2013

VICTORIAN ANNUAL PLANNING REPORT

Electricity Transmission Network Planning for Victoria

Published by

AEMO

Australian Energy Market Operator

ABN 94 072 010 327

ISSN: 1839-1710

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EXECUTIVE SUMMARY

The 2013 Victorian Annual Planning Report (VAPR) identifies constraints in the electricity Declared Shared Network (DSN), the costs associated with network congestion, and possible options to alleviate network limits. The assessments outlined in this report are based on an economic business case where benefits must exceed augmentation costs.

The report is published annually by the Australian Energy Market Operator (AEMO); the electricity transmission network planner and decision-maker for Victoria's DSN.

The 2013 VAPR shows that a reduction in forecast maximum demand has resulted in some augmentations being deferred by up to four years - these are highlighted in the table below.

The table also shows a number of augmentations still required over the next five years; these will require additional detailed analysis prior to commencing the Regulatory Investment Test for Transmission (RIT-T) process. The timing of these projects will be reassessed following the release of electricity demand forecasts in the 2013 National Electricity Forecasting Report.

Table 1 — RIT-T summary

	Project	Status	Approximate cost
Existing RIT-Ts	Heywood interconnector upgrade	Conclusions report (PACR) published in January 2013 recommended a third 500/275 kV transformer at Heywood as well as network augmentations in the South Australian region in 2016.	$45 million for the Victorian works.
	Regional Victoria Thermal Capacity	Draft report (PADR) published in March 2013 recommends installing a third Moorabool–Ballarat 200 kV line and uprating the Ballarat–Bendigo 220 kV line in 2016.	$126 million.
	Eastern Metropolitan Melbourne Thermal Capacity	Draft report (PADR) published in March 2013 recommends installing a third 500/220 kV transformer at Rowville in 2018.	$51 million.
Deferred RIT-Ts	Eastern Melbourne Reactive Support	RIT-T termination notice published in February 2013, due to reduced regional demand forecasts in the 2012 NEFR.	$8–10 million.
	Regional Victoria Reactive Support	RIT-T termination notice published in April 2013, due to reduced regional demand forecasts in the 2012 NEFR.	$5–10 million.
	Victorian Reliability Support (Murray–Dederang 330 kV line loading NSCAS)	RIT-T termination notice published in August 2012, due to reduced regional demand forecasts in the 2012 NEFR.	$17.4 million.
Requires detailed assessment	South-East Metropolitan Melbourne Supply (Rowville–Springvale–Heatherton, Rowville–Malvern and Ringwood–Thomastown 220kV line loading)	These 220 kV lines are at risk of becoming overloaded in the short term. Work to assess potential options to reduce this risk has begun. AEMO is working with local distribution businesses on potential solutions to ensure security of supply in this region.	Third Rowville–Springvale–Heatherton 220 kV line: $76 million.[1] Uprate Rowville–Malvern 220 kV line: $21 million.[1] Ringwood–Thomastown 220kV line: $8.9 million.[1]

	Project	Status	Approximate cost
	Western Metropolitan Melbourne Supply (Moorabool–Geelong 220 kV line loading and Keilor A2 and A4 500/220 kV transformer loading)	These network elements are at risk of being overloaded within the next five years. Work is underway on potential options to address these issues, running in parallel with a proposal to construct a new terminal station at Deer Park to meet electricity demand in this rapidly growing area.	Moorabool–Geelong 220 kV double-circuit line: $45 million.[1] Keilor A2 and A4 500/220 kV transformers: Marginal incremental cost per transformer as part of asset replacement.[1]
	South-west Victoria (Heywood–Moorabool 500 kV voltage unbalance)	An augmentation at Heywood Terminal Station to address uneven loading on transformers has been considered as part of the Heywood RIT-T and further assessments to balance voltage on the Moorabool–Heywood 500kV circuits will be undertaken in 2013–14.	Individual phase switching capacitor: $12.3 million.[1]
	South Morang H2 330/220 kV transformer loading	The South Morang H2 330/220 kV transformer is planned to be replaced in 2016, with a higher rated transformer than the existing one. The South Morang Terminal Station is located in a rapidly growing area west of Melbourne.	Marginal incremental cost as part of asset replacement
	VIC–NSW NSCAS assessment with TransGrid	Studies to assess the viability of increasing the transfer capability between the Victorian and New South Wales regions of the NEM will begin in 2013–14.	Less than $2 million per year to realise net market benefits.[1]

Note 1: These costs relate to one possible option only. Further assessment will need to be undertaken to determine the most suitable option to address these constraints, the cost of which may defer to that stated here.

The 2013 VAPR focuses on electricity transmission. A Victorian Gas Planning Report (VGPR), to be published in December 2013, will consolidate the gas information from the VAPR, the Victorian Gas System Adequacy report and the Victorian Gas Medium Term Outlook.

Performance

The electricity DSN performed reliably over the 2012–13 summer, with network load below its capacity and no interruptions due to overloaded transmission infrastructure (i.e., no unserved energy).

Victorian transmission asset owners' asset renewal information

The VAPR provides information on asset owners' asset renewal projects planned for the next 10-year period, as provided by the asset owners. This information has been included to provide a more comprehensive picture of transmission development in Victoria. The works and costs included are what SP AusNet provides the Australian Energy Regulator on asset replacement as part of their revenue reset process.

Generator access rights

In addition to identifying constraints in the electricity DSN, the 2013 VAPR investigates an option for generators to obtain greater access to the DSN at times of congestion.

This scheme builds on the optional firm access arrangements outlined in the AEMC's Transmission Frameworks Review and investigates a potential option for generators to pay for augmentations to alleviate identified constraints in exchange for rights to the transmission system.

This exploratory study shows how this option could be applied in Victoria under the current planning arrangements, and would foster competitive provision of transmission services. The example used is purely an illustration of how the scheme could be applied and is not a planned augmentation.

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CHAPTER 1 - INTRODUCTION

1.1 Introduction

The Victorian Annual Planning Report (VAPR) supports Victorian energy market investor decision making by providing electricity network planning information over a three to 10-year outlook period.

The VAPR includes the following:

- Information about the performance of the electricity Declared Shared Network (DSN) for the previous year, including performance at the time of maximum demand.
- Information about demand and supply.
- Information about committed augmentations. Committed projects are those where proponents have secured the necessary land and planning approvals and have entered into contracts for finance and generating equipment, and construction has either commenced or a firm date has been set.
- The latest medium-term outlook for emerging network limitations and their potential solutions.
- Chapter four outlines a new way of investing in Victorian transmission network augmentations to manage congestion. It explores the potential for an Optional Firm Access arrangement in Victoria, as per the AEMCs transmission framework review proposal.

The 2013 VAPR focuses on how reduced demand growth has affected the timing of augmentations identified in previous VAPRs.

1.1.1 Changes since 2012

The Australian Energy Market Operator (AEMO) is continuing to review the way it presents network planning information in order to provide stakeholders with more timely and focused information.

In 2012 AEMO moved away from printing a few large reports to electronically publishing a series of smaller reports focusing on specific issues. These are supported by supplementary reports and data files including maps and diagrams. For more information about these supplementary reports, see Section1.6.

Another key change to the VAPR since 2012 is a separate publication for Victorian gas transmission. The Victorian Gas Planning Report (VGPR) will be published in December each year, commencing December 2013. It will consolidate gas information previously published in the VAPR, the Victorian Gas System Adequacy report and Victorian Gas Medium Term Outlook, and will use demand forecasts based on the most recent winter period.

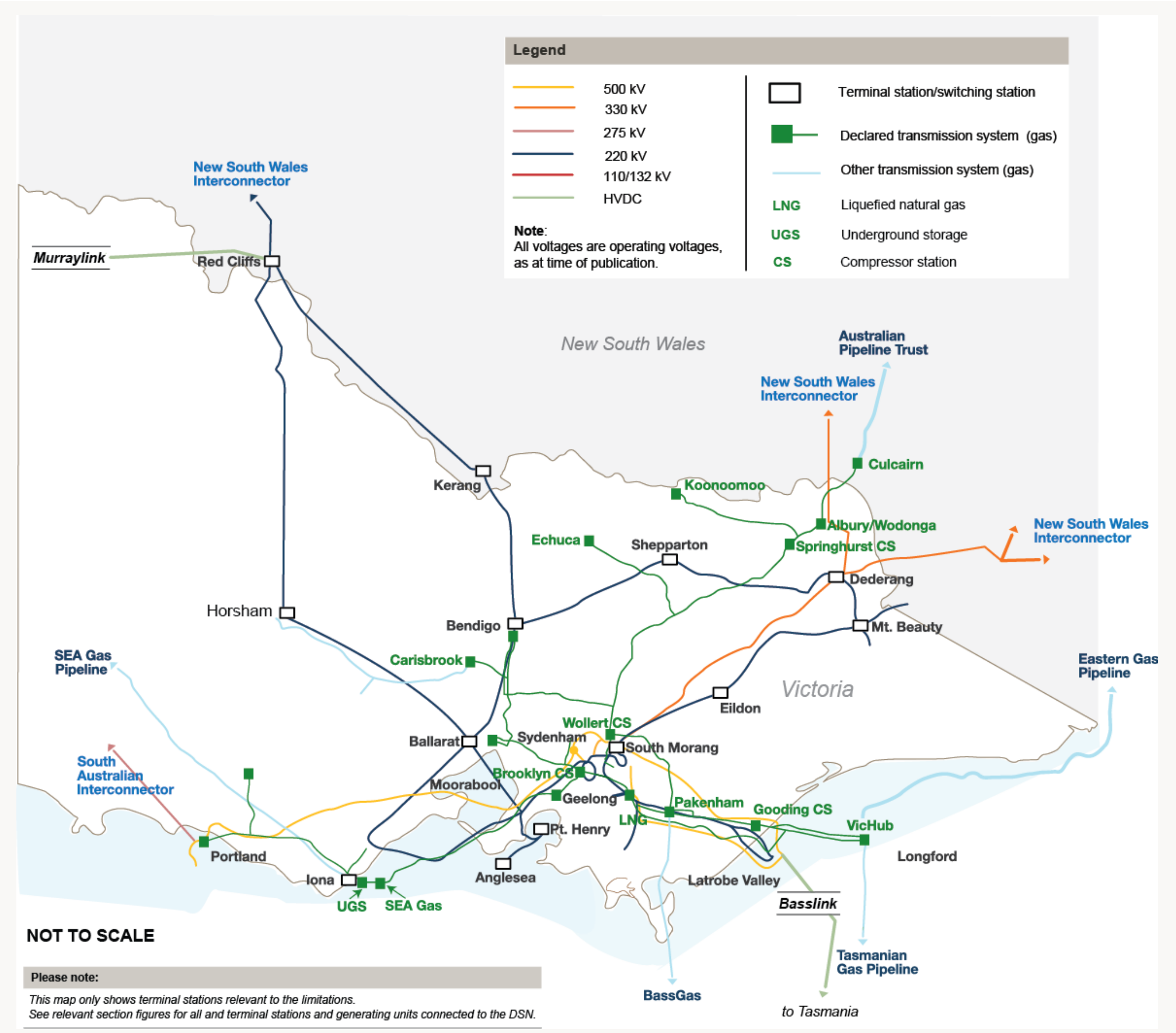
1.2 AEMO’s Victorian electricity and gas planning

Electricity DSN investment is predominantly driven by the need to reliably meet demand at times of maximum demand. Other investment drivers involve the location of demand, generation, and exports.

Although gas planning information will now be published in a separate report, AEMO will remain focused on integrated electricity and gas planning. AEMO’s business structure ensures close links between the two functions; for example a single team is responsible for both electricity and gas demand forecasts.

Figure 1-1 provides a high-level map of Victorian gas and electricity transmission. It shows the electricity DSN and its interconnections to neighbouring regions, and the gas Declared Transmission System (DTS) and other gas transmission pipelines.

Figure 1-1 — Victorian gas and electricity transmission



AEMO is responsible for planning and directing augmentations to the electricity DSN. AEMO owns no network infrastructure, and plans and procures services from third parties who own and maintain the electricity DSN assets.

The VAPR provides AEMO's assessment of future network development requirements, enabling market participants and other stakeholders to formulate and propose possible alternatives, including non-network solutions.

VAPR Rules obligations

Section 5.12.1 of the National Electricity Rules[1] (NER) requires AEMO to produce an annual planning report for the electricity DSN by 30 June each year. This obligation is satisfied by the 2013 VAPR and its supporting information, including the National Electricity Forecast Report (NEFR) and the Victorian Terminal Station Demand Forecasts (TSDF)[2], which addresses the requirement to publish forecast loads.

Victorian electricity planning approach

AEMO's Victorian electricity annual planning review considers the following:

- Demand forecasts (TSDF and NEFR).
- Planning proposals for future connection points.
- An asset replacement and refurbishment plan.
- A forecast of limitations and any inability to meet network performance requirements.
- An analysis of all proposed augmentations to the electricity DSN.

For more information, see the AEMO publication *Victorian Electricity Planning Approach*.[3]

1.3 The VAPR in the energy planning context

AEMO publishes other planning information for electricity networks in Victoria, including the Victorian Short-circuit Level Review.

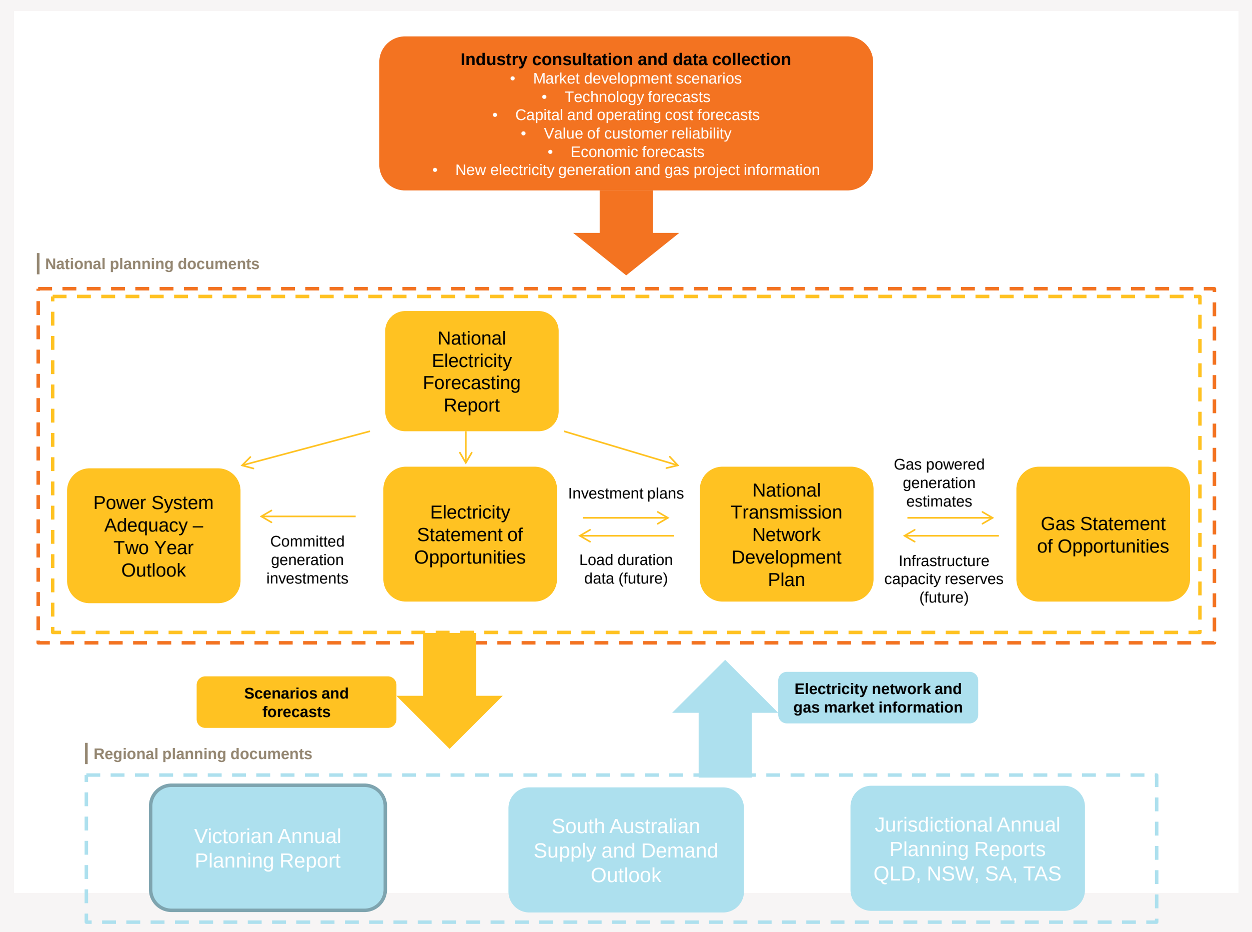
Other reports that focus on specific regions include the electricity Annual Planning Reports (APRs) published by the jurisdictional planning bodies (JPBs) for Queensland, New South Wales, South Australia and Tasmania. AEMO also publishes a range of reports as part of its South Australian advisory functions; these address the current state and future development of South Australian electricity supplies, and complement the South Australian JPB APR.

In the national context, AEMO produces the National Transmission Network Development Plan (NTNDP), which considers how the National Electricity Market (NEM) transmission network might develop in the long term. AEMO's Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO) investigate supply-side reliability and provide information about energy resources affecting eastern and south-eastern Australia.

Figure 1-2 shows how the VAPR links with other energy planning reports.

[1] AEMC. Available at http://aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.
[2] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.
[3] AEMO. Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.

Figure 1-2 — Energy planning reports and the VAPR



1.4 Responses to emerging issues

This section provides responses to new issues for 2013 that involve a persistent reduction in electricity demand growth, and emerging issues first identified in the 2012 VAPR.

1.4.1 Falling electricity demand growth

Historically, the NEM has experienced general increases in annual energy and maximum demand. Recently, however, annual energy growth has declined or stopped (depending on location) and future growth rate expectations are generally being revised downwards. Maximum demand growth has also slowed.

Reasons for this change include lower industrial demand, the high level of rooftop solar photovoltaics installed recently, which reduce the energy taken from the power system by customers; and changed customer behaviour in response to highly publicised electricity price increases and the adoption of energy efficiency measures.

Information presented in the 2012 VAPR was based on energy and maximum demand forecasts from 2011. Compared to these, the 2012 forecasts showed a significant reduction in maximum demand from summer 2012–13 onwards. As a result, after preparing the TSDF forecasts in September 2012, AEMO reassessed the timing of investments to address the limitations identified in the 2012 VAPR.

The network limitations and potential solutions identified in the 2013 VAPR reflect the changing environment. There is an overall decrease in annual energy and maximum demand growth, with localised areas of high growth due to residential developments south-east, north, and west of the Melbourne Metropolitan Area.

1.5 Content and structure of the 2013 VAPR

Executive summary: Outlines key messages.

Chapter 1, Introduction: Provides information about the 2013 VAPR and AEMO's responses to emerging issues affecting Victorian energy planning.

Chapter 2, Electricity transmission performance: Provides information about the performance of the Victorian electricity DSN during 2012–13 and maximum demand for the year.

Chapter 3, Electricity transmission development: Provides AEMO's responses to emerging electricity DSN limitations, including a summary of current RIT-Ts.

Chapter 4, Optional firm access arrangement example: Provides an example of a potential Optional Firm Access arrangement in Victoria, its potential benefits and the impact on electricity DSN planning requirements.

Appendix A, Electricity DSN ratings: Provides continuous and short-term ratings for the electricity DSN lines and transformers at the time of the maximum demand and the high power flow from Victoria snapshot.

Appendix B, New terminal stations in Victoria: Provides information about preferred approaches and locations for establishing new terminal stations in Victoria.

Appendix C, NTNDP Victorian development plan: Compares the results from Chapter 3 with the development plan for Victoria outlined in the 2012 NTNDP.

Measures and abbreviations: Provides the units of measure and abbreviations used throughout the VAPR, including Victorian power station and terminal station abbreviations.

Glossary and list of company names: Provides a glossary of terms and a list of the companies referred to throughout the VAPR.

1.6 Supporting information

This section provides links to other information about Victorian electricity DSN planning.

Information source	Website address
Maps and Network Diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Victorian Electricity Planning Approach	http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach
Victorian Transmission Network Planning Criteria	http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Transmission-Network-Planning-Criteria
2012 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting
Victorian regional electricity demand forecasts	http://www.aemo.com.au/Electricity/Planning/Forecasting
Victorian Terminal Station Demand Forecast 2012	http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria
Short-Circuit Levels for Victorian Electricity Transmission 2013–2017	http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report/Victorian-Short-Circuit-Level-Review
Annual NEM Constraint Report	http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report
Regulatory Investment Tests for Transmission	http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs
Transmission Connection Planning Report 2012	www.jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf
Connecting Victoria: Transmission Project Development Protocol	http://www.aemo.com.au/Electricity/Network-Connections/Community
Guidelines for Establishing Terminal Stations In Victoria	http://www.aemo.com.au/Electricity/Network-Connections

CHAPTER 2 - ELECTRICITY TRANSMISSION PERFORMANCE

Summary

The electricity DSN performed in a secure and reliable manner over the 2012–13 summer, with network load below its capacity and no interruptions due to overloaded transmission infrastructure (i.e., no unserved energy).

This chapter provides information about the performance of the current electricity Declared Shared Network (electricity DSN) under two sets of conditions (snapshots). The maximum demand snapshot assesses the DSN adequacy at the time of maximum demand for summer 2012–13, when the loading on many network elements is peaking. A high power flow from Victoria snapshot is also presented because some network elements are more heavily loaded during significant power flows from Victoria to New South Wales than during the maximum demand period.

Maximum native demand[1] over the 2012–13 summer was 9,792 MW. This occurred across the 30-minute period from 16:00 to 16:30 on 12 March 2013. This was relatively low compared to previous summers, but still higher than the 2011–12 summer maximum demand. For comparison, the highest historical native demand for Victoria was 10,603 MW during summer 2008–09, and the native demand peak in summer 2011–12 was 9,190 MW.

The high power flow from Victoria snapshot represents an instant in time, which is 01:00 on 7 October 2012. Power flow from Victoria to New South Wales at the time of the snapshot was 1,451 MW.

All network elements loadings were lower than 100% for both snapshots, under both system normal conditions (N loading) and as calculated for the loss of the most critical network element (N-1 loading).

In the high power flow from Victoria snapshot, the network elements with the highest loadings are the South Morang transformers and the Dederang – South Morang 330 kV lines, and these results are similar to those published in the 2012 VAPR.

Constraint equation impacts on interconnector power flows in 2012 are also presented. These show the number of hours that each interconnector was constrained at various levels of power flow.

The most significant constraint equation that bound in the Victorian electricity DSN elements in 2012 involved power flows from New South Wales to Victoria. This was to avoid potential overload of the Murray–Dederang no. 2 330 kV line for the loss of the parallel no.1 330 kV line when using 15-minute line ratings. This constraint was not as significant in 2011 due to the use of 5-minute ratings for these lines in conjunction with a load tripping contract, which expired in June 2012. This load tripping contract was not renewed as studies showed the estimated gross market benefits from a service similar to the previous contract are not considered sufficient.[2]

For links to supporting information relevant to this chapter (published separately), see Section 2.7.

[1] Native demand is a half-hourly average demand measure for Victoria, calculated by summing all scheduled, semi-scheduled and non-scheduled generation and net interconnector flows into Victoria. This accounts for total Victorian load and transmission network losses.

[2] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Victorian-Reliability-Support.

2.1 The Victorian electricity Declared Shared Network

The Victorian electricity DSN has developed and evolved since the early twentieth century when the Victorian Government sought to take advantage of Victoria's large Latrobe Valley coal reserves.

In 1917, the Brown Coal Advisory Committee recommended developing Victoria's brown coal reserves, and constructing a power station and transmission lines. The first capital works carried out to implement this recommendation involved developing the Yallourn Power Station, briquette factory, and open-cut, brown-coal mine in the Latrobe Valley. Work on hydroelectric power also commenced with the Rubicon Hydroelectric Scheme to Melbourne's north-east.

The electricity DSN was developed to connect the substantial brown coal and hydroelectric generation to load centres. Recently, generation developments in Victoria have shifted from high-carbon, fossil fuel-based power plant to natural gas and wind generation. Presently, there is much interest in connecting gas and renewable generation to the transmission network, with most generation connection inquiries concentrated in south-west and regional Victoria.

Today's Victorian transmission network comprises numerous transmission lines and transformers that link power stations to the distribution system. The 500 kV transmission lines primarily transport bulk electricity from generators in the Latrobe Valley in Victoria's east to the major load centre—Melbourne—and then onto the major smelter load and interconnection with South Australia in the west.

Strongly meshed 220 kV transmission lines service the metropolitan areas and Victoria's major regional cities, while 330 kV transmission lines connect to the New South Wales network. The 275 kV transmission lines provide an additional connection to South Australia. Victoria also has two High Voltage Direct Current (HVDC) interconnections: Murraylink to South Australia, and Basslink to Tasmania.

Electricity transmitted through extra high-voltage transmission is converted to lower voltages at terminal stations, where it is then transmitted via the distribution system. There are 33 terminal stations and 114 transformers connected to the electricity DSN. The total circuit distance covered by transmission lines is approximately 6,600 kilometres.

2.2 Network performance in 2012–13

This section outlines the electricity DSN's 2012–13 performance. Network performance was analysed under the following conditions:

- Maximum demand in Victoria. This snapshot shows many network elements under their maximum loading for the year. At the time of the maximum demand snapshot there was high power flow to Victoria from Tasmania, low flow to South Australia and moderate flow to New South Wales.
- High power flow from Victoria. This snapshot shows high loading on several network elements that are not typically heavily loaded under maximum demand conditions.

Table 2-1 lists system data at the time of the maximum demand and high power flow from Victoria snapshots derived from instantaneous State Estimator values obtained from the Energy Management System (EMS).[3]

[3] All DSN outages are restored (power flow is returned to major transmission lines out of service) when assessing network adequacy at the time of the snapshots.

Table 2-1 — Maximum demand and high power flow from Victoria snapshot summaries

Snapshot	Maximum demand	High power flow from Victoria
Date and time	**12 March 2013 16:30:37**	**07 October 2012 01:00:48**
Sum of Victorian loads at time of snapshot (instantaneous)	9,185 MW	5,012 MW
Temperature at Richmond	35.2 °C	17.6 °C
Power flow from South Australia (Heywood)	40 MW	-45 MW
Power flow from South Australia (Murraylink)	22 MW	-7 MW
Power flow from Tasmania	568 MW	433 MW
Power flow to New South Wales	293 MW	1,451 MW
Murray generation	1,416 MW	337 MW

The highest recorded native demand[4] during summer 2012–13 was 9,792 MW, which occurred within the 30-minute period from 16:00 to 16:30 on 12 March 2013. The 50% probability of exceedence[5] (POE) maximum demand projection for 2012–13 was 9,690 MW, according to AEMO's 2012 medium growth scenario Victorian forecasts.[6] The record Victorian native demand level is 10,603 MW, which occurred during summer 2008–09.

The supply-demand balance in Section 2.3 and the assessment of loading on the Victorian electricity DSN in Section 2.4 are based on these snapshots. The analysis presented does not represent the highest possible (worst case) loading of all electricity DSN elements, since Victorian electricity demand and interconnector power flows could have been higher had different conditions prevailed during summer 2012–13.

2.3 Supply and demand in 2012–13

This section presents a breakdown of generation capacity (based on generator registered capacities[7]) and demand at the time of the maximum demand and high power flow from Victoria snapshots described in Section 2.2. This breakdown indicates the transmission network's adequacy and how significantly power flows vary across the network as a whole. Information about reactive power supply and demand is also included.

The electricity DSN comprises the following Victorian electricity regions (see also Figure 2-1):

- Eastern Corridor.
- South-west Corridor.
- Northern Corridor.
- Greater Melbourne and Geelong.
- Regional Victoria.

2.3.1 Maximum demand conditions

Figure 2-1 shows a map of the Victorian electricity DSN, including the electricity regions and interconnectors and the Victorian transmission lines and their voltages. The arrows indicate power flow from one Victorian electricity

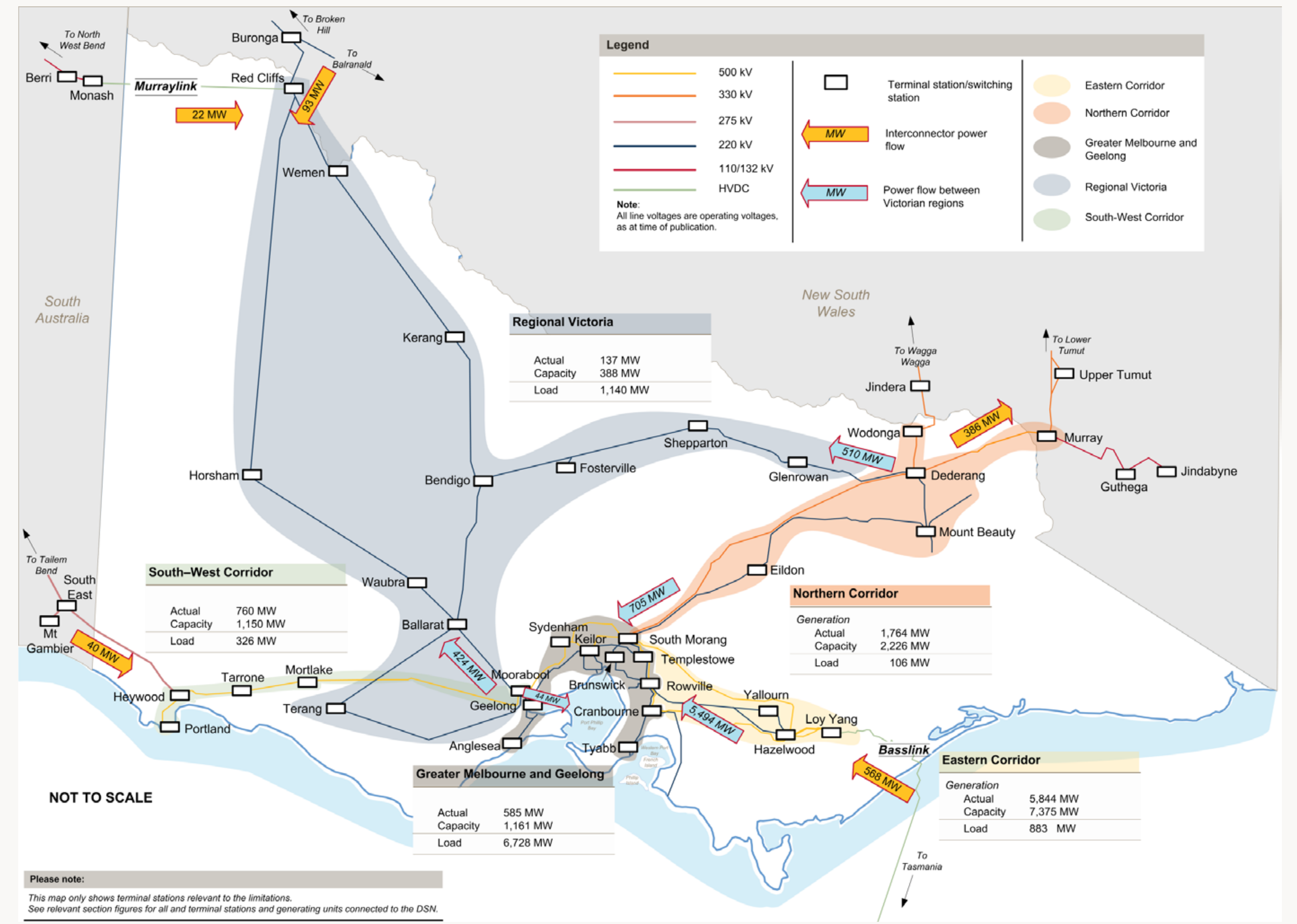
[4] The maximum native demand does not equal the sum of Victorian loads at the time of the maximum demand snapshot (in Table 2-1) because the snapshot refers to a single instant in time, not a half-hourly average. Also, transmission network losses are not included in the snapshot's total loads.
[5] The 50% POE forecast is the maximum demand level that is expected to be exceeded on average every 1 in 2 years.
[6] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.
[7] AEMO. Available at http://www.aemo.com.au/Electricity/Registration.

region to another, or across an interconnector. This flow might be along one or several transmission lines, depending on the regions.

Figure 2-1 shows that at the time of the maximum demand snapshot:

- Most of the Victorian load (73%) was concentrated in Greater Melbourne and Geelong.
- The majority of Victorian generation originated from the Eastern Corridor (64%) and the Northern Corridor (19%), with power flowing from these regions to Greater Melbourne, Geelong and Regional Victoria.
- Net power flow from New South Wales to Victoria comprised -385 MW via the Snowy corridor, and 94 MW from Buronga, supporting demand in Regional Victoria.
- Power flow from Tasmania to Victoria comprised 568 MW via the Basslink interconnector.
- Net power flow from South Australia to Victoria comprised 40 MW via the Heywood interconnector and 22 MW via the Murraylink interconnector.

Figure 2-1 — Generation, load and interconnector flow: maximum demand snapshot



Regional Victoria

Actual	137 MW
Capacity	388 MW
Load	1,140 MW

South–West Corridor

Actual	760 MW
Capacity	1,150 MW
Load	326 MW

Northern Corridor

Generation	
Actual	1,764 MW
Capacity	2,226 MW
Load	106 MW

Greater Melbourne and Geelong

Actual	585 MW
Capacity	1,161 MW
Load	6,728 MW

Eastern Corridor

Generation	
Actual	5,844 MW
Capacity	7,375 MW
Load	883 MW

Please note:

This map only shows terminal stations relevant to the limitations.
See relevant section figures for all and terminal stations and generating units connected to the DSN.

Table 2-2 shows interconnector power flows and approximate capability limits for the maximum demand snapshot, as well as the relevant constraint equation and its description. It also shows that during the maximum demand period, both the Heywood and VIC–NSW interconnector capabilities were reduced due to network outages at the time. For further information about the impact of constraint equations on interconnectors, see Section 2.5.

Table 2-2 — Interconnector power flow and limit, maximum demand snapshot

Interconnector	Actual power flow (MW)	Limit for five-minute dispatch interval (MW)	Limiting constraint equation	Constraint equation description
VIC–NSW	292	914 (export limit)	V>>N-LTUT_B	For an outage of the Lower Tumut to Upper Tumut 330 kV line, to avoid overloading the Murray to Lower Tumut 330 kV line for a loss of the Murray to Upper Tumut 330 kV line.
VIC–SA (Heywood)	-40[a]	-85 (import limit)	F_S++HYSE_L60	For an outage of one of the 500/275kV Heywood transformers, Lower 60 second FCAS requirement in SA to cater for a loss of the Heywood interconnection.
VIC–SA (Murraylink)	-22	-110 (import limit)	S>V_NIL_NIL_RBNW	To avoid overloading the North West Bend to Robertstown 132kV line for no contingencies.
TAS–VIC (Basslink)	568	570 (export limit)	F_MAIN++NIL_MG_R5	FCAS Raise 5-minute requirement for a Mainland Generation Event with Basslink able transfer FCAS.

a. Positive values generally indicate power flows from Victoria to other regions, with the exception of Basslink, where positive values indicate power flows from Tasmania to Victoria. Negative values indicate power flows in the opposite direction.

Table 2-3 lists the reactive power compensation supplied during the maximum demand snapshot. The table shows that at the time of maximum demand a significant amount of reactive power was supplied by shunt capacitors to maintain Victorian voltage quality and stability. At the time of the snapshot there was higher reactive demand than in previous years. This is because the 500 kV line reactors at the Moorabool terminal station were not out of service during this year's summer period.

Table 2-3 — Reactive power supply-demand balance, maximum demand snapshot

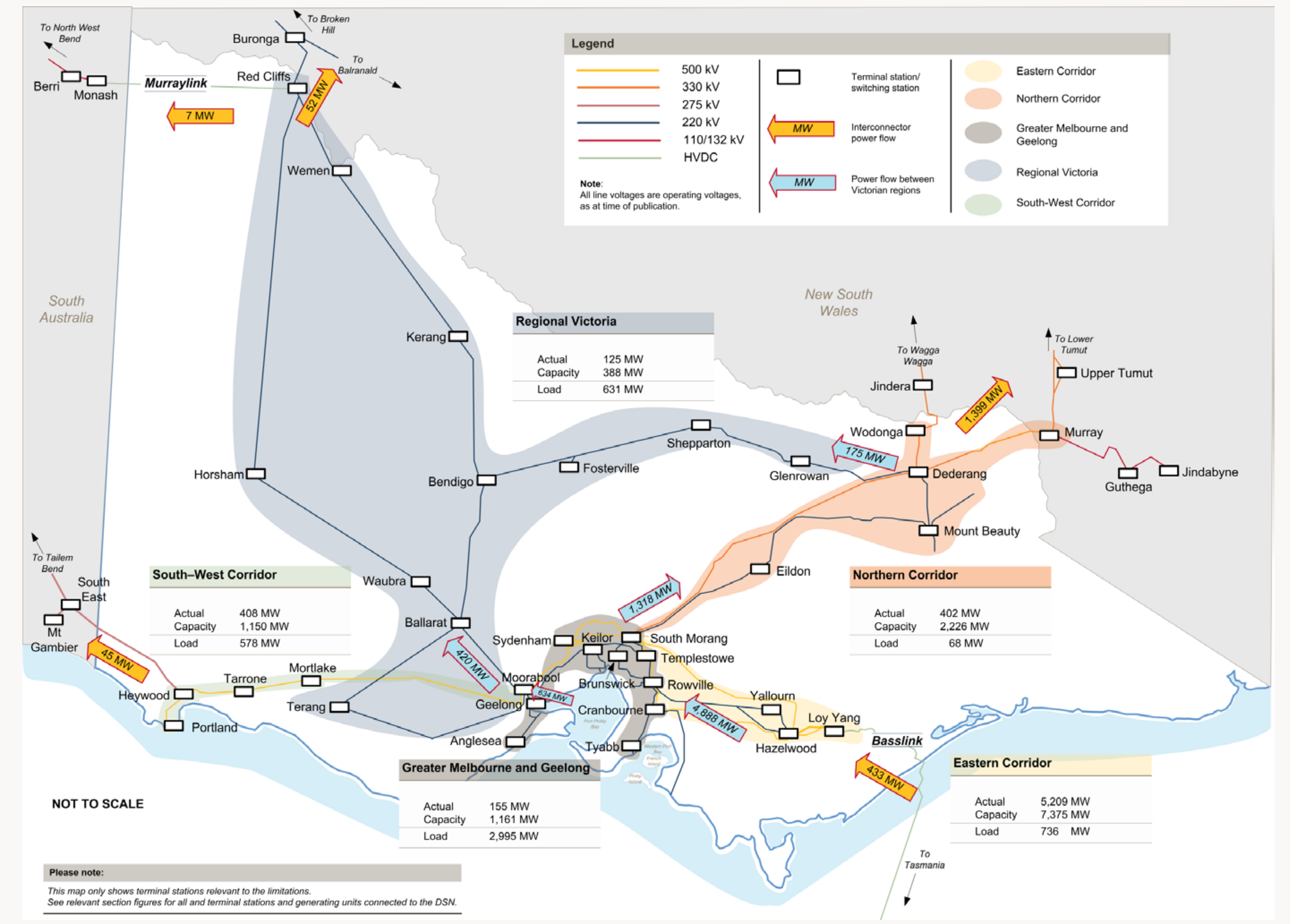
Reactive supply	MVAr	Reactive demand	MVAr
Generation	502	Loads	2,690
Static VAr compensators	-6	Shunt reactors	524
Synchronous condensers	-62	Line losses	4,247
Shunt capacitors	4,296	Inter-regional transfer	383
Line charging	3,114		
Total	**7,844**	**Total**	**7,844**

2.3.2 High power flow from Victoria

Figure 2-2 shows generation, load, and interconnector power flows during the high power flow from Victoria snapshot. It demonstrates that a large part of the Victorian load (61%) was concentrated in Greater Melbourne and Geelong, with the remainder split almost evenly between Regional Victoria, the South-west Corridor and the Eastern Corridor.

