

**IN THE AUSTRALIAN COMPETITION TRIBUNAL
AGL ENERGY LIMITED**

of 2014

**RE: PROPOSED ACQUISITION OF MACQUARIE GENERATION (A CORPORATION
ESTABLISHED UNDER THE ENERGY SERVICES CORPORATIONS ACT 1995
(NSW))**

ANNEXURE CERTIFICATE

This is the annexure marked "**AF-16**" annexed to the statement of **ANTHONY GARTH
FOWLER** dated 23 March 2014

Annexure AF-16

Filed on behalf of (name & role of party)	AGL Energy Limited		
Prepared by (name of person/lawyer)	Liza Carver		
Law firm (if applicable)	Ashurst Australia		
Tel	+61 2 9258 5897	Fax	+61 2 9258 6999
Email	Liza.Carver@ashurst.com		
Address for service (include state and postcode)	Level 35, 225 George Street, Sydney, NSW, 2000 DX 388 Sydney		

[Form approved 01/08/2011]

NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

For the National Electricity Market

2013



Purpose

The purpose of this publication is to provide an independent strategic view of the efficient development of the National Electricity Market (NEM) national transmission network over a 25-year planning horizon.

AEMO publishes the National Transmission Network Development Plan in accordance with clause 5.6A.2 of the National Electricity Rules (Rules).

This publication is based on information available to AEMO as at 1 November 2013, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

Note this document is subject to an important disclaimer which limits and/or excludes AEMO's liability for reliance on the information in it.

Please read the full disclaimer at the end of the document at page D1 before reading the rest of this document.

Revision History

Number	Date	Notes
1	12 December 2013	First issue

Published by

AEMO

Australian Energy Market Operator

ABN 94 072 010 327

Copyright © 2013 AEMO



EXECUTIVE SUMMARY

The 2013 National Transmission Network Development Plan (NTNDP) shows changes in National Electricity Market (NEM) electricity generation dynamics and network investment decisions over the next 25 years.

The NTNDP outlook is dependent on government policy decisions regarding renewable energy and carbon emissions reductions. NTNDP modelling indicates that the Large-scale Renewable Energy Target (LRET) is the main driver of generation investment, with the carbon price having a lesser impact.

The 2013 NTNDP models generation dispatch with the carbon price retained under current legislation. It also models a zero carbon price scenario without an explicit carbon emissions price. It does not model alternative ways of achieving carbon emissions reductions, such as the Federal Government's Direct Action plan.

Coal remains the dominant generation fuel over the outlook period. However, slow growth in electricity consumption and increases in wind and rooftop photovoltaic (PV) generation could lead to an oversupply of up to 4,000 MW of electricity generation capacity.

The NTNDP shows there are further reductions in new large-scale generation required in the NEM over the next 25 years: from \$46 billion in 2012 to \$27 billion in 2013. The estimated investment in additional main transmission capacity required over the next 25 years remains at \$5 billion, as forecast in 2012.

Localised electricity consumption reductions have led to some decreases in transmission asset utilisation. As a result, and with the reduced demand forecast, network augmentation needs are reducing and network asset refurbishment and replacement will be the dominant network investment type.

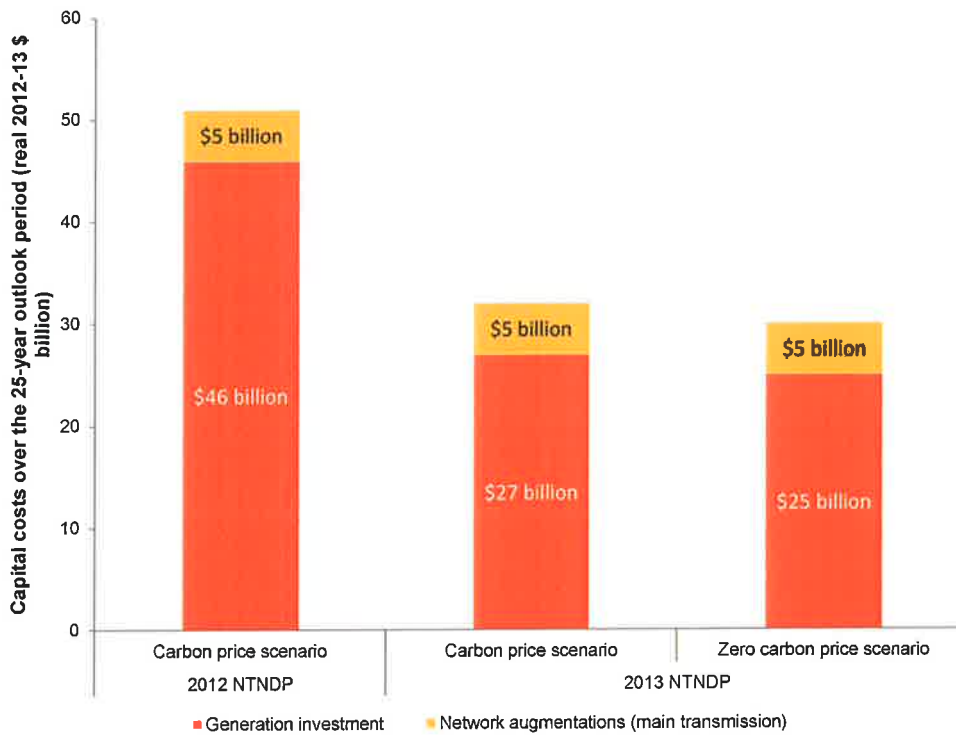
Network prices will also increase if electricity consumption continues to decline. This is because network pricing is based on recovering the network asset value over the (declining) energy base, rather than on the service delivered by the network.

Against this backdrop, and in light of changing reliability standards, network asset replacement decisions will provide an opportunity to optimise the type and capacity of the replaced assets, or to consider whether they need to be replaced at all.

The NTNDP identifies network asset refurbishment and replacement decision-making as a network planning priority requiring a high degree of transparency. AEMO is responding in 2014 by building on the NTNDP and producing more detailed five-to-seven-year independent network outlooks that consider the ongoing need of assets identified by transmission network service providers (TNSPs) to be replaced.

AEMO is pursuing initiatives to enable efficient investment decision-making, including developing independent transmission connection point forecasts and network investment needs for New South Wales and Tasmania, and reviewing projects under a new incentive scheme to support improved usage of existing network assets.

Figure 1 — Capital costs over the 25-year outlook period



The short- to medium-term outlook to 2020

The shorter-term outlook to 2020 is characterised by an increase in new renewable generation, generation retirements, and a need to focus on improved utilisation of the existing transmission network.

Key findings are:

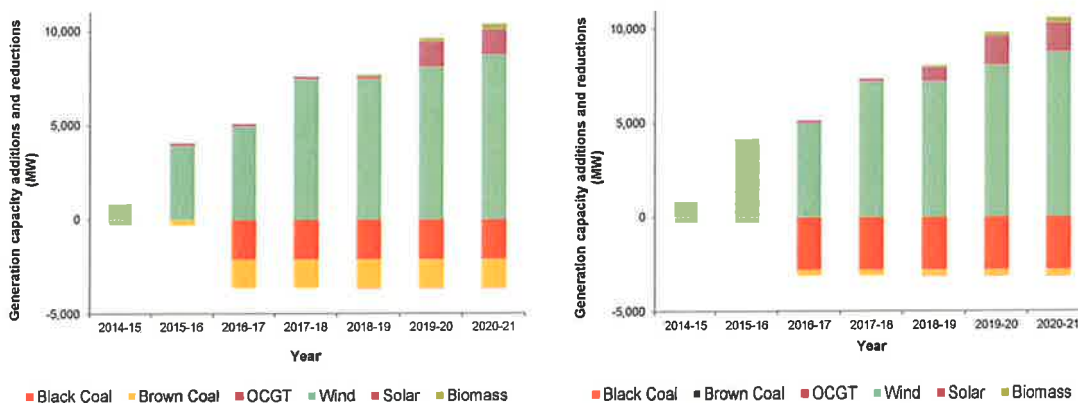
- All new generation to 2020 is expected to be renewable, with wind comprising 84%, large-scale solar PV 13%, and biomass 3%. This includes 168 MW of new wind generation that has recently come online in Tasmania, and a further 131 MW in Victoria, 270 MW in South Australia, and 386 MW in New South Wales committed to come online from 2014–15. AEMO is aware of close to 15,800 MW of proposed wind generation projects.
- The 2013 NTNDP estimates approximately 8,700 MW of new wind generation to connect to the transmission network by 2020, resulting in a total installed NEM wind generation capacity of around 11,000 MW.
- New renewable generation that comes online displaces existing baseload generation and adds to the current oversupply of generation capacity in the NEM signalling potential generation reductions. 2013 NTNDP modelling estimates a reduction of 3,700 MW in coal-fired generation capacity to 2020.¹ This is approximately 14% of the total current coal-fired installed generation capacity. Zero carbon price modelling results in reductions of around 3,100 MW, or 12% of coal-fired generation capacity.
- Under a carbon price scenario, there are considerable levels of retirement of both black and brown coal generation. The zero carbon price scenario sees the lower operating costs of brown coal generation result in a shift towards black coal generation retirement.

¹ While the modelling removed generation plant predominately in a single year, actual withdrawals would be expected to occur progressively.



- Baseload gas-powered generation output is reduced under both carbon price scenarios, driven by gas price assumptions that reach \$12/GJ by 2025.²
- The increase in renewable generation can create operational and power system security challenges. AEMO published the Integrating Renewable Energy—Wind Integration Studies Report³ in September 2013 outlining the main power system security issues and recommending short-term actions to support the integration of forecast wind generation.
- Connecting wind generation is expected to contribute to network congestion, particularly at times of high wind generation output. The NTNDP identifies the location of this potential congestion.
- NTNDP modelling has not identified a requirement for major investment in inter-regional augmentations following the completion of the Victoria–South Australia augmentation.⁴
- Transmission asset utilisation will also decrease where there are localised reductions in electricity consumption or generation retirements remote from population centres.
- TNSPs are delaying, or cancelling, a number of network augmentations that were under investigation or already committed given the minimal need for new capacity. Network asset refurbishment and replacement is likely to be a focus.

Figure 2 — Cumulative generation capacity additions and reductions in the carbon price scenario (left) and zero carbon price scenario (right)⁵



² Scenario 3, Sensitivity 4 in ACIL Tasman, 2012, Fuel cost projections: Updated Natural gas and coal outlooks for AEMO modelling. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>. Viewed 4 December 2013.

³ AEMO, Integrating Renewable Energy — Wind Integration Studies Report 2013. Available at: <http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy>. Viewed 4 December 2013.

⁴ AEMO and ElectraNet, South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T. Available at: <http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T>. Viewed 4 December 2013.

⁵ AEMO, Generation Information. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information>. Viewed 4 December 2013.

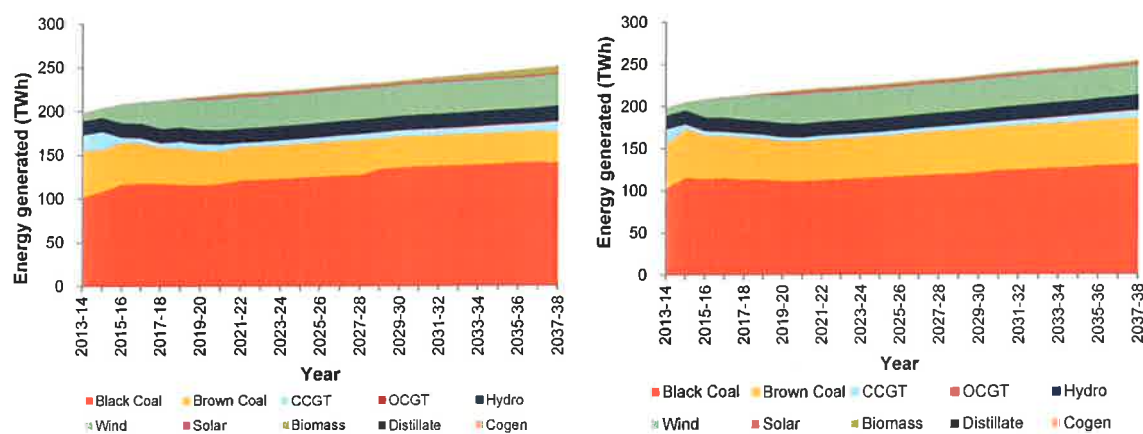
The longer-term outlook from 2020 to 2038

Figure 3 shows the energy generated by technology over the outlook period.

Key findings are:

- The NTNDP modelling indicates a reduction in brown coal generation capacity in around 2030 to deliver a total reduction of 4,200 MW in coal-fired generation by 2038. This is approximately 15% of the total current coal-fired installed generation capacity. Zero carbon price modelling indicates reductions by 2038 of around 3,700 MW, or 13% of coal-fired generation capacity.
- Coal continues to dominate over the 25-year outlook period and remaining coal-fired generation increases output beyond 2020.
- Biomass is the only new baseload plant with 1,000 MW installed in the carbon price scenario and about 330 MW installed in the zero carbon price scenario. Peaking generation, in the form of open cycle gas turbines (OCGTs), emerges towards the end of the outlook period.
- Geothermal generation, which the 2012 NTNDP modelled as coming online towards the end of the 25-year outlook period, is now beyond the outlook period.

Figure 3 — Energy generation by technology under the carbon price scenario (left) and zero carbon price scenario (right)



Supporting efficient investment

To support efficient investment decision-making in the medium term, AEMO is undertaking a number of initiatives:

- In 2013-14, AEMO is developing an independent assessment of the short- to medium-term transmission investment needs of New South Wales and Tasmania. This assessment will be an input to the 2014 transmission revenue determinations.
- AEMO is broadening the scope of its electricity forecasts by producing transmission connection point forecasts. The connection point forecasts AEMO is developing in 2014 for New South Wales and Tasmania will also be inputs to the Australian Energy Regulator's (AER) transmission revenue determination processes.
- AEMO is reviewing projects put forward by TransGrid, Transend Networks and ElectraNet under the AER's new network capability incentive scheme. The Network Capability Incentive Parameter Action Plan (NCIPAP) is designed to support improved usage of existing network assets through low-cost projects. As the national transmission planner, AEMO's role is to review that the proposed projects will deliver best value for money for consumers and ranking those priority projects accordingly.



CONTENTS

EXECUTIVE SUMMARY	III
CHAPTER 1 - ABOUT THE NTNDP	1
1.1 NTNDP modelling	1
1.2 Changes since the 2012 NTNDP	2
1.3 The NTNDP in the energy planning context	4
1.4 Content and structure of the 2013 NTNDP	4
1.5 Where to find more information	4
CHAPTER 2 - THE NATIONAL OUTLOOK	5
2.1 Capital investment summary	5
2.2 The short- to medium-term outlook to 2020	5
2.3 The longer-term outlook from 2020 to 2038	14
CHAPTER 3 - THE CHANGING NATURE OF PLANNING	21
3.1 A new paradigm for transmission planning	21
3.2 Transmission network utilisation	21
3.3 Transmission asset replacement	23
3.4 Asset retirement consideration	25
3.5 Conclusion	25
CHAPTER 4 - CURRENT AND UPCOMING NATIONAL TRANSMISSION PLANNER ACTIVITIES	26
4.1 Network Capability Incentive Parameter Action Plan	26
4.2 Transmission connection point electricity forecasts	27
4.3 Medium-term network outlooks	27
CHAPTER 5 - LINKS TO SUPPORTING INFORMATION	29

APPENDIX A - NETWORK LIMITATIONS **APP-1**

**APPENDIX B - NETWORK SUPPORT AND CONTROL
ANCILLARY SERVICES** **APP-9**

- B.1 NSCAS gaps for maintaining power system security APP-10
- B.2 NSCAS gaps for maximising market benefits APP-11
- B.3 Status of NSCAS gaps identified in 2012 APP-11
- B.4 AEMO's 2012–13 NSCAS acquisition APP-12

**APPENDIX C - MEDIUM-TERM NETWORK OUTLOOKS FOR
NEW SOUTH WALES AND TASMANIA – SCOPE OF
WORKS** **APP-13**

- C.1 Deliverables APP-13
- C.2 Details of delivery components APP-13
- C.3 Network needs assessment APP-14

IMPORTANT NOTICE **D-1**



TABLES

Table 1 — Links to supporting information	29
Table A-1 — Committed main transmission network projects across the NEM	APP-1
Table A-2 — NTNDP limitations on the main transmission network	APP-2
Table A-3 — Potential economic dispatch limitations	APP-3
Table A-4 — APR identified limitations on the main transmission network	APP-5
Table B-1 — Summary of NSCAS gaps for maintaining power system security	APP-10
Table B-2 — Network constraints selected for quantitative assessment, and results	APP-11
Table B-3 — summary of status of NSCAS gaps identified in 2012	APP-11
Table B-4 — Indicative NSCAS requirements and acquired amounts	APP-12

FIGURES

Figure 1 — Capital costs over the 25-year outlook period	iv
Figure 2 — Cumulative generation capacity additions and reductions in the carbon price scenario (left) and zero carbon price scenario (right)	v
Figure 3 — Energy generation by technology under the carbon price scenario (left) and zero carbon price scenario (right)	vi
Figure 4 — 2013 NEFR annual energy NEM forecast	3
Figure 5 — Comparison of carbon price trajectories modelled in the 2012 and 2013 NTNDPs	3
Figure 6 — Scenario capital cost comparison to 2037–38	5
Figure 7 — Generation capacity additions and reductions in the carbon price scenario	7
Figure 8 — Generation capacity additions and reductions in the zero carbon price scenario	7
Figure 9 — Total NEM generated energy by technology under the carbon price scenario	8
Figure 10 — Total NEM generated energy by technology under the zero carbon price scenario	8
Figure 11 — NTNDP network limitations on the main transmission network by 2020–21	11
Figure 12 — APR identified limitations on the main transmission network	12
Figure 13 — New generation by 2020–21 and potential economic dispatch limitations	13
Figure 14 — Generation capacity additions and reductions in the carbon price scenario	15
Figure 15 — Generation capacity additions and reductions in the zero carbon price scenario	15
Figure 16 — New generation development in the NEM by 2037–38 in the carbon price scenario	16
Figure 17 — Total NEM generated energy by technology in the carbon price scenario	17
Figure 18 — Total NEM generated energy by technology in the zero carbon price scenario	17
Figure 19 — CO ₂ -e emissions under the carbon price and zero carbon price scenarios, compared with the 2012 NTNDP carbon price scenario	18
Figure 20 — NTNDP network limitations on the main transmission network by 2037–38	20
Figure 21 — Average transmission line utilisation	22
Figure 22 — Changing proportion of augmentation to asset replacement expenditure	24
Figure B-1 — Process for meeting NSCAS needs identified by AEMO	APP-9



CHAPTER 1 - ABOUT THE NTNDP

The purpose of the National Transmission Network Development Plan (NTNDP) is to facilitate the development of an efficient national electricity network that considers potential transmission and generation investments. The NTNDP provides an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission network over a 25-year planning horizon. It is focused on large-scale electricity generation and the main transmission networks that connect this generation to population and industrial centres.

