the assessment comprise of dispatch cost benefits (including losses and voluntary load curtailment), unserved energy benefits and competition benefits. As discussed in section 6.2, benefits associated with the deferral of generation investment have been assumed to be zero for the six credible options analysed within this PADR.

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.

7.1.1. Key categories of market benefit

The main category of market benefits associated with increasing the transfer capability across QNI are related to reductions in the cost of supply from generators, i.e., the displacement of generating plant with a relatively high cost of fuel with those having lower fuel costs. The level of fuel cost savings differ between the scenarios, and are dependent on factors such as the relativity of load and energy growth between the regions on each side of the interconnector, projected gas prices, and differing generation development and retirement outcomes.

The market simulation studies carried out as part of this RIT-T assessment are forecasting increasing levels of utilisation and congestion across QNI in the northerly direction. The increased levels of northerly QNI transfers are the result of the following factors:

- Subdued load and energy growth within the southern states, coupled with load developments related to LNG and coal mines within the Queensland region;
- Development of significant wind generation within the southern states to meet the LRET; and
- Higher gas price projections which result in gas fuelled generating plant within the Queensland region being less competitive relative to lower cost black and brown coal, and wind generation, within the southern states.

The primary source of dispatch cost savings arise when the higher cost gas fuelled generation within the Queensland region are displaced by lower cost generation sources within the southern states as a result of an increase in transfer capability across QNI in the northerly direction.

Table 18 Gross Market Benefit of Credible Options (NPV $m, $2013/14)

Option	Scenario 1: Planning	Scenario 2: Fast world recovery	Scenario 3: Slow rate of change	Scenario 4: Planning, with low gas prices	Scenario 5: Planning with northern NSW 300 MW wind
Option 0: Northern NSW 330 kV Line Uprating	39.6	13.5	29.0	15.6	80.3
Option 1a: 50% Series Compensation	143.7	136.8	60.7	62.7	111.2
Option 1b: Series Compensation with Second Armidale SVC	136.0	127.9	56.9	61.3	101.9
Option 1c: 30% Series Compensation	125.9	109.0	57.9	51.4	117.8
Option 2a: Second Armidale SVC	11.1	6.3	1.5	3.2	5.3
Option 2b: New SVCs at Tamworth and Dumaresq and capacitors	144.9	139.7	56.8	56.9	112.9

Generator dispatch

Figure 7-1 below shows the breakdown of gross market benefits estimated for option 1c – 30% Series Compensation, under the Planning scenario.

It is clear from this figure that by far the primary category of market benefits for this option under this scenario is the reduction in generator dispatch costs. Under the Planning scenario (and all other scenarios assuming the NTNDP gas prices, i.e., all those except scenario 4), gas plants within the Queensland region are more expensive to operate relative to coal within the southern states.

It is also evident from the figure below that the market benefits can fluctuate from year to year. One of the reasons for these variances is related to the discrete sizes of new entry generation and retirements occurring within the different regions of the NEM. For example, the dip in market benefits around 2030 is due, in part, to the retirement of coal fired power stations within the South Australian region.

The flat line of market benefits beyond 2036 represents the modelling of residual benefits, which have been calculated by taking the average of market benefits within the last three years of the market simulation modelling time frame.

The competition benefits and reductions in unserved energy form a minor proportion of the total gross market benefits.

Figure 7-1: Option 1c – Gross market benefits: planning scenario ($m, $2013/14)

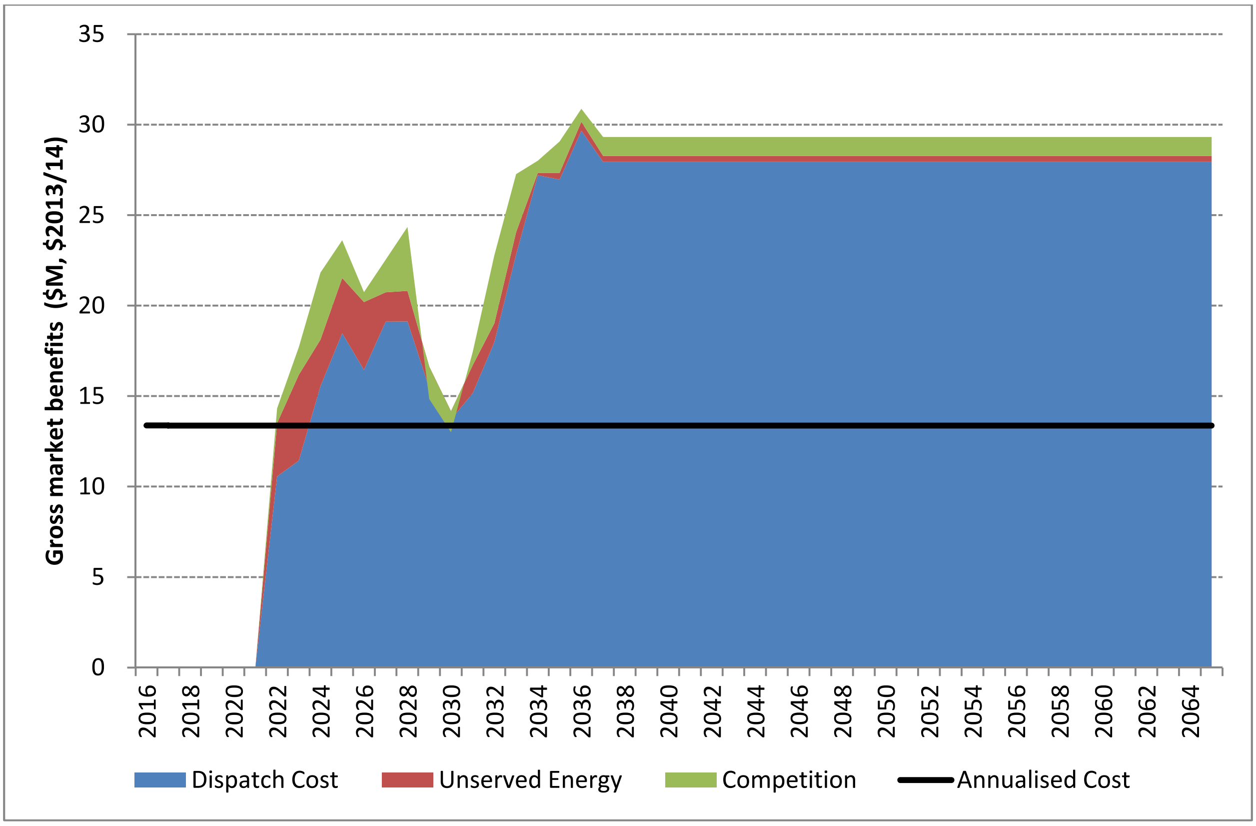


Figure 7-2, Figure 7-3 and Figure 7-4 below illustrate the changes in generation dispatch (GWh) in Queensland, NSW and Victoria across the 20 year period of market modelling (i.e., 2016 to 2036) for Option 1c under the planning scenario using 10% POE load forecasts. In particular, Figure 7-2 shows the decrease in gas generation output within the Queensland region as a result of Option 1c.

Figure 7-2: Option 1c – top three changes in QLD dispatch according to generation type (GWh) - planning scenario

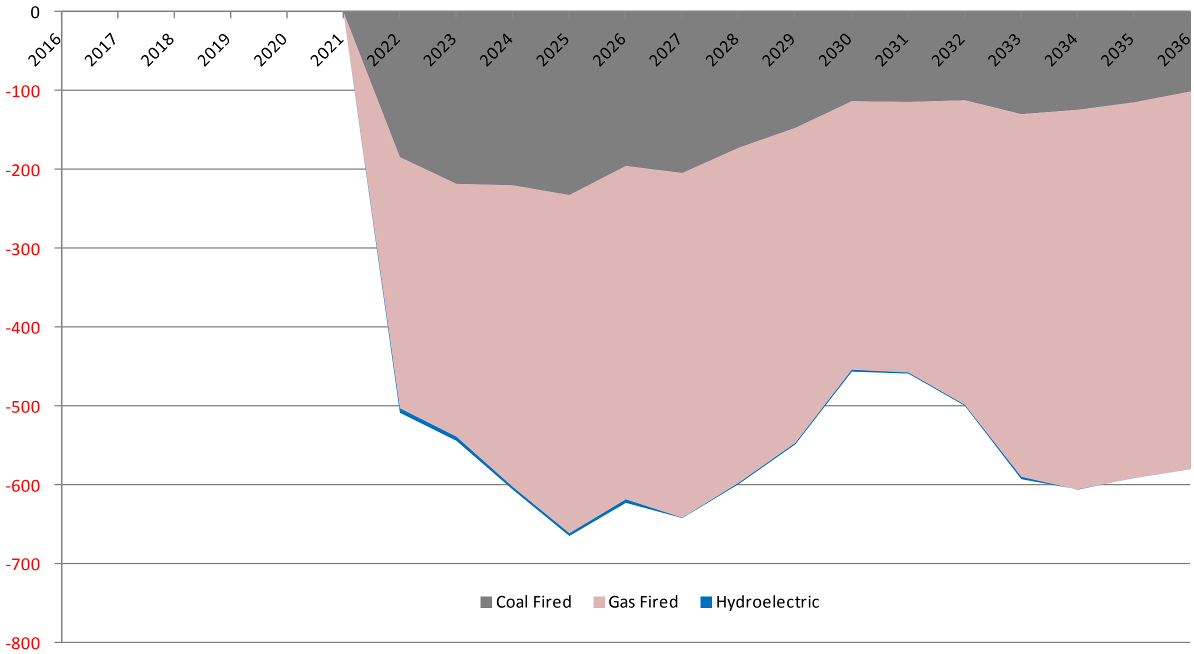


Figure 7-3: Option 1c – top three changes in NSW dispatch according to generation type (GWh), planning scenario

