2014 VICTORIAN ANNUAL PLANNING REPORT

ELECTRICITY TRANSMISSION NETWORK PLANNING FOR VICTORIA

Published: **JUNE 2014**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

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.

AEMO publishes the Victorian Annual Planning Report (VAPR) in accordance with clause 5.12 of the National Electricity Rules. This publication is based on information available to AEMO as at 31 March 2014, although AEMO has endeavoured to incorporate more recent information where practical.

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Acknowledgement

AEMO acknowledges the support, cooperation and contribution of all electricity industry participants in providing data and information used in this publication.

EXECUTIVE SUMMARY

The 2014 Victorian Annual Planning Report (VAPR) identifies a range of investment opportunities to address emerging network constraints.

The Australian Energy Market Operator (AEMO) is the jurisdictional planning body responsible for planning and directing augmentations to the Victorian electricity transmission declared shared network (DSN). AEMO publishes the VAPR, which considers the adequacy of the DSN to meet its reliability requirements over the next 10 years and signals possible network and non-network transmission investment opportunities for potential investors.

Emerging investment opportunities

Although overall maximum demand is slowing across the Victorian region, there are areas where growth in maximum demand necessitates network investment. This is mainly due to population growth. Accordingly, the 2014 VAPR identifies the following key investment opportunities to address constraints in the network over the next 10 years:

- Constraints on the Rowville–Malvern line, which services Malvern and surrounding metropolitan areas.
- Constraints on the Rowville–Springvale–Heatherton line, which services the metropolitan Springvale and Heatherton areas.
- Constraints on the Keilor – Deer Park – Geelong line, which will service parts of western Melbourne.
- Constraints on the Dederang–Shepparton line, which services parts of regional Victoria.
- Constraints on the Ballarat–Horsham line, which services parts of regional Victoria.
- Constraints on the Rowville A1 500/220 kV transformer, which services parts of eastern Melbourne metropolitan areas.

The VAPR also highlights opportunities for non-network solutions such as embedded generation and demand response to address emerging constraints. This could enable AEMO to implement lower-cost solutions to address network constraints.

Current investment opportunities

The 2014 VAPR presents the following key investment opportunities for which AEMO will be issuing invitations to tender (ITT):

- **The new 220 kV Deer Park Terminal Station**. An ITT will be issued in June 2014 requesting submissions to build, own, and operate this new terminal station.
- **Final stage of the Regional Victoria Thermal Capacity Upgrade Regulatory Investment Test for Transmission (RIT-T)**. An ITT will be issued in the third quarter of 2014 requesting network and non-network solutions in the Bendigo area. Further detail can be found in the supplementary Project Assessment Conclusions Report (PACR) which was published in June 2014.

Figure 1 presents a diagram of the emerging limitations and upcoming tenders.

Deferred investment

The 2014 VAPR has identified that a number of constraints previously identified as investment opportunities can now be deferred. This is due to a decrease in regional electricity maximum demand, and the announced closures of the Point Henry aluminium smelter and car manufacturing plants. For example, an opportunity to address the Geelong–Moorabool 220 kV line constraint identified in the 2013 VAPR has been deferred beyond the 10-year planning horizon, mainly due to the Point Henry closure.

AEMO has terminated the Eastern Metropolitan Melbourne Thermal Capacity Upgrade RIT-T based on 2013 electricity demand forecasts which showed a decline in maximum demand.

Network reliability

Network reliability is difficult to measure. Traditionally it has been measured by the level of redundancy provided. The 2014 VAPR assesses the merits of measuring reliability using Expected Unserved Energy (EUSE). EUSE represents the expected energy demand at risk at each connection point as a result of a network limitation.

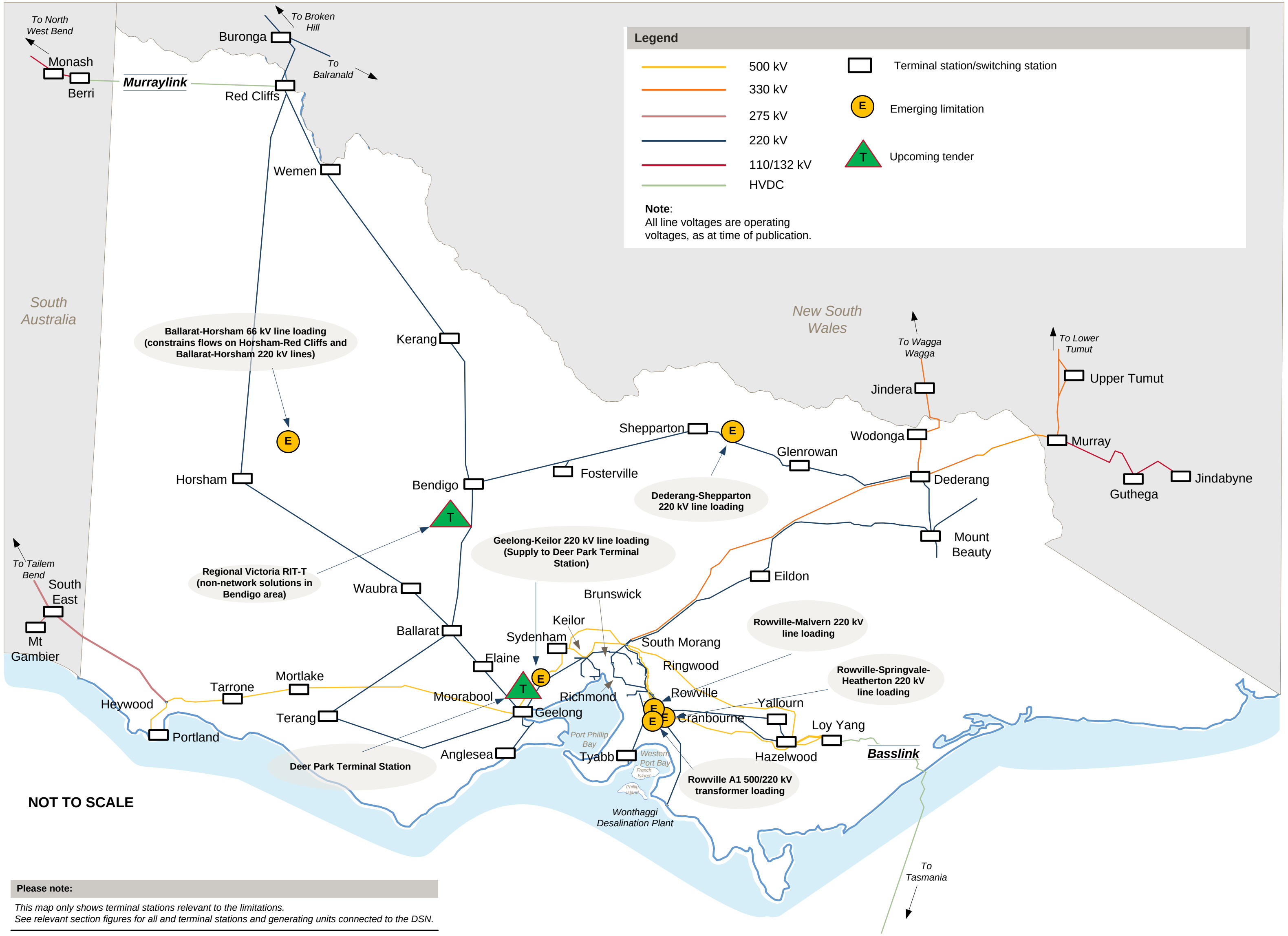
This methodology builds on AEMO's existing planning approach, which measures the total maximum EUSE of a network limitation.

Using South Morang Terminal Station as a case study, AEMO demonstrates how reliability levels can be measured under a range of contingencies. This will allow reliability levels to be tracked over time at connection point level rather than a regional level, giving customers greater transparency of network reliability levels. It will also enable customers to compare the cost of maintaining network reliability with alternative options.

The Victorian Availability Incentive Scheme (AIS) provides incentives to infrastructure asset owners to schedule outages outside peak demand periods. An assessment of the value the AIS provides to support reliability is reported as part of the 2014 VAPR.

The report shows that relatively few outages are scheduled on critical assets during peak periods, which is consistent with the incentives provided by the AIS. AEMO intends to work with the Australian Energy Regulator (AER) to incorporate the positive aspects of the AIS into the existing Service Target Performance Incentive Scheme.

Figure 1 — Emerging limitations and upcoming tenders



CONTENTS

IMPORTANT NOTICE I

EXECUTIVE SUMMARY II

CHAPTER 1 - INTRODUCTION 1

1.1 Introduction 1

CHAPTER 2 - NETWORK PERFORMANCE 2

2.1 Introduction 2
2.2 Network summary 2
2.3 Network performance 3
2.4 Victorian transmission constraints 9
2.5 Review of load interruption events 9
2.6 Review of supply to regional Victoria 10

CHAPTER 3 - NETWORK DEVELOPMENT 11

3.1 Transmission development overview 11
3.2 Regional transmission network limitations 11
3.3 DNSP planning 18
3.4 SP AusNet asset renewal 18
3.5 Short-circuit levels for the Victorian electricity transmission network: 2014–18 18

CHAPTER 4 - NETWORK RELIABILITY 19

4.1 Introduction 19
4.2 Methodology for measuring reliability using the Victorian economic planning approach 19
4.3 Case study: Reliability of supply for South Morang Terminal Station 20
4.4 Availability Incentive Scheme 22

APPENDIX A - LOADING AT TIMES OF HIGH NETWORK STRESS 25

A.1 DSN loading 25

APPENDIX B - DSN RATINGS 34

B.1 DSN ratings 34

APPENDIX C - VICTORIAN NETWORK DEVELOPMENT 40

C.1 Introduction 40
C.2 Terminal station requirements and location 40
C.3 Establishing terminal stations 41
C.4 Potential locations for new terminal stations in Victoria 41

APPENDIX D - KEY RIT-T FINDINGS 44

D.1 Introduction 44
D.2 Regional Victoria Thermal Capacity Upgrade RIT-T 45

APPENDIX E - TRANSMISSION NETWORK LIMITATION DETAIL 48

E.1 Introduction 48
E.2 Eastern Corridor network limitations 50
E.3 South-west Corridor network limitations 51
E.4 Northern Corridor network limitations 52
E.5 Greater Melbourne and Geelong network limitations 53
E.6 Regional Victoria network limitations 61

APPENDIX F - DISTRIBUTION NETWORK SERVICE PROVIDER PLANNING 65

APPENDIX G - SP AUSNET ASSET RENEWAL PLAN 67

APPENDIX H - SHORT-CIRCUIT LEVELS FOR THE VICTORIAN ELECTRICITY TRANSMISSION NETWORK 75

H.1 Purpose 75
H.2 Summary of modelling assumptions 75
H.3 Short-circuit level assessments 76
H.4 Short-circuit levels approaching station limits 77
H.5 Short-circuit level mitigation 79

MEASURES AND ABBREVIATIONS 81

Units of measure 81
Abbreviations 81
Victorian terminal and power stations 83

GLOSSARY 86

TABLES

Table 2-1 — Maximum demand and high power flow from Victoria snapshot summaries 2
Table 2-2 — Maximum demand snapshot: Interconnector power flow and limits 5
Table 2-3 — Maximum demand snapshot: Reactive power supply-demand balance 5
Table 2-4 — High power flow from Victoria snapshot: Interconnector power flow and limits 8
Table 2-5 — High power flow from Victoria snapshot: Reactive power supply-demand balance 8
Table 2-6 — DSN events that resulted in load interruptions during 2013–14 9
Table 3-1 — Priority transmission limitations requiring investment in the next five to ten years[a] 16
Table 4-1 — Expected USE at SMTS under different outage scenarios 21
Table 4-2 — Normalised total expected USE 21
Table B-1 — Maximum demand snapshot: DSN continuous and short-term ratings 34
Table B-2 — High power from Victoria snapshot: DSN continuous and short-term ratings 39
Table C-1 — Generation connection enquiries and applications 41
Table C-2 — Proposed new terminal stations for generation connection enquiries and applications 42
Table C-3 — Proposed new terminal stations for connecting load[a] 43
Table D-1 — Forecast loading for Regional Victorian Thermal Capacity – Bendigo Supply 45
Table D-2 — Forecast market impact for Regional Victorian Thermal Capacity 46
Table E-1 — Limitations being monitored in the Eastern Corridor 50
Table E-2 — Limitations being monitored in the South-west Corridor 51
Table E-3 — Limitations being monitored it the Northern Corridor 52
Table E-4 — Rowville–Malvern 220 kV line loading 54
Table E-5 — Rowville–Springvale–Heatherton 220 kV line loading 55
Table E-6 — Keilor – Deer Park – Geelong 220 kV line loading 57
Table E-7 — Rowville A1 500/220 kV transformer loading 58
Table E-8 — Limitations being monitored in Greater Melbourne and Geelong 59
Table E-9 — Dederang–Shepparton 220 kV line loading 61
Table E-10 — Ballarat–Horsham 66 kV line loading 62
Table E-11 — Limitations being monitored in Regional Victoria 63
Table F-1 — Distribution network service provider planning impacts 65
Table G-1 — SP AusNet 10-year asset renewal plan (cost estimates are in 2014 dollars) 68
Table H-1 — Committed and proposed network augmentations and generation connections 78

FIGURES

Figure 1 — Emerging limitations and upcoming tenders iv
Figure 2-1 — Maximum demand snapshot: Generation, load, and interconnector flow 4
Figure 2-2 — High power flow from Victoria snapshot: Generation, load, and interconnector power flow 7
Figure 4-1 — South Morang Terminal Station 20
Figure 4-2 — Critical transmission asset outage duration breakdown by month 22
Figure 4-3 — Summary of drivers for outages during peak periods 23
Figure 4-4 — Critical transmission asset financial impact breakdown by month 24
Figure 4-5 — Financial impact breakdown of outages during peak periods 24
Figure A-1 — Maximum demand snapshot: Eastern Corridor transmission network loading 27
Figure A-2 — Maximum demand snapshot: South-west Corridor transmission network loading 28
Figure A-3 — Maximum demand snapshot: Northern Corridor transmission network loading 29
Figure A-4 — Maximum demand snapshot: Greater Melbourne and Geelong transmission network loading 30
Figure A-5 — Maximum demand snapshot: Regional Victoria transmission network loading 31
Figure A-6 — Northern Corridor transmission network loading, high power flow from Victoria snapshot 33

CHAPTER 1 - INTRODUCTION

1.1 Introduction

The VAPR supports Victorian energy investment decision-making by providing electricity network planning information over a 10-year outlook period.

Chapter 2 contains information on the DSN performance throughout 2013–14, including performance at the time of maximum demand and high power flows from Victoria to New South Wales.

Chapter 3 identifies investment opportunities to address emerging constraints, provides updates on current regulatory tests for investment–transmission (RIT-T), and highlights projects deferred due to reduced demand growth and industrial closures.

Chapter 3 also highlights opportunities for non-network solutions such as embedded generation and demand response to address emerging constraints. These opportunities may possibly enable AEMO to implement lower-cost solutions to address network constraints.

Chapter 4 demonstrates how AEMO's Victorian economic planning approach1 can be applied to assess reliability. The report assesses the merits of measuring reliability using expected unserved energy (EUSE) on a terminal station basis as a measure of reliability. This chapter also presents data on the performance of the Availability Incentive Scheme (AIS).

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

CHAPTER 2 - NETWORK PERFORMANCE

2.1 Introduction

This chapter looks at the adequacy and performance of the DSN during periods of high stress. This covers the time of maximum demand in Victoria, and during high power flow from Victoria to New South Wales. These are both represented as "snapshots" throughout this chapter.

The two snapshots show that the DSN performed adequately with no supply interruptions due to overloaded transmission infrastructure.

This chapter also presents a summary of key load interruption events that occurred during 2013–14. A review of these events found that additional network infrastructure investment that may have prevented the load interruptions are not considered economically feasible given the low probability of outages.

2.2 Network summary

This section presents a summary of network data showing the prevailing conditions at the time of the two snapshots: maximum demand, and high power flow from Victoria. Table 2-1 presents data obtained from AEMO's Energy Management System (EMS).[2]

Both snapshots represent instances when the DSN is heavily loaded. They do not necessarily represent the maximum load experienced by every DSN asset, as this depends on prevailing system conditions such as generation patterns, interconnector flows, time of localised peak demand, as well as factors that influence dynamic ratings such as local temperature and wind speed.

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

	Maximum demand snapshot	High power flow from Victoria snapshot
Date and time	28 Jan 2014 16:30	03 Nov 2013 03:31
Sum of Victorian loads at time of snapshota	9,690 MW	3,843 MW
Operational demand during snapshotb	10,313 MW	4,981 MW
Temperature in Melbourne	40 °C	13 °C
Power flow to South Australia (Heywood)	-76 MW	95 MW
Power flow to South Australia (Murray link)	20 MW	-139 MW
Power flow from Tasmania	527 MW	323 MW
Power flow to New South Wales	-323 MW	1,310 MW
Murray generation	1,235 MW	0 MW

a) The loads are the instantaneous values at the exact time of snapshot. Network losses are not considered as part of Victorian load.

b) Operational demand is the sum of Victorian scheduled, semi-scheduled, non-scheduled wind greater than 30 MW, and net interconnector flow, for a half-hour trading interval. It typically represents when the DSN is most stressed.

[2] 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.

The highest recorded operational demand during summer 2013–14 was 10,313 MW, which occurred within the 30-minute period from 16.00 to 16.30 on 28 January 2014. This is significantly higher than last summer's maximum operational demand (9,774 MW) and came close to the 10% POE (10,473 MW) forecast of the National Electricity Forecasting Report (NEFR[3]).

2.3 Network performance

This section presents a breakdown of generation capacity (based on generator registered capacities), reactive power flows, and consumption at the time of the maximum operational demand and high power flow from Victoria snapshots. This breakdown gives an indication of network adequacy and the extent to which power flows vary across the DSN.

2.3.1 Maximum demand snapshot

Figure 2-1 reflects the time of Victorian maximum demand and the prevailing conditions such as generation, load, and interconnector flows. It also shows the electrical regions, their interconnectors, and the transmission lines and their voltages. The arrows indicate power flow from one Victorian electricity region to another, and the lines represent single or multiple transmission lines depending on the region.

The figure shows that at the time of the maximum demand snapshot:

- Two thirds of Victorian load was concentrated in Greater Melbourne and Geelong.
- The majority of Victorian generation originated from the Eastern (around 60%) and Northern corridors (around 20%), with power flowing from these regions to Greater Melbourne, Geelong, and Regional Victoria.
- Net power flow from New South Wales to Victoria comprised 135 MW via the Snowy Corridor, and 113 MW from Buronga.
- Power flow from Tasmania to Victoria comprised 527 MW via the Basslink interconnector.
- Net power flow from South Australia to Victoria comprised 76 MW via the Heywood interconnector and 20 MW via the Murraylink interconnector.

This snapshot shows many network elements under their maximum loading for the year. At the time of the maximum demand snapshot there was significant power flow into Victoria from Tasmania, and low power flow into Victoria from South Australia and New South Wales.

[3] Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013.

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

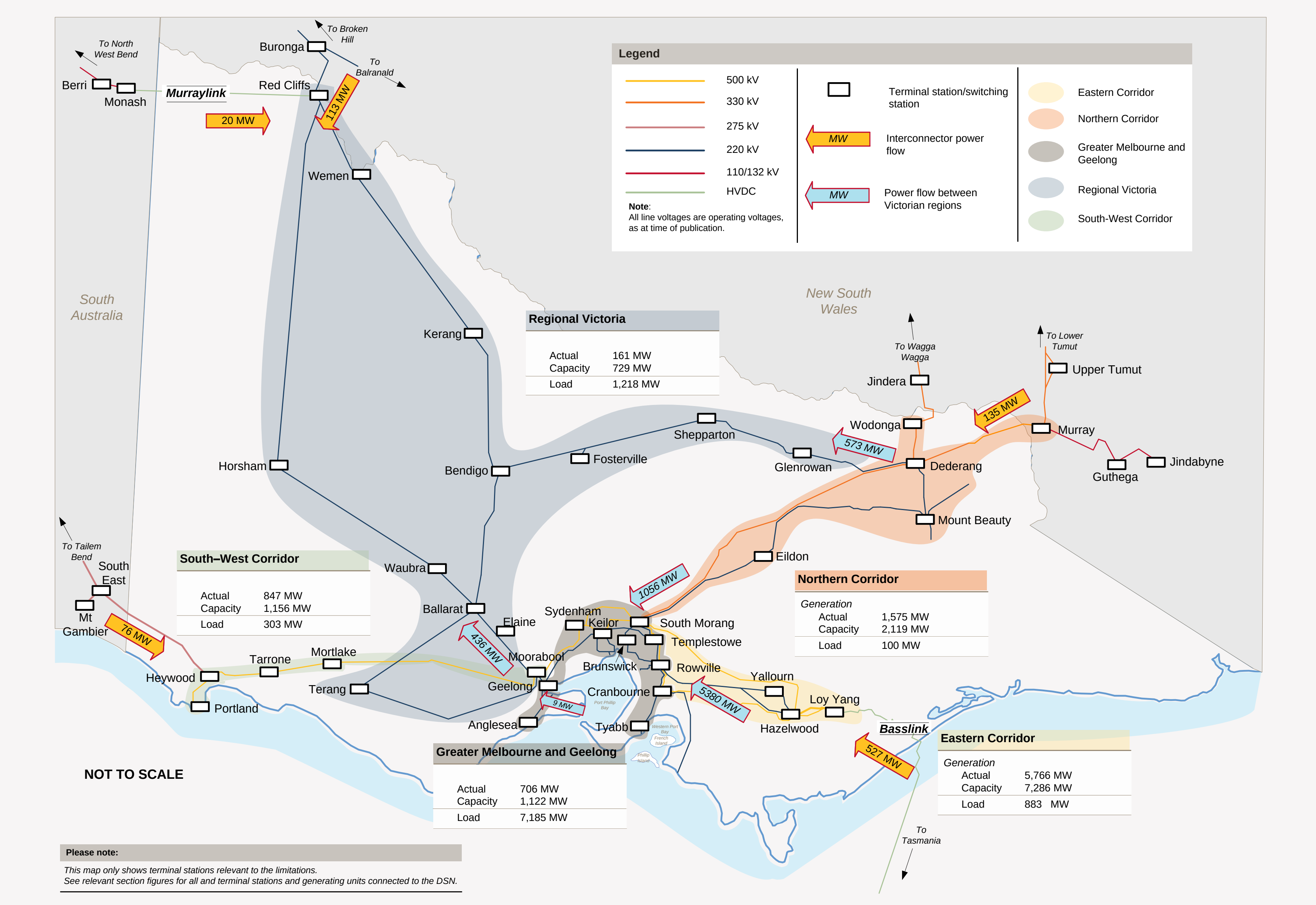


Table 2-2 below presents a summary of the interconnector power flows and approximate capability limits at the time of the maximum demand snapshot. The corresponding constraint equations and their descriptions are also presented.

Both the Heywood and the Victoria – New South Wales interconnector capabilities were reduced due to network outages at the time. Note that actual interconnector power flows during a five-minute interval might be outside the limits shown; these limits are approximate and are derived from constraint equations that represent physical limitations only at the end of each interval.