The 2013 NTNDP reflects a declining trend in electricity consumption. The 2013 National Electricity Forecasting Report (NEFR)⁶ shows three consecutive years of reduced electricity consumption for the NEM from 2010–11 to 2012–13 and projects slower growth than previous forecasts.

The lower electricity consumption forecasts result in a reduced requirement for new generation or transmission infrastructure to meet electricity demand. Given this, the NTNDP's short-term focus is on facilitating an efficient network investment response to the oversupply of generation capacity and, on the transmission side, the effective use of existing networks; including decisions around replacing network assets as they approach the end of their useful life. Asset replacement decisions are affected by network planning standards, which are moving from a focus on meeting a specific reliability standard that incorporates a capacity redundancy requirement, towards an economic planning approach that balances costs against the value of supply.

1.1 NTNDP modelling

This section provides information about the modelling approaches used in the 2013 NTNDP.

To develop an efficient national electricity network development outlook, the 2013 NTNDP builds on the existing power system and committed generation and transmission developments. It models a least-cost expansion of large-scale generation and the main transmission grid in the NEM over a 25-year period.

NTNDP modelling uses the latest set of electricity consumption and generation cost assumptions published by AEMO for a medium-growth scenario. It models current renewable energy policy and two carbon price trajectories:

- A **carbon price scenario** that reflects the current legislation, and a lower expectation of carbon prices from linking to international emissions trading schemes (Figure 5). This scenario is a revision of the Australian Treasury core projection used in the 2012 NTNDP.
- A **zero carbon price scenario** where the explicit price on carbon emissions is removed from 2014 onwards. This scenario models generation dispatch without an explicit carbon emissions price, recognising the Federal Government's intention to repeal current legislation. It does not model alternative ways of achieving carbon emissions reductions, such as the Federal Government's Direct Action plan.

Both scenarios model large scale renewable energy target at the current level.

AEMO has published a detailed description of the modelling methodology and the assumptions used in the NTNDP. The 2013 Planning Assumptions webpage⁷ includes consistent input data and assumptions to enable the modelling of five scenarios.⁸ The 2013 NTNDP modelling uses the input assumptions listed under the planning scenario.

⁶ AEMO. 2013 National Electricity Forecasting Report. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Viewed 4 December 2013.

⁷ AEMO. 2013 Planning Assumptions. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>. Viewed 4 December 2013.

⁸ AEMO. 2012 Scenarios Descriptions (final report). Available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/~media/Files/Other/planning/2012_Scenarios_Descriptions.ashx. Viewed 4 December 2013.

1.2 Changes since the 2012 NTNDP

This section provides information on changes made since the 2012 NTNDP.

The 2013 NTNDP considers lower projected electricity consumption growth than forecast in 2012 (Figure 4). Details of these changes were published in AEMO's 2013 NEFR, which identifies factors such as:

- Continued increases in domestic rooftop PV installations incentivised through feed-in tariffs and reduced system installation prices.
- Lower-than-expected growth in most industrial sectors.
- Higher estimated energy efficiency savings from measures implemented in changes to building standards and regulations.
- A higher estimate of customer response to extreme price events based on analysis of historical demand-side participation behaviour.⁹

AEMO estimated that 774 MW of rooftop PV generation capacity was installed in the NEM in 2012–13.¹⁰ Rooftop PV generation is treated as a demand offset contributing to the reduction in forecast demand.

The average annual growth rate for the 2013 NEFR medium scenario is 1.3% over a 10-year outlook period, compared to 1.5% in the 2012 NEFR.

AEMO has observed that actual electricity consumption in the first quarter of 2013–14 (from 1 July to 30 September 2013) was 3.5% below that forecast for that period. AEMO published an update to the 2013 NEFR in November 2013¹¹ revising the 2013–14 NEM electricity consumption forecasts by -1.3%. AEMO will continue to monitor forecast electricity consumption against actual electricity consumption.

The 2013 NTNDP also considers generation and transmission developments committed since the 2012 NTNDP.

Other key modelling inputs and assumptions, including generation costs and technical parameters, remain the same as those used in the 2012 NTNDP. The carbon price scenarios used in the 2013 NTNDP are outlined in Section 1.1.

⁹ The DSP forecast provided in the 2013 NEFR Methodology Information Paper is based on improved modelling and understanding of demand-side participation at various price levels and its expected growth over the outlook period. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013/NEFR-Supplementary-Information-2013>. Viewed 4 December 2013.

¹⁰ AEMO. Rooftop PV Information Paper Worksheets. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013/-/media/Files/Other/planning/NEFR/2013/2013%20NEFR%20Rooftop%20PV.ashx>. Viewed 4 December 2013.

¹¹ AEMO. Update: National Electricity Forecasting Report November 2013. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Viewed 4 December 2013.



Figure 4 — 2013 NEFR annual energy NEM forecast

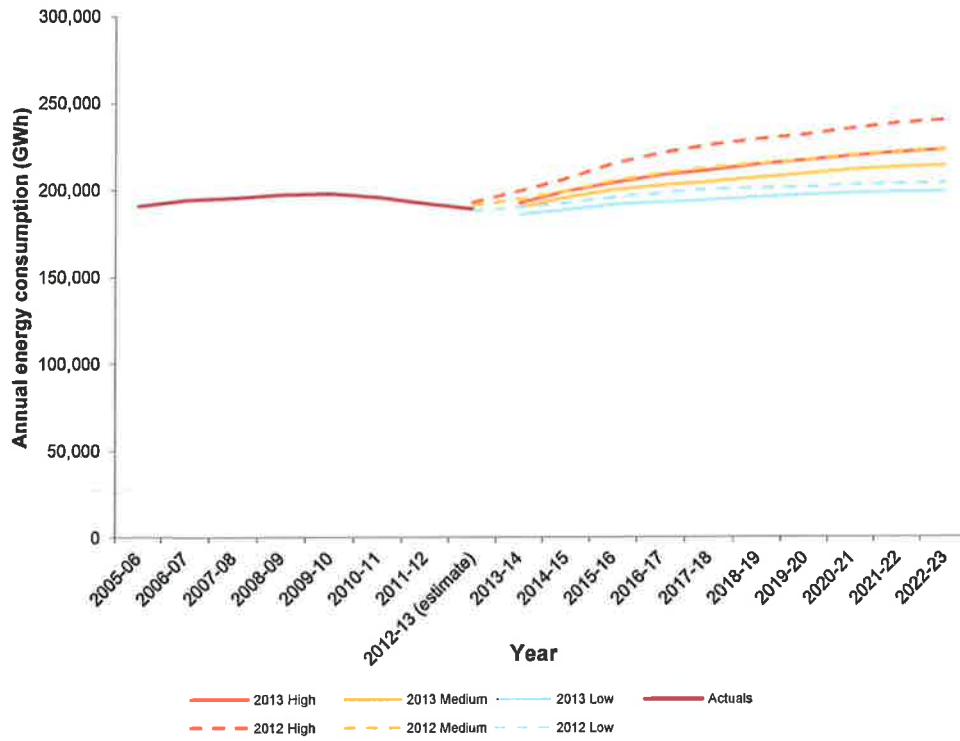
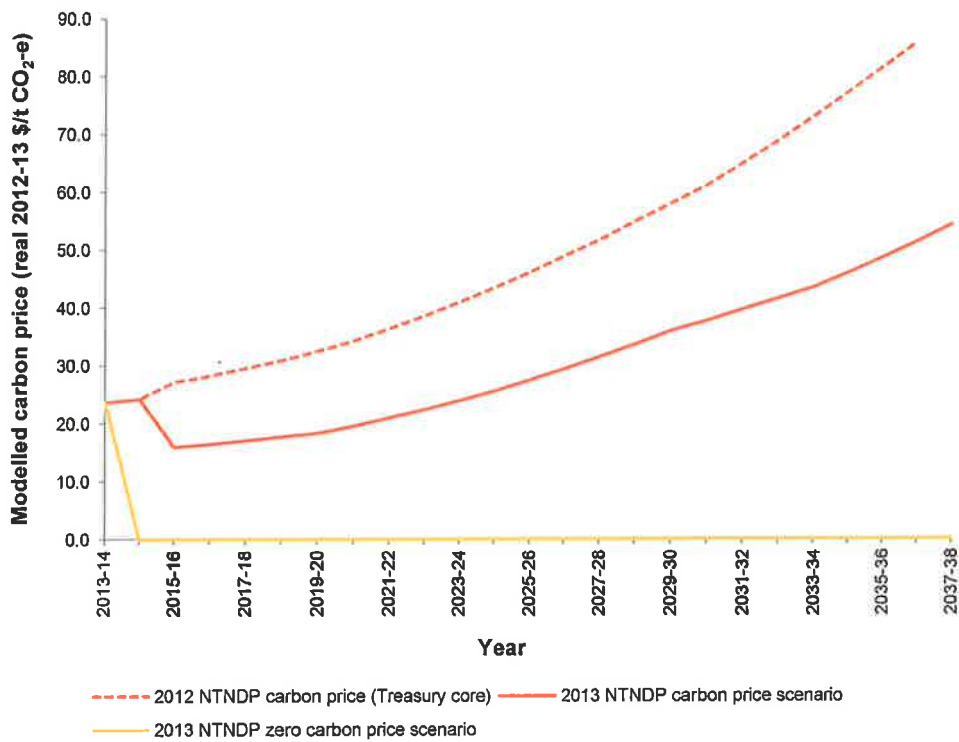


Figure 5 — Comparison of carbon price trajectories modelled in the 2012 and 2013 NTNDPs



1.3 The NTNDP in the energy planning context

The NTNDP is part of a suite of key planning publications that AEMO produces annually. Other publications include the National Electricity Forecast Report (NEFR), Electricity Statement of Opportunities (ESOO), and Gas Statement of Opportunities (GSOO). The NEFR provides annual electricity consumption and maximum demand forecasts and the ESOO and GSOO investigate supply-side reliability and provide information about energy resources affecting eastern and south-eastern Australia.

There are strong data and modelling links between these reports. For example, the NTNDP is informed by resource information contained in the GSOO, and the GSOO is informed by the projections of gas-powered generation (GPG) developed in the NTNDP.

Together with these planning publications, the NTNDP aims to provide the energy industry with a comprehensive body of information to assist network planners, policy-makers and investors.

1.4 Content and structure of the 2013 NTNDP

Chapter 2 provides an outlook of short- to medium-term (to 2020) and longer-term (2020 to 2038) developments.

Chapter 3 endorses a focus on transmission asset replacement decisions.

Chapter 4 outlines initiatives that AEMO is progressing to more effectively support efficient decision-making in transmission planning.

Chapter 5 provides links to related documents.

Appendix A provides a detailed list of network limitations identified in the NTNDP and those reported in annual planning reports.

Appendix B reports the findings from the Network Support and Control Ancillary Services (NSCAS) assessment.

Appendix C provides a scope for a medium-term network outlook, which AEMO will develop by mid-2014.

1.5 Where to find more information

In addition to the NTNDP report, AEMO's website includes the following additional information:

- The NTNDP database comprising a comprehensive set of input data to enable stakeholders to undertake their own modelling.
- Spreadsheets with detailed modelling results and graphs.
- A consolidated assessment of how the main transmission projects in transmission network service provider (TNSP) Annual Planning Reports relate to limitations observed in the 2013 NTNDP.

CHAPTER 2 - THE NATIONAL OUTLOOK

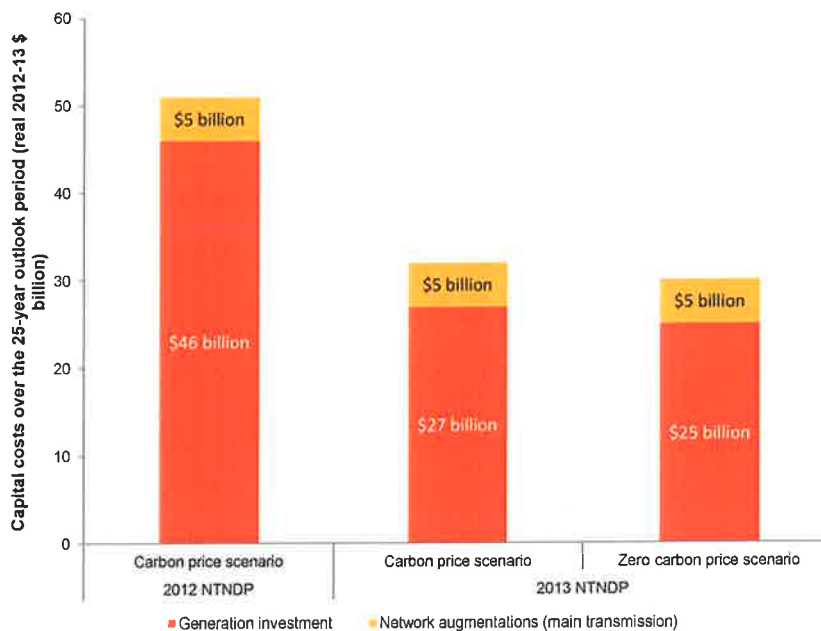
2.1 Capital investment summary

The need for new large-scale generation investment in the National Electricity Market (NEM) has reduced due to lower growth in energy consumption, rising rooftop PV generation, and increasing consumer response to recent electricity prices.

Based on NTNDP modelling, projected capital investment in large-scale generation over the next 25 years has fallen from \$46 billion in 2012, to \$27 billion in 2013. Investment needs for additional main transmission capacity remain as projected in 2012, at \$5 billion over the 25-year modelling horizon.

Figure 6 compares capital costs between the 2012 and 2013 NTNDP results.

Figure 6 — Scenario capital cost comparison to 2037–38



2.2 The short- to medium-term outlook to 2020

The period to 2020 is characterised by an increase in new renewable generation, withdrawal of existing baseload capacity, and a need to focus on improved utilisation of the existing transmission network.

The key drivers over this timeframe are:

- The Large-scale Renewable Energy Target (LRET), which incentivises renewable investment.
- Low projected consumption growth, reducing the need for additional supply sources.
- The combination of both factors, leading to the changed operation, dry storage, or retirement of some existing baseload generation.

Generation outlook

Figure 7 and Figure 8 show capacity additions and reductions by technology under the carbon price and zero carbon price scenarios. Figure 9 and Figure 10 show energy generated by technology under the same scenarios.

These charts provide insights into both the investment and output of future generation. In particular, the charts highlight that:

- Renewable generation investment dominates the new generation mix in the short- to medium-term, with over 10,000 MW of new wind, solar, and biomass generation installed by 2020–21. Wind represents 84% of this investment, with large-scale solar PV and biomass representing 13% and 3% respectively.
- Renewable investment is driven by LRET policy incentives, and remains largely consistent between the carbon price and zero carbon price scenarios, which assume the same renewable energy target.
- Under the carbon price scenario, NTNDP modelling indicates almost 3,700 MW (approximately 14%) of existing black and brown coal-fired generation by 2020 is retired or placed into dry storage. Under a zero carbon price scenario, this reduces to 3,100 MW (approximately 12%)—as the model relies less on gas-powered generation (GPG), and more heavily on existing coal generation to meet energy needs.
- Under a carbon price scenario, there are considerable levels of both black and brown coal retirement. This is in contrast to the zero carbon price scenario, in which the lower operating costs of brown coal generation results in a shift towards the retirement of black coal generation.
- Baseload GPG output reduces in the short-term under both carbon price scenarios, driven by gas price assumptions that reach \$12/GJ by 2025.¹²
- Combined black and brown coal-fired generation remains stable in the short term. Under the carbon price scenario, reduced brown coal-fired generation is balanced by increased output from existing black coal-fired generation. Coal remains the dominant generation fuel to 2020, and accounts for more than half of the energy produced under both carbon price scenarios.