Most Victorian generation (84%) was located in the Eastern Corridor with smaller amounts in the Northern Corridor (6%) and the South-west corridor (5%).

Figure 2-2 — Generation, load and interconnector power flow, high power flow from Victoria snapshot



At the time of the high power flow from Victoria snapshot, a substantial amount of power was coming from the base load generation concentrated in the Eastern Corridor. However, most of the power that flowed into Greater Melbourne and Geelong from the Eastern Corridor also flowed into the Northern Corridor for export to New South Wales.

Table 2-4 provides interconnector power flows and approximate capability limits for the high power flow from Victoria snapshot. The table also shows the relevant constraint equation and its description. For information about the impact of constraint equations on interconnectors, see Section 2.5. Actual interconnector power flows during a five-minute interval might be outside the limits shown; these limits are approximate and derive from constraint equations that represent physical limitations only at the end of each interval.

The Victoria–New South Wales interconnector was operating at its limit at the time.

Table 2-4 — Interconnector power flow and limit, high power flow from Victoria snapshot

Interconnector	Actual power flow (MW)	Limit for five-minute dispatch interval (MW)	Limiting constraint equation	Constraint equation description
VIC–NSW	1,468	1,473 (export limit)	V>>N-NIL_HA	To avoid overloading the Murray–Upper Tumut 330 kV line for a trip of the Murray–Lower Tumut 330 kV line.
VIC–SA (Heywood)	45	210 (export limit)	V::N_NILVB_BL_R	Prevent transient instability for fault and trip of a Hazelwood to South Morang 500 kV line.
VIC–SA (Murraylink)	7	0	SVML_000	Murraylink capacity of 0 MW (outage).
TAS–VIC (Basslink)	433	432 (export limit)	F_T++LREG_0050	Tasmania Lower Regulation Requirement greater than 50 MW.

Table 2-5 lists the reactive power supply-demand balance during the high power flow from Victoria snapshot. It demonstrates that at times of low demand, the amount of reactive power demand is significantly less than during peak demand.

Table 2-5 — Reactive power supply-demand balance, high power flow from Victoria snapshot

Reactive power supply	MVAr	Reactive power demand	MVAr
Generation	360	Loads	595
Static VAr compensators	4	Shunt reactors	590
Synchronous condensers	-17	Line losses	2,758
Shunt capacitors	123	Inter-regional transfer	-388
Line charging	3,086		
Total	**3,555**	**Total**	**3,555**

2.4 Victorian electricity DSN loading

This section describes the Victorian electricity DSN loadings for each snapshot. The maximum demand snapshot includes a description for each Victorian region. The high power flow from Victoria snapshot includes information about the Northern Corridor only, as this is the only region where loadings were higher under that snapshot.

The description for each region includes a map showing the loadings on transmission lines and transformers for the operating conditions at the time of the snapshot (see Section 2.2).

The snapshots considered in this section might not represent the worst operating conditions for some elements. This is because higher loadings might emerge (or have occurred in the past) due to increased demand, higher temperature, lower wind speed, installation of new generation, or increases in interconnector power flows. (For more information about transmission network development and network limitations, see Chapter 3.)

2.4.1 Interpreting the regional network loading maps

In each map, line loadings are shown as a percentage:

- The first value (top number) represents loading on a network element under system normal operation, with all transmission network elements in service (N loading).
- The second value (bottom number) represents the expected maximum loading on the same network element following the loss of the most critical network element[8] affecting the loading on the network element being represented (N-1 loading).

Transformer N and N-1 loadings are also shown as percentages in a table on each map. The percentage loadings are based on ratings shown in Appendix A, Table A–1.

The loadings shown are based on ratings used in real time, with N loadings being based on continuous ratings, and N-1 loadings on short-term ratings. The percentage loadings do not reflect other limitations that might result from stability or voltage collapse considerations. For circuits with more than one line, only one set of loading numbers is shown if the loading on each line in the circuit is the same.

For terminal stations connected to the electricity DSN by a single radial line, an N-1 outage represents an outage of the radial line itself, so no N-1 loading is calculated. For example, the Mount Beauty – West Kiewa 220 kV line shown in Figure 2-5.

2.4.2 Maximum demand snapshot

This section describes the electricity DSN loadings for each Victorian region at the time of the maximum demand snapshot.

Figure 2-3 to Figure 2-7 show the map for each Victorian region and the percentage loading on network elements at the time of the maximum demand snapshot.

Eastern Corridor

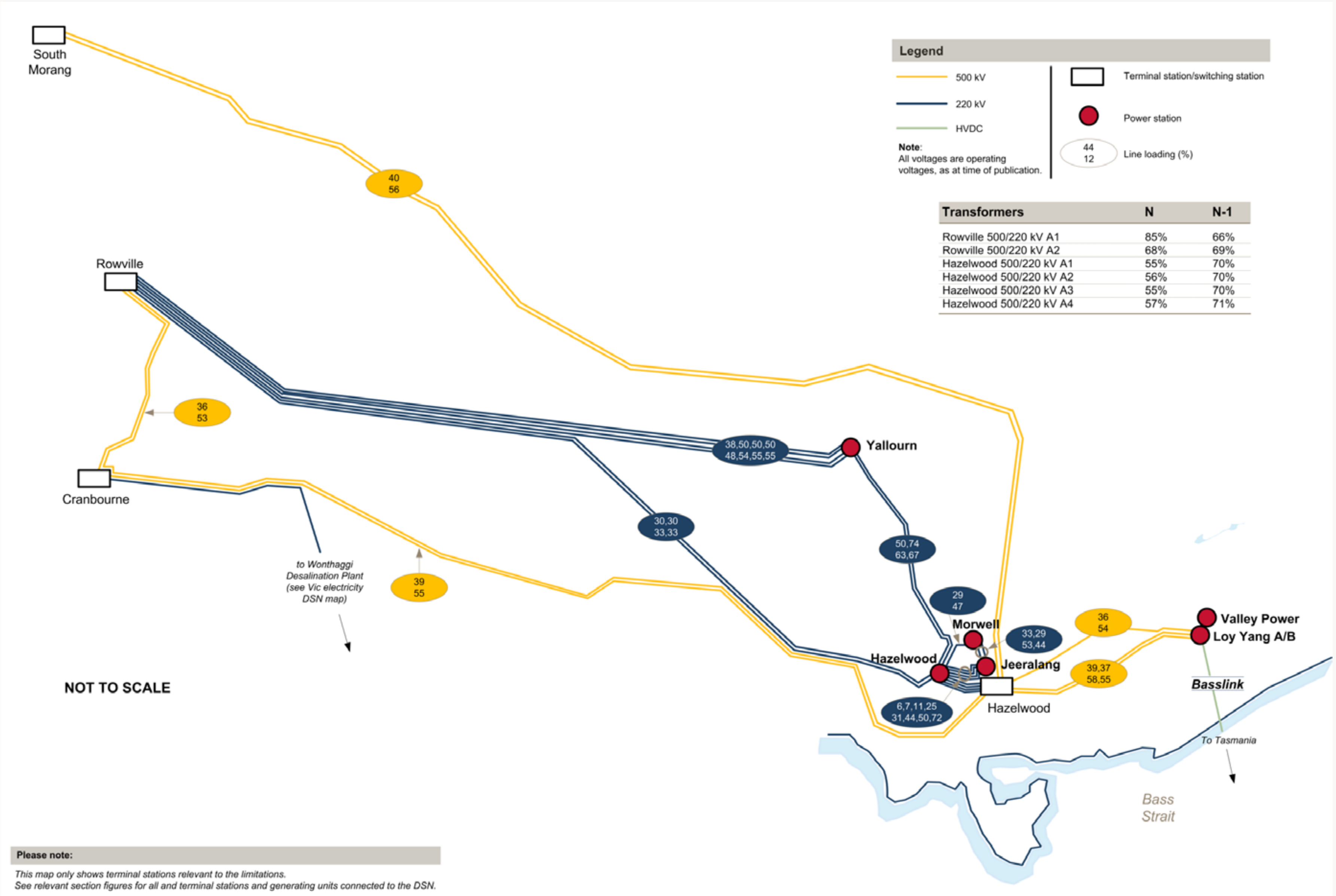
The Eastern Corridor connects the Melbourne Metropolitan Area load centre to generation in the Latrobe Valley. One of the oldest electricity corridors to Melbourne, it still dominates Melbourne's electricity supply, despite electrical connection to hydroelectric schemes to the north and to the adjoining National Electricity Market (NEM) regions; New South Wales, South Australia and Tasmania.

Figure 2-3 shows a map of the Eastern Corridor and the percentage loading on network elements at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

All network elements in the Eastern Corridor had N loadings and calculated N-1 loadings below 100%.

[8] All network outages at the time of maximum demand and high power flow from Victoria were restored before the network element loadings were determined.

Figure 2-3 — Eastern Corridor transmission network loading, maximum demand snapshot



Transformers	N	N-1
Rowville 500/220 kV A1	85%	66%
Rowville 500/220 kV A2	68%	69%
Hazelwood 500/220 kV A1	55%	70%
Hazelwood 500/220 kV A2	56%	70%
Hazelwood 500/220 kV A3	55%	70%
Hazelwood 500/220 kV A4	57%	71%

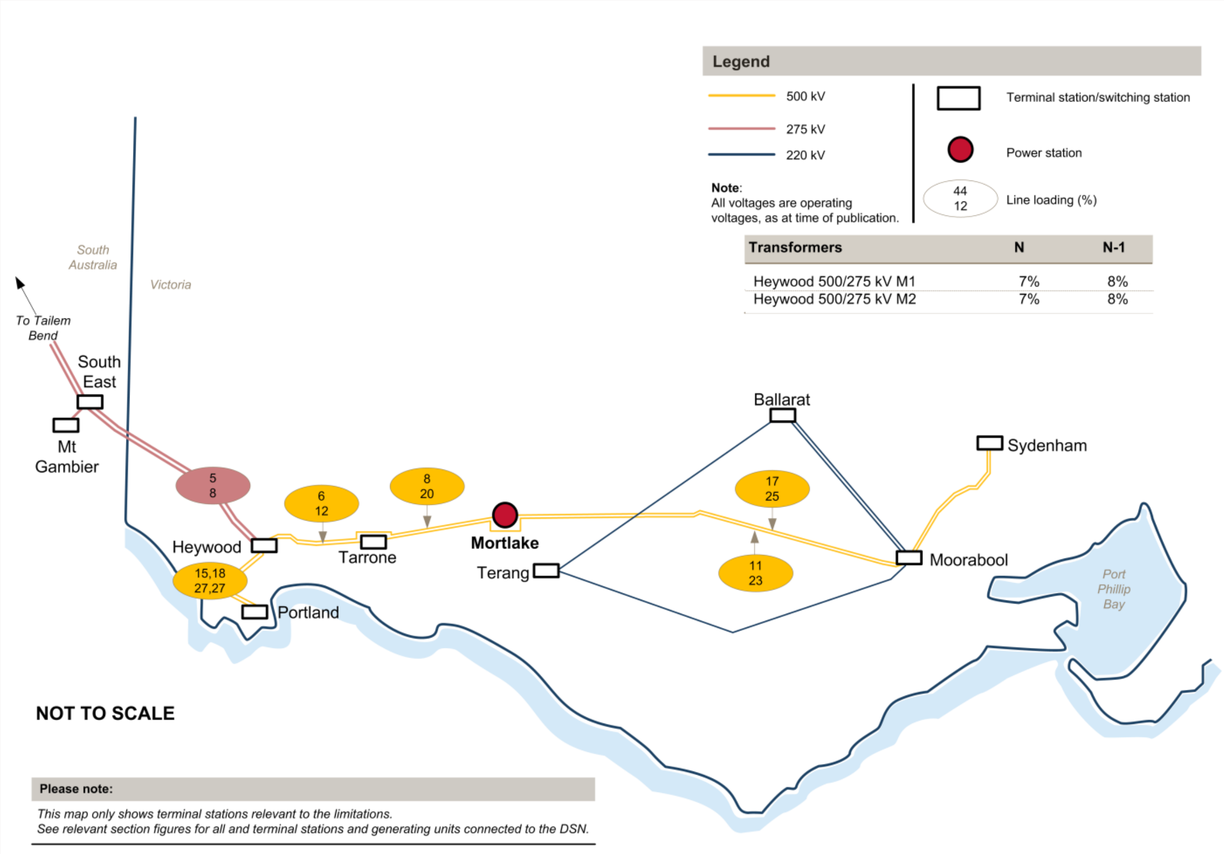
South-west Corridor

The South-west Corridor connects the Greater Melbourne and Geelong load centres with Heywood, Portland and South Australia. Although 220 kV transmission was originally established to supply load to South-western Victoria, 500 kV transmission was subsequently established to supply the Portland aluminium smelter. The last 25 years have seen this corridor's role develop, with electricity connections made to South Australia.

Figure 2-4 shows a map of the South-west Corridor and the percentage loading on network elements at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

All network elements in the South-west Corridor had N loadings and calculated N-1 loadings below 100%. There is also considerable spare thermal capability in the South-west Corridor after meeting the existing supply requirements for the Portland smelter, Geelong, and Regional Victoria load, and power flows to South Australia via the Heywood interconnector. Stability and power quality issues, however, might limit power flows ahead of thermal considerations.

Figure 2-4 — South-west Corridor transmission network loading, maximum demand snapshot



Transformers	N	N-1
Heywood 500/275 kV M1	7%	8%
Heywood 500/275 kV M2	7%	8%

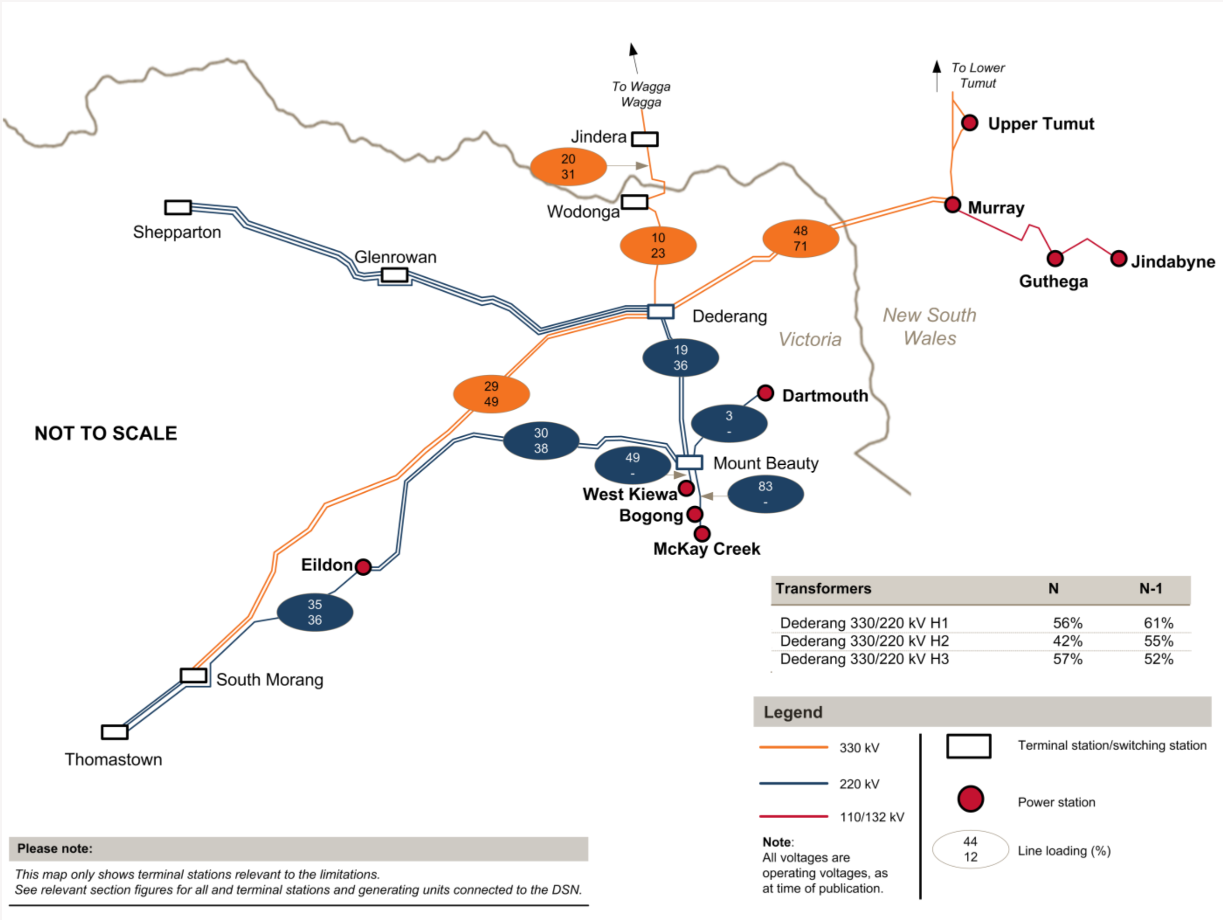
Northern Corridor

The Northern Corridor includes the interconnection to the New South Wales region. This corridor also includes electrical transmission for Victoria's Bogong, Dartmouth, Eildon, McKay Creek, and West Kiewa hydroelectric power stations.

Figure 2-5 shows a map of the Northern Corridor and the percentage loading on network elements at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

All network elements in the Northern Corridor had N loadings and calculated N-1 loadings of less than 100%.

Figure 2-5 — Northern Corridor transmission network loading, maximum demand snapshot



Transformers	N	N-1
Dederang 330/220 kV H1	56%	61%
Dederang 330/220 kV H2	42%	55%
Dederang 330/220 kV H3	57%	52%

Greater Melbourne and Geelong

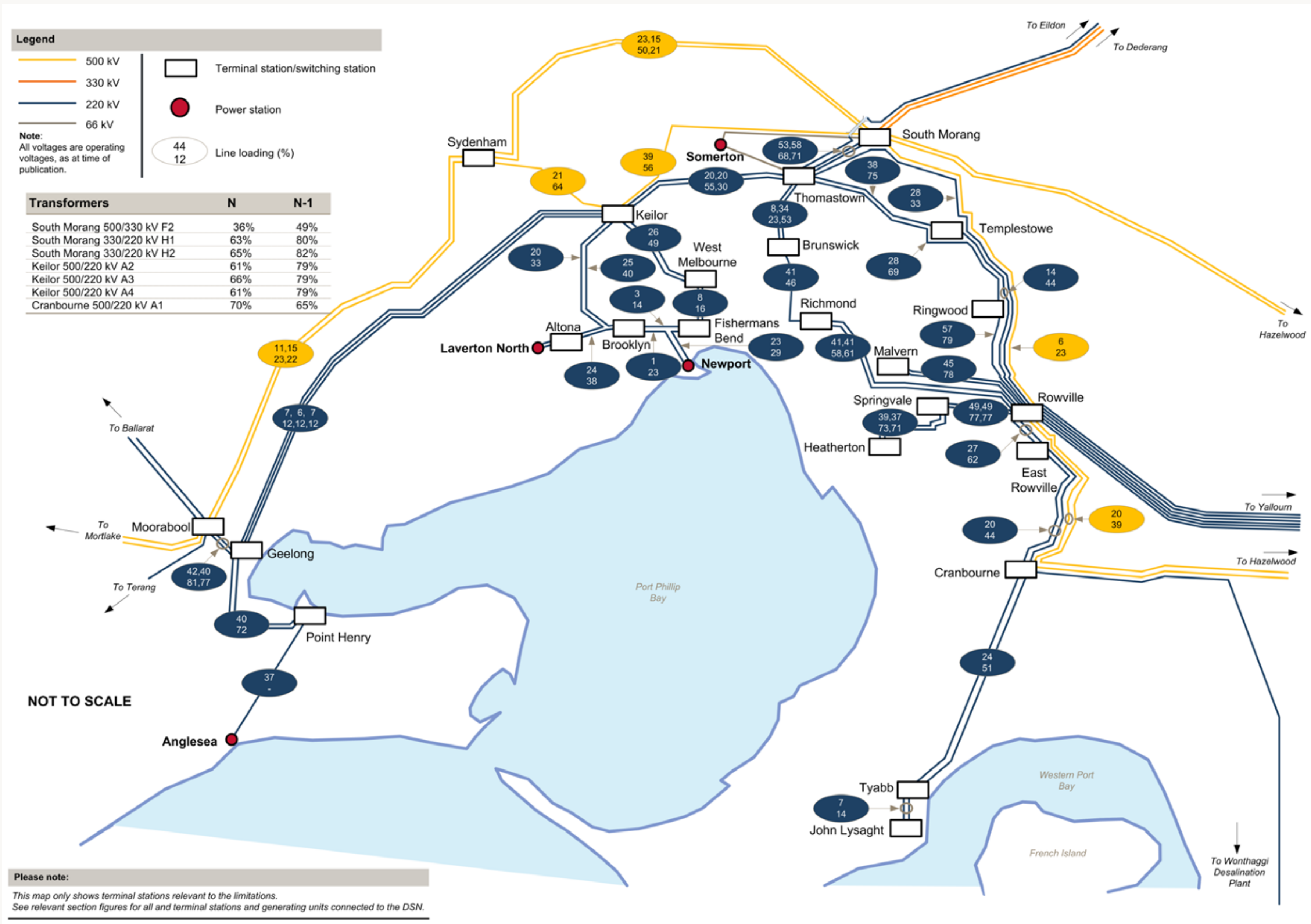
The infrastructure in and around Greater Melbourne and Geelong (encompassing the Melbourne Metropolitan Area, Geelong, and the Mornington Peninsula) has a demand centre configuration with the following:

- An outer 500 kV high-capacity ring around most of the territory being supplied.
- An inner 220 kV ring and radial connections (mainly supplied from the outer ring) to connection points spread throughout the area.

Figure 2-6 shows a map of Greater Melbourne and Geelong and the percentage loading at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

All network elements in Greater Melbourne and Geelong had N loadings and calculated N-1 loadings of less than 100% in the maximum demand snapshot.

Figure 2-6 — Greater Melbourne and Geelong transmission network loading, maximum demand snapshot



Transformers	N	N-1
South Morang 500/330 kV F2	36%	49%
South Morang 330/220 kV H1	63%	80%
South Morang 330/220 kV H2	65%	82%
Keilor 500/220 kV A2	61%	79%
Keilor 500/220 kV A3	66%	79%
Keilor 500/220 kV A4	61%	79%
Cranbourne 500/220 kV A1	70%	65%

Regional Victoria

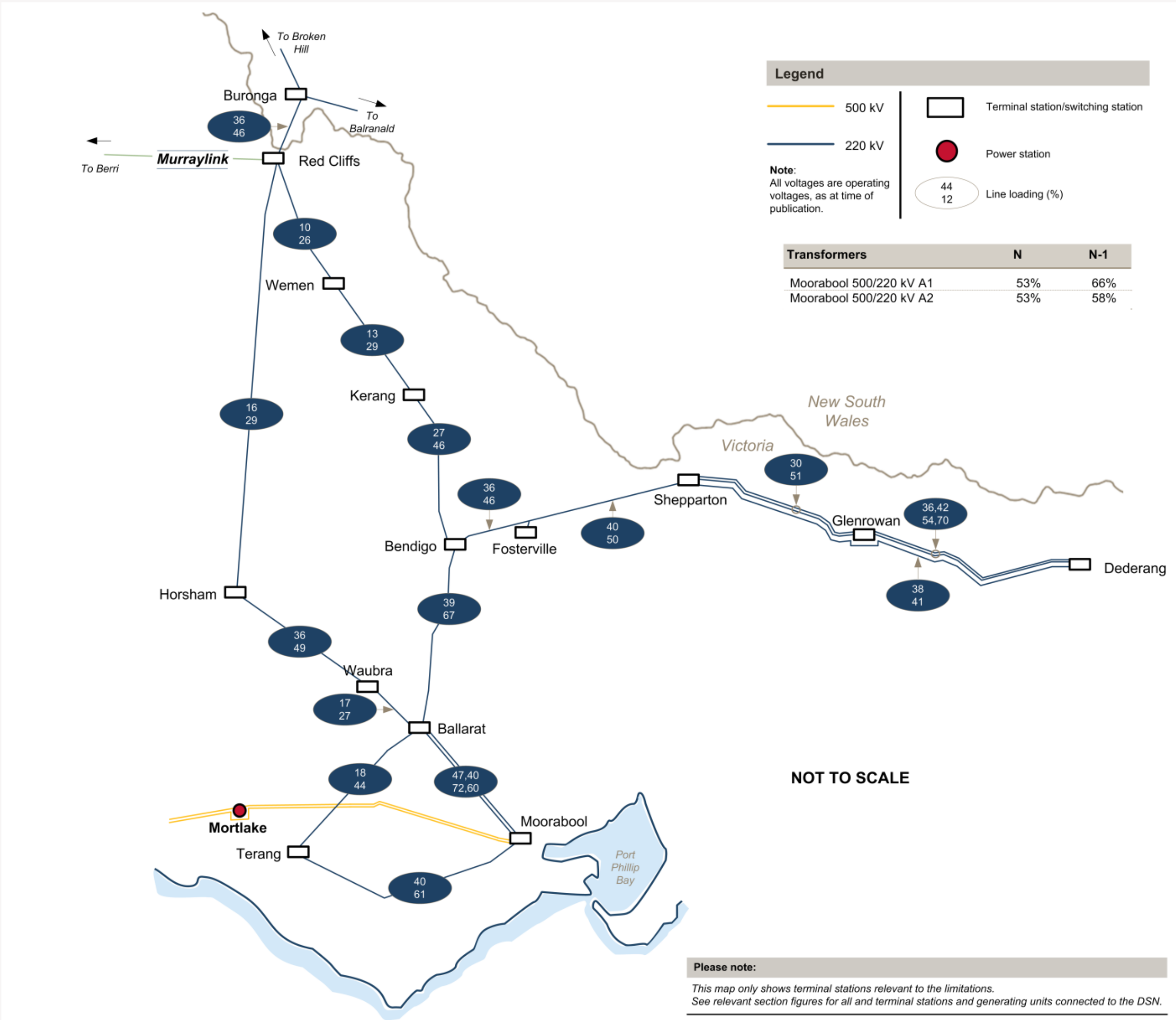
Victoria's regional areas are mainly served by a 220 kV transmission network that delivers energy to regional load centres.

A number of Regional Victoria's transmission lines also form parallel paths with the Northern Corridor. They are strongly influenced by the direction and level of power flow between Victoria and New South Wales; the level of demand at Regional Victorian terminal stations; and the level of power flow across the Murraylink HVDC interconnector between Berri in South Australia and Red Cliffs in Victoria.

Figure 2-7 shows a map of Regional Victoria and the percentage loading on network elements at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

All network elements in Regional Victoria had N loadings and calculated N-1 loadings of less than 100% in the maximum demand snapshot.

Figure 2-7 — Regional Victoria transmission network loading, maximum demand snapshot



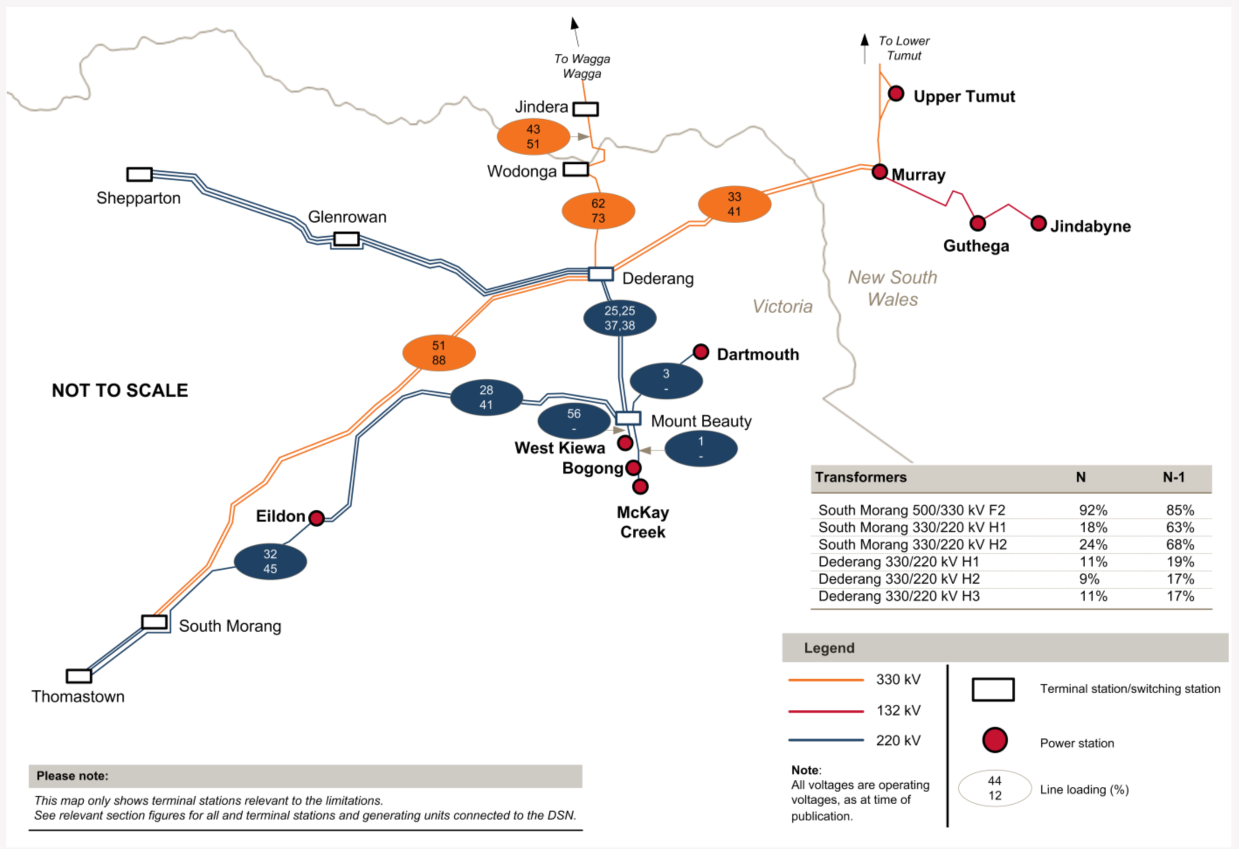
2.4.3 High power flow from Victoria snapshot

This section describes the electricity DSN loadings for the Northern Corridor at the time of the high power flow from Victoria snapshot. Only Northern Corridor elements are shown for this snapshot because this is the only region where electricity DSN elements tend to be more heavily loaded during high power flow from Victoria, rather than during high Victorian demand.

Figure 2-8 shows a map of the Northern Corridor and the percentage loading on network elements at the time of the snapshot. For information about how to interpret this map, see Section 2.4.1.

The percentage loadings are based on the ratings shown in Appendix A, Table A-2.

Figure 2-8 — Northern Corridor transmission network loading, high power flow from Victoria snapshot



The element with the highest system normal loading is the South Morang 500/330 kV F2 transformer. The high loading on this transformer normally occurs during light load periods late at night when there is high power flow to New South Wales.

The elements with the next highest loading were the Dederang – South Morang 330 kV lines, with a calculated N-1 loading of 88% each for the loss of the parallel Dederang – South Morang 330 kV line. These results are similar to those seen in the 2012 VAPR high export snapshot.

All other Northern Corridor network elements had N loadings and calculated N-1 loadings of below 80%.

2.5 Impact of Victorian transmission constraint equations

The National Electricity Market Dispatch Engine (NEMDE) dispatches generation within the thermal, voltage, and stability limits of the transmission network. These limits are expressed by constraint equations. A constraint equation is binding when it is limiting economic dispatch. A constraint equation is violating when NEMDE cannot adjust the dispatch to satisfy the conditions of the equation. When there is a violation, AEMO will take action to return the power system to a secure operating state.

This section presents information about the top 20 binding Victorian transmission constraint equations that had the largest market impact (highest Marginal Cost of Constraint (MCC)) in 2011 and 2012. This illustrates binding for all causes, and not all will necessarily be addressed by network planning solutions. The information provided is a high-level overview relating to the impact of transmission constraint equations across all periods. The constraints which have been included were selected according to the following criteria:

- Equations related to thermal capacity, voltage stability, or transient stability.
- Equations associated with transmission plant within Victoria or part of a Victorian interconnector.
- Equations occurring during system normal conditions (not related to an outage), or equations that did one of two things:
  - Applied during an outage and were binding for 10 hours or more.
  - Applied to Victorian equipment during an outage in another region.

In both 2011 and 2012, most of the constraint equations with a significant MCC over the year were thermal types.

The constraint equation with the largest impact in 2011 was a voltage stability equation that avoids voltage collapse for loss of the Darlington Point – Buronga (X5) line in New South Wales (V^SML_NSWRB_2). This equation limits power flow from Victoria to South Australia via the Murraylink interconnector. The high MCC is due to the replacement of Victorian generation with more expensive generation in South Australia.

In 2012 the constraint equation which had the largest impact was due to the thermal limit preventing the overload of the Murray–Dederang no.2 330 kV line for the loss of the parallel no.1 line. This constraint bound during high demand periods in Victoria, and set the limit for combined flow from the Snowy generation and VIC–NSW interconnector. The high MCC is due to the replacement of NSW generation with more expensive generation in Victoria.

Ten equations have been identified as presenting persistent market impacts (being in the top 20 during both 2011 and 2012). These are listed in Table 2-6.

Table 2-6 — Equations presenting persistent market impacts in both 2011 and 2012 in Victoria

Equation ID	Description
V>>V_NIL_1B	To avoid overloading the Dederang–Murray No.2 330 kV line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 15-minute ratings.
V>>SML_NIL_1	To avoid overloading the Ballarat–Moorabool No.1 220 kV line for loss of the parallel Ballarat–Moorabool No.2 line.
V::N_NILxxx[9]	To avoid transient instability for fault and loss of a Hazelwood – South Morang 500 kV line.

[9] This constraint equation is an aggregation of individual constraint equations.

Equation ID	Description
V^SML_NSWRB_2	For the outage of the New South Wales Murraylink runback scheme, to avoid voltage collapse for loss of the Darlington Point – Buronga (X5) line.
V>>SML_NIL_7A	To avoid overloading the Ballarat North – Buangor 66 kV line for loss of the Ballarat–Waubra–Horsham 220 kV line.
V>>V_NIL_1D	To avoid overloading the Dederang–Murray No. 2 line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 5-minute ratings.
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	To avoid overloading the South Morang F2 transformer when Yallourn Unit 1 is in 220 kV mode and Hazelwood is operating in radial mode.
V>V_NIL_RADIAL_7	To avoid overload of the Hazelwood A4 500/220 kV transformer for trip of the A3 transformer, with Yallourn unit 1 in 500 kV mode, radial mode, Hazelwood 1,2,3,4 busses split.
V>>V_NIL1A_R	To avoid overloading one Dederang – South Morang line (flow from South Morang – Dederang) for loss of the parallel line.
V>>V_NIL_5	To avoid overloading either of the Dederang – Mount Beauty 220 kV circuits (flow to the North) for a trip of the other circuit.

In 2012, the binding hours for the V::N_NILxxx constraint equations reduced significantly from those seen in previous years. The limit advice associated with these constraint equations was revised in late 2012 to account for recent network changes. The new constraint equation formulation is expected to bind less than the previous version would have. In both years, the most frequently binding constraint equations did not necessarily affect the market the most. For a comprehensive review and analysis of constraint equations and their market impacts in 2012, see AEMO's *NEM Constraint Report 2012*.[10]

Marginal Cost of Constraint

The MCC provides a measure of the effect that binding or violating constraint equations have on economic dispatch, by giving a relative measure of the impact of different constraint equations.

The MCC for an individual constraint equation is calculated by re-running the market dispatch engine after removing non-conforming, violating, and fixed loading constraint equations, and relaxing binding constraint equations until their marginal value is less than the constraint violation penalty factor (CVP) multiplied by the market price cap (MPC). This shows how much the cost of generation (based on generator bids) will be reduced at the margin.

The annual market impact of a constraint equation can be represented by summing the MCC in the periods when the equation binds or violates during that year.

The MCC is not the same as the market benefit from augmentations to address the limitation that the constraint equation represents. The MCC is based on generator bids, whereas assessments of market benefits from augmentations are, among other factors, based on estimates of changes in generator fuel costs.

For more information about the MCC, see Appendix C of the Australian Energy Regulator (AER) market impacts publication.[11]

[10] AEMO. Available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report.
[11] AER. Indicators of the Market Impact of Transmission Congestion—Decision: Appendix C. 9 June 2006.

Binding Victorian transmission constraint equations, 2011 and 2012

Table 2-7 and Table 2-8 provide information about the top 20 binding Victorian transmission constraint equations with the greatest market impact in 2011 and 2012. The information includes the constraint equation names, descriptions, market impact in dollar terms, and the number of hours they bound for the year (binding hours). Only constraint equations associated with transmission plant within Victoria or parts of Victorian interconnectors are considered.

Figure 2-9 and Figure 2-10 chart the market impacts and binding hours for Table 2-7 and Table 2-8, respectively.

Table 2-7 — Top 20 binding Victorian transmission constraint equations, 2011

Label	Equation ID	MCC ($)	Binding hours	Description
1	V^SML_NSWRB_2	480,721	15	For the outage of the New South Wales Murraylink runback scheme, to avoid voltage collapse for loss of the Darlington Point – Buronga (X5) line.
2	V>>SML_NIL_7A	362,910	22	To avoid overloading the Ballarat North–Buangor 66 kV line for loss of the Ballarat–Waubra–Horsham 220 kV line.
3	V>>V_NIL_5	140,353	54	To avoid overloading either of the Dederang – Mount Beauty 220 kV circuits (flow to the North) for a trip of the other circuit.
4	V>V_NIL_RADIAL_7	103,306	42	To avoid overloading the Hazelwood A4 transformer for a trip of the A3 transformer, Yallourn Unit 1 is in 500 kV mode and Hazelwood is in radial mode with the 1,2,3,4 busses split.
5	V::N_NILVxxx	65,345	1132	To avoid transient instability for fault and loss of a Hazelwood – South Morang line.
6	V>>N-NIL_HA	57,922	105	To avoid overloading the Murray – Upper Tumut (65) line for loss of the Murray – Lower Tumut (66) line.
7	V>V_NIL_RADIAL_3	52,445	15	To avoid overloading the Hazelwood A1 transformer for a trip of the A2 transformer, Yallourn Unit 1 is in 500 kV mode and Hazelwood is in radial mode with the 1,2,3,4 busses split.
8	V>>V_NIL_1D	50,489	Less than 1 hour	To avoid overloading the Dederang–Murray No. 2 line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 5-minute ratings.
9	V>>V_NIL_1B	36,520	30	To avoid overloading the Dederang–Murray No. 2 line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 15-minute ratings.
10	V>V_HWTX1_PAR_3-5_2	34,610	30	For outage of the Hazelwood A1 or A2 transformer, to avoid overloading the Rowville No.2 and No.1 220 kV lines for loss of the second Hazelwood A1 or A2 transformer.
11	V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	15,410	207	To avoid overloading the South Morang F2 transformer when Yallourn Unit 1 is in 220 kV mode and Hazelwood is operating in radial mode.
12	V>>V_NIL1A_R	12,584	159	To avoid overloading one Dederang – South Morang line (flow from South Morang – Dederang) for loss of the parallel line.
13	V>>SML_NIL_1	8,633	1	To avoid overloading the Ballarat–Moorabool No.1 line for loss of the parallel Ballarat–Moorabool No.2 line.
14	V::V_DDSM	8,367	41	For outage of the Dederang – South Morang line, to avoid transient instability for a fault and trip of the remaining Dederang – South Morang line.