Table 2-2 — Maximum demand snapshot: Interconnector power flow and limits

Interconnector	Actual power flow (MW)	Limit for 5-min dispatch interval (MW)	Limiting constraint equation	Constraint description
Vic–NSW	-323[a]	-447 import limit	V>>V_NIL_1B	Avoids overload of Dederang to Murray No.2 330 kV line for loss of the parallel No.1 line.
Vic–SA (Heywood)	-76	-150 import limit	S>>V_NIL_SETX_SETX	Avoids overloading a south-east 132/275 kV transformer for trip of the remaining South-east 132/275 kV transformer.
Vic–SA (Murray link)	20	16 import limit	V>>V_NIL_1B	Avoids overload of Dederang to Murray No.2 330kV line for loss of the parallel No.1 line.
Tas–Vic (Basslink)	527	516 import limit	VTBL_ROC	Rate of Change (Vic to Tas) constraint (200 MW/5-min) for Basslink.[b]

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.

b) Refer to AEMO's annual NEM constraint report for further detail. Available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report.

Table 2-3 below presents a summary of the reactive power supply-demand at the time of the maximum demand snapshot. A review of the data shows that a significant amount of reactive power was supplied by shunt capacitors to maintain Victorian voltage quality and stability.

Table 2-3 — Maximum demand snapshot: Reactive power supply-demand balance

Reactive supply	MVAr	Reactive demand	MVAr
From generation	561		
Static VAr compensators	6	Loads	2,673
Synchronous condensers	-94	Shunt reactors	400
Shunt capacitors	4,517	Line losses	4,613
Line charging	2,916	To interregional transfers	221
Total	**7,907**	**Total**	**7,907**

2.3.2 High power flow from Victoria snapshot

Figure 2-2 reflects the time of high power flow from Victoria and the prevailing conditions such as generation, load, and interconnector flows. It also shows the electricity regions, their interconnectors, and transmission lines and their voltages. The arrows indicate power flow from one Victorian electricity region to another, and the lines represent single or multiple transmission lines depending on the region.

The figure shows that at the time of high power flow from Victoria snapshot:

- Two-thirds of the Victorian load was concentrated in Greater Melbourne and Geelong, with the remainder split almost evenly between Regional Victoria, the South-west Corridor, and the Eastern Corridor.
- The majority of Victorian generation was located in the Eastern Corridor.
- There was high flow from Tasmania to Victoria, even under this light load condition.
- A substantial amount of power flow is from baseload generators concentrated in the Eastern Corridor. Also, the majority of flow from the Eastern Corridor into Greater Melbourne and Geelong passes into the Northern Corridor for export to New South Wales.

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

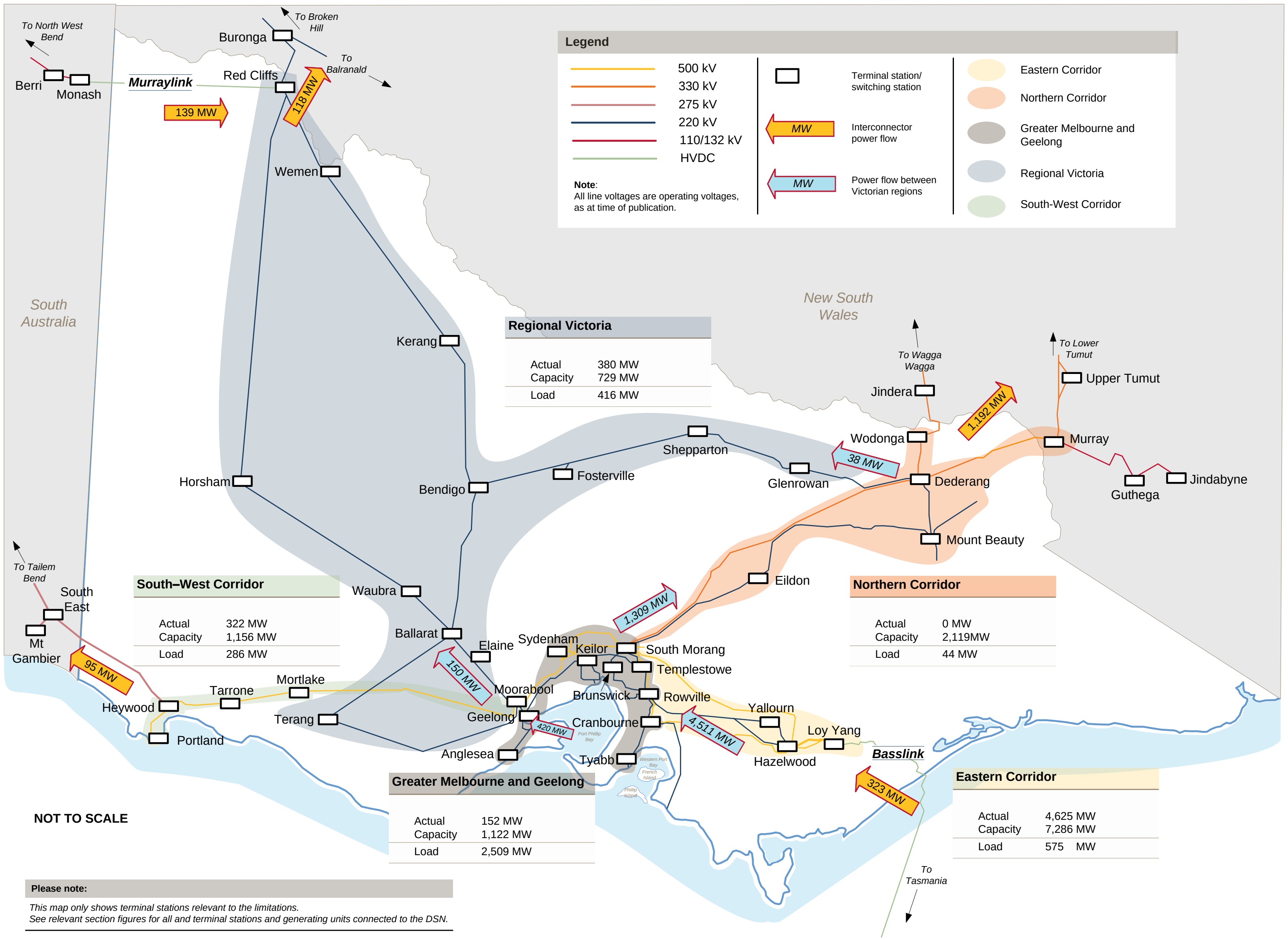


Table 2-4 below shows a summary of the interconnector power flows and approximate capability limits at the time of high power flow from Victoria. The corresponding constraint equations and their descriptions are also presented.

The table shows that the Victoria – New South Wales interconnector was operating at its limit at the time. Note that actual interconnector power flows during a five-minute interval might be outside the limits shown; these limits are approximate and are derived from constraint equations that represent physical limitations only at the end of each interval.

Table 2-4 — High power flow from Victoria snapshot: Interconnector power flow and limits

Interconnector	Actual power flow (MW)	Limit for 5-min dispatch interval (MW)	Limiting constraint equation	Constraint description[a]
Vic–NSW	1,310	1,306 export limit	V>>V_NIL1A_R	Avoids overload of either Dederang to South Morang 330 kV line (flow North) for trip of the parallel line.
Vic–SA (Heywood)	95	175 export limit	V>>S_NIL_SETB_SGKH	Avoids overload of Snuggery–Keith 132 kV on trip of a South East – Tailem Bend 275 kV line.
Vic–SA (Murraylink)	-139	-151 import limit	S>V_NIL_NIL_RBNW	Avoids overload of North West Bend to Robertstown 132 kV line for no contingencies.
Tas–Vic (Basslink)	323	371 export limit	F_T++NIL_TL_L60	Tasmania lower 60-second requirement for loss of two potlines, Basslink able to transfer Frequency Control Ancillary Services (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.

b) Refer to AEMO's annual NEM constraint report for further detail. Available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report.

Table 2-5 below shows a summary of the reactive power supply-demand at the time of high power flow from Victoria snapshot. The data shows that at times of low demand, the amount of reactive power demand is significantly lower than during peak demand.

Table 2-5 — High power flow from Victoria snapshot: Reactive power supply-demand balance

Reactive power supply	MVAr	Reactive power demand	MVAr
Generation	-125	Loads	461
Static VAr compensators	-15	Shunt reactors	726
Synchronous condensers	-62	Line losses	2,058
Shunt capacitors	125	Inter-regional transfer	-285
Line charging	3,036		
Total	**2,960**	**Total**	**2,960**

2.4 Victorian transmission constraints

AEMO uses constraint equations to operate the DSN securely and reliably within power system limitations (thermal, voltage, and stability). The constraint equations are implemented in the National Electricity Market Dispatch Engine (NEMDE), which dispatches generation to ensure operation within the bounds of power system limitations.

A constraint equation is considered to be binding when it limits economic dispatch. It is violating when NEMDE cannot adjust the dispatch to satisfy the conditions of the equation. When there is a violation, AEMO takes action to return the power system to a secure operating state.

Previously, the VAPR contained information on transmission constraint equations, including:

- Top 20 binding constraint equations with the greatest market impact.
- Persistently binding constraint equations in Victoria.
- Impact of constraint equations on interconnector utilisation.

This information (and additional constraint information) is available in AEMO's Annual Constraint Report.[4] Monthly constraint reports[5] also provide up-to-date information.

2.5 Review of load interruption events

This section reviews load interruption events that occurred during 2013–14 to identify whether additional network infrastructure investment is required. AEMO is responsible for transmission network planning; as such, this section does not consider distribution network events that may have resulted in load interruptions.

Table 2-6 below presents a summary of load interruption events that occurred during 2013–14.

Table 2-6 — DSN events that resulted in load interruptions during 2013–14

	Date	Summary	Impact
1	9 September 2013	Loads at Springvale and Heatherton were exposed to reduced reliability as one of the two Rowville–Springvale 220 kV lines was out of service. This was due to a combination of outages at Rowville Terminal Station due to project works. A fault within Rowville Terminal Station resulted in the loss of the in-service Rowville–Springvale 220 kV lines.	Loss of approximately 390 MW of load at Springvale and Heatherton terminal stations.
2	29 September 2013	The Ringwood–Rowville 220 kV line tripped. This resulted in multiple unexpected generation trips which led to voltage disturbances resulting in load reduction in Victoria.	Load reduced by approximately 100 MW in the Victoria due to voltage disturbance.
3	7 January 2014	Single phase trip on the Mortlake – Heywood – Alcoa Portland 500 kV line resulted in a voltage disturbance at Alcoa's Portland smelter.	Loss of approximately 465 MW of load at Alcoa's Portland smelter.
4	15 and 16 January 2014	Loss of supply to Wemen Terminal Station load due to a trip of the Kerang – Wemen – Red Cliffs 220 kV line. This line tripped three times, once on the 15 January and twice on 16 January resulting in three separate loss-of-supply events.	Three separate loss-of-supply events with approximately 42, 37, and 11 MW of load lost at Wemen Terminal Station.

[4] Available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report.
[5] Available at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Monthly-Constraint-Report.

A review of the first event found that a double breaker configuration at Rowville could have prevented the event, but such configurations are uncommon due to high costs. The double breaker configuration is not considered economically feasible given the low probability of outages. AEMO intends to conduct a priority assessment to address constraints on the Rowville–Springvale–Heatherton 220 kV line. The options being looked at as part of this assessment would reduce the impact of such events.

The second event was due to generator compliance and power quality issues which have been addressed through AEMO's non-compliance process. This event does not justify the need for network infrastructure investment.

The third event was due to low voltages at Alcoa Portland as a result of the fault and does not justify the need for network infrastructure investment.

A review of the fourth event found that Wemen Terminal Station is exposed to load interruption events for trips on the Kerang – Wemen – Red Cliffs 220 kV line. A review of the circumstances surrounding this event saw protection changes implemented to minimise the risk of similar events. While the review found that additional line circuit breakers at Wemen could have prevented this event, the cost to install these is not considered economically feasible given the low probability of outages. AEMO intends to discuss this with Powercor as part of the proposed connection of the second 220/66 kV transformer at Wemen.

A comprehensive list of power system operating incidents is provided on AEMO's website.[6]

2.6 Review of supply to regional Victoria

In addition to the above events, during the summer 2013-14 heat wave, operational measures were taken[7] to manage security and avoid pre-contingent load shedding in regional Victoria. At present, transfer into regional Victoria is predominantly constrained by the Ballarat–Moorabool and Ballarat–Bendigo 220 kV lines.

The operational measures were sufficient to prevent pre-contingent load shedding during the summer 2013–14 heat wave. Long-term solutions to address these constraints have been assessed in the Regional Victorian Thermal Capacity Upgrade RIT-T. More detail on this RIT-T is provided in Appendix D and on AEMO's website.[8]

[6] AEMO. Power System Operating Incident Reports. Available at http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Operating-Incident-Reports.
[7] Use of short-term five-minute line ratings and arming of post-contingent load shedding schemes.
[8] Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission.

CHAPTER 3 - NETWORK DEVELOPMENT

This chapter provides information about transmission network limitations in the DSN that are expected to impact the National Electricity Market (NEM) in the next 10 years and beyond. It also highlights the triggers leading to limitations based on changes in generation, imports, exports, and demand.

In addition, this chapter provides information on connection applications, distribution network service provider (DNSP) augmentation plans, SP AusNet's Asset Renewal Plan, and short-circuit levels on the DSN.

3.1 Transmission development overview

Appendix C provides a comprehensive list of generation and terminal station connection applications received by AEMO that are likely to be developed over the next 10 years. This information is provided in accordance with National Electricity Rules (NER) clause 5.12.2 (c) (2), which requires this report to include the planning proposals for future connection points.

3.2 Regional transmission network limitations

This section presents the findings from AEMO's review of transmission network limitations in Victoria's five electricity regions:

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

As part of the review, AEMO updated the status of limitations identified in the 2013 VAPR by reassessing power system and economic market (market simulation studies)[9] performance.

The information provided in this section is in accordance with NER clause 5.12.2 (c) (3)(4)(5)(6), which requires this report to forecast upcoming limitations and augmentations with relevant detail including their relationship to longer-term plans. The information is also in accordance with NER clause 8.11.10 which requires this report to indicate project contestability.

Each region's limitations are categorised in terms of the project status[10] and actions AEMO will take[11] to address them. The categories are:

- **Committed projects**. Proponents have secured the necessary land and planning approvals; have entered into contracts for finance and generating equipment; and have either commenced construction or set a firm date. The service dates provided reflect when full commercial operation is expected to begin.
- **Upcoming tenders.** The need for these projects has been confirmed through the RIT-T process. The projects are expected to be implemented within the next five years and AEMO will issue invitations to tender (ITT) within the next 12 months.

[9] AEMO. Victorian Electricity Planning Approach. Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.
[10] Committed projects and upcoming tenders.
[11] Current RIT-Ts, priority limitations, and monitoring limitations.

- **Current RIT-Ts**. Previous reviews conclude that these limitations significantly affect power system and market performance to the 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 these limitations.
- **Priority limitations**. The latest review concludes that these limitations affect power system and market performance to the extent that positive net market benefits might be realised with credible solutions to relieve them within the next five to 10 years. AEMO will undertake further assessment, possibly progressing to RIT-T applications within the next 12 months.
- **Monitoring limitations**. The latest review concludes that these limitations do not significantly affect power system and market performance, and that no positive net market benefits can be realised with credible solutions to relieve them within the next five to 10 years under forecast demand and generation developments. AEMO will not undertake further detailed assessment within the next 12 months but will continue to monitor triggering conditions.

The 2014 VAPR bases its limitation analysis on the transmission connection point forecasts developed by Victorian DNSPs. During 2014 AEMO will develop an independent set of Victorian transmission connection point forecasts for the first time in collaboration with DNSPs. These forecasts will be used as inputs into Victorian electricity planning studies commencing in the fourth quarter of 2014.

3.2.1 Regional transmission limitation changes since the 2013 VAPR

Eastern Corridor limitation changes since the 2013 VAPR

No changes.

South-west Corridor limitation changes since the 2013 VAPR

The key changes are:

- The Heywood Interconnector Upgrade RIT-T[12] has been approved by the AER and is now complete. The Victoria – South Australia interconnector congestion and Heywood 500/275/22 kV transformer loading limitations will be removed when the upgrade is commissioned.
- On 5 April 2013, ElectraNet submitted an application to the AER seeking a determination that the preferred option13 satisfied the RIT-T, as per NER clause 5.16.6. On 4 September 2013, the AER published its determination confirming this.14 AEMO published a Request for Tender in 2013 for the Victorian components, and the contract was awarded to SP AusNet in 2014. The estimated commissioning date is mid–2016.
- The Moorabool–Heywood–Portland 500 kV line voltage unbalance limitation, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring. AEMO is progressing the installation of voltage unbalance monitoring equipment in the area. Data from the equipment will be used to review the magnitude of the issue and calibrate the simulation model to review the existing constraints if required. AEMO expects to conduct this review in 2014–15.

Northern Corridor limitation changes since the 2013 VAPR

No changes.

[12] Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T.
[13] Installing 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.
[14] Available at http://www.aer.gov.au/sites/default/files/Heywood%20RIT-T%20determination_0.pdf.

Greater Melbourne and Geelong limitation changes since the 2013 VAPR

Key changes include:

- The Eastern Metropolitan Melbourne Thermal Capacity Upgrade RIT-T, which identified the need for a new Rowville 500/220 kV transformer, has been terminated based on AEMO's latest assessment using the 2013 demand forecasts. The limitation on the Rowville A1 500/220 kV transformer will be re-assessed in 2014–15 as a priority assessment based on AEMO's 2014 demand forecasts.
- A new priority limitation on the Keilor – Deer Park – Geelong 220 kV line is included in the 2014 VAPR. This limitation constrains flows on the 220 kV transmission network and is being driven by load transfer to the new Deer Park Terminal Station. This limitation was previously identified in the Deer Park RIT-T[15] including options to alleviate the limitation. The identified options and their timing will be reviewed in 2014–15.
- The East Rowville – Rowville 220 kV line loading limitation, flagged as monitoring in the 2013 VAPR, has been removed due to reduced forecast demand growth in the region.
- The Rowville 500/220 kV A2 transformer loading limitation, flagged as monitoring in the 2013 VAPR, has been removed due to reduced forecast demand growth in the region.
- The South Morang 330/220 kV H2 transformer loading limitation, flagged as a priority assessment in the 2013 VAPR, has been removed as SP AusNet intends to replace the existing H2 transformer as part of its asset renewal program. The new unit will have a higher short-term rating (1,000 MVA) with only marginal cost implications for this increase in rating. The transformer replacement is scheduled for 2016.
- The Geelong–Moorabool line limitation, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring due to industrial load shutdowns and reduced demand growth in the Greater Melbourne and Geelong area.
- The Keilor 500/220 kV A4 transformer loading limitation, flagged as a priority assessment in the 2013 VAPR, has been removed as SP AusNet plans to replace the existing A4 transformer as part of its asset renewal program. The new unit will have a higher short-term rating (1,000 MVA) with only marginal cost implications for this increase in rating. The transformer replacement is planned for around 2019.
- The Keilor 500/220 kV A2 transformer loading limitation, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring due to industrial load shutdowns and reduced demand growth in the region.
- The Ringwood–Thomastown 220 kV line loading limitation, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring due to reduced forecast demand growth in the region.
- Inadequate reactive power support in Metropolitan Melbourne, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring due to reduced forecast demand growth in the region.
- The Keilor–Thomastown No.2 220 kV line loading limitation, flagged as monitoring in the 2013 VAPR, has been removed as the Thomastown reconfiguration resulted in the line 1 and 2 loadings being interchanged. The Keilor–Thomastown No.1 220 kV line loading limitation is included as monitoring.

[15] Available at http://www.aemo.com.au/Consultations/Network-Service-Provider/Joint/Joint-Consultation-Paper-Western-Metropolitan-Melbourne-Transmission-Connection-and-Subtransmission.

Regional Victoria limitation changes since the 2013 VAPR

Key changes are:

- A new limitation on the Ballarat–Horsham 66 kV line is included in the 2014 VAPR. This limitation constrains flows on the 220 kV transmission network between Ballarat and Red Cliffs.
- The Dederang–Shepparton 220 kV line loading limitation, flagged as monitoring in the 2013 VAPR, has been upgraded to a priority assessment following completion of the Regional Victorian Thermal Capacity RIT-T. Once the existing Moorabool–Ballarat 220 kV line and Ballarat–Bendigo 220 kV line limitations are removed as part of the Regional Victoria Thermal Upgrade RIT-T, the ratings of this line may start to cause congestion under peak loading conditions.
- The inadequate reactive power support limitation in this region, flagged as a priority assessment in the 2013 VAPR, has been downgraded to monitoring due to industrial load shutdowns and reduced demand growth in Regional Victoria.

3.2.2 Committed projects

Brunswick Terminal Station

This proposed connection is for a new 66 kV supply from the existing Brunswick Terminal Station comprising three 225 MVA 220/66 kV transformers.[16] The proposed service date is mid-2017.

Heywood Interconnector Upgrade

A third 500/275 kV Heywood transformer and 500 kV bus-tie will increase transfer capacity between South Australia and Victoria. This project includes supporting augmentations in South Australia, and has an expected service date of mid-2016.

Ballarat–Bendigo 220 kV Line Wind Monitoring

Wind monitoring will be installed on the Ballarat–Bendigo 220 kV line allowing an increase in line rating. This project is scheduled for completion in 2014 and was identified through the Regional Victorian Thermal Capacity RIT-T process as the first stage of the preferred option.

A new Moorabool–Ballarat 220 kV circuit was also proposed as a second stage of the preferred option from the Regional Victorian Thermal Capacity RIT-T and is expected to be committed in mid-2014 and scheduled for completion in 2017–18.

3.2.3 Upcoming tenders

Deer Park Terminal Station

An ITT will be issued mid–2014 requesting submissions to build, own, and operate this new 220 kV terminal station.[17]

Stage three of the Regional Victorian Thermal Capacity Upgrade

An ITT will be issued late-2014 requesting submissions for non-network solutions in the Bendigo area. More detail is available in the update to the Project Assessment Conclusions Report (PACR) of the RIT-T, published in June 2014.[18]

[16] NERA consulting. Proposed augmentation for Melbourne inner suburbs and CBD supply. Available at http://www.aemo.com.au/Consultations/Network-Service-Provider/Joint/Proposed-Augmentation-for-Melbourne-Inner-Suburbs-and-CBD-Supply.

[17] Powercor, Jemena and AEMO. Joint regulatory test report. Available at http://www.aemo.com.au/Consultations/Network-Service-Provider/Joint/Joint-Consultation-Paper-Western-Metropolitan-Melbourne-Transmission-Connection-and-Subtransmission.

[18] Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Regional-Victorian-Thermal-Capacity-Upgrade.

3.2.4 Current RIT-Ts

TNSPs must undertake a RIT-T for all proposed transmission investment projects except in circumstances described in NER clause 5.16.3.

AEMO follows the three-stage RIT-T process set out in the NER:

a) **Stage 1**: Prepare a Project Specification Consultation Report (PSCR) to inform the market of the upcoming network limitations and potential solutions, including information on non-network solutions.
b) **Stage 2**: Prepare a Project Assessment Draft Report (PADR) to present the results of the economic cost-benefit test and identify the preferred investment option for consultation.
c) **Stage 3**: Prepare a Project Assessment Conclusions Report (PACR) with an investment recommendation. This is followed by the procurement process.