The renewable generation investment identified above includes a number of newly commissioned and committed wind generation projects, including:

- Gullen Range (166 MW), Boco Rock (113 MW) and Taralga (107 MW) wind farms in New South Wales.
- Mt Mercer (131 MW) wind farm in Victoria.
- Snowtown 2 North (144 MW) and Snowtown 2 South (125 MW) wind farms in South Australia.
- Musselroe (168 MW) wind farm in Tasmania.

With the addition of 8,700 MW of new wind generation by 2020–21, the NEM will have an installed wind capacity of over 11,000 MW. AEMO is currently aware of close to 15,800 MW of proposed wind generation projects.

¹² Scenario 3, Sensitivity 4 in ACIL Tasman, 2012, Fuel cost projections: Updated Natural gas and coal outlooks for AEMO modelling. Available at: <http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>. Viewed 4 December 2013.



Figure 7 — Generation capacity additions and reductions in the carbon price scenario

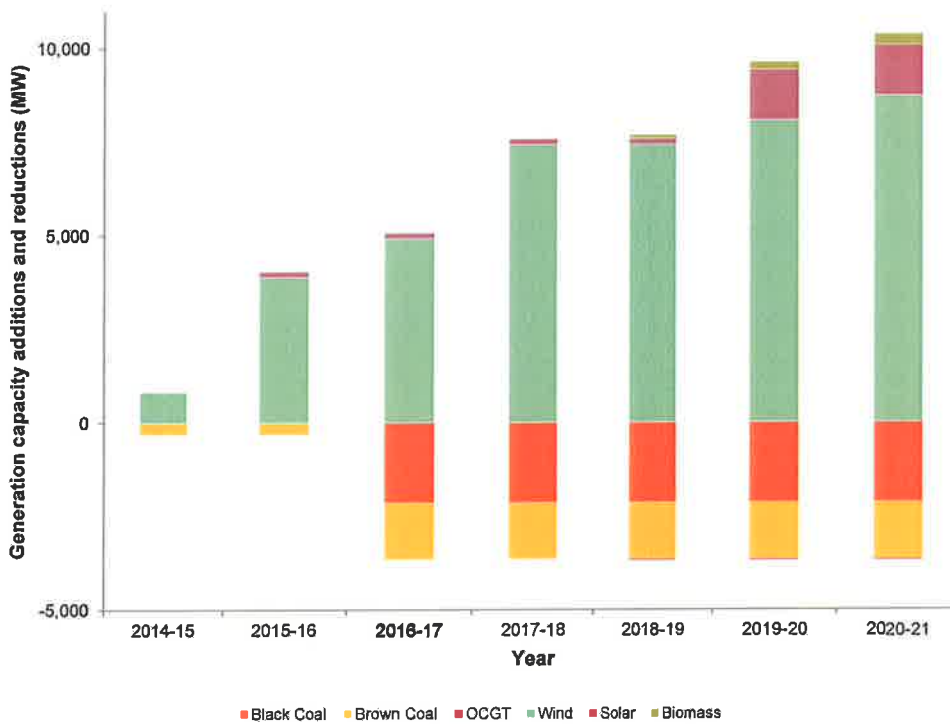


Figure 8 — Generation capacity additions and reductions in the zero carbon price scenario

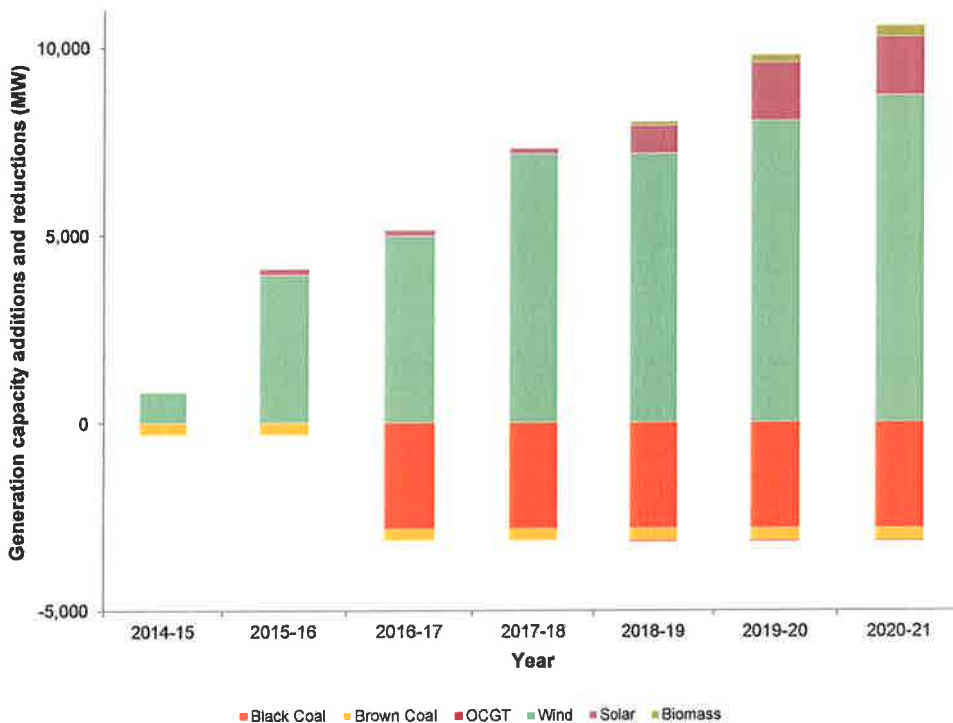


Figure 9 — Total NEM generated energy by technology under the carbon price scenario

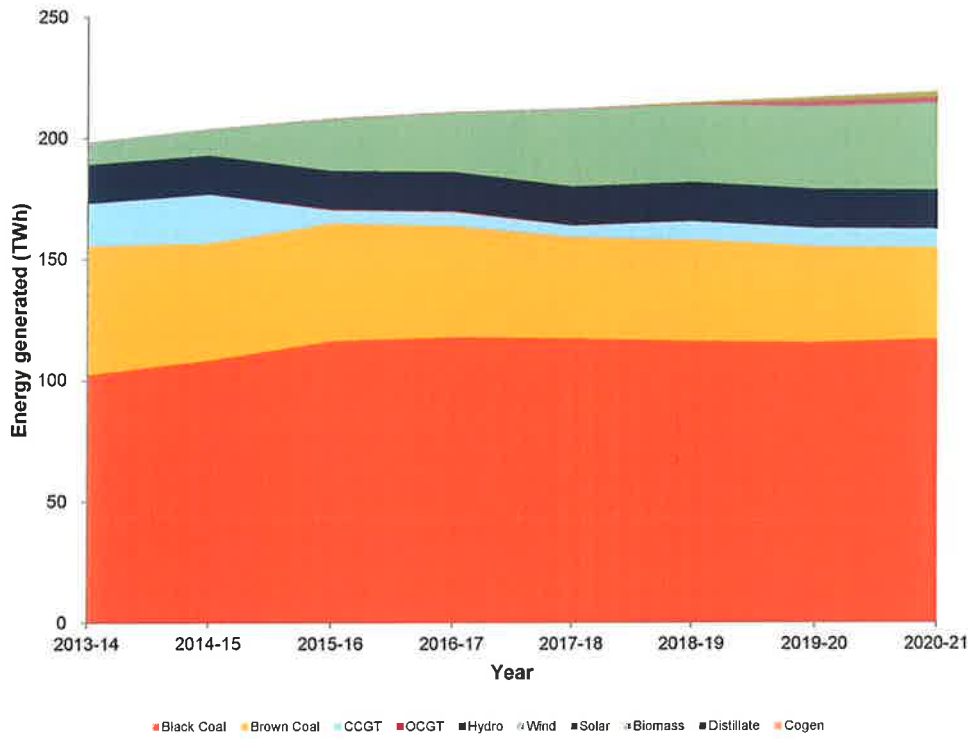
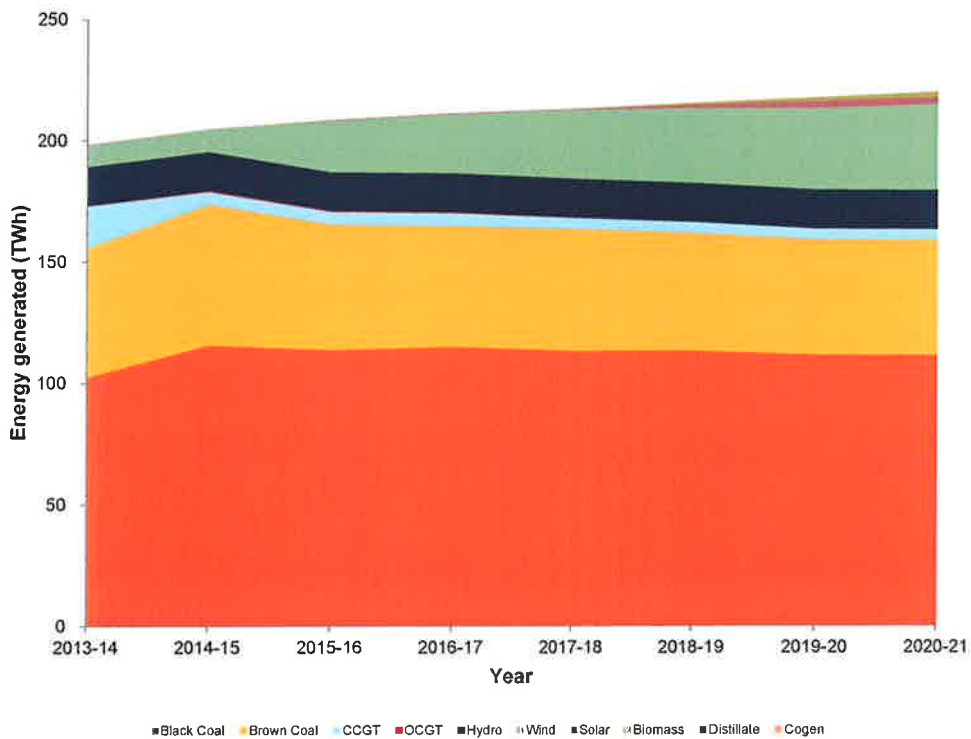


Figure 10 — Total NEM generated energy by technology under the zero carbon price scenario





Transmission development outlook

The NTNDP's transmission development analysis focuses on assessing the adequacy of the main transmission network to reliably support major power transfers between NEM generation and demand centres (referred to as NTNDP zones).

AEMO also conducts an analysis of the needs for Network Support and Control Ancillary Services (NSCAS) over a five-year horizon. NSCAS are ancillary services procured by transmission network service providers (TNSPs) (or AEMO as a last resort) to maintain power system security and reliability, or to increase the power transfer capabilities of the transmission network.

Key observations are:

- Compared to the 2012 NTNDP, the reduced growth in electricity consumption results in reduced network limitations in all regions, with the exception of Queensland where the electricity consumption forecast has increased.
- The NTNDP modelling does not identify a requirement for major investment in inter-regional augmentations following the completion of the Victoria – South Australia augmentation.¹³
- The limitations on the main transmission network are the same under both carbon price scenarios and have an estimated capital cost of around \$3.5 billion.
- AEMO has not identified a need for further NSCAS beyond the New South Wales requirements that are currently being addressed by AEMO under contract.¹⁴

Figure 11 shows the location of identified network limitations on the main transmission network. These include both TNSP committed projects and reliability-driven network limitations identified through NTNDP modelling. Each limitation is identified by a reference code. These limitations are listed in the legend, with further details provided in Appendix A.

Consumption growth in each NTNDP zone is largely met by new generation in the same zone. This reflects the least-cost modelling approach, which locates new generation to minimise overall generation and transmission costs. If future generation development differs from the projected investment patterns, other network limitations may arise and would need to be addressed.

Figure 12 provides limitations on the main transmission network identified by TNSPs in their 2013 Transmission Annual Planning Reports (APRs).¹⁵

Increases in renewable generation can create operational and power system security challenges. AEMO published the Integrating Renewable Energy—Wind Integration Studies Report in September 2013¹⁶, outlining power system security issues and recommending short-term actions to support the integration of forecast wind generation.


Connecting wind generation to the power system is expected to contribute to network congestion, particularly at times of high wind generation output, which affects economic generation dispatch. The NTNDP identifies the location of potential network congestion that may arise if new generation development occurs in line with the least-cost modelling.

¹³ AEMO and ElectraNet. South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T. Available at: <http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T>. Viewed 4 December 2013.

¹⁴ See Appendix B for the results of the NSCAS analysis.

¹⁵ Appendix A provides further information about these limitations; a more complete list of TNSP APR projects can be found on the 2013 NTNDP page of AEMO's website.

¹⁶ AEMO. Integrating Renewable Energy — Wind Integration Studies Report 2013. Available at: <http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy>. Viewed 4 December 2013.



Economic dispatch limitations arise because network capability places a limit on the amount of generation that can be dispatched in a particular location, leading to the potential dispatch of more expensive plant ahead of less expensive plant. The difference between these limitations and the emerging reliability limitations identified in Figure 11 is that the economic dispatch limitations do not lead to loss of supply as there is sufficient network capacity to meet forecast consumption levels.

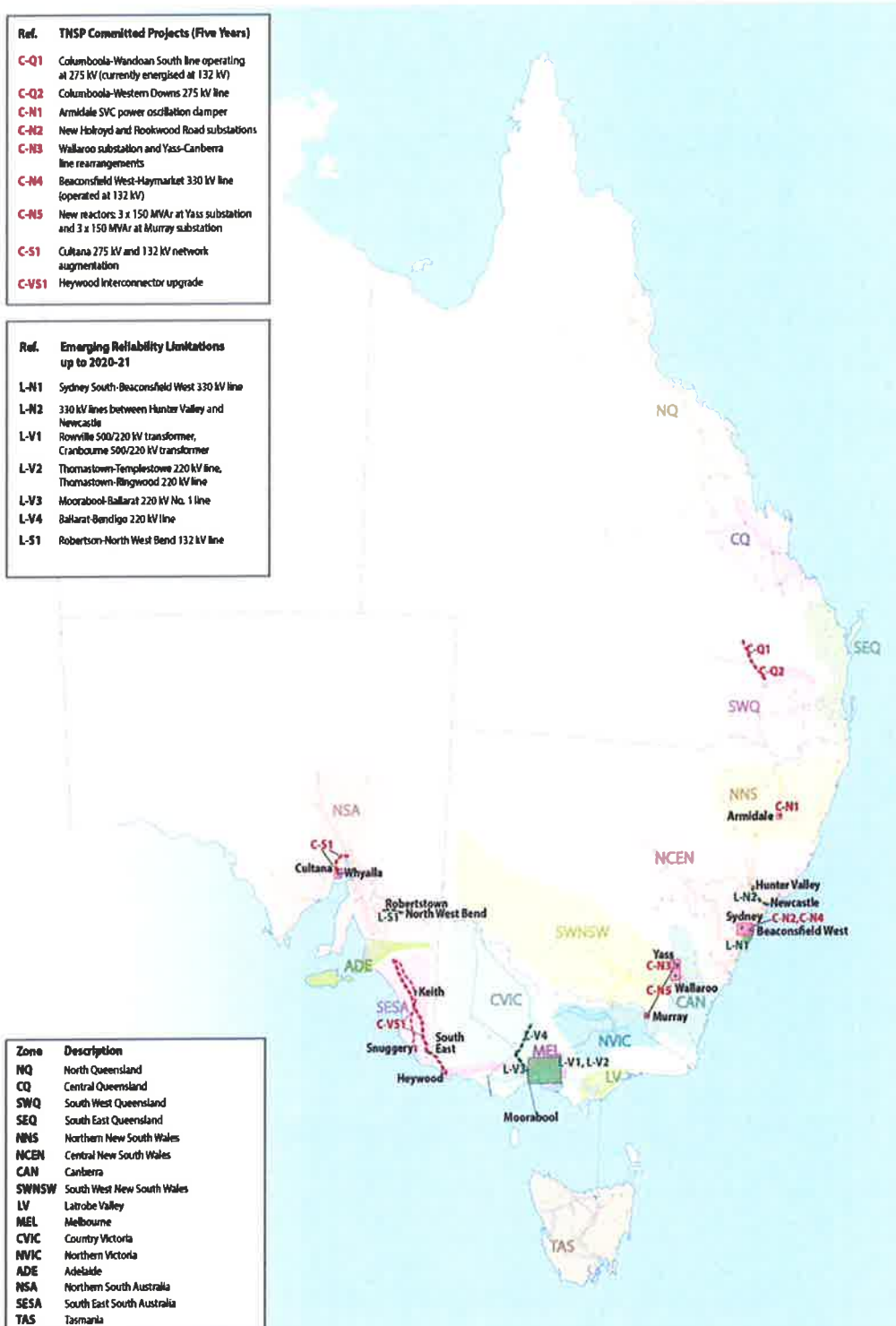
Figure 13 shows the location of new generation to 2020, together with potential economic dispatch limitations. To justify network augmentation, the magnitude and market impact of this, and other, modelled network congestion will need to be considered against the costs of augmentation using an economic cost-benefit framework closer to the time of generation connections.

The Optional Firm Access (OFA) model, if implemented, would also target these areas of congestion by allowing generators to purchase firm access to the transmission network, and may drive new network investment. OFA is an Australian Energy Market Commission (AEMC) proposal as part of its Transmission Frameworks Review to improve market efficiency by providing transmission network access certainty for generators.¹⁷

¹⁷ AEMC, *Transmission Frameworks Review — Final Report*. Available at: <http://www.aemc.gov.au/market-reviews/completed/transmission-frameworks-review.html>. Viewed 4 December 2013.