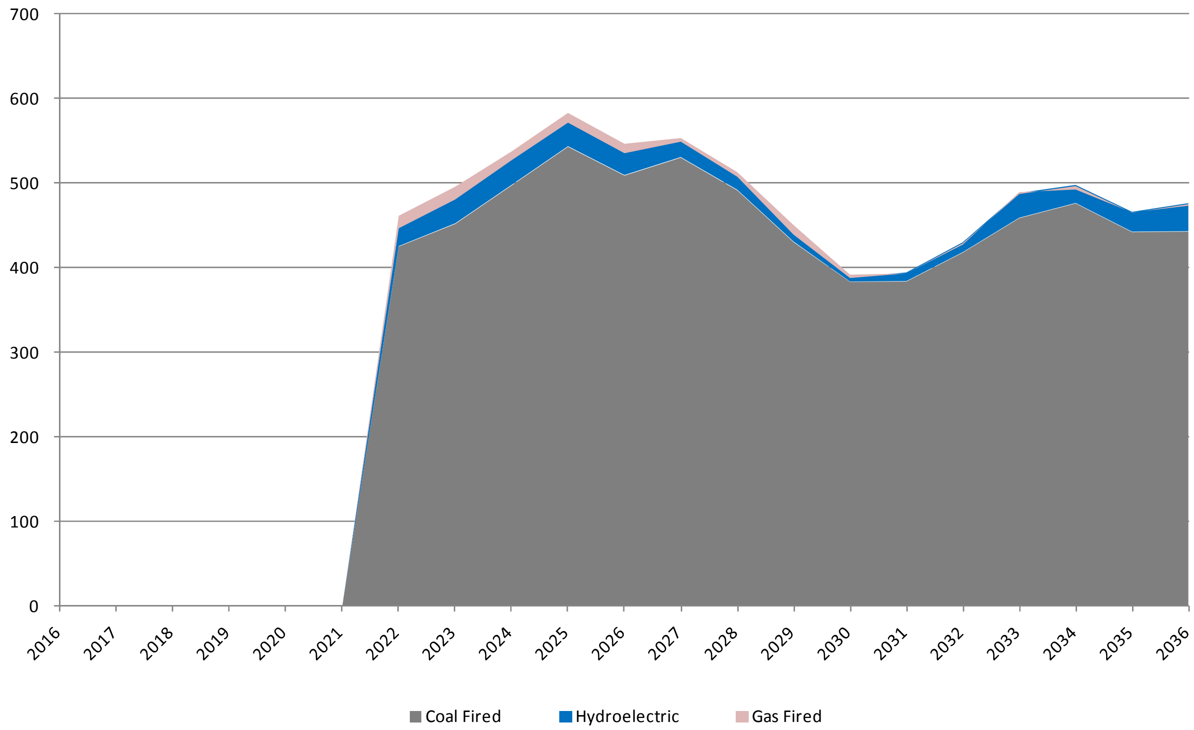
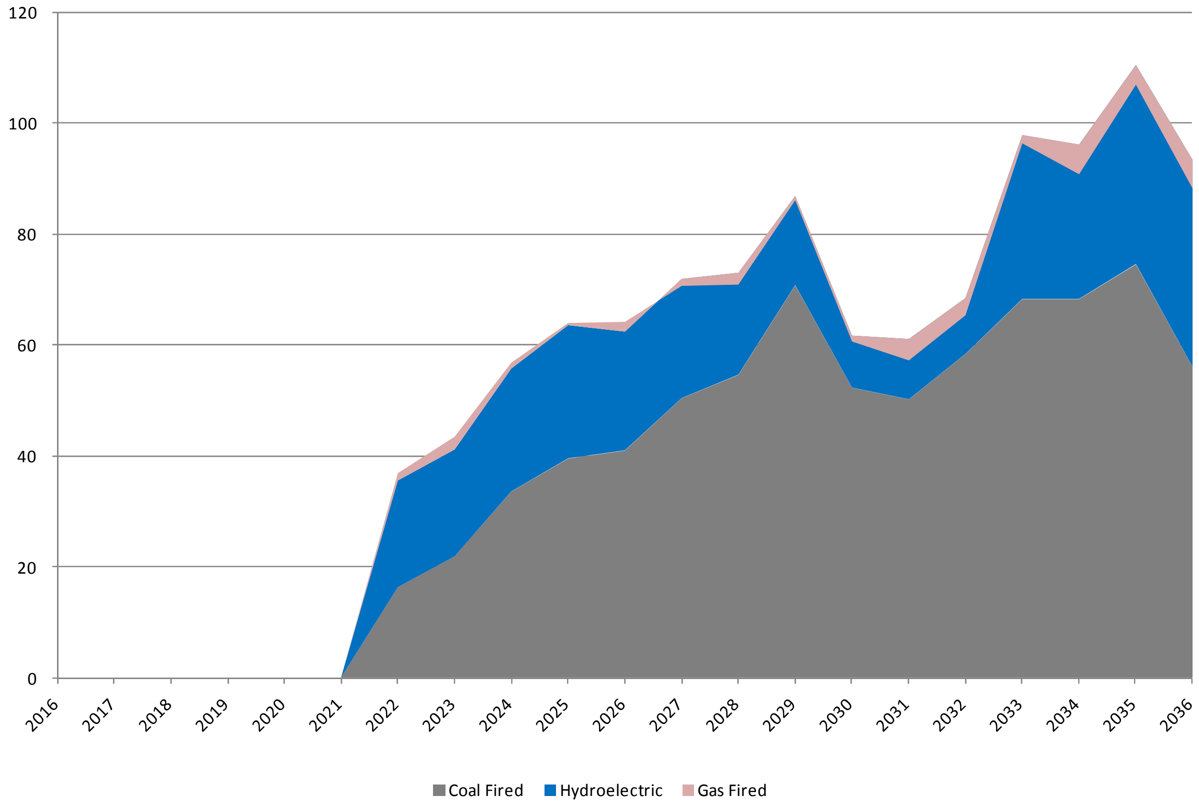


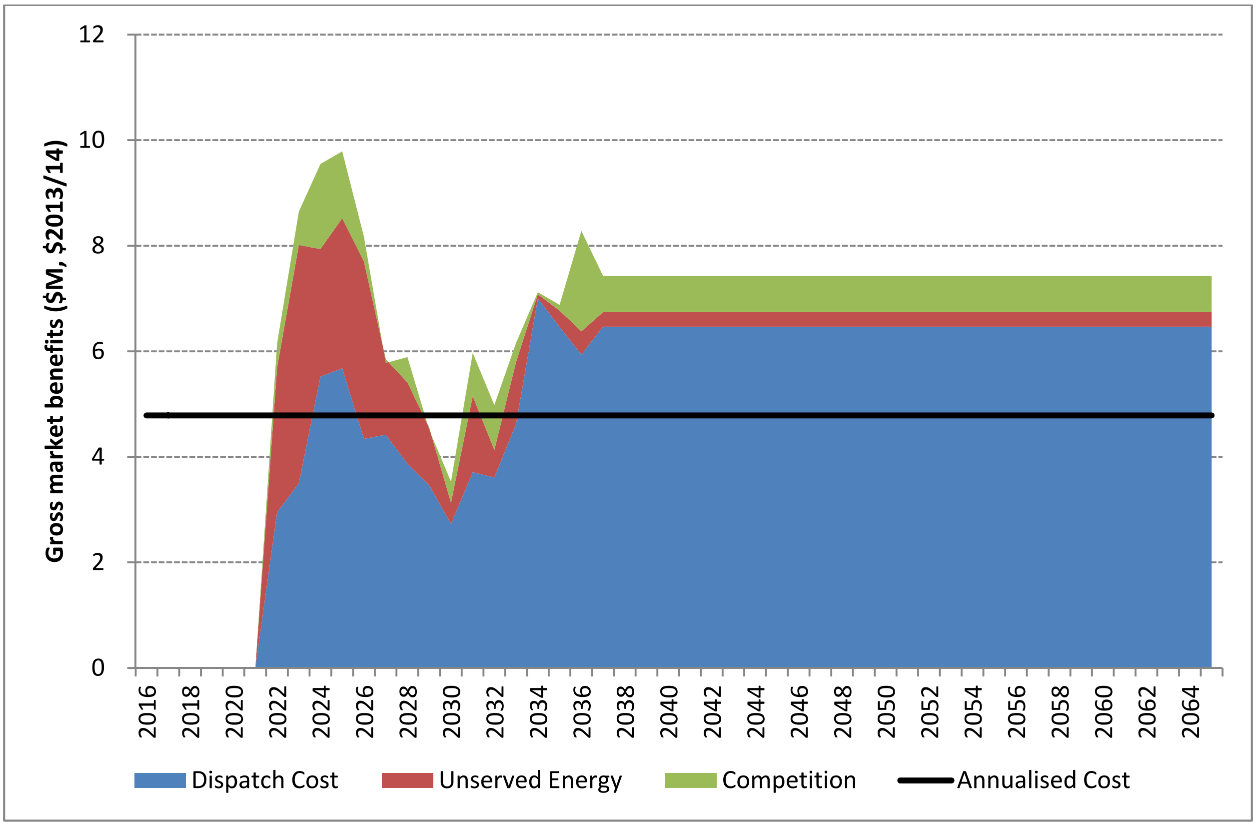
Figure 7-4: Option 1c – top three changes in VIC dispatch according to generation type (GWh), planning scenario



The overall pattern and breakdown of gross market benefits under the planning scenario is very similar for Options 1a and 2b (shown in section 7.2 below to be ranked effectively equal first with option 1c in term of net market benefits under the planning scenario). The market benefits estimated for Option 2a are also driven primarily by changes in dispatch costs under the planning scenario, but not realised until later in the modelling horizon because of the assumed optimal commissioning date of 2030.

Option 0 is estimated to deliver relatively high market benefits associated with reductions in unserved energy under the planning scenario. This is a result of Option 0 being effective in increasing the thermal transfer capability into Queensland during summer peak conditions (i.e., when the incidence of unserved energy is more likely to occur). This illustrated in the figure below.

Figure 7-5: Option 0 – Gross market benefits: Planning scenario ($m, $2013/14)