Regional Victorian Thermal Capacity Upgrade RIT-T

AEMO is currently progressing a further assessment to update the third stage of the Regional Victorian Thermal Capacity upgrade to address line loading limitations on the Ballarat–Bendigo 220 kV line. The RIT-T identifies that investment is required to avoid involuntary load reduction that prevents loading transmission network assets loading beyond their thermal capability.

The PACR was published in October 2013 using AEMO's 2012 demand forecasts. The preferred option has three augmentation stages:

- Stage 1: Install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2015–16.
- Stage 2: Install the third Moorabool–Ballarat 220 kV circuit in 2017–18.
- Stage 3: Up-rate the Ballarat–Bendigo 220 kV line in 2019–20.

The first stage is committed and the second stage is expected to be committed in mid-2014. These stages have a combined cost of $28.4 million.

An update to the PACR, which included a re-assessment of stage 3, was published in June 2014. It considered proposals received from network and non-network service providers.

The updated results indicates that the option with the highest net market benefit is to re-conductor the Ballarat–Bendigo 220 kV line in 2018–19, with a weighted net market benefit of $96.4 million.

The option providing the second highest net market benefit is to contract generation (incrementally, up to 120 MW in firm capacity) at Bendigo as a non-network option from 2016–17, with a weighted net market benefit of $92.6 million.

As the difference in net market benefits between the two options is small, considering the uncertainties in key assumptions such as option costs and lead times, AEMO will seek firm quotes on network and non-network options via a request for firm offer and an ITT respectively.

More detail about the Regional Victorian Thermal Capacity Upgrade RIT-T is provided in Appendix D and on AEMO's website.[19]

3.2.5 Priority limitations

Table 3-1 summarises the priority limitations that are likely to lead to future investment in the next five to 10 years. Additional detail is available in Appendix E.

3.2.6 Monitoring limitations

Appendix E contains the list of limitations that are currently being monitored and are unlikely to lead to future investment within the 10-year planning period.

[19] Available at http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission.

Table 3-1 — Priority transmission limitations requiring investment in the next five to ten years[a]

Limitation	Drivers	Possible network solution	Possible non-network solution	Average annual market impact[b]
Greater Melbourne and Geelong limitation summary				
Rowville–Malvern 220 kV line loading **(refer to Table E4 in Appendix E)**	Increased demand at Malvern Terminal Station.	• Up-rate the Rowville–Malvern 220 kV lines. • Cut-in the Rowville–Richmond 220 kV No.1 and No.4 circuits at Malvern Terminal Station to form the Rowville–Malvern–Richmond No.3 and No.4 circuits. • 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.	Demand management or new generation of 60 MW (44 MWh) at Malvern Terminal Station beginning in summer 2014–15.	$1.5 million
Rowville–Springvale–Heatherton 220 kV line loading **(refer to Table E5 in Appendix E)**	Increased demand at either Springvale or Heatherton terminal stations.	• Augment transformers, or change transformer switching configurations at Heatherton, and replace the limiting line assets on the Rowville–Springvale–Heatherton line. • Install a third 220 kV line between Rowville and Springvale. • Install a new overhead double circuit 220 kV line between Cranbourne and Heatherton. • Install a new underground 220 kV cable between Cranbourne and Heatherton. • Install a new underground 220 kV cable between Malvern and Heatherton.	Demand management or new generation of 35 MW (6.6 MWh) at the Springvale or Heatherton terminal stations beginning in summer 2014–15.	$3.1 million
Keilor – Deer Park – Geelong 220 kV line loading **(refer Table E6 in Appendix E)**	Establishment of Deer Park Terminal Station.	• Cut-in the Keilor–Geelong 220 kV No.1 circuit into Deer Park Terminal Station. • Two 100 MVAr capacitor banks at Deer Park Terminal Station.	Demand management or new generation of 4 MW (0.3 MWh) at Deer Park Terminal Station beginning in summer 2017–18.	$2.2 million
Rowville A1 500/220 kV transformer loading **(refer Table E7 in Appendix E)**	Increased demand in Eastern Metropolitan Melbourne.	• Install a second 500/220 kV 1,000 MVA transformer at Cranbourne • Install a third 500/220 kV 1,000 MVA transformer at Rowville. • Establish a new 500 kV switchyard by cut-in of the existing Rowville – South Morang 500 kV line and install a 500/220 kV transformer at Ringwood. • Establish a new 500 kV switchyard by cut-in of the existing Rowville – South Morang 500 kV line and install a 500/220 kV transformer at Templestowe.	Demand management or new generation of 16 MW (5 MWh) at Ringwood terminal station beginning summer 2014–15.	$1.1 million

a) Megawatt, megawatt hours, and dollar amounts are indicative. Unless noted as having been studied as part of a RIT-T assessment, further assessment is necessary to refine requirements.

b) Average over the first five years.

Limitation	Drivers	Possible network solution	Possible non-network solution	Average annual market impact[b]
Regional Victoria limitation summary				
Dederang–Shepparton 220 kV line loading **(refer to Table E9 in Appendix E)**	Increased demand in Regional Victoria. Increased import from New South Wales.	• Install wind monitoring. • Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line. • Up-rate the existing Dederang–Shepparton conductors. • Replace the existing Dederang–Glenrowan 220 kV lines with a new double circuit line. • Replace the existing Dederang–Shepparton 220 kV line with a new double circuit line at an estimated cost of $260 million.	Demand management or new generation of 74 MW (78 MWh) at Bendigo, Fosterville, or Shepparton terminal stations beginning in summer 2014–15.	$ 2.3 million
Ballarat–Horsham 66 kV line loading **(refer to Table E10 in Appendix E)**	Renewable generation in Regional Victoria.	• Upgrade limiting sections of the Ballarat–Horsham 66 kV line.	Automated post-contingent bus splitting scheme on the 66 kV Ararat–Ballarat line.	$ 0.83 million

3.2.7 Network support and control ancillary services

Addressing gaps identified in the 2012 NTNDP

The 2012 National Transmission Network Development Plan (NTNDP) network support and control ancillary services (NSCAS) assessment[20] identified a potential NSCAS gap in relieving the New South Wales to Victoria voltage stability limitation.

This voltage stability limitation constrains electricity transfer from New South Wales to Victoria. AEMO has been managing this limitation via reactive power support procured through a contract with a generator. This contract is primarily for maintaining system security, but is also used to achieve net market benefit. The 2013 NTNDP[21] NSCAS assessment confirmed the ongoing requirement for this agreement.

In 2013–14 AEMO procured reactive power support using this contract on winter and summer high demand days. AEMO and TransGrid will continue to jointly investigate other economical options for filling the NSCAS gap.

3.3 DNSP planning

In undertaking augmentation planning, AEMO considers DNSP plans for existing and new connection points and addresses the impact of DNSP plans in its transmission network limitation assessments.

AEMO addresses the general impact of distribution network load growth on the DSN by modelling this growth at connection points. AEMO and DNSPs undertake joint planning to address connection asset limitations and potential solutions (for example, installing additional transformers at existing connection points or establishing new connection points). This identifies the most efficient solution for both the distribution network and the DSN.

Appendix F lists the preferred connection modifications from the 2013 Transmission Connection Planning Report[22], and potential DSN impacts and considerations. This information is provided in accordance with NER clause 5.12.2 (c) (2), which requires this report to include the planning proposals for future connection points.

3.4 SP AusNet asset renewal

Appendix G contains SP AusNet's current list of asset renewal projects planned for the next 10–year period as well as an outline of SP AusNet's asset renewal plan. This information is provided in accordance with NER clause 5.12.2 (c) (7), which required this report to include detail on transmission network asset replacements.

3.5 Short-circuit levels for the Victorian electricity transmission network: 2014–18

The short-circuit levels for the Victorian electricity transmission network is in Appendix H. The report provides information on the capability of Victoria's electricity transmission network to withstand short-circuit currents over a five-year outlook period from 2014 to 2018.

The report will be useful to stakeholders intending to connect to the DSN. Stakeholders can use the information for preliminary assessments to determine the capability of the network to accommodate an intended connection. The information will also be useful to stakeholders who own equipment that may be affected by transmission network current flows (or who plan to invest in such equipment). Stakeholders can use the information to assess the impact of high network current flows during faults.

[20] AEMO. Network Support and Control Ancillary Services Assessment. Available at http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/Network-Support-and-Control-Ancillary-Services-Assessment-2012.
[21] Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.
[22] 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.

CHAPTER 4 - NETWORK RELIABILITY

4.1 Introduction

This chapter presents AEMO's proposed methodology for measuring reliability of supply at connection points. The methodology is based on AEMO's current processes and methods for planning the Victorian transmission network. This information will contribute to developing a new national framework for transmission reliability by clarifying how the Victorian approach works in practice.

AEMO welcomes comments and feedback on the proposed methodology 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.

Reliability of supply can be seen as the proportion of customer demand that can be continuously supplied. Lower reliability poses a greater risk of supply interruptions to customers. The level of compensation provided to network businesses should take into consideration the level of reliability they provide.

Measuring and forecasting the reliability of supply provided by transmission networks is not a simple task. Trying to measure reliability from historical outcomes alone does not provide a good indication of actual or future reliability. Traditionally, to ensure high levels of reliability of supply, deterministic levels of network element redundancy have been specified in planning standards.

On 1 November 2013, the Australian Energy Market Commission (AEMC) published a report in which it recommended developing a national framework for transmission reliability.[23] As part of this review AEMO recommended the adoption of methods similar to the current Victorian economic planning approach. This framework, in conjunction with the Value of Customer Reliability (VCR) which is being developed by AEMO, can be used by National Electricity Market (NEM) jurisdictions to set reliability standards using an economic approach, and would also enable benchmarking reliability at individual connection points across the NEM.

To complement the discussion on reliability measures, Section 4.4 provides outage data on transmission network assets which are subject to the Availability Incentive Scheme (AIS). The AIS is managed by AEMO in Victoria and is used to maximise reliability and security. It is designed to financially incentivise owners of critical transmission assets (such as transformers and transmission lines) to schedule outages outside peak periods.

4.2 Methodology for measuring reliability using the Victorian economic planning approach

In Victoria an economic planning approach is used to balance the cost of an augmentation with the benefits achieved. This does not rely on traditional deterministic standards of network redundancy, but allows for load shedding, or unserved energy (USE), to occur.

Transmission elements typically have low failure rates. AEMO amalgamates historical outage results for similar types of transmission equipment to derive network outage probability models. These outage probability models are then used as an input to the economic modelling.

Transmission network flows can change direction depending on a number of factors such as overall regional demand, interstate demand, interconnector flows, and generation dispatch. Transmission outages can also affect large areas of the network and lead to widespread outages. As generation outages can result in changes to power flows across the transmission network, generation reliability is also considered when assessing overall reliability of supply. To capture these aspects in its modelling, AEMO generally[24] uses constraint equations and market models

[23] AEMC. Review of the National Framework for Transmission Reliability. Available at http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-national-framework-for-transmission.

[24] Where studies involve radial supplies to loads, this can be simplified to spreadsheet models.

to quantify how much USE could occur at terminal stations under a number of different network outage conditions, as well as under different generation and demand conditions.[25]

To determine optimal timing for Victorian network upgrades, an economic value is then placed on this expected USE using the value of customer reliability (VCR). Upgrades occur once the annualised cost of an upgrade is less than the annual benefits obtained from having the upgrade in place.

This type of analysis can provide a range of other outputs such as the maximum annual amount of demand at risk, total annual USE, and times of supply shortfall per terminal station. These could be used to quantify reliability and risk per terminal station, and be made available to interested parties.

While USE breakdown per terminal station is not undertaken currently for the VAPR, it could be accommodated using existing study methods.

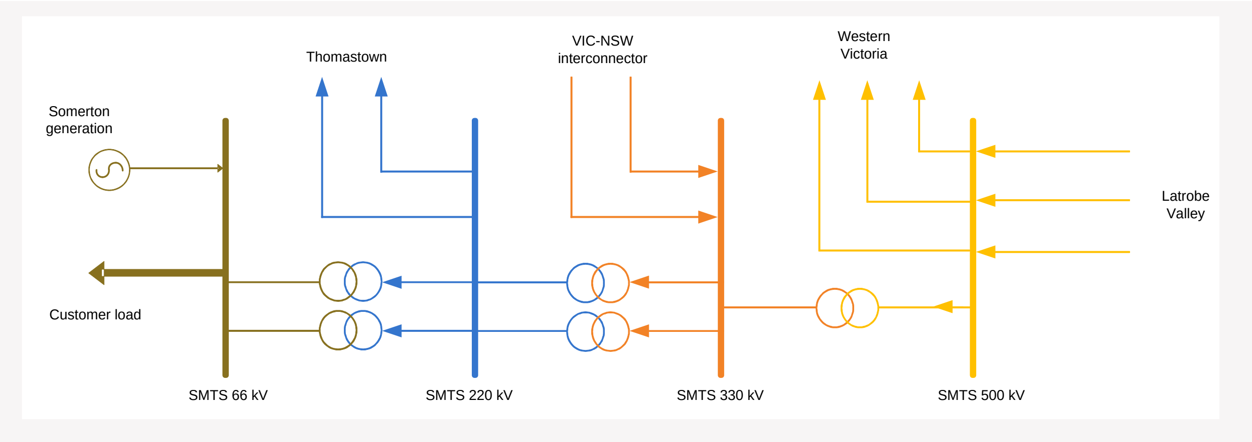
4.3 Case study: Reliability of supply for South Morang Terminal Station

Using South Morang Terminal Station (SMTS) as a case study, this assessment demonstrates how reliability can be measured under a range of contingencies.

Figure 4-1 is a schematic layout of SMTS. This large terminal station was selected as it can affect power flows on the Victorian – New South Wales interconnector, it incorporates transformers and transmission lines of varying voltage levels, and it has embedded generation on the 66 kV network.

The arrows show the expected direction of power flow during peak periods.

Figure 4-1 — South Morang Terminal Station



As per the usual VAPR studies, AEMO initially used load flow screening studies to reduce the number of selected network elements and outage events to include in the case study. AEMO also used the same generation and demand assumptions that were used for the VAPR studies.

In this case study, high impact low probability outages were included to also demonstrate the materiality of the outcomes. Studying the impact of any particular network element being out of service requires a separate outage constraint set and market study run, so the number of outage events are usually minimised to those materially affecting the results.

AEMO's assessment results show that when there are no network outages, no USE is expected at SMTS.

[25] Available at http://www.aemo.com.au/Consultations/National-Electricity-Market/2014-Planning-Studies-Consultation. This contains more background on the planning assumptions such as demand and generation scenarios, and modelling methods AEMO used.

For a single South Morang 220/66 kV transformer outage the results assume neighbouring Somerton generation units will operate if available. With three of the four Somerton generation units available, no USE is expected. This is consistent with DNSP studies[26], which also use effective USE and VCR as economic measures to justify upgrades.

Table 4-1 shows that to ensure secure network operation, the following outages result in USE:

Table 4-1 — Expected USE at SMTS under different outage scenarios

Outage	Expected USE (MWh)									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Single SMTS 330/220 kV transformer	0	0	0	0	0	0	0	0	0.001	0.012
Single Rowville 500/220kV transformer	0	0	0	0	0	0.001	0.005	0.013	0.034	0.088
Both SMTS 220/66kV transformers[a]	4.4	4.6	4.7	4.8	4.9	4.9	5.0	5.1	5.1	5.1

a) In this case, the 66 kV network may also be used to alter power flows and reduce the risk of load shedding.

The worst event would be the failure of both 220/66 kV transformers at the same time, which disconnects all load at SMTS. When weighted to account for the probability of these transformer outage events, the results show very low risk of load shedding.

Note that this case study shows the level of load shedding at SMTS only and does not report the impact on neighbouring terminal stations. (For example concurrent USE at Rowville is not presented in this example, but it would be included when presenting results for all terminal stations.)

As seen in the first two outage results in the table below, the expected USE levels for these contingencies is negligible.

To compare different terminal stations, AEMO has normalised these reliability results and represented them as a single percentage. Table 4-2 below shows the sum of all expected USE for different outages weighted by the SMTS annual energy forecast supply.

Table 4-2 — Normalised total expected USE

Total expected USE as a percentage of SMTS station energy (% 10^{-3})										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of all outages	0.465	0.473	0.469	0.469	0.470	0.467	0.471	0.476	0.476	0.481

In general, reliability of supply for SMTS is considered high due to the terminal station having a variety of transmission connections (220 kV, 330 kV, and 500 kV) as well as having the option to alter the dispatch of interconnector flows and significant embedded generation.

Given the low probability of some network events, such as two elements failing concurrently, this level of analysis is usually only carried out as part of detailed studies such as RIT-Ts, where the low level of expected USE could either alter the most economic upgrade chosen, or influence investment timing.

[26] Jemena, CitiPower, Powercor, SP AusNet and United Energy. 2013 Transmission Connection Planning Report. Available at http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Transmission%20Connection%20Planning%20Report%202012.pdf.

If these reliability indices are adopted as part of the standard annual Victorian transmission planning process, some upfront work will be required to determine the level of USE that is considered material for reporting. This will reduce the number of outage combinations that need to be included in the analysis to a manageable level.

4.4 Availability Incentive Scheme

In Victoria, AEMO manages and operates the Availability Incentive Scheme (AIS) to maximise reliability and security. This scheme is designed to financially incentivise owners of critical transmission assets (such as transformers and transmission lines) to schedule outages outside peak periods.

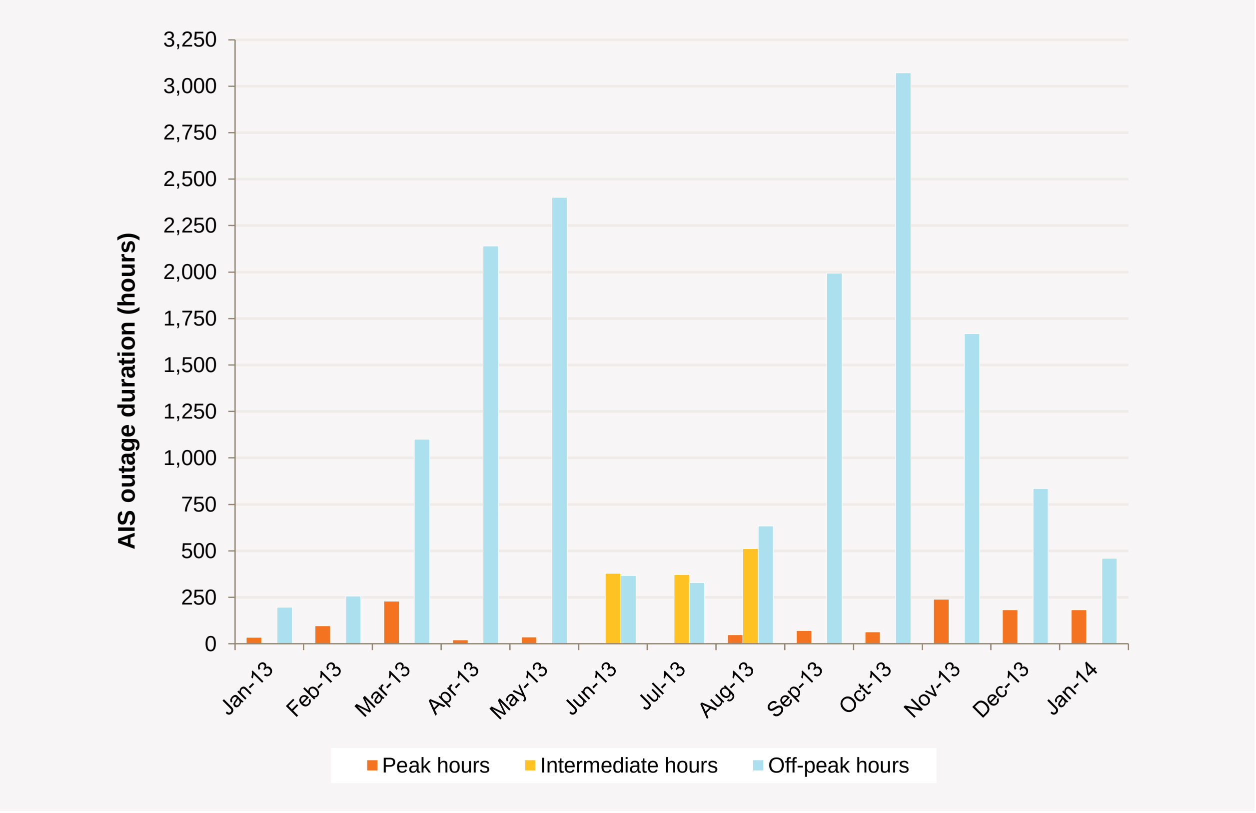
This section presents outage data on transmission network assets included under the AIS.

The AIS was introduced in 2002 and exists in parallel with the Service Target Performance Incentive Scheme (STPIS) in Victoria. The STPIS was implemented by the Australian Energy Regulator (AER) in 2007 to encourage asset owners to maintain or improve reliability for customers and to reduce the market impact of transmission congestion by rewarding or penalising asset owners for meeting specified service targets.

Introducing the STPIS changed the context in which the AIS operates. In some cases, AIS incentives designed to avoid outages during peak periods[27] conflict with STPIS incentives.

Figure 4-2 shows that outages on transmission assets involved in the AIS occurred predominantly during periods designated as off-peak by the AIS.

Figure 4-2 — Critical transmission asset outage duration breakdown by month



[27] As classified under the AIS.

AEMO conducted analysis to investigate the drivers behind outages occurring during peak periods. The results of this analysis, in Figure 4-3 below, show that while most outages during peak periods were due to major plant failure and third party requests, some were planned maintenance outages.