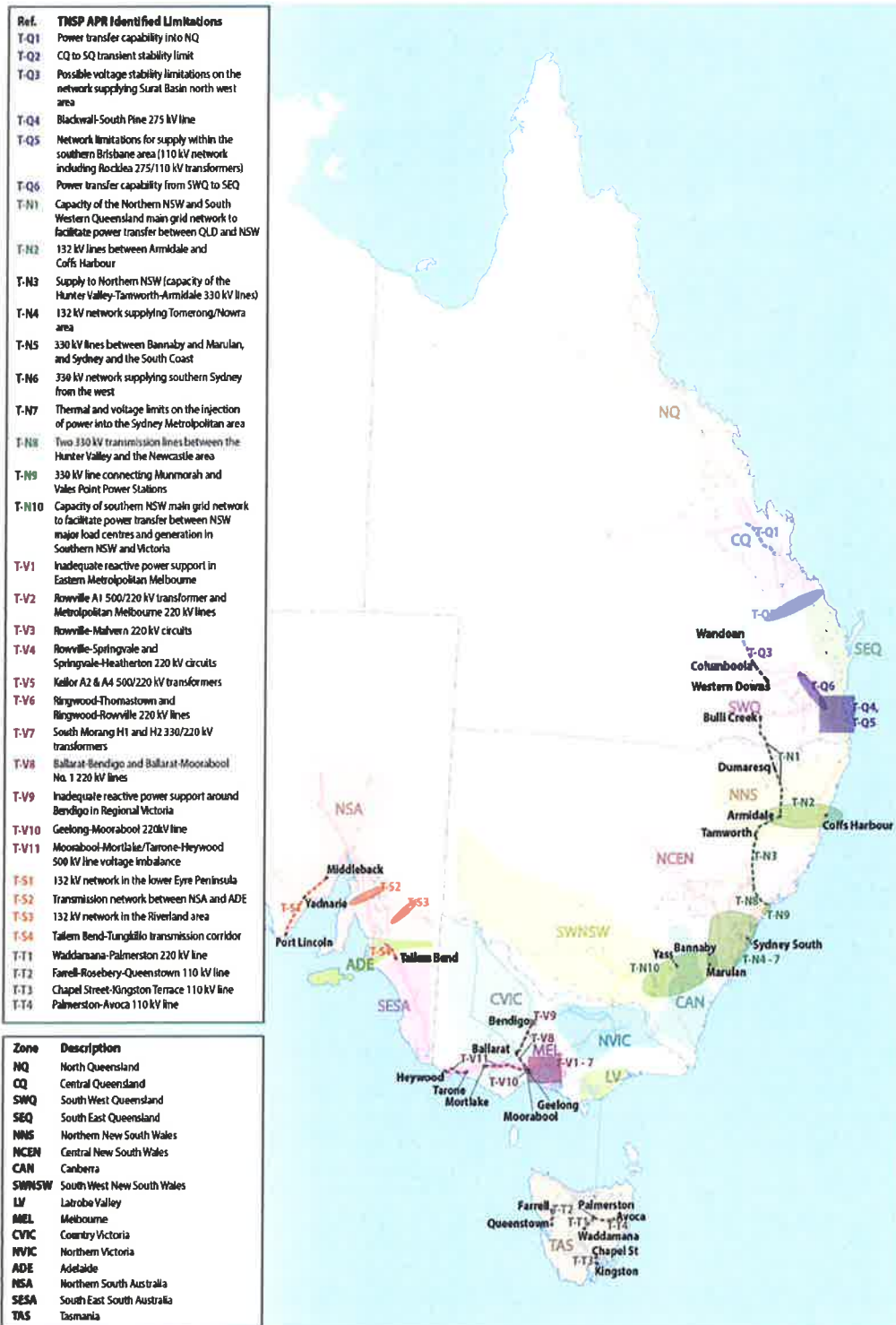


Figure 11 — NTNDP network limitations on the main transmission network by 2020–21¹⁸



¹⁸ Appendix A provides further information about these limitations.

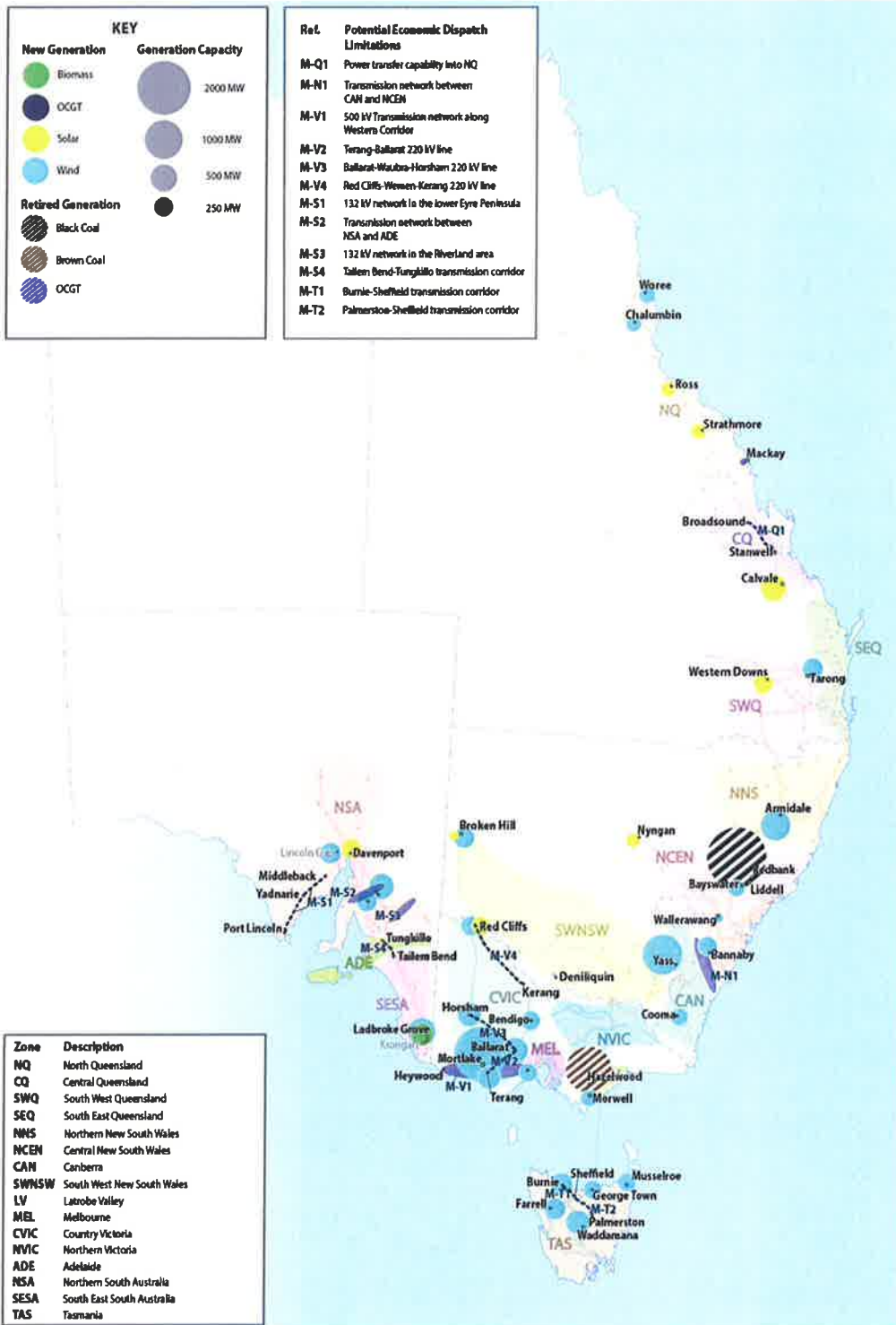
Figure 12 — APN identified limitations on the main transmission network¹⁹



¹⁹ Appendix A provides further information about these limitations.



Figure 13 — New generation by 2020–21 and potential economic dispatch limitations²⁰



²⁰ Appendix A provides further information about these limitations.

2.3 The longer-term outlook from 2020 to 2038

The LRET target reaches its cap in 2020 and no further investment is required to meet demand growth until around 2025. Peaking GPG capacity then becomes an economic way to meet demand growth to the end of the study horizon in 2037–38.

The key driver over this timeframe is continued consumption growth, which eases current oversupply conditions, and drives the need for additional peaking capacity toward 2025.

The carbon pricing assumptions combined with the gas-price assumptions are not sufficient to incentivise a transition from coal- to gas-powered generation within the 25-year study horizon.

Generation outlook

Figure 14 and Figure 15 show capacity additions and reductions by technology under the carbon price and zero carbon price scenarios respectively. Figure 16 shows the geographical location of these capacity additions and reductions by 2037–38 under the carbon price scenario. Figure 17 and Figure 18 show energy generated by technology.

These charts provide insights into both the investment and output of future generation. In particular, the charts highlight that:

- No new wind or solar investment occurs between the LRET cap in 2020 and the end of the study horizon under either carbon price scenario. This differs from the 2012 NTNDP results which showed large-scale renewable energy generation becoming economic toward the end of the 25-year outlook period under a higher carbon price and higher electricity consumption projections.
- Peaking generation, in the form of open cycle gas turbines (OCGTs), emerges to meet peak demand growth from around 2025.
- Under the carbon price scenario, 700 MW of biomass investment occurs between 2030 and 2038 to add to the 300 MW installed by 2020. The zero carbon price scenario results in about 330 MW of new biomass generation capacity.
- Under both carbon price scenarios, 2013 NTNDP modelling indicates reduced brown coal generation capacity in around 2030, delivering a total reduction of coal-fired generation by 2038 of 4,200 MW under the carbon price scenario and 3,700 MW under the zero carbon price scenario.
- Consumption growth beyond 2020 is largely met by increased output from existing coal generation, which continues to dominate over the 25-year outlook period.
- GPG output remains largely constant across the horizon under both carbon price scenarios, representing a reduction in output compared with the 2012 NTNDP. This is largely driven by the reduced demand and carbon pricing assumptions used in the 2013 NTNDP.
- Geothermal generation, which the 2012 NTNDP modelled as coming online towards the end of the 25-year outlook period, is now beyond 2037–38.



Figure 14 — Generation capacity additions and reductions in the carbon price scenario

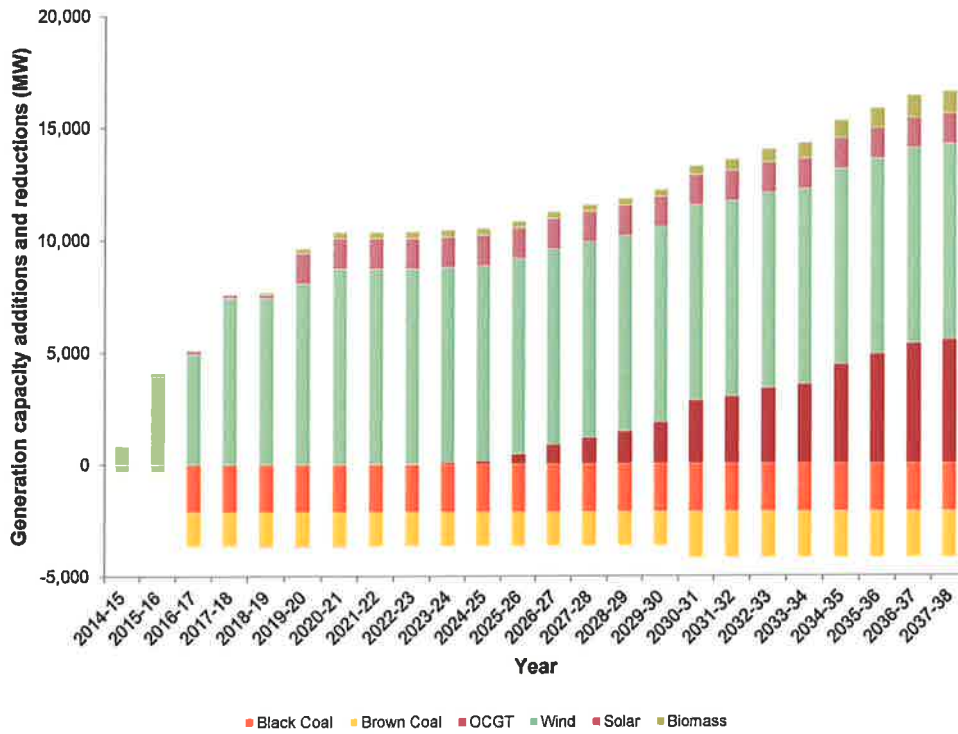


Figure 15 — Generation capacity additions and reductions in the zero carbon price scenario

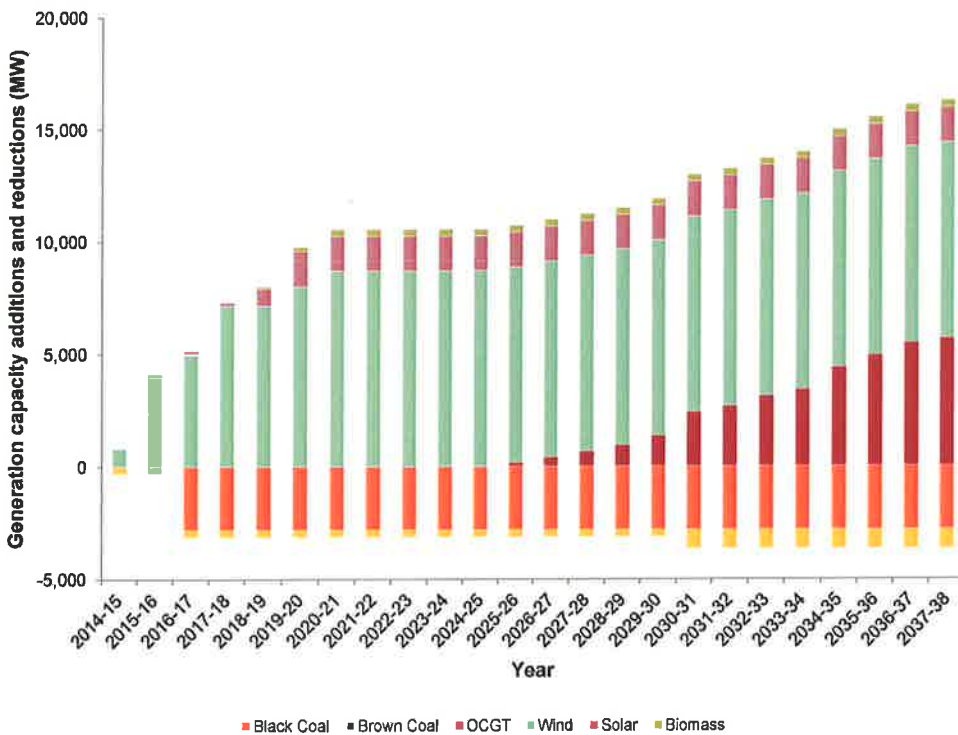


Figure 16 — New generation development in the NEM by 2037–38 in the carbon price scenario

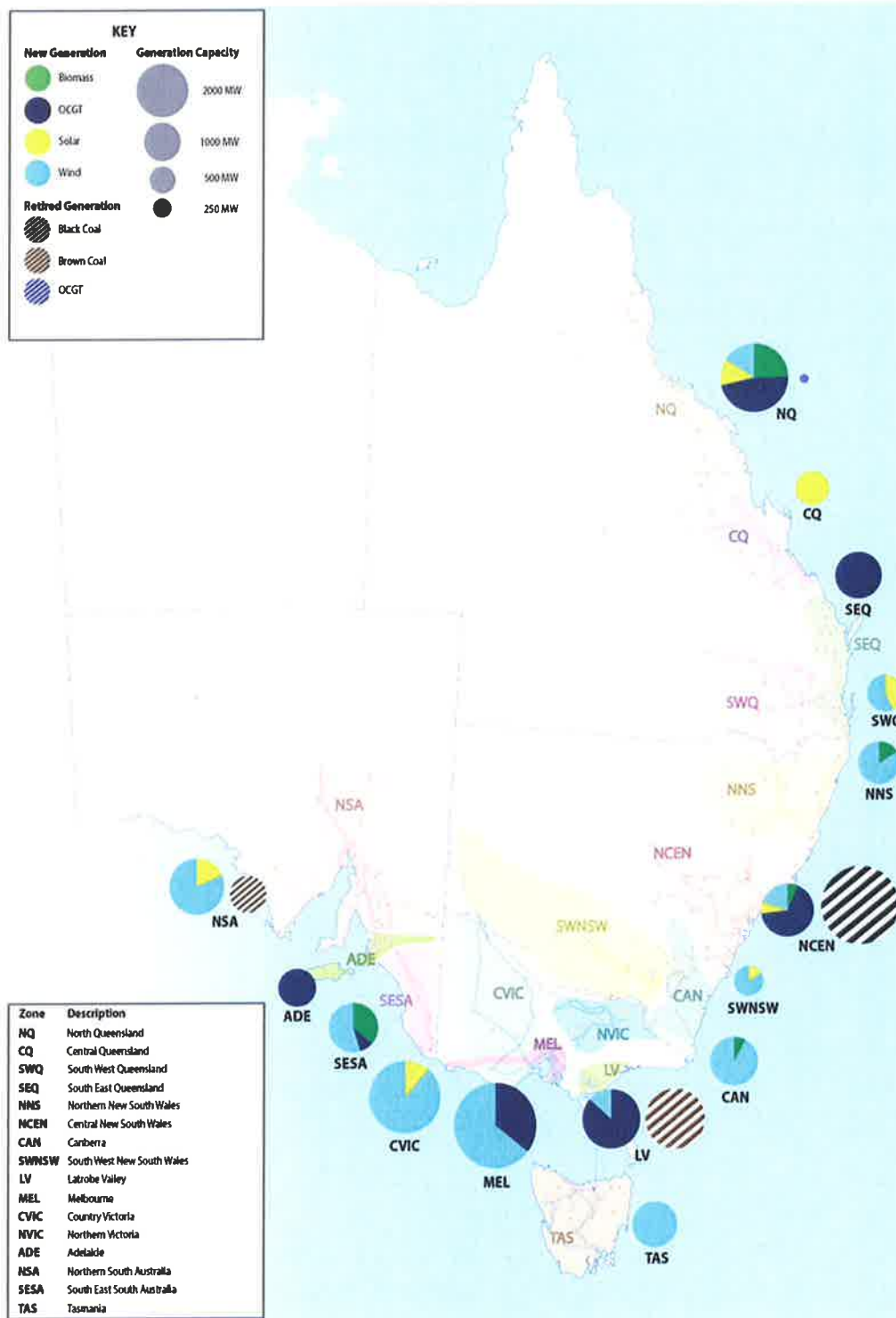




Figure 17 — Total NEM generated energy by technology in the carbon price scenario

