TRANSMISSION CONNECTION PLANNING REPORT

Produced jointly by the Victorian Electricity Distribution Businesses

2013

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Produced jointly by the five Victorian Electricity Distribution Businesses

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EXECUTIVE SUMMARY

This document sets out a joint report on transmission connection asset planning in Victoria, prepared by the five Distribution Businesses ("the DBs")[1], in accordance with the transmission planning requirements of Clause 3.4 of the Victorian Distribution Code and clause 5.13.2 of the National Electricity Rules (the Rules).

In Victoria the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the shared transmission network[2]. The assets connecting the DBs' distribution networks to the shared transmission network are known as transmission connection assets. These assets provide prescribed transmission services in accordance with Chapter 6A of the Rules. The connection assets are located within terminal stations, which are owned, operated, and maintained by the transmission asset owner, SPI PowerNet.

The Victorian jurisdiction has not set deterministic planning standards that apply to transmission connection assets. Accordingly, for the purpose of identifying emerging constraints, and subject to meeting the standards in schedule 5.1 of the Rules and other applicable instruments such as the Victorian Electricity Distribution Code, the DBs apply a probabilistic planning approach. That approach involves estimating the probability of a transmission plant outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability. This calculation enables the assessment of:

- the amount (and value) of energy that is expected not to be supplied if no augmentation is undertaken, and therefore
- whether it is economic to take action to reduce or eliminate expected supply interruptions.

The DBs' approach is consistent with that applied by AEMO in planning the Victorian shared transmission network[3].

Implicit in the use of a probabilistic approach is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available terminal station capacity will be insufficient to meet actual demand and significant load shedding could be required.

In accordance with Part B (Network Planning and Expansion) of Chapter 5 of the Rules, the planning standard applied by the DBs in relation to transmission connection assets is the Regulatory Investment Test for Transmission (RIT-T), the purpose of which is set out in clause 5.16.1(b) of the Rules as follows:

> "To identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."

It is noted that "reliability corrective action" involves investment (which may consist of network options or non-network options) to satisfy the technical requirements of schedule 5.1 of the Rules or an applicable regulatory instrument, such as the Victorian Electricity Distribution Code.

[1] The five DBs are: Jemena Electricity Networks (Vic) Ltd, CitiPower, Powercor Australia, United Energy, and SPI Electricity. SPI Electricity is owned by the SP AusNet Group, a diversified energy infrastructure business that also owns the Victorian electricity transmission system. Throughout this document "SPI PowerNet" refers to the transmission business of SP AusNet and "SPI Electricity" refers to the electricity distribution business of SP AusNet.

[2] The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single point. This network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.

[3] See: http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Transmission-Network-Planning-Criteria

The assessment presented in this report, and summarised in the table on the following pages sets out the DBs' Transmission Connection Planning Report for 2013. It is emphasised that this report does not present the detailed investment decision analysis that is required under the RIT-T. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station over the forecast period.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those terminal stations where further detailed consultation and analysis, in accordance with the RIT-T, is required. This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of the network to best meet the needs of end-customers.

The DBs are required by clause 3.4 of the Victorian Electricity Distribution Code to provide, among other things, an indication of the magnitude, and potential impact of loss of load for each transmission connection. This information is summarised in the table on the following pages, in the form of estimates of "expected unserved energy"[4] for each terminal station in the year in which augmentation of the terminal station is likely to be required, for two forecasts of demand: the first forecast has a 10% probability of being exceeded, while the second forecast has a 50% probability of being exceeded.

For each terminal station, the table also identifies alternatives to network augmentation that may alleviate constraints. Following the summary table is a map showing the approximate locations of the SPI PowerNet-owned connection terminal stations.

Unless noted otherwise in this report including the accompanying risk assessment documents, the relevant DB(s) have not identified any issues relating to compliance with applicable standards that would be likely to drive the need for augmentation of transmission connection assets at this time.

It is noted that as conditions change and as new information becomes available, the indicative timing of any remedial action required to address an emerging constraint or possible non-compliance with an applicable standard may also change. For instance, changes in demand forecasts from one year to the next may result in changes in the timing of remedial action at some stations. Further details are set out in the individual risk assessments for each of the terminal stations.

Parties seeking further information about any matter contained in this report should contact any one of the following people:

- Neil Gascoigne, A/Manager Network Strategy, CitiPower / Powercor, phone 9683 4472.
- Stephen Lees, Lead Engineer, Subtransmission Network Planning, SP AusNet, phone 9695 6217 (for matters relating to SPI Electricity).
- Rodney Bray, Manager Network Planning, United Energy, phone 8846 9745.
- Ashley Lloyd, Network Capacity and Development Manager, Jemena, phone 8544 9239.