Figure 4-3 — Summary of drivers for outages during peak periods

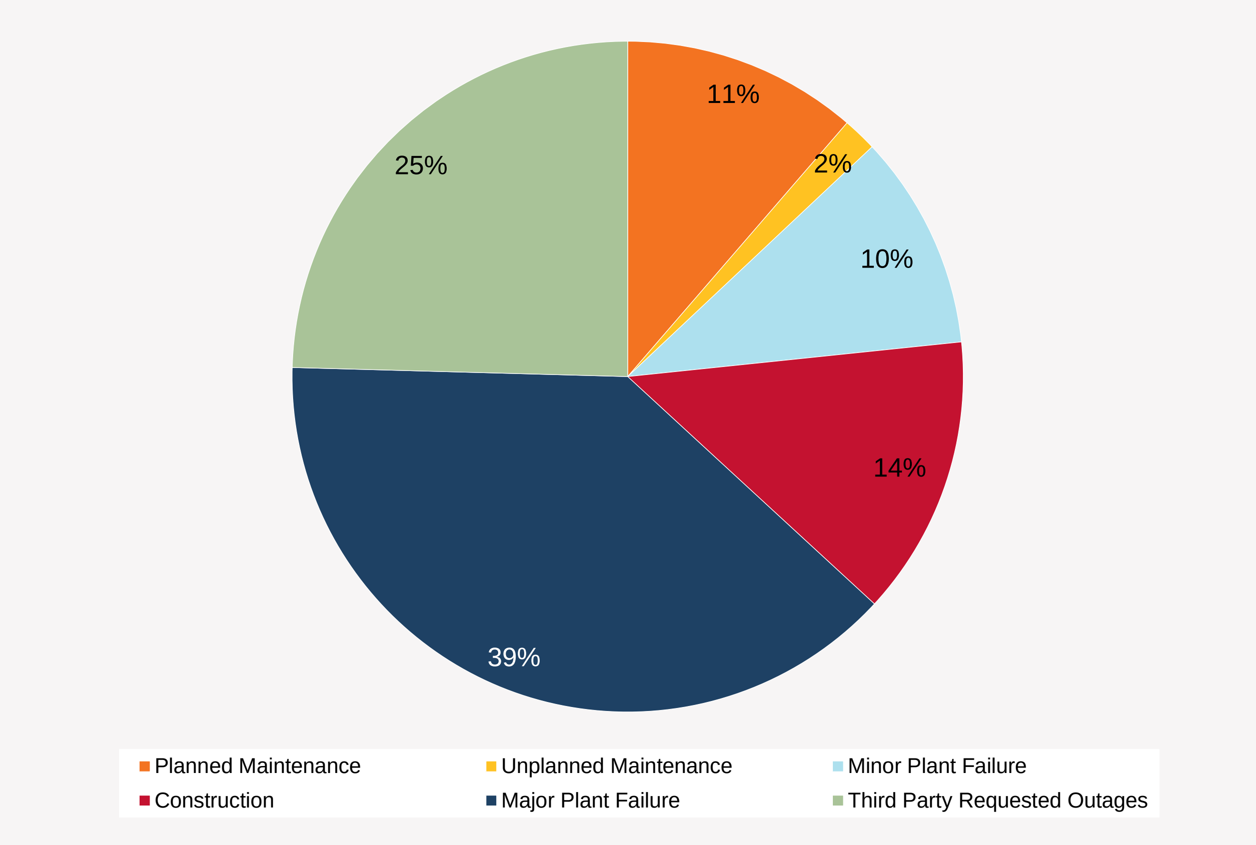


Figure 4-4 below shows the corresponding financial impact of the outage durations shown in Figure 4-2.

Figure 4-5 also shows that relatively few outages are scheduled on critical assets during peak periods, which is consistent with the incentives provided by the AIS.

The STPIS also plays a role in influencing the scheduling of outages, and as such is expected to have contributed to the data shown in this section. AEMO will further explore how the benefits of both schemes can best be aligned, with a view to incorporating the positive aspects of the AIS into the STPIS.

Figure 4-4 — Critical transmission asset financial impact breakdown by month

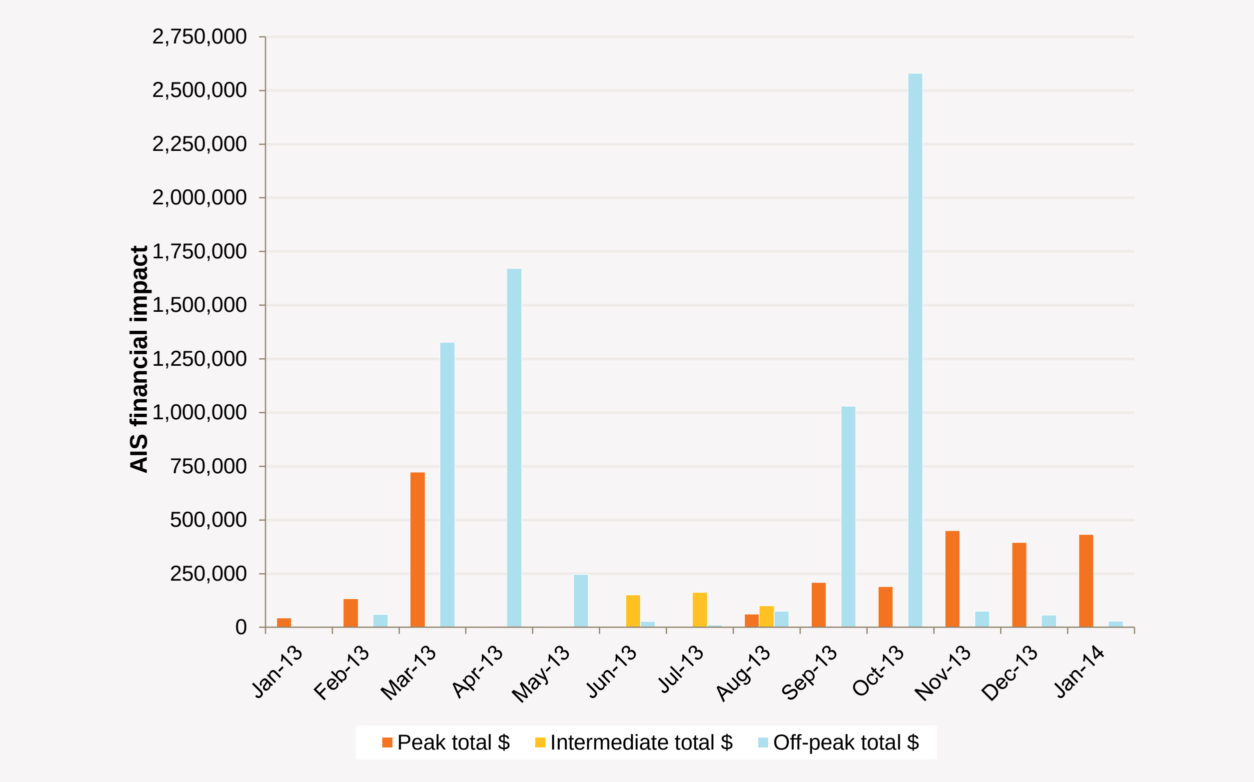
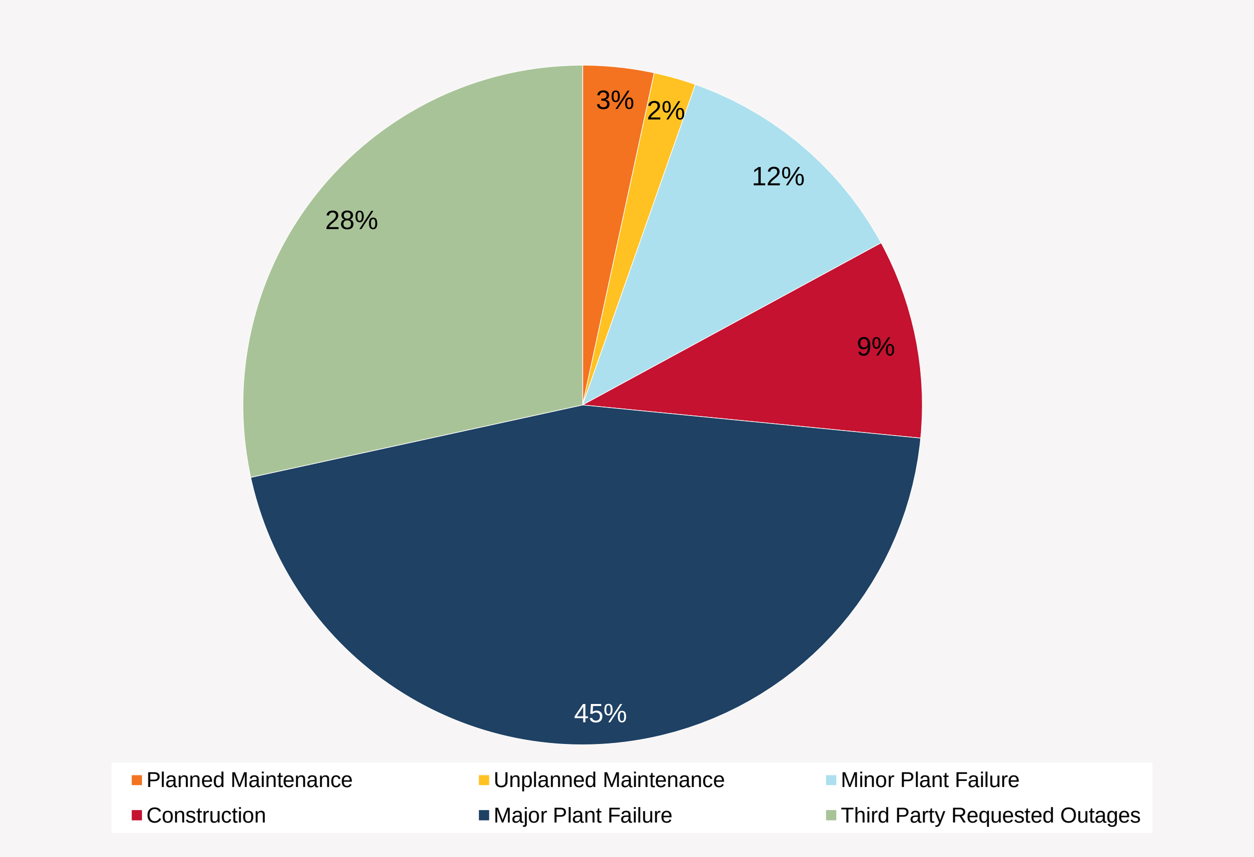


Figure 4-5 — Financial impact breakdown of outages during peak periods



APPENDIX A - LOADING AT TIMES OF HIGH NETWORK STRESS

A.1 DSN loading

This appendix presents the DSN loading during periods of high stress — the time of maximum demand and high export from Victoria snapshots.

For the maximum demand snapshot, network element loading for each Victorian region is presented. For the high power flow from Victoria snapshot, network element loading for the Northern Corridor is presented as this is the only region where loadings were higher under that snapshot.

The two snapshots are based on Victorian regional demand and represent instances when the DSN is heavily loaded. They do not necessarily represent the maximum load experienced by every network element as this depends on prevailing system conditions such as generation patterns, interconnector flows, time of local peak demand, and factors that influence dynamic ratings (such as temperature and wind speed).

A.1.1 Interpreting the regional network loading maps

Each of the maps below show line loadings 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[28] (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 B.

The loadings shown are based on ratings used in real time. N loadings are 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. Only one set of loading numbers is shown for circuits with more than one line if the loading on each line is the same.

For terminal stations connected to the 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. One example is the Mount Beauty – West Kiewa 220 kV line.

A.1.2 Maximum demand snapshot

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

Figure A-1 to Figure A-5 show each Victorian region and the percentage loading on network elements at the time of the 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 A-1 shows the percentage loading on Eastern Corridor network elements at the time of the snapshot.

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

All Eastern Corridor network element N loadings and calculated N–1 loadings were below 100%.

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 develop, with electricity connections made to South Australia.

Figure A-2 shows the percentage loading on South-west Corridor network elements at the time of the snapshot.

All South–west Corridor network element N loadings and calculated N–1 loadings were 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 load, Regional Victoria load, and power flows to South Australia via the Heywood interconnector. However, it is possible that stability and power quality issues may limit power flows ahead of thermal considerations.

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 A-3 shows the percentage loading on Northern Corridor network elements at the time of the snapshot.

All Northern Corridor network elements had N loadings and calculated N–1 loadings of less than 100% during the maximum demand snapshot.

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:

- 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 A-4 shows the percentage loading on Greater Melbourne and Geelong network elements at the time of the snapshot.

All Greater Melbourne and Geelong network elements had N loadings and calculated N–1 loadings of less than 100% during the maximum demand snapshot. The N–1 loading of Point Henry is not included given a special control scheme is activated for N–1 conditions resulting in an overload.

Regional Victoria

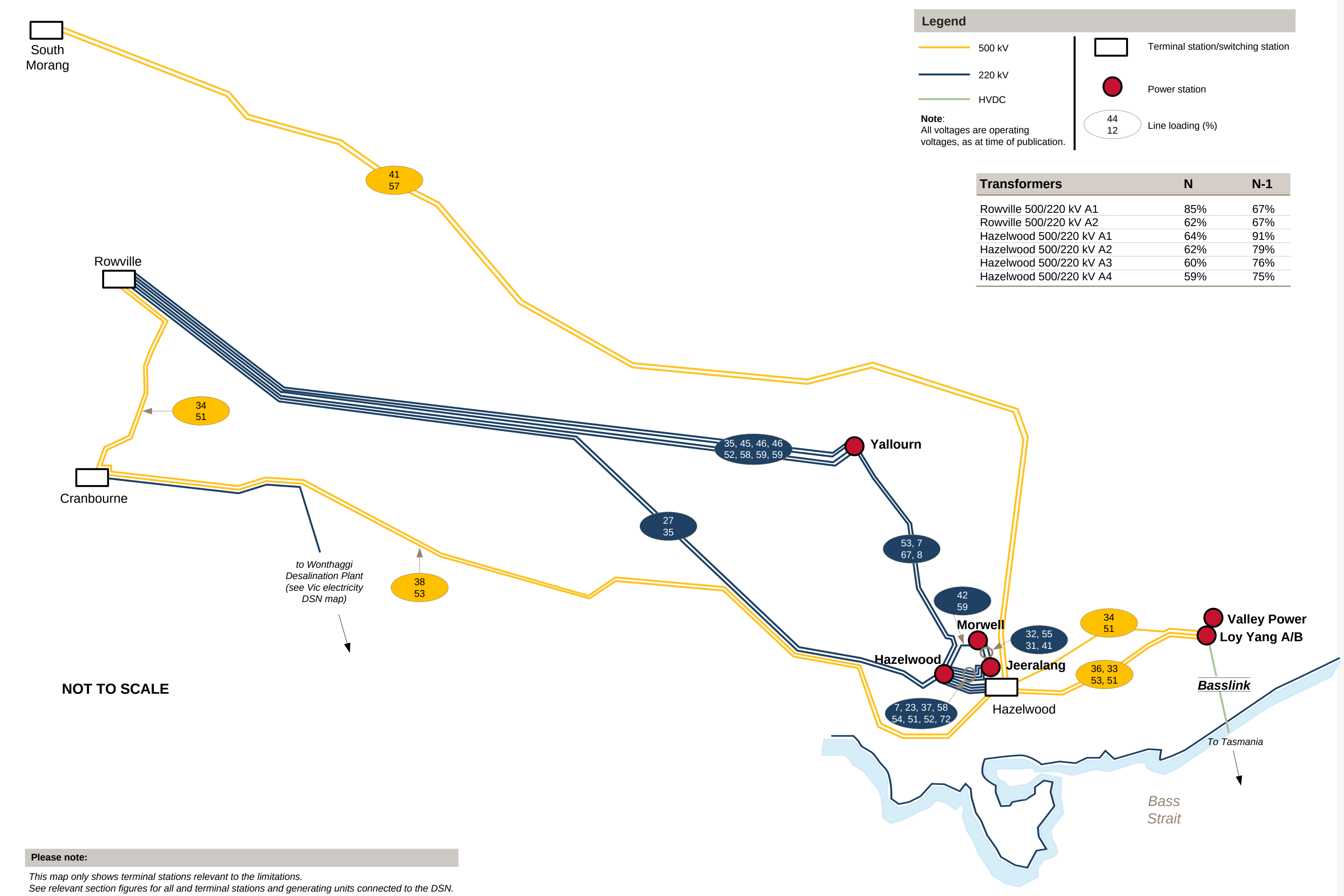
Victoria's regional areas are mainly served by a 220 kV transmission network that delivers energy to regional load centres.

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 A-5 shows the percentage loading on Regional Victoria network elements at the time of the snapshot.

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

Figure A-1 — Maximum demand snapshot: Eastern Corridor transmission network loading

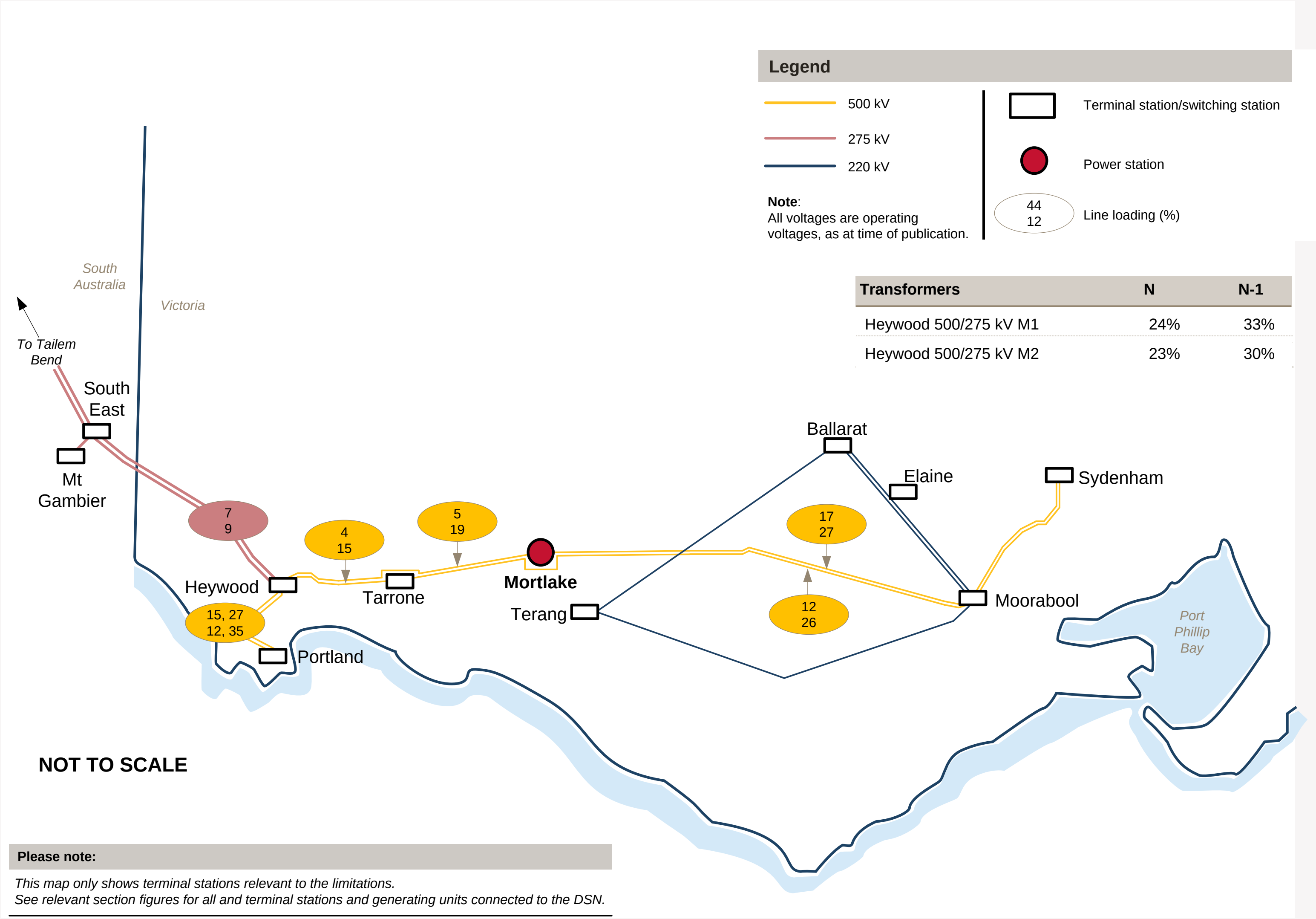


Transformers	N	N-1
Rowville 500/220 kV A1	85%	67%
Rowville 500/220 kV A2	62%	67%
Hazelwood 500/220 kV A1	64%	91%
Hazelwood 500/220 kV A2	62%	79%
Hazelwood 500/220 kV A3	60%	76%
Hazelwood 500/220 kV A4	59%	75%

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.

Figure A-2 — Maximum demand snapshot: South-west Corridor transmission network loading

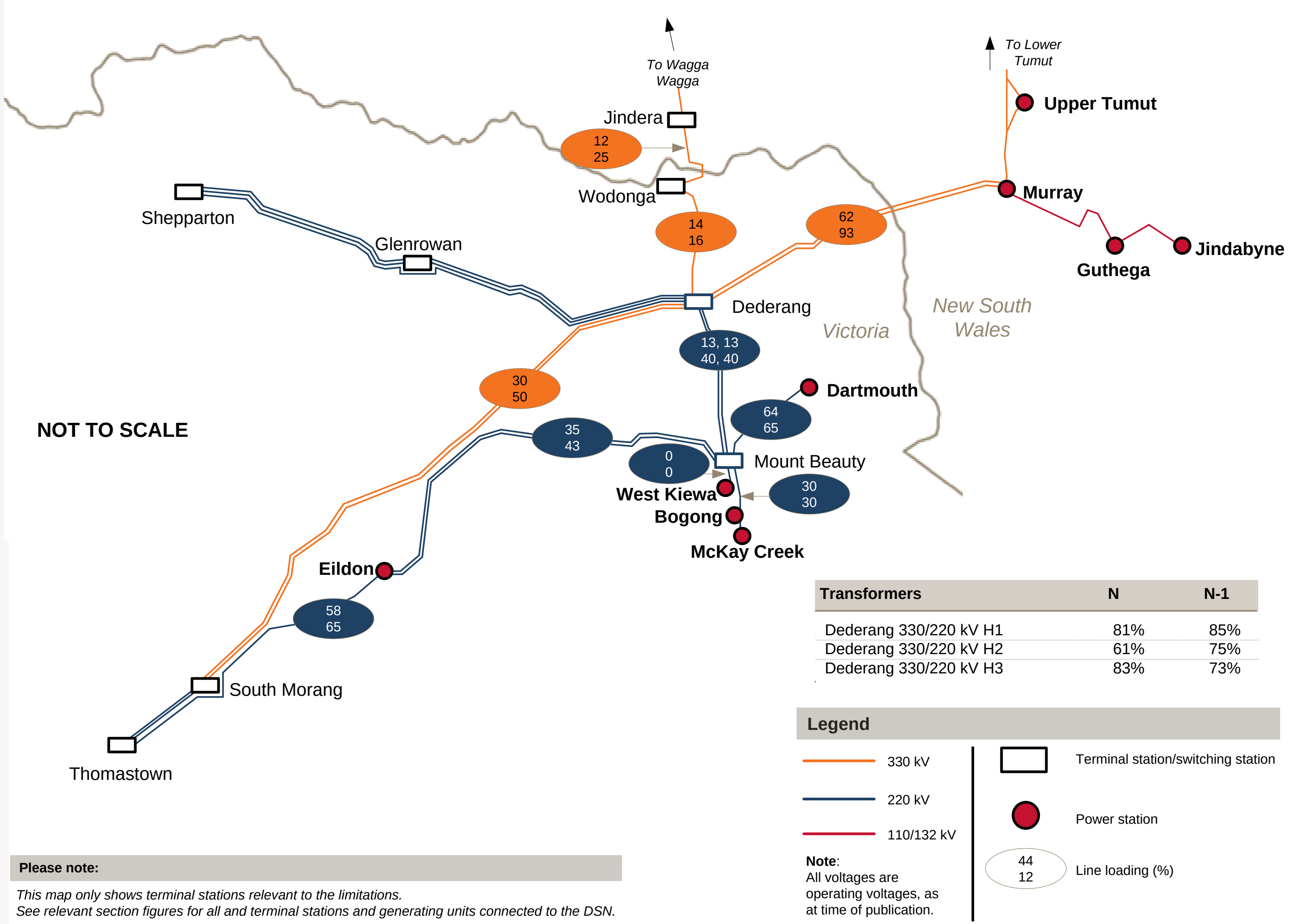


Transformers	N	N-1
Heywood 500/275 kV M1	24%	33%
Heywood 500/275 kV M2	23%	30%

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.