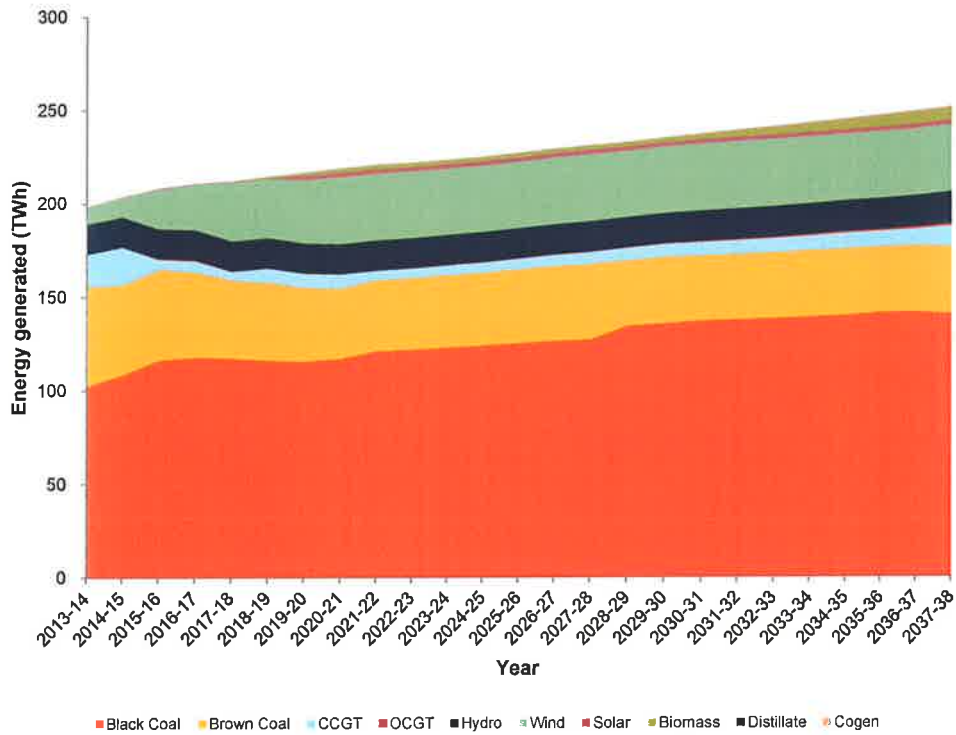
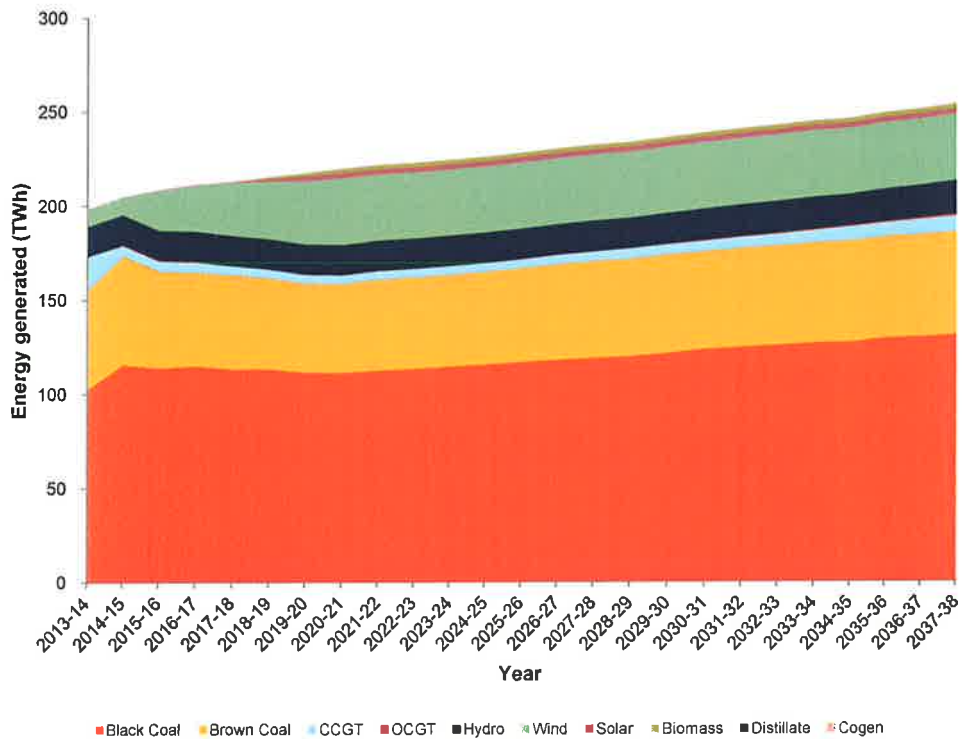


Figure 18 — Total NEM generated energy by technology in the zero carbon price scenario



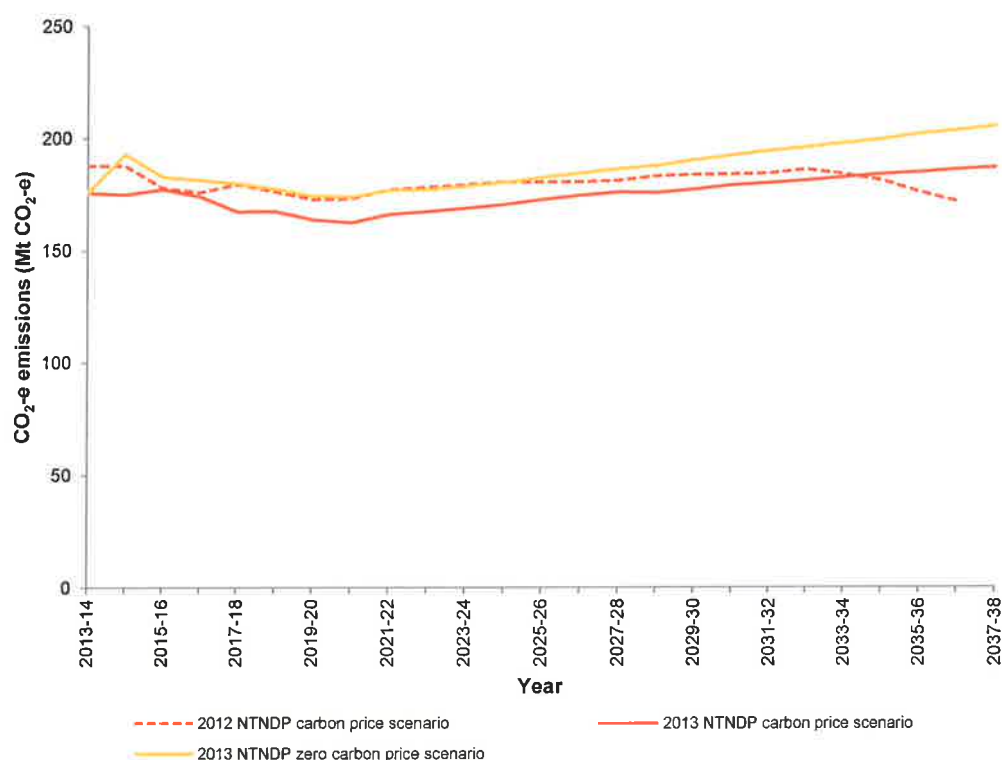
Carbon dioxide-equivalent emissions

Figure 19 shows the total carbon dioxide-equivalent (CO₂-e) emissions in the NEM under both the carbon price and zero carbon price scenarios, and compares these with the 2012 NTNDP.

This chart highlights that:

- The carbon price scenario results in approximately 9% lower total annual emissions by the end of the 25-year outlook period (187 Mt compared with 205 Mt in the zero carbon price scenario).²¹
- Under both carbon price scenarios, the total emissions decrease during the period of LRET-driven renewable investment to 2020, before trending upwards as demand grows with only limited further investment in renewables.
- The 2012 NTNDP carbon price scenario resulted in lower total emissions than either 2013 scenario, despite having a higher consumption projection. This is due to the 2012 NTNDP's assumption of a higher carbon price trajectory, which reduces the output of higher carbon-emitting plant, and the effect of new geothermal generation from 2033, which is no longer identified in the 2013 NTNDP modelling.
- The initial rise in emissions under the zero carbon price scenario is due to the removal of the carbon price. This is followed by a decline as new renewable investment enters the market from 2015–16.

Figure 19 — CO₂-e emissions under the carbon price and zero carbon price scenarios, compared with the 2012 NTNDP carbon price scenario



²¹ The reductions are for NEM carbon dioxide-equivalent emissions from NEM generation. The modelling does not calculate the effect of the carbon price on other parts of the economy or imports of international abatement certificates.



Transmission development outlook

Figure 20 presents NTNDP network limitations on the main transmission network by 2037–38. The same limitations were identified under both the carbon price and zero carbon price scenarios.

Limitations identified include emerging reliability limitations and potential economic dispatch limitations. Both types of limitation arise because the network capability limits the ability of power transfers on specific parts of the network.

The distinction between the two types of limitation is that the potential economic dispatch limitations do not give rise to a loss of supply. Although more expensive generation plant may be dispatched ahead of less expensive plant, network capability is sufficient to meet forecast consumption levels. Potential economic dispatch limitations have been identified mainly at times of high wind generation output.

Emerging reliability limitations are those that lead to a loss of supply that cannot be resolved by rescheduling generation.

Appendix A contains further information about each of the identified limitations.

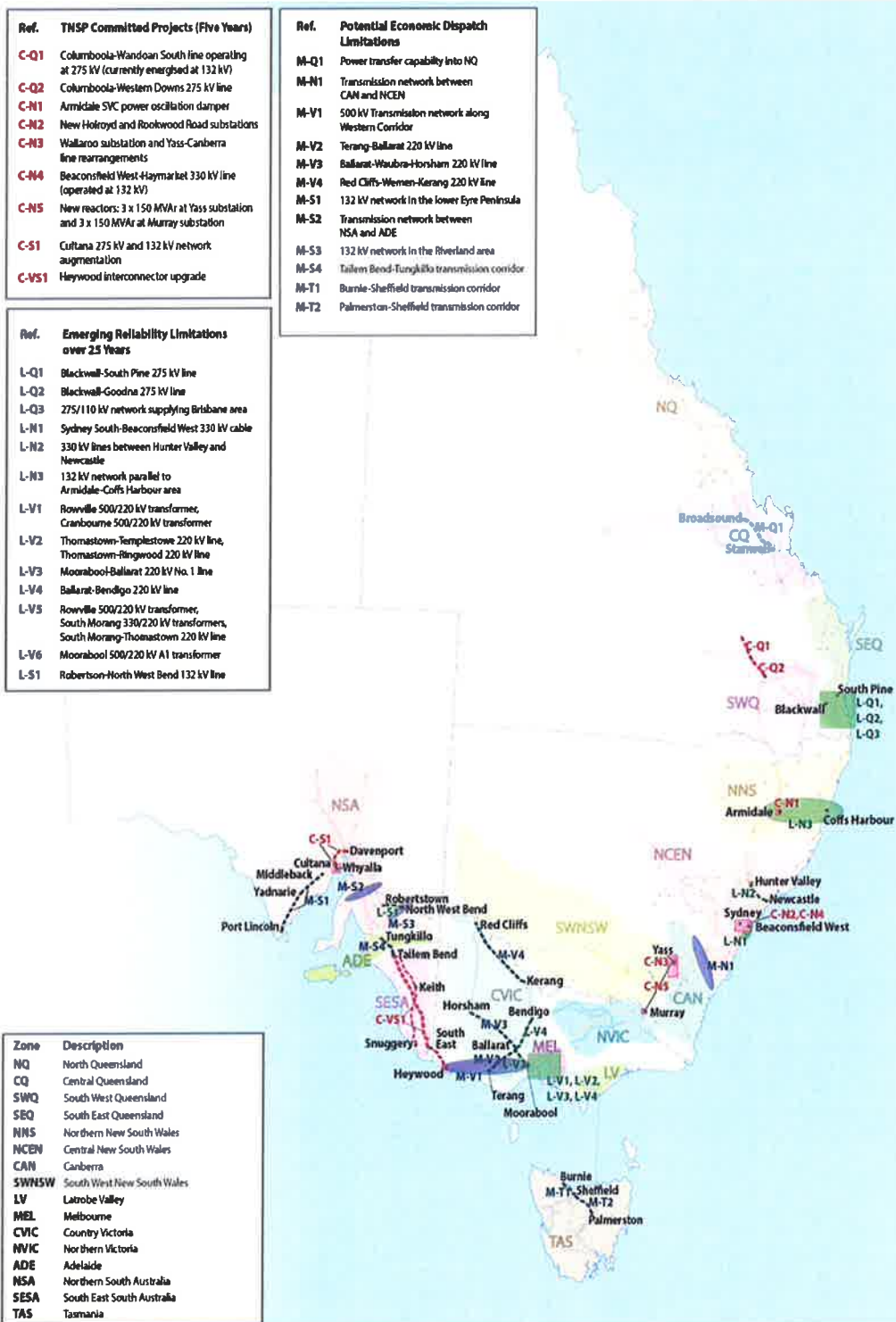
Main transmission augmentation costs

The 2013 NTNDP estimates total new transmission asset investment to be \$5 billion under both carbon price scenarios. This includes investment in upgrading the main transmission network capacity, and connecting new generation to the nearest transmission connection point (assuming standard connection configurations). It does not include works to address localised needs associated with new generation connections.

Further transmission investment will also be required to replace ageing assets, and to address local transmission requirements driven by local demand growth. As indicated in Chapter 3, investment in network augmentation is likely to be small relative to the required investment in transmission asset replacement over the 25-year outlook period.

Transmission asset utilisation will also decrease where there are localised reductions in electricity consumption or generation retirements remote from population centres. As transmission assets approach the end of their useful life, there is an opportunity to review and optimise the required network capacity given changes in demand outlooks and planning standards. This is further discussed in Chapter 3.

Figure 20 — NTNDP network limitations on the main transmission network by 2037–38²²



²² Appendix A provides further information about these limitations.



CHAPTER 3 - THE CHANGING NATURE OF PLANNING

3.1 A new paradigm for transmission planning

Until 2010–11, electricity demand had been steadily increasing since the establishment of large-scale power systems in the NEM. The primary problem for transmission planners was to determine the most cost-effective way to increase power system capability to meet peak demand growth.

Over the last three years, however, electricity demand has been reducing and an update to AEMO's National Electricity Forecasting Report (NEFR) forecast indicates a further decline for 2013–14.²³

Over this period, network utilisation has also declined.

Network prices will increase if electricity consumption continues to decline. This is because network pricing is based on recovering the network asset value over the (declining) energy base, rather than on the service delivered by the network.

Current projected consumption growth in most regions is below historical averages. In this new paradigm it is important to avoid over-investment in the network, and to not overlook opportunities to reduce the cost of maintaining the transmission network at an appropriate level of reliability. Under these conditions, the following considerations become increasingly important:

- **Greater transparency of transmission asset replacements:** Expenditure in asset replacement will now dominate over network augmentations and there will need to be greater transparency in justifying replacements.
- **Adopting economic reliability standards:** An economic form of reliability standards weighs up the costs of investment in network reliability against the economic benefits of achieving the level of reliability. With low consumption growth, if new network assets are added early, they will result in an extended period of low utilisation. It is even more important in this environment that the timing and size of investments are economically justified. This also applies to asset replacement decisions.
- **Considering non-network solutions:** Solutions such as generation or demand management, in place of conventional network augmentations, also become more important when consumption growth is low. This is because non-network solutions can provide the required service over a longer period in these conditions than under a higher consumption growth trend.

This chapter describes these three considerations in further detail.

3.2 Transmission network utilisation

An analysis of the historical loadings of transmission lines shows a downward trend for the average utilisation (the power flow divided by the line rating) of the transmission network. Figure 21 shows the average utilisation of transmission lines over the last six years.