Any of these contact officers will either be able to answer your queries or will direct you to the organisation that is best placed to provide you with the information you are seeking.

[4] Throughout this report, the terms "energy at risk" and "expected unserved energy" are used to provide an indication of the magnitude, and potential impact of loss of load for each terminal station. In this report:

> "Energy at risk" is, for a given forecast of demand, the total energy that would not be supplied from a terminal station if: a major outage of a transformer occurs at that station in a specified year; the outage has a mean duration of 2.6 months; and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of energy that would arise in the unlikely event of a major outage of a transformer.
>
> "Expected unserved energy" is the energy at risk weighted by the probability of a major outage of a transformer, where a "major outage" is defined as one that has a mean duration of 2.6 months. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year, taking into account the very low probability that one transformer at the station will not be available because of a major outage.

Summary of risk assessment and options for alleviation of constraints

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Altona – Brooklyn (ATS/BLTS)	2017	16.7 MWh in 2023 ($1.39 million)	3.6 MWh in 2023 ($0.3 million)	Implement load transfers to the proposed Deer Park Terminal Station in 2017	Included in the cost of works associated with the proposed Deer Park Terminal	Demand reduction; Local generation
Altona no 3 & 4 (ATS West) 66 kV	If the proposed new DPTS does not proceed, not before 2020	41.6 MWh ($2.9 million)	25.8 MWh ($1.8 million)	If the proposed new DPTS does not proceed, install additional transformation capacity and reconfigure 66 kV exits at ATS.	$1.8 million	Demand reduction; Local generation
Ballarat (BATS)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
Bendigo 22 kV (BETS 22 kV)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
Bendigo 66 kV (BETS 66 kV)	Not before 2023	15.1 MWh ($1.2 million)	6.7 MWh ($0.52 million)	Install an additional 150 MVA 220/66 kV transformer.	$1.2 million	Demand reduction; Local generation
Brooklyn 22 kV (BLTS 22 kV)	Under current load forecasts, no augmentation of capacity is expected to be required within the ten year planning horizon. However, proposed future residential development (the scope of which is presently uncertain) may trigger the need for action to be taken to address emerging constraints at some time over the planning horizon.					
Brunswick 22 kV (BTS 22 kV)	No augmentation of capacity is expected to be required within the ten year planning horizon.					

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Brunswick 66 kV (BTS 66 kV)	2015/16	BTS 66 kV will be a new 66 kV source of supply, to be established with 3 x 225 MVA 220/66 kV transformers. BTS 66 kV is a committed project and is expected to be established in 2015/16 to reinforce the security of supply to the northern and inner suburbs and the Central Business District areas, and to provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood.				
Cranbourne 66 kV (CBTS 66 kV)	2022/23, in the absence of network support arrangements	46.5 MWh in 2023 ($3.3 million)	28.1 MWh in 2023 ($2.0 million)	Install a fourth transformer.	$2 million	Demand reduction; Local Generation. Recent reductions in demand forecasts for CBTS have enabled SPI Electricity and United Energy to suspend negotiations with a proponent of network support arrangements. Network support would enable deferral of augmentation by up to two years.
Deer Park (DPTS)	DPTS 66 kV is a proposed future terminal station located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is required to offload both transformer groups at KTS by Nov 2017 to avoid excessive load at risk and load exceeding 'N' ratings of plant at KTS in summer 2017/18. The establishment of DPTS will enable a large amount of augmentation work at ATS West and ATS/BLTS to be deferred. Powercor, Jemena Electricity Networks and AEMO published a regulatory test analysis of the proposed Deer Park Terminal station in May 2012. A copy of the report is available at http://www.powercor.com.au/West_Metro_SubTransmission/. That report used 2011 demand forecasts. The risk assessment for Keilor Terminal Station in this Transmission Connection Planning Report uses the latest (2013) terminal station load forecasts, and suggests that Deer Park Terminal Station be commissioned before the summer of 2017/18.					
East Rowville (ERTS)	Not before 2023	0.1 MWh ($6,300)	Nil	Off-load ERTS by transferring Dandenong South zone substation onto a new terminal station in Dandenong.	Not yet estimated	Demand reduction; Local Generation.