Figure A-3 — Maximum demand snapshot: Northern Corridor transmission network loading

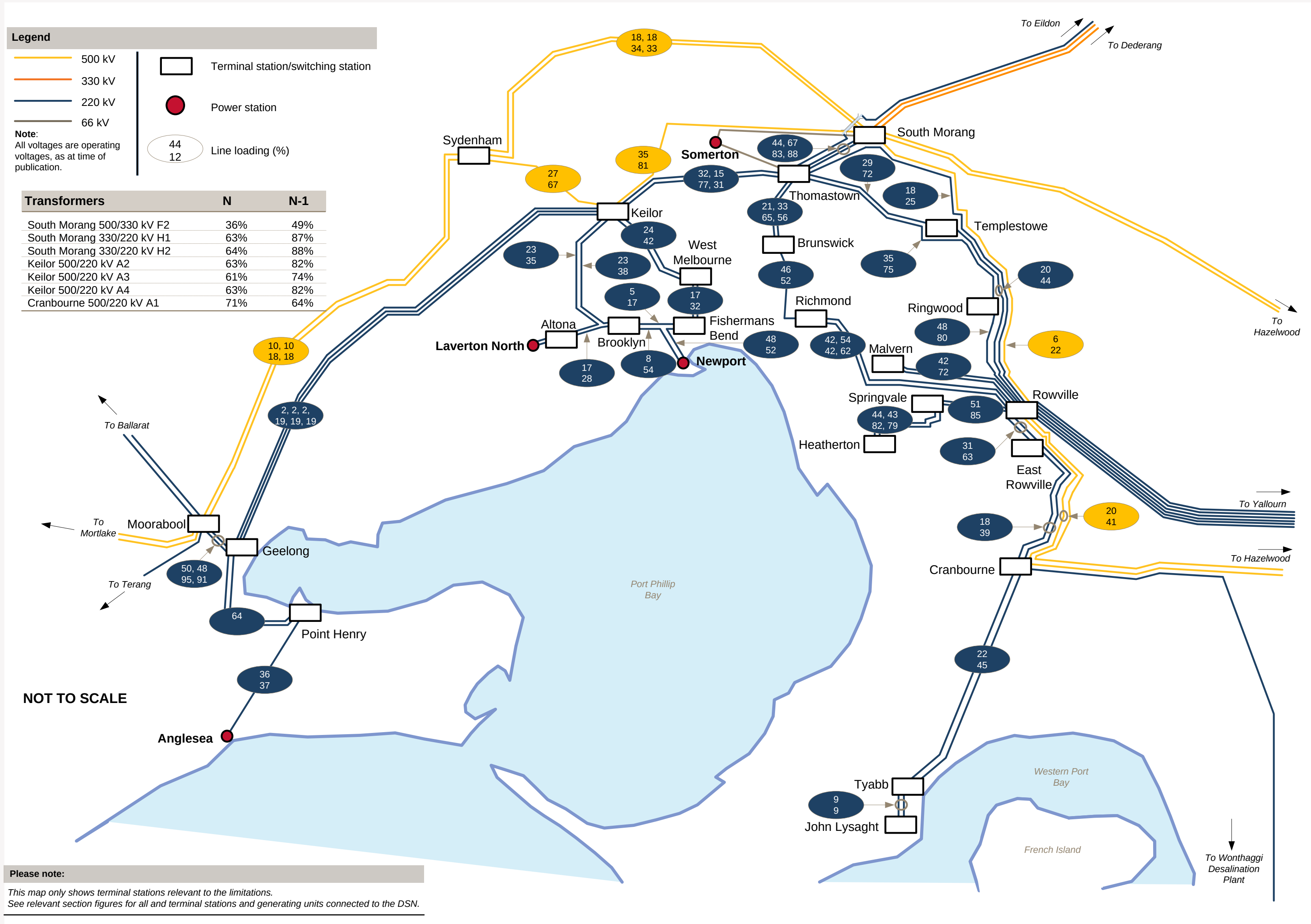


Transformers	N	N-1
Dederang 330/220 kV H1	81%	85%
Dederang 330/220 kV H2	61%	75%
Dederang 330/220 kV H3	83%	73%

Please note:

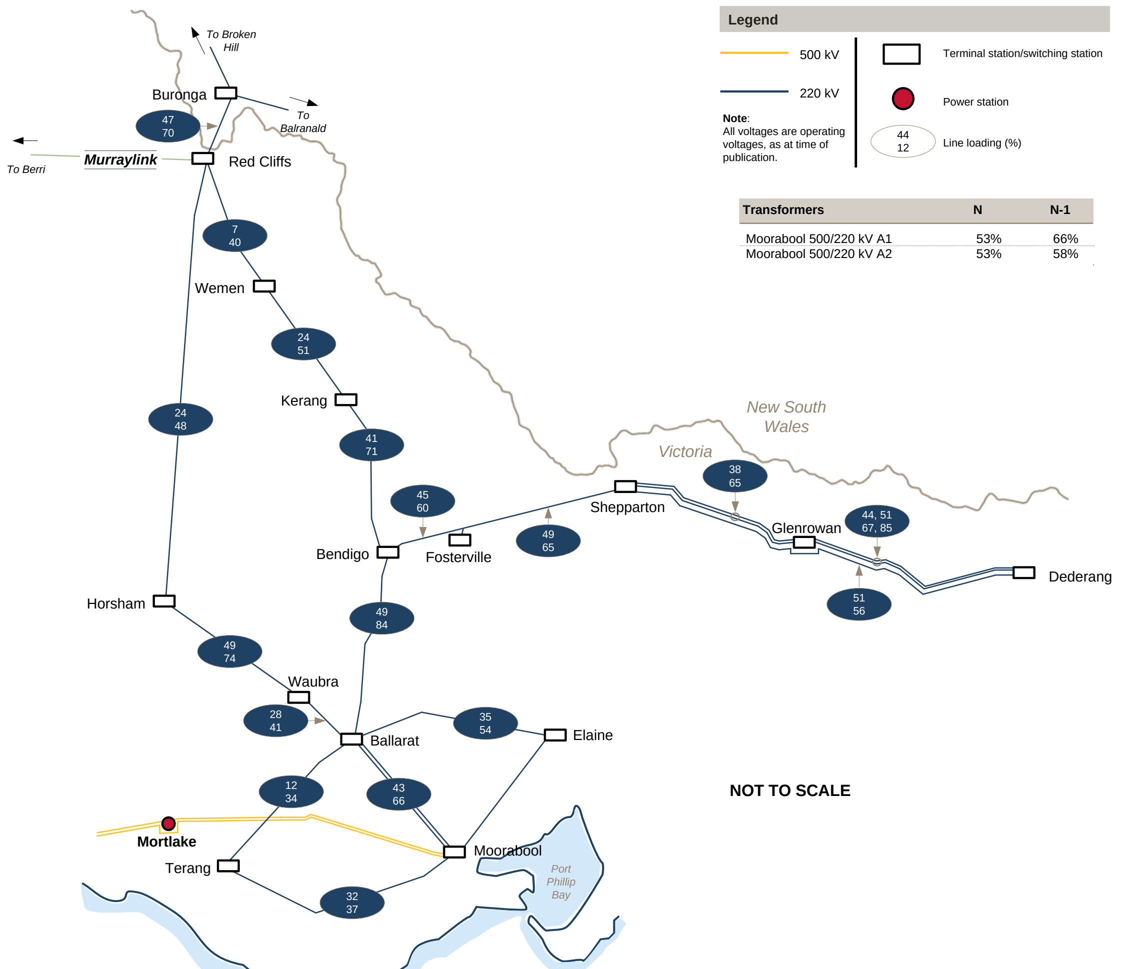
This map only shows terminal stations relevant to the limitations.
See relevant section figures for all and terminal stations and generating units connected to the DSN.

Figure A-4 — Maximum demand snapshot: Greater Melbourne and Geelong transmission network loading



Transformers	N	N-1
South Morang 500/330 kV F2	36%	49%
South Morang 330/220 kV H1	63%	87%
South Morang 330/220 kV H2	64%	88%
Keilor 500/220 kV A2	63%	82%
Keilor 500/220 kV A3	61%	74%
Keilor 500/220 kV A4	63%	82%
Cranbourne 500/220 kV A1	71%	64%

Figure A-5 — Maximum demand snapshot: Regional Victoria transmission network loading



Transformers	N	N-1
Moorabool 500/220 kV A1	53%	66%
Moorabool 500/220 kV A2	53%	58%

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.

A.1.3 High power flow from Victoria snapshot

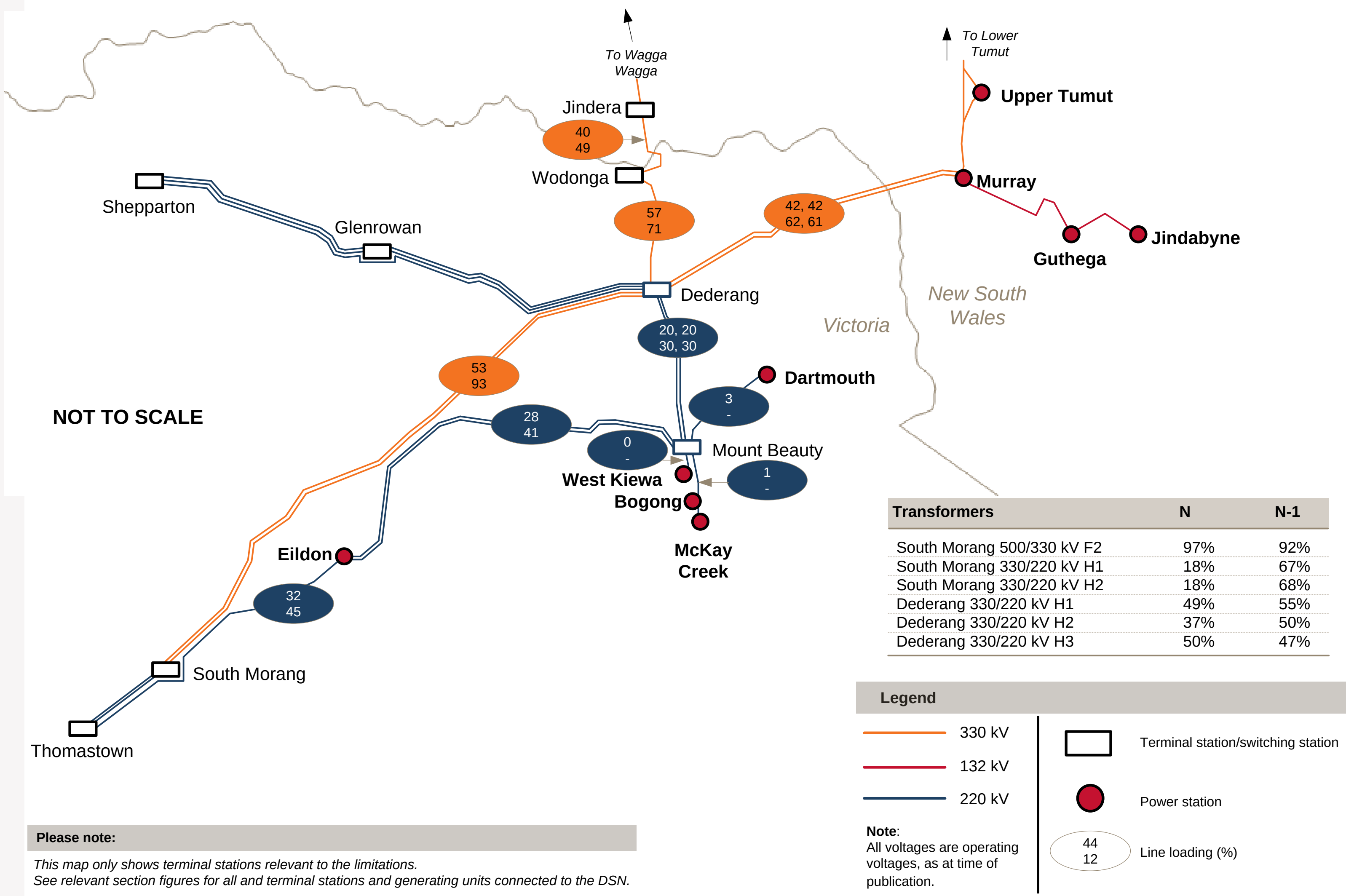
This section describes the DSN loadings for the Northern Corridor at the time of the high power flow from Victoria snapshot. Only Northern Corridor elements are shown for this snapshot as this is the only region where DSN elements tend to be more heavily loaded during high power flow from Victoria, rather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

Figure A-6 shows the percentage loading on Northern Corridor network elements at the time of the 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 93% each for the loss of the parallel Dederang – South Morang 330 kV line. These results are similar to those seen in the 2013 VAPR high export snapshot.

Figure A-6 — Northern Corridor transmission network loading, high power flow from Victoria snapshot



Transformers	N	N-1
South Morang 500/330 kV F2	97%	92%
South Morang 330/220 kV H1	18%	67%
South Morang 330/220 kV H2	18%	68%
Dederang 330/220 kV H1	49%	55%
Dederang 330/220 kV H2	37%	50%
Dederang 330/220 kV H3	50%	47%

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.

APPENDIX B - DSN RATINGS

B.1 DSN ratings

This appendix presents information DSN ratings[29] at the time of the snapshots presented in Chapter 2.

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

Table B-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)[30], 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 B-1 — Maximum demand snapshot: DSN continuous and short-term ratings

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	2,529	2,529	S
		South Morang – Hazelwood 2	2,529	2,529	S
		Hazelwood – Rowville 3	3,277	3,277	S
		Hazelwood – Cranbourne	3,277	3,277	S
	220 kV	Yallourn – Rowville 5	414	414	D/W
		Yallourn – Rowville 6	408	408	D/W
		Yallourn – Rowville 7	411	411	D/W
		Yallourn – Rowville 8	410	410	D/W
		Hazelwood – Yallourn 1	421	421	D
		Hazelwood – Yallourn 2	436	491	D

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

[30] 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 ratings—are provided to AEMO for use in real-time operations.

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	Rating type
		Hazelwood – Rowville 1	412	412	D
		Hazelwood – Rowville 2	410	410	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	862	1,121	D
		Hazelwood – Jeeralang 3	443	573	D
		Hazelwood – Jeeralang 4	443	549	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	2,771	2,771	S
		Moorabool – Tarrone	2,683	2,683	S
		Moorabool – Mortlake	2,598	2,598	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	529	529	S
		Heywood – South East 2	529	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	857	857	S
		Wodonga – Dederang	743	743	S
		Dederang – Murray 1	1,015	1,167	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	Rating type
Northern Corridor	220 kV	Dederang – Murray 2	1,015	1,167	D
		Dederang – South Morang 1	877	877	D
		Dederang – South Morang 2	877	877	D
		Dederang – Mt Beauty 1	319	394	D
		Dederang – Mt Beauty 2	317	391	D
		Mt Beauty – Dartmouth	230	230	S
		Mt Beauty – Bogong	332	332	D
		Mt Beauty – West Kiewa	97	97	S
		Elildon 220kV – Thomastown 220kv 1	527	616	D
		Eildon – Mt Beauty 1	302	366	D
		Eildon – Mt Beauty 2	302	365	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	2,445	2,445	S
		Sydenham – Moorabool 2	2,445	2,445	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	3,097	3,097	S
		Rowville – Cranbourne	2,771	2,771	S
	220 kV	Anglesea – Point Henry	228	228	S
		Geelong – Point Henry 1	238	262	S
		Geelong – Point Henry 2	238	262	S
		Geelong – Moorabool 1	751	751	D
		Geelong – Moorabool 2	781	781	D
		Geelong – Keilor 1	257	318	D/W
		Geelong – Keilor 2	261	322	D/W
		Geelong – Keilor 3	258	319	D/W
		Keilor – Altona	720	876	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	Rating type
Greater Melbourne and Geelong		Keilor – Brooklyn	814	832	D
		Brooklyn – Altona	720	792	D
		Brooklyn – Newport	805	827	D
		Brooklyn – Fishermans Bend	823	823	D
		Newport – Fishermans Bend	809	861	D
		Fishermans Bend – West Melbourne 1	349	420	D
		Fishermans Bend – West Melbourne 2	349	420	D
		Keilor – West Melbourne 1	800	841	D
		Keilor – West Melbourne 2	801	842	D
		Keilor – Thomastown 1	462	478	S
		Keilor – Thomastown 2	543	687	S
		South Morang – Thomastown 1	549	604	S
		South Morang – Thomastown 2	549	604	S
		Thomastown – Brunswick 1	629	734	D
		Thomastown – Brunswick 3	741	741	D
		Thomastown – Ringwood	707	780	D
		Thomastown – Templestowe	685	764	D
		Templestowe – Rowville	762	762	D
		Thomastown – Rowville	550	605	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	613	716	D
		Rowville – Richmond 2	613	646	D
		Springvale – Heatherton 1	384	416	D
		Springvale – Heatherton 2	398	431	D
		Rowville – East Rowville 1	778	843	D
		Rowville – East Rowville 2	778	843	D
		East Rowville – Cranbourne 1	775	775	D
		East Rowville – Cranbourne 2	775	775	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	Rating type
Greater Melbourne and Geelong		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
	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	313	313	D
		Red Cliffs – Wemen	255	281	D
		Wemen – Kerang	255	280	D
		Horsham – Waubra	308	308	S
		Waubra – Ballarat	302	302	D
		Kerang – Bendigo	315	315	D
		Ballarat – Bendigo	248	362	D
		Ballarat – Terang	325	325	D
		Ballarat – Moorabool 1	366	436	D/W
		Ballarat – Elaine	587	587	S
		Elaine – Moorabool 1	420	420	S
		Terang – Moorabool	276	335	D
		Bendigo – Fosterville	483	491	D/W
		Fosterville – Shepparton	483	491	D/W
		Shepparton – Glenrowan 1	458	458	D
		Shepparton – Glenrowan 3	455	455	D

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	Rating type
		Shepparton – Dederang	297	350	D
Regional Victoria		Dederang – Glenrowan 1	493	541	D
		Dederang – Glenrowan 3	423	423	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 B-2 — High power from Victoria snapshot: DSN continuous and short-term ratings

Region	Voltage	Lines/transformers	Continuous rating (N)	Short–term rating (N–1)	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	1,110	1,110	D
		Dederang – South Morang 2	1,106	1,106	D
	220 kV	Dederang – Mt Beauty 1	470	576	D
		Dederang – Mt Beauty 2	465	570	D
		Mt Beauty – Dartmouth	230	230	S
		Mt Beauty – Bogong	323	323	D
		Mt Beauty – West Kiewa	97	97	S
		Elildon 220 kV – Thomastown 220kv 1	376	376	D
		Eildon – Mt Beauty 1	376	376	D
		Eildon – Mt Beauty 2	699	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

APPENDIX C - VICTORIAN NETWORK DEVELOPMENT

C.1 Introduction

This appendix outlines the preferred approach to locating and establishing new terminal stations in Victoria. It also lists the latest generation connection enquiries and proposed new terminal stations.

AEMO's policy and guidelines for establishing new terminal stations in Victoria[31] exist to streamline the process for connecting generators and loads, and to increase the economic efficiency of transmission network augmentations.

New terminal stations can be initiated by:

- A TNSP identifying the need for DSN augmentations to deliver future capacity requirements.
- Applications to connect generation or major loads to the DSN.
- Plans for new terminal stations necessary to meet distribution network demand, as outlined in the 2013 Transmission Connection Planning Report.[32]

C.2 Terminal station requirements and location

The need for a new terminal station can be initiated by:

- A TNSP identifying the need for DSN augmentations to deliver future capacity requirements.
- Applications to connect generation or major loads to the DSN.
- Plans for new terminal stations necessary to meet distribution network demand, as outlined in the 2013 Transmission Connection Planning Report.[32]

In determining a terminal station location, AEMO considers the following factors:

- For augmenting transmission capabilities or maintaining 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 overall net market benefits.
- For connecting new generation, AEMO identifies a preferred location and the connection applicant selects the location that best suits their needs.

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

- The requirements of connecting parties.
- Planned expansions of the 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.

[31] AEMO. Available at http://www.aemo.com.au/~/media/Files/Other/network_connections/0174-0018%20pdf.ashx.
[32] Jemena, CitiPower, Powercor, SP AusNet and United Energy. Available at http://www.sp-ausnet.com.au/CA2575630006F222/Lookup/Projects/$file/TCPR%202013.pdf.

C.3 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 including:

- Determining what to build in the initial stage of connection to the network (with future expansion 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.[33]

C.4 Potential locations for new terminal stations in Victoria

The main drivers for new terminal stations are generator connections to the 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 DSN capability), the current demand projections are not high enough to require new terminal stations to be developed within the next 10-years solely to augment DSN capability.

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

Table C-1 — Generation connection enquiries and applications

ID[a]	Project[a]	Generation type	Capacity (MW)	Location	Service date
W1	Ararat Wind Farm	Wind farm	240	Approximately 9–17 km north east of Ararat in Western Victoria.	TBA
W2	Berrybank Wind Farm	Wind farm	178	Approximately 16 km east of Lismore in Western Victoria.	TBA
W3	Hawkesdale Wind Farm	Wind farm	62	Approximately 4 km south of Hawkesdale in Western Victoria.	TBA
W4	Dundonnell Wind Farm	Wind farm	312	Dundonnell in Western Victoria connecting to Mortlake Terminal Station.	Late-2017
W5	Crowlands Wind Farm	Wind farm	82	Approximately 20–25 km North east of Ararat in Western Victoria.	TBA

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

ID[a]	Project[a]	Generation type	Capacity (MW)	Location	Service date
W7	Mt Gellibrand Wind Farm	Wind farm	189	Approximately 22 km north east of Colac in Western Victoria.	March 2017
W8	Penshurst Wind Farm	Wind farm	442	Approximately 13 km south of Penshurst in Western Victoria.	TBA
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.	Mid-2017
W11	Bald Hills Wind Farm	Wind farm	107	Approximately 12 km south east from Tarwin Lower in South Gippsland.	Late-2014
G2	Tarrone Gas Generator	OCGT	500–600	Approximately 50 km west of Heywood in Western Victoria.	TBA

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

More information on generation projects and project advancement criteria is available on AEMO's generation information page.[34]

To achieve 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 C-2 lists future terminal station locations selected to support this preference.

Table C-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	Ballarat–Waubra–Horsham 220 kV line, approximately 85 km from Horsham.	Ararat Wind Farm (17 km)	TBA
Mt Gellibrand Terminal Station	Moorabool–Tyabb 220 kV line, approximately 53 km from Moorabool.	Mt Gellibrand Wind Farm (5 km)	March 2017
Stockyard Hill Terminal Station	Moorabool–Heywood/Portland 500 kV No.1 or No. 2 line, approximately 94 km from Moorabool.	Stockyard Hill Wind Farm (50 km) Berrybank Wind Farm (22 km)	Mid-2017
Crowlands Terminal Station	Ballarat–Waubra–Horsham 220 kV line, approximately 75 km from Horsham.	Crowlands Wind Farm (1km)	TBA

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

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

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

Project	Driver	Service date
Deer Park Terminal Station	Offload Altona, Brooklyn, and Keilor terminal stations due to increased demand in the area.	Late-2017
Dandenong Terminal Station	Offload East Rowville and Heatherton terminal stations due to increased demand in the area.	After 2023
Donnybrook Terminal Station or Summerton Terminal Station	Offload Thomastown due to increased demand in the area.	After 2023

a) Jemena, CitiPower, Powercor, SP AusNet and United Energy. Available at http://www.sp–ausnet.com.au/CA2575630006F222/Lookup/Projects/$file/TCPR%202013.pdf.