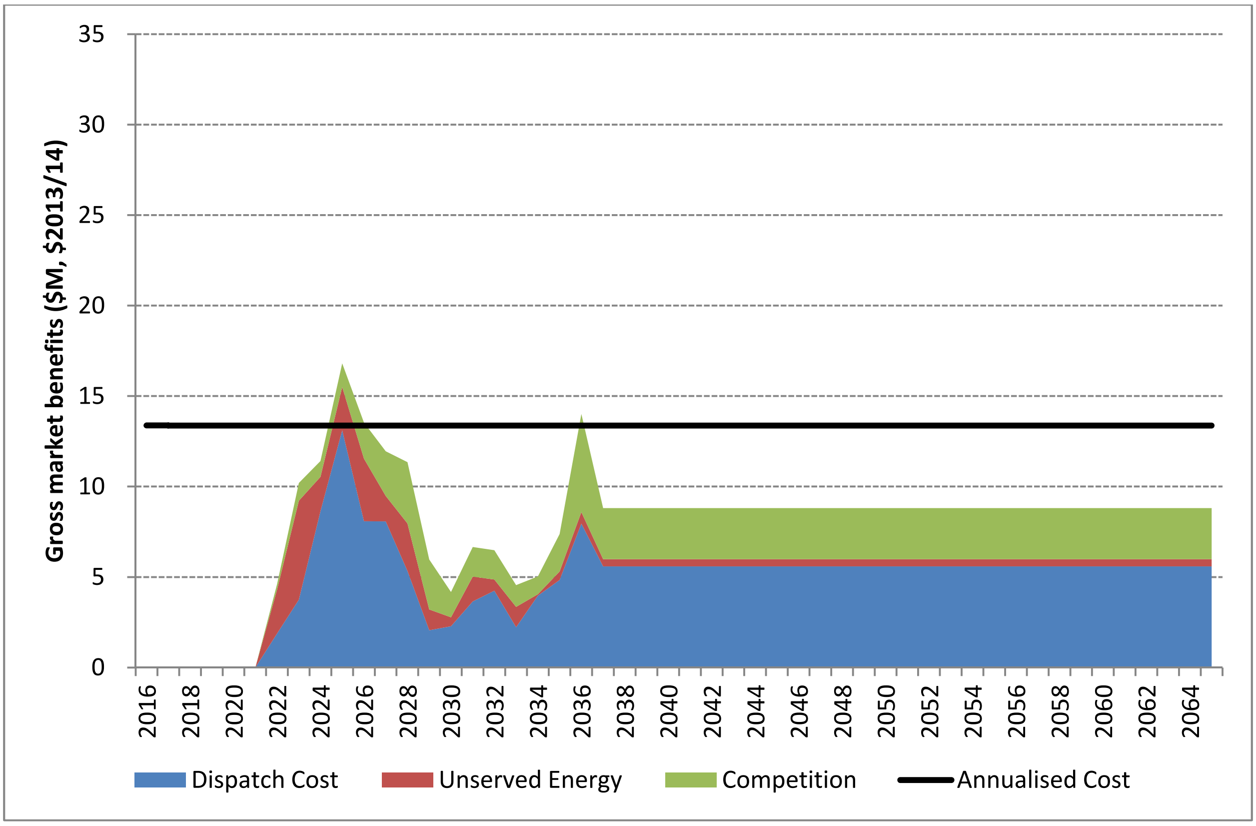


Gas prices

The estimated market benefits associated with changes in generation dispatch costs are significantly lower under the scenario with reduced gas prices (i.e., scenario 4). This is primarily due to gas fuelled generation within the Queensland region being more competitive compared to coal fired plant within the southern states, resulting in lower levels of binding constraints. The differences in fuel costs between gas and coal fired plant are lower under this scenario, which result in reduced dispatch cost savings when constraints across QNI are alleviated.

The breakdown of gross market benefits estimated for option 1c – 30% Series Compensation under the planning scenario with reduced gas prices is shown in Figure 7-6 below.

Figure 7-6: Option 1c – Gross market benefits: Planning with low gas prices scenario ($m, $2013/14)

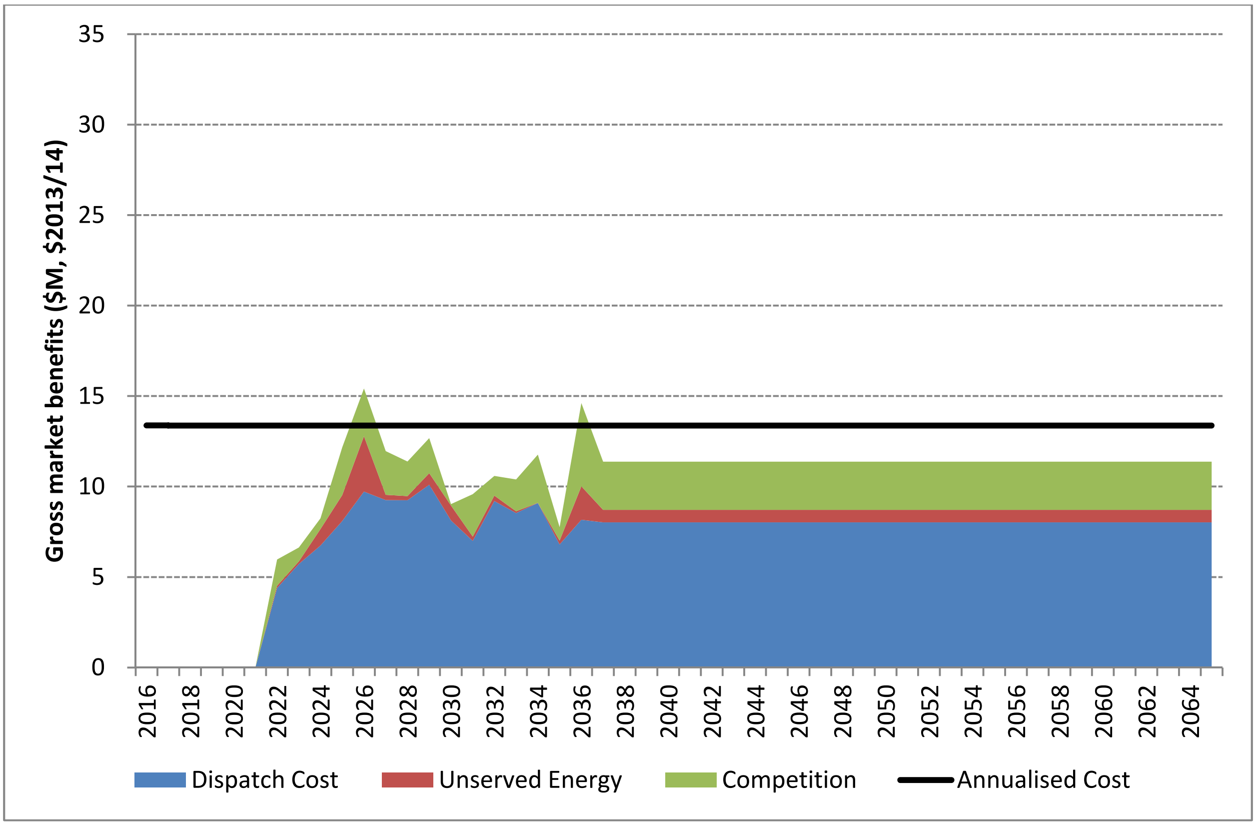


Load growth

Under the Slow Rate of Change scenario, the dispatch cost savings are significantly lower compared to scenarios with higher levels of energy and demand growth.

The breakdown of gross market benefits estimated for option 1c – 30% Series Compensation, under the slow rate of change scenario is shown in Figure 7-7 below.

Figure 7-7: Option 1c – Gross market benefits: Slow Rate of Change scenario ($m, $2013/14)



Retirement of Redbank Power Station

Redbank coal fired power station was commissioned in 2001. It is located between Singleton and Rothbury, with a capacity of 151 MW. When Redbank generator is in service, it is capable of supplying loads within the northern NSW area, which alleviates loadings across the parallel 330 kV lines from Liddell to Tamworth via Muswellbrook. Although the power station is currently operating, the owner, Redbank Energy, placed the power station in receivership in 2013 due to high amounts of debt.[35]

The least cost generation expansion modelling shows retirement of Redbank power station within the first year of the study period for all scenarios with the exception of the Fast World Recovery scenario (i.e. scenario 2). If Redbank continues to operate, this reduces loadings across the critical Liddell to Tamworth 330 kV circuits, and therefore decreases the need for line uprating of these circuits. In these cases, the net market benefits of the QNI upgrade options with the relatively larger increases in stability limits (i.e., options 1a, 1b and 2b) are higher, since QNI northerly flows are now less likely to be limited by thermal ratings.

Under scenarios where Redbank is assumed to retire (i.e., all scenarios besides scenario 2), the market benefits associated with uprating the northern NSW 330 kV circuits are higher (i.e. option 0) compared to scenarios where Redbank continues to operate. However, as shown in Table 19 below, Option 0 is only

35 ABC News article dated 8 October 2013. Available at: http://www.abc.net.au/news/2013-10-08/redbank-power-fail/5008980

ranked first in the Slow Rate of Change and Planning (with 300 MW of additional wind in northern NSW) scenarios.

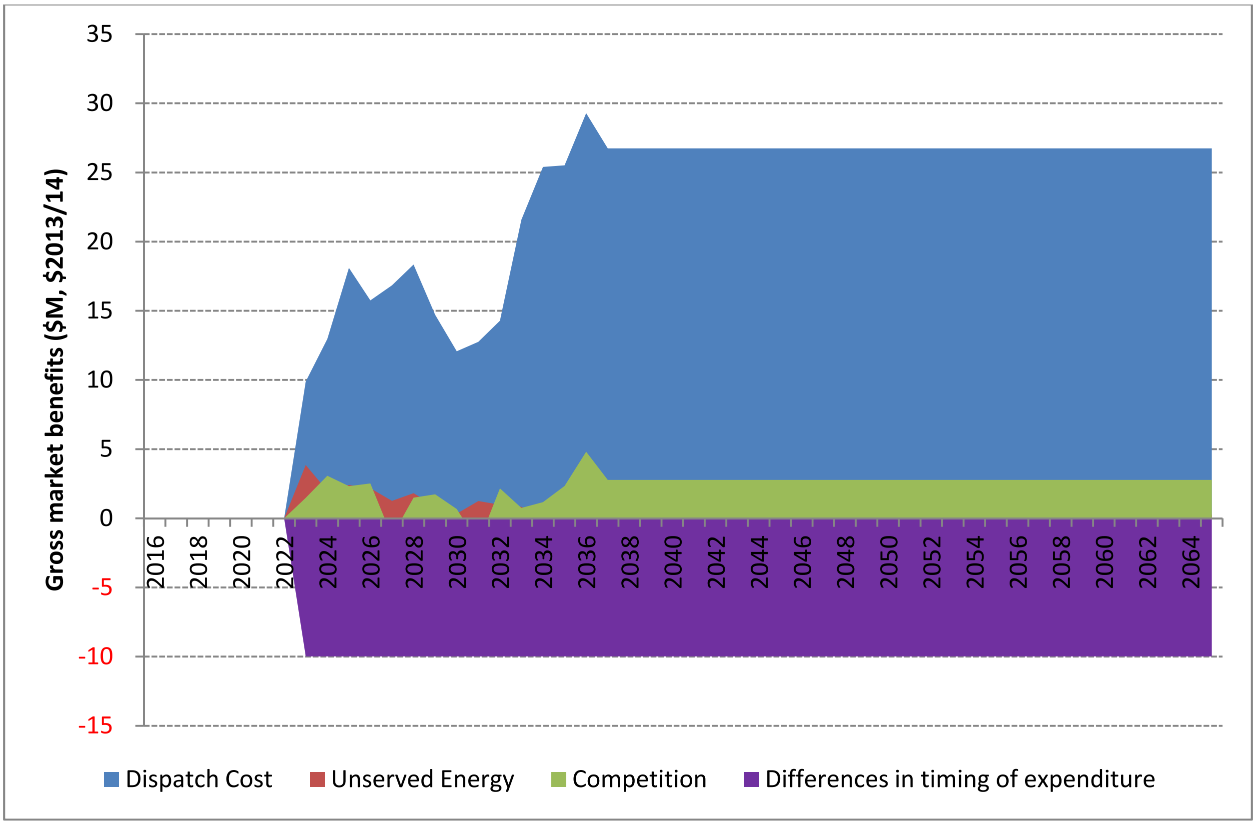
New wind generation in northern NSW

As discussed above, TransGrid is aware of various wind proponents interested in the connection of wind generation near the mid-point of the Armidale to Dumaresq line. In order to capture this potential development within the RIT-T assessment, an additional wind scenario assuming the establishment of a 300 MW wind farm within this area has been included.

Under this scenario additional network costs associated with the development of wind generation for each option are incurred as summarised in Table 17 above. Options 1a and 1b have significantly higher costs associated with wind connection than the other options under this scenario. The difference in connection costs has been included in this RIT-T assessment as a negative market benefit (ie, a market cost).