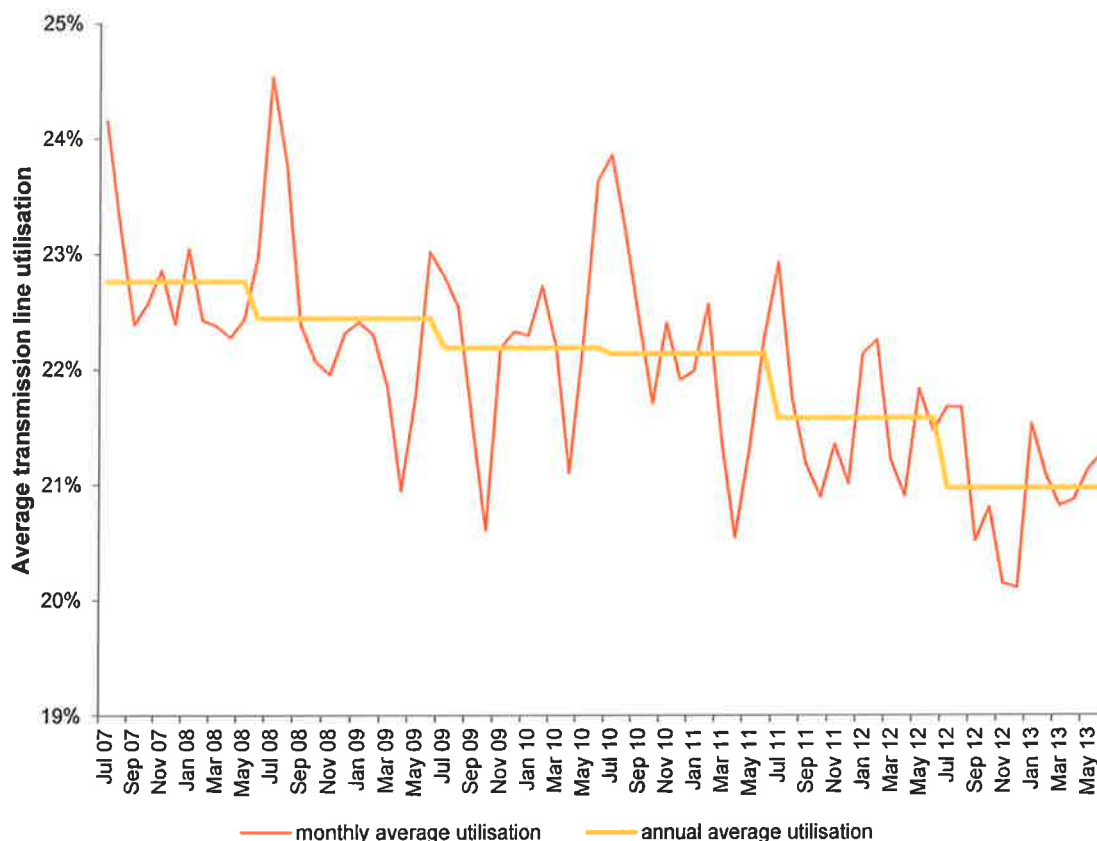
This chart was produced by extracting the historical power flow on around 270 transmission lines²⁴ from AEMO's operational energy management system (EMS) database, and dividing this by the line rating. The utilisation across all of these lines was averaged at monthly resolution to produce insights into overall utilisation trends.

²³ AEMO, Update: National Electricity Forecasting Report November 2013. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/~/_media/Files/Other/planning/2013%20NEFR%20Update_November%202013.pdf.ashx. Viewed 4 December 2013.

Being a sample of transmission lines, the trends are representative.

At a local level, utilisation of some transmission lines has increased while others have reduced. The overall situation presented in Figure 21 shows a general downward trend.

Figure 21— Average transmission line utilisation



Loading on the transmission network is affected by a number of factors including:

- The network configuration, including the number and capacity of transmission lines running in parallel.
- Electricity consumption.
- The location and operation of existing generation plant.
- The connection of new generation plant, its location, operation, and impact on existing generation.

AEMO's analysis indicates that the major factor over the last three years is reduced electricity consumption. The utilisation reductions in 2008–09 and 2009–10 are mainly caused by the connection of new generation near load centres and network augmentation.

²⁴ The sample covers all regions and represents approximately 60% of the transmission lines at 220 kV and above. The historical records were obtained at half-hourly resolution across the six years.



From a planning and investment perspective, the crucial factor is the loading on individual transmission elements and expectations about how this will change in the future. This also needs to take account of the loading on the lines under a single credible contingency (the unexpected outage of any system element). During a credible contingency, utilisation increases on other network elements as they pick up the loading from the element that is on outage.

While the analysis presented in this section is indicative only, it does show a trend of some parts of the transmission network becoming less utilised.

3.3 Transmission asset replacement

There are two major drivers for investment in new transmission assets:

- The need to replace assets that are at the end of their serviceable life.
- The need to augment the network to provide additional capability.

A common practice in network planning is to align these two drivers. For example, consider an area supplied by two transformers, both of which require replacement. Rather than replacing them with two new units of the same capacity, it may be prudent to replace them with higher capacity units to account for forecast demand growth in the area. To date, this approach has served the NEM well in a high-demand growth environment.

When demand growth projections are very low, however, the need to augment the network reduces and asset replacement becomes the main investment driver.

Current demand growth projections for most regions sit well below historical averages. This has led transmission network service providers (TNSPs) to delay, or cancel, a number of network augmentations that were under investigation or already committed. In comparison, the reduction in committed asset replacements has not been of the same magnitude.

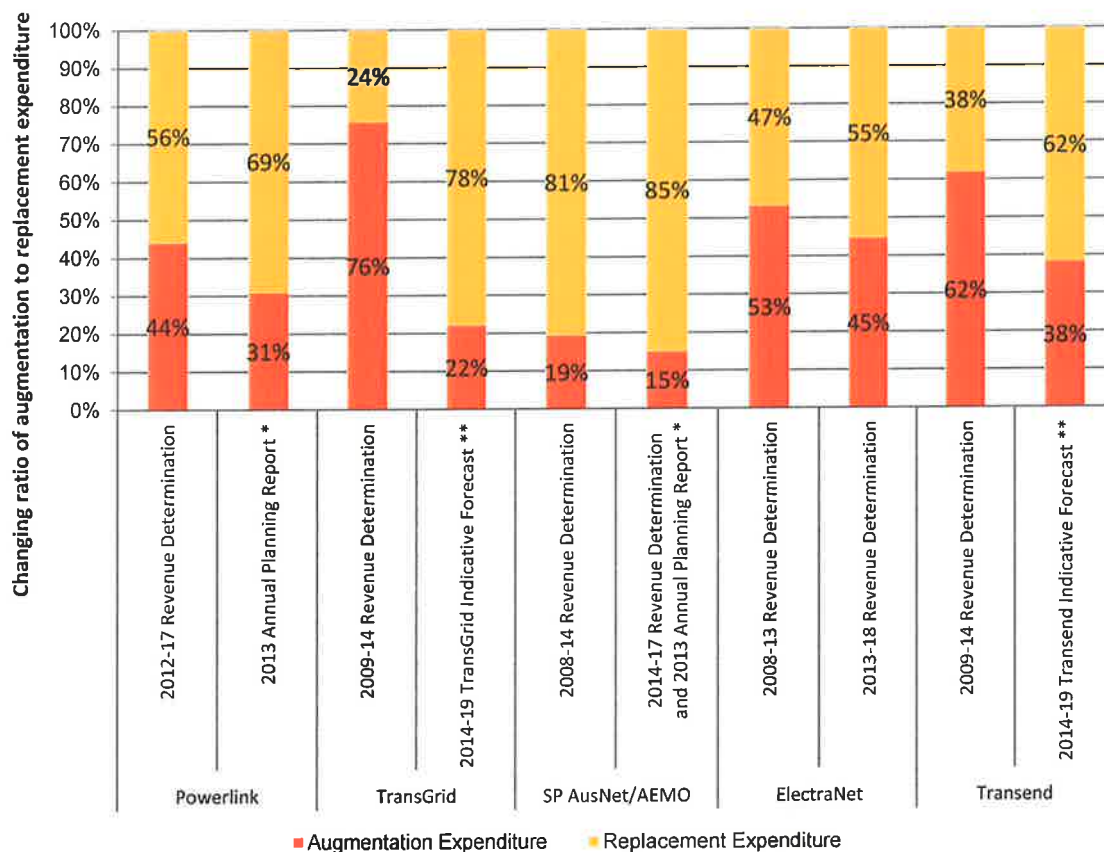
AEMO expects future capital expenditure to be dominated by asset replacements, not network augmentations.

Figure 22 shows the results of a high-level analysis of capital expenditure classes and how these are changing. The analysis was performed by comparing publicly-available information. The best data comes from the revenue determination final decisions by the Australian Energy Regulator (AER) as they include all types of expenditure, fully costed and expressed over a common five-year period for all expenditure types.

This information is more difficult to obtain from other sources, such as annual planning reports, because not all of the information is provided. As a result, analysis is indicative where annual planning reports have been used and AEMO has used other sources, including AEMO's own estimates, to address data gaps.

Figure 22 shows a clear trend across the NEM that the proportion of asset replacement expenditure has increased.

Figure 22 – Changing proportion of augmentation to asset replacement expenditure



Notes:

- * In developing capital expenditure forecasts from APRs, cost estimates for replacement projects were obtained from current and historical APRs where available. Cost estimates for committed projects were sourced from published regulatory test information. AEMO estimated the cost of projects where there was no publicly-available cost information.
The SP AusNet/AEMO data for the period 2014–17 is a combination of SP AusNet’s revised revenue proposal to the AER and AEMO’s 2013 APR.
- ** TransGrid and Transend Networks provided AEMO with an indicative estimate of replacement and augmentation capital expenditure for the 2014–19 period.

Asset replacement is a key factor in setting future network expenditure, and AEMO understands that TNSPs consider planning needs in asset replacement decisions. However, given that network utilisation is decreasing in some locations, it is important that there is transparency in replacement decision-making and that each major replacement is justified through annual planning reports or other public documents.



3.4 Asset retirement consideration

In an environment of continued slow growth, replacing ageing assets with new assets of higher capability may not be prudent. In assessing asset replacement, network service providers (NSPs) must consider any excess capacity in the network.

A number of factors could lead to excess capacity, including:

- A reduction in local demand.
- Network expansions in response to anticipated demand growth that did not eventuate.
- A change in prevailing power flows as a result of changes in generation dispatch, particularly if generation retires.

Depending on excess capacity in the network and the estimated local consumption it serves, it may be more cost-effective to replace it with one of the same capacity, a lower capacity, or completely retire it.

Capacity can also be optimised and costs reduced by applying economic reliability standards that ensures the timing and size of expenditure reflects the economic benefits of the service provided. An economic standard is even more important under low demand growth, or where the peak demand is much higher than the average, as the economic benefits are smaller and grow more slowly over time.

Non-network solutions, such as embedded generation and demand management, can often provide marginal capacity increases to areas of constrained supply. With low consumption growth, the additional marginal capacity supplied by non-network solutions may be sufficient to delay network augmentations by several years.

In addition, given that many non-network solutions can be implemented through contractual arrangements or non-permanent assets, there is less risk of stranding assets if demand growth is lower than expected.

3.5 Conclusion

Given the importance of asset replacement to capital expenditure plans, it is important there is sufficient scrutiny given to proposed asset replacement and to not assume that existing transmission capacity and redundancy is required into the future.

Asset replacement decisions need transparent justification (such as Regulatory Investment Tests—Transmission (RIT-Ts) and in annual planning reports (APRs)) that explore the future need of those assets and considers the cost of replacement against the value of the service provided, and considering cost-effective non-network solutions.

AEMO is expanding the analysis it undertakes in the short- to medium-term period of the NTNDP to include an independent view of the future need of assets identified for replacement. See Appendix C for further information.

CHAPTER 4 - CURRENT AND UPCOMING NATIONAL TRANSMISSION PLANNER ACTIVITIES

AEMO is undertaking a number of initiatives as part of its national transmission planner function. These are:

- Reviewing and endorsing low-cost projects, the Network Capability Incentive Parameter Action Plan (NCIPAP), under a new incentive scheme.
- Developing transmission connection point electricity forecasts.
- Developing shorter-term network outlooks.

Each of these is discussed below.

4.1 Network Capability Incentive Parameter Action Plan

Part of a new incentive scheme designed by the Australian Energy Regulator (AER), the Network Capability Component (NCC) of the transmission service target performance incentive scheme (STPIS)²⁵, supports improved usage of existing network assets through low-cost transmission projects.

Under the NCC, transmission network service providers (TNSPs) prepare and submit a NCIPAP outlining the key network capability limitations and proposing operational and/or minor capital expenditure to improve network capability. AEMO has a formal role in prioritising the projects that will deliver best value for money for consumers and ranking these priority projects.

AEMO is currently reviewing applications from three transmission network service providers (TNSPs): TransGrid, ElectraNet, and Transend Networks and has completed a review of SP AusNet's application.

AEMO adopts a highly interactive approach to these reviews by engaging with TNSPs both prior to their application and throughout the review. Using its experience as national transmission planner and system and market operator, AEMO assists TNSPs with project identification and in estimating the market benefits these priority projects would deliver.

AEMO's objectives are to ensure that:

- The projects proposed by TNSPs will deliver best value for money for consumers.
- There are sufficient projects to meet or exceed the NCIPAP's cost target so that the highest priority projects can be selected.²⁶
- All projects are ranked from greatest to least value by the size of the net market benefits they provide.
- Each priority project describes the existing limit it is targeting and includes a target capability value that is clearly identifiable and measurable.
- The rationale for each transmission circuit or injection point limit is reasonable (and reflects the limit provided in network constraint equations where appropriate).

²⁵ AER, Service target performance incentive scheme version 4 — December 2012 amendment. Available at: <http://www.aer.gov.au/node/9780>. Viewed 4 December 2013.

²⁶ AER guidelines require that the average annual total expenditure of priority projects must not be greater than 1% of TNSPs' average maximum allowed revenue.



4.2 Transmission connection point electricity forecasts

Demand forecasts enable coordinated decision-making across the electricity and gas industries by providing a fundamental basis for infrastructure investment. These investment decisions are typically made at a local level, and are primarily based on connection point forecasts. Currently AEMO develops forecasts only at a regional level using a top-down approach; these forecasts do not directly take into account local issues.

In 2014 AEMO will produce connection point forecasts for Tasmania and New South Wales. As well as assisting in AEMO's review of the medium-term transmission development requirements for these regions, the forecasts will also inform the AER's assessment of the Transend Networks and TransGrid revenue reset applications.

In June 2013, following extensive industry consultation, AEMO published a consistent methodology for connection point forecasts across the National Electricity Market (NEM). This methodology, available on AEMO's website, is being used to develop the connection point forecasts.²⁷

In developing the forecasts, AEMO has been working with distribution network service providers (DNSPs) to compile available key data and information. AEMO is also actively seeking data from other key stakeholders including industrial customers; local government councils; and government departments such as the Australian Bureau of Statistics, Department of Industry, Clean Energy Regulator, and Bureau of Meteorology. Independent experts have also been engaged to provide additional advice and reviews.

AEMO is also improving the quality of its regional NEM (energy and demand) forecasts, including a check for structural breaks in the historical time series to provide improved regional energy forecasts. AEMO has published an action plan outlining these improvements that addresses the main findings and recommendations from a review of the forecasting methodologies.²⁸

4.3 Medium-term network outlooks

AEMO is phasing in the development of medium-term network outlooks. It will commence with New South Wales and Tasmania in 2014 to enable these to be inputs into the AER's transmission revenue determination processes.


Previous NTNDP reports have identified network requirements for the NEM's main transmission network only. The medium-term network outlooks will use AEMO's connection point forecasts to provide an independent view on localised transmission network needs and will include commentary on projects identified by TNSPs as network improvements and major transmission asset replacements.

The outlooks will cover an independent assessment of the following:

- Needs for transmission network augmentations (including timing and augmentation options) to meet forecast electricity consumption, triggered by the connection of specific large demand connections, or based on delivering positive net market benefits.
- Needs for augmentations to the shared transmission network required to support new transmission connections.
- Major asset replacement projects, commenting on the ongoing need for network capability for the asset being replaced and the capacity of the new asset. The outlooks will not comment on replacement drivers or the current asset conditions.

²⁷ AEMO. Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand — Report. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting>. Viewed 4 December 2013.

²⁸ AEMO. 2014 National Electricity Forecasting Report (NEFR) Action Plan. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013>. Viewed 4 December 2013.



AEMO will undertake power system simulations to identify thermal and voltage limitations in the New South Wales and Tasmanian transmission networks over the next five to seven years. The study will:

- Apply the jurisdictional planning criteria.
- Apply economic planning criteria for selected projects.
- Focus on identifying thermal and voltage network limitations.
- Use transparent and robust modelling assumptions.
- Comment on potential network and non-network options to address identified limitations.
- Comment on the ongoing planning need of major asset replacements.

AEMO will engage with stakeholders during the development of the outlooks.

AEMO is engaging with the AER to ensure that the form and timing of deliverables is useful for the AER's revenue determination processes.

Appendix C provides a scope for this network assessment.



CHAPTER 5 - LINKS TO SUPPORTING INFORMATION

Table 1 provides links to additional information provided either as part of the 2013 NTNDP accompanying information suite, or other related AEMO planning information.