Label	Equation ID	MCC ($)	Binding hours	Description
15	V::V_EPTT	8,006	23	For an outage of the Eildon–Thomastown line, to avoid transient instability for fault and trip of a Dederang – South Morang line.
16	V::N_SMCS_xxx	4,612	53	For an outage of the South Morang 330 kV series capacitor, to avoid transient instability for a fault and trip of a Hazelwood–South Morang 500 kV line when Hazelwood is in radial mode.
17	V>>V_TTS_B3_2	3,304	12	For an outage of the Thomastown No. 3 220 kV bus, to avoid overloading the Thomastown – South Morang No. 2 220 kV line for a trip of the South Morang F2 transformer.
18	V::N_DDMS_xxx	2,929	33	For an outage of a Dederang–Murray line, to avoid transient instability for a fault and trip of a Hazelwood – South Morang 500 kV line when Hazelwood is in radial mode.
19	V>>V_SMTXF2_6	2,538	17	For an outage of the South Morang F2 transformer, to avoid overload of a Thomastown – South Morang circuit for a trip of the parallel Thomastown – South Morang circuit.
20	V::N_BUDP_xxx	2,530	44	For an outage of the Buronga – Darlington Point 220 kV line, to avoid transient instability for a fault and trip of a Hazelwood – South Morang 500 kV line when Hazelwood is in radial mode.

Figure 2-9 — Top 20 binding Victorian transmission constraint equations, 2011

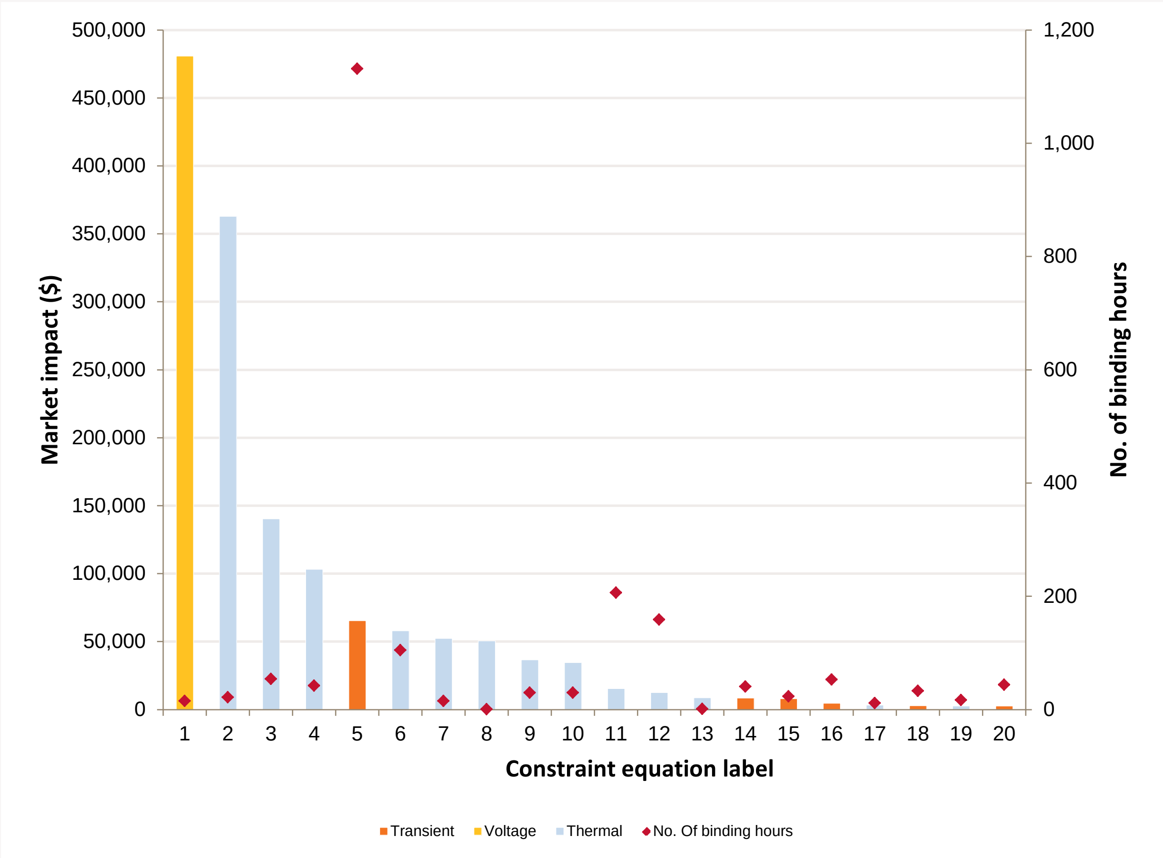
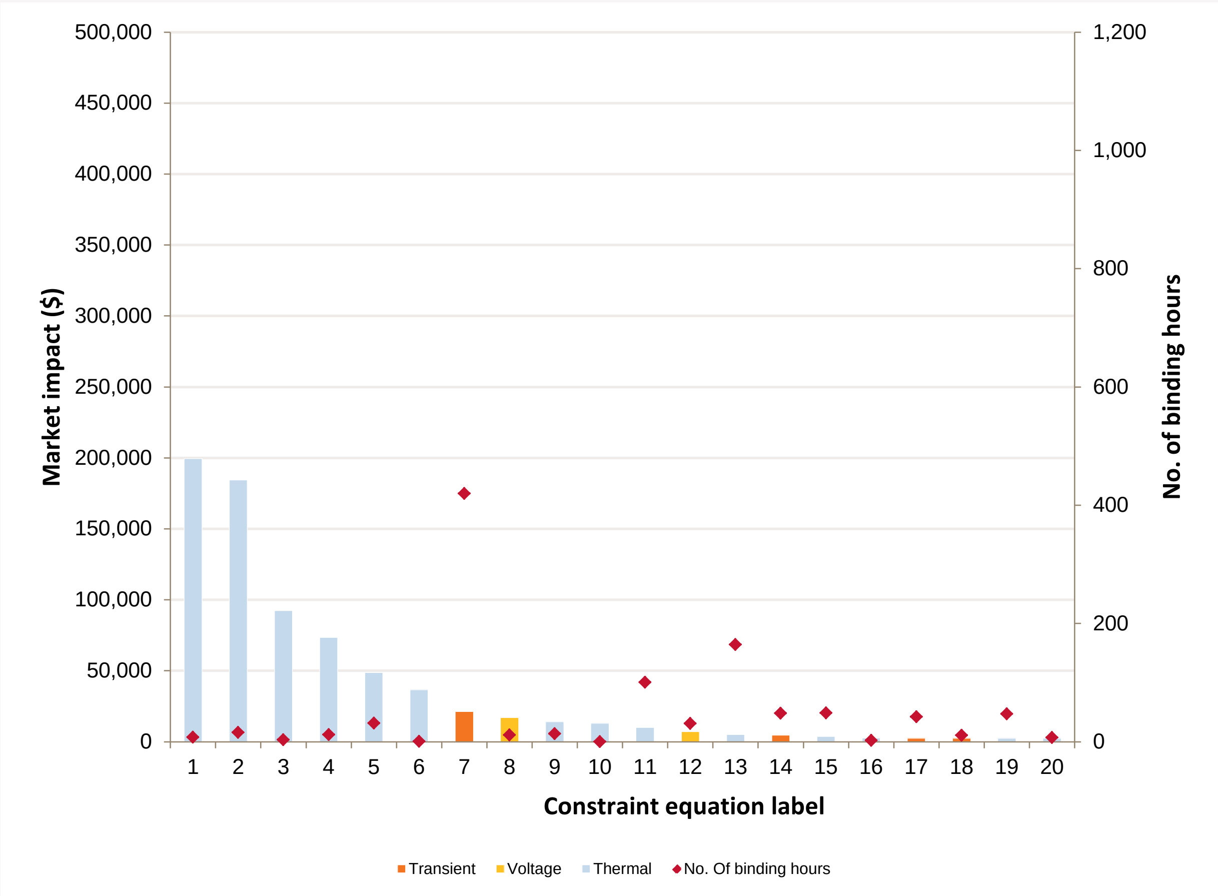


Table 2-8 — Top 20 binding Victorian transmission constraint equations, 2012

Label	Equation ID	MCC ($)	Binding hours	Description
1	V>>V_NIL_1B	199,598	7	To avoid overloading the Dederang–Murray No.2 330 kV line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 15-minute ratings.
2	V>V_HWTS_TX3_3-5_MOD	184,356	16	For outage of a Hazelwood A3 or A4 transformer, to avoid overloading the Rowville–Yallourn No.5, 6, 7 or 8 220 kV lines for trip of the second Hazelwood A4 or A3 transformer.
3	V>>SML_NIL_1	92,355	3	To avoid overloading the Ballarat–Moorabool No.1 220 kV line for loss of the parallel Ballarat–Moorabool No.2 line.
4	V>SMLBAHO4	73,526	12	For outage of a Ballarat–Horsham or Bendigo–Kerang 220 kV line, to avoid overloading the Buronga–Redcliffs (0X1) 220 kV line for trip of Bendigo–Kerang, or Ballarat–Horsham 220 kV line.
5	V>SML_BUDP_2	48,799	32	For outage of a Buronga–Balranald–Darlington Pt. (X5) 220 kV line, to avoid overloading a Horsham–Waubra 220 kV line section on trip of Bendigo–Kerang 220 kV line.
6	V>>V_NIL_3	36,539	Less than 1 hour	To avoid overloading either Dederang – South Morang 330 kV line (flow South) for trip of the parallel line.
7	V::N_NILxxx	21,337	420	To avoid transient instability for fault and loss of a Hazelwood – South Morang 500 kV line.
8	V^SML_NSWRB_2	17,024	12	For the outage of the New South Wales Murraylink runback scheme, to avoid voltage collapse for loss of the Darlington Point–Buronga (X5) line.
9	V>>SML_NIL_7A	14,177	14	To avoid overloading the Ballarat North–Buangor 66 kV line for loss of the Ballarat–Waubra–Horsham 220 kV line.
10	V>>V_NIL_1D	12,900	Less than 1 hour	To avoid overloading the Dederang–Murray No. 2 line for loss of the parallel line No. 1 line with the DBUSS-Line control scheme enabled, based on 5-minute ratings.
11	VS_HYTS_TX	9,984	101	Heywood interconnector limit for Victoria to South Australia flows based on Heywood transformer 30-minute rating.
12	V_APHY1_1	7,078	31	For the outage of the Heywood to APD No. 1 500 kV line section and Heywood M2 500/275 kV transformer, limit voltage unbalance at the APD 500 kV bus with one Mortlake unit in service.
13	V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	4,983	164	To avoid overloading the South Morang F2 transformer when Yallourn Unit 1 is in 220 kV mode and Hazelwood is operating in radial mode.
14	V::N_HWSM_xxx	4,537	48	For outage of the Hazelwood–South Morang or Hazelwood–Cranbourne or Hazelwood–Rowville 500 kV line, to avoid transient instability for fault and trip of a Hazelwood–South Morang 500 kV line.
15	V>S_NIL_HYTX_HYTX	3,682	48	Heywood interconnector limit for Victoria to South Australia flows to avoid overloading a 500/275 kV Heywood transformer for loss of the parallel transformer, based on 30-minute ratings.

Label	Equation ID	MCC ($)	Binding hours	Description
16	V>V_NIL_RADIAL_7	2,585	2	To avoid overload of the Hazelwood A4 500/220 kV transformer for trip of the A3 transformer, with Yallourn unit 1 in 500 kV mode, radial mode, Hazelwood 1,2,3,4 busses split.
17	V::N_HYSE_xxx	2,458	42	For an outage of a Heywood – South East 275kV line, to avoid transient instability for fault and trip of a Hazelwood – South Morang 500 kV line.
18	V::N_DDSM2	2,451	11	For outage of the Dederang – South Morang line, to avoid transient instability for a fault and trip of a Hazelwood – South Morang 500 kV line.
19	V>>V_NIL1A_R	2,355	47	To avoid overloading one Dederang – South Morang line (flow from South Morang – Dederang) for loss of the parallel line.
20	V>>V_NIL_5	2,303	7	To avoid overloading either of the Dederang – Mount Beauty 220 kV circuits (flow to the North) for a trip of the other circuit.

Figure 2-10 — Top 20 binding Victorian transmission constraint equations, 2012



2.6 Interconnector utilisation

Figure 2-11 to Figure 2-14 show the impact that constraint equations had on interconnector utilisation in 2012. The stacked columns show the number of hours when various equation types were binding and resulted in constrained flow on the interconnector, for various levels of interconnector power flow.

The number of binding hours for the 10 constraint equations with the most binding hours is shown for each interconnector. The equations are divided into the following categories:

- System normal or outage equations related to transient stability.
- System normal or outage equations related to voltage stability.
- System normal or outage equations related to thermal capacity.
- Equations related to frequency control ancillary services (FCAS).
- Other constraint equations. This category also includes all other binding constraint equations that were not in the top 10.

Positive values (on the right-hand side) generally indicate power flows from Victoria to other regions, with the exception of Basslink, where positive values indicate power flows from Tasmania to Victoria. Negative values indicate power flows in the opposite direction.

For each level of power flow shown, the total number of hours that each constraint equation was binding has been added together to form the columns. In some cases the total number of binding hours for constraints at a particular power flow exceeds the number of hours that the power flow was at that level. This is because it is possible for more than one constraint equation to be binding at a particular time.

The figures show that interconnector power flows are constrained throughout the range of possible power flows and as a result there is no single value for an interconnector's capability.

Figure 2-11 — VIC–NSW interconnector power flow and binding hours for constraint equation types impacting interconnector power flow

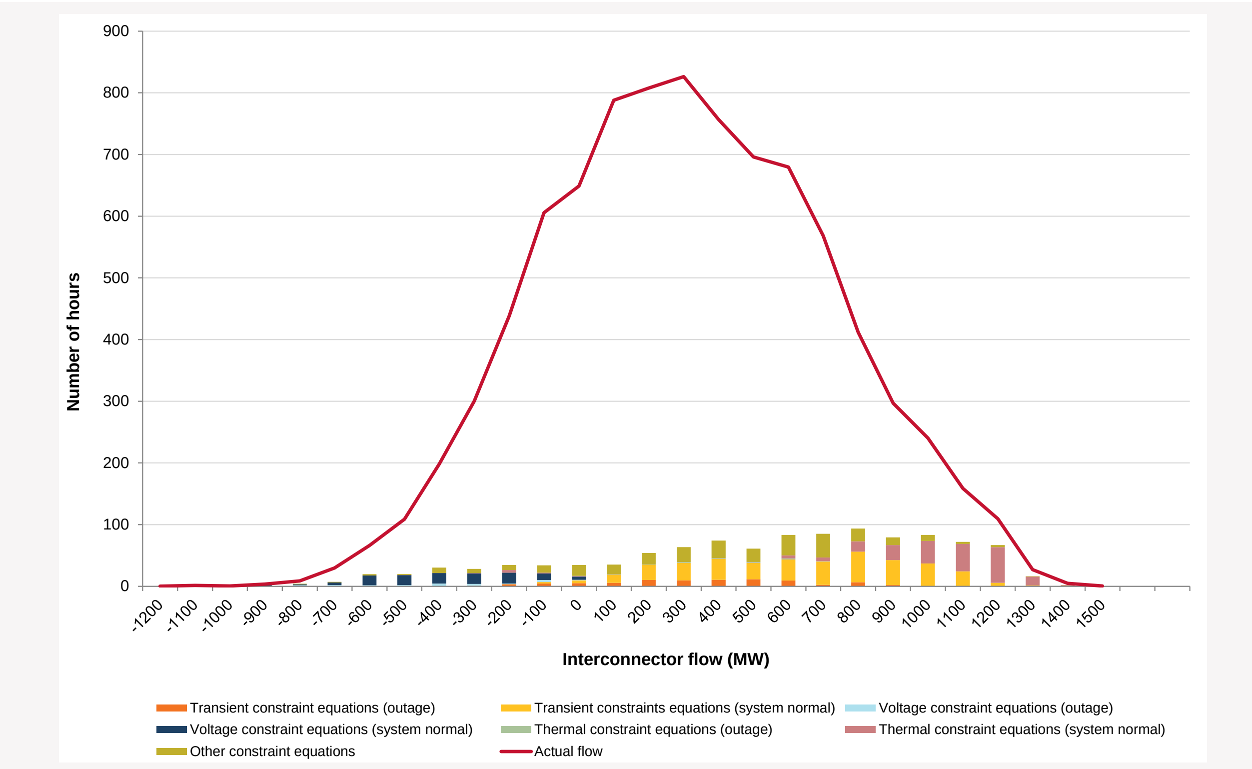


Figure 2-12 — VIC–SA (Heywood) interconnector power flow and binding hours for constraint equation types impacting interconnector power flow

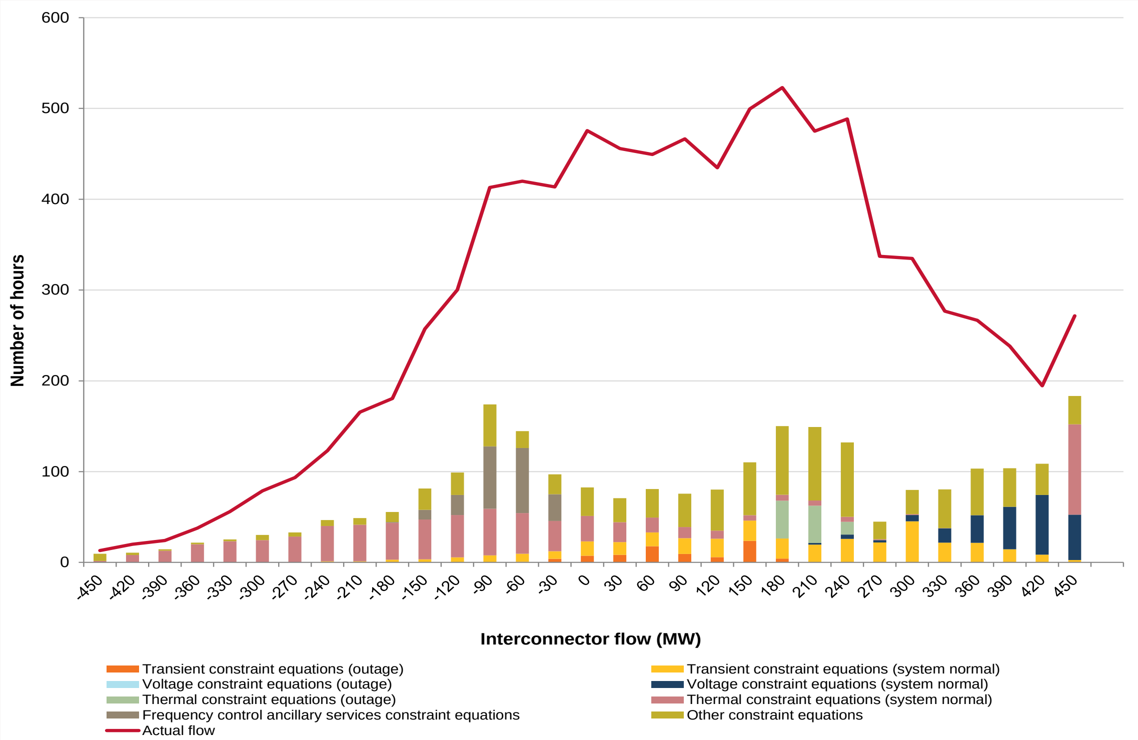


Figure 2-13 — VIC–SA (Murraylink) interconnector power flow and binding hours for constraint equation types impacting interconnector power flow

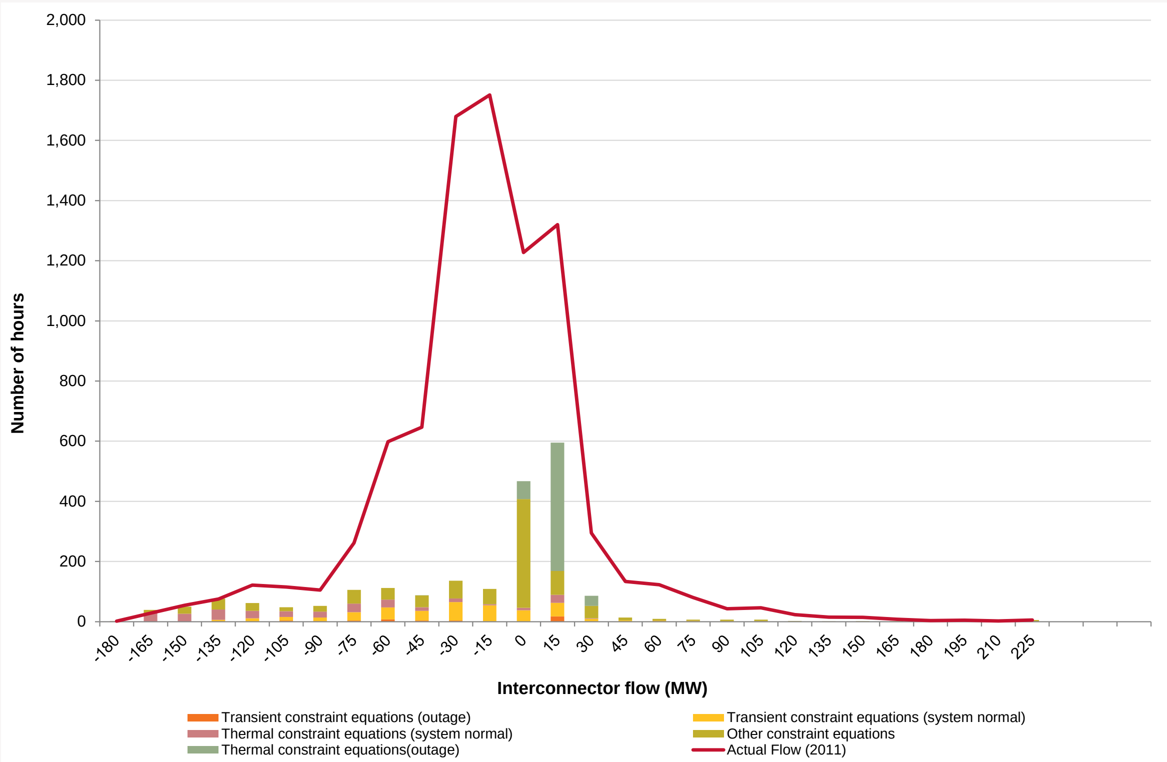
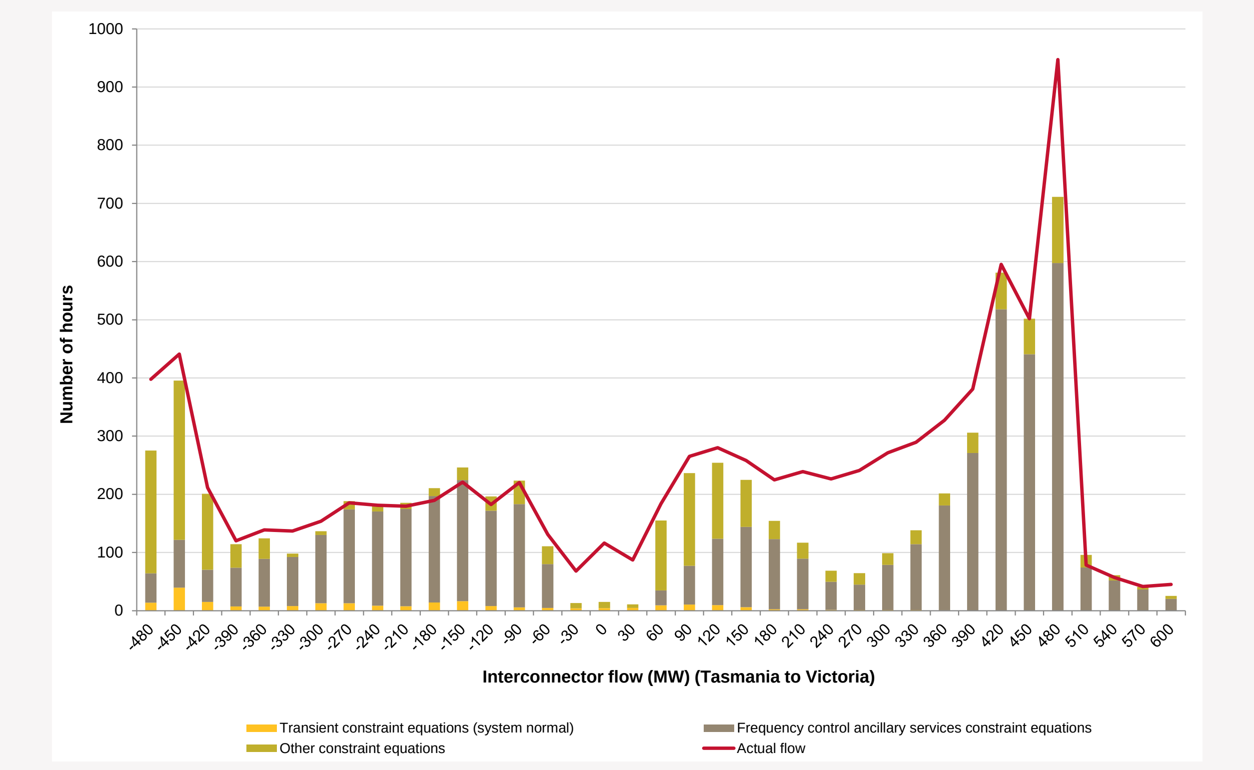


Figure 2-14 — TAS–VIC (Basslink) interconnector power flow and binding hours for constraint equation types impacting interconnector power flow



2.7 Supporting information

This section provides links to other information about Victorian electricity DSN. Some of this information appeared in previous VAPRs.

Information source	Website address
2012 National Electricity Forecasting Report (NEFR)	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012
Victorian regional demand forecasts	http://www.aemo.com.au/Electricity/Planning/Forecasting
Victorian Terminal Station Demand Forecast 2012–13 to 2022–23	http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria
Economic outlook	http://www.aemo.com.au/Electricity/Planning/Forecasting
Short-circuit Levels for Victorian Electricity Transmission 2013–17	http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report/Victorian-Short-Circuit-Level-Review
Annual NEM Constraint Report	http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report

CHAPTER 3 - ELECTRICITY TRANSMISSION DEVELOPMENT

Summary

This chapter provides information about transmission network limitations in the electricity Declared Shared Network (electricity DSN) expected to impact the electricity market in the next three to 10 years and beyond. It also highlights the triggers leading to limitations based on changes in generation, imports, exports, and demand.

Eastern Corridor

In the Eastern Corridor, minor market impacts are forecast over the period, and no unserved energy is anticipated. The relevant network limitations will be reassessed if additional generation is located in the Latrobe Valley.

South-west Corridor

Increased Victoria – South Australia (Heywood) interconnector congestion is forecast due to expected wind farm development in South Australia. AEMO and ElectraNet have completed a Project Assessment Conclusions Report (PACR) for a joint Regulatory Investment Test for Transmission (RIT-T) application that investigated increasing the interconnector's capability.

The RIT-T concluded that an upgrade of capacity to a notional 650 MW in both directions has positive net market benefits. This upgrade is expected to be commissioned and in service in mid-2016.

In the South-west Corridor, new generation connections have led to network limitations involving the Moorabool–Heywood 500 kV circuits and the Heywood transformers, particularly under network prior outage conditions. A Heywood bus-tie to address the uneven loading limitation on the Heywood transformers was recommended as part of the Heywood interconnector RIT-T upgrade. Further assessment of the voltage unbalance limitation on the Moorabool–Heywood 500 kV circuits will be undertaken in 2013–14.

Northern Corridor

In the Northern Corridor, potential restrictions on the New South Wales – Victoria interconnector power flows in the New South Wales to Victoria direction are forecast, but only result in minor market impacts over the period studied. The limitations are not forecast to cause unserved energy, and AEMO will continue to monitor triggers that could necessitate an increase in the interconnector capability.

Greater Melbourne and Geelong

In Greater Melbourne and Geelong, demand growth will lead to network limitations that might require load reduction to avoid overloading on lines and transformers, as well as causing voltage instability.

The 2012 VAPR noted RIT-Ts would be undertaken for the identified thermal limitations associated with the Rowville – East Rowville and Ringwood–Thomastown 220 kV lines; transformers at Rowville and Cranbourne; and a voltage stability limitation in supplying the entire Eastern Melbourne area.

It was also noted that further assessment of network limitations was required, including the Rowville–Springvale–Heatherton 220 kV lines, the South Morang 330/220 kV transformer loadings, and a Western Melbourne voltage stability limitation.

These limitations have been reassessed to account for the 2012 National Electricity Forecasting Report (NEFR) and 2012 Terminal Station Demand Forecasts (TSDF), with the following results:

- A RIT-T termination notice for the Eastern Melbourne Reactive support RIT-T has been published due to the limitation and augmentation timing being deferred, but a new combined Eastern and Western

Melbourne reactive support limit being identified for further assessment.

- A RIT-T Project Assessment Draft Report (PADR) has been completed for the Eastern Metropolitan thermal limitations recommending a third Rowville 500/220 kV transformer in 2018.
- The Rowville–Springvale–Heatherton 220 kV line loading limitation and the Malvern–Rowville 220 kV line loading limitation and augmentation timings being deferred, but still categorised as a priority assessment.
- The Thomastown–Ringwood–Rowville 220 kV line loading limitation and augmentation timing being deferred, but still categorised as a priority assessment.
- Studies highlight the need to upgrade the South Morang 330/220 kV transformers in conjunction with SP AusNet's asset renewal program starting in 2016.

AEMO will further assess these limitations in 2013–14 in collaboration with the relevant distribution network service providers.

Regional Victoria

In Regional Victoria, demand growth has led to network limitations that might require load reduction to avoid significant overloading on transmission lines, particularly on the Ballarat–Bendigo and Ballarat–Moorabool 220 kV lines.

AEMO initially commenced two RIT-T applications to identify the preferred solutions, but has since combined both assessments into a single application. The RIT-T recommends installing wind monitoring on the Bendigo–Ballarat 220 kV line in 2014–15, and uprating the Bendigo–Ballarat 220 kV line and installing a third Moorabool–Ballarat 220 kV line in 2016–17.

In the 2012 VAPR, additional reactive support in Regional Victoria was also forecast within the next five years, and AEMO had published a Project Specification Consultation Report (PSCR) for this limitation. Following reassessment using the 2012 NEFR and TSDF forecasts, a RIT-T termination notice was published as the limitation and augmentation timing was deferred until at least 2019–20.

New and additional generation connected to the 500 kV transmission network around Moorabool has resulted in a loading increase on the 500/220 kV transformers at Moorabool and Keilor, and on the Geelong–Moorabool 220 kV lines. Load reduction or generation re-dispatch might also be required within the next 10 years to avoid significant overloading.

For links to supporting information relevant to this chapter (published separately), see Section 3.6.

3.1 Transmission development overview

This section presents a summary of planned electricity DSN augmentation projects derived from data provided by connection applications. For more information about generation projects and project advancement criteria, see AEMO's generation information page.[1]

Committed projects are those where proponents have secured the necessary land and planning approvals and have entered into contracts for finance and generating equipment; and construction has either commenced or a firm date has been set. The service dates provided derive from connection application information, and represent the date when full commercial operation is expected to begin.

Project locations are shown on Figure 3-1 using the reference numbers (beginning with 'C') provided for each committed project.

3.1.1 Committed projects

Brunswick Terminal Station – C1

A connection application has been received for a new 66 kV supply from the existing Brunswick Terminal Station. The proposed connection comprises three 225 MVA 220/66 kV transformers. The proposed service date is mid-2015.

Elaine Terminal Station – C2

A new wind farm (Mount Mercer Wind Farm) is being developed in the vicinity of Elaine, and a new Elaine Terminal Station is being established to enable its connection to the electricity DSN. Elaine Terminal Station will be cut into the existing Moorabool–Ballarat 220 kV No.2 line approximately 20 kilometres from the Ballarat Terminal Station. The proposed service date is 2014.

Mount Mercer Wind Farm – C3

A new wind farm comprising 64 turbines with an installed capacity of 130 MW is being constructed. It will connect to the Moorabool–Ballarat 220 kV No.2 line at Elaine Terminal Station, which is being established for this purpose. The proposed service date is late-2014.

3.1.2 Publicly announced and proposed transmission projects

Alcoa Portland emergency bus-tie

A 500 kV emergency bus-tie has been proposed by Alcoa for use during Alcoa Portland–Heywood 500 kV line and circuit breaker outages to ensure continued supply to the Alcoa Portland Aluminium Smelter. The proposed service date is mid-2014.

Deer Park Terminal Station

Powercor has proposed a terminal station at Deer Park, with two 225 MVA 220/66 kV transformers connecting to the existing Keilor–Geelong 220 kV No.2 line. The proposed service date is late-2017.

3.1.3 Transmission network limitation summary

This section summarises the electricity DSN limitations by Victorian electricity region:

- Eastern Corridor.
- South-west Corridor.
- Northern Corridor.
- Greater Melbourne and Geelong.
- Regional Victoria.

[1] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

Each region's limitations are presented in terms of the actions AEMO will take to address them, which fall into one of the following categories:

- Current RIT-Ts. Previous reviews concluded that these limitations significantly affect power system and market performance, to an extent that positive net market benefits can be realised with credible solutions to relieve them within the next five years. AEMO has commenced RIT-T applications to identify the preferred solution to address the limitation.
- Upcoming RIT-Ts. The latest review concluded that these limitations significantly affect power system and market performance, to an extent that positive net market benefits can be realised with credible solutions to relieve them within the next five years. AEMO will commence RIT-T applications within the next 12 months to identify the preferred solution to address the limitation.
- Priority assessment. The latest review concluded that these limitations significantly affect power system and market performance, to an extent that positive net market benefits might be realised with credible solutions to relieve them within the next five–10 years. AEMO will undertake further assessment of these limitations, possibly progressing to RIT-T applications over the next 12 months.
- Monitoring. The latest review concluded that these limitations do not significantly affect power system and market performance, to an extent that no positive net market benefits can be realised with credible solutions to relieve them within the next five–10 years under forecast demand and generation developments. AEMO will not undertake further detailed assessment for the next 12 months but will continue to monitor the triggering conditions.

AEMO bases its limitation analysis on the Victorian terminal station demand forecast and maximum demand (MD) forecasts developed in September 2012 and November 2012, respectively. AEMO is currently reviewing its electricity demand forecasts and intends to publish the updated forecasts in mid-2013. These updated forecasts will be used in upcoming RIT-Ts and for further assessment of limitations.

Figure 3-1 shows the Victorian (and its near-border) transmission network. It also shows the committed projects (listed in Section 3.1.1) and network limitations (in Table 3-1) related to RIT-T applications or assessments that AEMO may conduct in 2013–14.

A guide to reading the maps and legends

Transmission lines are depicted by coloured lines, with colours indicating voltages.

Terminals or switching stations are shown by a hollow rectangle.

Committed transmission augmentations are shown by a shaded rectangle containing a reference number.

A circle containing the letter C and a reference number represents a committed load connection.

A shaded circle containing the letter L and a reference number represents a limitation in the priority assessment category.

A shaded diamond containing the letter C and a reference number depicts a committed generating unit.

A shaded triangle containing the letter R and a reference number depicts a limitation related to a RIT-T/joint planning project.

Figure 3-1 — Victorian transmission network, committed projects and limitations

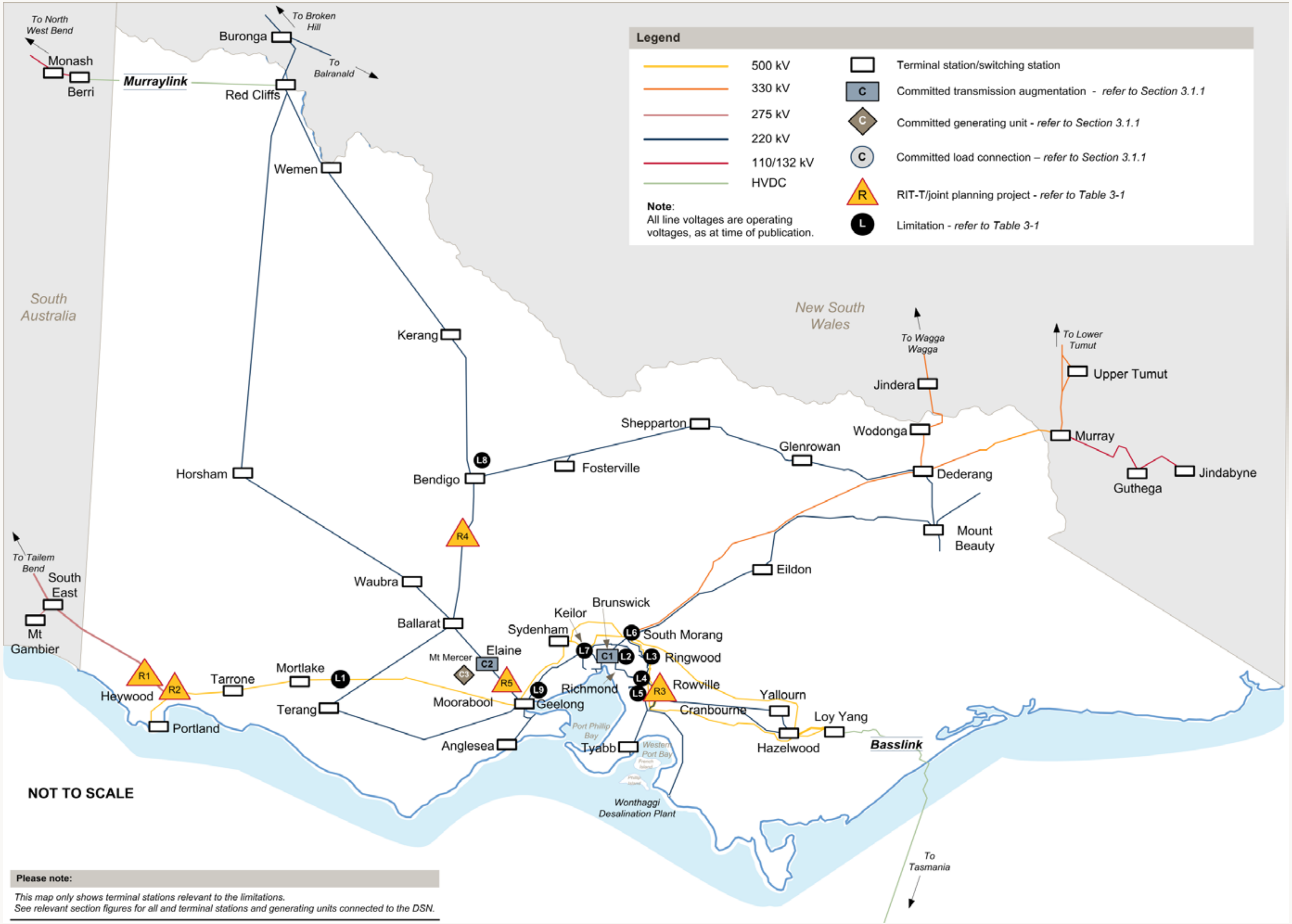


Table 3-1 lists a summary of the network limitations for each Victorian region. The suggested network solutions are only regarded as possible, and need to be confirmed by RIT-T applications.