APPENDIX D - KEY RIT-T FINDINGS

D.1 Introduction

This appendix outlines the key findings of the currently active RIT-Ts identified in Section 3.2. The detailed findings 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:

- 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[35], transmission line percentage loadings are based on standard continuous ratings and short-term ratings at 45 ºC 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 load shedding required both pre- and post-contingency to avoid the network limitation.[36] Energy at risk is the resulting unserved energy (USE).
- Expected USE, which is a portion of the energy at risk after taking into account the probability of forced outages.
- Limitation cost, which is the total additional cost due to both re-dispatching generators and the expected USE.

The DSN 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 USE, 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.

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

[36] 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.

D.2 Regional Victoria 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 2014–15.

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 ºC is 204 MVA (continuous) and 227 MVA (short term)[37], is limited by the conductor, and has a design operating temperature of 65 ºC. 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 ºC 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 preferred option, identified in the Project Assessment Conclusion Report (PACR) published in October 2013, is to install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2015–16 (stage 1), followed by installing the third Moorabool–Ballarat 220 kV circuit in 2017–18 (stage 2), and up-rating the Ballarat–Bendigo 220 kV line to a maximum operating temperature of 82 ºC in 2019–20 (stage 3).

This upgrade is expected to increase the combined capability of existing Moorabool–Ballarat lines by about 65% and increase the capability of the Ballarat–Bendigo 220 kV line by about 50%.

The total project cost, including operating costs, is estimated at $126.2 million (in present value terms). This reflects $93.0 million to address limitations on the Ballarat–Bendigo line and $33.2 million to address limitations on the Moorabool–Ballarat No.1 line.

Net market benefits over the life of the project are more than $317 million (in present value terms). Positive net market benefits would commence from the first year of operation.

Table D-1 — Forecast loading for 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%

[37] AEMO has reviewed assumptions in calculating the short-term ratings since the publication of the PACR and as a result the assumption on pre-contingent loading has been updated. The short-term ratings used for further assessment will differ from those published in the PACR and this VAPR.

Table D-2 — Forecast market impact for 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
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 their commercial and technical feasibility in the consultation period for the Project Assessment Draft Report (PADR). However, AEMO 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 – A 21 MW demand management program beginning in 2014–15.

RIT-T status

AEMO published the PACR in October 2013.

Subsequent to issuing the PADR and prior to publishing the PACR, AEMO received proposals from EnerNoc, NovaPower, and Transmission Operations Australia (TOA) on possible non-network solutions using demand management and embedded generation to minimise the potential USE. AEMO has discussed these proposals with all three entities but noted that it had insufficient information to consider these to be credible options at the time of the PACR publication.

To maximise the net market benefit from the investment, AEMO proposed in the PACR to commit to stages 1 and 2 of the preferred option and recommended that stage 3 be placed on hold, with the need and timing for this stage to be further assessed against recent proposals received from non-network service providers.

As no dispute was raised under NER clause 5.16.5(a), AEMO is now proceeding with procuring services to implement stages 1 and 2 of the preferred option as non-contestable augmentations.

An update to the PACR, which included a re-assessment of stage 3 was published in June 2014, considering recently received proposals from network and non-network service providers. The re-assessment indicates that the option with the highest net market benefit is to re-conductor the Ballarat to Bendigo 220 kV line in 2018–19, with a weighted net market benefit of $96.4 million.

The option which provides the second highest net market benefit is to contract generation (up to 120 MW in firm capacity) at Bendigo as a non-network option from 2016–17, with a weighted net market benefit of $92.6 million.

As the difference in net market benefits between these two options is very small, and considering the uncertainties in key assumptions such as option costs and lead times, AEMO will seek firm quotes on the network and non-network options via a request for firm offer and ITT respectively.

APPENDIX E - TRANSMISSION NETWORK LIMITATION DETAIL

E.1 Introduction

Information provided for each category

For limitations identified as priority assessments in Section 3.2.5, this appendix provides:

- The background, a description, and the operating conditions under which the limitation will occur.
- The impact, including the relevant constraint equation's binding hours over the past year (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 limitations AEMO is monitoring as identified in Section 3.2.6, this appendix provides:

- A description of the network limitation.
- A list of possible alleviation options.
- The indicative triggers.[38]
- A cross-check with the limitations identified in the 2013 NTNDP.

Sections E.2 to E.6 provide further detail on the limitations identified in sections 3.3.1 and 3.3.1 of the 2014 VAPR.

Transmission network limitation review approach

In assessing the impact of limitations, AEMO 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 of 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 load shedding required to avoid the network limitation. Energy at risk is the resulting USE.
- Expected USE, 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 USE.

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 market simulation testing. For this reason, DSN performance analysis results (the percentage loadings) can show more severe impacts than the market simulations.

AEMO derives forecast transmission plant loadings using load flow simulations, and develops load flow base cases for these simulations using the following inputs:

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

- The 10% probability of exceedance (POE) terminal station demand for maximum demand base cases. For more information, see 2013 Victorian Terminal Station Demand.[39]
- Historical maximum power transfers for a high Victoria to New South Wales power transfer base case.
- Typical generation dispatch and interconnector power transfer patterns 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 AEMO considers necessary for maintaining the power system in a satisfactory, secure, and reliable state during summer maximum demand periods.
- Standard continuous ratings and short-term ratings at 45 ºC and 0.6 m/s wind speed, unless otherwise indicated.[40]
- 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 schemes allow the lines to operate up to their five-minute short-term ratings.
- 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.[41]

AEMO bases the market impact of each network limitation 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 2013 NTNDP planning scenario.

For more information about the transmission network limitation review approach, see the Victorian Electricity Planning Approach.[42]

[39] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.
[40] 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.
[41] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand.
[42] AEMO. Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.

E.2 Eastern Corridor network limitations

Current RIT-Ts

No current RIT-Ts relate to the Eastern Corridor.

Priority limitations

No priority limitations relate to the Eastern Corridor.

Monitoring limitations

Table E-1 lists Eastern Corridor limitations that AEMO is monitoring.

Table E-1 — Limitations being monitored in the Eastern Corridor

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
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 identify 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.
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 identify 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.
Rowville–Yallourn 220 kV line loading	A new 500/220 kV transformer at Hazelwood with an estimated cost of $41 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 identify 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. The line upgrade is unlikely to be a contestable project.
Hazelwood 500/220 kV transformer loading	A new 500/220 kV transformer at Hazelwood with an estimated cost of $41 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 identify 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. The line upgrade is unlikely to be a contestable project.

E.3 South-west Corridor network limitations

Current RIT-Ts

No current RIT-Ts relate to the South-west Corridor.

Priority limitations

No priority limitations relate to the South-west Corridor.

Monitoring limitations

Table E-2 lists South-west Corridor network limitations that AEMO is monitoring.

Table E-2 — Limitations being monitored in the South-west Corridor

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
Moorabool–Heywood–Portland 500 kV line voltage unbalance[43]	A switched capacitor with individual phase switching at Heywood or near Alcoa Portland with an estimated cost of $12.6 million. A static VAr compensator (SVC) or a synchronous static compensator (STATCOM) at an estimated cost of $47.3 million. Additional transposition towers along the Moorabool – Heywood – Alcoa Portland 500 kV line at an estimated cost of $ 35.2 million.	New generation connections along the Moorabool – Heywood – Alcoa Portland 500 kV line potentially introduce voltage unbalance along the line. The impact of voltage unbalance levels increase in proportion to power flow magnitude and direction, new generation connection points, and output generated.	Limitation related to voltage quality. This limitation was not considered as part of 2013 NTNDP scope.	The switched capacitor and static VAr two options are likely to be contestable projects. The line transposition is unlikely to be a contestable project.
Voltage instability or collapse	New dynamic reactive compensation (for example, static VAr compensation) at Heywood or Alcoa Portland with an estimated cost of $47.3 million.	During a prior outage of the Heywood – Alcoa Portland 500 kV No.1 line. Vic–SA interconnector capacity upgrade to more than 650 MW.	Limitation related to voltage quality. This limitation was not considered as part of 2013 NTNDP scope.	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 $431.8 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 identified that this limitation arises during periods of high wind generation and thermal generation in Vic South-west corridor and high import from South Australia.	The new line is likely to be a contestable project.

[43] AEMO is organising for voltage unbalance monitoring equipment to be installed in the area. The data from the equipment will be used to review the magnitude of the limitation and possibly calibrate the simulation model to review the existing constraints. AEMO expects to conduct this review in 2014–15.

E.4 Northern Corridor network limitations

Current RIT-Ts

No current RIT-Ts relate to the Northern Corridor.

Priority limitations

No priority limitations relate to the Northern Corridor.

Monitoring limitations

Table E-3 lists Northern Corridor network limitations that AEMO is monitoring.

Table E-3 — Limitations being monitored it the Northern Corridor

Limitation	Possible network solution	Trigger	2013 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 NSW import and Murray generation.	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	These are both likely to be contestable projects.
Dederang – South Morang 330 kV line loadings	Up–rating the two existing lines 82 ºC (conductor temperature) operation and series compensation at an estimated cost of $15.9 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 NSW import and export.	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	The new line is likely to be a contestable project.
Dederang – Mount Beauty 220 kV line loading	Installing a wind monitoring scheme with an estimated cost of $514k or up-rating the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82 ºC, at an estimated cost of $23.7 million.	Increased NSW import and export.	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	These are unlikely to be contestable projects.

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
Eildon–Thomastown 220 kV line loading	Installing a wind monitoring scheme at an estimated cost of $514k or up-rating the Eildon–Thomastown 220 kV line, including terminations to 75 ºC operation, at an estimated cost of $75.7 million.	Increased NSW import and export.	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	This is unlikely to be a contestable project.
Dederang 330/220 kV transformer loading	Installing a fourth 330/220 kV transformer at Dederang at an estimated cost of $26.3 million.	At times of over 2,500 MW of imports from NSW and Murray generation (with the DBUSS transformer control scheme is active).	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	The new transformer 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 NSW import and export.	The NTNDP did not identify additional Vic–NSW interconnector capacity in the least cost generation and transmission expansion modelling study, and as such no requirement for this upgrade was noted.	These are unlikely to be contestable projects.

E.5 Greater Melbourne and Geelong network limitations

Current RIT-Ts

No current RIT-Ts relate to the Greater Melbourne and Geelong area.

The Eastern Metropolitan Melbourne Thermal Capacity RIT-T has been terminated based on AEMO's latest assessment using the 2013 demand forecasts. The limitation on the Rowville A1 500/220 kV transformer will be re-assessed in 2014–15 based on 2014 demand forecasts.

Priority limitations

Table E-4 to Table E-6 provide detail on the Greater Melbourne and Geelong area network limitation on which AEMO will conduct priority assessments.

Table E-4 — 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 Malvern area will lead to further increases in loading of the Rowville–Malvern 220 kV line 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 the circuits can be increased from a 15-minute rating to a 5-minute rating. Additionally, wind monitoring to allow for dynamic rating is expected to be installed on the Rowville–Malvern line in 2016–17.
Impact on transmission network performance	Under peak demand conditions in summer and following an outage of one of the Rowville–Malvern 220 kV lines, the remaining Rowville–Malvern 220 kV line is forecast to be loaded over its short-term (15-minute) rating from 2014. Unless the automatic load shedding scheme is enabled, pre-contingency load shedding may be required to ensure post-contingent loading remains within the thermal capability of the Rowville–Malvern 220 kV lines. With the scheme enabled, no pre-contingent load shedding is forecast to be required within the next five years, but load may 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 ºC are 204 MVA (continuous), 237 MVA (short term 15-minute) and 282 MVA (short term 5-minute). The installation of wind monitoring to allow for dynamic ratings will provide for additional capacity on these lines. Historical information suggests that the Rowville–Malvern No.1 and No.2 line may be unavailable for approximately 2.3 and 3.3 hours (respectively) annually per circuit due to unplanned outages.
Possible network options for alleviation	Three network options are being considered to alleviate this limitation: • Uprate the Rowville–Malvern 220 kV lines from 65 ºC to 82 ºC maximum conductor operating temperature at an estimated cost of $21.6 million. • Cut-in the Rowville–Richmond 220 kV No.1 and No.4 circuits at Malvern Terminal Station to form the Rowville–Malvern–Richmond No.3 and No.4 circuits at an estimated cost of $15.5 million. This option increases reliability of supply 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 $25.7 million. None of these options is likely to be a contestable project.
Forecast loading	(see below)
Non–network option	A load reduction, or new generation of 60 MW (44 MWh) at Malvern Terminal Station in 2014–15, is expected to delay the occurrence of this limitation by 12 months.
Conclusion	AEMO previously commenced a detailed assessment of all limitations in the south-east Melbourne area, including this limitation, in conjunction with the distribution businesses to identify and assess options to address these limitations and other limitations in the area. Due to the overall reduction in forecast demand growth, some assessments were put on hold and are scheduled to recommence mid–2014. 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.

Forecast loading

	2014–15	2015–16	2016–17[44]	2017–18	2018—19
N loading	64%	66%	64%	64%	66%
N–1 loading (15-minute rating)	111%	114%	110%	111%	113%
N–1 loading (5-minute rating)	89%	91%	88%	89%	90%

[44] Drop in forecast loading is due to the installation of wind monitoring facilities.

Table E-5 — 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 increase 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 and one 220/66 kV transformer at Springvale due to the configuration at Springvale Terminal Station. A loss of one Springvale–Heatherton 220 kV line will also lead to the loss of one 220/66 kV transformer at Heatherton due to the configuration at Springvale Terminal Station. 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 the circuits can be increased from a 15-minute rating to a 5-minute rating.
Impact on transmission network performance	Under peak demand conditions in summer and following an outage of one of the Rowville–Springvale 220kV lines, the remaining Rowville–Springvale 220 kV line is forecast to be loaded over its short-term (15-minute and 5-minute) rating from 2014–15. The loads at Springvale and Heatherton may be curtailed pre-contingent to ensure the post-contingent loading remains within the thermal capability of the Rowville–Springvale 220 kV line. Similarly, following the loss of one of the Rowville–Springvale 220 kV lines, the remaining Springvale–Heatherton 220 kV line is forecast to be loaded over its short-term (15-minute) rating from 2014–15. In addition, an outage of either of these double-circuit lines will result in total loss of supply to the relevant terminal station or terminal 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 may 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 ºC are: • Rowville–Springvale: 698 MVA (continuous), and 802 MVA (15-minute short term), and 882 MVA (5-minute short term). • Springvale–Heatherton: 349 MVA (continuous), and 405 MVA (15-minute 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 provides increased rating. Based on this effective wind speed of 0.72 m/s, the Rowville–Springvale 220 kV line has a 712 MVA (continuous), 840 MVA (15-minute short term) and 882 MVA (5-minute short term) rating at 45 ºC. Historical information suggests that: • Rowville–Springvale No. 1 circuit will be unavailable for approximately 1.92 hours annually due to unplanned outages. • Rowville–Springvale No. 2 circuit will be unavailable for approximately 2.92 hours annually due to unplanned outages. • Each Springvale–Heatherton circuit will be unavailable for approximately 2.96 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).

		2014–15	2015–16	2016–17	2017–18	2018—19
Forecast loading	Rowville–Springvale line					
	N loading	64%	66%	66%	67%	69%
	N–1 loading (15-minute rating)	109%	112%	113%	114%	116%
	N–1 loading (5-minute rating)	104%	106%	107%	109%	111%
	Springvale–Heatherton line					
	N loading	59%	60%	60%	61%	61%
	N–1 loading	102%	104%	103%	104%	106%

Possible network options for alleviation

Five network options are being considered to alleviate this limitation:

- Augment transformers, or change transformer switching configurations at Heatherton along with replacement of the limiting line assets on the Rowville–Springvale–Heatherton line.
- Install a third 220 kV line between Rowville and Springvale to increase the capacity by about 800 MVA at an indicative cost of $78.2 million. This line is a combination of approximately 5.5 km of underground cable and 1.7 km of overhead line with a lead time of 36 months.
- Install a new overhead double circuit 220 kV line between Cranbourne and Heatherton to increase the capability by approximately 800 MVA at an indicative cost of $90.5 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 indicative cost of $690 million, including 10 km of tunnelling.
- Install a new underground 220 kV cable between Malvern and Heatherton to increase the capability by approximately 400 MVA at an indicative cost of $393 million, including 8 km of tunnelling. This option increases the loading on the Rowville–Malvern 220 kV line which, due to the present and forecast Rowville–Malvern 220 kV line loading, will require additional works that have not been included in this cost.

The last four options are likely to be contestable projects.

Non-network option

A load reduction, or new generation of 35 MW (6.6 MWh) at the Springvale or Heatherton Terminal Station in 2014–15, is expected to delay the occurrence of this limitation by 12 months.

Conclusion

AEMO previously commenced a detailed assessment of all limitations in the south-east Melbourne area, including this limitation, in conjunction with the distribution businesses to identify and assess options to address these limitations and other limitations in the area. Due to the overall reduction on loads, some assessments were put on hold and are scheduled to recommence mid-2014. 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.

Table E-6 — Keilor – Deer Park – Geelong 220 kV line loading

Background	A joint regulatory test by AEMO, Powercor and Jemena was conducted to address constraints at terminal stations servicing Jemena and Powercor's distribution networks in the western Melbourne metropolitan area. The preferred option of the joint regulatory test was a new 220 kV terminal station at Deer Park which is planned to connect to the existing Geelong–Keilor No.2 220 kV line in 2017. The first stage of this project will involve installing two 225 MVA 220/66 kV transformers at Deer Park Terminal Station. Additional stages were also identified as part of the joint regulatory test to address N–1 limitations such as the Keilor – Deer Park – Geelong 220 kV line loading limitation.
Impact on transmission network performance	Under peak demand conditions in summer and following an outage of either the Keilor – Deer Park or Geelong – Deer Park 220kV line on a 45 ºC day, the remaining Keilor – Deer Park or Geelong – Deer Park 220 kV line is forecast to be loaded above its short-term (15-minute and 5-minute) rating. Pre-contingent load management may be required to ensure post–contingent loading remains within the thermal capability of the remaining Keilor – Deer Park – Geelong 220 kV line.
Technical details	The ratings for the Keilor – Deer Park 220 kV line at 45 ºC and assuming a 1.0m/s wind speed are 220 MVA (continuous), 228 MVA (15-minute short term) and 255 MVA (5-minute short term). The ratings for the Geelong – Deer Park 220 kV line at 45 ºC and assuming a 1.0 m/s wind speed are 220 MVA (continuous), 252 MVA (15-minute short term) and 339 MVA (5-minute short term). Historical information suggests that the Keilor–Geelong No.2 220 kV line may be unavailable for approximately five hours annually due to unplanned outages.

Forecast loading

	2017–18	2018–19	2019–20	2023–24
Keilor – Deer Park 220 kV line				
N loading	85%	86%	92%	100%
N–1 loading (15-minute rating)	115%	120%	129%	167%[45]
N–1 loading (5-minute rating)	103%	108%	116%	167%
Deer Park – Geelong 220 kV line				
N loading	35%	38%	41%	64%
N–1 loading (15-minute rating)	110%	116%	127%	150%
N–1 loading (5-minute rating)	81%	86%	94%	111%

Possible network options for alleviation	The following network options have been identified by a previous RIT-T to alleviate the overloading on the Keilor – Deer Park – Geelong 220 kV line: • Connection of second 220 kV line (Keilor – Geelong No.1) at Deer Park at a cost of $12 million. • Two 100 MVAr capacitor banks at Deer Park at a cost of $12.5 million.
Non–network option	A load reduction, or new generation of 4 MW (0.3 MWh) at the Deer Park Terminal Station in 2014–15, is expected to delay the occurrence of this limitation by 12 months.
Conclusion	AEMO, in consultation with Powercor and Jemena will review this limitation as well as the timing of options identified in the previous RIT-T in 2014–15.

[45] Overload is based on continuous rating, the as short-term rating is not available when the N loading is at 100%.

Table E-7 — Rowville A1 500/220 kV transformer loading

Background	The Rowville A1 500/220 kV tie transformer is a key component in supplying electricity from the 500 kV transmission network to the Eastern Melbourne Metropolitan Area. In particular, the Rowville A1 transformer supplies load to the radial connection points at Malvern, Springvale, and Heatherton Terminal Stations, and with support from Thomastown Terminal Station. It also supplies load to the connection points at the Ringwood and Templestowe Terminal Stations in Melbourne's inner eastern suburbs.
Impact on transmission network performance	Depending on Yallourn Power Station generation, overloading of the Rowville transformer can occur during peak demand conditions with all transmission plant in service. With the Yallourn Power Station generating at 100% of capacity, and supplying electricity directly to the 220 kV network, the Rowville A1 transformer is expected reach its load carrying capacity by approximately 2020–21. During the critical contingency (outage of Cranbourne A1 500/220 kV transformer), loading on the Rowville A1 500/220 kV transformer will remain with its short-term rating over next 10 years, but post–contingent action must be taken within 30 minutes. This requires the load supplied to the Cranbourne, East Rowville, and Tyabb Terminal Stations to be constrained to bring the Rowville transformer loading back within its continuous rating.
Technical details	The Rowville A1 500/220 kV transformer is rated at 1,000 MVA (continuous), 1,250 MVA (for two hours) and 1,500 MVA (for 30 minutes). Historical information suggests that the Rowville transformers will be unavailable for approximately 16.38 hours annually per transformer due to unplanned outages.
Forecast loading	See table below
Possible network options for alleviation	Four network options are being considered for alleviating this limitation: • Installation of a second 500/220 kV 1,000 MVA transformer at Cranbourne, with an indicative cost of $51.5 million • Installation of a third 500/220 kV 1,000 MVA transformer at Rowville, with an indicative cost of $52.4 million • Establishing a new 500 kV switchyard at Ringwood Terminal Station by connection (cut-in) of existing Rowville – South Morang 500 kV line at Ringwood, and installation of the first 500/220 kV 1,000 MVA transformer at Ringwood, with an indicative cost of $107.9 million. • Establishing a new 500 kV gas-insulated switchyard at Templestowe Terminal Station by connection (cut-in) of existing Rowville – South Morang 500 kV line at Templestowe, and installation of the first 500/220 kV 1,000 MVA transformer at Templestowe, with an indicative cost of $187 million.
Non-network option	A load reduction, or additional generation, of 16 MW at Malvern and Ringwood in 2014–15, is expected to delay the occurrence of this limitation by 12 months.
Conclusion	The market benefit associated with the identified network options is sufficient to justify augmentation by approximately 2021–22 which is beyond the augmentation project lead time as an outcome from Eastern Metropolitan Regional Thermal RIT-T. AEMO will review this limitation as well as the options and their timing in 2014–15.

Forecast loading:

	2015–16	2018–19	2020–21	2022–23
N Loading	88%	97%	101%	104%
N–1 Loading (30 minutes)	69%	76%	80%	82%

Monitoring limitations

Table E-8 lists the Greater Melbourne and Geelong limitations that AEMO is monitoring.