Table 1 — Links to supporting information

Information Source	Website Address
2013 National Transmission Network Development Plan – report and modelling results	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan
Glossary (2012 NTNDP)	http://aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~media/Files/electricity/planning/reports/NTNDP/2012NTNDPGlossary
Planning Assumptions (including information on modelling inputs)	http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions
Network Support and Control Ancillary Services (NSCAS) Description and Quantity Procedure	http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure
Scenario descriptions	http://www.aemo.com.au/Electricity/Planning/Related-Information/~media/Files/Other/planning/2012_Scenarios_Descriptions.ashx
Generator Information page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information
2013 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013
2013 Wind Integration Studies Report	http://aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy
2012 National Transmission Network Development Plan	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan
Maps and network diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Introduction to the Australian NEM	http://www.aemo.com.au/~media/Files/Other/corporate/0000-0262%20pdf.ashx
Joining the NEM Guide	http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/Electricity-Statement-of-Opportunities-2011/2011-ESOO-Electronic-Information/~media/Files/Other/planning/esoo/ESOO2011_CD/documents/Attachm ent_2%20pdf.ashx



THIS PAGE IS BLANK INTENTIONALLY



Appendix A - NETWORK LIMITATIONS

This appendix provides more details about the network limitations illustrated in the maps in Chapter 2. The reference code in the tables matches the reference in the map legends.

NTNDP analysis identifies limitations occurring within five-year time periods:

- 2013–14 to 2017–18.
- 2018–19 to 2022–23.
- 2023–24 to 2027–28.
- 2028–29 to 2032–33.
- 2033–34 to 2037–38.

Table A-1 lists projects affecting the main transmission network that have undergone all stages of the regulatory investment test for transmission (RIT-T) and are considered to be committed. These projects are illustrated geographically in Figure 11.

Table A-1 — Committed main transmission network projects across the NEM

Reference	Region	Zone	Project	Anticipated timing
C-Q1	Queensland	SWQ	The Columboola – Wandoan South line operating at 275 kV (currently energised at 132 kV).	Winter 2014
C-Q2	Queensland	SWQ	The Columboola – Western Downs 275 kV line.	Winter 2014
C-N1	New South Wales	NNS	An Armidale SVC power oscillation damper.	2013
C-N2	New South Wales	NCEN	Establishment and connection of the Holroyd and Rookwood Road Substations.	Early 2014
C-N3	New South Wales	CAN	Establishment of the Wallaroo Substation and Yass and Canberra area line rearrangements.	2018
C-N4	New South Wales	NCEN	Beaconsfield West – Haymarket 330 kV cable (operated at 132 kV).	2013
C-N5	New South Wales	SWNSW	New reactors: 3 x 150 MVar at Yass substation and 3 x 150 MVar at Murray substation.	Mid-2014
C-S1	South Australia	NSA	Cultana 275 kV and 132 kV network augmentation.	2014
C-VS1	Victoria and South Australia	MEL–SESA	<p>The incremental augmentation of the Victoria to South Australia interconnector (Heywood):</p> <p>Scope of work in Victoria:</p> <ul style="list-style-type: none"> • A third 370 MVA 500/275 kV transformer and bus tie at Heywood. <p>Scope of work in South Australia:</p> <ul style="list-style-type: none"> • 275 kV series compensation. • Reconfiguration and decommissioning of the 132 kV network. • Control scheme to enable increased wind generation in SESA when both South East 275/132 kV transformers are in-service. 	2016

Table A-2 lists limitations on the main transmission network that are identified in the NTNDP as affecting network ability to reliably supply customer load. These may not include limitations on lower-voltage (below 220 kV) networks or in supplying local load at times outside of the regional maximum demand.

The location of these limitations is illustrated geographically in Figure 11 and Figure 20.

Table A-2 — NTNDP limitations on the main transmission network

Reference	Region	NTNDP zone	Carbon price scenario timing	Observed limitation	Network needs
L-Q1	Queensland	SEQ	2028–29 to 2032–33.	Overload of the Blackwall – South Pine 275 kV circuit for an outage of Mount England – South Pine 275 kV circuit.	An additional 275 kV capability from Blackwall to South Pine.
L-Q2	Queensland	SEQ	2033–34 to 2037–38.	Overload of the Blackwall–Goodna 275 kV circuit for a single transmission element outage.	An additional 275 kV capability from Blackwall to Belmont.
L-Q3	Queensland	SEQ	2028–29 to 2032–33.	Overload of the 275/110 kV network supplying the Brisbane area.	An additional 275/110 kV capability in the Brisbane area.
L-N1	New South Wales	NCEN	2013–14 to 2017–18.	Overload of the Sydney South – Beaconsfield West 330 kV line for an outage of the Sydney South – Haymarket 330 kV line.	A new supply to the Beaconsfield West Substation from another 330 kV supply point.
L-N2	New South Wales	NCEN	2013–14 to 2017–18.	Transmission limitations on the 330 kV lines between Hunter Valley and Newcastle.	If generation retirement occurs in the Newcastle area.
L-N3	New South Wales	NNS	2023–24 to 2027–28.	Overload of the 132 kV network supplying north coast demand centres for an outage of the Amidale – Coffs Harbour 330 kV line.	Reinforce the connection between the inland 330 kV transmission network and the north coast demand centres.
L-V1	Victoria	MEL	2018–19 to 2022–23.	Overload of the Rowville 500/220 kV transformer for an outage of the Cranbourne 500/220 kV transformer (and vice versa).	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.
L-V2	Victoria	MEL	2018–19 to 2022–23.	Overload of the Thomastown–Templestowe and Thomastown–Ringwood 220 kV circuits for an outage of the Rowville 500/220 kV A1 transformer.	Connection of the Rowville–Templestowe 220 kV circuit at Ringwood.
L-V3	Victoria	CVIC	2013–14 to 2017–18.	Overload of the Moorabool–Ballarat 220 kV No.1 circuit for an outage of the Moorabool–Ballarat 220 kV No.2 circuit.	Additional transmission capability from Moorabool to Ballarat.
L-V4	Victoria	CVIC	2013–14 to 2017–18.	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	Additional transmission capability from Ballarat to Bendigo.
L-V5	Victoria	MEL	2028–29 to 2032–33.	Overload of the Rowville 500/220 kV A1 transformer for system normal operation, and overload of a South Morang 330/220 kV transformer and a South Morang – Thomastown 220 kV circuit for an outage of the parallel transformer/circuit.	An additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area.



Reference	Region	NTNDP zone	Carbon price scenario timing	Observed limitation	Network needs
L-V6	Victoria	MEL	2028–29 to 2032–33.	Overload of the Moorabool 500/220 kV A1 transformer for an outage of Moorabool 500/220 kV A2 transformer.	An additional 500/220 kV transformer in the Western Metropolitan Melbourne area.
L-S1	South Australia	NSA	2013–14 to 2017–18.	Transmission limitation on the Robertstown – North West Bend 132 kV line during times of peak load conditions in the Riverland area when Murraylink is not importing into South Australia.	Additional transmission capability from Robertstown to North West Bend.

Table A-3 lists limitations on the main transmission network that are identified in the NTNDP as affecting the economic dispatch of generation. This means that the physical capacity of some network elements prevents some cheaper generation operating ahead of some more expensive generation. These limitations, which are listed in Table A-2, have been identified mainly during times of high wind generation output and do not lead to a loss of supply to customers.

The location of these limitations is illustrated geographically in Figure 13 and Figure 20.

Table A-3 — Potential economic dispatch limitations

Reference	Region	NTNDP zone	Potential limitation	Dispatch scenario
M-Q1	Queensland	NQ	Power transfer capability into NQ.	Insufficient transmission capability north of Stanwell area to reduce the reliance on high cost NQ generation (including relatively high-cost liquid-fuelled generating units) during 2018–19 to 2022–23.
M-N1	New South Wales	CAN	Transmission limitations on the network between CAN and NCEN at times of peak demand. Generation in SWNSW and import from VIC may be constrained.	High levels of wind generation in the CAN zone when power flows north from the SWNSW zone (or Victoria) to the CAN zone.
M-V1	Victoria	MEL	Transmission limitations on the 500 kV network along the Western Corridor.	High wind generation in the MEL zone. High imports from South Australia combined with moderate levels of OCGT generation also contribute to this limitation.
M-V2	Victoria	CVIC	Transmission limitations on the Terang–Ballarat 220 kV line.	If a high proportion of new wind generation is built at Terang or along Terang–Ballarat corridor.
M-V3	Victoria	CVIC	Transmission limitations on the Ballarat–Waubra–Horsham 220 kV line.	If a high proportion of new wind generation is built at Horsham or along Ballarat–Horsham or Horsham – Red Cliffs corridor.
M-V4	Victoria	CVIC	Transmission limitations on the Red Cliffs – Wemen – Kerang 220 kV line.	If a high proportion of new wind generation is built at Red Cliffs or along Red Cliffs – Kerang corridor.
M-S1	South Australia	NSA	Transmission limitations on the 132 kV network in the lower Eyre Peninsula.	High levels of wind generation in the lower Eyre Peninsula.

Reference	Region	NTNDP zone	Potential limitation	Dispatch scenario
M-S2	South Australia	NSA	Transmission limitations on the network between NSA and ADE.	High levels of wind generation in the NSA zone.
M-S3	South Australia	NSA	Transmission limitations on the Robertstown – North West Bend 132 kV line.	High levels of wind generation in the NSA zone.
M-S4	South Australia	SESA	Transmission limitations on the Tailern Bend –Tungkillo transmission corridor.	New generation east of Adelaide or high import from Victoria.
M-T1	Tasmania	TAS	Transmission limitations on the Burnie–Sheffield transmission corridor.	New generation in North-West Tasmania.
M-T2	Tasmania	TAS	Transmission limitations on the Sheffield-Palmerston transmission corridor.	New generation in Central Tasmania.

In addition to the above limitations, Table A-4 shows the following limitations may arise in the Victorian, South Australian and Tasmania regions due to dispatch of wind generation ahead of non-wind generation. See AEMO's Integrating Renewable Energy—Wind Integration Studies Report²⁹ for more information.

Table A-4 — Potential limitations due to wind generation dispatch

Region	Potential limitation	Dispatch scenario
South Australia	Likely curtailment of new entry wind generation limited by multiple network constraints and challenges in power system frequency control due to displacement of conventional generation.	Dispatch of wind generation ahead of non-wind generation.
Victoria	Possible curtailment of new entry wind generation limited by multiple network constraints.	Dispatch of wind generation ahead of non-wind generation.
Tasmania	Likely curtailment of new entry wind generation limited by multiple network constraints and challenges in power system frequency control due to displacement of conventional generation.	Dispatch of wind generation ahead of non-wind generation.

Table A-5 lists limitations and projects affecting the main transmission network identified by the transmission network service providers (TNSPs) in their 2013 transmission annual planning reports (APRs).

The location of these limitations is illustrated geographically in Figure 12.

APRs contain additional limitations and proposed projects beyond those on the main transmission network. AEMO has produced a consolidated summary of these, which is available on the 2013 NTNDP webpage.³⁰

²⁹ AEMO, Integrating Renewable Energy—Wind Integration Studies Report 2013. Available at: <http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy>. Viewed 4 December 2013.

³⁰ AEMO, 2013 National Transmission Network Development Plan. Available at: <http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Overview>. Viewed at: 4 December 2013.



Table A-5 — APR identified limitations on the main transmission network

Reference	Region	NTNDP zone	Limitation addressed	2013 APR project status	2013 APR anticipated timing	2013 NTNDP
T-Q1	Queensland	NQ	Power transfer capability into NQ (Stanwell–Broadsound 275 kV line).	Proposed timing subject to customer commitment.	Economic timing beyond the five-year APR outlook.	Limitations of power transfer capability into NQ have been identified in the 2013 NTNDP.
T-Q2	Queensland	CQ	CQ to SQ transient stability limit.	Proposed.	Timing subject to generation commitment.	Limitations between CQ and SQ could arise under certain generation dispatch scenarios and outage conditions.
T-Q3	Queensland	SWQ	Possible voltage stability limitations on the network supplying Surat Basin north west area.	Proposed.	Summer 2016–17.	Require voltage stability studies based on the dynamic characteristics of motor loads - not within the scope of the 2013 NTNDP.
T-Q4	Queensland	SEQ	Blackwall – South Pine 275 kV line.	Deferred.	Timing beyond the five-year APR outlook.	Limitation arises in the 2013 NTNDP expansion plan.
T-Q5	Queensland	SEQ	Network limitations for supply within the southern Brisbane area (110 kV network including Rocklea 275/110kV transformers).	Proposed.	Timing beyond the five-year APR outlook. Energex is undertaking an on-going review of limitations in its supply network.	Limitation arises in the 2013 NTNDP expansion plan.
T-Q6	Queensland	SEQ	Power transfer capability from SWQ to SEQ.	Proposed.	Timing beyond the five-year APR outlook.	Limitations between SEQ and SWQ could arise if large amount of new generation currently modelled in SEQ is located in SWQ.
T-N1	New South Wales	NNS	Capacity of the Northern NSW and South Western Queensland main grid network to facilitate power transfer between QLD and NSW.	Under consultation.	Timing subject to outcome of a market benefit assessment.	Reactive plant would be required to increase the transfer capability between Queensland and New South Wales. However, least cost modelling did not identify the need.
T-N2	New South Wales	NNS	132 kV lines between Armidale and Coffs Harbour.	Proposed.	Not within 5-years.	Limitation in the 2013 NTNDP expansion plan during 2023–24 to 2027–28.
T-N3	New South Wales	NNS	Supply to Northern NSW (capacity of the Hunter Valley – Tamworth – Armidale 330 kV lines).	Proposed.	Within 5-years.	The need does not arise according to the NTNDP expansion plan.

Reference	Region	NTNDP zone	Limitation addressed	2013 APR project status	2013 APR anticipated timing	2013 NTNDP
T-N4	New South Wales	NCEN	The 132 kV network supplying the Tomerong/Nowra area.	Proposed.	Within 5 years.	Local supply issue - not captured in the 2013 NTNDP.
T-N5	New South Wales	NCEN	The 330 kV lines between Bannaby and Marulan, and Sydney and the South Coast.	Proposed.	Not within 5 years.	The need does not arise according to the NTNDP expansion plan.
T-N6	New South Wales	NCEN	The 330 kV network supplying southern Sydney from the west.	Proposed.	Not within 5 years.	The need does not arise according to the NTNDP expansion plan.
T-N7	New South Wales	NCEN	Thermal and voltage limits on the injection of power into the Sydney Metropolitan area.	Proposed.	Within 5 years.	Due to the noted derating of cable 41 and retirement of other 132 kV cables, it is likely that there is a need to augment supply to the Sydney metropolitan area.
T-N8	New South Wales	NCEN	The two 330 kV transmission lines between the Hunter Valley and the Newcastle Area.	Proposed.	Not within 5 years.	The 2013 NTNDP analysis identified the need following retirement of generation in the Newcastle area.
T-N9	New South Wales	NCEN	330 kV line connecting the Munmorah and Vales Point Power Stations.	Proposed.	Not within 5 years.	The need does not arise according to the NTNDP expansion plan.
T-N10	New South Wales	SWNSW	Capacity of the southern NSW main grid network to facilitate power transfer between NSW major load centres and generation in Southern NSW and Victoria.	Proposed.	Within 5 years.	The need does not arise according to the NTNDP expansion plan.
T-V1	Victoria	MEL	Inadequate reactive power support in Metropolitan Melbourne.	Proposed.	Around 2019–20.	Deferral of additional reactive support is consistent with the 2013 NSCAS analysis.
T-V2	Victoria	MEL	Rowville A1 500/220 kV transformer and Metropolitan Melbourne 220 kV lines.	Current RIT-T in progress.	2018–19.	Limitation arises in the 2013 NTNDP.
T-V3	Victoria	MEL	Rowville–Malvern 220 kV circuits.	Proposed.	Within 10 years.	Limitation arises in the 2013 NTNDP.



Reference	Region	NTNDP zone	Limitation addressed	2013 APR project status	2013 APR anticipated timing	2013 NTNDP
T-V4	Victoria	MEL	Rowville–Springvale and Springvale–Heatherton 220 kV circuits.	Proposed.	Within 10 years.	Limitation arises in the 2013 NTNDP.
T-V5	Victoria	MEL	Keilor A2 and A4 500/220 kV transformers.	Proposed.	Within 10 years.	Limitation arises in the 2013 NTNDP.
T-V6	Victoria	MEL	Ringwood–Thomastown and Ringwood–Rowville 220 kV lines.	Proposed.	Within 10 years.	Limitation arises in the 2013 NTNDP.
T-V7	Victoria	MEL	South Morang H1 and H2 330/220 kV transformers.	Proposed.	First transformer (H2) to be upgraded in 2016–17.	Limitation arises in the 2013 NTNDP.
T-V8	Victoria	CVIC	Ballarat–Bendigo and Ballarat–Moorabool No.1 220 kV lines.	Current RIT-T in progress.	2016–17.	Limitation arises in the 2013 NTNDP.
T-V9	Victoria	CVIC	Inadequate reactive power support around Bendigo in Regional Victoria.	Proposed	Deferred until 2019 or later.	Deferral of additional reactive support is consistent with the 2013 NSCAS analysis.
T-V10	Victoria	CVIC	Geelong–Moorabool 220 kV line.	Proposed.	NCIPAP project timing 2015–16.	Included in the 2013 NTNDP modelling.
T-V11	Victoria	MEL	Moorabool–Mortlake/Tarrone–Heywood 500 kV line voltage unbalance.	Proposed.	Within 5 to 10 years.	Quality-of-supply issue - not within the 2013 NTNDP scope.
T-S1	South Australia	NSA	132 kV network on the lower Eyre Peninsula.	Proposed.	Timing subject to connection application.	The 2013 NTNDP does not specifically consider potential spot load increases in this part of the network.
T-S2	South Australia	NSA	Transmission network between NSA and ADE.	Proposed.	Not stated.	Limitation has been addressed in the NTNDP plan.