Table 3-1 — Electricity transmission network limitation summary

Limitation	Possible network solution	Drivers	Status	Figure 3-1 reference
Eastern Corridor (see Section 3.2.2)				
Hazelwood–Loy Yang 500 kV line loading	A new (fourth) single circuit 500 kV line between Hazelwood and Loy Yang.	Generation dispatch/new generation connected around the Latrobe Valley 500 kV transmission network, or increased import via Basslink.	Monitoring.	N/A
Latrobe Valley–Melbourne 500 kV line loading	A new (additional) 500 kV line from Hazelwood to Melbourne (Cranbourne, Templestowe, or another site).	Generation dispatch/new generation connected around the Latrobe Valley 500 kV and/or 220 kV transmission networks, or increased import via Basslink.	Monitoring.	N/A
Rowville–Yallourn 220 kV line loading	Upgrading the 220 kV lines between Hazelwood, Yallourn, and Rowville, and/or an additional 500/220 kV transformer installation at Hazelwood.	Generation dispatch/new generation connected to the Yallourn 220 kV transmission network.	Monitoring.	N/A
Hazelwood 500/220 kV transformer loading	An additional 500/220 kV transformer installation and/or upgrading the 220 kV lines between Hazelwood, Yallourn, and Rowville.	Generation dispatch/new generation connected to the Latrobe Valley 220 kV transmission network.	Monitoring.	N/A
South-west Corridor (see Section 3.2.3)				
Victoria–South Australia interconnector congestion	A third Heywood transformer and supporting network augmentations in South Australia.	New wind generation in South Australia.	Current RIT-T with ElectraNet (see Section 3.2.1).	R1
Heywood 500/275/22 kV transformer loadings	Installation of a 500 kV bus-tie at Heywood Terminal Station.	Commissioning of Mortlake Power Station, MacArthur wind farm and further new generation.	Current RIT-T, as part of the Victoria–South Australia interconnector (see Section 3.2.1).	R2
Moorabool–Heywood–Portland 500 kV line voltage unbalance	Installation of a switched shunt capacitor with individual phase switching at Heywood or near the Portland Alcoa plant.	Prior outage and new generation connections along the Moorabool–Heywood 500 kV lines.	Priority assessment.	L1
Voltage instability or collapse	Additional dynamic reactive compensation.	Prior outage and new generation/increased bi-directional power transfer between Victoria and South Australia on the Heywood interconnector.	Monitoring.	N/A

Limitation	Possible network solution	Drivers	Status	Figure 3-1 reference
South-west–Melbourne 500 kV line loading	A new (additional) Moorabool – Mortlake/Tarrone – Heywood 500 kV line.	New generation connections along the Moorabool–Heywood 500 kV circuits or around Moorabool.	Monitoring.	N/A
Northern Corridor (see Section 3.2.4)				
Dederang–South Morang 330 kV line loading	Installation of a new South Morang–Dederang 330 kV line, or up-rating of the existing lines.	Increased New South Wales import/export.	Monitoring.	N/A
Murray–Dederang 330 kV line loading	Installation of a new Murray–Dederang 330 kV line or a new Jindera–Dederang 330 kV line.	Increased import from New South Wales.	Monitoring.	N/A
Dederang–Mount Beauty 220 kV line loading	Wind monitoring installation or line up-rating of the Dederang–Mount Beauty 220 kV line.	Increased generation in the Eildon/Kiewa area or increased export to New South Wales.	Monitoring.	N/A
Eildon–Thomastown 220 kV line loading	Installing wind monitoring or line up-rating of the Eildon–Thomastown 220 kV line.	Increased import from New South Wales.	Monitoring.	N/A
Dederang 330/220 kV transformer loading	A new 330/220 kV transformer installation at Dederang Terminal Station.	Increased import from New South Wales.	Monitoring.	N/A
Voltage collapse at South Morang, Dederang, Wodonga, and Jindera	Capacitor bank installation, and/or controlled series compensation at Dederang Terminal Station.	Increased import from New South Wales.	Monitoring.	N/A
Greater Melbourne and Geelong (see Section 3.2.5)				
Inadequate reactive power support in Metropolitan Melbourne	Additional reactive power compensating plant installation.	Increased demand in Metropolitan Melbourne.	Priority Assessment.	L2
Cranbourne A1 500/220 kV transformer and Rowville A2 500/220 kV transformer loading	A new 500/220 kV transformer at Cranbourne Terminal Station.	Increased demand in Eastern Metropolitan Melbourne.	Monitoring.	NA
Rowville A1 500/220 kV transformer loading	A new 500/220 kV transformer at Rowville, or a new 500 kV switchyard and 500/220 kV transformation at Ringwood.	Increased demand in Metropolitan Melbourne.	Current RIT-T (see Section 3.2.2).	R3

Limitation	Possible network solution	Drivers	Status	Figure 3-1 reference
Ringwood–Thomastown 220 kV line loading	Connection of Ringwood Terminal Station to the existing Rowville–Templestowe 220 kV line, or a new 500 kV switchyard and 500/220 kV transformer at Ringwood.	Increased demand at Ringwood Terminal Station.	Priority assessment.	L3
Rowville–Malvern 220 kV line loading	Rowville–Malvern 220 kV line up-rating and/or wind monitoring installation.	Increased demand at Malvern Terminal Station.	Priority assessment.	L4
Rowville–Springvale–Heatherton 220 kV line loading	A new Cranbourne-Heatherton 220 kV double circuit line or underground cable, or a new 220 kV underground cable between Heatherton and Malvern.	Increased demand at Springvale and/or Heatherton Terminal Stations.	Priority assessment.	L5
Templestowe–Thomastown line loading	Cut-in the Thomastown–Ringwood 220 kV line at Templestowe, or install a new (third) 1,000 MVA 500/220 kV transformer at Rowville.	Load growth around the Melbourne Metropolitan area.	Monitoring.	N/A
South Morang H2 330/220 kV transformer loading	Replacement of the existing transformer with a higher-rated unit.	Increased demand in Metropolitan Melbourne and/or increased import from New South Wales.	Priority assessment.	L6
South Morang H1 330/220 kV transformer loading	Replacement of the existing transformer with a higher-rated unit.	Increased demand in Metropolitan Melbourne and/or increased import from New South Wales.	Monitoring	N/A
South Morang–Thomastown 220 kV No.1 and No.2 line loading	Connection of South Morang Terminal Station to the existing Thomastown–Rowville 220 kV line or Eildon–Thomastown 220 kV line.	Increased demand in Metropolitan Melbourne.	Monitoring	N/A
South Morang F2 500/330 kV transformer loading	A new 500/330 kV or 500/220 kV transformer at South Morang Terminal Station.	Increased export to New South Wales.	Monitoring.	N/A
Keilor A2 500/220 kV transformer and Keilor A4 500/220 kV transformer loading	A new 500/220 kV transformer at Keilor, or replacement of the existing transformers with higher-rated units.	Increased demand in Western Metropolitan Melbourne.	Priority Assessment.	L7
Keilor–Thomastown 220 kV No.2 line loading	Uprate existing line or a new 500/220 kV transformer at Rowville.	Increased demand in Metropolitan Melbourne.	Monitoring.	N/A

Limitation	Possible network solution	Drivers	Status	Figure 3-1 reference
Rowville–Ringwood 220 kV line loading	Connection of Ringwood Terminal Station to the existing Rowville–Templestowe 220 kV line, or a new 500 kV switchyard and 500/220 kV transformer at Ringwood (the same solution as for the Ringwood–Thomastown 220 kV line loading).	Increased demand at Ringwood Terminal Station.	Monitoring.	N/A
Rowville–East Rowville 220 kV line loading	A new 500/220 kV transformer at Cranbourne, an East Rowville-Rowville 220 kV line uprating, or a new underground cable between East Rowville and Rowville.	Increased demand in Eastern Metropolitan Melbourne.	Monitoring	N/A
Increase in fault levels beyond network plant capability	Replace switchgear with higher fault-level capability plant, install series reactors to limit the fault level contribution of new and existing plant and, if reliably and economically feasible, un-mesh the transmission network.	Increased demand and impedance changes from connecting new transmission network plant and generating units.	Monitoring.	N/A
Regional Victoria (see Section 3.2.6)				
Inadequate reactive power support	Additional reactive power compensating plant installation.	Increased demand in Regional Victoria and interconnector exports.	Priority Assessment.	L8
Ballarat–Bendigo 220 kV line loading	Wind monitoring installation and/or line up-rating to 82 ºC conductor temperature.	Increased demand in Regional Victoria.	Current RIT-T (see Section 3.2.3).	R4
Ballarat–Moorabool 220 kV No.1 line loading	Install a third Ballarat–Moorabool 220 kV circuit (new circuit will be strung on existing towers).	Increased demand in Regional Victoria.	Current RIT-T (see Section 3.2.3).	R5
Geelong–Moorabool 220 kV line loading	Upgrading the limiting station assets at Geelong Terminal Station or installing a new single circuit or double circuit Geelong–Moorabool 220 kV line.	Increased demand in Geelong and Keilor areas.	Priority assessment.	L9
Moorabool 500/220 kV transformer loading	Install a third Moorabool 500/220 kV transformer.	New generation in South Western Victoria, and increased Regional Victorian and Geelong demand.	Monitoring	N/A
Bendigo–Fosterville–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV, or up-rate the existing conductor from 82 ºC to 90 ºC.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Monitoring.	N/A

Limitation	Possible network solution	Drivers	Status	Figure 3-1 reference
Dederang–Glenrowan 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line, or uprate or replace the existing Dederang–Glenrowan 220 kV or Dederang–Shepparton 220 kV lines with a new double circuit line.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Monitoring.	N/A
Dederang–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line, or uprate or replace the existing Dederang–Glenrowan 220 kV or Dederang–Shepparton 220 kV lines with a new double circuit line.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Monitoring.	N/A
Glenrowan–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line, or replace the Glenrowan–Shepparton 220 kV line with a double circuit line.	Increased demand at Shepparton Terminal Station.	Monitoring.	N/A
Ballarat–Waubra–Horsham 220 kV line loading	Upgrade the Ballarat–Waubra–Red Cliffs line termination at Horsham or replace the existing Ballarat–Waubra–Horsham 220 kV line with a double circuit line.	Increased demand at the Horsham Terminal Station.	Monitoring.	N/A
Kerang–Wemen–Redcliffs 220 kV line loading	Replace the Kerang–Wemen–Redcliffs 220 kV line with a double circuit line.	Increased demand at the Kerang Terminal station.	Monitoring.	N/A
Moorabool–Terang 220 kV line loading	Up-rate or replace the existing Ballarat–Terang 220 kV line with a double circuit line.	Increased demand at Terang Terminal Station.	Monitoring.	N/A
High fault level	Operational arrangements, series reactor installation, or switchgear replacement.	Increased demand and/or generation, particularly in Regional Victoria.	Monitoring.	N/A

3.1.4 Network support and control ancillary services (NSCAS)

Addressing NSCAS gaps identified in the 2012 NTNDP

The 2012 NTNDP NSCAS assessment[2] identified a potential NSCAS gap in relieving the New South Wales to Victoria voltage stability limitation.

[2] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Network-Support-and-Control-Ancillary-Services-Assessment-2012.

AEMO will address this potential NSCAS gap by investigating whether any suitable NSCAS options can be acquired at an appropriate cost to deliver a positive net market benefit. If so, then AEMO may start a tendering process to acquire the suitable NSCAS.

As this potential NSCAS gap is associated with the New South Wales to Victoria interconnector, AEMO will conduct the investigation in conjunction with TransGrid.

3.2 Summary of Regulatory Investment Test for Transmission applications

TNSPs are required to undertake a Regulatory Investment Test for Transmission (RIT-T) for all proposed transmission investment projects.[3]

AEMO follows the three-stage process set out in the NER for undertaking RIT-Ts:

- Stage one involves preparing a Project Specification Consultation Report (PSCR). The PSCR informs the market of the upcoming network limitations and potential solutions, with a focus on providing information to proponents of non-network solutions.
- Stage two involves preparing a Project Assessment Draft Report (PADR). The PADR presents the results of the economic cost-benefit test and identifies the preferred investment option for consultation.
- Stage three involves preparing a Project Assessment Conclusions Report (PACR). The PACR makes an investment recommendation, which is followed by the procurement process.

This section summarises the RIT-Ts undertaken since publication of the 2012 VAPR, and presents detailed findings for each RIT-T. Information relating to the RIT-Ts AEMO is currently undertaking can be found on AEMO's website.[4]

AEMO's 2012 VAPR identified the need to undertake RIT-Ts to determine the best options for managing the following limitations:

- Uneven Heywood 500/275/22 kV transformer loadings and voltage instability (collapse) in the vicinity of Heywood and the Portland Alcoa plant (see Figure 3-1, reference R1 and R2).
- Inadequate reactive power support in Eastern Metropolitan Melbourne.
- Loading relating to the Cranbourne A1 500/220 kV transformer, Rowville A2 500/220 kV transformer, and Rowville A1 500/220 kV transformer (see Figure 3-1, reference R3).
- East Rowville – Rowville 220 kV line loading.
- Ringwood–Thomastown 220 kV line loading.
- Inadequate reactive power support around Bendigo in Regional Victoria.
- Ballarat–Bendigo 220 kV line loading (see Figure 3-1, reference R4).
- Ballarat–Moorabool 220 kV No.1 line loading (see Figure 3-1, reference R5).

The information presented in the 2012 VAPR was based on energy and maximum demand forecasts from 2011. Compared to these, the 2012 NEFR forecasts showed a significant reduction in maximum demand from summer 2012–13 onwards. As a result, after preparing the TSDF forecasts in September 2012, AEMO reassessed the timing of investments to address the limitations previously identified.

This resulted in the following changes to the RIT-T assessments:

[3] Except in the circumstances described in clause 5.16.3 of the NER.
[4] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs.

- AEMO has reviewed the Eastern Metropolitan reactive requirements need taking into account updated demand projections, and published a RIT-T termination notice in February 2013 noting that due to reduced demand, this limitation and augmentation timing has now been deferred until at least 2018–19.
- AEMO has reviewed the Regional Victoria reactive requirements need taking into account updated demand projections, and published a RIT-T termination notice in April 2013 noting that due to reduced demand, this limitation and augmentation timing has now been deferred until at least 2019.
- The two RIT-Ts for the Bendigo–Ballarat and Bendigo–Moorabool line loadings have been combined into a single assessment in order to better assess and co-ordinate the upgrade. The PADR for this RIT-T was published in March 2013.
- An additional scenario was added to the Heywood interconnector RIT-T assessment in order to ascertain the impact of reduced demand on market benefits. Results showed the market benefits were not sensitive to this change. The PACR for this RIT-T was published in January 2013.
- The Eastern Metropolitan Melbourne Thermal Capacity RIT-T was reassessed with the revised demand forecasts. The results showed that the preferred upgrade option of a third Rowville 500/220kV transformer is now only required by 2018–19. The PADR for this RIT-T was published in March 2013.
- East Rowville – Rowville 220 kV line loading, which was included in the Eastern Metropolitan Melbourne Thermal Capacity RIT-T, has been resolved by SP AusNet revising the station interplant connections that were limiting the line’s short-term rating.
- Ringwood–Thomastown 220 kV line loading was reassessed taking into account updated demand projections; the proposed RIT-T was not initiated. This limitation is still a priority assessment for AEMO.

Table 3-2 summarises the RIT-Ts AEMO undertook in 2012.

Table 3-2 — RIT-T summary

RIT-T	Limitations addressed	Summary of the identified investment needs	RIT-T status	VAPR section reference
South Australia – Victoria (Heywood) Interconnector Upgrade	South Australia – Victoria (Heywood) interconnector congestion. Uneven Heywood 500/275/22 kV transformer loadings and voltage instability (collapse) in the vicinity of Heywood and the Portland Alcoa plant.	The investment is required to realise market benefits from relieving congestion on the Heywood interconnector. Identified preferred option is: • A third Heywood transformer, with other network augmentations in South Australia and Victoria at an estimated cost of $107.7 million ($45 million for the Victorian works). The estimated commissioning date is July 2016. A revised scenario using the lower demand forecasts was included in the RIT-T assessment. The results highlighted that the change in market benefits were not significant and the selection of the preferred option did not change.	PACR published January 2013.	Section 3.2.1
Eastern Metropolitan Melbourne Reactive Support	Inadequate reactive power support in Eastern Metropolitan Melbourne.	The investment was previously required to avoid involuntary load reduction to prevent voltage instability. Studies making use of revised forecasts showed this limitation has been deferred until 2018–19 or later.	PSCR published November 2011. RIT-T termination notice published February 2013.	
Eastern Metropolitan Melbourne Thermal Capacity	Loading relating to the Cranbourne A1 500/220 kV transformer, Rowville A2 500/220 kV transformer, and Rowville A1 500/220 kV transformer. East Rowville – Rowville 220 kV line loading.	The investment is required to avoid involuntary load reduction to prevent loading transmission network assets beyond their thermal capability. Identified preferred option is: • A third Rowville 500/220 kV transformer, at an estimated cost of $51 million in 2018. The preferred solution primarily addresses loading issues on the Rowville A1 500/220 kV transformer. The RIT-T assessment was initially delayed in order to take into account the 2012 NEFR and TSDF forecasts. The reduction in demand forecasts has resulted in the Cranbourne A1 500/220 kV transformer, Rowville A2 500/220 kV transformer and East Rowville – Rowville 220 kV line loading issues being delayed beyond the study period.	PADR published March 2013.	Section 3.2.2

RIT-T	Limitations addressed	Summary of the identified investment needs	RIT-T status	VAPR section reference
Regional Victoria Reactive Support	Inadequate reactive power support around Bendigo in Regional Victoria.	The investment was previously required to avoid involuntary load reduction to prevent voltage instability. Studies making use of revised forecasts showed this limitation has been deferred until 2019 or later.	PSCR published January 2012. RIT-T termination notice published April 2013.	
Regional Victorian Thermal Capacity – Bendigo Supply	Ballarat–Bendigo 220 kV line loading.	The investment is required to avoid involuntary load reduction to prevent loading transmission network assets beyond their thermal capability.	Combined into one RIT-T in conjunction with the Ballarat–Moorabool 220 kV No.1 line loading RIT-T.	Section 3.2.3
Regional Victorian Thermal Capacity – Ballarat Supply	Ballarat–Moorabool 220 kV No.1 line loading.	The investment is required to avoid involuntary load reduction to prevent loading transmission network assets beyond their thermal capability. Identified preferred option is: • Install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2014–15, followed by up-rating the Ballarat–Bendigo 220 kV line and installing the third Moorabool–Ballarat 220 kV circuit in 2016–17. These upgrades have a combined estimated cost of $126 million. The RIT-T assessment was initially delayed in order to take into account the 2012 NEFR and TSDF forecasts.	PADR published March 2013.	Section 3.2.3
Victorian Reliability Support	Murray–Dederang 330 kV line loading	A non-network service was previously required to realise market benefits from increasing power transfer capability between New South Wales and Victoria during periods of low reserve in Victoria. Revised forecasts show the need to acquire a non-network service is deferred until at least 2015-16.	RIT-T update published in August 2012.	

Detailed findings for each RIT-T (see Section 3.2.1 to Section 3.2.3) include:

- Identified need.
- Technical details.
- Key results from a power system performance assessment and an economic analysis of market performance.
- Credible network and non-network options.
- RIT-T status.

The key results from the power system performance assessments and the economic analysis of market performance incorporate forecasts that include the following:

- Percentage loadings of the transmission plant associated with the network limitation under N and N-1 conditions, based on the continuous and short-term ratings respectively. Unless advised otherwise[5], transmission line percentage loadings are based on standard continuous ratings and short-term ratings at 45 °C and 0.6 m/s wind speed.
- Reactive power margin for RIT-Ts that address voltage stability limitations.
- Load and energy at risk. Load at risk is the MW load shedding required both pre- and post-contingency to avoid the network limitation.[6] Energy at risk is the resulting unserved energy.
- Expected unserved energy, which is a portion of the energy at risk after taking into account the probability of forced outage.
- Limitation cost, which is the total additional cost due to both re-dispatching generators and the expected unserved energy.

The power system performance analysis results (percentage loading or reactive power margin) provide information about when the transmission components associated with a limitation might be overloaded, or when the reactive power margin in an area might become insufficient (leading to potential voltage instability or voltage collapse).

The economic analysis results (load and energy at risk, expected unserved energy, and limitation cost) refine the power system analysis to quantify the load reduction required to avoid overloading or voltage instability.

While generally consistent, any differences between the timings derived from the power system and market performance analyses are due to different assumptions involving operating conditions (such as demand), temperature, wind speed, or network configuration.

3.2.1 South Australia – Victoria (Heywood) Interconnector Upgrade

Identified need

This RIT-T was an ElectraNet and AEMO joint study to address limitations associated with the South Australia – Victoria (alternating current) interconnector at Heywood. It involved the thermal capabilities and voltage stability of the transmission network in South Australia's south-east, and thermal capacity limitations of the Heywood transformers, including limitations caused by uneven loading on the transformers.

Technical details

The Heywood 500/275 kV transformers are rated at 370 MVA (continuous) and 525 MVA (short term). These transformers set the limit for the interconnector at 460 MW. Many other factors can limit the interconnector flow to less than 460 MW, including the following:

- Thermal limitations and voltage stability in the South Australian network.
- Thermal limitations and transient stability in the Victorian network.

[5] For lines with wind monitoring installed, historical wind speed data was analysed to identify the wind speed occurring during the top 5% of demand periods with a 95% confidence interval.

[6] This excludes the load shedding after the first contingency to prepare for the second contingency. In cases where AEMO calculated load at risk for multiple scenarios, the load at risk results correspond with the worst case scenario with the highest load at risk.

- Oscillatory stability limits.

Key results

The RIT-T results show that this upgrade delivers a net market benefit through significant reductions in generation dispatch costs over the longer term.

The preferred option (Option 1b in Table 3-3 below) is to install a third transformer and 500 kV bus-tie at Heywood in Victoria, series compensation on 275 kV transmission lines in South Australia, and 132 kV network reconfiguration works in South Australia. This is expected to increase interconnector capability by about 40% in both directions, enabling increased wind energy exports from South Australia and also increasing lower-cost generation imports into South Australia.

The estimated commissioning date for this option is July 2016. The total capital cost is estimated at $107.7 million ($2011–12, equating to $79.8 million in present value terms). This reflects $45.0 million investment in Victoria and $62.7 million in South Australia, with net market benefits of more than $190 million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

Table 3-3 — Heywood RIT-T upgrade options studied

Option	Description	Notional limit (MW)		Increase from current limit (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	Third Heywood transformer + 100 MVAr capacitor + 132 kV works.	550	550	90	90
Option 1b	Third Heywood transformer + series compensation + 132 kV works.	650	650	190	190
Option 2a	Option 1a + third south-east transformer.	550	550	90	90
Option 2b	Option 1b + third south-east transformer.	650	650	190	190
Option 3	New Krongart–Heywood 500 kV interconnector + 275 kV works.	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVAr capacitor.	460	460	-	-
Option 5	200 MW DM + Option 1b.	650	650	190	190
Option 6a	Control schemes + 500 kV bus-tie.	550	460	90	-
Option 6b	Control schemes + Option 1b minus third Heywood transformer.	570–690	460	110–230	-

Non-network options considered and progressed included demand-side responses and control schemes as stand-alone options and in conjunction with network upgrades to operate existing network assets at higher short-term ratings.

RIT-T status

AEMO and ElectraNet published the PACR in January 2013. ElectraNet have now applied to the AER to make a determination as to whether the preferred option satisfies the RIT-T, as per section 5.16.6 of the NER.

ElectraNet will then seek AER approval of this investment as a contingent project. AEMO is developing functional requirement specifications for the Victorian components of the preferred option, which is expected to be put to tender in the second half of 2013.

3.2.2 Eastern Metropolitan Melbourne Thermal Capacity

Identified need

This RIT-T addresses potential overloads on the Rowville A1 500/220 kV transformer and Metropolitan Melbourne 220 kV lines.

Without augmentation to address this limitation, the supply security of customers in Eastern Metropolitan Melbourne is at risk during summer peak demand periods from 2015–16.

These limitations are driven by increasing forecast maximum demand in Metropolitan Melbourne.

Technical details

The rating for the Rowville and Cranbourne 500/220 kV transformers are 1000 MVA (continuous), 1250 MVA (for two hours) and 1500 MVA (for 30 minutes).

Key results

The results show that this upgrade delivers a positive net market benefit through significant reductions in involuntary load shedding over the long term.

The proposed preferred option is to install a new (third) 500/220 kV transformer at Rowville in 2018–19. This project will provide an additional 1000 MVA capacity to Metropolitan Melbourne.

The total project cost, including operating costs, is estimated at $51 million (in present value terms), and is expected to deliver net market benefits of $522 million (in present value terms) over the life of the project with positive net market benefits commencing from the first year of operation.

Table 3-4 — Forecast loading - Eastern Metropolitan Melbourne Thermal Capacity

	2015–16	2016–17	2017–18	2018–19
N loading				
CBTS A1 transformer	86%	90%	87%	88%
ROTS A1 transformer	94%	98%	100%	101%
N-1 loading				
ERTS–ROTS line	87%	93%	88%	90%

Table 3-5 — Forecast market impact - Eastern Metropolitan Melbourne Thermal Capacity

	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ million)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	62	100	10	0.6
2016–17	136	299	30	1.9
2017–18	258	761	78	4.9
2018–19	294	1,193	128	7.9

	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ million)
2019–20	763	3,202	362	22.4
2020–21	1,077	5,330	626	38.8
2021–22	1,564	11,005	1,359	84.2
2022–23	1,962	17,952	2,464	152.6

Credible options

The following six options were included as potential credible options in this RIT-T assessment:

- Option 1 – Cranbourne A2 500/220 kV transformer installation and Hazelwood–Rowville 500 kV line connection at Cranbourne Terminal Station, with a total estimated cost of $83 million, including $14 million in operating costs.
- Option 2 – Rowville A3 500/220 kV transformer installation, with a total estimated cost of $51 million, including $8 million in operating costs.
- Option 3 – Ringwood 500 kV switchyard establishment and Ringwood A1 500/220 kV transformer installation, with a total estimated cost of $105 million, including $17 million in operating costs.
- Option 4 – Templestowe 500 kV switchyard establishment and Templestowe A1 500/220 kV transformer installation, with a total estimated cost of $182 million, including $30 million in operating costs.

AEMO did not receive any non-network proposals to the RIT-T to assess whether they are commercially and technically feasible. However, AEMO has assessed the commercial feasibility of pseudo non-network options based on cost assumptions gathered from non-network service providers for similar demand management and local generation assessments to which AEMO has been party.

- Option 5 – Demand management of 30 MW at Ringwood 66 kV bus and 12 MW at Malvern 66 kV bus, with a total estimated cost of $40 million, including $37 million in operating costs.
- Option 6 – Local generator installation of 75 MW at Ringwood 66 kV bus, with a total estimated cost of $120 million.

RIT-T status

The PADR was published in March 2013.

3.2.3 Regional Victorian Thermal Capacity Upgrade RIT-T

Identified need

This RIT-T addresses potential overloads on the Ballarat–Bendigo and Moorabool–Ballarat No.1 220 kV lines.

Without augmentation to address this limitation, the supply security of customers in north-west Victoria is at risk during summer peak demand periods from 2013–14.

These limitations are driven by increasing forecast maximum demand in regional Victoria, and constrained import into Victoria via the Murraylink interconnector due to limitations on South Australia's Riverland network.

Technical details

The rating for the Ballarat–Bendigo line at 45 °C is 204 MVA (continuous) and 227 MVA (short term), is limited by the conductor, and has a design operating temperature of 65 °C. Ambient temperature is monitored to enable dynamic adjustment of this line's rating; however no wind monitoring facilities have been installed.

The rating for the Ballarat–Moorabool No.1 line at 45 °C and 1 m/s wind speed is 227 MVA (continuous) and 233 MVA (short term), is limited by the conductor, and has a design operating temperature of 65 ºC. Ambient temperature and wind speeds are monitored to enable dynamic adjustment of the line's rating.

Key results

The results show that this upgrade delivers a positive net market benefit through significant reductions in involuntary load shedding over the long term.

The proposed preferred option is to install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2014–15, followed by up-rating the Ballarat–Bendigo 220 kV line to a maximum operating temperature of 82 ºC and installing the third Moorabool–Ballarat 220 kV circuit in 2016–17. This upgrade is expected to increase the capability of the Ballarat–Bendigo line by about 50% and increase the combined capability of existing Moorabool–Ballarat lines by about 65%.

The total project cost, including operating costs, is estimated at $126.2 million (in present value terms). This reflects $93.0 million for addressing limitations on the Ballarat–Bendigo line and $33.2 million for addressing limitations on the Moorabool–Ballarat No.1 line, with net market benefits of more than $325 million (in present value terms) over the life of the project. Positive net market benefits would commence from the first year of operation.

Table 3-6 — Forecast loading - Regional Victorian Thermal Capacity – Bendigo Supply

	2013–14	2014–15	2015–16	2016–17
Moorabool–Ballarat 220 kV No. 1 line loading				
N loading	91%	91%	91%	92%
N-1 loading	160%	161%	161%	164%
Ballarat–Bendigo 220 kV line loading				
N loading	57%	60%	64%	66%
N-1 loading	139%	143%	146%	148%

Table 3-7 — Forecast market impact - Regional Victorian Thermal Capacity

Year	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ million)
2013–14	251	1,480	570	35.3
2014–15	253	1,387	586	36.3

Year	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ million)
2015–16	278	1,538	616	38.2
2016–17	305	2,037	751	46.6
2017–18	331	2,126	814	50.5
2018–19	280	2,379	825	51.1
2019–20	285	2,366	954	59.1
2020–21	298	2,976	1,062	65.8
2021–22	285	3,451	995	61.6
2022–23	330	4,822	1,240	76.8

Credible options

The following 11 options were included as potential credible options in this RIT-T assessment:

- Option 1a – Uprating the existing Ballarat–Bendigo and Moorabool–Ballarat lines to a maximum operating temperature of 82 ºC.
- Option 1b – Installing a wind monitoring facility on the Ballarat–Bendigo line, together with works set out in Option 1a.
- Option 2 – Uprating the Ballarat–Bendigo line to maximum operating temperature of 82 ºC, and uprating the Moorabool–Ballarat No.1 line to a maximum operating temperature of 90 ºC.
- Option 3a – Uprating the Ballarat–Bendigo line to a maximum operating temperature of 82 ºC and installing the third Moorabool–Ballarat circuit.
- Option 3b – Installing a wind monitoring facility on the Ballarat–Bendigo line, together with works set out in Option 3a.
- Option 4a – Uprating the Ballarat–Bendigo line to a maximum operating temperature of 90 ºC and installing the third Moorabool–Ballarat circuit.
- Option 4b – Installing a wind monitoring facility on the Ballarat–Bendigo line, together with works set out in Option 4a.
- Option 5 - Uprating the Ballarat–Bendigo line to a maximum operating temperature of 82 ºC and replacing the existing Moorabool–Ballarat No.1 line with a new 220 kV double circuit line.
- Option 6 - Replacing the existing Ballarat–Bendigo line with a new 220 kV double circuit line and uprating the Moorabool–Ballarat No.1 line to a maximum operating temperature of 82 ºC.
- Option 7 - Replacing the existing Ballarat–Bendigo line with a new 220 kV double circuit line and installing the third Moorabool–Ballarat circuit.

AEMO did not receive any non-network proposals to the RIT-T to assess whether they are commercially and technically feasible. However, AEMO has assessed the commercial feasibility of pseudo non-network option based on cost assumptions gathered from non-network service providers for similar demand management assessments to which AEMO has been party.

- Option 8 – 21 MW demand management (DM) program beginning in 2014–15.

RIT-T status

AEMO published the PADR in March 2013.

3.3 Summary of potential future non-network options

The MW amounts and timings shown in this section are indicative, and it is expected that unless noted as studied as part of a RIT-T assessment, further assessment is necessary to refine requirements.

Table 3-8 — Possible non-network option summary

Limitation	Possible network solution	Possible non-network option	Status	Timeframe
South-west Corridor (see Section 3.2.3)				
Victoria–South Australia interconnector congestion	A third Heywood transformer and supporting network augmentations in South Australia.	A five-year, 200 MW demand management program in the South Australia region was studied as an option as part of the RIT-T.	Current RIT-T with ElectraNet (see Section 3.2.1).	2013–14
Greater Melbourne and Geelong (see Section 3.2.5)				
Rowville A1 500/220 kV transformer loading	A new 500/220 kV transformer at Rowville, or a new 500 kV switchyard and 500/220 kV transformation at Ringwood.	Demand management of 30 MW at the Ringwood Terminal Station and 12 MW at the Malvern terminal station, or local generator installation of 75 MW at the Ringwood Terminals Station has been studied as options in the RIT-T.	Current RIT-T (see Section 3.2.2).	2015–16
Ringwood–Thomastown 220 kV line loading	Connection of Ringwood Terminal Station to the existing Rowville–Templestowe 220 kV line, or a new 500 kV switchyard and 500/220 kV transformer at Ringwood.	Demand management or new generation of 18 MW at the Ringwood Terminal Station.	Priority assessment.	2016–17
Rowville–Malvern 220 kV line loading	Rowville–Malvern 220 kV line up-rating and/or wind monitoring installation.	If reliant upon 15-minute ratings only, demand management or new generation of 9 MW at the Malvern Terminal Station.	Priority assessment.	2013–14
Rowville–Springvale–Heatherton 220 kV line loading	A new Cranbourne-Heatherton 220 kV double circuit line or underground cable, or a new 220 kV underground cable between Heatherton and Malvern.	Demand management or new generation of 39 MW at the Springvale or Heatherton Terminal Stations.	Priority assessment.	2013–14
Keilor A2 500/220 kV transformer and Keilor A4 500/220 kV transformer loading	A new 500/220 kV transformer at Keilor, or replacement of the existing transformers with higher-rated units.	Demand management or new generation of 3 MW at the Keilor, Geelong, Altona, Brooklyn, Fishermans Bend or West Melbourne Terminal Stations.	Priority Assessment.	2013–14
Regional Victoria (see Section 3.2.6)				
Ballarat–Bendigo 220 kV line loading	Wind monitoring installation and/or line up-rating to 82 ºC conductor temperature.	Demand management of 21 MW at the Bendigo and Ballarat terminal stations has been studied as an option in the RIT-T.	Current RIT-T (see Section 3.2.3).	2014–15

Limitation	Possible network solution	Possible non-network option	Status	Timeframe
Ballarat–Moorabool 220 kV No.1 line loading	Install a third Ballarat–Moorabool 220 kV circuit (new circuit will be strung on existing towers).	Demand management of 21 MW at the Bendigo and Ballarat terminal stations has been studied as an option in the RIT-T.	Current RIT-T (see Section 3.2.3).	2014–15
Geelong–Moorabool 220 kV line loading	Upgrading the limiting station assets at Geelong Terminal Station or installing a new single circuit or double circuit Geelong–Moorabool 220 kV line.	Demand management of 2 MW at the Point Henry Smelter or Geelong Terminal Station.	Priority assessment.	2014–15

3.4 Regional transmission network limitations

This section presents the findings from a review of transmission network limitations by Victorian electricity region.

The status of each limitation listed in the 2012 VAPR was updated based on a reassessment comprising power system performance analysis and economic analysis of market performance (market simulation studies). The review also identified new limitations due to localised demand growth and other changes in operating conditions.

Victorian transmission network limitations are listed for each region under three categories for action:

- Current RIT-Ts.
- Priority assessments.
- Monitoring.

For more information about these categories, see Section 3.1.3.

Information on current RIT-Ts has been collated in Section 3.2.

Information provided for each category

For each limitation identified for priority assessments, this section provides the following:

- The background, a description, and the operating conditions under which the limitation will occur.
- The impact, including the relevant constraint equation's binding hours during 2012 (for existing network limitations represented by constraint equations).
- Technical details, including the transmission plant ratings associated with the network limitation and the derived outage rates (based on historical data).
- Possible alleviation options, including network options and non-network options.
- Information about economic evaluation of possible augmentations.
- Recommendations for the next step of the investigation.

For each limitation AEMO is monitoring, this section provides higher level information. This including the following:

- A description of the network limitation.
- A list of possible alleviation options.
- The indicative triggers.[7]
- A cross-check with the 2012 NTNDP results.

[7] Triggers are the operating conditions under which a limitation will start to restrict demand growth or generation dispatch.

Transmission network limitation review approach

The forecast impact considers information (from power system performance analysis and market simulations) each year for the next five years regarding the following:

- The percentage N and N-1 loadings[8] of the transmission plant associated with the network loading limitation, based on the continuous and short-term ratings respectively.
- The load and energy at risk. Load at risk is the MW load shedding required to avoid the network limitation. Energy at risk is the resulting unserved energy.
- Expected unserved energy, which is a portion of the energy at risk after taking into account the probability of forced outage.
- Dispatch cost, which is the additional cost from re-dispatching generation.
- Limitation cost, which is the total additional cost due to both re-dispatching generators and the expected unserved energy.

These considerations are similar to the forecasts incorporated in the key results from the power system performance assessments and the economic analysis of market performance (for more information, see Section 3.2).

The power system performance analysis results (the percentage loadings) might show more severe impacts than the market simulations. This is because the power system performance analysis generally uses more conservative assumptions about demand, temperature and wind speed, to capture as many network limitations as possible for later testing with market simulations.

The forecast transmission plant loadings are derived using load flow simulations, and AEMO developed load flow base cases for these simulations using a series of inputs:

- The 10% probability of exceedance (POE) terminal station demand forecast AEMO developed and published in September 2012 for maximum demand base cases. For more information, see the Victorian Terminal Station Demand Forecast 2012–13 to 2022–23.[9]
- Historical maximum power transfers for a high Victoria to New South Wales power transfer base case.
- The typical generation dispatch and interconnector power transfer pattern under the given operating conditions.
- The system normal operational configuration for the existing Victorian transmission network.
- Committed transmission network augmentation projects, and other projects (or their equivalent), which—in AEMO's reasonable opinion—are necessary for maintaining the power system in a satisfactory, secure and reliable state during summer maximum demand periods.
- Unless indicated[10], standard continuous ratings and short-term ratings at 45 °C and 0.6 m/s wind speed.
- Unless indicated, 15-minute ratings are used as short-term ratings for transmission lines. Some transmission lines in Victoria are equipped with automatic load shedding schemes, which once enabled will avoid overloading by disconnecting preselected load blocks following a contingency. These automatic load shedding schemes allow the lines to be operated up to their five-minute short-term ratings.

[8] For descriptions of N and N-1 loadings, see Chapter 2, Section 2.4.1.

[9] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.

[10] For lines with wind monitoring installed, historical wind speed data was analysed to identify the wind speed occurring during the top 5% of demand periods with a 95% confidence interval.

- Wind generation availability during maximum demand of 6.5% of the installed capacity is assumed. For more information, see the Wind Contribution to Peak Demand study results.[11]

The market impact of each network limitation is based on probabilistic market simulations that apply the following:

- Weighted 50% POE and 10% POE maximum demand forecasts (weighted 70% and 30%, respectively).
- Historical wind generation availability.
- Historical load profiles.
- Dynamic ratings based on historical temperature traces.
- Non-committed new and retired generation as per the 2012 NTNDP Planning Scenario.