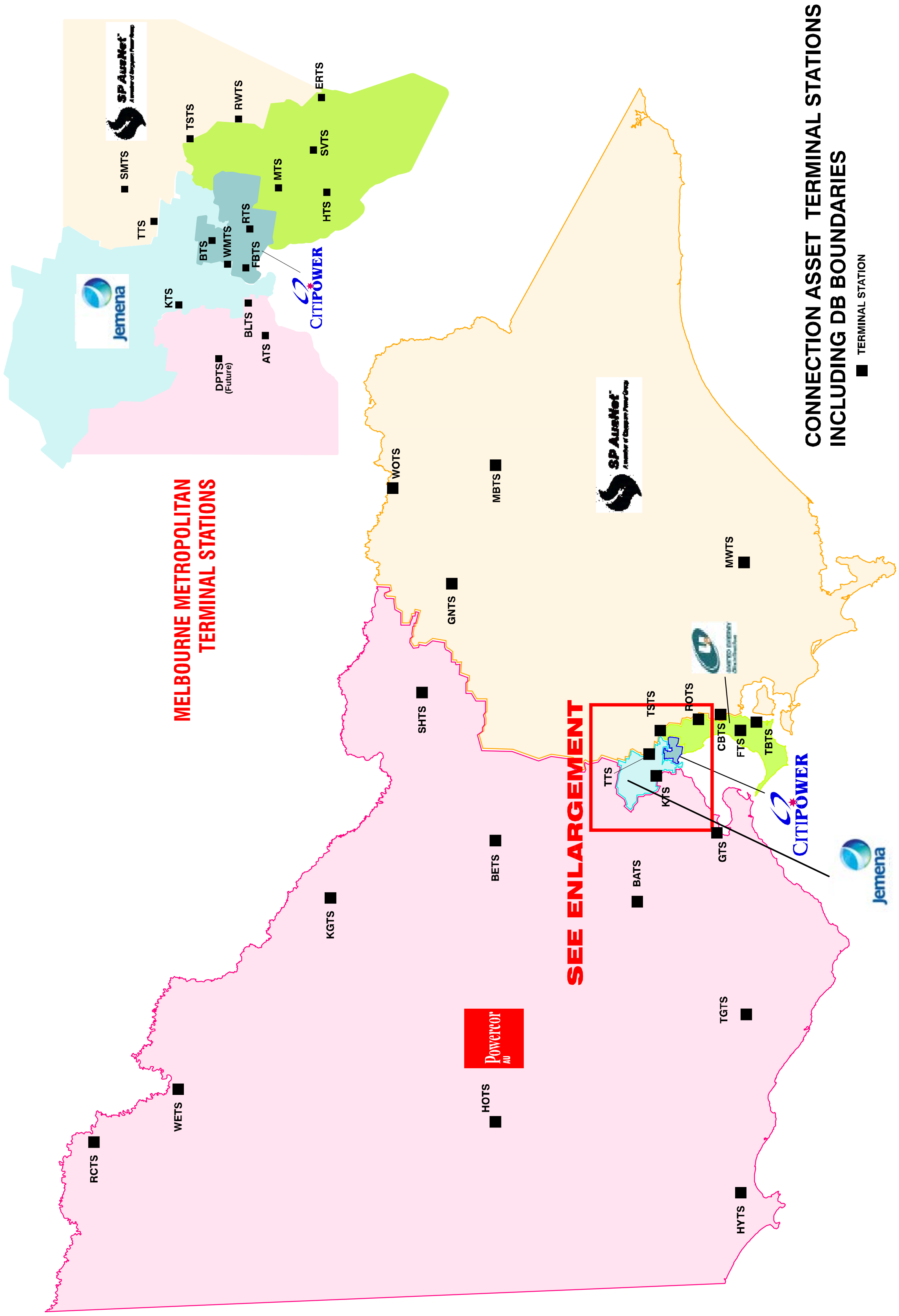
Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Fishermans Bend (FBTS)	Prior to 2020	144 MWh in 2020 ($14.2 million)	2.3 MWh in 2020 ($0.22 million)	Implement auto-switching on the 66 kV bus tie CB to allow all 3 transformers to operate.	$52,000	Demand reduction; Local generation.
Frankston (FTS)	Prior to 2022	13.8 MWh in 2023 ($1.0 million)	8.8 MWh in 2023 ($0.65 million)	Establish a new 66 kV loop from CBTS to supply a new 66/22 kV zone substation in the Skye / Carrum Downs area.	$1.6 million	Demand reduction; Local Generation
Geelong (GTS)	The need for augmentation or other corrective action is not expected to arise over the next ten years.					
Glenrowan (GNTS)	SPI PowerNet has commenced construction work to replace the existing 110 MVA transformer with a new three-phase 150 MVA 220/66kV transformer, which is the standard rating for new 220/66 kV connection transformers. This work will be completed before summer 2014/15 and will increase the capacity at the station. Prior to that work being completed, there is a very small amount of energy at risk under 10th percentile summer conditions for the next (2013-14) summer. Following completion of the transformer replacement, no augmentation of capacity is expected to be required within the ten year planning horizon.					
Heatherton (HTS)	Not before 2023	30.2 MWh ($2.2 million)	24.4 MWh ($1.7 million)	Establish a new 220/66 kV terminal station in Dandenong	$7 million	Demand reduction; Local Generation
Horsham (HOTS)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
Heywood (HYTS 22 kV)	A 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on the existing 2 x 500/275/22 kV South Australian / Victorian interconnecting transformers. The station presently supplies a small number of customers. There is sufficient capacity at the station to supply all expected 22 kV load over the forecast period, even with one transformer out of service.					