Figure 7-8 below shows the breakdown of gross market benefits estimated for option 1a – 50% Series Compensation, under this scenario.

Figure 7-8: Option 1a – Gross market benefits: Planning with northern NSW 300 MW wind scenario ($m, $2013/14)



The wind farm adds dynamic reactive support to the system, increasing base line stability transfers across QNI. In addition, the wind farm alleviates the potential for thermal limitations across the Liddell to Tamworth 330 kV circuits when the plant is operating. The amount of dynamic reactive support, when the wind farm is not generating and/or off-line, is dependent to a degree on assumptions regarding to design of the wind farm in relation to meeting performance standards. TransGrid and Powerlink have taken a conservative view to quantifying market benefits, in that it is assumed that the wind farm is capable of providing dynamic reactive support to the system, even when generating at low levels or off-line. This assumption is considered to provide a conservative measure of potential market benefits, since the base line QNI transfer capability could be lower with the wind farm not operating, resulting in higher levels of market benefit when upgrading the stability limits across QNI.

7.2. Net market benefits

Table 19 below summarises the net market benefit in NPV terms for each credible option under each scenario. The net market benefit is the gross market benefit (as set out in Table 18) minus the costs of each option, all in present value terms). The highest ranked credible option(s) in each scenario are shown in bold text. Furthermore, any options found to have a negative net market benefit (i.e., are ranked below the 'do nothing' option) are shown in red text.

The table also shows the corresponding ranking of each option, for each scenario, with the options ranked from 1 to 6 in order of descending net market benefit.

In summary:

- under the Planning scenario, the PV of net benefits of Options 1a, 1c and 2b are effectively ranked equal first;
- under the Fast World Recovery scenario, the PV of net benefits of Options 1a and 2b are effectively ranked equal first;
- under the Slow Rate of Change scenario, all credible options have a negative net market benefit, except Option 0 which is marginally positive; and
- under the Planning with low gas price scenario, all credible options have a negative net market benefit; and
- under the Planning with 300 MW wind scenario, Option 0 is ranked first.

Importantly, under scenarios 3 and 4, all options investigated are found to have a negative net market benefit (with the exception of option 0 under scenario 3 which is found to be marginally positive). As a consequence, all of the options are ranked less than the 'do nothing' option, and cannot be expected to result in an overall net benefit to the market.

TransGrid and Powerlink have undertaken a range of sensitivity analysis to test the robustness of the RIT-T outcomes to differences in the weightings of the scenarios and also to changes in key input assumptions. These are discussed in section 7.3 below.

Table 19 Net Market Benefit and Ranking of Each Credible Option, Under Each Scenario (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	13.0	5th	-13.1	6th	**2.4**	**1st**	-11.0	2nd	**53.7**	**1st**
1a: 50% Series Compensation	50.5	**=1st**	**43.6**	**=1st**	-32.5	4th	-30.4	4th	-32.3	4th
1b: 50% Series Compensation + 2nd Armidale SVC	31.4	4th	23.3	4th	-47.7	6th	-43.3	6th	-48.4	5th
1c: 30% Series Compensation	51.6	**=1st**	34.7	3rd	-16.5	3rd	-22.9	3rd	43.4	2nd
2a: 2nd Armidale SVC	1.7	6th	-3.1	5th	-7.9	2nd	**-6.2**	**1st**	-4.1	6th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	53.5	**=1st**	**48.3**	**=1st**	-34.7	5th	-34.6	5th	21.4	3rd

7.3. Weighting of reasonable scenarios

Table 19 above shows that the credible option(s) ranked first differs across the reasonable scenarios investigated.

To illustrate the sensitivity of results to the weightings applied, TransGrid and Powerlink have investigated the following scenario weights:

- equal weights of 20% to each scenario;
- 35% to Planning and Fast World Recovery scenarios, 10% to other scenarios;
- 35% to Slow Rate of Change and Planning with low gas prices scenarios, 10% to other scenarios; and
- 60% Planning with wind scenario, 10% to other scenarios.

The results of these different weights are shown in Table 20 below. In summary:

- assigning higher relative probabilities to the Planning and Fast World Recovery scenarios generally increases the weighted PV of net benefits and favours Options 1c, 1a and 2b;
- assigning higher relative probabilities to the Slow Rate of Change and Planning with low gas prices scenarios reduces the weighted PV of net benefits and favours Option 0; and
- assigning a higher relative probability to the Planning with wind scenario generally increases the weighted PV of net benefits and favours Options 0 and 1c and, to a lesser extent, Option 2b.

Overall, TransGrid and Powerlink have found that the selection of a preferred credible option(s) under the RIT-T is not robust to the weighting applied to the reasonable scenarios. Importantly, the selection of the preferred option depends on the weightings assumed. Furthermore, as shown in Table 19 above, many of the credible options are shown to have negative net market benefits and so be ranked below the ‘do nothing’ option.

Table 20: Probability weighted net market benefits and ranking under different scenario weightings, (NPV $m, $2013/14)

	Equal weighting (20% each)		35% to Planning and Fast World Recovery scenarios, 10% to others		35% to Slow Rate of Change and Planning with low gas prices scenarios, 10% to others		60% Planning with wind scenario, 10% to others	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	9.0	3rd	4.5	5th	2.4	**1st**	31.4	**=1st**
1a: 50% Series Compensation	-0.2	4th	23.4	3rd	-15.8	5th	-16.3	5th
1b: 50% Series Compensation + 2nd Armidale SVC	-16.9	6th	5.2	4th	-31.2	6th	-32.6	6th
1c: 30% Series Compensation	18.1	**1st**	30.6	**=1st**	-0.8	2nd	30.8	**=1st**
2a: 2nd Armidale SVC	-3.9	5th	-2.3	6th	-5.5	3rd	-4.0	4th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	10.8	2nd	30.8	**=1st**	-11.9	4th	16.1	3rd

7.4. Other sensitivities

TransGrid and Powerlink have tested the robustness of the RIT-T assessment to both the inclusion of competition benefits and a number of sensitivity tests around the input assumptions.

Specifically, TransGrid and Powerlink have investigated:

- the net market benefits of the options excluding competition benefits;
- a reduction in QNI capacity provided by the options;
- an increase in the cost of the credible options; and
- differences in the discount rate used in the NPV assessment.

The results of each of these are discussed below.

7.4.1. Net market benefits without competition benefits

The costs and benefits excluding competition benefits of the credible options are summarised Table 21 below, for each reasonable scenario.

The identification of the top credible option(s) within each scenario is found to be robust to the exclusion of competition benefits (i.e., Options 1a, 1c and 2b are all ranked effectively first with and without competition benefits). However, the results show that there is no preferred credible option across scenarios if competition benefits are excluded from the assessment. Specifically, there is no consistency across the scenarios in terms of the top ranked credible option(s). Further, many credible options are found to have negative net market benefits and hence be ranked below the ‘do nothing’ option.

Table 21: PV net market benefits of the credible options excluding competition benefits, (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	9.3	5th	-12.3	6th	**-2.1**	**1st**	-10.7	2nd	**45.9**	**1st**
1a: 50% Series Compensation	40.4	**=1st**	34.9	2nd	-44.2	5th	-46.6	4th	-41.6	5th
1b: 50% Series Compensation + 2nd Armidale SVC	22.2	4th	16.5	4th	-58.9	6th	-62.6	6th	-54.8	6th
1c: 30% Series Compensation	43.8	**=1st**	28.1	3rd	-27.2	3rd	-33.6	3rd	31.6	2nd
2a: 2nd Armidale SVC	0.8	6th	-2.8	5th	-8.4	2nd	**-7.2**	**1st**	-6.7	4th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	**40.5**	**=1st**	**42.6**	**1st**	-42.8	4th	-47.6	5th	10.1	3rd

7.4.2. Sensitivity to reduction in the capacity provided by the options

An investigation was carried out to determine the robustness of net market benefits to assumed increases in QNI stability limits provided by each of the QNI upgrade options. This was assessed by setting the limit increase (offset) for each of the QNI upgrade options to 75% of the initial value. The thermal rating increases across the Liddell to Tamworth 330 kV circuits, however, remain unchanged.

The sensitivity testing of the results to differences in the capacity provided by the options was requested in submissions to the PSCR.

Table 22 below shows the net market benefits of the options assuming the reduced transfer capability increases. Given the market modelling involved, this sensitivity has only been run for the Planning scenario. The modelling found a general decrease in net market benefits for all options. The options with the lower levels of stability limit increases were affected more than those projects which provided higher levels of limit increase.

Under this sensitivity, option 1c is no longer ranked first. Instead, Options 1a and 2b are effectively ranked equal first, with Option 1c ranked third.

Table 22: Sensitivity to a 25% reduction in capacity under the planning scenario,

(NPV $m, $2013/14)

Option	Net Market Benefits	Ranking
0: Northern NSW 330 kV Line Uprating	12.7	5th
1a: 50% Series Compensation	**46.3**	**=1st**
1b: 50% Series Compensation + 2nd Armidale SVC	30.7	4th
1c: 30% Series Compensation	37.4	3rd
2a: 2nd Armidale SVC	1.1	6th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	**44.5**	**=1st**

7.4.3. Sensitivity to changes in the cost of augmentation options

For the purpose of assessing the investment risks, the costs and benefits of each of the options have been assessed, assuming the capital cost of each of the option is increased by 25%. In addition, given the inherent uncertainty in costs at this stage, TransGrid and Powerlink have also assessed the net market benefits of each option assuming the capital cost of each of the option is decreased by 25%. The sensitivity testing of the results to differences in the costs of the options was requested in submissions to the PSCR.

Table 23 and

Table 24 below show the net market benefits of the options, under each scenario, assuming these changes in costs.

The identification of the top credible option(s) within each scenario is found to be largely robust to these assumed higher and lower capital costs. However, the results show that there is no preferred credible option across scenarios under these alternate capital cost assumptions. Specifically, there is no consistency across the scenarios in terms of the top ranked credible option(s). Further, many credible options are found to have negative net market benefits and hence be ranked below the ‘do nothing’ option.