Reference	Region	NTNDP zone	Limitation addressed	2013 APR project status	2013 APR anticipated timing	2013 NTNDP
T-S3	South Australia	NSA	Robertstown – North West Bend 132 kV line.	Proposed.	Not stated.	<p>Limitation arises during times of peak load conditions in the Riverland area of South Australia when Murraylink is not importing into South Australia. It was also observed under high levels of wind generation in the NSA zone.</p> <p>AEMO and ElectraNet are currently undertaking a joint planning study to identify solutions to the potential reliability limitation.</p>
T-S4	South Australia	ADE	Tailem Bend - Tungkillo transmission corridor.	Proposed.	Not stated.	Limitation has been addressed in the NTNDP plan.
T-T1	Tasmania	TAS	Waddamana – Palmerston 220 kV line.	Proposed.	2016.	Limitation has not been identified in the NTNDP expansion plan.
T-T2	Tasmania	TAS	Farrell – Rosebery – Queenstown 110 kV line.	Proposed.	2017.	Supply to radial load – not within the 2013 NTNDP scope.
T-T3	Tasmania	TAS	Chapel Street – Kingston Tee 110 kV line.	Proposed.	2019.	Supply to radial load – not within the 2013 NTNDP scope.
T-T4	Tasmania	TAS	Palmerston–Avoca 110 kV line	Proposed.	2014.	Supply to radial load – not within the 2013 NTNDP scope.



Appendix B - NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

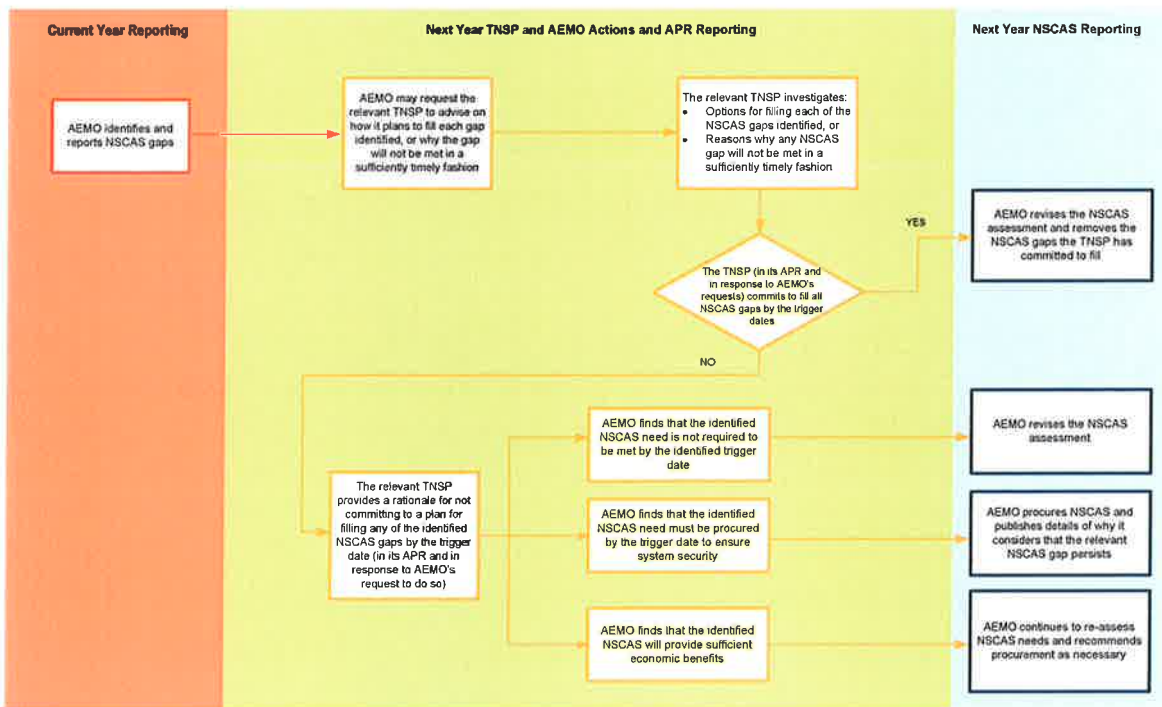
Network Support and Control Ancillary Services (NSCAS) are procured to maintain power system security and reliability, and to maintain or increase the power transfer capabilities of the network.

Transmission network service providers (TNSPs) have primary responsibility for acquiring NSCAS. Each year AEMO identifies any gaps between NSCAS needs and the NSCAS currently acquired; this assists TNSPs in decision-making with respect to NSCAS procurement over a five-year horizon.

Where AEMO has identified NSCAS gaps, the TNSP is required to consider whether to make arrangements to meet the relevant NSCAS gap and advise AEMO accordingly. AEMO will acquire NSCAS to prevent any adverse impact on power system security and reliability.

Figure B-1 provides a summary of the process for addressing the NSCAS needs identified by AEMO.

Figure B-1 — Process for meeting NSCAS needs identified by AEMO



Refer to the NSCAS description and NSCAS quantity procedures on AEMO's website for additional information.³¹

³¹AEMO. NSCAS Description and Quantity Procedure: <http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure>. Viewed 4 December 2013.

B.1 NSCAS gaps for maintaining power system security

Table B-1 provides a summary and commentary on the NSCAS gaps identified for each region as part of the 2013 NSCAS assessment.

Table B-1 — Summary of NSCAS gaps for maintaining power system security

Region	NSCAS gaps	Comment
Queensland	None	No NSCAS gaps of any type have been identified for the next five years.
New South Wales	None	The 2013 assessment confirmed the ongoing requirement of the current NSCAS arrangements in New South Wales (Section B.4).
Victoria	None	High voltages are likely to appear in the Victorian 500 kV network under certain system operating conditions. This will be managed with network switching operations.
South Australia	None	No NSCAS gaps of any type have been identified for the next five years.
Tasmania	None	<p>AEMO is monitoring voltage control at George Town. This does not constitute an NSCAS gap because voltage levels can be maintained within the operational target limits. However, this can result in potential quality of supply issues.</p> <p>In August 2013, Transend Networks advised that voltage swings experienced at George Town are mainly caused by switching operation of capacitor banks at George Town Converter Station during times of low fault level at the George Town 220 kV Substation. An interim operational measure has been established. Transend Networks and AEMO are looking at both short- and long-term solutions to manage voltage at George Town.</p> <p>AEMO's 2013 Wind Integration Studies Report³² indicates that voltage control at George Town would become more challenging during conditions of high Basslink transfer (in both directions) with a further increase of wind generation in Tasmania. AEMO will continue to monitor the situation and follow up with Transend Networks on any quality-of-supply issues.</p>

³² AEMO. September 2013. Integrating Renewable Energy — Wind Integration Studies Report. Available at: <http://aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy>. Viewed 4 December 2013.



B.2 NSCAS gaps for maximising market benefits

Table B-2 provides a summary of the two constraints selected for quantitative assessment of market benefits. These two constraints were selected from an initial analysis of the top 51 network constraints that resulted in market impacts, as identified in the 2012 NEM Constraint Report.³³

Table B-2 — Network constraints selected for quantitative assessment, and results

Network limitation	Market impact (2012)	Binding hours (2012)	Assessment result
Robertstown – North West Bend line loading limitation	\$114,000	69	Potential market benefits associated with avoiding unserved energy were identified. AEMO and ElectraNet are currently undertaking joint planning to investigate options which can deliver a positive net market benefit.
Tungkillo – Tailem Bend line loading limitation constraining South Australian export to Victoria ^a	\$87,000	3	No material market impact for South Australia export to Victoria. Although the historical impact with the Tungkillo – Tailem Bend has been for South Australia exports to Victoria, this line is likely to limit transfers in the other direction after the completion of the South Australia – Victoria (Heywood) interconnector incremental upgrade. ³⁴

a. Referring to constraint S>NIL_CGTB_TUTB which limits South Australia export to Victoria.

B.3 Status of NSCAS gaps identified in 2012

Table B-3 provides a summary of the status of NSCAS gaps identified in 2012.

Table B-3 — summary of status of NSCAS gaps identified in 2012

Potential NSCAS gap identified in 2012	Status
A need for voltage control ancillary service (VCAS) ^a to provide absorbing reactive power to avoid over voltages in Snowy and Kangaroo regions in NSW	See Section B.4.
Potential NSCAS gap in relieving the Robertstown – North West Bend line loading limitation	AEMO and ElectraNet are progressing a joint planning study on this limitation.
Potential NSCAS gap in relieving the New South Wales to Victoria voltage stability limitation	AEMO and TransGrid have, in their respective Annual Planning Reports, committed to jointly investigate whether a suitable NSCAS option can be acquired to deliver a positive net market benefit.

a. VCAS is voltage control ancillary service, to maintain voltage within specific limits and avoid voltage instability for system security purposes or improve power transfer limits for net market benefits purposes. For more information, see the NSCAS description in <http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure>.

³³ AEMO. 2012 NEM Constraint Report. Available at: <http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report>. Viewed 4 December 2013.

³⁴ AEMO and ElectraNet. South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T. Available at: <http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T>. Viewed 4 December 2013.

B.4 AEMO's 2012–13 NSCAS acquisition

Table B-4 lists the NSCAS AEMO acquired in 2012–13 for voltage control ancillary services (VCAS). The table also shows the NSCAS requirements identified in the 2012 and 2013 NSCAS assessments in New South Wales. The 2013 assessment confirms the ongoing requirement of VCAS and that the current contracts are adequate.

Table B-4 — Indicative NSCAS requirements and acquired amounts

Region	NSCAS type	NSCAS acquired ³⁵	2012 identified indicative requirements	2013 identified indicative requirements
New South Wales	VCAS (absorbing)	800 MVar	790–800 MVar	780 MVar

AEMO's NSCAS Agreements are with Snowy Hydro from 30 June 2013 to 1 July 2018 and TransGrid from the date when TransGrid can provide a full NSCAS service (tentatively 1 January 2015 to 30 June 2019³⁶). AEMO will scale back the NSCAS provided by Snowy Hydro when TransGrid's reactors become available.

AEMO's NSCAS agreement with Snowy Hydro

AEMO has an NSCAS agreement with Snowy Hydro for the provision of VCAS by running hydro generation units as synchronous condensers. This provides both absorbing and supplying reactive power as a bundled reactive capability.

Although only absorbing VCAS is required to suppress high voltages, AEMO uses the supplying reactive power available for enhancing the transfer capability from New South Wales to Victoria at times when this is considered to provide a positive net benefit.

Under the NSCAS agreement with Snowy Hydro, the VCAS cost depends on the dispatched quantity, not the contracted quantity.

AEMO's NSCAS agreement with TransGrid

Under AEMO's NSCAS services agreement with TransGrid, 800 MVar absorbing VCAS was contracted from TransGrid and includes:

- The installation of reactors at Murray Switching Station and Yass Substation.
- Switching out of existing transmission lines, including the Capital – Kangaroo Valley 330 kV line 3W and the Bannaby – Mt Piper 500 kV lines 5A6 and 5A7.
- Other transmission network plant as agreed between the parties.

³⁵ MVar means megavolt amperes reactive and are a unit of reactive power, similar to what megawatts (MW) are to active power. Reactive power is a necessary component of alternating current electricity. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which in turn is essential for maintaining security and reliability.

³⁶ Likely to be March-April 2014, based on TransGrid's current project schedule.



Appendix C - MEDIUM-TERM NETWORK OUTLOOKS FOR NEW SOUTH WALES AND TASMANIA – SCOPE OF WORKS

This appendix describes the scope of works for AEMO's independent assessment of the need for transmission network augmentations in New South Wales and Tasmania for the five-year period between 1 July 2014 and 30 June 2019. The assessment complements AEMO's long-term outlooks, considers more localised network requirements, and includes ongoing capacity requirements for major asset replacements.

New South Wales and Tasmania are the first regions for this more detailed assessment to enable AEMO's network outlooks to be an input into the Australian Energy Regulator's (AER) upcoming revenue determination processes, which commence in 2014.

AEMO will respond to queries about these outlooks and provide further independent advice and reviews of relevant plans and submissions as required.

C.1 Deliverables

The key deliverables from this assessment are:

- a) By mid-2014, a report covering the following:
 - Transmission network augmentation requirements (including timing and augmentation options) under both the transmission network service provider (TNSP) demand forecasts (as detailed in the 2013 transmission annual planning reports (APRs)) and AEMO's independent transmission connection point forecasts.
 - Upstream augmentations required to support new transmission connections.
 - Major asset replacement projects, commenting on the ongoing network capability requirement for an asset being replaced and new asset capacity, but not commenting on the condition of the existing asset or the replacement driver.
 - Potential contingent projects based on market benefits or spot load increases.
- b) By mid-2014:
 - Maximum demand forecasts for all transmission connection points

C.2 Details of delivery components

C.2.1 Transmission connection point forecasts

Forecast development

In 2013–14, AEMO will develop 10% and 50% probability of exceedence (POE) maximum demand forecasts for all transmission connection points located in New South Wales and Tasmania for a medium growth scenario over a 10-year outlook period.

AEMO will apply the methodology it developed in 2012–13 and published in June 2013³⁷ and will develop forecasts with the support of industry experts as independent advisors and peer reviewers. Engagement with network service providers

³⁷ AEMO. Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand. Available at: <http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting>. Viewed 4 December 2013.

In developing the transmission connection point forecasts, AEMO will collaborate with network service providers (NSPs), major customers and affected stakeholders in each region. AEMO intends to engage with these stakeholders on an ongoing basis on data and information access, input assumptions, methodology, and forecasting assumptions, and will also discuss the results with NSPs prior to publication.

C.3 Network needs assessment

AEMO's report will cover all load-driven network limitations over a five-year outlook period.

These load-driven network limitations would be expected to form the basis for an *ex-ante* augmentation proposal, which contributes to the AER's determination of allowed revenue TNSPs are able to recover. Some projects addressing load-driven network limitations may be contingent to the extent that the limitations are triggered by uncertain but large demand changes.

AEMO will also cover opportunities for market-benefits network augmentations. AEMO expects that in the revenue reset proposal these would be contingent projects.

Transmission network and connection assets

AEMO will undertake power system simulations to identify thermal and voltage limitations in the New South Wales and Tasmanian transmission networks over the outlook period.

The study will:

- Apply the jurisdictional planning criteria.
- Consider the appropriate identification and level of risk adoption in accordance with applicable jurisdictional planning criteria.
- Focus on identifying thermal limitations and voltage problems.
- Use the latest load flow model developed by AEMO from operational information, and information obtained from TransGrid and Transend Networks.
- Use transparent and robust modelling assumptions.
- Use TransGrid and Transend Networks' 2013 APR connection point load forecast for the initial round of studies and then AEMO's connection point load forecast for a second round of studies.
- Identify potential augmentations driven by market benefits or potential spot load growth, and categorise them as contingent projects.

Plant thermal ratings

The thermal ratings of network elements will be sourced from AEMO's operational database. This database has the lowest rating of transmission lines and transformers between two nodes. Additional rating information has been obtained from TransGrid and Transend Networks from the Network Capability Improvement Parameter Action Plan (NCIPAP) application, including information about the equipment that sets specific critical ratings. This additional information will be used to inform potential options to address identified limitations.

Options

AEMO will identify potential network and non-network solutions to the forecast limitations.

AEMO will assess whether there are alternatives to major new augmentations, such as measures to enhance the existing network capability or demand-side solutions. AEMO will also consider whether a forecast limitation could be addressed more efficiently via works on a neighbouring transmission network.

AEMO will refer to TransGrid and Transend Networks' APRs, regulatory test reports, regulatory investment tests for transmission (RIT-Ts), and other information as well as AEMO's own analysis and self-generated options.



Project timing

The timing of the network limitations and proposed options will be identified using:

- A medium growth scenario.
- Existing jurisdictional reliability standards.

In addition, AEMO will apply economic planning criteria for selected projects to determine the economic timing of project implementation. In such cases additional scenarios will be applied in the analysis.

Contingent projects

In developing the network outlooks, AEMO will also consider opportunities to enhance market efficiency through augmentations that deliver positive net market benefits.

In a revenue proposal sense AEMO expects market benefit driven augmentations, as well as load-driven network augmentations triggered by uncertain but large demand connections (or spot loads) to be classified as contingent projects.

AEMO will identify augmentations in this category to facilitate the AER's consideration of AEMO's network outlook. In these instances, AEMO will advise what triggers should be implemented for the proposed contingent projects.

If required, AEMO may revise the list of contingent projects following consideration of projects from the TNSPs' list of contingent projects when this list is available.

Asset replacement projects

AEMO's report will include a limited review of the asset replacement projects for the 2014–19 period listed in TNSPs' 2013 APRs and information provided to AEMO as part of the network capability improvement parameter action plan (NCIPAP) review. AEMO will comment on the ongoing network capability need for the asset being replaced but not on the conditions of the existing asset or the drivers for replacement.

Engagement with TNSPs

In developing the network outlook, AEMO will collaborate with TransGrid and Transend Networks. AEMO intends to engage with the TNSPs on input assumptions and methodology, and also to discuss the results prior to their publication.



THIS PAGE IS BLANK INTENTIONALLY



Important Notice

Disclaimer

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (including information and reports from third parties) should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all participants in providing data and information used in this publication.

Copyright

© 2013 Australian Energy Market Operator Limited. The material in this publication may be used in accordance with the copyright permissions on AEMO's website.