For more information about the transmission network limitation review approach, see the Victorian Electricity Planning Approach.[12]

3.4.1 Eastern Corridor

Current RIT-Ts

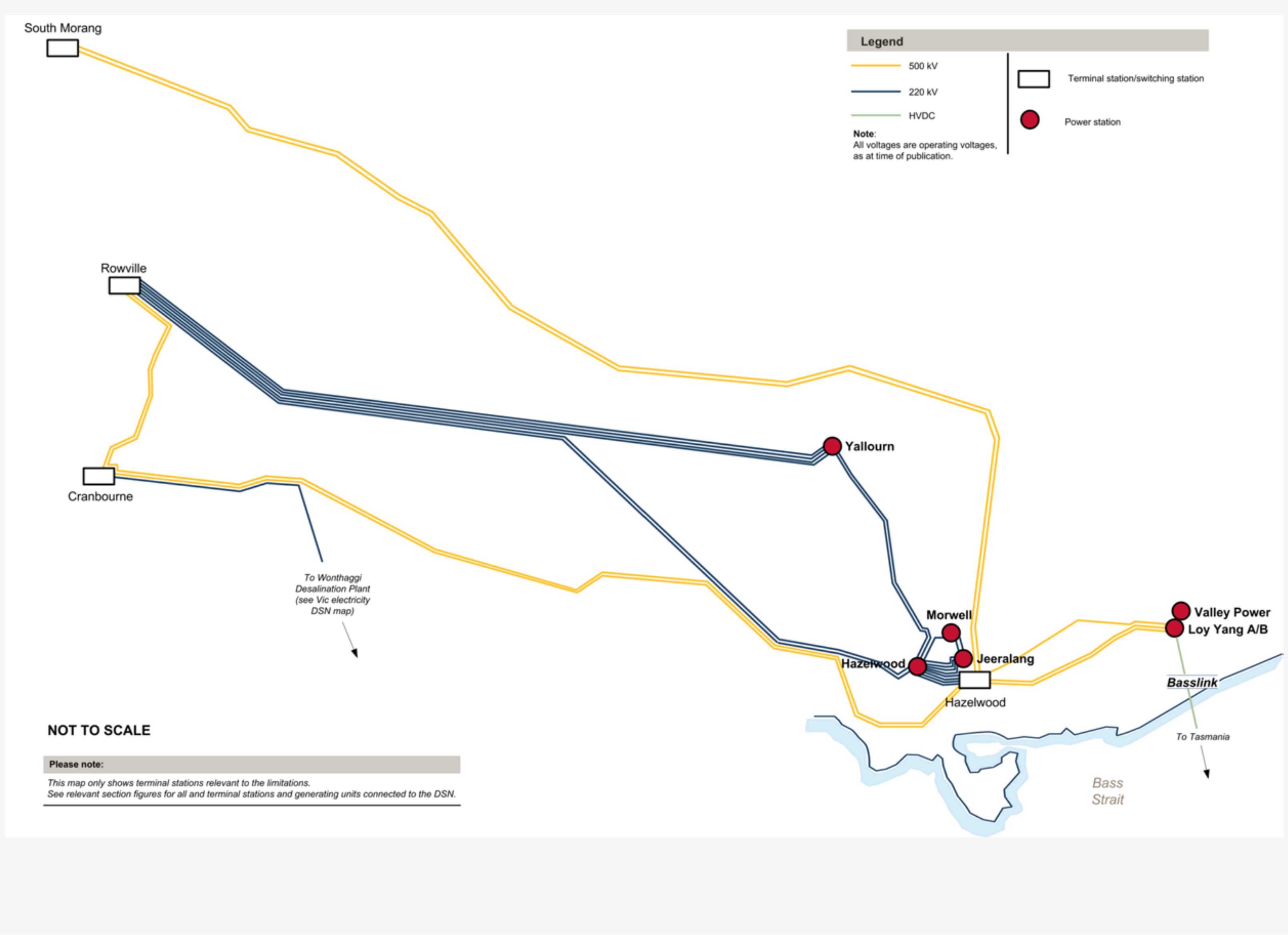
No current RIT-Ts relate to the Eastern Corridor.

Priority assessments

No priority assessments relate to the Eastern Corridor. Figure 3-2 shows the schematic of the Eastern Corridor transmission network.

[11] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand.
[12] AEMO. Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.

Figure 3-2 — Eastern Corridor transmission network



Monitoring

Table 3-9 lists Eastern Corridor limitations that AEMO is monitoring, and their possible network solutions, triggers, and 2012 NTNDP status.

Table 3-9 — Limitations being monitored – Eastern Corridor

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Latrobe Valley–Melbourne 500 kV line loading	A new (additional) 500 kV single circuit line from Hazelwood to Melbourne (Cranbourne, Templestowe or another site) with an estimated cost of $224 million plus any fault level mitigation works (for a new 500 kV Hazelwood–Cranbourne line).	When over 2,500 MW of new Latrobe Valley generation is connected to the 500 kV transmission network. This is when total generation in the Latrobe Valley (excluding Yallourn) reaches approximately 8,100 MW.	The NTNDP did not include this limitation, as no scenario modelled this level of additional generation in the Latrobe Valley.	The new line is likely to be a contestable project.
Hazelwood 500/220 kV transformer loading	A new 500/220 kV transformer at Hazelwood with an estimated cost of $40 million plus any fault level mitigation works. Upgrade the 220 kV Hazelwood–Rowville or Yallourn–Rowville lines.	When significant new generation is connected to the Latrobe Valley 220 kV transmission network, and/or when there is significant capacity increase in the Hazelwood or Yallourn Power Stations.	The NTNDP did not include this limitation, as no scenario modelled significant capacity increases in either the Hazelwood or Yallourn Power Stations.	The new transformer is likely to be a contestable project.
Rowville–Yallourn 220 kV line loading	A new 500/220 kV transformer at Hazelwood with an estimated cost of $40 million plus any fault level mitigation works. Upgrade the 220 kV Hazelwood–Rowville or Yallourn–Rowville lines.	When significant new generation is connected to the Latrobe Valley 220 kV transmission network and/or when there is significant capacity increase in the Hazelwood or Yallourn Power Stations.	The NTNDP did not include this limitation, as no scenario modelled significant capacity increases in either the Hazelwood or Yallourn Power Stations.	The new transformer is likely to be a contestable project.
Hazelwood – Loy Yang 500 kV line loading	A new (fourth) single circuit 500 kV line between Hazelwood and Loy Yang with an estimated cost of $68 million (excluding easement cost).	When over 1,500 MW of new generation is connected to the 500 kV transmission network between Hazelwood and Loy Yang.	The NTNDP did not include this limitation, as no scenario modelled this level of additional generation in this part of the network.	The new line is likely to be a contestable project.

Eastern Corridor changes since the 2012 VAPR

There have been no changes in assessment statuses for the Eastern Corridor limitations since the 2012 VAPR.

3.4.2 South-west Corridor

Current RIT-Ts

Current RIT-Ts involving the South-west Corridor include the following:

- The South Australia – Victoria (Heywood) Interconnector Upgrade (see Section 3.2.1).

Priority assessments

AEMO will conduct priority assessments on the following South-west Corridor network limitations:

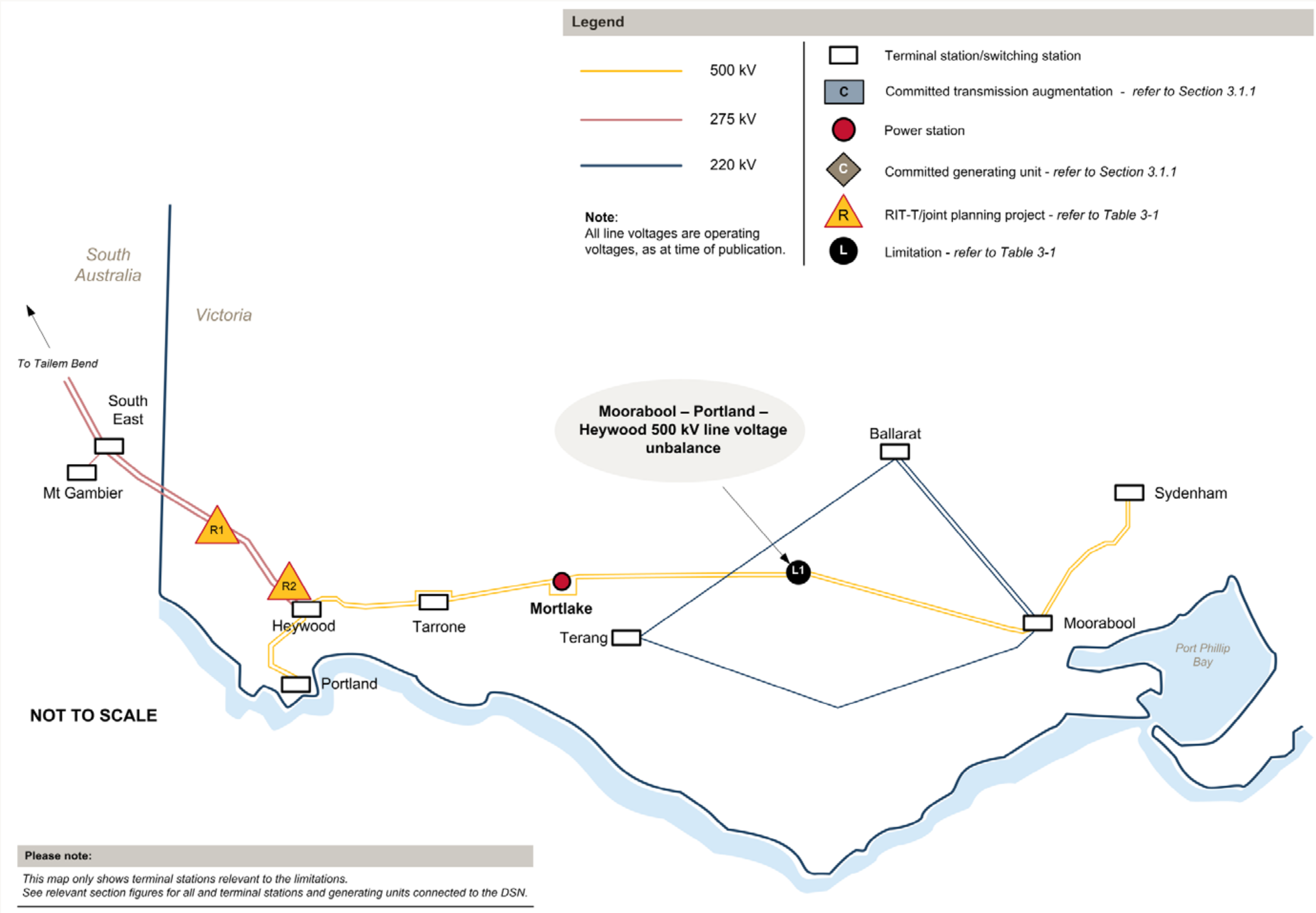
- Moorabool–Heywood–Portland 500 kV line voltage unbalance.

Table 3-10 — Moorabool–Heywood–Portland 500 kV line voltage unbalance

Background	The Moorabool–Heywood/Alcoa Portland 500 kV circuits have two transposition points evenly spaced over one third of each circuit, which maintain voltage balance between phases. At these transpositions, the three-phase conductors of each circuit are rotated by exchanging the physical positions of the phase conductors to reduce mutual couplings between the two parallel circuits over the length of 273 kilometres. The Moorabool – Heywood/Alcoa Portland 500 kV line was constructed in the early 1980s to supply the Alcoa Portland Aluminium Smelter. In 1989, Heywood interconnection was added via a tee connection that forms a three-ended line for each circuit. AEMO has received a number of new generation connection applications on the Moorabool – Heywood/Alcoa Portland 500 kV line at various points, potentially introducing voltage unbalance along these lines. The impact of voltage unbalance levels increase in proportion to power flow magnitude and direction, new generation connection points, and output generated.
Impact on transmission network performance	The establishment of Mortlake Power Station, McArthur Wind Farm and any additional new generation connections might produce voltage unbalance levels on the Moorabool – Heywood/Alcoa Portland 500 kV line in excess of the maximum allowable limit defined in the NER during certain outage conditions. Voltage unbalance constraint equations during certain outage conditions have been developed for use in the National Electricity Market Dispatch Engine (NEMDE) to constrain Mortlake and McArthur Wind Farm generation output to maintain voltage unbalance to within acceptable levels. In addition, the proposed installation of a Heywood 500 kV bus-tie to prevent uneven transformer loadings and voltage collapse will have an impact, and might potentially slightly reduce voltage unbalance levels.
Technical details	Constraint equations are required on 500 kV connected generation to limit negative sequence voltage on the Alcoa Portland 500 kV busbar to 0.5% of nominal voltage for system normal and prior circuit outage conditions (as specified in Table S5.1a.1 of the NER).
Possible network options for alleviation	Three options are being considered to alleviate this limitation: • A switched capacitor with individual phase switching at Heywood or near Alcoa Portland with an estimated cost of $12.3 million. • A static VAr compensator (SVC) or a synchronous static compensator (STATCOM) at an estimated cost of $46 million. • Additional transposition towers along the Moorabool – Heywood/Alcoa Portland 500 kV line at an estimated cost of $34.2 million. The first two options are likely to be contestable projects.
Non-network options	This network limitation is driven by generation in the South-west Corridor and by Victoria to South Australia power transfers, and is managed by generation re-dispatch. Non-network options to alleviate this limitation include load reduction or new sources of supply elsewhere in Victoria.
Economic evaluation of possible augmentations	Preliminary economic evaluation of the possible options has indicated the present value cost of this limitation is marginally smaller than the cost of available augmentation options. AEMO believes that more detailed analysis is required before a decision can be made.
Conclusion	A further cost-benefit analysis of this limitation will be conducted in 2013–14.

Figure 3-3 shows the schematic of the South-west Corridor transmission network. It also shows any network limitations related to current RIT-Ts, upcoming RIT-Ts or priority assessments.

Figure 3-3 — South-west Corridor transmission network



Monitoring

Table 3-11 lists South-west Corridor network limitations that AEMO is monitoring and their possible network solutions, triggers, and 2012 NTNDP status.

Table 3-11 — Limitations being monitored – South-west Corridor

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Voltage instability or collapse	New dynamic reactive compensation (for example, static VAr compensation) at Heywood/Alcoa Portland with an estimated cost of $46 million.	During a prior outage of the Heywood–Alcoa Portland 500 kV No.1 line. Victoria – South Australia interconnector capacity upgrade to more than 650 MW.	Not modelled in the NTNDP, but other developments, such as new generation connections and additional 500 kV lines, might alleviate the impact of this limitation.	Static VAr compensation is likely to be a contestable project.
Inadequate South-west – Melbourne 500 kV thermal capacity	A new Moorabool–Mortlake/Tarrone–Heywood 500 kV line with an estimated cost of $420 million.	When significant wind generation and/or GPG (over 2,500 MW in addition to the existing generation from Mortlake) is connected to the transmission network.	The NTNDP noted that generation rescheduling was modelled to overcome this network limitation, but that 500 kV augmentations between Heywood and Moorabool are an alternative potential solution.	The new line is likely to be a contestable project.

South-west Corridor changes since the 2012 VAPR

The key changes include the following:

- AEMO and ElectraNet have now completed the PACR stage of the RIT-T related to the Heywood interconnector upgrade, which also took into account uneven Heywood 500/275/22 kV transformer loading when identifying investment needs and the preferred solution.

3.4.3 Northern Corridor

Current RIT-Ts

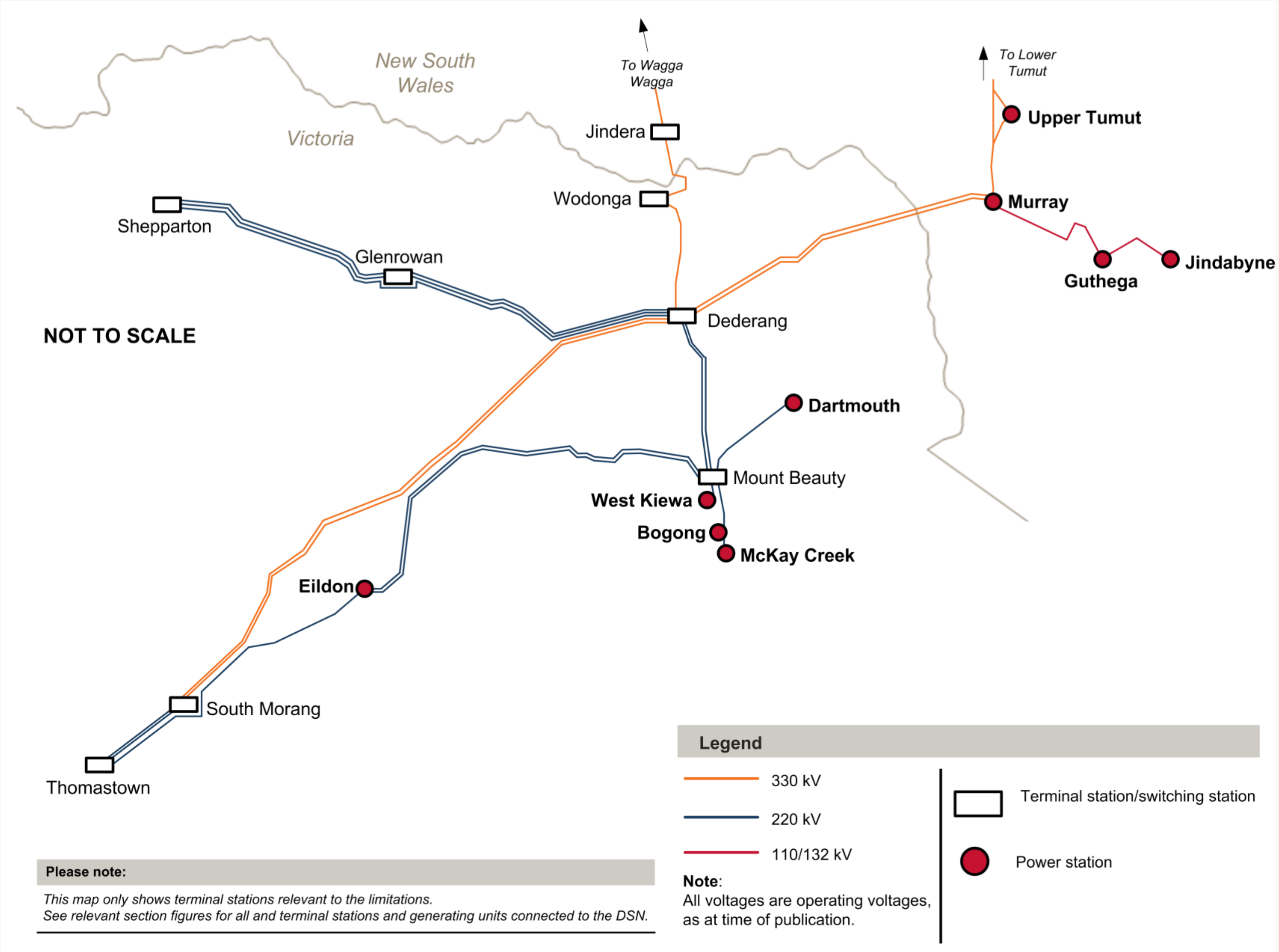
There have been no RIT-Ts involving the Northern Corridor.

Priority assessments

AEMO has not identified a need to conduct priority assessments on any Northern Corridor network limitations.

Figure 3-4 shows the schematic of the Northern Corridor transmission network.

Figure 3-4 — Northern Corridor transmission network



Monitoring

Table 3-12 lists Northern Corridor network limitations that AEMO is monitoring and their possible network solutions, triggers, and 2012 NTNDP status.

Table 3-12 — Limitations being monitored – Northern Corridor

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Murray–Dederang 330 kV line loading	Installing a new (third) 1,060 MVA 330 kV line between Murray and Dederang with an estimated cost of $183 million (excluding easement costs) or a new (second) 330 kV line from Dederang to Jindera at an estimated cost of $121 million (excluding easement costs).	Increased New South Wales import and Murray generation.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	These are both likely to be contestable projects.
Dederang – Mount Beauty 220 kV line loading	Installing a wind monitoring scheme with an estimated cost of $500k or up-rating the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82 ^{o}C, at an estimated cost of $23 million.	Increased New South Wales import and export.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	These are unlikely to be contestable projects.
Eildon–Thomastown 220 kV line loading	Installing a wind monitoring scheme at an estimated cost of $500k or up-rating the Eildon–Thomastown 220 kV line, including terminations to 75 ^{o}C operation, at an estimated cost of $73.6 million.	Increased New South Wales import and export.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	This is unlikely to be a contestable project.
Inadequate transformer capacity at Dederang	Installing a fourth 330/220 kV transformer at Dederang at an estimated cost of $25.6 million.	At times of over 2,500 MW of imports from New South Wales and Murray generation (with the DBUSS transformer control scheme is active).	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	The new transformer is likely to be a contestable project.

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Dederang – South Morang 330 kV line loadings	Up-rating the two existing lines 82 ^{o}C (conductor temperature) operation and series compensation at an estimated cost of $15.5 million. Installing a new (third) 330 kV, 1,060 MVA single circuit line between Dederang and South Morang with 50% series compensation to match the existing lines, at an estimated cost of $340.7 million (excluding easement costs, and subject to obtaining the necessary easement).	Increased New South Wales import and export.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	The new line is likely to be a contestable project.
Voltage collapse at South Morang, Dederang, Wodonga, and Jindera	Installing additional capacitor banks and/or controlled series compensation at Dederang and Wodonga Terminal Stations.	Increased New South Wales import and export.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	These are unlikely to be contestable projects.

Northern Corridor changes since the 2012 VAPR

Key changes include the following:

- The Dederang – South Morang 330 kV line loading limitation is no longer a priority assessment due to a reassessment of instrumentation and protection limits and short-term rating capabilities of the series capacitors, as well as the reduced Victoria – New South Wales interconnector capability without the use of load tripping schemes.

3.4.4 Greater Melbourne and Geelong

Current RIT-Ts

Current RIT-Ts involving Greater Melbourne and Geelong include the following:

- Eastern Metropolitan Melbourne Thermal Capacity (see Section 3.2.2).

Priority assessments

AEMO will conduct priority assessments on the following network limitations in the Greater Melbourne and Geelong area:

- Rowville–Malvern 220 kV line loading.
- Rowville–Springvale–Heatherton 220 kV line loading.
- Ringwood–Thomastown 220 kV line loading.
- Keilor 500/220 kV A2 and A4 transformer loading.
- Melbourne Metropolitan voltage stability.
- South Morang H2 330/220 kV transformer loading.

Table 3-13 — Rowville–Malvern 220 kV line loading

Background	Malvern Terminal Station is supplied by a radial double circuit 220 kV line from Rowville Terminal Station. Expected load growth increases around the Malvern area will lead to further increases in loading of the Rowville–Malvern 220 kV lines for the forecast period and beyond. An automatic load shedding scheme associated with this line was implemented in 2012. When this scheme is enabled, the short-term ratings of these circuits can be increased from a 15-minute rating to a five-minute rating.
Impact on transmission network performance	Under peak demand conditions in summer and following an outage of one of the Rowville–Malvern 220 kV circuits, the remaining Rowville–Malvern 220 kV circuit is forecast to be loaded over its short-term (15-minute) rating from summer 2013–14. Unless the automatic load shedding scheme is enabled, pre-contingent load shedding might be required to ensure post-contingent loading remains within thermal capability of the line. With the scheme enabled, no pre-contingent load shedding is forecast to be required within the next five years, but load might still need to be curtailed following an outage of one of the Rowville–Malvern circuits.
Technical details	The ratings for the Rowville–Malvern line at 45 °C are 204 MVA (continuous), 237 MVA (short-term, 15-minutes) and 282 MVA (short-term, five-minutes). No dynamic rating facility is provided for this line. Historical information suggests that the Rowville–Malvern line might be unavailable for approximately 3.96 hours annually per circuit due to unplanned outages.
Possible network options for alleviation	Four network options are being considered to alleviate this limitation: • Install wind monitoring facilities to enable full dynamic line rating at an estimated cost of $300k. The maximum capacity increase with wind monitoring is approximately 30%. • Up-rate the existing Rowville–Malvern 220 kV lines from 65 ºC to 82 ºC maximum conductor operating temperature at an estimated cost of $21 million. • Cut-in the Rowville–Richmond 220 kV No.1 and No.4 circuits at the Malvern Terminal Station to form the Rowville–Richmond–Malvern No.3 and No.4 circuits, at an estimated cost of $15 million. This option increases supply reliability to Malvern Terminal Station. • Loop-in and switch the Rowville–Richmond 220 kV No.1 and No.4 circuits at Malvern Terminal Station to form the Rowville–Malvern 220 kV No.2 and No.4, and the Richmond–Malvern 220 kV No.1 and No.4 circuits, at an estimated cost of $25 million. None of these options are likely to be contestable projects.
Forecast loading	See forecast loading table below.
Non-network option	If reliant upon 15-minute ratings only, a load reduction, or new generation of 9 MW at the Malvern Terminal Station from 2013–14 is expected to delay the occurrence of this limitation by 12 months.
Economic evaluation of possible augmentations	Preliminary analysis indicates that the limitation's present value cost is sufficient to install wind monitoring facility to enable full dynamic rating of the Rowville–Malvern 220 kV lines.
Conclusion	AEMO has commenced a detailed assessment of this limitation in conjunction with the distribution businesses to identify and assess options to address this limitation. These options will form part of a wider study of the Eastern Metropolitan Melbourne upgrade requirements for a number of lines in this part of the network.

Forecast loading:

	2013–14	2014–15	2015–16	2016–17	2017–18
N loading	59%	60%	61%	61%	62%
N-1 loading (15-minute rating)	102%	105%	106%	106%	109%
N-1 loading (5-minute rating)	85%	88%	89%	90%	91%

Table 3-14 — Rowville–Springvale–Heatherton 220 kV line loading

Background	Springvale Terminal Station is supplied by a radial double circuit 220 kV line from Rowville Terminal Station. Heatherton Terminal Station is supplied by a radial double circuit 220 kV line from Springvale Terminal Station. Expected load growth increases around Springvale and Heatherton areas will lead to further increases in loading of the Rowville–Springvale 220 kV line for the forecast period and beyond. Expected load growth increases around Heatherton will lead to further increases in loading of the Springvale–Heatherton 220 kV line for the forecast period and beyond. A loss of one of the Rowville–Springvale 220 kV line leads to the loss of the Rowville–Springvale–Heatherton 220 kV line. An automatic load shedding scheme associated with the Rowville–Springvale 220 kV line was implemented in 2012. When this scheme is enabled, the short-term ratings of these circuits can be increased from a 15-minute rating to a five-minute rating.
Impact on transmission network performance	Under peak demand conditions in summer and following an outage of one of the Rowville–Springvale 220 kV circuits, the remaining Rowville–Springvale 220 kV circuit is forecast to be loaded over its short-term (15-minute and five-minute) ratings from 2013–14. Pre-contingent load shedding at Springvale and Heatherton might be required to ensure the post-contingent loading remains within thermal capability of the line. Similarly, following the loss of one of the Rowville–Springvale 220 kV lines (which leads to the loss of the Rowville–Springvale–Heatherton 220 kV line), the remaining Heatherton–Springvale line is forecast to be loaded over its short-term rating (15-minute) from 2014–15. Pre-contingent load shedding at Heatherton might be required to ensure the post-contingent loading remains within the thermal capacity of this line. In addition, an outage of either of these double-circuit lines will result in total loss of supply to the relevant terminal station or stations. A Rowville–Springvale line tower failure can result in a loss of over 900 MW of load for an extended period of time. However, a portion of load might be supplied from nearby terminal stations via emergency distribution network rearrangements taking anywhere from minutes to hours to implement.
Technical details	The per-circuit ratings for the Rowville–Springvale–Heatherton line at 45 °C and 0.6 m/sec are: • Rowville–Springvale: 698 MVA (continuous), 802 MVA (short-term, 15-minutes) and 882 MVA (short-term, 5-minutes) • Springvale–Heatherton: 349 MVA (continuous) and 405 MVA (short-term). The Rowville–Springvale line is equipped with dynamic rating facility (including wind monitoring). The Springvale–Heatherton line has a dynamic rating facility but without wind monitoring. Historical wind analysis relevant to the Rowville–Springvale 220 kV line indicates an average effective wind speed of 0.72 m/s during peak demand periods providing increased ratings. Based on this effective wind speed of 0.72 m/s, the Rowville–Springvale line has a 712 MVA (continuous) and 840 MVA (short-term, 15-minute) and 882 MVA (short-term, five-minute) rating at 45 ^{o}C. Historical information suggests: • The Rowville–Springvale No.1 circuit will be unavailable for approximately 2.93 hours annually due to unplanned outages. • The Rowville–Springvale No.2 circuit will be unavailable for approximately 3.92 hours annually due to unplanned outages. • Each Springvale–Heatherton circuit will be unavailable for approximately 3.96 hours annually due to unplanned outages. • The probability of a double circuit outage is forecast to be 0.0023% (equating to approximately 0.2 hours annually on average).

<table>
<tr><th></th><th></th><th>2013–14</th><th>2014–15</th><th>2015–16</th><th>2016–17</th><th>2017–18</th></tr>
<tr><td rowspan="7">Forecast loading</td><td>Rowville–Springvale line</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>N loading</td><td>63%</td><td>65%</td><td>66%</td><td>67%</td><td>68%</td></tr>
<tr><td>N-1 loading
(15-minute rating)</td><td>108%</td><td>111%</td><td>113%</td><td>114%</td><td>116%</td></tr>
<tr><td>N-1 loading
(5-minute rating)</td><td>103%</td><td>106%</td><td>107%</td><td>108%</td><td>110%</td></tr>
<tr><td>Springvale–Heatherton line</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>N loading</td><td>53%</td><td>58%</td><td>59%</td><td>60%</td><td>60%</td></tr>
<tr><td>N-1 loading</td><td>92%</td><td>101%</td><td>102%</td><td>103%</td><td>105%</td></tr>
<tr><td>Possible network options for alleviation</td><td colspan="6">Five network options are being considered to alleviate this limitation:
• Upgrade station assets at Rowville, Springvale and Heatherton terminal stations which limit the thermal capability of the Rowville–Springvale–Heatherton 220 kV lines.
• Install a third 220 kV line between Rowville and Springvale to increase the capacity by approximately 800 MVA at an estimated cost of $76 million. This line is a combination of approximately 5.5 kilometres of underground cable and 1.7 kilometres of overhead.
• Install a new overhead double circuit 220 kV line between Cranbourne and Heatherton to increase the capability by approximately 800 MVA at an estimated cost of $88 million, subject to procuring an easement for overhead line construction.
• Install a new underground 220 kV cable between Cranbourne and Heatherton to increase the capability by approximately 400 MVA at an estimated cost of $671 million, including 10 kilometres of tunnelling.
• Install a new underground 220 kV cable between Malvern and Heatherton to increase the capability by approximately 400 MVA at an estimated cost of $382 million, including 8 kilometres of tunnelling. This option increases the loading on the Rowville–Malvern 220 kV line. This will require additional works that have not been included in this cost, due to the present and forecast Rowville–Malvern 220 kV line loading.

The last four options are likely to be contestable projects.</td></tr>
<tr><td>Non-network option</td><td colspan="6">A load reduction, or new generation of 39 MW at the Springvale Terminal Station or Heatherton Terminal Station in 2013–14, is expected to delay the occurrence of this limitation by 12 months.</td></tr>
<tr><td>Economic evaluation of possible augmentations</td><td colspan="6">Preliminary analysis indicates that the limitation’s present value cost is sufficient to increase the thermal capability of the Rowville–Springvale–Heatherton 220 kV lines.</td></tr>
<tr><td>Conclusion</td><td colspan="6">AEMO has commenced a detailed assessment of this limitation in conjunction with the distribution businesses to identify and assess options to address this and other limitations in the area. Options to address this limitation will form part of a wider study of the South-east Metropolitan Melbourne upgrade requirements for a number of lines in this part of the network.</td></tr>
</table>

Table 3-15 — Keilor A2 and A4 500/220kV transformer loadings

Background	The Keilor A2 and A4 500/220 kV transformers are key components in supplying electricity from the 500 kV transmission network to Geelong and the Western Melbourne Metropolitan area. These tie transformers are connected in parallel supplying load to connection points at Keilor, Altona, Brooklyn, Fishermans Bend, West Melbourne and Geelong with the support from three Keilor-Geelong 220 kV lines, local generation from Laverton North Gas Station and Newport Power Station. High loadings on Keilor A2 and A4 500/220 kV transformers are most likely to occur at times of maximum demand in Geelong and the Western Melbourne Metropolitan area.
Impact on transmission network performance	During maximum summer demand, a single unplanned outage of the Keilor A2 or A4 500/220kV transformer can result in load shedding at Geelong and in the Western Melbourne Metropolitan area from summer 2014–15. This limitation's impact may worsen with load growth in the Geelong and Western Melbourne Metropolitan area, and reduced generation at Laverton North Gas Station and Newport Power Station.
Technical details	The Keilor A2 and A4 500/220kV transformers are both rated at 750 MVA (continuous) and 810 MVA (for two hours). Historical information suggests that the A2 and A4 transformers will each be unavailable for approximately 16.38 hours annually due to unplanned outages.
Forecast loading	See forecast loading table below.
Possible network options for alleviation	The following network option is being considered to alleviate this limitation: • Install a fourth Keilor 750 MVA 500/220 kV transformer at an estimated cost of $44 million. • Procure higher rated transformers at a marginal cost increase when the transformers are replaced as part of asset renewal in 2018. The first option is likely to be a contestable project.
Non-network option	A load reduction, or new generation of 3 MW in 2014–15 at the Keilor, Geelong, Altona, Brooklyn, Fishermans Bend or West Melbourne Terminal Stations, is expected to delay the occurrence of this limitation by 12 months.
Economic evaluation of possible augmentations	Preliminary analysis indicates that the limitation's present value cost is likely to exceed the costs of the network options identified.
Conclusion	AEMO's high-level cost-benefit assessment found that net market benefits from relieving this limitation are possible with the identified network options. AEMO will undertake a detailed assessment of this limitation in the next 12 months. This will take into account the SP AusNet asset renewal plan, which currently shows the A4 transformer is proposed to be replaced in 2018, as well as other proposed augmentations such as increased transformation capacity at South Morang and Rowville.

Forecast loading:

	2013–14	2014–15	2015–16	2016–17	2017–18
N loading	71%	71%	72%	74%	76%
N-1 loading	92%	91%	93%	96%	98%

Table 3-16 — Ringwood–Thomastown 220 kV line loading

Background	Without augmentation, loading on the Ringwood–Thomastown line is forecast to exceed its short-term rating following a critical contingency (loss of the Rowville–Ringwood 220 kV line) from summer 2016–17. As a result, pre-contingent load shedding might be necessary in the area supplied by Ringwood to ensure loading levels remain within asset limits. With augmentation of only the Ringwood–Thomastown line, loading on the Ringwood–Rowville line is forecast to exceed its short-term rating following a critical contingency (loss of the Ringwood–Thomastown 220 kV line) from summer 2018–19. As a result, without additional augmentation, pre-contingent load shedding might be necessary in the area supplied by Ringwood to ensure loading levels remain within asset limits.
Impact on transmission network performance	During 10% POE maximum demand conditions in summer and following an outage of one of the Rowville–Ringwood 220 kV circuits, the remaining Ringwood–Thomastown 220 kV circuit is forecast to be overloaded without load reduction from summer 2016–17. The loads at Ringwood must be curtailed pre-contingency to prevent this overload.
Technical details	The Ringwood–Thomastown line is rated at 616 MVA (continuous) and 653 MVA (short-term) at 45 °C. Ambient temperature is monitored to enable dynamic monitoring and adjustment of this line's rating, however, no wind monitoring facilities have been installed. The Ringwood–Rowville line is rated at 664 MVA (continuous) and 664 MVA (short-term) at 45 °C. Historical information suggests the Ringwood–Rowville line might be unavailable for 2.22 hours annually due to unplanned outages, and the Ringwood–Thomastown line for 2.79 hours annually.
Forecast loading	See forecast loading table below

Forecast loading:

	2013–14	2014–15	2015–16	2016–17	2017–18
Ringwood–Thomastown line					
N loading	33%	37%	39%	38%	39%
N-1 loading	97%	98%	99%	100%	101%
Ringwood–Rowville line					
N loading	65%	63%	62%	63%	63%
N-1 loading	96%	97%	97%	98%	99%

Possible network options for alleviation	The network options considered include: • Connecting (cut-in) the Rowville–Templestowe 220 kV 751 MVA circuit at Ringwood Terminal Station, at an estimated cost of $9.6 million. • Upgrading the existing Ringwood–Thomastown 220 kV line to a rated conductor temperature of 94 ºC (685 MVA continuous rating at 45 ºC ambient temperature), at an estimated cost of $6.6 million; and replacing isolators at Ringwood Terminal Station, which are limiting the Ringwood–Rowville 220 kV line rating, at an estimated cost of $2.25 million, for a total estimated cost of $8.85 million. Neither of these options are likely to be contestable projects.
Non-network option	Non-network options to address this limitation involve an 18 MW load reduction, or new generation at the Ringwood Terminal Station by 2016–17.
Economic evaluation of possible augmentations	Preliminary analysis indicates that the limitation's present value cost is likely to exceed the costs of the network options identified.

Conclusion	AEMO’s high-level cost-benefit assessment found that the net market benefits from augmenting this line are likely to justify augmentation. AEMO will undertake a detailed assessment of this limitation in the next 12 months in conjunction with the distribution businesses to identify and assess options to address this limitation.

Table 3-17 — Melbourne Metropolitan Area voltage stability

<table>
<tr><td>Background</td><td>Demand is forecast to increase steadily in the Melbourne Metropolitan Area. This includes the Eastern Melbourne Metropolitan area around Cranbourne and Rowville, as well as the Western Melbourne Metropolitan area around Keilor and Western Melbourne. Additional reactive power support will be required to support this increased demand, and it must be located close to the load growth centres.</td></tr>
<tr><td>Impact on transmission network performance</td><td>Without the installation of additional reactive power support to ensure system security and avoid voltage collapse following a contingency event, loads in the Melbourne Metropolitan area may need to be shed pre-contingent. The critical N-1 contingencies are: outage of the Newport Power Station or outage of the Cranbourne–Hazelwood 500 kV circuit.

Following the critical contingency (Newport Power Station or the Cranbourne–Hazelwood 500 kV circuit), reactive power margins at locations around the Melbourne Metropolitan area can end up being less than the requirement set out in the NER when the Victorian regional maximum demand exceeds approximately 11,000 MW. This exposes the power system to a risk of voltage instability.</td></tr>
<tr><td>Technical details</td><td><table>
<tr><th>Terminal Station</th><th>Keilor 500 kV</th><th>Keilor 220 kV bus 1/3</th><th>Keilor 220 kV bus 2</th><th>Cranbourne 500 kV</th><th>Cranbourne 220 kV</th></tr>
<tr><td>Maximum fault level (MVA)</td><td>18,150</td><td>11,515</td><td>12,465</td><td>16,194</td><td>11,273</td></tr>
<tr><td>Required reactive power margin (MVAr)</td><td>182</td><td>115</td><td>125</td><td>162</td><td>113</td></tr>
</table></td></tr>
<tr><td>Possible network options for alleviation</td><td>Staged installation of additional reactive power support in the western and eastern parts of the Melbourne Metropolitan area.

It is unlikely that this would be a contestable project.</td></tr>
<tr><td>Non-network option</td><td>Load reduction or new generation in the Melbourne Metropolitan Area, such as at the Keilor, Altona, Brooklyn, and West Melbourne terminal stations.</td></tr>
<tr><td>Economic evaluation of possible augmentations</td><td>The economic evaluation indicates that the optimal timing for starting to install additional reactive power support is around 2019–20.</td></tr>
<tr><td>Conclusion</td><td>In 2013–14, AEMO may conduct a review of the need and timing of additional reactive power support in the Melbourne Metropolitan area. This will occur if the 2013 TSDF indicates a significant increase in forecast customer demand compared with the demand forecasts used in this assessment.