Table 23: PV net market benefits of the credible options assuming 25% higher capital costs, (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	7.0	5th	-19.1	6th	**-3.6**	**1st**	-17.0	2nd	**47.7**	**1st**
1a: 50% Series Compensation	**29.5**	**=1st**	22.6	2nd	-53.5	4th	-51.5	4th	-52.3	5th
1b: 50% Series Compensation + 2nd Armidale SVC	7.8	4th	-0.2	4th	-71.3	6th	-66.9	6th	-71.1	6th
1c: 30% Series Compensation	**34.8**	**=1st**	17.9	3rd	-33.2	3rd	-39.7	3rd	26.7	2nd
2a: 2nd Armidale SVC	-0.4	6th	-5.2	5th	-10.1	2nd	**-8.3**	**1st**	-6.3	4th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	**32.8**	**=1st**	27.6	**1st**	-55.3	5th	-55.2	5th	0.8	3rd

Table 24: PV net market benefits of the credible options assuming 25% lower capital costs, (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	20.0	5th	-6.1	6th	**9.4**	**1st**	**-3.9**	**=1st**	**60.8**	**=1st**
1a: 50% Series Compensation	**75.2**	**=1st**	**68.3**	**=1st**	-7.8	4th	-5.8	4th	-6.7	5th
1b: 50% Series Compensation + 2nd Armidale SVC	59.1	4th	51.0	4th	-20.0	6th	-15.6	6th	-19.8	6th
1c: 30% Series Compensation	**71.3**	**=1st**	54.4	3rd	3.2	2nd	**-3.3**	**=1st**	**63.1**	**=1st**
2a: 2nd Armidale SVC	4.2	6th	-0.6	5th	-5.5	3rd	**-3.7**	**=1st**	-1.6	4th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	**77.7**	**=1st**	**72.5**	**=1st**	-10.4	5th	-10.4	5th	45.7	3rd

7.4.4. Sensitivity to changes in the discount rate

TransGrid and Powerlink have tested the sensitivity of the results to changes in discount rate. Specifically sensitivities have been carried out using a lower bound discount rate of 6.28% as reflective of the regulatory weighted average cost of capital (WACC)[36] and an upper bound discount rate of 13%.

Table 25 and Table 26 below show the estimated net market benefits of the options, under each scenario, assuming these alternative discount rates.

The identification of the top credible option(s) within each scenario is found to be largely robust to these assumed higher and lower discount rates. However, the results show that there is no preferred credible option across scenarios under these alternate discount rate assumptions. Specifically, there is no consistency across the scenarios in terms of the top ranked credible option(s). Further, many credible options are found to have negative net market benefits and hence be ranked below the 'do nothing' option.

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

Table 25: PV net market benefits of the credible options assuming a 6.28% discount rate, (NPV $m, $2013/14)

	Scenario 1: Planning		**Scenario 2: Fast World Recovery**		**Scenario 3: Slow Rate of Change**		**Scenario 4: Planning with low gas prices**		**Scenario 5: Planning with northern NSW 300 MW wind**	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	40.9	5th	-8.3	6th	**22.0**	**=1st**	-7.5	3rd	124.6	2nd
1a: 50% Series Compensation	**177.1**	**=1st**	**129.2**	**=1st**	-1.9	3rd	2.8	2nd	48.2	4th
1b: 50% Series Compensation + 2nd Armidale SVC	146.6	4th	103.8	3rd	-21.8	6th	-14.3	6th	19.4	5th
1c: 30% Series Compensation	157.3	3rd	95.5	4th	**20.0**	**=1st**	**3.5**	**1st**	145.2	**=1st**
2a: 2nd Armidale SVC	13.2	6th	0.4	5th	-12.5	5th	-7.8	5th	-2.2	6th
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	**179.0**	**=1st**	**132.9**	**=1st**	-8.1	4th	-7.6	4th	116.0	3rd

Table 26: PV net market benefits of the credible options assuming a 13% discount rate, (NPV $m, $2013/14)

	Scenario 1: Planning		Scenario 2: Fast World Recovery		Scenario 3: Slow Rate of Change		Scenario 4: Planning with low gas prices		Scenario 5: Planning with northern NSW 300 MW wind	
Option	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
0: Northern NSW 330 kV Line Uprating	3.6	4th	-13.4	6th	**-3.7**	**1st**	-11.3	2nd	**28.6**	**1st**
1a: 50% Series Compensation	11.0	3rd	14.5	2nd	-38.2	4th	-36.9	4th	-50.9	5th
1b: 50% Series Compensation + 2nd Armidale SVC	-2.2	6th	-1.2	4th	-49.3	6th	-46.1	6th	-60.3	6th
1c: 30% Series Compensation	**16.6**	**1st**	12.7	3rd	-26.0	3rd	-29.1	3rd	10.6	2nd
2a: 2nd Armidale SVC	-0.5	5th	-2.9	5th	-5.2	2nd	**-4.4**	**1st**	-3.4	3rd
2b: New SVCs at Dumaresq and Tamworth + Switched Shunt Capacitors at Dumaresq, Armidale and Tamworth	13.8	2nd	**18.7**	**1st**	-39.1	5th	-38.8	5th	-6.4	4th

8. Proposed preferred option recommendation

This RIT-T assessment has not identified a preferred credible option. Instead, TransGrid and Powerlink consider it prudent to recommend the 'do nothing' option as the preferred option under this RIT-T.

The analysis undertaken has shown that the selection of a preferred credible option is critically dependent on the weights assigned to the reasonable scenarios. Specifically, each scenario investigated offered a different outcome as shown in the table below.

Table 27: Results Obtained Under the Different Reasonable Scenarios Investigated

Scenario 1: Planning	Scenario 2: Fast World Recovery	Scenario 3: Slow Rate of Change	Scenario 4: Planning with low gas prices	Scenario 5: Planning with northern NSW 300 MW wind
Options 1a, 1c and 2b are effectively ranked equal first	Options 1a and 2b are effectively ranked equal first	Option 0 is the only option with a positive estimated net market benefit*	All credible options have a negative net market benefit*	Option 0 is ranked first

** All credible options with a negative net market benefit are ranked less than the 'do nothing' option.*

Sensitivity testing on the weights applied to the reasonable scenarios found that:

- assigning higher relative probabilities to the Planning and Fast World Recovery scenarios generally increases the weighted PV of net benefits and favours Options 1c, 1a and 2b;
- assigning higher relative probabilities to the Slow Rate of Change and Planning with low gas prices scenarios reduces the weighted PV of net benefits and favours Option 0; and
- assigning a higher relative probability to the planning (with wind) scenario generally increases the weighted PV of net benefits and favours Options 0 and 1c and, to a lesser extent, Option 2b.

Overall, the outcome of this RIT-T is not found to be robust under the changes in the weightings applied to each of the reasonable scenarios.

The identification of an exclusive preferred credible option has also not been found to be robust to a number of other assumptions – namely:

- the assumption that the options may offer 25% less capacity;
- assuming 25% higher or lower capital costs; and
- higher and lower discount rates.

The analysis has however identified four key scenario parameters affecting the ranking of options (and magnitude of market benefits estimated):

1. future gas prices in Queensland;
2. the possible retirement of Redbank power station;
3. the development of wind farms in northern NSW; and
4. forecast demand and energy growth.

At this stage, it is the view of TransGrid and Powerlink that considering the level of uncertainty surrounding these factors and the weighting that should be applied to different scenarios that it is prudent to not recommend a preferred credible option but to continue to monitor developments in these factors.

In addition, TransGrid and Powerlink will continue to investigate the feasibility of any non-network option proposed or otherwise identified and encourage interested parties to make submissions regarding possible non-network solutions. Information contained in any submissions received on non-network options would be taken into account as part of the PACR for this RIT-T process as well as part of any later RIT-T assessment undertaken for QNI.

TransGrid and Powerlink intend to publish the PACR for this RIT-T as soon as practicable after receiving submissions on this PADR. TransGrid and Powerlink envisage that the range of scenarios considered and the outcomes of this assessment will remain valid within that timeframe and the analysis will not have to be redone.

Appendix A Checklist of compliance with NER clauses

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(k) of the NER version 60.

NER Clause	Summary of Requirements	Relevant section in PADR
5.16.4(k)	A Transmission Network Service Provider must prepare a project assessment draft report, which must include: • a description of each credible option assessed; • a summary of, and commentary on, the submissions to the *Project Specification Consultation Report*; • a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each *credible option*; • a detailed description of the methodologies used in quantifying each class of material market benefit and cost; • the reasons why the TNSP has determined that a class or classes of market benefit are not material, where relevant; • 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; • the results of an NPV analysis of the net market benefit of each *credible option* and accompanying explanatory statements regarding the results;	 3 4 Appdx G 6.1 6.3 5 6.3 5.5 6.3 7 Appdx E
5.16.4(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).	8

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.

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 5.15.2(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: (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 5.3 of this report.

The reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand and energy projections associated with each of the scenarios have however been updated to reflect the latest demand and energy forecasts developed by AEMO, as published in its November 2013 NEFR update.

TransGrid and Powerlink have included the following five scenarios in undertaking the RIT-T analysis presented in this PADR.

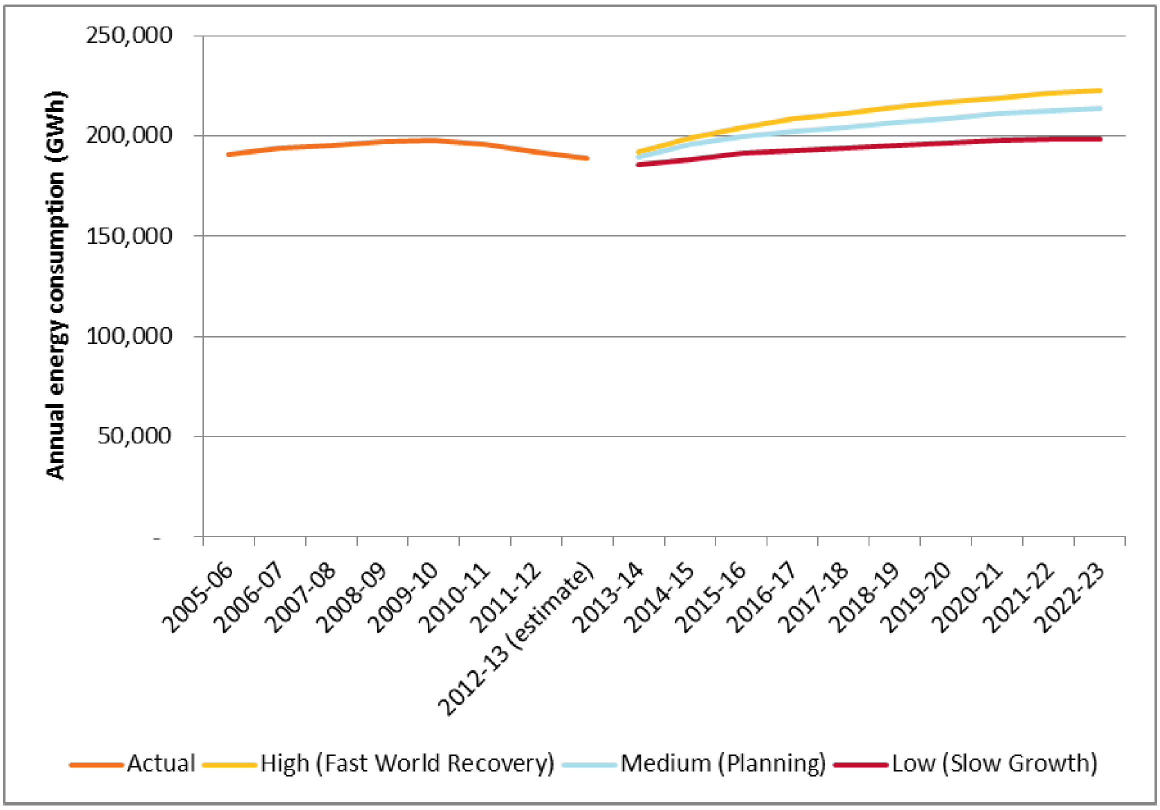
- Scenario 1: Planning
- Scenario 2: Fast World Recovery (FWR)
- Scenario 3: Slow Rate of Change (SRC)
- Scenario 4: Planning with reduced gas price forecasts
- Scenario 5: Planning with 300 MW wind development in northern NSW.