Table E-8 — Limitations being monitored in Greater Melbourne and Geelong

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
Inadequate reactive power support in Metropolitan Melbourne	Additional reactive power compensating plant installation.	Increased demand in Metropolitan Melbourne.	2013 NSCAS study identified deferral of additional reactive support in Metropolitan Melbourne area beyond 2018–19.	It is unlikely that this would be a contestable project.
Rowville–Ringwood 220 kV line loading.	Connection of Ringwood Terminal Station to the existing Rowville–Templestowe 220 kV line.	Load growth or additional loads connected to Ringwood Terminal Station.	The NTNDP identified that this limitation occurs in the 2018–19 to 2022–23 period.	The line cut-in is unlikely to be a contestable project.
Ringwood–Thomastown 220 kV line loading.	New (third) 500/220 kV transformer at Rowville, with an estimated cost of $52.4 million, plus any fault level mitigation works. This option was identified as part of the Eastern Metropolitan Melbourne Thermal Capacity RIT-T.	Load growth or additional loads connected to Ringwood Terminal Station.	The NTNDP identified that this limitation occurs in the 2018–19 to 2022–23 period.	The new transformer is likely to be a contestable project.
Templestowe–Thomastown 220 kV line loading	Cut-in the Thomastown–Ringwood 220 kV line at Templestowe (cost to be estimated in 2014–15), or a new (third) 500/220 kV transformer at Rowville, with an estimated cost of $52.4 million, plus any fault level mitigation works.	Load growth around the Melbourne Metropolitan area.	The NTNDP that this limitation was likely to require augmentation in the 2018–19 to 2022–23 period.	The line cut-in is unlikely to be a contestable project. The new transformer is likely to be a contestable project.
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 $56.5 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 $74 million, plus any fault level mitigation works.	Additional export capability from Vic to NSW.	No requirement for this upgrade was identified.	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 NSW.	The NTNDP identified that this limitation occurs in the 2028–29 to 2032–33 period.	This is unlikely to be a contestable project.

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
South Morang–Thomastown No.1 and No.2 220kV line loading	New (third) 500/220 kV transformer at Rowville, with an estimated cost of $52.4 million, plus any fault level mitigation works. This option was identified as part of the Eastern Metropolitan Melbourne Thermal Capacity RIT-T.	Load growth around the Melbourne Metropolitan area.	The NTNDP identified that this limitation occurs in the 2028–29 to 2032–33 period.	The new transformer is likely to be a contestable project.
Keilor–Thomastown 220 kV No.1 line loading	Up-rate the Keilor–Thomastown 220 kV No.1 line to 82 ºC conductor temperature (800 MVA at 35 ºC ambient temperature), with an estimated cost of $10.3 million, or install a new (third) 1,000 MVA 500/220 kV transformer at Rowville, with an estimated cost of $52.4 million, plus any fault level mitigation works.	Load growth around the Melbourne Metropolitan area.	The NTNDP identified an additional 500/220 kV transformer in the Eastern Metropolitan Melbourne area. This would remove overloading on the Keilor–Thomastown 220 kV line.	The line upgrade is unlikely to be a contestable project. The new transformer is likely to be a contestable project.
Keilor 500/220 kV A2 transformer loading	Install a fourth Keilor 750 MVA 500/220 kV transformer at an estimated cost of $45.2 million.	Demand in Geelong and the Western Melbourne Metropolitan area.	The NTNDP identified an additional 500/220 kV transformer in the Western Metropolitan area in the 2028–29 to 2032–33 period.	The new transformer is likely to be a contestable project.
Cranbourne A1 500/220 kV transformer loading	A new 500/220 kV transformer at Cranbourne Terminal Station with an estimated cost of $85.3 million.	Load growth around the Eastern Melbourne Metropolitan area.	The NTNDP identified that this limitation occurs in the 2018–19 to 2022–23 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 and driven by increased demand and impedance changes from connecting new network plant and generation.	This limitation related to fault levels which is not within the 2013 NTNDP scope.	These works are unlikely to be contestable.
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 regions.	2013 NTNDP modelled replacement of limiting station assets at Geelong Terminal Station.	These works are unlikely to be contestable.

E.6 Regional Victoria network limitations

Current RIT-Ts

Current RIT-Ts involving Regional Victoria include the following:

- Regional Victorian Thermal Capacity Upgrade RIT-T.

More detail on the above RIT-T is available in Appendix D.

Priority limitations

Table E-9 below provides detail on the Regional Victorian region network limitation on which AEMO will conduct priority assessments.

Table E-9 — Dederang–Shepparton 220 kV line loading

Background	Once the existing Moorabool–Ballarat 220 kV line and Ballarat–Bendigo 220 kV line limitations are removed as part of the Regional Victoria Thermal Upgrade RIT-T, the ratings of this line may then start to cause congestion under peak loading conditions. For the contingency of a Dederang–Glenrowan 220 kV line, the loading of the Dederang–Shepparton circuit may exceed its short-term thermal rating.
Impact on transmission network performance	Within the next five years, under Victorian maximum demand conditions, when a Dederang–Glenrowan 220 kV line trips, the loading of the Dederang–Shepparton circuit may exceed its short-term thermal rating. The loading on the Dederang–Shepparton lines can be reduced by re-dispatching generation and limiting import from NSW, but this may increase Victorian market prices due to the need to dispatch higher-cost plant in Vic, SA, and Tas. Also during high demand periods, the output from generating units which can be used to reduce the loadings of the Dederang–Shepparton line may have already been maximised. Under this situation, involuntary load reduction will occur.
Technical details	The Dederang–Shepparton 220 kV line is rated at 204 MVA (continuous) and 211 MVA (for 15 minutes) at 45 ºC. The line has dynamic line ratings installed, but not with wind monitoring. Historical information suggests that the: • Dederang–Glenrowan 220 kV no.1 line will be unavailable for approximately 5.2 hours annually due to unplanned outages. • Dederang–Glenrowan 220 kV no.3 line will be unavailable for approximately 4.2 hours annually due to unplanned outages.
Forecast Loading	see below
Possible network options for alleviation	• Install wind monitoring at an estimated cost of $0.6 million • Install a phase angle regulating transformer on the Bendigo–Fosterville–Shepparton 220 kV line at an estimated cost of $44.2 million. • Up-rate the existing Dederang–Shepparton conductors from 65 ºC to 82 ºC rated conductor temperature at an estimated cost of $60.7 million. • Replace the existing Dederang–Glenrowan 220 kV lines with a new double circuit line at an estimated cost of $117.7 million (AEMO cost estimate) • Replace the existing Dederang–Shepparton 220 kV line with a new double circuit line at an estimated cost of $260 million.
Non-network option	A load reduction, or new generation of 74 MW (78 MWh) at the Shepparton terminal station in 2014–15, is expected to delay the occurrence of this limitation by 12 months.
Conclusion	The preliminary economic analysis indicates that installation of wind monitoring would be justified to relieve this limitation. AEMO will investigate this limitation further in consultation with SP AusNet.

Forecast Loading

	2014–15	2015–16	2016–17	2017–18	2018–19
N loading	78%	80%	81%	79%	80%
N–1 loading	100%	102%	104%	101%	102%

Table E-10 — Ballarat–Horsham 66 kV line loading

Background	An outage of either the Horsham – Red Cliffs or Ballarat–Horsham 220 kV line can result in the 66 kV loads being fed radially from either the Horsham or Ballarat ends. This increases loading on the Ballarat–Horsham 66 kV line which consists of five line sections.[46] Limitations on the Ballarat–Horsham 66 kV line sections are driven by: • High wind penetration in the Horsham and Ballarat area with the limiting element being the Ararat – Challicum Hills 66 kV line section. • Local demand. Currently, the 66 kV line is manually split during planned outages. This splits Challicum Hills generation into the Horsham or Ballarat ends thereby reducing loadings on the 66 kV network.
Impact on transmission network performance	Preliminary analysis[47] indicates that the Ararat – Challicum Hills 66 kV line section may exceed its short-term thermal rating for outages on the Horsham – Red Cliffs or Ballarat–Horsham 220 kV lines. The level of overload is dependent on various factors including generation levels, demand and interconnector flows. Other Ballarat–Horsham 66 kV line sections are also being investigated for potential limitations.
Technical details	The summer rating of 43.4 MVA (continuous) was used for the Ararat – Challicum Hills 66 kV line. Each section of the 66 kV tie has a different rating and AEMO is confirming the ratings with Powercor. Historical information suggests that the: • Horsham – Red Cliffs 220 kV line will be unavailable for approximately 7.5 hours annually due to unplanned outages. • Ballarat – Horsham 220 kV line will be unavailable for approximately 5.4 hours annually due to unplanned outages.
Forecast loading	The forecast loading on the Ararat – Challicum Hills 66 kV line section are presented below.
Possible network options for alleviation	Upgrade the Challicum Hills – Ararat 66 kV line (project cost will be established in 2014–15).
Non–network option	Automatic post-contingent bus splitting scheme at Challicum Hills for outage of the Horsham – Red Cliff or Ballarat–Horsham 220 kV lines. The total cost of this scheme is estimated to be less than $300k and will be further investigated in 2014–15.
Conclusion	AEMO, in consultation with Powercor will review the ratings and limitations on the Ballarat–Horsham 66 kV line sections including options and their timing in 2014–15.

	2014–15	2015–16	2016–17	2017–18	2018–19
N loading	77%	79%	79%	79%	81%
N–1 loading	96%	99%	100%	102%	104%

[46] Ballarat – Ballarat North, Ballarat North – Challicum Hills, Challicum Hills – Ararat, Ararat–Stawell and Stawell–Horsham.
[47] Based on presently available operational ratings which AEMO is confirming with Powercor.

Monitoring limitations

Table E-11 below lists the Regional Victoria limitations that AEMO is monitoring.

Table E-11 — Limitations being monitored in Regional Victoria

Limitation	Possible network solution	Trigger	2013 NTNDP status	Contestable project status
Inadequate reactive power support	Staged installation of additional reactive power support in Regional Victoria. Load reduction or new generation in Regional Victoria, such as Bendigo, Kerang, Fosterville, Red Cliffs and Wemen Terminal Station.	Increased demand and/or decrease in power factor in Regional Victoria.	2013 NSCAS study identified deferral of additional reactive support in Regional Victoria beyond 2018–19.	Additional reactive support is unlikely 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 $50.4 million.	Increase in load growth in Geelong and Regional Victoria or high import from SA or increased generation in the South-west Corridor	The NTNDP identified that this limitation occurs in the 2028–29 to 2032–33 period.	The new transformer is likely to be a contestable project.
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 $44.2 million, or up-rate the existing conductor from 82 ºC to 90 ºC at an estimated cost of $57.6 million.	Increased demand in Regional Victoria and/or increased import from NSW.	Significant wind and solar generation developments in CVIC[48] region and no requirement for any increased import from NSW 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 $44.2 million; or replace the existing Dederang–Glenrowan 220 kV lines with a new double circuit line (project cost will be established in 2014–15); 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 NSW.	Significant wind and solar generation developments in CVIC[48] region and no requirement for any increased import from NSW 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.

[48] CVIC refers to Regional Victoria in the NTNDP context.

Limitation	Possible network solution	Trigger	2013 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 $44.2 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 CVIC region and no requirement for any increased import from NSW 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 2014–15), 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 identified that this limitation occurs if high proportion of the new wind generation is built at Horsham or along Ballarat–Horsham and Horsham – Red Cliffs corridors.	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 identified that this limitation occurs, if high proportion of the new wind generation is built at Red Cliffs or along Red Cliffs – Kerang corridor.	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 $59.6 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.	The NTNDP identified that this limitation occurs if high proportion of wind generation is built at Terang or Moorabool–Terang corridor.	The new transmission line 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 location-based and driven by increased demand and impedance changes from connecting new network plant and generation.	This limitation is related to fault levels, which is not within the 2013 NTNDP scope.	These works are unlikely to be contestable projects.

APPENDIX F - DISTRIBUTION NETWORK SERVICE PROVIDER PLANNING

This appendix lists the preferred connection modifications from the 2013 Transmission Connection Planning Report[49], and the potential DSN impacts and considerations.

Table F-1 — Distribution network service provider planning impacts

Location/terminal station	Preferred connection modification	DSN impacts and considerations
Altona 66 kV	Load transfer to the proposed Deer Park Terminal Station in 2017.	This will increase line flows in the Western Melbourne Metropolitan area transmission loop and has been taken into consideration in AEMO's assessment of upcoming limitations in Greater Melbourne and Geelong in Chapter 3.
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 taken into consideration in AEMO's assessment of upcoming limitations in Greater Melbourne and Geelong in Chapter 3.
Cranbourne 66 kV	Install a fourth Cranbourne 150 MVA 220/66 kV transformer by summer 2022–23.	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 after summer 2022–23 to meet local demand and offload the Heatherton 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 Heatherton terminal station 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 to Deer Park Terminal Station will increase line flows in the Western Melbourne Metropolitan Area transmission loop and has been taken into consideration in AEMO's assessment of upcoming limitations in Greater Melbourne and Geelong in Chapter 3.
East Rowville 66 kV	Load transfer to the proposed Dandenong Terminal Station after 2023.	Load transfer from East Rowville will impact power flows in the 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 2020.	Placing the third transformer on load will increase the 66 kV fault levels, although this increase will be mitigated by the normally open bus–tie.

[49] 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	DSN impacts and considerations
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 before 2022.	This may impact emergency load shedding groups and will be assessed in detail closer to the proposed installation date.
Keilor 66 kV	Install a 100 MVAr capacitor bank on the Keilor Terminal Station (B34) group prior to summer 2015–16. Load transfer to the proposed Deer Park Terminal Station from 2017.	Installing capacitor banks at the 66 kV level will reduce the DSN's reactive power requirements. AEMO will consider 66 kV reactive power support when planning the DSN's reactive power needs.
Morwell 66 kV	Install a fourth 220/66 kV transformer after 2021–22 (assuming Bairnsdale and Morwell power stations are available).	This will increase the 66 kV fault levels.
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 2015–16. 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 taken into consideration in AEMO's assessment of upcoming limitations.
Wemen 66 kV	Install a second 220/66 kV transformer after 2018.	The 66 kV fault levels will increase and are expected to remain within ratings without mitigation measures.
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 taken into consideration in AEMO's assessment of upcoming limitations.

APPENDIX G - SP AUSNET ASSET RENEWAL PLAN

This appendix outlines SP AusNet's transmission asset renewal process and provides a list of their planned asset renewal projects for the next 10-year period.

SP AusNet's asset renewal plan is based on asset performance and condition and failure risk, as well as other operational factors affecting the assets' economic life. Information about how asset renewals are integrated into augmentation planning is available on AEMO's website.[50]

Asset renewal objectives

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

- Safety of customers, the community, and workers.
- Quality, reliability, and security of electricity transmission services.
- Compliance with regulation, codes, licences, contracts, and industry standards.
- Future quality, reliability, and security of supply performance risks.
- Minimising total lifecycle costs by considering capital, maintenance, and operational risk costs.
- Minimising the volatility of renewal works and associated material, skill, and revenue requirements.
- Minimising project delivery risks and the potential impact of renewal works on network availability, market participants, and connected parties.
- Minimising immediate and future environmental impacts.
- Minimising network security risks by replacing obsolete protection and control equipment no longer supported by manufacturers.
- Modernisation of protection and control systems to provide remote interrogation and diagnostics.

Asset renewal options

The following options are considered in the evaluation of asset renewal:

- **Replace–upon–Failure** is only employed in circumstances where the impact of asset failure on network performance, health, safety, and 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 of health, safety, and environmental factors as well as community cost based on the asset performance. This option 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 most 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.

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

- **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.

SP AusNet 10-year asset renewal plan

SP AusNet's 10-year plan (in calendar years) focuses on major asset renewal projects. The scope of works listed in Table G-1 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 (2014–17). 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 G-1 — SP AusNet 10-year asset renewal plan (cost estimates are in 2014 dollars)

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
KGTS SVC thyristors and control upgrade	KGTS	Upgrade thyristors and thyristor controls on static VAr compensator.	5	2014
Station Control Systems Replacement	Various	Upgrade RTU and circuit breaker (CB) controls at ATS, HWTS, HWPS, YPS and LYPS B.	5	2014
OPGW on ROTS–RTS via MTS	ROTS–RTS Line	Install 11 km of OPGW on ROTS–RTS Line via MTS.	5	2014
Synchronous Condensers Refurbishment – stage one	FBTS, TSTS, BLTS	Synchronous Condenser auxiliary and safety systems replacement and upgrade.	5	2014
DDTS H1 330/220 kV Transformer Replacement	DDTS	Replace the H1 ACEC 225/340 MVA 330/220 kV transformer.	17	2014
ERTS Switchgear Replacement	ERTS	Replace 220 kV current transformers (CTs) and three 66 kV bulk oil CBs.	3	2014
GTS B1 and B3 Transformer and 66 kV CB Replacement	GTS	Replace B1 and B3 transformers with 150 MVA 220/66 kV transformers. Replace four 66 kV bulk oil CBs.	21	2014
MWTS B2 Transformer Replacement	MWTS	Replace B2 transformer with a 150 MVA 220/66 kV transformer and replace four 66 kV single phase CVTs.	8	2014
ROTS 220 kV CB Replacement	ROTS	Replace seven 220 kV bulk oil CBs and install new CB management system.	17	2014
TTS 66 kV Bus Tie CB Replacement	TTS	Replace Bus 1–2 and Bus 3–4 66 kV Bus Tie CBs at TTS.	2	2014

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
OPGW TBTS–JLA	TBTS–JLA Line	Install Optical Ground Wire (OPGW) on TBTS–JLA line to replace copper supervisory cable – 2.4 km.	2	2015
Replace BLTS Synchronous Condenser AVR	BLTS	Replace obsolete Automatic Voltage Regulator (AVR) for Synchronous Condenser at BLTS.	2	2015
Replace Synchronous Condenser control circuits	TSTS and FBTS	Replace Synchronous Condenser control circuits.	3	2015
GNTS B1 220/66 kV transformer, 220 kV CB and 66 kV CB Replacement	GNTS	Replace B1 220/66 kV transformer, eight 220 kV air blast CBs, three 66 kV CBs and install new protection and CB management systems.	30	2015
Synchronous Condensers Protection Replacement	BLTS, FBTS and TSTS	Replace synchronous condenser (SCO) protection systems	3	2015
Replace 22 kV Switchgear at RCTS and KGTS	RCTS KGTS	Replace 22 kV switchgear at RCTS and KGTS	4	2015
RWTS 220 kV CB Replacement	RWTS	Replace nine 220 kV bulk oil CBs and provide new CB management system.	21	2015
SHTS 66 kV CB Replacement	SHTS	Replace four 66 kV bulk oil CBs.	2	2015
HWPS 220 kV CB Replacement – stage three	HWPS	Replace eleven bulk oil CBs.	8	2016
All–dielectric Self Support (ADSS) cable Replacement Program	Network	Replace end-of-life ADSS cables except in LV. Replace ADSS FBTS–Mary St., replace ADSS RWTS–TSTS, replace ADSS TSTS–ELM–WT–TTS, replace ADSS RWTS–BRA, replace ADSS TTS–BTS, replace ADSS NPSD–Yarraville–BLTS, replace ADSS HTS–MTS and replace ADSS HTS–SVTS.	10	2016
Latrobe Valley supervisory cable upgrade	Latrobe Valley	Replace copper cable with Optical Ground Wire (OPGW and miscellaneous communication works. XA76 – Replace Copper Supervisory Cables with OPGW – HWPS, MPS, MWTS, JLTS, HWTS and YPS. XA22 – Install OPGW YPS–YWPS 1/2, YPS–YWPS 3/4 and between YWPS Comms Building, X864 – Install 58 km of OPGW HWTS–LYPS.	13	2016
Current Transformer Replacements	HWTS, LY	Replace selected 500 kV CTs at HWTS and selected 66 kV CTs at LY.	5	2016
SMTS 330/220 kV Transformer Replacement – stage one	SMTS	Replace the H2 transformer with a new 750 MVA 330/220 kV transformer and retain the existing H2 FERRANTI 330/220 kV transformer as a cold spare transformer.	34	2016
YPS 220 kV CB Replacement stage one	YPS	Replace seven minimum oil 220 kV CBs and the associated oil CTs.	21	2016
HYTS–SESS Line Communications	HYTS, SESS	Install 91 km of fibre cable between HYTS and SESS.	6	2017

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
Install 500 kV CB Management Relays at KTS	KTS	Install 500 kV CB Management Relays for seven CBs.	5	2017
HTS Redevelopment	HTS	Replace B1, B2 and B3 transformers with 150 MVA 220/66 kV transformers, two 220 kV minimum oil CBs and eleven 66 kV bulk oil CBs. Replace associated protection and control systems.	59	2017
RTS Redevelopment	RTS	Replace existing infrastructure with three 225 MVA 220/66 kV transformers, three breaker-and-half 220 kV GIS switchbays, four 66 kV GIS busses, 22 kV switchboard and associated protection and control systems.	175	2017
Transmission fall arrest installation program	Line	Transmission cable fall arrest installation program on 4500 EHV towers (220 kV towers in country areas and 330 kV flat Delta Towers – DDTS–SMTS 1 and 2 lines).	20	2017
Transmission line insulator replacement	Line	Transmission line insulator replacement on Priority 2 insulators (4,385 strings from selected lines with 20 mm pins and the rest of 16 mm pin insulators).	5	2017
ROTS No.2 SVC Controls Replacement	ROTS	Replace SVC controls on ROTS No.2 SVC.	2	2017
Transmission conductor replacement	Line	Transmission conductor replacement on HYTS–APD Nos 1 & 2; CBTS–TBTS; GTS–PTH; HWPS–HWTS; HWPS–ROTS 1 & 2; YPS–ROTS 5 & 6; YPS–ROTS Aux A & B. Ground wire replacement on KTS–WMTS; ROTS–MTS; SVTS–HTS; NPSD–BLTS; RWTS–TTS lines (20km of ground–wire and conductor in total).	10	2017
DDTS–SMTS No.1 and 2 330 kV Line Tower Replacement	Line	Replace up to 24 selected towers on the SMTS–DDTS No.1 and 2 330 kV lines.	20	2017
Operational Support Refresh	Network	Replace end-of-life support system and remote network management system. Integrate Communication Assets into Geospatial Information System (GIS). Upgrade electricity transmission communication network management systems. Consolidate communication data and standardise design drawings. Upgrade Intelligent Electronic Device (IED) Communications software. Create an out-of-band network for management of communication devices. Update the asset management system with new communication asset data as part of completion of works.	4	2017
Transmission fall arrest installation program on rack structures inside terminal stations	Line	Transmission fall arrest installation program on rack structures inside terminal stations, stage one Metro Stations.	2	2017
FBTS 220 kV and 66 kV CB Replacement stage one	FBTS	Replace one minimum oil 220 kV CB, six 66 kV bulk oil and three 66 kV minimum oil CBs.	20	2018
HWPS 220 kV CB Replacement – stage four	HWPS	Replace the remaining seven 220 kV bulk oil CBs and install remote operated isolators.	24	2018