The need for additional reactive power support in the Metropolitan Melbourne area will depend on whether it can be provided by generators in the Latrobe Valley and around Moorabool, potentially increasing the loading on transformers at Moorabool and Keilor. This impact may be offset by the proposed new (additional) transformer at Rowville, as detailed in section 3.2.2.</td></tr>
</table>

Table 3-18 — South Morang H2 330/220 kV transformer loading

Background	In series with the two South Morang – Thomastown 220 kV circuits, the South Morang H1 and H2 330/220 kV transformers share the duty of supplying Victorian metropolitan loads with the 500/220 kV metro tie transformers at Moorabool, Keilor, Rowville, and Cranbourne. Before the Thomastown 220 kV bus reconfiguration in 2012, the South Morang H1 transformer had higher loadings than the South Morang H2 transformer due to uneven load sharing. The loading of South Morang H1 and H2 transformers are now more evenly balanced. In addition to helping supply the Melbourne Metropolitan Area load, the South Morang transformers also form part of the New South Wales – Victoria interconnector by connecting the two Dederang – South Morang 330 kV transmission circuits to Melbourne. During maximum demand conditions with high import from New South Wales into Victoria, the South Morang 330/220 kV transformers can become overloaded.
Impact on transmission network performance	Within the next five years, under Victorian maximum demand conditions, when a South Morang – Thomastown 220 kV No.1 line trips, resulting in loss of the South Morang H1 transformer, the load may exceed the South Morang H2 transformer's short-term thermal rating. Following the critical contingency (the simultaneous outage of South Morang – Thomastown 220 kV No.1 circuit and the South Morang H1 330/220 kV transformer), import from New South Wales and Murray generation will need to be reduced, to avoid overloading the South Morang H2 transformer. Reduced imports from New South Wales and Murray generation will have to be replaced by generation which can supply the Victorian metropolitan loads without increasing the loading on the South Morang H2 transformer. This generation re-dispatch may increase Victorian market prices due to the need to dispatch higher-cost generation plant in Victoria, South Australia, and Tasmania. Also, if the replacement generation is fully dispatched or unavailable for any reason, load shedding may be required to avoid overloading the South Morang H2 transformer.
Technical details	The South Morang 330/220 kV transformers comprise three single-phase units per transformer and are rated at 700 MVA (continuous) and 750 MVA (for 30 minutes). Historical information suggests that the: • South Morang – Thomastown No.1 circuit will be unavailable for approximately 3.94 hours annually due to unplanned outages. • South Morang transformers will each be unavailable for approximately 91.1 hours annually due to unplanned outages. The two South Morang transformers are nearing the end of their effective lives, and SP AusNet plans to replace the H2 transformer in 2016–17 and the H1 transformer in 2024. As part of this asset replacement, AEMO is currently working with SP AusNet to assess the cost-benefits of installing transformers with higher ratings.

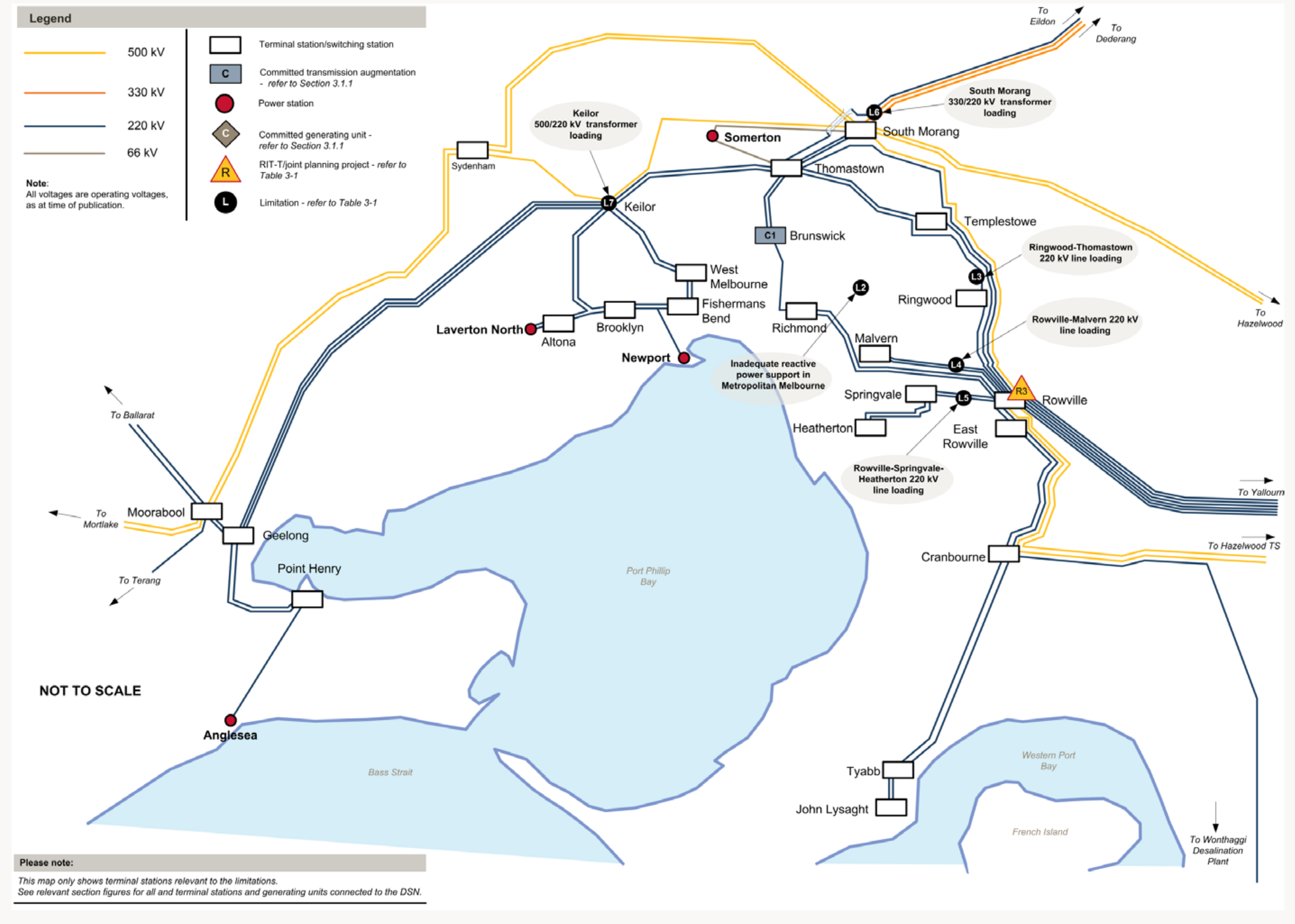
Forecast Loading

	2013–14	2014–15	2015–16	2016–17	2017–18
N loading	73%	73%	78%	79%	80%
N-1 loading	92%	92%	97%	98%	100%

Possible network options for alleviation	Four network options have been considered to alleviate this limitation: • A new (third) 330/220 kV 700 MVA transformer at South Morang, and connection (cut-in) of the Thomastown–Rowville 220 kV 550 MVA line at South Morang, at an indicative cost of $52 million, plus any fault level mitigation works. • A new 500/220 kV 1000 MVA transformer at South Morang, and connection (cut-in) of the Thomastown–Rowville 220 kV 550 MVA line at South Morang, at an indicative cost of $73.7 million, plus any fault level mitigation works. The existing Rowville – South Morang 220 kV line is a 500 kV designed line, so the cut-in at South Morang will create the No.4 Rowville – South Morang 500 kV line and a third South Morang – Thomastown 220 kV line. • Replacement of 330/220 kV transformers at South Morang with 1,000 MVA rated transformers, at an indicative cost of $77.8 million, plus any fault level mitigation works. SP AusNet plans to replace the first 330/220 kV 700 MVA transformer in 2016 as part of their asset renewal plan. The estimated incremental cost for replacing the existing transformers with higher capacity transformers is $21 million. • Replacement of the 330/220 kV transformers at South Morang with 700 MVA rated transformers with higher short-term ratings (above 900 MVA), at an indicative cost of $61.3 million, plus any fault level mitigation works. SP AusNet intends to complete the replacement of the first 330/220 kV 700 MVA transformers in 2016 as part of their asset renewal plan. These new units will have higher short-term ratings than the existing units. The third option is also likely to require connection (cut-in) of either the Thomastown–Rowville 220 kV 549 MVA line at South Morang, at an indicative cost of $10 million; or connection (cut-in) of the Eildon–Thomastown 220 kV 408 MVA line at South Morang, at an indicative cost of $8 million, to avoid overloading the existing South Morang – Thomastown 220 kV lines. The line cut-in costs have not been included in the indicative estimate for the third option. The first three options are likely to be contestable projects.
Non-network option	This limitation is driven by Melbourne Metropolitan area loads and generation, as well as New South Wales – Victoria interconnector flows, and can be partially managed by re-dispatch. Non-network options to alleviate this limitation include load shedding or additional generation in the Melbourne Metropolitan area.
Economic evaluation of possible augmentations	The market benefits from network constraint alleviation are only sufficient to justify the replacement of the H2 transformer with a higher short-term capacity unit as part of the like-for-like asset replacement.
Conclusion	SP AusNet intends to replace the existing H2 South Morang transformer as part of their asset renewal program. The new unit will have a higher short-term rating (above 900 MVA MVA) with only marginal cost implications. The first transformer replacement is expected to be completed in 2016.

Figure 3-5 shows the schematic of the Greater Melbourne and Geelong transmission network. It also shows any network limitations related to current RIT-Ts or priority assessments.

Figure 3-5 — Greater Melbourne and Geelong transmission network



Monitoring

Table 3-19 lists the Greater Melbourne and Geelong transmission network limitations that AEMO is monitoring and their possible network solutions, triggers, and 2012 NTNDP status.

Table 3-19 — Limitations being monitored – Greater Melbourne and Geelong

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
South Morang F2 500/330 kV transformer loading	A new (second) 1,000 MVA 500/330 kV transformer at South Morang at an estimated cost of $55 million, plus any fault-level mitigation works, or a new 1,000 MVA 500/220 kV transformer at South Morang and connection (cut-in) of the Thomastown–Rowville 220 kV line at South Morang at an estimated cost of $72 million, plus any fault level mitigation works.	Additional export capability from Victoria to New South Wales.	No Victoria to New South Wales interconnector upgrade was modelled, and as such no requirement for this upgrade was noted.	The new transformer is likely to be a contestable project.
South Morang H1 330/220 kV transformer loading	Replacement of the existing transformer with a higher rated unit In conjunction with SP AusNet's asset replacement program.	Increased demand in Metropolitan Melbourne and/or increased import from New South Wales.	The NTNDP noted that this limitation was likely to require augmentation in the 2027–28 to 2031–32 period.	This is unlikely to be a contestable project.
South Morang–Thomastown No.1 and No.2 220kV line loading	Connection (cut-in) of the Thomastown–Rowville 220 kV 549 MVA line at South Morang, with an estimated cost of $10 million, plus any fault level mitigation works Connection (cut-in) of the Eildon–Thomastown 220 kV 408 MVA line at South Morang, with an estimated cost of $8 million, plus any fault level mitigation works.	Load growth around the Melbourne Metropolitan area.	The NTNDP noted that this limitation was likely to require augmentation in the 2027–28 to 2031–32 period.	This is unlikely to be a contestable project.
Keilor–Thomastown 220 kV No.2 line loading	Up-rate the Keilor–Thomastown 220 kV No.2 line to 82 °C conductor temperature (800 MVA at 35 °C ambient temperature), with an estimated cost of $10 million, or install a new (third) 1,000 MVA 500/220 kV transformer at Rowville, with an estimated cost of $51 million, plus any fault level mitigation works.	Load growth around the Melbourne Metropolitan area.	The NTNDP identified an additional 500/220 kV transformer at Rowville, Ringwood or Templestowe in the 2017–18 to 2021–22 period. This would remove overloading on the Keilor-Thomastown 220 kV lines.	The new transformer is likely to be a contestable project.

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Rowville–Ringwood 220 kV line loading.	This limitation will also be considered as part of the Ringwood–Thomastown 220 kV line loading limitation.	Load growth or additional loads connected to Ringwood Terminal Station.	The NTNDP identified an additional 500/220 kV transformer at Rowville, Ringwood or Templestowe and connection of the Rowville–Templestowe 220 kV line at Ringwood in the 2017–18 to 2021–22 period. This would remove overloading on Rowville–Ringwood 220 kV line.	
Templestowe–Thomastown 220 kV line loading	Cut-in the Thomastown–Ringwood 220 kV line at Templestowe (cost to be estimated in 2013–14), or install a new (third) 1,000 MVA 500/220 kV transformer at Rowville, with an estimated cost of $51 million, plus any fault level mitigation works.	Load growth around the Melbourne Metropolitan area.	The NTNDP noted that this limitation was likely to require augmentation in the 2017–18 to 2021–22 period.	The new transformer is likely to be a contestable project.
Rowville–East Rowville 220 kV line loading	A new 500/220 kV transformer at Cranbourne with an estimated cost of $83 million, an East Rowville – Rowville 220 kV line uprating at an estimated cost of $33 million, or a new 220 kV underground cable between East Rowville and Rowville at an estimated cost of $58 million.	Load growth around the Eastern Melbourne Metropolitan area.	The NTNDP identified an additional 500/220 kV transformer in the 2012–13 to 2016–17 period. This augmentation would remove the overloading on Rowville-East Rowville 220 kV circuits.	The new transformer is likely to be a contestable project.
Cranbourne A1 500/220 kV transformer and Rowville A2 500/220 kV transformer loading	A new 500/220 kV transformer at Cranbourne Terminal Station with an estimated cost of $83 million.	Load growth around the Eastern Melbourne Metropolitan area.	The NTNDP noted that this limitation was likely to require augmentation in the 2012-13 to 2016-17 period.	The new transformer is likely to be a contestable project.
Increase in fault levels beyond network plant capability	Replace switchgear with plant with higher fault-level capabilities, install series reactors to limit the fault-level contribution of new and existing plant and, if reliably and economically feasible, un-mesh the transmission network.	Fault levels are a location-based issue driven by increased demand and impedance changes from connecting new network plant and generation.	The NTNDP did not assess fault levels.	These works are unlikely to be contestable.

Greater Melbourne and Geelong changes since the 2012 VAPR

Key changes include the following:

- The status of the South Morang–Thomastown 220 kV No.1 line loading limitation is no longer a priority assessment, as the revised studies no longer show sufficient market benefits to justify augmentation in the short to medium term.
- The South Morang 330/220 kV transformers studies showed new transformers with increased short-term ratings can be economically justified as part of the SP AusNet asset renewal program.
- The Keilor–Sydenham 500 kV line loading limitation, which was identified in the 2012 VAPR, has been alleviated following the replacement of the limiting protection equipment at Keilor by SP AusNet.
- The Ringwood–Thomastown 220 kV line loading limitation is now a priority assessment.
- The Keilor A2 and A4 transformer limitation is now a priority assessment, and will be assessed in conjunction with SP AusNet's asset replacement of these transformers in 2018.
- The Western Metropolitan Melbourne voltage stability assessment has been incorporated into the Metropolitan Melbourne voltage stability assessment.
- The East Rowville–Rowville 220 kV line loading limitation, which was included in the 2012 VAPR and the Eastern Metropolitan Melbourne Thermal Capacity RIT-T, has been resolved by SP AusNet revising the station interplant connections that were limiting the line's short-term rating. This limitation is now a monitoring status.
- The Cranbourne A1 transformer is now a monitoring status due to reduced local demand.

3.4.5 Regional Victoria

Current RIT-Ts

Current RIT-Ts involving Regional Victoria include the following:

- Regional Victorian Thermal Capacity Upgrade RIT-T (see Section 3.2.4).

Priority assessments

AEMO will conduct priority assessments on the following Regional Victoria network limitations:

- Geelong–Moorabool 220 kV line loading.
- Regional Victoria voltage stability.

Table 3-20 — Geelong–Moorabool 220 kV line loading

Background	The Geelong–Moorabool 220 kV double circuit line forms one of the main supply routes to the Geelong Terminal Station and the Point Henry Smelter. These loads are also supplied by three Geelong–Keilor 220 kV circuits and local generation from Anglesea Power Station. High loading on the Geelong–Moorabool 220 kV line is most likely to occur at times of maximum demand at the Geelong Terminal Station and Point Henry Smelter. During maximum demand periods the loading of the Geelong–Moorabool line presents a thermal limitation during system normal conditions, in preparation for loss of one of the parallel Geelong–Moorabool 220 kV circuits. This limitation's impact will increase with load growth at the Geelong Terminal Station or reduced output from Anglesea Power Station. If the Point Henry Smelter reduces demand, then the requirement to address the limitation will be delayed.
Impact on transmission network performance	During summer maximum demand conditions and following a single unplanned outage of one of the Geelong–Moorabool lines, the remaining Geelong–Moorabool line is forecast to be overloaded from summer 2016-17. The loads at Point Henry and Geelong Terminal Station must be curtailed pre-contingency to prevent this overload.
Technical details	The ratings for the Geelong–Moorabool No.1 line at 45 °C is 720 MVA (continuous), limited by the conductor (with a design operating temperature of 82 ºC) and 743 MVA (short-term), limited by a switch at Geelong Terminal Station. The ratings for the Geelong–Moorabool No.2 line at 45 °C is 720 MVA (continuous), limited by the conductor (with a design operating temperature of 82 ºC) and 749 MVA (short-term), limited by a switch at Geelong Terminal Station. Both lines have a dynamic rating facility, providing thermal ratings with reference to real-time ambient temperature. Historically, the Geelong–Moorabool line has been unavailable for 2.9 hours per circuit annually due to unplanned outages.
Forecast loading	(see table below)
Possible network options for alleviation	The following network options are being considered to alleviate this limitation: • Upgrade the limiting station assets at Geelong Terminal Station at an estimated cost of $0.87 million. This option does not increase the continuous rating of the circuits, but will increase the short-term ratings by approximately 121 MVA and 115 MVA for Geelong–Moorabool No.1 and No.2 lines respectively (based on 45 ºC and 0.6 m/s). • Install a new Geelong–Moorabool 220kV double circuit line at an estimated cost of $45 million. The capacity increase with is approximately 1440 MVA (continuous rating based on 45 ºC and 0.6 m/s) • Install a new Moorabool–Geelong 220kV single circuit line. The project cost will be established in 2013–14. The capacity increase with this option is approximately 720 MVA (continuous rating based on 45 ºC and 0.6 m/s). The last two options are likely to be contestable projects.

Forecast loading:

	2013–14	2014–15	2015–16	2016–17	2017–18
Geelong–Moorabool No.1 line					
N loading	48%	48%	54%	57%	61%
N-1 loading	89%	89%	99%	105%	113%
Geelong–Moorabool No.2 line					
N loading	48%	48%	54%	57%	61%
N-1 loading	88%	88%	99%	104%	112%

Non-network option	A load reduction, or new generation of 1 MW to 2 MW in 2014 or 2015 at the Point Henry Smelter or Geelong Terminal Station is expected to delay the occurrence of this limitation by 12 months.
Economic evaluation of possible augmentations	Analysis indicates that the limitation's present value cost is likely to exceed the identified network options. As a result, augmentation to relieve this limitation is likely to be economically justified.
Conclusion	AEMO's high-level cost-benefit assessment found that net market benefits from relieving this limitation are possible with the identified network options. AEMO and SP AusNet are working in collaboration to propose the replacement of switches at Geelong Terminal Station at an estimated cost of $0.87 million. This limitation has been identified for further detailed assessment to identify the most likely timing for further upgrades. Recent announcements regarding reduction in demand due to closure of the Ford manufacturing plant will be taken into account when assessing timeframes to implement a solution for this limitation.

Table 3-21 — Regional Victoria voltage stability

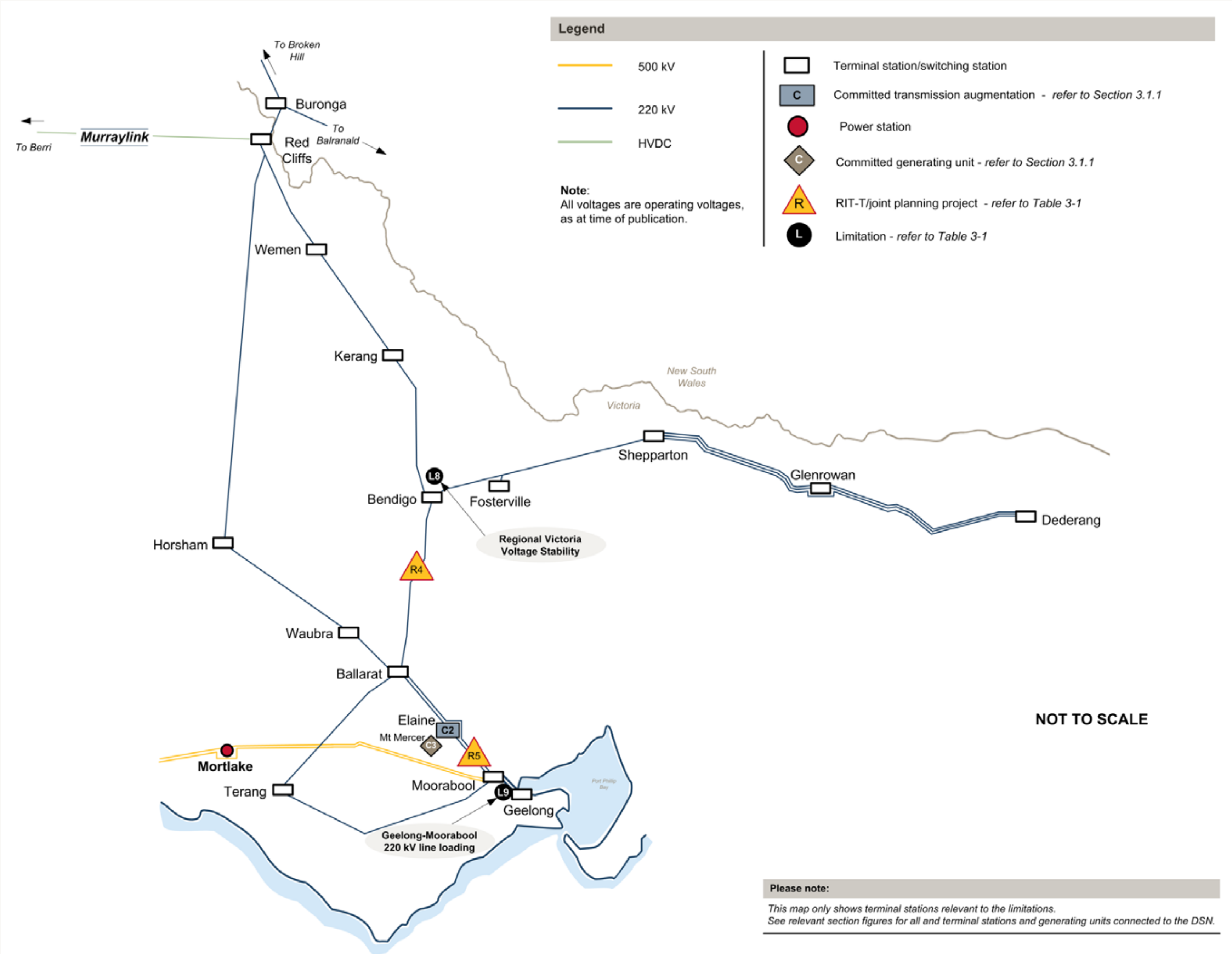
Background	Demand is forecast to increase steadily in Regional Victoria, including loads supplied from Bendigo, Kerang, Fosterville, Red Cliffs and Wemen terminal stations. Additional reactive power support will be required to support this increased demand, and it must be located close to the load growth centres.
Impact on transmission network performance	Without the installation of additional reactive power support to ensure system security and avoid voltage collapse following a contingency event, loads in Regional Victoria might need to be shed pre-contingency. The critical N-1 contingency will be an outage of the Bendigo–Ballarat 220 kV circuit. Following the critical contingency, the reactive power margins at locations around Bendigo can be less than the requirement set out in the NER when the Regional Victoria customer demand (excluding transmission losses and generation auxiliary loads) exceeds approximately 1,035 MW, exposing the power system to a risk of voltage instability. In calculating the Regional Victorian customer demand limit, the two new 220/22 kV transformers at Bendigo have been taken into account (see section 3.3).
Technical details	(see technical details table below)
Possible network options for alleviation	Staged installation of additional reactive power support in Regional Victoria. This is unlikely to be a contestable project.
Non-network option	Load reduction or new generation in the Regional Victoria Area, such as the Bendigo, Kerang, Fosterville, Red Cliffs and Wemen terminal stations.
Economic evaluation of possible augmentations	An economic evaluation indicates that the earliest timing for additional reactive power support is around 2019–20.
Conclusion	In 2013–14, AEMO may conduct a review of the need and timing of additional reactive power support in Regional Victoria. This will occur only if the 2013 TSDF indicates a significant increase in forecasted customer demand compared with the demand forecast used in this assessment.

Technical details:

Terminal Station	Bendigo 220kV	Kerang 220kV	Fosterville 220kV	Red Cliffs 220kV	Wemen 220kV
Maximum fault level (MVA)	2,330	1,413	1,868	2,032	1,103
Required reactive power margin (MVAr)	23	14	19	20	11

Figure 3-6 shows a schematic of the Regional Victoria transmission network. It also shows any network limitations related to current RIT-Ts or priority assessments.

Figure 3-6 — Regional Victoria transmission network



Monitoring

Table 3-21 lists the Regional Victoria transmission network limitations that AEMO is monitoring, and their possible network solutions, triggers, and 2012 NTNDP status.

Table 3-22— Limitations being monitored – Regional Victoria

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Bendigo–Fosterville–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line at an estimated cost of $43 million, or up-rate the existing conductor from 82 ºC to 90 ºC at an estimated cost of $56 million.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Significant wind and solar generation developments in this region and no requirement for any increased import from New South Wales has resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transformer is likely to be a contestable project.
Dederang–Glenrowan 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line at an estimated cost of $43 million; or replace the existing Dederang–Glenrowan 220 kV lines with a new double circuit line (project cost will be established in 2013–14); or replace the existing Dederang–Shepparton 220 kV line with a new double circuit line at an estimated cost of $253 million.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Significant wind and solar generation developments in this region and no requirement for any increased import from New South Wales has resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transformer or new transmission lines are likely to be contestable projects.
Dederang–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line at an estimated cost of $43 million, or up-rate the existing Dederang–Shepparton conductors from 65 ºC to 82 ºC rated conductor temperature at an estimated cost of $59 million; or replace the existing Dederang–Glenrowan 220 kV lines with a new double circuit line (project cost will be established in 2013–14), or replace the existing Dederang–Shepparton 220 kV line with a new double circuit line at an estimated cost of $253 million.	Increased demand in Regional Victoria and/or increased import from New South Wales.	Significant wind and solar generation developments in this region and no requirement for any increased import from New South Wales has resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transformer or new transmission lines are likely to be contestable projects.

Limitation	Possible network solution	Trigger	2012 NTNDP status	Contestable project status
Glenrowan–Shepparton 220 kV line loading	Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line at an estimated cost of $43 million; or replace the existing Dederang–Shepparton 220 kV line with a new double circuit line at an estimated cost of $253 million.	When there is significant load growth at the Shepparton Terminal Station.	Significant wind and solar generation developments in this region and no requirement for any increased import from New South Wales has resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transformer or new transmission lines are likely to be contestable projects.
Ballarat–Waubra–Horsham 220 kV line loading	Upgrade the Ballarat–Waubra–Red Cliffs line termination at Horsham Terminal Station (cost to be estimated in 2013–14), or replace the Ballarat–Waubra–Horsham–Red Cliffs 220 kV line with a double circuit line at an estimated cost of $855 million.	When there is significant load growth at the Horsham Terminal Station.	The NTNDP notes that the existing Ballarat–Waubra–Horsham line can be overloaded given high wind generation during moderate demand periods, if high portion of the new wind generation is built at Horsham and Red Cliffs.	The new transmission line is likely to be a contestable project.
Kerang–Wemen–Red Cliffs 220 kV line loading	Replace the existing Bendigo–Kerang–Wemen–Red Cliffs 220 kV line with a new double circuit 220 kV circuit line at an estimated cost of $683 million.	When there significant load growth at the Kerang Terminal Station.	The NTNDP notes that the existing Kerang–Wemen–Red Cliffs line can be overloaded given high wind generation during moderate demand periods, if high portion of the new wind generation is built at Horsham and Red Cliffs.	The new transmission line is likely to be a contestable project.
Moorabool–Terang 220 kV line loading	Up-rate the existing conductor from 65 ºC to 82 ºC rated conductor temperature at an estimated cost of $58 million, or replace the existing Moorabool–Terang 220 kV line with a new double circuit 220 kV line at an estimated cost of $247 million.	When there significant load growth at the Terang Terminal Station. This can be offset by additional generation at Terang Terminal Station.	Significant wind generation developments in this region distributed across Ballarat, Bendigo, Horsham, Terang and Red Cliffs terminal stations resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transmission line is likely to be a contestable project.
Moorabool 500/220 kV transformer loadings	Installation of a third Moorabool 1,000 MVA 500/220kV transformer at an estimated cost of $49 million.	Increase in load growth in Geelong and Regional Victoria or high import from South Australia or increased generation in the South-west Corridor	Significant wind and solar generation developments in this region and an additional 500/220 kV transformer requirement in the Western Metropolitan area has resulted in no upgrade requirement in the timeframes and scenarios studied.	The new transformer is likely to be a contestable project.
High fault levels	Operational arrangements, series reactor installation, and switchgear replacement.	Increased demand and/or generation, particularly in Regional Victoria.	The NTNDP did not assess fault levels.	These works are unlikely to be contestable projects.

Regional Victoria changes since the 2012 VAPR

Key changes include the following:

- The status of the Moorabool A1 500/220 kV transformer load limitation is no longer a priority assessment, due to use of a higher short-term rating (1310 MVA compared to 1250 MVA previously).

3.5 Distribution network service provider planning

AEMO uses load forecasts provided by distribution network service providers (DNSPs) for its electricity DSN planning. In undertaking augmentation planning, AEMO does the following:

- Accounts for DNSP plans for existing and new connection points.
- Addresses the impact DNSP plans have on electricity DSN planning in its transmission network limitation assessments.

The general impact that distribution load growth has on the electricity DSN is addressed by modelling this growth at connection points. AEMO and the DNSPs undertake joint planning when addressing connection asset limitations and their potential solutions (for example, installing additional transformation at existing connection points or establishing new connection points). This identifies the most efficient solution for both the distribution network and the electricity DSN.

Table 3-22 lists the preferred connection modifications from the 2012 Transmission Connection Planning Report[13], and the potential electricity DSN impacts and considerations.

Table 3-23 — Distribution network service provider planning impacts

Location/terminal station	Preferred connection modification	Electricity DSN impacts and considerations
Altona 66 kV	Load transfer to the proposed Deer Park Terminal Station in 2017.	Load transfer to Deer Park Terminal Station will increase line flows in the Western Melbourne Metropolitan area transmission loop. The increased power flow remains within the ratings of the electricity DSN and the impact is insignificant. CitiPower, Jemena, and AEMO have completed a joint Regulatory Test application for the establishment of the Deer Park Terminal Station.
Ballarat 66 kV	Install a third Ballarat 150 MVA 220/66 kV transformer from 2022. Contingency plans exist to reduce supply interruptions due to Ballarat 220/66 kV transformer outages. Up to 10 MVA of load is transferred to Horsham using distribution (66 kV) ties in an emergency.	The impact of these emergency measures on the electricity DSN is insignificant. Installation of the third transformer will increase local 66 kV fault levels.
Bendigo 66 kV and 22 kV	Install two new 75 MVA 220/22 kV transformers by late-2013, separating 66 kV and 22 kV points of supply and transferring load from the existing (220/66/22 kV) transformation.	The fault level impact of new 220/22 kV transformers at Bendigo has been assessed and remains within the DSN ratings.
Brunswick 66 kV	Establish a new 66 kV supply point with three 225 MVA 220/66 kV transformers in 2015–16. This enables West Melbourne and Richmond Terminal Station off-loading and increases local supply reliability.	The transfer of load from the west and east of the Melbourne Metropolitan Area to its north has been included in the assessment of upcoming limitations in Greater Melbourne and Geelong presented in Section 3.2.5.

[13] Jemena, CitiPower, Powercor, SP AusNet and United Energy. Available at http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf.

Location/terminal station	Preferred connection modification	Electricity DSN impacts and considerations
Cranbourne 66 kV	Install a fourth Cranbourne 150 MVA 220/66 kV transformer by summer 2021–22.	The 66 kV fault levels are likely to increase with installation of a fourth transformer, although this will be mitigated by a 66 kV bus re-arrangement.
Dandenong 66 kV	Establish a terminal station at Dandenong with 220/66 kV transformation by summer 2022–23 to meet local demand and offload the Heatherton, Springvale and East Rowville terminal stations.	Establishing the Dandenong Terminal Station will require new transmission lines connecting Dandenong to the Cranbourne Terminal Station. The transfer of load from Springvale and Heatherton terminal stations will reduce the network power flows, especially on the Rowville–Springvale–Heatherton 220 kV radial line.
Deer Park 66 kV	Establish a terminal station at Deer Park with 220/66 kV transformation supplied from Keilor–Geelong 220 kV transmission by November 2017.	Load transfer from Altona 66 kV and Keilor 66 kV will increase line flows in the Western Melbourne Metropolitan Area transmission loop. The increased flow remains within the ratings of the electricity DSN and the impact is insignificant. CitiPower, Jemena, and AEMO have completed a joint Regulatory Test application for the establishment of the Deer Park Terminal Station.
East Rowville 66 kV	Load transfer to Cranbourne Terminal Station or to the proposed Dandenong Terminal Station after 2022.	Load transfer from East Rowville will impact power flows in the electricity DSN and joint planning will be undertaken.
Fishermans Bend 66 kV	Implement a 66 kV bus-tie normally open/auto-close control so all three transformers can be in service by 2016.	Installing a third transformer on load will increase the 66 kV fault levels, although this increase will be mitigated by the normally open bus-tie.
Frankston 66 kV	Establish a new 66 kV loop from Cranbourne Terminal Station to supply a new 66/22 kV zone substation in the Skye and Carrum Downs area after 2022.	This might impact the emergency load shedding groups and will be assessed in detail closer to the proposed installation date.
Geelong 66 kV	Undertake 66 kV loop rearrangements to enable the fourth 220/66 kV transformer to operate under normal conditions, rather than having it as a hot standby transformer in 2012.	Fault levels will increase (220 kV and 66 kV), although this increase will be mitigated by the normally open bus-tie and 66 kV loop rearrangements.
Glenrowan 66kV	Install a third Glenrowan 220/66 kV transformer after 2021.	Installing a third transformer will increase local 66 kV fault levels.
Keilor 66 kV	Reconfigure 66 kV bus bars into two groups so that all five 150 MVA 220/66 kV transformers can be normally in service and maintain fault levels within limits. Install a 100 MVAr capacitor bank on the Keilor Terminal Station (B34) group prior to summer 2014–15. Load transfer to the proposed Deer Park Terminal Station from 2017.	Permanent connection of a fifth transformer on load will increase local 66 kV fault levels, although this increase will be mitigated by the 66 kV bus rearrangements. Installing capacitor banks at the 66 kV level will reduce the electricity DSN's reactive power requirements. AEMO will consider 66 kV reactive power support when planning the electricity DSN's reactive power needs.

Location/terminal station	Preferred connection modification	Electricity DSN impacts and considerations
Malvern 66 kV	Install a third Malvern 220/66 kV transformer after 2022 and potential transfer load from Springvale.	Installing a third transformer will increase local 66 kV fault levels. Load transfer from Springvale will increase the loading on the Rowville–Malvern 220 kV lines, which are currently operating close to capacity. Joint planning will be undertaken to formulate the optimal solution.
Morwell 66 kV	Install a fourth 220/66 kV transformer in 2021/22 (assuming Bairnsdale and Morwell power stations are available).	Installation of a fourth transformer will increase the 66 kV fault level.
Richmond 66 kV	Transfer load to the proposed new Brunswick 66 kV connection point from 2015. Additional transformation will be provided at the proposed Brunswick Terminal Station instead of the Richmond Terminal Station by 2014–15. Prior to establishing the Brunswick 66 kV switchyard, emergency load transfers from Richmond Terminal Station to the Malvern and Templestowe terminal stations are planned.	The impact of the load transfer has been included in the assessment of upcoming limitations presented in Section 3.2.5.
Ringwood 22 kV	Install a third transformer by approximately 2022.	Installing a third transformer will increase 22 kV fault levels.
Ringwood 66 kV	Install a fifth 220/66 kV transformer and 66 kV capacitor banks at Ringwood Terminal Station in 2022.	Installing a fifth transformer will increase 66 kV fault levels. Installing capacitor banks at the 66 kV level will reduce the electricity DSN's reactive power requirements. AEMO will consider 66 kV reactive power support when planning electricity DSN reactive power needs.
South Morang 66 kV	Install a third 225 MVA 220/66 kV transformer in 2021.	Existing fault level at South Morang 66 kV is close to the maximum fault rating (>90%, limited by the Use of System Agreement (UoSA)), with the 66 kV bus in parallel mode. Installing an additional transformer will increase the fault level. Joint planning will be undertaken to formulate an optimal solution.
Templestowe 66 kV	Install a fourth 220/66 kV transformer after 2022.	Existing fault levels at Templestowe 66 kV are close to the maximum fault rating, even with the existing 66 kV bus split arrangement. It is highly likely that installing an additional transformer will require fault level mitigation action to ensure 66 kV fault levels remain within plant ratings. 220 kV fault levels remain within the limits of the electricity DSN ratings.
Terang 66 kV	Install a third 220/66 kV transformer after 2022.	Installing a third 220/66 kV transformer will increase local 66 kV fault levels.

Location/terminal station	Preferred connection modification	Electricity DSN impacts and considerations
Tyabb 66 kV	Install a third 220/66 kV transformer at Tyabb in 2013–14.	The Tyabb 220 kV switchyard needs to be reconfigured with additional 220 kV circuit breakers to provide a bus-tie and accommodate a new Tyabb transformer. The 220 kV and 66 kV fault levels remain within electricity DSN ratings.
Wemen 66 kV	Install a second 220/66 kV transformer by approximately 2022.	The 66 kV fault levels will increase.
West Melbourne 22 kV	Transfer load to the proposed Brunswick 66 kV connection point in 2015–16.	The impact of the load transfer has been included in the assessment of upcoming limitations presented in Section 3.2.5.
West Melbourne 66 kV	Transfer load to the proposed Brunswick 66 kV connection point in 2015–16.	The impact of the load transfer has been included in the assessment of upcoming limitations presented in Section 3.2.5.
Wodonga 66 kV	Install a third 330/66 kV transformer at Wodonga after 2021.	Installing a third transformer will increase the 66 kV fault levels.

3.6 SP AusNet asset renewal

This section outlines SP AusNet's transmission asset renewal process and provides SP AusNet's current list of asset renewal projects planned for the next 10-year period. SP AusNet states that the asset renewal plan is based on asset performance, and condition and failure risk, as well as other operational factors affecting the assets' economic life. For information about how asset renewals are integrated into augmentation planning, see the Victorian Planning Approach available on AEMO's website.[14]

Asset renewal objectives

The objective of asset renewal is to achieve sustainable outcomes in the following areas:

- Health, safety and environment.
- Network performance and community impacts due to network outages.
- Minimising asset lifecycle costs by optimising capital, and operational and maintenance expenditure.
- Integrating asset renewal and augmentation plans.
- Physical security of assets.
- Complying with regulations, codes, licences, contracts, industry standards, and other obligations.

Asset renewal options

The following options are considered in the asset renewal evaluation:

- **Replace-upon-Failure** is only employed in circumstances where the impact of asset failure on network performance, health, safety and the environment is insignificant or non-existent; and where the asset has a short procurement and replacement lead-time.
- **Renewal on Condition or Performance** optimises the asset's lifecycle cost with due consideration for health, safety and environmental factors as well as community cost based on the asset performance. This strategy requires sufficient asset condition and performance monitoring to predict deterioration of the respective plant with sufficient lead-time to enable renewal prior to failure.
- **Renewal by Asset Class** is employed when a class of asset has either a higher-than-acceptable failure rate or exhibits a greater degree of deterioration than other asset types. This approach avoids widespread deterioration in network performance due to multiple asset class-related failures.
- **Renewal on a Bay-by-bay (or Scheme/Network)** basis is employed when it is economic to replace all primary plant and equipment within a specific station bay or scheme. This strategy is often adopted for terminal station renewals.
- **Replacement of Whole Station in Existing Location (Brownfield)** is employed when it is economic to replace all assets as part of a single, coordinated project within the existing station or location. (This is normally when station assets are approaching the end of their life and there are advantages in station reconfiguration.)
- **Replacement of Whole Station in New Location (Greenfield)** is employed when constructing a replacement station on a new site. It is a more expensive strategy than undertaking works within an existing station as it requires procuring new land, establishing key infrastructure, and relocating associated lines. It is usually only economic when the existing infrastructure is inadequate or in poor condition, or when replacement works cannot occur without sustained supply disruption due to limitations at the existing site.