C.1.Electricity energy projections

The electricity energy projection associated with each of the following scenarios is shown in Figure C-1.

- Scenarios 1, 4 & 5 – based on 2013 NEFR ‘medium’ forecast (Planning Scenario);
- Scenario 2 – based on 2013 NEFR ‘high’ forecast (Fast World Recovery – FWR); and
- Scenario 3 – based on 2013 NEFR ‘low’ forecast (Slow Rate of Change Scenario – SRC).

Figure C-1: Annual energy forecasts for the NEM



Source: AEMO, 2013 NEFR, available at:

http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

C.2 Gas prices

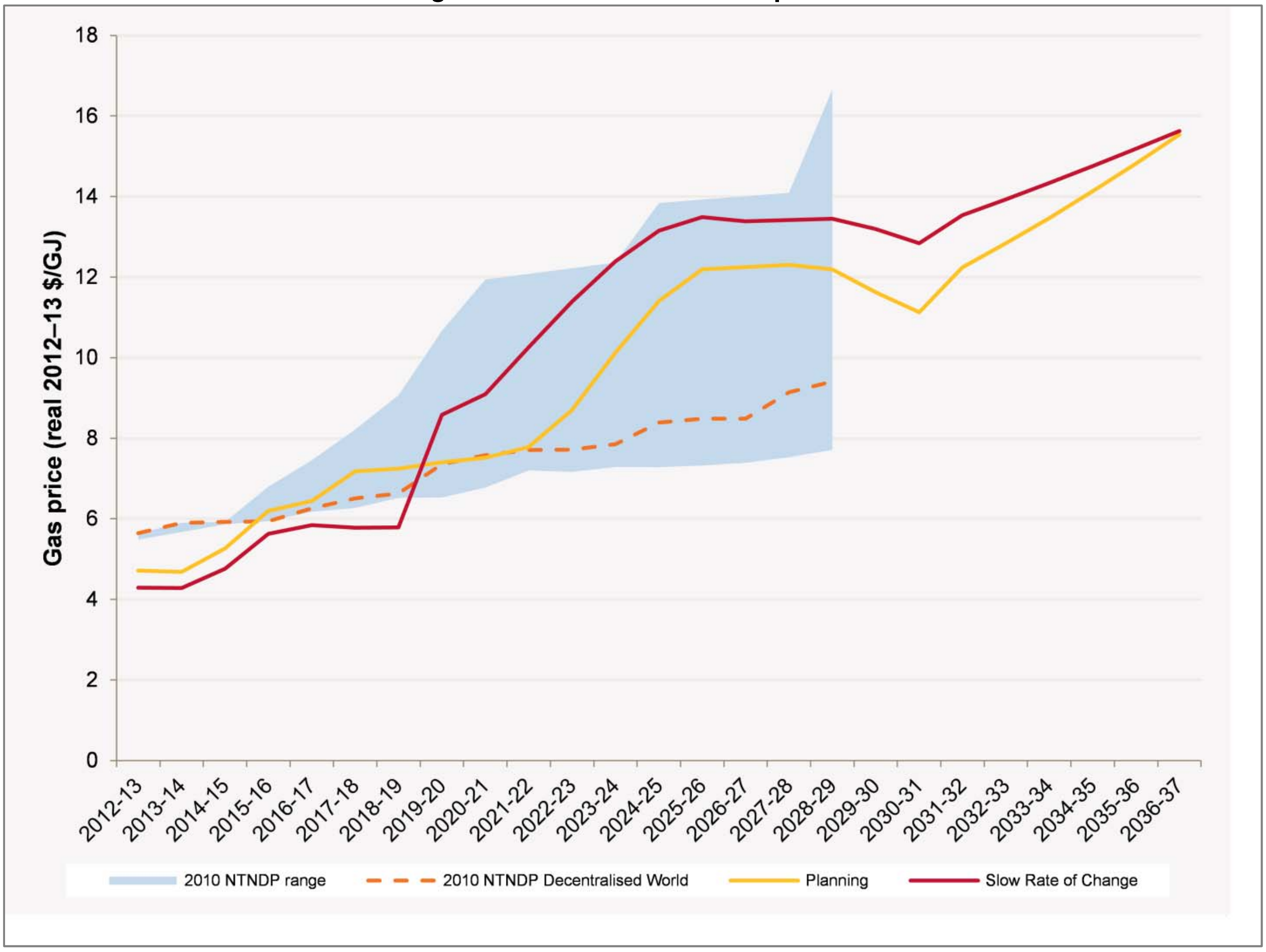
The 2012 NTNDP gas price projections have been used as the basis for fuel price assumptions when undertaking the RIT-T analysis presented in this PADR:

- Scenarios 1, 2, 3 & 5 – based on 2012 NTNDP forecasts; and
- Scenario 4 – 2/3 of the 2012 NTNDP forecasts.

Figure C-2 demonstrates the range of gas prices covered in the 2012 NTNDP. For the five scenarios considered by Powerlink and TransGrid in this PADR the following gas price projections have been assumed:

- Scenarios 1 & 5 – based on the 2012 NTNDP Planning scenario gas price assumptions;
- Scenarios 2 – based on the 2012 NTNDP Fast World Recovery scenario gas price assumptions;
- Scenario 3 – based on the 2012 NTNDP Slow Rate of Change scenario gas price assumptions; and
- Scenario 4 – 2/3 of the 2012 NTNDP Planning scenario gas price assumptions.

Figure C-2: Gas Price Assumptions



Source: AEMO, 2012 National Transmission Network Development Plan, p. 5-11 – available at: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan

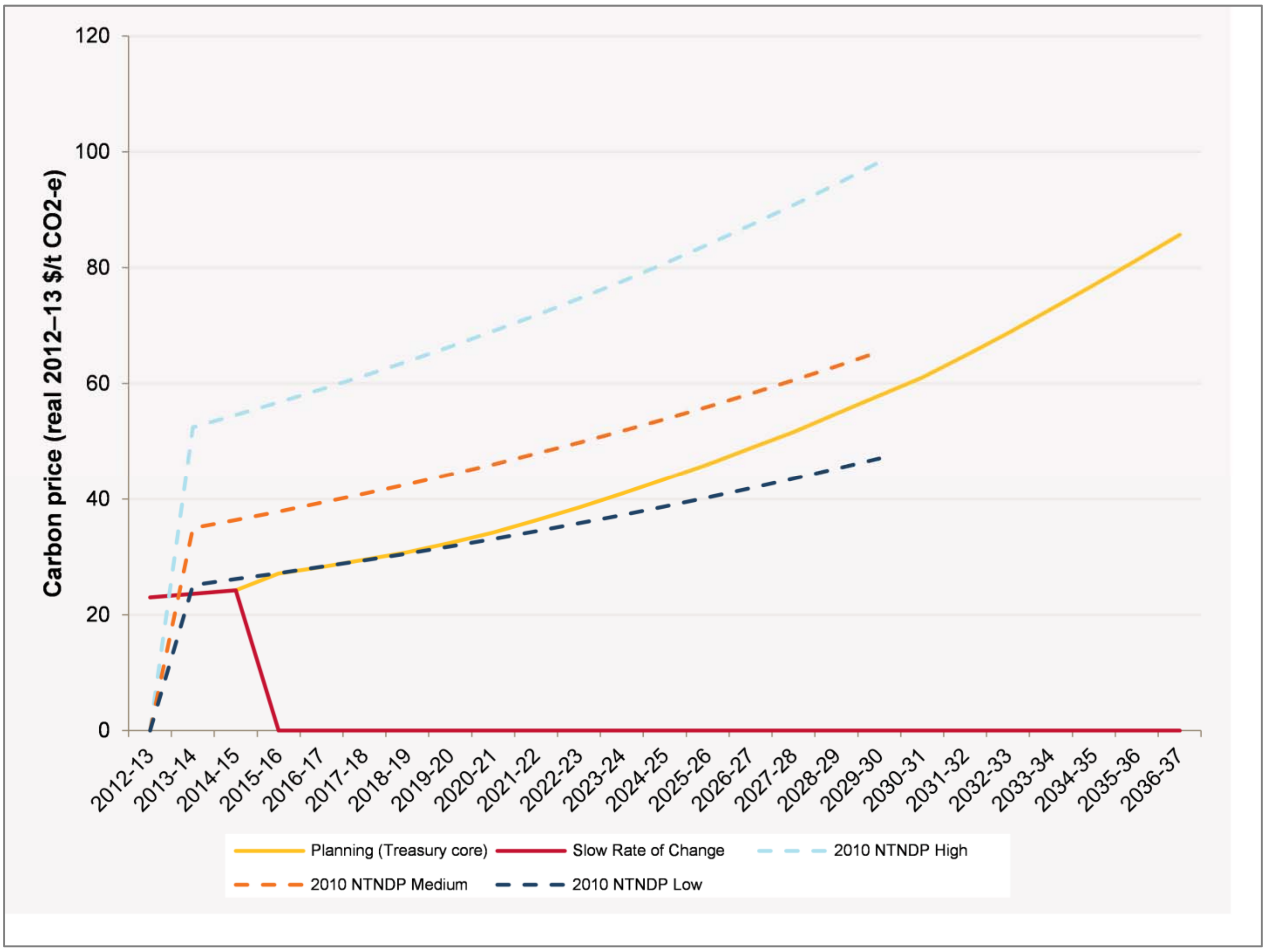
C.3 Carbon price

These carbon price trajectories for the 2012 NTNDP are shown in Figure C-3 below in yellow and red.

For the five scenarios considered by Powerlink and TransGrid in this PADR the following carbon price trajectories have been assumed:

- Scenarios 1, 2, 4 & 5 – based on the Australian Treasury's 'core' policy scenario carbon price (yellow trace); and
- Scenario 3 – assumes the absence of a carbon price after an initial three-year carbon price period, which is consistent with the current expectation of repeal (red trace).