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
PLC replacement	MBTS, DPS, RCTS, BSS	Replace Power Line Carrier on MBTS–DPS and RCTS–BSS lines (required for protection). Mt Beauty to Dartmouth (41 km) and Red Cliffs to Buronga (21 km) in NSW.	3	2018
Replace 1990 vintage line differential protections.	Various	Replace obsolete Siemens 7SD511, GEC LFCB and Mitsubishi MCD line current differential protection relays at ATS, BLTS, ERTS, FBTS, HWPS, KTS, MTS, NPSD, ROTS, RWTS, SMTS, SVTS, TSTS, TTS, and YPS.	19	2018
SVC Protection Replacement	KGTS, HOTS and ROTS	Replace obsolete SVC Protection Relays at KGTS, HOTS and ROTS (ROTS – No.1 SVC & No.2 SVC).	4	2018
HOTS SVC Controls Replacement	HOTS	Replace Static VAr Compensator (SVC) controls at HOTS.	2	2018
KTS A4 500/220 kV and B4 220/66 kV Transformer Replacement	KTS	Replace A4 English Electric transformer with a 750 MVA 500/220 kV transformer. Replace B4 English Electric transformer with a 150 MVA 220/66 kV transformer. Install new transformer protection.	48	2019
RWTS B4 220/66 kV Transformer and 66 kV CB Replacement	RWTS	Replace B4 220/66 kV transformer and six 66 kV bulk oil CBs.	16	2019
BETS–KGTS Line Communications	BETS–KGTS Line	Replace ground wire with Optical Ground Wire (OPGW) or Radio link BETS–KGTS 123 km.	13	2019
OTN Replacement program	Network	Replace end-of-life Operational Telephony Network at 48 terminal stations.	5	2019
HOTS 66 kV CB Replacement	HOTS	Replace five 66 kV bulk oil CBs, one 66 kV LTCB and provide new protection and CB Management.	4	2019
Synchronous Condensers Refurbishment – stage two	FBTS, TSTS, BLTS	Synchronous Condenser machine and auxiliary systems refurbishments.	9	2019
WMTS Redevelopment	WMTS	Replace three 150 MVA 220/66 kV transformers (B1, B2 & B3), seven 220 kV switch bays, 16 x 66 kV switch bays, 22 kV switch boards and all protection and control systems with GIS located in buildings.	207	2019
Upgrade SCADA at Non–SCIMS and Old SCIMS Sites	Various	Upgrade SCADA at Non–SCIMS and old SCIMS sites at 12 Stations – NPSD, KTS (500 kV & 220 kV), SMTS, SYTS, MLTS, JLTS, ROTS, LYPSA, ERTS, SVTS, TBTS and TSTS.	12	2019
LV ADSS replacement	HWTS, MWTS, YPS, TH5	Replace ADSS in Latrobe Valley 40 km.	3	2019
OPGW on FTS–CBTS (Tower 87)	FTS–CBTS Line	Install 8.2 km of Optical Ground Wire (OPGW) on FTS–CBTS Line to Tower 87 to provide communications link to FTS.	2	2019
Computer Network replacement (Operational Data Network)	Network	Replace end-of-life and unsupported network technology with a modern standards based system.	15	2020

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
BLTS 220 kV, 66 kV and 22 kV CB Replacement	BLTS	Replace four 220 kV minimum oil CBs, five minimum oil 66 kV CBs and two bulk oil 22 kV CBs.	43	2020
Current Transformer Replacements	HWTS, LYPS	Replace selected 500 kV CTs at HWTS and LYPS.	4	2020
Serial Server Replacement Program	Network	Replace 74 end-of-life serial servers for Asset Data Gathering.	5	2020
Comms battery upgrade and replacement program	Network	Upgrade and replace 100 end-of-life communications batteries and battery chargers.	5	2020
Replace PLCs on Network Control Schemes (DBUSS, VFRB & BARBS)	Various	Replace Programmable Logic Controllers on Network Control Schemes (DBUSS, VFRB & BARBS) at various locations.	2	2020
Replace Load Shedding Schemes	Various	Replace load shedding schemes at 24 stations.	2	2020
DC Supply Upgrade stage three	Various	Upgrade the DC Supply at stations not covered by X803 & XA29 (BATS – 50VDC COMMS A&B; ERTS – 50VDC COMMS A&B; FTS – 250VDC Supply; FTS – 50VDC Control Supply; KGTS – 50VDC COMMS A&B; SHTS – 50VDC COMMS A&B; SMTS – 250VDC Y Supply (500 kV RLY HOUSE); SMTS – 50VDC COMMS A&B; SMTS – 125VDC X&Y Supplies (Series Capacitor bank control building) and SYTS – 50VDC COMMS A&B).	14	2020
Radio Replacement program	Network	Replace end-of-life radio links (65).	5	2020
Digital Multiplexing equipment replacement program	Network	Replace end-of-life digital multiplexing equipment (180).	19	2020
Replace CB programmable logic controllers	Various	Replace 525 obsolete PLCs for CB controls at various terminal stations: ATS, BATS, BETS, BLTS, CBTS, DDTS, ERTS, FTS, FVTS, GNTS, GTS, HOTS, HWTS, HYTS, KGTS, KTS, LY, LYPS, LYPSB, MBTS, MLTS, MTS, MWTS, RCTS, ROTS, RWTS, SHTS, SMTS, SVTS, TBTS, TGTS, TTS, WBTS & WETS.	6	2020
WBTS–HOTS Line Communications	WBTS–HOTS Line	Install 141 km ofOptical Ground Wire (OPGW) on WBTS–HOTS line.	14	2020
Replace Energy Metering	Various	Replace 488 Obsolete EDMI Energy Meters at various terminal stations: APD, ATS, BATS, BETS, BLTS, CBTS, DDTS, DPS, ESPY, ERTS, FBTS, FVTS, GNTS, GTS, HOTS, HWPS, HYTS, JLTS, KGTS, KTS, LY, LYPSA&B, MBTS, MKPS, MPS, MTS, MWTS, NPSD, PTH, RCTS, RWTS, SHTS, SMTS, SVTS, TBTS, TGTS, TRTS, TSTS, TTS, WBTS, WETS, WKPS, WOTS & YPS.	5	2020
Replace weather stations at terminal stations	Various	Replace weather stations at 22 terminal stations: BATS, BETS, DDTS, EPS, GNTS, GTS, HOTS, HWTS, HYTS, KGTS, KTS, Mary St., MBTS, MLTS, RCTS, ROTS, RTS, SHTS, SVTS, TGTS, WOTS & YPS.	6	2020

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
MPS No.1 and 2 220/11 kV Transformer Replacement	MPS	Replace No.1 and 2 220/11 kV transformers and provide new protection.	21	2020
RCTS 66 kV Reactor Replacement	RCTS	Replace No.1 and No.2 66 kV Reactors.	12	2020
RCTS 66 kV CB replacement	RCTS	Replace four 66 kV CBs.	3	2020
RCTS R1 Transformer Replacement	RCTS	Replace R1A and R1B transformers.	10	2020
SHTS 66 kV CB Replacement	SHTS	Replace five 66 kV bulk oil CBs.	4	2020
Transmission fall arrest installation program on rack structures inside terminal stations	Line	Transmission fall arrest installation program on rack structures inside terminal stations, stage one Country Stations.	3	2020
SVTS Redevelopment stage one	SVTS	Replace B1, B2 and B3 220/66 kV transformers, five 220 kV minimum oil CBs and selected 66 kV CBs.	81	2021
TSTS B2 Transformer and 66 kV CB Replacement	TSTS	Replace B2 220/66 kV transformer, two 66 kV minimum oil CBs and thirteen 66 kV bulk oil CBs, and install new protection and control systems.	37	2021
KGTS–WETS–RCTS Line Communications	KGTS–WETS–RCTS Line	Replace 233 km of ground wire with Optical Ground Wire (OPGW).	24	2021
FTS 66 kV CB Replacement	FTS	Replace seven bulk oil 66 kV CBs.	6	2021
OPGW on RCTS–HOTS Line	RCTS–HOTS Line	Install 277 km of Optical Ground Wire (OPGW) on RCTS–HOTS Line.	28	2022
ERTS Redevelopment stage one	ERTS	Replace two 220 kV minimum oil CBs, selected 66 kV CBs and associated protection and control systems.	20	2022
FBTS B1 and B4 Transformer Replacement	FBTS	Replace B1 English Electric and B4 Toshiba transformers with two 150 MVA 220/66 kV transformers.	10	2022
Transmission fall arrest installation program	Line	Transmission fall arrest installation program on 275 kV, 330 kV and 500 kV towers.	14	2022
Transmission conductor replacement	Line	Transmission conductor replacement – 37 km of ground-wire and conductor.	18	2022
Transmission line insulator replacement	Line	Transmission line insulator replacement Priority 3 insulators (approx. 5,000 strings from lines with 20 mm pins).	5	2022
MSS–DDTS No.1 and 2 330 kV Line Tower Replacement	Line	MSS–DDTS No.1 and No. 2 330 kV selected Line Tower Replacement.	25	2022

Project name	Location	Scope of work summary	Cost estimate ($M)	Target completion date
OPGW on HYTS–SESS Line	HYTS–SESS 1&2 Line	Install 80 km of Optical Ground Wire (OPGW) on HYTS–SESS Line to Tower 51.	9	2022
TBTS 66 kV CB Replacement	TBTS	Replace seven minimum oil 66 kV CBs.	5	2022
TTS B4 Transformer and 66 kV CB Replacement	TTS	Replace B4 150 MVA 220/66 kV transformer and eleven bulk oil and minimum oil 66 kV CBs. Install new transformer protection and CB management system.	25	2022
WOTS 66 kV CB Replacement	WOTS	Replace six 66 kV minimum oil CBs.	5	2022
GTS B4 Transformer and 66 kV CB Replacement	GTS	Replace B4 TOSHIBA transformer with a 150 MVA 220/66 kV transformer and replace six 66 kV bulk oil CBs.	16	2023
GNTS 66 kV CB Replacement	GNTS	Replace six bulk oil 66 kV CBs.	4	2023
HYTS 500 kV and 275 kV CB Replacement	HYTS	Replace four 500 kV and two 275 kV CBs.	16	2023
LYPS 500 kV CB Replacement stage one	LYPS	Replace five 500 kV CBs (Single Switched).	13	2023
RTS L1 and L4 Transformer Replacement	RTS	Replace L1 and L4 transformers and associated protection and control systems.	20	2023
SMTS 330/220 kV Transformer Replacement – stage two	SMTS	Replace the H1 transformer with a new 750 MVA 330/220 kV transformer and retire both old H transformers. Purchase a spare 330/220 kV single phase transformer.	35	2023

APPENDIX H - SHORT-CIRCUIT LEVELS FOR THE VICTORIAN ELECTRICITY TRANSMISSION NETWORK

H.1 Purpose

This appendix provides information relating to the Victorian electricity transmission network's capability to withstand short-circuit currents over a five-year outlook period (2014–18) and forms part of a suite of documents that AEMO will publish in conjunction with the 2014 Victorian Annual Planning Report (VAPR).

This information is useful for stakeholders who:

- Intend to connect to the Victorian electricity transmission network and may use it as a basis for a preliminary assessment of the network's capability to accommodate an intended connection.
- Own equipment that may be affected by transmission network current flows (or who plan to invest in such equipment) can assess the impact of high network current flows during faults.

H.2 Summary of modelling assumptions

Network representation

Short-circuit levels in this appendix are based on a network model with all generators, transmission plant, and relevant sub-transmission lines included and in service.

Victoria's neighbouring transmission networks (in New South Wales and South Australia) are represented by simplified equivalent networks that represent the committed generation and transmission projects in those regions.

Generation and transmission plant changes in Tasmania will not affect short-circuit levels in Victoria as the two regions are connected through a high-voltage direct current (HVDC) link.

Network data

Transmission connection assets, sub-transmission assets, and distribution network embedded generators included in the model are based on information supplied by the distribution businesses and SP AusNet.

Loads

Victorian loads at individual terminal stations have been set to equal the diversified maximum demand from the 2013 Victorian Terminal Station Demand Forecasts[51], as this condition maximises short-circuit currents.

Total Victorian regional demand is set to the medium-growth, summer 10% probability of exceedence (POE) demand forecasts in the in the 2013 National Electricity Forecasting Report.[52]

Pre–fault voltage profile

The short-circuit currents are proportional to pre-fault voltage, which is reported alongside the short-circuit levels calculated at each location.

Network switching modes and outage conditions

The transmission network is assumed to be normally operated in one of six switching modes: R0, R1, R2, R5, R5M, and R6. These normal switching modes are detailed in the supporting document.[53]

[51] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.
[52] AEMO. Available at http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013.
[53] AEMO. Short-circuit levels for Victorian electricity transmission network: 2014-2018. Available at http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report/VAPR-Supporting-Information.

AEMO calculated short-circuit levels under each of these modes and the fault level and mode; the highest fault level at each location is presented in this appendix.

Short-circuit levels were also assessed under select outage conditions where automatic control schemes are known to result in increased short-circuit levels.

Reactive plant and HVDC

Short-circuit levels presented in this appendix include contributions from shunt capacitor banks and HVDC interconnectors (Basslink and Murraylink).

The assumptions of reactive plant and HVDC applied in the short-circuit current calculation are described in the supporting document.[54]

Prior to calculating the short-circuit levels, static VAR compensators (SVC) are converted from their synchronous condenser model, typically used in steady state assessments, to an equivalent maximum shunt capacitance. This represents the behaviour of an SVC shortly after inception of a short circuit.

Network development plan

Committed and proposed network augmentations and generation connections to the transmission and distribution networks affect short-circuit levels. The supporting data[54] describes the transmission network developments considered in this fault level assessment.

While AEMO is aware of other connection proposals, these were not sufficiently advanced at the time this assessment was prepared, so they are not considered in this appendix. Such proposals will affect short-circuit levels if they proceed.

Outside Victoria, only new generation developments in South Australia and New South Wales located near the Victorian border affect Victorian short-circuit levels. AEMO is not aware of any such developments over the five-year outlook period.

H.3 Short-circuit level assessments

AEMO determined the short-circuit levels for three-phase and single phase-to-ground faults for the five-year outlook period based on the assumptions described in H2.

The supporting data[54] presents the short-circuit levels and limits for each bus under system normal conditions and selected outage conditions.

Short-circuit level information for each bus throughout the five-year outlook period comprises:

- Pre-fault voltage level (kV).
- Three-phase-to-ground short-circuit level (3ph kA) and the related switching mode that delivers the highest short-circuit level.
- Single phase-to-ground short-circuit level (1ph kA) and the related switching mode that delivers the highest short-circuit level.

The switching modes and outage conditions include:

- Normal switching modes: R0, R1, R2, R5, R5M, and R6.
- Outage conditions, identified by normal switching modes plus “ID” followed by a number, corresponding to the specific outage condition.

Short-circuit level bus and limit information is also provided for each bus, and comprises:

[54] AEMO. Short-circuit levels for Victorian electricity transmission network: 2014-2018. Available at http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report/VAPR-Supporting-Information.

- Base voltage (kV), which is the nominal bus voltage level.
- Three-phase short-circuit level limit (3ph kA) and its basis.
- Single phase-to-ground short-circuit level limit (1ph kA) and its basis.

Where short-circuit limits are specified in a Use of System Agreement (UoSA), the basis for each limit is the lesser of:

- The lowest circuit breaker rating.
- The limit stated in the UoSA with the distribution business.

Where short-circuit limits are not specified in the UoSA, the basis for each limit is the lesser of:

- The lowest circuit breaker rating.
- The National Electricity Rules limit.

H.4 Short-circuit levels approaching station limits

AEMO's modelling for this appendix shows that the following 15 terminal stations have short-circuit levels forecast within the upper 5% of their short-circuit limits during the five-year outlook period.

- Brooklyn Terminal Station
- East Rowville Terminal Station
- Geelong Terminal Station
- Hazelwood Power Station
- Jeeralang Terminal Station
- Keilor Terminal Station
- Moorabool Terminal Station
- Morwell Terminal Station
- Red Cliffs Terminal Station
- Richmond Terminal Station
- Ringwood Terminal Station
- Rowville Terminal Station
- Templestowe Terminal Station
- Thomastown Terminal Station
- West Melbourne Terminal Station

AEMO will continue to monitor these locations to ensure that their short-circuit levels remain within the limits set by the National Electricity Rules and the UoSA for circuit breaker capabilities.

Short-circuit levels are affected by network configurations such as new connections and network augmentations, as well as changes in electricity consumption.

Committed and proposed network augmentations and generation connections to the transmission and distribution networks are outlined in Table H-1 and detailed in the supporting documentation Short-circuit Levels for the Victorian Electricity Transmission Network 2014–18.

Table H-1 — Committed and proposed network augmentations and generation connections

Commissioning date	Project	Type
2013–14	Bendigo Terminal Station Rebuild (Stage 1)	Network
	Brooklyn Terminal Station Rebuild	Network
	Mount Mercer Wind Farm and Elaine Terminal Station Establishment	Generation
	Tyabb Terminal Station Third Transformer Installation	Network
2014–15	Ararat Wind Farm Establishment	Generation
	Bald Hills Wind Farm Establishment	Generation
	Bendigo Terminal Station Rebuild (Stage 2)	Network
	Crowlands Wind Farm Establishment	Generation
	Dederang Terminal Station Transformer Replacement	Network
	Geelong Terminal Station Rebuild	Network
	Glenrowan Terminal Station Rebuild	Network
	Melbourne Airport Embedded Generation Installation	Generation
	Morwell Terminal Station Rebuild	Network
2015–16	Brunswick Terminal Station Redevelopment	Network
	Fishermans Bend Terminal Station Rebuild	Network
	Richmond Terminal Station Redevelopment	Network
	Ryan's Corner and Hawkesdale Wind Farm Establishment	Generation
	South Morang Terminal Station Rebuild	Network
	West Melbourne Terminal Station Redevelopment	Network
2016–17	Stockyard Hill Wind Farm and Lismore Terminal Station Establishment	Generation
	Dundonnell Wind Farm Establishment	Generation
	Heatherton Terminal Station Redevelopment	Network
	Heywood Terminal Station Third Transformer Installation	Network
	Mt Gellibrand Wind Farm Establishment	Generation
	Penshurst Wind Farm Establishment	Generation
	Ringwood Terminal Station Rebuild	Network
2017–18	Ballarat Terminal Station to Moorabool Terminal Station Third Circuit Installation	Network
	Deer Park Terminal Station Establishment	Network

H.5 Short-circuit level mitigation

Of the 15 locations where fault levels are approaching limits, the following five are forecast to exceed the existing short-circuit limits within the five-year outlook.

- Hazelwood 220 kV
- Moorabool 220 kV
- Morwell 66 kV
- Richmond 220 kV and 22 kV
- West Melbourne 220 kV

Options for reducing short-circuit currents in the Victorian electricity transmission network include:

- Operational switching, where selected transmission network circuit breakers may be switched to open, to reduce short-circuit current contributions into critical buses. This is already being undertaken at several locations within the Victorian network, including Hazelwood Power Station 220 kV, Thomastown 220 kV, Rowville 220 kV, Keilor 220 kV, and several 66 kV buses.
- Network redevelopment, such as further bus splits at critical buses or taking circuits out of service during select periods.
- Installing short-circuit current limiting reactors.
- Upgrading the short-circuit current capability of terminal stations by replacing affected plant (such as earth grids, civil structures, circuit breakers, and other switchgear).

Preferred short-circuit level mitigation options are developed on a case-by-case basis, with each project undergoing a comprehensive technical and economic justification.

Specific mitigation measures for each of the locations identified are outlined below:

H.5.1 Hazelwood Power Station

SP AusNet has commenced a staged process to replace aged and limiting circuit breakers at Hazelwood Power Station as part of their asset refurbishment program.

Following completion of the fourth stage, scheduled for 2017, this station will be fully rated for short-circuit levels up to 40 kA. The short-circuit level forecast at the Hazelwood B2 220 kV bus is still expected to exceed the 40 kA circuit breaker limit.

Given this, AEMO will continue to manage prospective short-circuit levels at Hazelwood Power Station through operational switching arrangements to ensure that short-circuit levels remain within network asset limits.

H.5.2 Moorabool Terminal Station

All 220 kV circuit breakers at Moorabool Terminal Station are rated for short-circuit levels up to 40 kA. SP AusNet will be investigating the short-circuit level withstand capability of the earth grid at Moorabool Terminal Station as part of its Network Capability Incentive Parameter Action Plan (NCIPAP) for 2014–17.

AEMO and SP AusNet are working to have this station re–designated as a Metro station, rather than a Country station. This will increase the station limit from 26.2 kA to 40 kA, in line with National Electricity Rules (NER) limits.

H.5.3 Morwell Terminal Station

Following replacement of the existing B2 220/66 kV transformer at Morwell, currently planned for 2014–15, the 66 kV short-circuit level at Morwell is forecast to exceed the UoSA limits. This will occur under outage conditions only.

AEMO and SP AusNet will develop operational measures that ensure short-circuit levels remain within limits.

H.5.4 Richmond Terminal Station

Although both the three-phase and single phase-to-ground lowest circuit breaker rating at Richmond 220 kV is 26.3 kA, only part of the bus short-circuit current flows through the limiting circuit breaker.

Based on the short-circuit current expected to flow through individual circuit breakers, AEMO calculates that the equivalent bus short-circuit level limits could be as high as 29.3 kA for three-phase and 28.8 kA for single phase-to-ground faults before the circuit breaker reaches its limit.

As Richmond 220 kV short-circuit levels are forecast to remain within these equivalent bus short-circuit level limits, no mitigation measures are required at this stage.

While Richmond 22 kV bus short-circuit levels are forecast to reach NER limits in 2017–18, the short-circuit contribution through individual circuit breakers is expected to remain within network asset limits.

AEMO will continue to monitor short-circuit levels at Richmond and will implement appropriate short-circuit level mitigation measures if required.

H.5.5 West Melbourne Terminal Station

Although the single phase-to-ground lowest circuit breaker rating at West Melbourne 220 kV is 26.3 kA, only part of the bus short-circuit current flows through the limiting circuit breaker.

AEMO calculates that the equivalent bus short-circuit level limits could be as high as 27.1 kA for single phase-to-ground before the circuit breaker reaches its limit.

Although West Melbourne 220 kV bus short-circuit levels are still forecast to reach the circuit breaker limit in 2013-14, these short-circuit levels will be controlled to remain within these circuit breaker limits operationally as required.

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
kA	Kiloamps
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
m/s	Metres per second
3ph	Three phase

Abbreviations

Abbreviation	Expanded name
AC	Alternating current
AEST	Australian Eastern Standard Time
BOM	Bureau of Meteorology
CAGR	Compound average growth rate
CB	Circuit breaker
CCGT	Combined-cycle gas turbine (a type of GPG)
CPI	Consumer price index
CT	Current transformer
CVT	Capacitor voltage transformer
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)

Abbreviation	Expanded name
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
MD	Maximum demand
MDQ	Maximum daily quantity
MHQ	Maximum hourly quantity
MSOR	Market and System Operation Rules
NCAS	Network control ancillary service
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)
OPGW	Optical Ground Wire
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

Abbreviation	Expanded name
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

Victorian terminal and power stations

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

Abbreviation	Name
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
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

Abbreviation	Name
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
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 known as 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

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 an 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).
Demand-side participation	The act of voluntarily shedding electrical load by prior arrangement.

Term	Definition
Demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses or 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 its 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.
National Institute of Economic and Industry Research	A private economic research, consulting, and training group.

Term	Definition
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 to be 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 one 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.