[14] AEMO. Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.

SP AusNet 10-year asset renewal plan

The SP AusNet 10-year plan (in calendar years) focuses on major asset renewal projects. The description of the scope of works listed in Table 3-23[15] includes the main plant items. SP AusNet regularly undertakes asset condition surveys to quantify specific line works. This asset renewal plan identifies expected needs, such as replacing insulators and possible corroded conductors.

While the project completion dates in the table below indicate likely project timing, they are subject to further analysis prior to approval. A higher degree of uncertainty exists for projects outside the current transmission reset period (2008–2014 and 2014–2017). The cost estimates provided are indeed estimates and could vary significantly due to factors such as outages required to implement the project. These estimates allow for the entire project cost, including project management, overheads, and finance.

Wherever possible, these asset renewal works are planned to minimise network outages, and are scheduled at times of lower system demand. The asset renewal plan is subject to change based on results of further analysis, asset failures necessitating project reprioritisation, and regulatory revenue decisions.

Table 3-24 — SP AusNet 10-year asset renewal plan (cost estimates are in 2013 dollars)

Project name	Scope of work summary	Cost estimate ($ million)	Target completion date
BETS–KGTS Tower Replacement	Replacement of 12 towers on the BETS-KGTS Line.	8	2013
MWTS 66 kV CB Replacement	Replace 8 X 66 kV bulk oil CBs.	3	2013
BLTS Redevelopment	Replace transformers, transformer 220 kV CBs, protection and communication.	50	2013
BETS R2A/2B 220/66 kV Transformer Group Replacement	Replace R2A/2B 220/66 kV transformer group with 1 x 150 MVA 220/66 kV transformer.	9	2013
ROTS 220 kV CB Replacement	Replace 7 x bulk oil 220 kV CBs and install new CB management.	17	2013
GTS B1 and B3 Transformer and 66 kV CB Replacement	Replace B1and B3 ASEA transformers with 150 MVA 220/66 kV transformers. Replace 4 x 66 kV bulk oil CBs.	21	2013
Transmission line structure, conductor and insulator replacement	Transmission line structure, conductor and insulator replacement.	12	2013
HWPS 220 kV CB Replacement - Stage 2	Replace 5 x 220 kV bulk oil CBs.	12	2013
Synchronous Condensers Refurbishment - Stage 1	Synchronous condenser auxiliary and safety systems replacement and upgrade.	5	2014
KGTS SVC thyristors and control upgrade	Upgrade thyristors and thyristor controls.	5	2014
Station Control Systems Replacement	Station control systems replacement.	5	2014

[15] See the acronym list at the back of this publication for information about the acronyms used in this table.

Project name	Scope of work summary	Cost estimate ($ million)	Target completion date
Replace BLTS Synchronous Condenser AVR	Replace BLTS synchronous condenser AVR.	2	2014
OPGW on ROTS-RTS via MTS	Install OPGW on ROTS–RTS Line via MTS.	4	2014
OPGW TBTS-JLA	Install OPGW on TBTS–JLA line to replace copper supervisory cable.	1	2014
DDTS H1 330/220 kV Transformer Replacement	Replace H1 ACEC 225/340 MVA 330/220 kV transformer.	17	2014
ERTS Switchgear Replacement	Replace 220 kV CTs and 3 x 66 kV bulk oil CBs.	2	2014
GNTS B1 220/66 kV Transformer, 220kV CB and 66kV CB Replacement	Replace B1 220/66 kV transformer, 8 x 220 kV air blast CBs, 3 x 66 kV CBs and install new protection and CB management.	30	2014
MWTS B2 Transformer Replacement	Replace B2 ASEA transformer with 150 MVA 220/66kV transformer and replace 4 66 kV single phase CVTs.	7.6	2014
TTS 66 kV Bus-tie CB Replacement	Replace 66 kV bus-tie CBs.	1.7	2014
Replace Synchronous Condenser control circuits	Replace synchronous condenser control circuits.	3	2014
Synchronous Condensers Protection Replacement	Replace SCO protection systems.	3	2014
SHTS 66 kV CB Replacement	Replace 4 x 66 kV bulk oil CBs.	2	2015
RWTS 220 kV CB Replacement	Replace 9 x 220 kV bulk oil CBs and provide new CB management.	20	2015
HWPS 220 kV CB Replacement - Stage 3	Replace 11 x 220 kV bulk oil CBs.	8	2015
Latrobe Valley supervisory cable upgrade	Replace copper cable with OPGW and miscellaneous communication works.	10	2016
Install 500 kV CB Management Relays at KTS	Install 500 kV CB management relays at KTS (7 CBs).	5	2016
Replace 1990 vintage line differential protections	Replace 1990 vintage line differential protections.	19	2016
FBTS B1 Transformer, 220 kV and 66 kV CB Replacement	Replace B1 ENGLISH ELECTRIC transformer with a 150 MVA 220/66 kV transformer. Replace 66kV bulk oil and 66 kV minimum oil CBs.	22.8	2016
WMTS Redevelopment	Replace 3 x 150 MVA 220/66 kV transformers (B1, B2 & B3), 7 x 220 kV switch bays, 16 x 66 kV switch bays, 22 kV switch bays and all protection and control.	176	2016
RTS Redevelopment	Replace with 3 x 225 MVA 220/66 kV transformers, 220 kV GIS, 66 kV GIS, 22 kV switchboard and secondary systems.	198	2016

Project name	Scope of work summary	Cost estimate ($ million)	Target completion date
Current Transformer Replacements	Replace selected 500kV CTs at HWTS and selected 66 kV CTs at LY.	5	2016
SMTS H1 and H2 Transformer Replacement - Stage 1	Install new 700 MVA 330/220 kV transformer and keep H2 FERRANTI 700 MVA 330/220 kV transformer as a cold spare transformer.	32.6	2016
YPS 220 kV CB Replacement - Stage 1	YPS 220 kV CB Replacement Stage 1. Replace minimum oil 220 kV CBs and all oil CTs.	20.6	2016
Transmission fall arrest installation program	Transmission fall arrest installation program.	11	2017
Transmission line insulator replacement	Transmission line insulator replacement.	4	2017
BETS-KGTS Line Communications	Replace ground wire with OPGW or a Radio Link BETS-KGTS.	7	2017
ROTS No.2 SVC Controls Replacement	Replace SVC controls at ROTS No.2 SVC.	2	2017
HTS Rebuild	Replace B1, B2 and B3 ASEA transformers with 150 MVA 220/66 kV Transformers, 2 x 220 kV minimum oil CBs and 11 x 66 kV bulk oil CBs. Also replace protection and control.	56.8	2017
Transmission conductor replacement	Transmission conductor replacement.	17	2017
HWPS 220 kV CB Replacement - Stage 4	Replace remaining 220 kV bulk oil CBs and install ROIs.	20.4	2017
RWTS B4 220/66 kV Transformer and 66 kV CB Replacement	Replace B4 ASEA 220/66 kV transformer and 6 x 66 kV bulk oil CBs.	15.8	2017
DDTS-SMTS No.1 and 2 330 kV Line Tower Replacement	DDTS-SMTS No.1 and 2 330 kV line tower replacement.	19	2017
SVC Protection Replacement	Replace SVC protection.	4	2018
HOTS SVC Controls Replacement	Replace SVC controls at HOTS.	2	2018
OTN Replacement program	Replace end of life operational telephony network.	4	2018
TSTS Synchronous Condenser	Refurbish SCO – Stage 2.	4	2018
KTS A4 500/220 kV and B4 220/66 kV Transformer Replacement	Replace A4 transformers with a 750 MVA 500/220 kV Transformer. Replace B4 transformer with a 150 MVA 220/66 kV transformer. Install new transformer protection.	48	2018
Synchronous Condensers Refurbishment - Stage 2	Synchronous condenser machine and auxiliary systems refurbishments.	6	2019
Upgrade SCADA at Non-SCIMS & Old SCIMS Sites	Upgrade SCADA at non-SCIMS & old SCIMS sites (20 stations).	12	2019

Project name	Scope of work summary	Cost estimate ($ million)	Target completion date
OPGW on FTS-CBTS (Tower 87)	Install OPGW on FTS-CBTS Line to Tower 87 to provide communications link to CBTS.	1	2019
BLTS 220 kV, 66 kV and 22 kV CB Replacement	Replace 4 x 220 kV minimum oil, 66 kV and 22 kV CBs.	43.1	2019
SVTS Redevelopment Stage 1	Replace B1, B2 and B3 ASEA 220/66kV transformers, 220kV minimum oil CBs and selected 66 kV CBs.	81.1	2019
TSTS B2 Transformer and 66 kV CB Replacement	Replace B2 ASEA 220/66kV transformer, 2 x 66 kV minimum oil CBs and 13 x 66 kV bulk oil CBs, and install new protection and control.	36.8	2020
DC Supply Upgrade Stage 3	DC Supply Upgrade Stage 3 (stations not covered by X803 & XA29).	14	2020
KGTS-WETS-RCTS Line Communications	Replace ground wire with OPGW.	18	2020
Radio Replacement program	Replace end of life radio links.	4	2020
Digital Multiplexing equipment replacement program	Replace end of life digital multiplexing equipment.	20	2020
Replace CB PLC controls	Replace CB PLC controls (500 PLCs).	6	2020
WBTS-HOTS Line Communications	Install OPGW on WBTS-HOTS Line.	9	2020
Current Transformer Replacements	Replace selected 500 kV CTs at HWTS and LYPS.	4	2020
Replace Energy Metering	Replace energy metering (600 meters).	5	2020
Replace Weather Stations at Terminal Stations	Replace weather stations at 22 terminal stations.	6	2020
MPS No.1 and 2 220/11 kV Transformer Replacement	Replace No.1 and 2 220/11 kV transformers and provide new protection.	21	2020
RCTS 66 kV Reactor Replacement	Replace No.1 and No.2 66 kV reactors.	12	2020
FTS 66 kV CB Replacement	Replace 7 x bulk oil 66 kV CBs.	7	2020
ERTS Redevelopment Stage 1	Replace 2 x 220 kV minimum oil CBs and 66 kV CB.	20	2020
SHTS 66 kV CB Replacement	Replace 5 x 66 kV bulk oil CBs.	4	2021
OPGW on RCTS-HOTS Line	Install OPGW on RCTS-HOTS Line.	16	2021
HOTS 66 kV CB Replacement	Replace 5 x 66 kV bulk oil CBs and provide new protection and CB management.	5	2021
TBTS 66 kV CB Replacement	Replace 7 x minimum oil 66 kV CBs.	5	2021
Transmission fall arrest installation program	Transmission fall arrest installation program.	32	2022

Project name	Scope of work summary	Cost estimate ($ million)	Target completion date
Transmission conductor replacement	Transmission conductor replacement.	20	2022
Transmission line insulator replacement	Transmission line insulator replacement.	3	2022
MSS-DDTS No.1 and 2 330 kV Line Tower Replacement	MSS-DDTS No.1 and 2 330 kV line tower replacement.	20	2022
TTS B4 Transformer and 66 kV CB Replacement	Replace B4 ASEA 150 MVA 220/66 kV transformer and bulk oil and minimum oil 66 kV CBs. Install new transformer protection and CB management.	23	2022
GTS B4 Transformer and 66 kV CB Replacement	Replace B4 TOSHIBA transformer with a 150 MVA 220/66 kV transformer and replace 66 kV bulk oil CBs.	16	2022
OPGW on HYTS-SESS Line	Install OPGW on HYTS-SESS line to tower 51.	5	2022
WOTS 66kV CB Replacement	Replace 6 x 66 kV minimum oil CBs.	5	2022
LY 66 kV CB Replacement	Replace 16 x 66 kV minimum oil CBs and provide 12 x CB management.	14	2022
WMTS L1 and L3 Transformer Replacement	Replace L1 and L3 ASEA transformers.	33	2022

3.7 Supporting information

This section provides links to other information about Victorian electricity DSN planning. Some of this information appeared in previous VAPRs.

Information source	Website address
Victorian regional demand forecasts	www.aemo.com.au/Electricity/Planning/Forecasting
Victorian terminal station demand forecasts	http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria
Short-Circuit Levels for Victorian Electricity Transmission	http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report/Victorian-Short-Circuit-Level-Review
Regulatory Investment Tests for Transmission	www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs
Victorian Transmission Network Planning Criteria	http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Transmission-Network-Planning-Criteria
Victorian Electricity Planning Approach	http://aemo.com.au/Electricity/Policies-and-Procedures/Planning
Transmission Connection Planning Report 2012 (TCPR 2012)	http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf

CHAPTER 4 - OPTIONAL FIRM ACCESS ARRANGEMENT EXAMPLE

Summary

The 2013 Victorian Annual Planning Report (VAPR) identifies limitations in the electricity Declared Shared Network (DSN), the estimated costs associated with network congestion, and possible options to alleviate network limits.

This chapter explores a new proposed way of investing in Victorian transmission network augmentations: optional firm access rights arrangements. These arrangements aim to manage congestion that affects generators' ability to dispatch their energy when there are limits on the transmission network.

Access right arrangements create financial certainty for generators by ensuring they receive payment for their energy even when transmission network congestion prevents actual dispatch. This will also encourage efficient investment in transmission infrastructure, supporting builds in the right locations to help reduce network congestion.

In its recently released Transmission Frameworks Review[1], the Australian Energy Market Commission (AEMC) outlines proposed optional firm access rights arrangements.

As the electricity transmission network planner and decision-maker for investment in Victoria's DSN, AEMO has built on the AEMC's proposal, adding practical modifications for a more efficient arrangement that recognises the differences in Victoria's planning arrangements compared to other states on Australia's eastern seaboard. AEMO also takes into account incentive-based regulation and negotiations with regulated monopolies.

This chapter provides a summary of the AEMC's proposal, and introduces AEMO's proposed modifications.

It also considers how AEMO's planning role might change under a framework that provides generators with greater input into decisions over what gets built, when, and at what cost. Other matters reviewed in this chapter are the charging arrangements for optional firm access rights, the AER's role, and whether the optional firm access framework will accommodate competition to build new transmission assets. It considers the future roles of incumbent and new transmission asset owners under a competitive asset provision model.

The limitations that are the most likely candidates for this framework are set out in Table 3-1 in Chapter 3. AEMO has taken one of these limitations—the Hazelwood 500/220 kV transformer loading limitation in the Latrobe Valley—as a case study to demonstrate how access rights may operate. The example used is purely an illustration of how the scheme could be applied and is not a planned augmentation.

The characteristics of the Hazelwood 500/220 kV transformer limitation (outlined in Chapter 3) have been simplified for the purposes of this case study. Further assessments are required to consider how optional firm access would apply with more complex constraints and bidding behaviours, and under other conditions such as outages.

AEMO welcomes comments and feedback on the work set out in this chapter, and invites views on how this analysis could be progressed further. Feedback should be emailed to **planning@aemo.com.au**.

[1] AEMC. Available at: http://www.aemc.gov.au/Market-Reviews/Completed/transmission-frameworks-review.html.

4.1 The AEMC's optional firm access framework

The AEMC's proposed optional firm access framework can be summarised as containing the following key features:

- **Regional structure remains unchanged.**
  Nodal pricing is not introduced, and the current market regions and interconnectors remain. Customer and non-scheduled generator settlement are unaffected. Participants would continue to contract against regional reference node (RRN) prices.
- **Generator firm access is financial, not physical.**
  Physical dispatch priorities remain as they are presently; the dispatch engine selects the cheapest feasible combination of presented bids. Generator access rights are recognised purely through ex-post settlement adjustments after network congestion has occurred. Money is debited from dispatched "non-firm" generators (who have not purchased access rights) and credited to "firm" generators, whether or not they are physically dispatched. The incentives for generators to bid down to the price floor at times of congestion are removed, resulting in more efficient dispatch.

  AEMO's control of the physical network through dispatch engine constraint equations is unaffected. After the event AEMO would conduct automated settlement adjustments according to pre-defined rights advised by the TNSP. By design, settlement is balanced in all conditions; there are no uplift payments.
- **Generators seek rights from the TNSP.**
  Rights are negotiated between the TNSP and the generator, and are then advised to AEMO, who applies the settlement adjustment. The AEMC has proposed an initial free allocation of rights to incumbent generators, determined by their historical levels of access. This initial allocation phases out, although the period has not been specified, and generators would then either purchase rights from the TNSP or become non-firm.
- **The network is built to satisfy the firm access.**
  The TNSP should provide network services to support the firm access, and should also look to expand the network where generators seek more access. Failure to deliver the network capacity that has been sold triggers a penalty regime, reducing the network's revenue.
- **Geographical extent of the firm access.**
  The AEMC approach anticipates the TNSP providing firm access from the generator connection point to the RRN. This would involve recognising the rights across all the flowgates[2] in its region where the generator it is physically located.
- **Generator access pricing would be a mathematical formula.**
  The generator's access charge is based on a Long-Run-Incremental-Charge (LRIC) technique. This technique determines the total cost of upgrading the network to support the generator's rights for the period that the rights are held, as well as customers' reliability needs. Generators would pay an amount equivalent to their rights, with the remaining costs borne by end use customers.
- **The TNSP would remain a fully regulated monopoly.**
  The model presumes TNSPs are regulated for-profit monopolies with state-wide planning responsibilities. Because of the pricing approach, TNSPs would be incentivised to over-price and under-allocate network access to generators. As such, generator interests would require regulatory protection from the AER as customer interests do now.
- **The TNSP continues to augment downstream networks to support customer reliability.**

[2] The term "flowgate" has the same meaning as used in the Transmission Frameworks Review, being points of congestion on the network represented in the dispatch process.

Augmentations using the Regulatory Investment Test would continue purely to support customers. Resulting expenditure would continue to form part of the regulated asset base, and would be funded by customers. In time, this would see upstream parts of the network become funded by generators and downstream by customers.

- **"Firm" access is not completely firm in all conditions.**
  Where the network is limited in an abnormal way, such as during a severe line outage, it would be impossible to fund all the firm access rights the TNSP has sold. The cost of this shortfall would be shared between the firm generators and the TNSP, who would be required to contribute some market payments to the generator, subject to a sharing percentage and exposure cap. This mechanism provides partial protection to the generator and a strong incentive to the TNSP to provide service quality.

- **Optional firm access is "optional".**
  No generator is obliged to purchase rights. The settlement adjustments effectively result in firm generators receiving the regional price, and non-firm generators receiving their nodal price during congestion. The latter could be a rational choice for generators who do not sell firm hedge contracts, such as wind generators.

  A generator may also seek partial rights (less than their capacity) from a TNSP; time-sculpted rights (e.g., only firm during business hours); or "super-firm" rights (i.e., less scaling back during network outages).

4.2 Practical amendments to the optional firm access model

The framework in this section builds on the AEMC's optional firm access model. It contains several amendments which recognise the differences in Victoria's planning arrangements.

The key features of the amended framework (particularly those related to planning) and a comparison with the AEMC's proposed model are set out below.

- **Planning** – Registered (or intending) TNSPs can propose augmentations to the transmission network to support the access rights levels desired by individual generators. AEMO would be responsible for providing planning information and advice to generators about the current network capability, AEMO's views on the potential augmentation options to meet desired access levels, and indicative costs of those options. Generators would then be responsible for undertaking their own assessment to determine the preferred augmentation option.

  AEMO's role would be similar to the AEMC's proposal, in which its provision of contestability of views in planning and promoting national coordination is enhanced.

  Unlike the AEMC's proposal, the amended framework envisages that AEMO (not a regulated asset owner) continues to be responsible for all network planning within Victoria.

- **Decision-making** – Generators would be responsible for investment decision-making. This contrasts with the AEMC's proposal which nominates TNSPs being responsible for investment decisions.

- **Procurement** – Generators would have the ability to procure an augmentation using competitive tendering arrangements if the augmentation could be defined as a "separable augmentation"; this is an augmentation that can technically and commercially be provided by a third-party and exceeds a certain dollar threshold.

  This enables generators to source a more competitive price for their access rights rather than rely on a regulated outcome which would involve the AER regulating the price of new assets. In contrast, the AEMC's approach envisages that all services are provided by the regulated asset owner.

- **Pricing** – Generators would pay a charge for identified additional augmentations. In the simplified example presented, the LRIC pricing arrangement would be identical to a deep connection charge; a charge based on a network augmentation that does not relate solely to its connection.

- **Network operation** – Incumbent and new entrant asset owners would be responsible for operating network assets to meet defined performance levels. These are specified in individual contracts with the generator or in the service target levels specified by the AER. This differs from the AEMC's proposal, which does not include a mix of negotiated and prescribed services. TNSPs would not be exposed to market risk; rather, they would be exposed to a capped performance incentive set out in the AER's service targets or in individual contracts.
- **Revenue regulation** – The acquisition of new access rights from a network augmentation would be subject to a negotiating framework, rather than AER revenue regulation, as proposed by the AEMC. The exception to this would be modifications to the service targets scheme. This avoids the AER conducting a project-by-project assessment based on a 20-year planning horizon.
- **Negotiating framework** - The AER would be responsible for developing a negotiating framework that ensures generators can negotiate on fair and reasonable terms with asset owners, particularly where an augmentation to provide access levels is not considered "separable". The AEMC's model does not include such a provision.

Given the potentially complex interactions of these arrangements with other market and regulatory arrangements, changes may be required to ensure that the framework: delivers efficient pricing and investment outcomes; is practical to implement; and does not impose undue risk on all involved. Further, given the unique arrangements that prevail in Victoria, the framework would need to be modified in other states if it were to be rolled out nationally.

Several interim steps could be considered to transition towards a firm access rights framework. For example, the allocation of existing rights could be achieved ahead of finalising arrangements for providing new rights. These interim steps could also allow rights to be traded between rights holders.

The remainder of this chapter explores the affect these arrangements could have on an existing limitation in the Latrobe Valley.

4.3 The Hazelwood 500/220 kV transformer limitation

The Hazelwood transformers have been a point of congestion affecting several Latrobe Valley generators since 2000, when the generation capacity in this part of the electricity network increased from historic levels.

In Chapter 3, AEMO forecasts limitations on the Hazelwood 500/220 kV transformers, mainly driven by generation dispatch or new generation connected to the Latrobe Valley 220 kV transmission network.

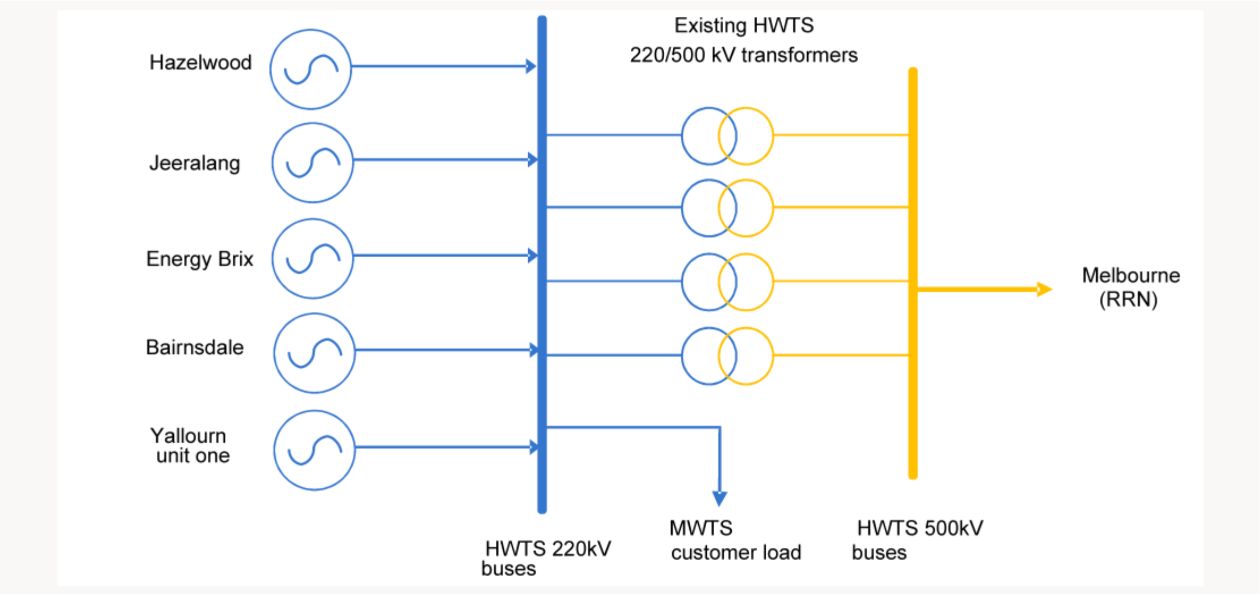
The limitation is of a radial nature, with almost equal impact on a small number of generators.

Expanding the transformer capability does not materially affect other parts of the network, or customer reliability. As such, the market benefits of an expansion are almost fully captured by the generators subject to the limitation.

4.3.1 Network topology

In a highly simplified form[3], the limitation affects the following scheduled generators shown in Figure 4-1. Note that this simplified example ignores potential flowgates downstream of Hazelwood Terminal Station.

Figure 4-1 — Simplified network arrangements



4.3.2 Generator current access and observed congestion

The capacity of the 500/220 kV transformers is limited by the short-term rating of the remaining transformers upon the contingency of one transformer.

In a simplified fully-radial form, the constraint can be expressed as:

Dispatched Gen (Hazelwood + Jeeralang + Morwell + Bairnsdale + Yallourn unit 1) ≤ RHS

RHS = 3* transformers' short-term rating + generator aux load + Morwell Terminal Station (MWTS) customer load.[4]

Using assumptions around high generation/average MWTS demand conditions:

= 1,914 + 179 + 260 = 2,353[5]

The installed generation capacity is set out in Table 4-1.

[3] Note that in the real configuration the HWTS 220 kV buses are not tied, but are connected via the short HWTS-JLTS 220 kV lines, in order to limit fault currents. This means the real constraint coefficients are not exactly equal, varying from 0.8235 to 1.0.

[4] Note that in actual dispatch the there is one constraint protecting each of the four transformers.All these terms appear in the LHS and RHS of each constraint, however due to slightly mismatched impedance, the coefficients vary slightly from unity.

[5] Note this demand is dynamically calculated in real dispatch.

Table 4-1 — Generation capacities

Generator	Winter capacity (MW) (note 1)	Summer capacity (MW) (note 1)	Registered max capacity (MW)
Hazelwood	1,708	1,600	1,760
Jeeralang	484	416	560
Energy Brix	75	75	195
Bairnsdale	84	70	94
Yallourn unit 1	360	360	380
Total	2,711	2,521	2,989

Note 1: Capacities quoted are the higher of AEMO's generator information page and recent observed unit performances under high and low temperature conditions.

This limitation, in its simplified form, could theoretically constrain off generation by 636 MW in system normal if generators all simultaneously attempted to dispatch to their registered maximum capacities in average demand conditions. Under more realistic current operating capacities, it would be expected to constrain off generation by about 358 MW in winter and less in summer.

4.3.3 Initial allocation

An optional firm access flowgate requires an initial allocation of entitlements. The AEMC design proposes to do this in proportion to current non-firm access achieved in actual dispatch. Because the flowgate capacity is already over-subscribed (i.e., there is more generation than transmission capacity), there would be no additional access available for purchase beyond this initial allocation.

Determining initial allocations is inherently contentious and a fair and objective measure is required. Capacities that AEMO publishes for registration and for planning purposes are self-disclosed and not subject to technical verification. This is because in an energy-only market these quantities have no impact on commercial income.

To identify a genuine maximum capacity for each station, the highest recently observed output has been used. Operation to date in the current financial year (1 July 2012 – 28 February 2013) was sampled, as this represents capacity as presented to the market since carbon pricing began. The highest output for each unit was identified and summed for a station flowgate entitlement.

Table 4-2 — Flowgate entitlements based on historic data

Generator	Sum of highest by unit outputs 2012/13 (MW)	Initial Flowgate entitlement "E_{ik}" (%)	Flowgate entitlement of 2,353 MW (MW)
Bairnsdale	90	3.3	78
Hazelwood	1,740	64.0	1,506
Jeeralang	441	16.3	382
Energy Brix	85	3.2	74
Yallourn unit 1	360	13.3	311

4.3.4 Settlement adjustments with initial entitlements

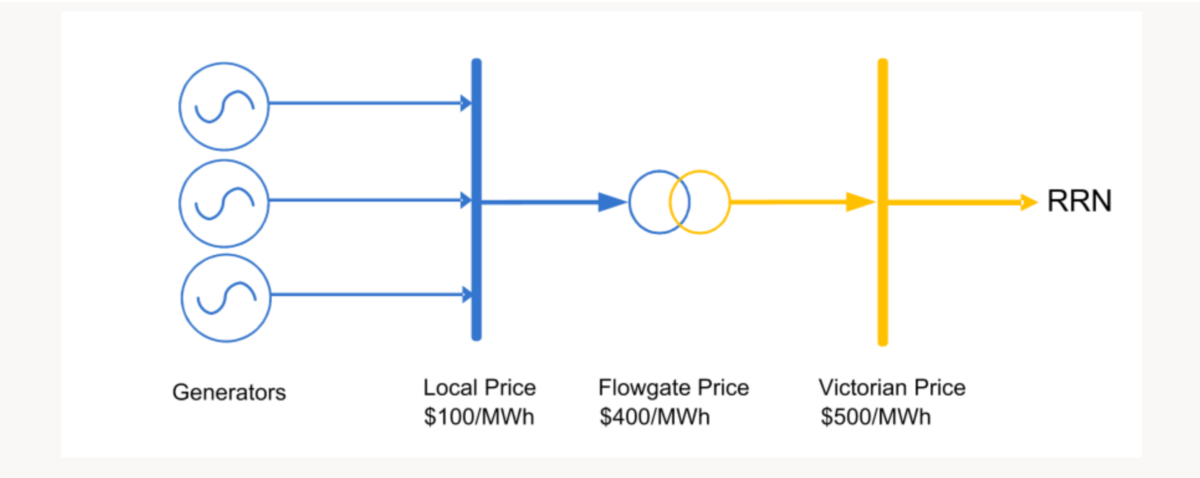
The following adjustments are drawn from Section 4 and Section 12 of the AEMC's technical report.

For this exercise the Hazelwood transformer constraints are simplified into a single constraint of a radial form where all scheduled generators have unity participation factors. The constraint has no interconnector terms or constrained on generators. This means the following adjustments are simpler than the generalised adjustments provided by the AEMC.

Although the AEMC's technical report determines allocation in MW units, this example uses a simpler percentage form. The Firm Access Standard (FAS) scaling factor will be 100%, as this is system normal.

Assume the Victorian RRN price is $500/MWh and the Hazelwood transformer constraint is binding. The local price upstream of the Hazelwood transformer flowgate is $100/MWh. The local price would be found by inspecting AEMO's published marginal price of the constraint for the Hazelwood transformers; in this case the "flowgate price" would be $400/MWh,

Figure 4-2 — Network locational prices



All generators are available and presenting high availability as per Table 4-3. For the purposes of simplifying this example, assume all output is bid at the one bid price. The flowgate capacity is 2,353 MW, as described above.

In this case, because all generators have availability exceeding their flowgate entitlements, their actual entitlements would be scaled back proportional to availability.

Table 4-3 — Proportional entitlements

Generator	Bid availability (MW)	Bid price ($/MWh)	Dispatch (MW)	Actual entitlement (MW)	Regional settlement ($,000)	Flowgate adjustment ($,000)	Net ($,000)
Yallourn	360	30	360	323	180	-14.44	165.56
Hazelwood	1,650	40	1,650	1,484	825	-66.12	758.88
Energy Brix	80	50	80	72	40	-3.2	36.8
Jeeralang	440	100	263	395	131.5	53.16	184.66
Bairnsdale	85	150	0	76	0	30.6	30.6
Total	2,615		2,353		1,176.5	0	1,176.5

When the flowgate price is apportioned by availability, the incentive for disorderly bidding is removed. When the constraint binds, generators are no longer incentivised to offer at the market floor price, so the generation pattern is more consistent with an efficient merit order.

At first glance, the first three generators here appear to suffer debits due to the flowgate adjustment. However, when compared to a realistic counter-factual of all generators bidding at the floor price and being constrained pro-rata, every generator is anticipated to be marginally more profitable (after allowing for running costs), as they capture the dispatch efficiency benefits.

As the generators receive firm access to the Victorian RRN price according to their actual entitlements, they are at a lower risk of contracting up to that volume.

4.3.5 Providing access with a network augmentation

Options to provide network access

In the 2007 Victorian Annual Planning Report[6], VENCorp (now AEMO) considered the option of installing a fifth Hazelwood 500/220 kV transformer to address the emerging limitations. At the time this was estimated to cost approximately $40 million as a contestable project.

The transformer would add 638 MVA to the capacity of the network, and the flowgate capacity would increase from 2,353 MW to 2,953 MW.

The present value of the project’s market benefits was estimated at only $1.7 million, so the augmentation was not considered further.

The augmentation would have little impact on customers. The constraint is most severe in winter, when generation capacity is highest and MWTS 66 kV customer load is lower. Customer reliability/avoided capacity benefits accrue mostly in summer.

The assessed benefits were mostly rescheduled generation, (i.e. lower operating cost generation). While these tend to be minor net gains, there are likely to be much more significant wealth transfers involved; from generators outside the constrained location to those within it. These transfers could well exceed $40 million. If the augmentation were to proceed, it would be a prime candidate for funding by the generators who benefit.

While there might be other options that could alleviate the constraint, such as a new transmission lines, these options are not explored further in this chapter and would be unlikely to proceed due to cost.

Augmentation requirements

The fifth transformer would be considered a “contestable augmentation”, both because of its cost and technical ability to be provided by a party other than the incumbent transmission asset owner.

The process proposed would provide the generator the ability to enter into an agreement with AEMO to install the transformer, specify who could build the transformer, or could have AEMO conduct a competitive tender process. These options are presently available to generators for augmentations to facilitate their connection.

AEMO would specify the minimum technical requirements that the transformer would need to satisfy in order to ensure a secure and safe operating state.

The incumbent transmission asset owner would need to be involved in the process, given the associated interface works that require the transformer to be physically connected to the existing network. The terms and conditions of the incumbent owner’s involvement would need to be established within the existing regulatory framework the National Electricity Law and the National Electricity Rules, such as the provision of access rights.

[6] The 2007 VAPR is available by request as it has been archived from the AEMO website.

While this approach imposes some administrative costs, the benefits of contestability in the construction, ownership and operation of network augmentations has been estimated to save 20–30% of the augmentation capital costs, and around 1% on annual operating costs.[7]

All costs of the separable augmentation and the interface works would be borne by the generator who desired the access rights.

Interaction with the regulatory arrangements

As part of the negotiation process, AEMO, the generator and asset owner would determime the terms and conditions under which that asset would provide the desired access level. This could include negotiations around compensation in the event of an outage; the timing, length and nature of outages; and any other matters subject to negotiation.

At a minimum, the contract would need to include some form of financial compensation in the event of an outage or constraint below the agreed access level. This would be set out in the AER’s negotiating framework.

The new transformer would need to work in concert with the existing transformers. Therefore, the shared services provided by all of these assets would be provided via a mix of negotiated and prescribed services, which is presently the case on the existing network.

The revenues for the prescribed services would continue to be regulated by the AER under the specified revenue-setting framework. The charges for those would also be allocated under the present transmission pricing arrangements. The prescribed services would also be subject to the AER’s Service Targets Performance Incentive Scheme (STPIS) and the Availability Incentive Scheme. Both the availability and congestion components of these schemes could potentially be modified to better reflect the needs of generators at relevant points on the network. Over time, this is likely to provide outcomes that would replicate those arising from negotiations.

4.3.6 Allocation of augmented flowgate entitlements

One scenario allowing for considering of how optional firm access arrangements would work in practice is to assume that new generation is connected in the Latrobe Valley. For the purpose of this example, AEMO has postulated the following construction scenario occurring after the initial allocations:

- Construction of 500 MW combined-cycle gas turbine capacity by Hazelwood.
- Construction of the Bald Hills 107 MW (semi-scheduled[8]) wind farm.
- Retirement of Energy Brix.
- Retention of all other existing capacity.

The augmentation and closure of Energy Brix releases some (600 + 72.4) MW of additional flowgate entitlement. This would not be subject to initial allocation, and would have to be purchased by generators seeking increased firm access.

For the purpose of this example, it is presumed that this release of capacity will be purchased by Yallourn and Hazelwood and that Bald Hills Wind Farm, an intermittent generator, chooses to enter as a non-firm generator.

All the generators are at adjacent nodes, so Energy Brix would be able to transfer its initial allocation to one of these buying generators[9], as long as it could satisfy the TNSP that it was an equivalent counterparty.

[7] See AEMO’s submissions to the Transmission Frameworks Review and Productivity Commission.
[8] Semi-scheduled wind farms are subject to network constraint in the same manner as scheduled generators, unlike legacy non-scheduled plants which receive effectively fully firm access.
[9] See AEMC Technical Report: Section 7.3.8.

Table 4-4 — Entitlement comparisons

Generator	Original entitlement of 2,353 MW (MW)	Purchases (MW)	New entitlement of 2,953 MW (MW)
Bairnsdale	78	0	78
Hazelwood	1,506	625	2,132
Jeeralang	382	0	382
Energy Brix	74	-74	0
Yallourn unit 1	311	48	360
Bald Hills	0	0	0
Total	2,353	674	2,953

4.3.7 Settlement adjustments with augmented allocations

A similar bidding pattern as before is assumed, as is a $500/MWh Victorian RRN price and a $400/MWh flowgate price. Hazelwood's capacity has increased by 500 MW, and Bald Hills Wind Farm can achieve 80 MW of unconstrained output.

Table 4-5 — Settlement adjustments

Generator	Availability (MW)	Bid price ($/MWh)	Dispatch (MW)	Entitlemen t (MW)	Actual entitlement (MW)	Regional settlement ($,000)	Flowgate settlement ($,000)	Net ($,000)
Bald Hills	80	-50	80	0	0	40	-32	8
Yallourn	360	30	360	360	360	180	0	180
Hazelwood	2,150	40	2,150	2,132	2,132	1,075	-7	1,068
Energy Brix	0	-	0	0	0	0	0	0
Jeeralang	440	100	363	382	382	181.5	7.68	189
Bairnsdale	85	150	0	78	78	0	31.32	31.32
Total	3,115		2,953	2,953		1,476.5	0	1,476.5

Several projected outcomes of this case study are worth noting:

- Having purchased 48 MW additional entitlement from the augmentation, Yallourn is able to achieve firm access to the Victorian RRN price up to its full availability of 360 MW.
- Having expanded its capacity by 500 MW and purchased 625.9 MW, Hazelwood is able to greatly increase its level of firm access to the Victorian RRN price.
- Jeeralang and Bairnsdale, who did not participate in funding the augmentation, receive identical income. Their access is not harmed by the new entrants, and they do not free-ride on the augmentation.
- Bald Hills, which had no initial entitlement and declined to purchase additional entitlement, receives only the local $100/MWh local price for its output. This non-firm access could be a commercial choice for an intermittent generator that is unlikely to contract firm output to the Victorian RRN. However, the local price provides the correct locational incentive for the new-entrant wind farm.
- The incentive to bid at-cost remains, so the physical dispatch remains consistent with an efficient merit order. A wind farm's marginal cost is negative due to the production of renewable energy certificates. In a

counter-factual of no optional firm access, all generators would rebid to the market floor price and lower-cost generators lose dispatch volume, including semi-scheduled wind farms.

4.3.8 Scope for further work

This scheme builds on the proposed optional firm access arrangements outlined in the AEMC's Transmission Frameworks Review and investigates an option for generators to pay for augmentations to alleviate identified limitations in exchange for rights to the transmission system.