Figure C-3: Carbon Price Assumptions



Source: AEMO, 2012 National Transmission Network Development Plan, p. 5-12 – available at: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan

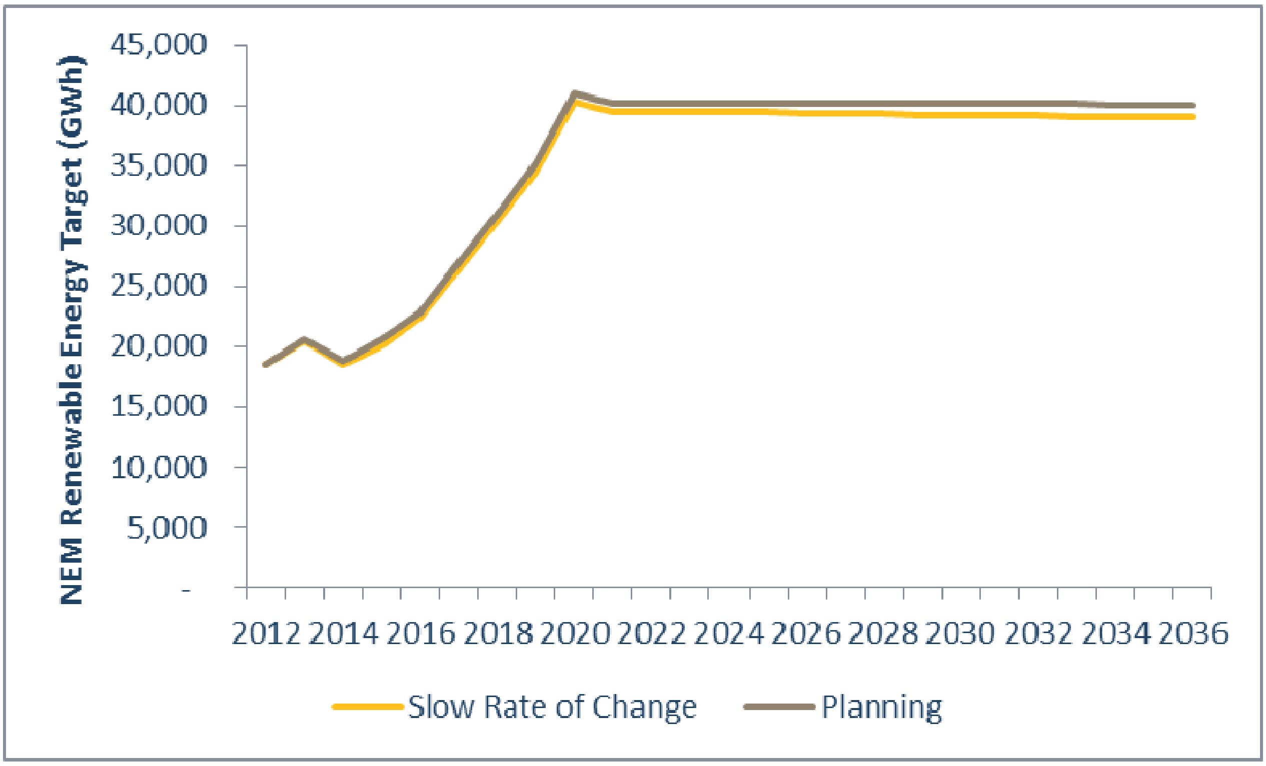
C.4 Carbon reduction targets below 2000 levels

For the purpose of the RIT-T analysis, the following carbon reduction targets (below 2000 levels) have been assumed in line with the 2012 NTNDP, ie:

- Scenarios 1, 2, 4 & 5 – 5% reduction by 2020, 80% reduction by 2050 (2012 NTNDP 'planning' scenario); and
- Scenario 3 – zero reduction by 2020, 80% reduction by 2050 (2012 NTNDP 'slow rate of change' scenario).

The total modelled renewable energy target under these two trajectories is shown in Figure C-4 below.

Figure C-4: Modelled Renewable Energy Target



Source: AEMO, 2012 National Transmission Network Development Plan, 'Modelling Assumptions and Data – v3' – available at: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/Assumptions-and-Inputs

Appendix D Generation builds and retirements – See separate spreadsheet

Appendix E NPV results – See separate spreadsheet

Appendix F Results of the First Pass Assessment

As discussed in section 3.2, TransGrid and Powerlink also considered six additional potential credible options, and undertook a more limited market modelling exercise as part of a 'first pass assessment' of these options.

For each of these options, the first-pass analysis involved using monte-carlo time sequential market simulations employing realistic generator bidding behaviour under the Fast World Recovery scenario only (outlined in section 5.3 above). TransGrid and Powerlink are of the view that if an upgrade option is not economic under the Fast World Recovery scenario (i.e., with high economic growth), it was unlikely to be economic under the other scenarios and sensitivities (with medium and low economic growth), and therefore uneconomic overall.

It can be seen that the large scale QNI upgrade options (i.e. 330 kV, 500 kV and HVDC) are uneconomic by a significant amount. Hence, these options were ruled out from further assessment. Options 3 and 6 are not economic as these options increase stability limits across QNI which, for the most part, do not set the transfer capacity across QNI (i.e. these options do not address the critical contingency limits). These options are also unlikely to be economic under the other scenarios and sensitivities, and hence were ruled out from further detailed assessment.

The results of this assessment are summarised in the table below, for all options.

Table 28: Results of the first pass assessment, ($m 2013/14)

Option	Description	Project Capital Cost	Net Benefits
0	Northern NSW 330 kV Line Uprating	$46.5	-$21.4[37]
1a	50% Series Compensation	$179.5	$90.2
1b	Series Compensation with 2nd Armidale SVC	$222.0	$69.3
1c	30% Series Compensation	$130.0	$59.6
2a	Second Armidale SVC	$53.5	$11.1
2b	Tamworth and Dumaresq SVCs	$176.2	$107.5
3	High Speed Protection Scheme	$2.1	-$1.0
4A	Second 330 kV HVAC Interconnector (Bayswater to Western Downs)	$1,300	-$942.9
4B	Second 330 kV HVAC Interconnector (Armidale to Bulli Creek)	$560	-$223.7
4C	New 500 kV HVAC Interconnector (Bayswater to Western Downs)	$2,300	-$1,911.6
5	High Voltage Direct Current (HVDC) Back to Back Converter Stations	$445	-$147.1
6	Hunter Valley Braking Resistor	$8.1	-$7.0

[37] Although the net market benefits shown for this option are negative, it was found that this project could have positive market benefits under cases where Redbank power station no longer continued to operate. Hence, this option was retained for more detailed analysis.

Appendix G Submissions received in response to the PSCR

The following table is a summary of the issues raised by each submission. A response to each issue by Powerlink and TransGrid is included. Each of the submissions is published on Powerlink's and/or TransGrid's websites.

Table L1 Summary of PSCR submissions and responses

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
AEMO	Timing of investment	NTNDP 2012 studies indicate the economic timing for investment has been extended by 10 to 15 years into the future and AEMO does not see the economic or system reliability justification for action at this time.	This report contains an analysis of market benefits across a wider range of potential future market development scenarios and network upgrade options than the NTNDP 2012, which may lead to different conclusions under some cases. The market studies contained within this report also focus on examining market benefits using realistic bidding behaviour models and include an assessment of competition benefits. In addition, Powerlink and TransGrid have observed some differences in forecast generation retirement outcomes between these studies and the NTNDP, which may potentially lead to different outcomes under some of the scenarios.
Private Generators	Use of historical data	Whilst it is important to review previous QNI power flows and constraint performance, the extent to which historical performance is a predictor of the future needs to be carefully assessed.	Agreed. The modelling for this PADR is not based on extrapolation of past performance as a predictor of future needs. The modelling is based on forecast future electricity demands across the NEM, and market modelling of generator dispatch to meet that future demand.
		The identified need for increased QNI capacity as described in the consultation FF is based on the 2010 NTNDP scenarios and demand forecasts. The 2010 NTNDP used demand forecast information from the National Transmission Statement 2009 (Volume 2 Modelling and Analysis). Given the substantial reduction in actual demand and forecast demand since 2009, it is important that any analysis of potential market benefits from increasing QNI capacity use the most recent forecast data.	TransGrid and Powerlink note that the reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand projection associated with each of these scenarios has however been updated to reflect the latest demand forecasts developed by AEMO, as published in its November 2013 NEFR update.
	Economic sensitivities	It is feasible that the economy and therefore the market could be moving into a period of low demand, low growth and low carbon prices. The sensitivities around these economic parameters are further likely to suggest that a large-scale upgrade is not warranted at this point in time.	The RIT-T requires that credible options be assessed against a range of realistic scenarios, or future states of the world. The scenarios examined for this PADR include one with a low (zero) carbon price. In addition, the electricity demand projections associated with each of the scenarios investigated reflects the latest demand forecasts developed by AEMO, as published in its November 2013 NEFR update.

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
	Intra-regional constraints	From table 2.9 in the PSCR the two most dominant causes of binding constraints were transient stability (58% of the time), followed by FCAS (30%). It is understood that most, if not all of the options discussed in the consultancy report would alleviate the stability constraints. However, it is not at all clear that any of the options would alleviate the FCAS constraints. If this is the case, then it would appear that even if QNI were upgraded, a substantial amount of constrained operation may remain due to FCAS constraints.	FCAS constraints occur on QNI when one of the two circuits from Bulli Creek - Dumaresq - Armidale - Tamworth is out of service for maintenance or following a fault, or when AEMO declares the trip of both circuits to be a credible contingency. This is due to the need to secure FCAS services to cover the event of severing the interconnection and Queensland operating as an electrical island, separate from the rest of the NEM. Options which include additional circuits in parallel with the existing QNI circuits, such as options 4(a) to 4(c) in the PSCR, would alleviate these FCAS constraints. These options however were found to have a high cost, relative to the market benefits and to not be economically feasible overall.
		There is a general view that given the uncertainty regarding demand and the need for a large scale upgrade of the interconnector, a more substantive review of intra-regional constraints would be more beneficial at this point in time. For instance, ongoing uncertainty around the 855/871 constraint, and ongoing congestion arising from Calvale/Wurdong in Queensland and Armidale/Tamworth in New South Wales should be considered ahead of any large scale interconnector upgrade.	Powerlink is able to advise that two new 275 kV transmission circuits between Calvale and Stanwell were commissioned in late 2013, which are anticipated to relieve congestion associated across feeders 855/871. Where appropriate the uprating of the following lines has been included in the options being considered in this PADR: • Line 84 – Liddell to Tamworth; • Line 83 – Liddell to Muswellbrook; and • Line 88 – Muswellbrook to Tamworth.
	Low-cost options	While it appears unlikely that any large-scale upgrade is required at this point in time, the consultation report suggests that at least one low-cost no-regrets option should proceed regardless of the study outcomes. At a cost of $5 million, with a two year payback, option 3 appears to be an initiative that can be initiated without recourse to a RIT-T process.	We assume the reference to a two year payback for option 3 is taken from section 3.4 of the PSCR. The time (in years) in that table is the estimated time to implement an option, not an estimated payback period.