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Keilor (KTS)	Prior to summer 2017/18	128.8 MWh in 2017/18 ($9.3 million)	39.3 MWh in 2017/18 ($2.8 million)	Install a 100 MVAr capacitor bank on the KTS(B34) group prior to summer 2015/16, then proceed with the development of a new Terminal Station at Deer Park.	$600,000 for the capacitor bank and $12.5 million for the new Terminal Station.	Demand reduction; Local generation.
Kerang (KGTS)	No augmentation of capacity is expected to be required at KGTS within the ten year planning horizon.					
Malvern 22 kV (MTS 22 kV)	No augmentation of capacity is expected to be required at MTS 22 kV within the ten year planning horizon.					
Malvern 66 kV (MTS 66 kV)	Not before 2023	0.1 MWh ($7,500)	Nil	Install a third transformer	$2 million	Demand reduction; Local Generation
Morwell (MWTS)	Not before 2023 (assuming a total contribution of 60 MVA from existing embedded generators)	24 MWh ($1.83 million)	9 MWh ($0.69 million)	Install a new fourth 220/66 kV transformer at MWTS.	$2.5 million (for fourth transformer)	Continued availability of Bairnsdale and Morwell Power Stations will enable the need for network augmentation to be deferred to at least 2023.
Mount Beauty (MBTS)	At times of high demand and with low output from Clover Power Station a transformer outage at MBTS could result in the loss of some customer load for a period of no more than 4 hours, as the “hot spare” transformer at the station is brought into service. The value of expected unserved energy is approximately $7,000 in 2022. Installation of full switching of the hot spare transformer at MBTS to eliminate this risk is estimated to cost around $2 million so it would not be economic to carry out this work during the 10 year planning horizon.					

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Red Cliffs 22 kV (RCTS 22 kV)	2018	2.9 MWh under N conditions ($0.28 million)	Nil	Augment the transformer 22 kV connections on the two 35 MVA transformers to improve capacity under N conditions.	$0.03 million	Demand reduction; Local generation.
Red Cliffs 66 kV (RCTS 66 kV)	Not before 2023	12.1 MWh ($0.78 million) in 2023	4.2 MWh ($0.27 million) in 2023	Replace one of the existing 70 MVA transformers with a new 140 MVA unit.	$1.2 million	Demand reduction; Local generation.
Richmond 22 kV (RTS 22 kV)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
Richmond 66 kV (RTS 66 kV)	2015 - 2017	31.5 MWh in 2017 ($2.9 million)	9.0 MWh in 2017 ($0.8 million)	Permanently transfer load away to the proposed BTS 66 kV station via both the high voltage distribution and subtransmission networks from 2015 and 2017 respectively.	$3.5 million for terminal station and subtransmission works required to effect subtransmission load transfers	Demand reduction; Local generation. CitiPower and United Energy would welcome proposals from potential providers of network support to reduce the load at risk at RTS 66 kV over the period to 2017. Please contact CitiPower or United Energy for further information.
Ringwood 22 kV (RWTS 22 kV)	Not before 2023	0.07 MWh ($5,100)	Nil	Install a third transformer	$1.5 million	Demand reduction; Local generation.
Ringwood 66 kV (RWTS 66 kV)	Not before 2023	3.3 MWh ($0.23 million)	Nil in 2023	Further investigate the following options: installation of a fifth 220/66 kV transformer at RWTS; and installation of new 66 kV capacitor banks at RWTS	Not yet estimated. (The indicative cost of installing a 5th transformer at RWTS is estimated to be $2 million per annum)	Demand Reduction; Embedded generation.