Whilst there are challenges of implementing the optional firm access scheme, this chapter indicates that it could be applied to Victoria under the current planning arrangements. That is, it could be achieved and potentially benefit from the separation of asset planning from asset ownership. This is both from the perspective of an independent assessment of the options' technical needs, and the competitive provision of the transmission services.

The constraint considered in this chapter is a relatively simple example. Further assessments are required to consider how optional firm access would apply with more complex constraints and bidding behaviours and under other conditions such as outages.

Stakeholder feedback is welcome on this chapter. Please email feedback to **planning@aemo.com.au**.

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APPENDIX A - ELECTRICITY DSN RATINGS

A.1 Victorian electricity DSN ratings

This appendix presents information about electricity Declared Shared Network (electricity DSN) ratings[1] at the time of the snapshots presented in Chapter 2.

Table A-1 presents the continuous and short–term line and transformer ratings at the time of the maximum demand snapshot.

Table A-2 presents continuous and short–term line and transformer ratings information for the Northern Corridor at the time of the high power flow from Victoria snapshot.

Rating types are shown in the tables as 'D' (dynamic rating), 'D/W' (dynamic rating with wind monitoring) and 'S' (static rating).

Dynamic ratings from SP AusNet's System Overload Control Schemes (SOCS)[2], which are used in real time by AEMO system operators, take into account the ambient temperature and a solar heating factor calculation based on the date and time. For lines equipped with wind monitoring facilities, SOCS also takes into account the actual wind speed, otherwise a standard wind speed of 0.6 m/s is assumed.

The rating for equipment with static ratings is based on ambient temperatures that assume a wind speed of 0.6 m/s. Short-term ratings are not available for some lines with static ratings; in these circumstances a short-term rating equal to the continuous rating is assumed.

Table A-1 — Victorian electricity DSN continuous and short-term ratings, maximum demand snapshot

Region	Voltage	Lines/transformers	Continuous rating (N)	Short-term rating (N-1)	Rating type
Eastern Corridor	500 kV	Loy Yang – Hazelwood 1	2,869	2,869	S
		Loy Yang – Hazelwood 2	3,008	3,008	S
		Loy Yang – Hazelwood 3	3,008	3,008	S
		South Morang – Hazelwood 1	2,698	2,698	S
		South Morang – Hazelwood 2	2,698	2,698	S
		Hazelwood – Rowville 3	3,276	3,276	S
		Hazelwood–Cranbourne	3,276	3,276	S
	220 kV	Yallourn – Rowville 5	368	436	D/W
		Yallourn – Rowville 6	361	428	D/W
		Yallourn – Rowville 7	361	429	D/W
		Yallourn – Rowville 8	361	428	D/W

[1] AEMO. Available at http://www.aemo.com.au/Electricity/Data/Network-Data/Transmission-Equipment-Ratings.

[2] SOCS is software installed at the Victorian regional transmission network service provider control centre, which calculates dynamic real-time ratings of selected overhead lines and the Brunswick–Richmond cable. Its outputs—including continuous, 15-minute and 5-minute rating— are provided to AEMO for use in real-time operations.

Region	Voltage	Lines/transformers	Continuous rating (N)	Short-term rating (N-1)	Rating type
Eastern Corridor		Hazelwood – Yallourn 1	438	438	D
		Hazelwood – Yallourn 2	474	524	D
		Hazelwood – Rowville 1	369	438	D
		Hazelwood – Rowville 2	364	432	D
		Hazelwood–Morwell	277	348	S
		Jeeralang – Morwell 1	376	376	S
		Jeeralang – Morwell 2	376	376	S
		Hazelwood – Jeeralang 1	749	749	D
		Hazelwood – Jeeralang 2	903	1,187	D
		Hazelwood – Jeeralang 3	467	620	D
		Hazelwood – Jeeralang 4	464	609	D
	500/220 kV	Rowville 500/220 kV A1 Transformer	1,000	1,500	S
		Rowville 500/220 kV A2 Transformer	1,000	1,500	S
		Hazelwood 500/220 kV A1 Transformer	600	638	S
		Hazelwood 500/220 kV A2 Transformer	600	638	S
		Hazelwood 500/220 kV A3 Transformer	600	638	S
		Hazelwood 500/220 kV A4 Transformer	600	638	S
South–west Corridor	500 kV	Tarrone–Heywood	2,683	2,683	S
		Moorabool–Tarrone	2,165	2,165	S
		Moorabool–Mortlake	2,165	2,165	S
		Mortlake–Heywood	2,683	2,683	S
		Heywood – Portland 1	1,386	1,386	S
		Heywood – Portland 2	1,386	1,386	S
	275 kV	Heywood – South East 1	496	529	S
		Heywood – South East 2	496	529	S
	500/275 kV	Heywood 500/275 kV M1 Transformer	370	525	S
		Heywood 500/275 kV M2 Transformer	370	525	S
Northern Corridor	330 kV	Jindera–Wodonga	914	914	S
		Wodonga–Dederang	743	743	S
		Dederang – Murray 1	1,015	1,167	D
		Dederang – Murray 2	1,015	1,167	D
		Dederang – South Morang 1	939	939	D
		Dederang – South Morang 2	936	936	D
	220 kV	Dederang – Mt Beauty 1	355	436	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short-term rating (N-1)	Rating type
		Dederang – Mt Beauty 2	355	436	D
		Mt Beauty – Dartmouth	230	-	S
		Mt Beauty – Bogong	334	-	D
		Mt Beauty – West Kiewa	97	-	S
		Eildon – Mt Beauty 1	344	390	D
		Eildon – Mt Beauty 2	344	390	D
		Eildon–Thomastown	613	699	D
	330/220 kV	Dederang 330/220 kV H1 Transformer	225	315	S
		Dederang 330/220 kV H2 Transformer	340	400	S
		Dederang 330/220 kV H3 Transformer	240	400	S
Greater Melbourne and Geelong	500 kV	Sydenham – Moorabool 1	2,521	2,521	S
		Sydenham – Moorabool 2	2,521	2,521	S
		Sydenham – Keilor	1,949	1,949	S
		South Morang – Keilor	2,598	2,598	S
		South Morang – Sydenham 1	2,598	2,598	S
		South Morang – Sydenham 2	2,651	2,651	S
		South Morang – Rowville	3,277	3,277	S
		Rowville–Cranbourne	2,771	2,771	S
	220 kV	Anglesea – Point Henry	228	-	S
		Geelong – Point Henry 1	238	262	S
		Geelong – Point Henry 2	238	262	S
		Geelong – Moorabool 1	785	785	D
		Geelong – Moorabool 2	825	825	D
		Geelong – Keilor 1	363	449	D/W
		Geelong – Keilor 2	368	455	D/W
		Geelong – Keilor 3	366	435	D/W
		Keilor–Altona	775	943	D
		Keilor–Brooklyn	855	855	D
		Brooklyn–Altona	775	853	D
		Brooklyn–Newport	826	826	D
		Brooklyn – Fishermans Bend	823	823	D
		Newport – Fishermans Bend	861	861	D
		Fishermans Bend – West Melbourne 1	376	452	D
		Fishermans Bend – West Melbourne 2	376	452	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short-term rating (N-1)	Rating type
Greater Melbourne and Geelong	220 kV	Keilor – West Melbourne 1	872	873	D
		Keilor – West Melbourne 2	874	875	D
		Keilor – Thomastown 1	543	562	S
		Keilor – Thomastown 2	612	775	S
		South Morang – Thomastown 1	590	649	S
		South Morang – Thomastown 2	590	649	S
		Thomastown – Brunswick 1	681	777	D
		Thomastown – Brunswick 3	740	740	D
		Thomastown–Ringwood	767	816	D
		Thomastown–Templestowe	743	797	D
		Templestowe–Rowville	762	762	D
		Thomastown–Rowville	591	650	D
		Ringwood–Rowville	701	701	D
		Rowville – Malvern 1	240	279	S
		Rowville – Malvern 2	240	279	S
		Rowville – Springvale 1	751	898	D/W
		Rowville – Springvale 2	751	898	D/W
		Rowville – Richmond 1	664	729	D
		Rowville – Richmond 2	664	681	D
		Springvale – Heatherton 1	416	438	D
		Springvale – Heatherton 2	429	453	D
		Rowville – East Rowville 1	845	891	D
		Rowville – East Rowville 2	845	891	D
		East Rowville – Cranbourne 1	775	775	D
		East Rowville – Cranbourne 2	775	775	D
		Cranbourne – Tyabb 1	543	543	D
		Cranbourne – Tyabb 2	543	543	D
		Tyabb – John Lysaght 1	183	183	S
		Tyabb – John Lysaght 2	183	183	S
		Brunswick–Richmond	450	650	D
	500/220 kV	Keilor 500/220 kV A2 Transformer	750	810	S
		Keilor 500/220 kV A3 Transformer	750	810	S
		Keilor 500/220 kV A4 Transformer	750	810	S
		Cranbourne 500/220 kV A1 Transformer	1,000	1,500	S

Region	Voltage	Lines/transformers	Continuous rating (N)	Short-term rating (N-1)	Rating type
Greater Melbourne and Geelong	500/330 kV	South Morang 500/330 kV F2 Transformer	1,000	1,200	S
	330/220 kV	South Morang 330/220 kV H1 Transformer	700	750	S
		South Morang 330/220 kV H2 Transformer	700	750	S
Regional Victoria	220 kV	Red Cliffs – Buronga	265	265	S
		Red Cliffs – Horsham	324	324	D
		Red Cliffs – Wemen	306	325	D
		Wemen–Kerang	308	326	D
		Horsham–Waubra	322	322	S
		Waubra–Ballarat	323	323	D
		Kerang–Bendigo	323	323	D
		Ballarat–Bendigo	304	367	D
		Ballarat–Terang	325	325	D
		Ballarat – Moorabool 1	311	369	D/W
		Ballarat – Moorabool 2	484	485	D/W
		Terang – Moorabool	240	240	D
		Bendigo–Fosterville	440	513	D/W
		Fosterville–Shepparton	440	513	D/W
		Shepparton – Glenrowan 1	503	503	D
		Shepparton – Glenrowan 3	495	495	D
		Shepparton–Dederang	347	415	D
		Dederang – Glenrowan 1	526	581	D
		Dederang – Glenrowan 3	450	450	D
	500/220 kV	Moorabool 500/220 kV A1 Transformer	1,000	1,310	S
		Moorabool 500/220 kV A2 Transformer	1,000	1,500	S

Table A-2 — Victorian electricity DSN continuous and short-term ratings, high power from Victoria snapshot

Region	Voltage	Lines/transformers	System normal rating (MVA)	N–1 rating (MVA)	Rating type
Northern Corridor	330 kV	Jindera–Wodonga	966	1,008	S
		Wodonga–Dederang	743	743	S
		Dederang – Murray 1	1,015	1,167	D
		Dederang – Murray 2	1,015	1,167	D
		Dederang – South Morang 1	1,104	1,104	D
		Dederang – South Morang 2	1,104	1,104	D
	220 kV	Dederang – Mt Beauty 1	470	570	D
		Dederang – Mt Beauty 2	470	570	D
		Mt Beauty – Dartmouth	230	–	S
		Mt Beauty – Bogong	322	–	D
		Mt Beauty – West Kiewa	97	–	S
		Eildon – Mt Beauty 1	376	376	D
		Eildon – Mt Beauty 2	377	377	D
		Eildon–Thomastown	694	694	D
	330/220 kV	Dederang 330/220 kV H1 Transformer	225	315	S
		Dederang 330/220 kV H2 Transformer	340	400	S
		Dederang 330/220 kV H3 Transformer	240	400	S
	500/330 kV	South Morang 500/330 kV F2 Transformer	1,000	1,200	S
	330/220 kV	South Morang 330/220 kV H1 Transformer	700	750	S
		South Morang 330/220 kV H2 Transformer	700	750	S

APPENDIX B - NEW TERMINAL STATIONS IN VICTORIA

B.1 Introduction

This appendix outlines the preferred approach to locating and establishing new terminal stations in Victoria.

New terminal stations can be initiated by the following:

- A transmission network service provider (TNSP) identifying the need for electricity Declared Shared Network (electricity DSN) augmentations to deliver future capacity requirements.
- Applications to connect generation or major loads to the electricity DSN.
- Plans for new terminal stations necessary to meet distribution network demand, as outlined in the Transmission Connection Planning Report 2012.[1]

B.2 Background

The approach of connecting multiple generation connections to a single terminal station in the electricity DSN has been under development since 2010 (as reported in the 2010 VAPR). It was initiated in response to the large volume of applications to connect to the Regional Victorian and South-west Corridor transmission networks.

As Victorian transmission planner, AEMO proposed this approach to circumvent technical issues associated with connecting multiple generating systems in close proximity. This approach also enables better coordination of proposed connections within similar timeframes.

The policy and guidelines for establishing new terminal stations in Victoria[2] were developed as part of the Victorian Connection Initiatives program. The guidelines are designed to streamline the process for connecting generators and loads, and to increase the economic efficiency of transmission network augmentations.

The policies and guidelines seek to achieve several objectives. These include greater transparency of policies and processes, more efficient planning for long-term requirements, and creating an environment that supports competition and delivers more cost-effective service outcomes.

B.3 Terminal station requirements and location

The need for a terminal station can be identified either through annual planning processes undertaken by AEMO or the Victorian distribution network service providers' (DNSP), or through a generator connection application.

In determining a terminal station location, the following factors are considered:

- For augmenting transmission capabilities or maintaining electricity DSN security, AEMO determines the location based on providing maximum economic benefit to all National Electricity Market (NEM) participants.
- For augmenting distribution system capabilities to meet increasing demand, AEMO and the respective DNSP jointly determine the location based on reducing the overall cost of meeting demand.
- For connecting new generation, AEMO identifies a preferred location and the connection applicant is responsible for selecting the location that best suits their needs.

[1] Jemena, CitiPower, Powercor, SP AusNet and United Energy. Available at http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf.

[2] AEMO. Available at http://www.aemo.com.au/~/media/Files/Other/network_connections/0174-0018%20pdf.ashx.

AEMO may plan a terminal station to accommodate one dedicated connection or multiple connections to the electricity DSN. The number of connections at a planned terminal station depends on several factors, including the following:

- The requirements of connecting parties.
- Planned expansions of the electricity DSN.
- The likelihood of multiple generating systems connecting to the terminal station (depending on factors such as the availability of a large energy resource).
- Forecast DNSP requirements depending on expanding load centres.

B.4 Establishing terminal stations

When the need for a terminal station is identified, AEMO, SP AusNet, the relevant DNSPs and interested parties undertake joint planning to determine the most effective and economic approach.

Establishing a terminal station involves a series of activities. These include the following:

- Determining what to build in the initial stage of the connection to the network (with future expansion being on a needs basis).
- Determining the requirements for expansion to the ultimate station configuration, including access arrangements for subsequent connections to the terminal station.
- Selecting a suitable site or identifying site options to consider.
- Engaging and communicating with the community and stakeholders.
- Procuring land and easements.
- Determining how costs of land, earthworks and infrastructure will be shared between multiple connecting parties, noting that some of these may not be identified until years after the terminal station is actually built.
- Securing planning approvals.

During the establishment of a terminal station, applicants should consider technical aspects, commercial aspects, planning and approvals, as well as community and stakeholder engagement.

For more information about the process followed by AEMO and connecting parties, including new terminal station configurations, see the Guidelines for Establishing Terminal Stations in Victoria.[3]

B.5 Potential locations for new terminal stations in Victoria

The main drivers for new terminal stations at this point in time are generator connections to the electricity DSN and projected load increases at existing terminal stations.

Although some terminal stations developed for these reasons may also be used for future network switching and voltage transformation (and increasing electricity DSN capability), due to forecast demand growth it is unlikely that any will be developed within the next 10-years solely to augment electricity DSN capability.

Table B-1 summarises the latest generation connection enquiries and applications received by AEMO that are likely to be developed over the next 10-years.

[3] AEMO. Available at http://www.aemo.com.au/~/media/Files/Other/network_connections/0174-0018%20pdf.ashx.

Table B-1 — Generation connection enquiries and applications

ID[a]	Project[b]	Generation type	Capacity (MW)	Location	Service date
W1	Ararat Wind Farm	Wind farm	255	Approximately 9–17 km north east of Ararat in Western Victoria.	2015
W2	Berrybank Wind Farm	Wind farm	178	Approximately 16 km east of Lismore in Western Victoria.	2015
W3	Hawkesdale Wind Farm	Wind farm	62	Approximately 4 km south of Hawkesdale in Western Victoria.	TBA
W4	Dundonnell Wind Farm	Wind farm	270	Dundonnell in Western Victoria connecting to Mortlake terminal station.	TBA
W5	Crowlands Wind Farm	Wind farm	82	Approximately 20–25 km North east of Ararat in Western Victoria.	Early 2015
W6	Mt Mercer Wind Farm	Wind farm	131.2	Approximately 30 km south of Ballarat in Western Victoria.	End of 2014
W7	Mt Gellibrand Wind Farm	Wind farm	189	Approximately 22 km north east of Colac in Western Victoria.	Late 2014
W8	Penshurst Wind Farm	Wind farm	600	Approximately 13 km south of Penshurst in Western Victoria.	2017
W9	Ryans Corner Wind Farm	Wind farm	134	Approximately 8 km east of Yambuk in Western Victoria.	TBA
W10	Stockyard Hill Wind Farm	Wind farm	TBA	Approximately 48 km west of Ballarat in Western Victoria.	TBA
W11	Bald Hills Wind Farm	Wind Farm	106.6	Approximately 12 km south east from Tarwin Lower in South Gippsland,	TBA
G1	Shaw River Power Station (Stage 1)	CCGT	500	Near Orford in Western Victoria.	TBA
G2	Tarrone Gas Generator	OCGT	500-600	Approximately 50 km west of Heywood in Western Victoria.	TBA
S1	Kerang Solar Farm 1	Solar farm	30	Kerang in Northern Victoria connecting to Kerang Terminal Station.	TBA
S2	Kerang Solar Farm 2	Solar farm	30	Kerang in Northern Victoria connecting to Kerang Terminal Station.	TBA

a. Approximate project locations are shown on Figure B1 using these IDs.

b. AEMO expects terminal stations to connect more than one generation project.

For the most cost-effective outcome, AEMO prefers to connect generation developments within the same vicinity (within a radius of approximately 30–50 km) to a single terminal station. Table B-2 lists future terminal station locations selected to support this preference.

Table B-2 — Proposed new terminal stations for generation connection enquiries and applications

Terminal station	Possible line cut in and location	Project and approximate distance to terminal station	Service date
Ararat Terminal Station (ARTS)	BATS–WBTS–HOTS 220 kV line, approximately 85 km from Horsham.	Ararat Wind Farm (17 km)	2015
Elaine Terminal Station (ELTS)	MLTS–BATS 220 kV No. 2 line, approximately 20 km from BATS.	Mt Mercer Wind Farm (16 km)	End-2014
Mt Gellibrand Terminal Station (MGTS)	MLTS–TGTS 220 kV line, approximately 53 km from MLTS.	Mt Gellibrand Wind Farm (5 km)	Late-2014
Stockyard Hill Terminal Station (STTS)	MLTS–HYTS/APD 500 kV No.1 or No. 2 line, approximately 94 km from MLTS.	Stockyard Hill Wind Farm (50 km) Berrybank Wind Farm (22 km)	TBA.
Crowlands Terminal Station	BATS–WBTS–HOTS 220 kV line, approximately 75 km from Horsham.	Crowlands Wind Farm (1km)	Early-2015

Table B-3 lists likely terminal station developments to address Victorian demand growth over the next 10-years.

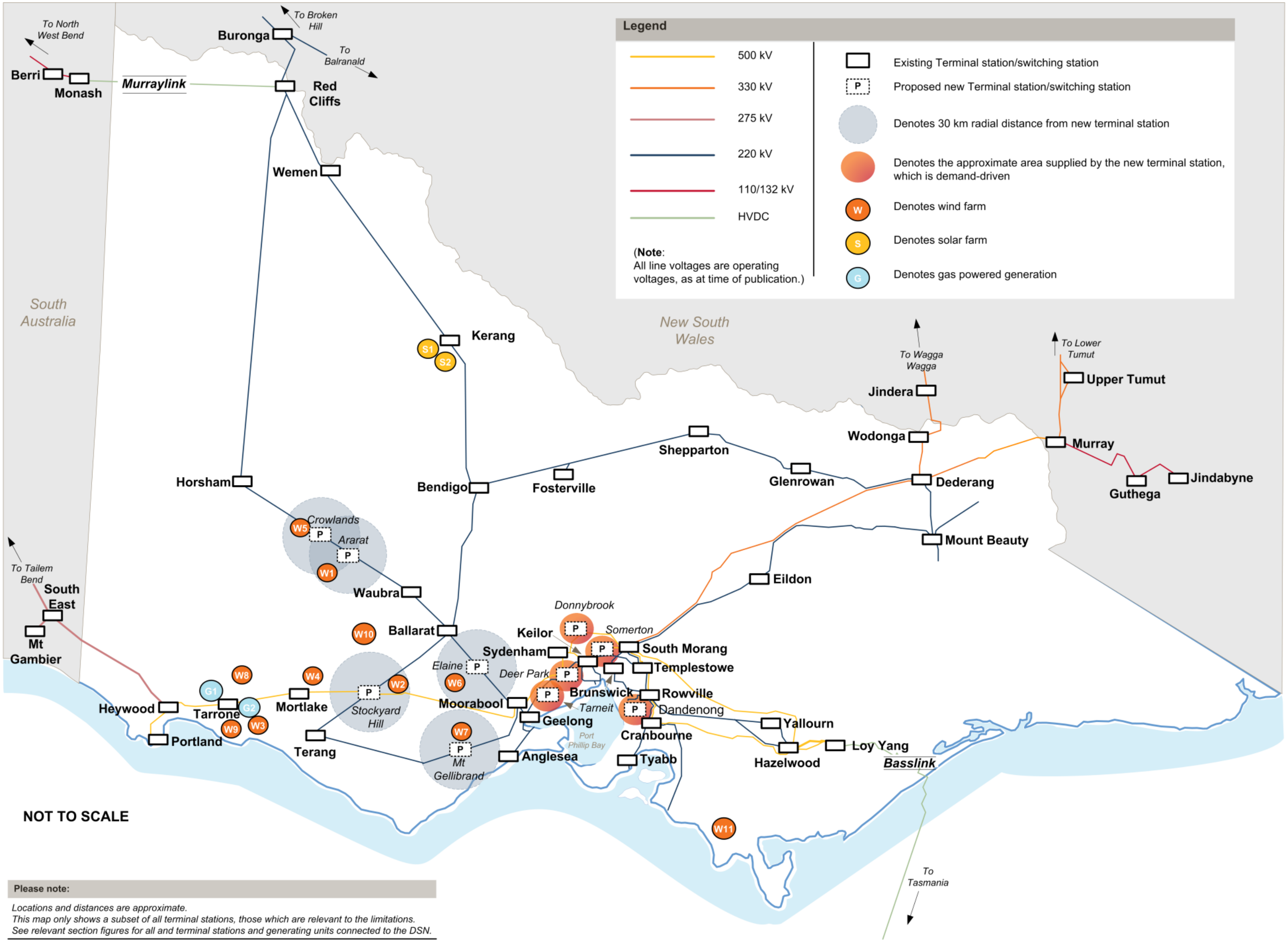
Table B-3 — Proposed new terminal stations for connecting load[a]

Project	Driver	Service date
Deer Park Terminal Station (DPTS)	Increased demand in the area to offload Altona, Brooklyn, and Keilor terminal stations.	Late-2017
Dandenong Terminal Station (DNTS)	Increased demand in the area to offload East Rowville and Heatherton terminal stations.	2022–23
Donnybrook Terminal Station (DBTS) or Summerton Terminal Station (SOTS)	Increased demand in the area to offload Thomastown.	2021 or later
Tarneit Terminal Station (TATS)	Increased demand in the area to offload Deer Park Terminal Station.	2030

a. Jemena, CitiPower, Powercor, SP AusNet and United Energy. Available at http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf.

Figure B1 shows the approximate locations of the proposed terminal stations, and possible connecting generation.

Figure B1 — Proposed terminal stations/switch stations and generation



Please note:

Locations and distances are approximate.
This map only shows a subset of all terminal stations, those which are relevant to the limitations.
See relevant section figures for all and terminal stations and generating units connected to the DSN.

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APPENDIX C - NTNDP VICTORIAN DEVELOPMENT PLAN

This appendix compares the results from Chapter 3 with the development plan for Victoria outlined in the 2012 National Transmission Network Development Plan (NTNDP).

The 2013 VAPR limitation assessment summarised each limitation using the following categories:

- Current Regulatory Investment Tests for Transmission (RIT-Ts). AEMO has commenced RIT-T applications to identify the preferred solution to address the limitation.
- Upcoming RIT-T. AEMO will commence RIT-T applications within the next 12 months to identify the preferred solution to address the limitation
- Priority assessment. AEMO will undertake further assessment of these limitations, possibly progressing to RIT-T applications over the next 12 months.
- Monitoring. AEMO will not undertake further detailed assessment for the next 12 months but will continue to monitor the triggering conditions.

The 2013 VAPR does not identify any upcoming RIT-Ts.

See Chapter 3, Section 3.1.3 for more information about the limitation categories.

Table C-1 summarises the first 10-year results from the 2012 NTNDP planning scenario, and presents the relevant findings from the limitation assessment (for more information, see Chapter 3).

Table C-1 — Transmission developments from the 2012 NTNDP analysed in the VAPR

Limitation identified	2012 NTNDP timing	2013 VAPR category	2013 VAPR discussion	2013 VAPR reference
Overload of the Rowville 500/220 kV A2 transformer for an outage of the Cranbourne 500/220 kV A1 transformer (and vice versa).	2012–13 to 2016–17	Current RIT-T.	These augmentations address network limitations involving the Cranbourne and Rowville 500/220 kV transformers that are addressed in the East Metropolitan Melbourne Thermal Capacity RIT-T.	Section 3.2.2 Table 3.16
Overload of the Rowville 500/220 kV A1 transformer under system normal conditions, and overload of the Thomastown–Templestowe and Thomastown–Ringwood 220 kV circuits for an outage of the Rowville 500/220 kV A1 transformer.	2017–18 to 2021–22			
Overload of a Keilor 500/220 kV transformer for an outage of the parallel transformer.	2022–23 to 2026–27	Priority Assessment.	This limitation will be reviewed in line with the SP AusNet asset replacement plan, which currently has the Keilor A4 transformer due for replacement in 2018.	Table 3.15

Limitation identified	2012 NTNDP timing	2013 VAPR category	2013 VAPR discussion	2013 VAPR reference
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.	2022–23 to 2026–27	Priority Assessment.	The need for this augmentation is driven by demand growth in the western part of the Greater Melbourne Metropolitan Area and Geelong. Due to the H2 transformer being replaced by SP AusNet in 2016 as part of the asset replacement program, the requirement for increased capacity is currently being reviewed.	Table 3.18
Overload of a Moorabool–Geelong 220 kV circuit for an outage of the parallel circuit.	2022–23 to 2026–27	Priority Assessment.	An upgrade to these circuits is being considered as part of the SP AusNet NCIPAP application.	Table 3.20
Overload of the Moorabool–Ballarat 220 kV No.1 circuit for an outage of the Moorabool–Ballarat 220 kV No.2 circuit.	2012–13 to 2016–17	Current RIT-T.	This augmentation addresses line loading limitations on the Ballarat–Moorabool line that are addressed in the Regional Victoria Thermal Capacity RIT-T.	Section 3.2.3
Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	2012–13 to 2016–17	Current RIT-T.	These augmentations address line loading limitations on the Ballarat–Bendigo line and are addressed in the Regional Victoria Thermal Capacity RIT-T.	Section 3.2.3
Emerging network limitations arise on a number of radially connected 220 kV circuits (Rowville–Springvale, Springvale–Heatherton, Rowville–Malvern).	Dependant on connection point forecast and load transfers.	Priority Assessment.	AEMO has commenced a detailed assessment of these limitations in conjunction with the distribution businesses to identify and assess options to address them. These options will form part of a wider study of the Eastern Metropolitan Melbourne upgrade requirements for several lines in this part of the network.	Table 3.13 Table 3.14

DISCLAIMER

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AEMO publishes the Victorian Annual Planning Report (VAPR) to address requirements of clause 5.12.1 and 5.12.2 of the National Electricity Rules (NER).

The purpose of this publication is to provide information relating to electricity supply and demand and network capability and development, for Victoria's electricity Declared Shared Network.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all participants in providing the data and information used in the Victorian Annual Planning Report.

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MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
C	Celsius (a unit of temperature measurement usually expressed as °C - degrees Celsius)
GWh	Gigawatt hours
K	Thousand
km	Kilometres
kV	Kilovolts
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
m/s	Metres per second

Abbreviations

Abbreviation	Expanded name
AC	Alternating current
AEST	Australian Eastern Standard Time
BOM	Bureau of Meteorology
CAGR	Compound average growth rate
CCGT	Combined cycle gas turbine (a type of GPG)
CPI	Consumer price index
DB	Distribution business
DBUSS	Dederang bus splitting (control scheme)
DNSP	Distribution network service provider
DSP	Demand-side participation
DSN	Declared Shared Network (electricity)
EDST	Eastern Daylight Savings Time (see also AEST)
EHV	Extra high voltage
ESC	Essential Services Commission
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary service
FEED	Front-end Engineering and Design
GPG	Gas powered generation
GRP	Gross regional product
GSOO	Gas Statement of Opportunities
GSP	Gross state product
HVDC	High voltage direct current
LNG	Liquefied natural gas
LOR	Lack of Reserve
LRA	Long-run average
MCC	Marginal Cost of Constraint
MCE	Ministerial Council on Energy
MD	Maximum demand
MDQ	Maximum daily quantity
MHQ	Maximum hourly quantity
MSOR	Market and System Operation Rules
NCAS	Network control ancillary service

Abbreviation	Expanded name
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NGL	National Gas Law
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NPV	Net present value
NSCAS	Network Support and Control Ancillary Service
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine (a type of GPG)
RIT-T	Regulatory Investment Test for Transmission
POE	Probability of exceedence
SRMC	Short-run marginal cost
SVC	Static Var compensator
TCPR	Transmission Connection Planning Report
TNSP	Transmission network service provider
TOC	Transmission Operations Centre
USE	Unserved energy
VAPR	Victorian Annual Planning Report
VCIRG	Victorian Connections Industry Reference Group
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Networks Corporation (now AEMO)

Victorian terminal and power station abbreviations

Abbreviation	Name
Terminal station	
APD	Portland Aluminium Customer Substation
ATS	Altona Terminal Station
BATS	Ballarat Terminal Station
BLLY	Basslink Loy Yang Converter Station
BETS	Bendigo Terminal Station
BLTS	Brooklyn Terminal Station
BTS	Brunswick Terminal Station
CBTS	Cranbourne Terminal Station
DDTS	Dederang Terminal Station
DPTS	Deer Park Terminal Station
ERTS	East Rowville Terminal Station
FBTS	Fishermans Bend Terminal Station
FVTS	Fosterville Terminal Station
FTS	Frankston Terminal Station
GTS	Geelong Terminal Station
GNTS	Glenrowan Terminal Station
HWTS	Hazelwood Terminal Station
HTS	Heatherton Terminal Station
HYTS	Heywood Terminal Station
HOTS	Horsham Terminal Station
JLA	Bluescope Steel Customer Substation
JLTS	Jeeralang Terminal Station
KTS	Keilor Terminal Station
KGTS	Kerang Terminal Station
LY	Loy Yang Switching Station
MTS	Malvern Terminal Station
MLTS	Moorabool Terminal Station
MWTS	Morwell Terminal Station
MBTS	Mount Beauty Terminal Station
MLRC	Murraylink Converter Station (at Red Cliffs)
MSS	Murray Switching Station
PtH	Point Henry Customer Substation

Abbreviation	Name
RCTS	Red Cliffs Terminal Station
RTS	Richmond Terminal Station
RWTS	Ringwood Terminal Station
ROTS	Rowville Terminal Station
SHTS	Shepparton Terminal Station
SMTS	South Morang Terminal Station
SVTS	Springvale Terminal Station
SYTS	Sydenham Terminal Station
TATS	Tarneit Terminal Station
TRTS	Tarrone Terminal Station
TSTS	Templestowe Terminal Station
TGTS	Terang Terminal Station
TTS	Thomastown Terminal Station
TBTS	Tyabb Terminal Station
WBTS	Waubra Terminal Station
WETS	Wemen Terminal Station
WMTS	West Melbourne Terminal Station
WOTS	Wodonga Terminal Station
WDP	Wonthaggi Desalination Plant Customer Substation
Power station	
APS	Anglesea Power Station
BDPS	Bairnsdale Power Station
BOPS	Bogong Power Station
CHWF	Challicum Hills Wind Farm
CLPS	Clover Power Station
DPS	Dartmouth Power Station
EPS	Eildon Power Station
HPS	Hume Power Station
HWPS	Hazelwood Power Station
JLGS	Jeerelang Gas Station
LNGS	Laverton North Gas Station
LYPS	Loy Yang Power Station
MCWF	Macarthur Wind Farm
McKPS	McKay Creek Power Station
MPS	Morwell Power Station

Abbreviation	Name
MOPS	Mortlake Power Station
M1	Murray Power Station 1
M2	Murray Power Station 2
NPSD	Newport D Power Station
OWF	Oaklands Wind Farm
PTWF	Portland Wind Farm
SOPS	Somerton Power Station
VPGS (or LYGS)	Valley Power (or Loy Yang Gas) Station (also Valley Power Peaking Facility)
WBPS	Waubra Wind Farm
WKPS	West Kiewa Power Station
YPS	Yallourn Power Station
YWPS	Yallourn West Power Station
YWF	Yambuk Wind Farm

GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Term	Definition
1-in-2 peak day	The 1-in-2 peak day demand projection has a 50% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedence (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
Alternating current	A current where the movement of electric charge periodically reverses direction.
Annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity and demand, and other planning information.
Breaker-and-a-half	A substation configuration where there are three circuit breakers for every two circuits, with each circuit sharing a common centre breaker. This allows for isolation and maintenance of breakers without service disruption.
Brownfield	A tract of land developed for industrial purposes, polluted, and then abandoned.
Central dispatch	The process managed by AEMO for the dispatch of scheduled generating units and other services in accordance with clause 3.8 of the NER.
Compound annual growth rate	The year-over-year growth rate over a specified period of time.
Connection asset	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).
Connection asset limitation	A limitation applying to an asset connecting the electricity transmission network to the distribution network.
Limitation (electricity)	Any limitations on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
Constraint (equation) value estimate	An electricity transmission network limitation’s expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example, increased fuel cost).
Contestable augmentation	An electricity transmission network augmentation for which the capital cost is reasonably expected to exceed $10 million and that can be constructed as a separate augmentation (i.e., the assets forming that augmentation are distinct and definable).
Contingency	Either a forced or planned outage. An event affecting the power system that is likely to involve electricity generating unit or transmission element failure or removal from service.
Credible contingency	Any planned or forced outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults.
Critical contingency	The specific forced or planned outage that has the greatest potential to impact the electricity transmission network at any given time.
Customer	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point; and is registered by AEMO as a Customer under Chapter 2 of the NER.
Demand-side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).

Term	Definition
Demand-side participation	The act of voluntarily shedding electrical load by prior arrangement.
Demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
Flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
Forced outage	An unplanned outage of an electricity transmission network element (for example, a transmission line, transformer, generator, or reactive plant).
Front-end Engineering and Design	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.
Gas powered generation	Where electricity is generated from either combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT).
Generator	A person who engages in the activity of owning, controlling, or operating a generating system that is connected to—or who otherwise supplies electricity to—a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 of the NER. For the purposes of Chapter 5 of the NER, the term includes a person who is required to, or intends to register in that capacity.
Generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as ‘used in station load’).
Generator-terminal basis	Refers to the demand for electricity as measured at the generator terminals. This measure includes generator auxiliary loads.
Greenfield	Land (as a potential industrial site) not previously developed or polluted.
High voltage direct current	Direct current is a current where the movement of electric charge is only in one direction. High voltage direct current increases power transfer efficiencies over long distances.
Jurisdiction	An area over which legal authority extends; the Australian Commonwealth, states or territories.
Load shedding	Disconnection of electricity customer load.
Marginal Cost of Constraint	A measure of the effect that binding or violating constraint equations have on economic dispatch, by providing a relative measure of the impact of different constraint equations.
Market Customer	A Customer who has classified any of it loads as a market load and who is also registered by AEMO as a Market Customer under Chapter 2 of the NER
Market Participant	A party who is registered by AEMO as a Market Generator, Market Customer or Market Network Service Provider under Chapter 2 of the NER (each as defined by the NER).
Metering	The act of recording electricity and gas data (such as volume, peak, and quality parameters) for the purpose of billing or monitoring quality of supply.
Metering data	The data obtained from a metering installation, including energy data.
N-1 condition	Following a single credible contingency (as used in VAPR network adequacy analysis).
N-1-1 condition	Following a single credible contingency with a prior outage (either forced or planned).
National Electricity Law	The National Electricity Law set out in the schedule to the National Electricity (South Australia) Act 1996 (SA) and applied in each of the participating jurisdictions.
National Electricity Market	The wholesale market for electricity supply in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.
National Electricity Rules	The National Electricity Rules govern the operation of the National Electricity Market. The Rules have the force of law, and are made under the National Electricity Law.

Term	Definition
National Institute of Economic and Industry Research	A private economic research, consulting, and training group.
Non-contestable augmentation	Electricity transmission network augmentations that are not considered to be economically or practically classified as contestable augmentations.
Non-credible contingency	Any planned or forced outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
Planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24-hours' notice.
Post-contingent	The timeframe after a power system contingency occurs.
Pre-contingent	The timeframe before a power system contingency occurs.
Prior outage conditions	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage.
Probability of exceedence	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% probability of exceedence (POE) maximum demand will, on average, be exceeded only 1 year in every 10.
Reactive energy	A measure in var hours (varh) of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
Reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as the following: • Alternating current generators. • Capacitors, including the capacitive effect of parallel transmission wires. • Synchronous condensers. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.
Retailer	A seller of bundled energy service products to a customer.
Satisfactory operating state	Operation of the electricity transmission network so all plant is operating at or below its ratings (whether the continuous or (where applicable) short-term rating).
Secure operating state	Operation of the electricity transmission network in such a way that if a credible contingency occurs, the network will remain in a 'satisfactory' state.
Sent-out basis	A measure of demand and energy at the connection point between the generating system and the electricity transmission network. The measure includes consumer load, and transmission and distribution losses.
Shoulder season	The period between low (summer) and high (winter) gas demand. It includes the calendar months of April, May, October, and November.
Statement of Opportunities	The Statement of Opportunities published annually by AEMO.
Summer	In terms of the electricity industry, December to February of a given fiscal year.
System normal (N) condition	All system components are in service (as used in network adequacy analysis).
System normal limitation	A limitation that arises even when all electricity plant is available for service.
Unserved energy (USE)	The amount of energy that cannot be supplied because there is insufficient generation to meet demand.

Term	Definition
Value of customer reliability	The value consumers place on having a reliable supply of energy, which is equivalent to the cost to the consumer of having that supply interrupted.
Winter	In terms of the electricity industry, June to August of a given calendar year.

List of company names

Company	Full Company Name	ABN/ACN
AEMO	Australian Energy Market Operator	94 072 010 327
AER	Australian Energy Regulator (ABN provided for Australian Competition and Consumer Commission)	94 410 483 623
AEMC	Australian Energy Market Commission	49 236 270 144
ElectraNet	Electranet Pty Ltd	41 094 482 416
SP AusNet	SP Australia Networks (Transmission) Ltd	48 116 124 362

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