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
			The NER require that the RIT-T be applied when the estimated cost of the most expensive option which is technically and economically feasible has an estimated capital cost in excess of the threshold, currently $5 million. Even if the high capacity, very high cost options are considered to not be economically feasible, there are still a number of feasible options that are estimated to cost in excess of the threshold.
CS Energy	RIT-T	Agrees with statements made by AGL to the Productivity Commission that the RIT-T is not competitively neutral in that it overvalues the benefit of an interconnector by not accounting for market risk. The RIT-T can include avoided costs for reserve capacity when generators receive no such payments for reserve capacity in the NEM.	Powerlink and TransGrid are required to apply the RIT-T published by the AER. Under the RIT-T market benefits must include the benefit of changes in costs for parties, other than the TNSPs, due to the difference in timing of new plant, unless we can demonstrate that the benefit will not materially affect the outcome, or the cost and effort to model the benefit is disproportionate to the scale, size and potential benefits of the credible options being considered. The RIT-T also requires that market development modelling be undertaken on a least cost basis, including meeting any minimum reserve requirements.
		Under static assumptions the difference in supply costs in each region has to be significant to justify an interconnector upgrade. Such differences have not been evident across the major interconnections in the NEM since inception.	Noted. The modelling undertaken for this PADR is not based on such static assumptions.

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
		Under dynamic conditions, increasing transfer capacity is coupled with investment in generators within the exporting region to service incremental demand in the importing region. A way of easing the investment hurdle would be to assume persistent oversupply in one region. Under this scenario the importing region's long run costs of investing in a generator would be compared with the exporting region's short-run costs (Fuel) and the interconnector cost.	Powerlink and TransGrid have not assumed a persistent oversupply of generation in any part of the NEM. The capital and operating costs of all new entrant generators are included in the economic assessment.
	Demand forecasts	An alternative would be if there were extremely bullish assumptions on demand growth, thus bringing forward investment cost of supply from generators. Given the existing uncertainty over future electricity demand and poor investment environment for generation, there appears to be little in the way of benefits to be captured in the RIT-T	TransGrid and Powerlink note that the reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand projection associated with each of these scenarios has however been updated to reflect the latest demand forecasts developed by AEMO, as published in its November 2013 NEFR update.
	New entrant generators	The RIT-T needs to consider only real capacity that must rely on NEM spot revenue to be paid, rather than capacity required under the reliability standards as specified in the ESOO.	The RIT-T requires that market development modelling, such as new entrant generators, be undertaken on a least cost basis, including meeting any minimum reserve requirements. Market driven modelling may also be undertaken, where appropriate, but as a complement to the least cost modelling, not as a substitute. The question of least-cost modelling versus market driven modelling was explicitly considered by the AER when developing the RIT-T.
	Fuel costs	Should consider whether there will be any difference in fuel costs and prices if marginal generators, whose fuel cost is set by international markets through LNG or coal export, are pricing on the opportunity cost of selling gas or coal back into the international markets.	The market simulations reported in this PADR use the fuel costs published by AEMO as part of the 2012 NTNDP.
	Network losses	Marginal losses are already reflected in regional reference prices (RRPs). If changes in network losses are then included the RIT-T may be double dipping the benefit in losses.	In all market simulations, including the do nothing case, network losses are captured in the total cost of production. Losses are not determined or valued using the RRP.

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
	Competition benefits	Given that assumptions must be made of offer prices for competing generators, CS Energy questions competition benefits in the RIT-T. Competition benefits should be specified separately and all assumptions disclosed publicly. Notes that Powerlink does not intend to do this.	In response to feedback received on the PSCR, Powerlink and TransGrid published a separate consultation document *Methodology for Assessing Competition Benefits* in April 2013. That document set out further particulars on the methodology and key assumptions to be adopted when assessing competition benefits. In addition, although it is not required under the RIT-T, TransGrid and Powerlink have provided the results of the RIT-T modelling in a way which separately identifies the amount due to competition benefits.
	Cost assumptions	Question the reliability of results if uncertainty in costs remains in the range +/- 25%, as for the previous QNI upgrade study	The RIT-T requires sensitivity testing of a range of the input parameters, including the costs of credible options. The sensitivity testing reported in this PADR reflects the range of uncertainty in the estimated costs of credible options.
DSDIP	Local Industry Policy	The proponent, Ergon Energy (sic), as a government owned corporation is covered by s.11 of the Queensland Industry Participation Policy Act 2011 (QIPP Act) and required to comply with the local industry policy under s.16 of the QIPP Act)	The PSCR is part of the regulatory consultation process set out in the NER, and is directed to eliciting information to inform the market modelling and to identify options which should be incorporated in the analysis, particularly non-network options. It is not a tendering process. Where Powerlink is the proponent of a network solution the commitment to the Local Industry Policy will be incorporated into contracts for the supply of equipment as part of implementing a network solution.
Energex	Non-network options	Has no information on non-network options which may relieve the constraints.	Noted.
Epuron (White Rock Wind Farm)	Demand forecasts	We consider that the recent reduction of demand in the NEM is likely to materially change the economic justification for each of the QNI upgrade options.	TransGrid and Powerlink note that the reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand projection associated with each of these scenarios has however been updated to reflect the latest demand forecasts developed by AEMO, as published in its November 2013 NEFR update. The analysis has also been undertaken under a scenario with low demand growth (slow rate of change scenario).

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
	New entrant generators	We understand that the connection of a wind farm to QNI is likely to have an impact on the design of a number of the QNI Upgrade Credible Options identified in the Consultation Report, however we believe that there are a number of potential technical solutions that would enable the wind farm connection to proceed without impeding any future QNI Upgrade, should the economic justification of the QNI Upgrade be confirmed.	The market simulations reported in this PADR include a scenario of significant wind farm development at a point between Armidale and Dumaresq. Under this scenario the series capacitor options have had their level of compensation, costs, and resultant changes in QNI capability adjusted to reflect the different network development.
NGF	New entrant generators	Wish to see a complete list of all proposed new generation builds including sub-regional specific location and commissioning date	The PADR shows the quantum and type of new generation builds in each jurisdiction (Appendix D), together with the year of commissioning.
	Competition benefits	If competition benefits are claimed the PADR should include the bid structure for all generators and the quantum of competition benefits identified as a separate item.	The PADR provides the quantum of competition benefits identified as a separate item, and discusses the methodology used.
	Voluntary load shedding	The PADR should include data regarding voluntary load shedding and quantum of benefits identified as a separate item.	The market modelling in effect incorporates DM resources as an additional 'generator' that may be dispatched, and as implemented within the market models as a scheduled load. The changes in voluntary load shedding are therefore reflected in the overall dispatch outcome. The market benefits associated with changes in voluntary load shedding make up a minor portion of this market benefit.
	Intra-regional constraints	The PADR should include the impact on intra-regional congestion for each option and data of any additional transmission upgrades required for the RIT-T options to provide the nominal upgrade. Concerned that some options, such as option 4a, would lead to increased intra-regional congestion between the generation centre and the RRN, significantly reducing the nominal benefits of the options.	TransGrid and Powerlink have included the costs of investments needed to relieve intra-regional constraints where relevant, as part of the cost of the option for augmenting the capacity of QNI. Specifically, options 1a, 1b, 1c and 2b all include the cost of uprating lines 83, 84 and 88. Options 4a and 5 included in the first pass assessment (outlined in section 3.2.2 above) also include investments to address intra-regional constraints.
	Demand forecasts	The NGF supports the use of the 2013 AEMO demand and energy forecasts as opposed to internal Powerlink and TransGrid in the PADR modelling.	TransGrid and Powerlink note that the reasonable scenarios adopted for this RIT-T are largely based on scenarios developed by AEMO for the 2012 NTNDP. The electricity demand projection associated with each of these scenarios has however been updated to reflect the latest

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
			demand forecasts developed by AEMO, as published in its November 2013 NEFR update.
	Capacity of options	Section 3 of the PSCR contains details of several options for upgrading QNI. The PSCR is unclear if these projects are cumulative of if a higher cost option may only deliver a partial increase in capacity above one of the lower cost upgrade options. Request that all options are reordered from lowest to highest cost and only the amount of nominal increase in interconnector capacity over the lower cost option is shown as a capacity increase benefit.	Each option is assessed as a complete, stand-alone option with any capacity increase being the increase from the current capacity. The costs are the estimated costs for all works necessary to provide that capacity increase across QNI.
	Cost assumptions	Concerned that costs of options may be understated. Claim that TNSP tend to undercost planning proposals in order to achieve regulatory approvals and observe large cost increases during the construction phase. Seek a binding and enforceable guarantee that actual costs will not exceed nominal costs by more than 10%.	TransGrid and Powerlink note that there are inevitably uncertainties in the costing of options, particularly at the earlier stages of the development process. The RIT-T requires sensitivity testing of a range of the input parameters, including the costs of credible options. TransGrid and Powerlink have undertaken a number of sensitivity tests on the costs of the options. In addition, TransGrid and Powerlink 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 (provided that that value remains positive).
	Capacity of options	Concerned that historical QNI capacity outcomes have been less than the nominal capacity. What guarantees will be provided that the nominal capacity of the proposed upgrade will actually be achieved?	The actual capacity of QNI at any time depends on a wide range of power system conditions, including generator dispatch outcomes. For instance, when the trip of Kogan Creek (as the largest generator in the Queensland Region), is the most limiting factor for QNI northward flow, any increase in Kogan Creek dispatch would result in a corresponding decrease in QNI capacity. Also, as part of the co-optimisation of constraints AEMO may include QNI as a controllable term on the LHS of other network constraints. If those other network constraints become binding the capacity of QNI may be adjusted to allow those other constraints to be satisfied.

Submission by	Issue raised	Comment	Response by Powerlink and TransGrid
			In addition, TransGrid and Powerlink have undertaken a sensitivity test on the RIT-T results in relation to a lower assumed level of additional capacity. The RIT-T outcome was found to be unaffected by a lower capacity assumption.
Origin	Market Benefits	Origin believes a QNI upgrade would: 1. Deliver least overall cost energy to the NEM; 2. Improve economic investment in the NEM; 3. Unlock additional competition benefits; and 4. Potentially increase reliability of supply in the NEM.	Powerlink and TransGrid agree with Origin that a QNI upgrade could deliver market benefits of the type identified by Origin. The RIT-T requires Powerlink and TransGrid to assess the net market benefits to all those who generate, transmit, distribute and consume electricity in the NEM.
Stanwell	Assumptions	Request the PADR include more detailed information on the financial modelling associated with each option, including costs and timing of new generation developments, generator bidding behaviour, derivation of competition benefits, and intra-regional transmission developments and impacts for intra-regional transmission congestion.	More detailed information on these aspects is included in the appendices of this PADR.
Wind Prospect	New entrant generators	Wind Prospect is developing the Sapphire Wind Farm east of Inverell and is looking to connect to the TransGrid 330 kV network between Armidale and Dumaresq. Proposes that TransGrid consider the development of a new switching station along the Armidale to Dumaresq 330 kV line which can facilitate the connection of renewable energy projects and result in the following: - lower cost of energy due to shared connection assets for generation projects; - improved network impedance with SVCs installed at the new switching station and Armidale; and - improved switching and protection capabilities on circuits 8C and 8E.	The market simulations reported in this PADR include a scenario of significant wind farm development at a point between Armidale and Dumaresq. Under this scenario the series capacitor options have had their level of compensation, costs, and resultant changes in QNI capability adjusted to reflect the different network development.