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
Shepparton (SHTS)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
South Morang (SMTS)	Not before 2023	11.6 MWh, assuming no generation from Somerton PS ($0.76 million)	3.5 MWh, assuming no generation from Somerton PS ($0.23 million)	Install a third 225 MVA 220/66 kV transformer at SMTS.	$2.2 million (including the cost of fault limiting reactors)	Demand Reduction Embedded generation
Springvale (SVTS)	Not before 2022	2.6 MWh ($221,000)	1.1 MWh ($98,000)	Rebalance the bus group loads by transferring Oakleigh East and Clarinda substations from SVTS1266 to SVTS3466..	$0.25 million	Demand reduction; Local generation
Templestowe (TSTS)	Not before 2023	0.8 MWh ($53,500)	0.04 MWh ($2,500)	Install an additional transformer at the station.	$1.7 million	Demand reduction; Local generation
Thomastown (TTS)	Not before 2023 (for establishment of new terminal station)	4 MWh ($252,000)	0.3 MWh ($19,000)	By 2020/21, undertake work to enable load to be balanced between transformer group TTS (B12) and group TTS (B34), so that the load on each bus group is kept below its respective N rating. Develop a new terminal station at either Donnybrook or Somerton.	$6.5 million for new terminal station	Demand reduction; Local generation
Terang (TGTS)	Not before 2023	3.4 MWh ($275,000)	1.9 MWh ($155,000)	Install an additional transformer. Impact of embedded wind generation may defer timing.	$1.4 million	Demand reduction; Local generation
Tyabb (TBTS)	Installation of a 150 MVA 220/66 kV third transformer at TBTS is expected to be completed prior to summer 2013/14, after which time there will be sufficient N-1 capacity to meet projected demand at the station over a ten year planning horizon.					
Wemen (WETS)	Not before 2018	17.9 MWh ($1.81 million)	11.5 MWh ($1.16 million)	Installation of a second transformer.	$1.2 million	Demand reduction; Local generation

Terminal Station	Indicative timing for completion of preferred network solution	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at customer interruption cost)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10th percentile demand forecast	50th percentile demand forecast			
West Melb 22 kV (WMTS 22 kV)	No augmentation of capacity is expected to be required within the ten year planning horizon.					
West Melb 66 kV (WMTS 66 kV)	2015	255 MWh ($25.4 million)	Nil	Permanently transfer load away to new BTS 66 kV station via both the high voltage distribution and subtransmission networks. Prior to completion of BTS, CitiPower and Jemena Electricity Networks propose to implement contingency plans to transfer load via the 66 kV and 11 kV networks, and utilise the “Normal Open” transformer capacity. CitiPower would welcome proposals from proponents of non-network solutions to provide network support services to reduce the load at risk at WMTS 66 kV over the period to 2015 - 2016.	Refer to the Regulatory Test, published 31 May 2011.	Demand management, until the new BTS 66 kV station is completed.
Wodonga (WOTS)	Not before 2023	22.5 MWh ($1.6 million) excluding generation from Hume PS or any other source	4.7 MWh ($340,000) excluding generation from Hume PS or any other source	Installation of a third transformer at WOTS. Prior to constructing any network augmentation, SPIE will seek expressions of interest in a network support agreement to reduce loading on the remaining WOTS 330/66/22 kV transformer	$2.2 million	Demand management, local generation


CONNECTION ASSET TERMINAL STATIONS
INCLUDING DB BOUNDARIES
TERMINAL STATION
MELBOURNE METROPOLITAN
TERMINAL STATIONS
SEE ENLARGEMENT
SP AusNet
Jemena
CitiPower
Powercor AU
SMTS
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DPTS (Future)
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TGTS
HOTS
WETS
RCTS
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1 INTRODUCTION AND BACKGROUND

1.1 Purpose of this report

This document sets out a joint report on transmission connection asset planning in Victoria, prepared by the five Victorian electricity Distribution Businesses (the DBs)[5], in accordance with the requirements of clause 3.4 of the Victorian Electricity Distribution Code and clause 5.13.2 of the National Electricity Rules (the Rules).

It is emphasised that this report does not present detailed investment decision analyses. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station over the forecast period.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those terminal stations where further consultation and detailed analysis - in accordance with Regulatory Investment Test for Transmission - is required. This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of the network to best meet the needs of end-customers.

1.2 Victorian joint planning arrangements for transmission connection assets

For the purpose of this report, transmission connection assets are those parts of the transmission system which are dedicated to the connection of customers at a single point. In Victoria:

- the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the Victorian shared transmission network;[6] and

- The Australian Energy Market Operator (AEMO, formerly VENCorp)[7] is responsible for planning and directing the augmentation of the shared transmission network.

It is noted that pursuant to Chapter 6A of the Rules, transmission connection assets are used to provide prescribed transmission services.

Figure 1 below illustrates the distinction between the shared transmission network and transmission connection assets.

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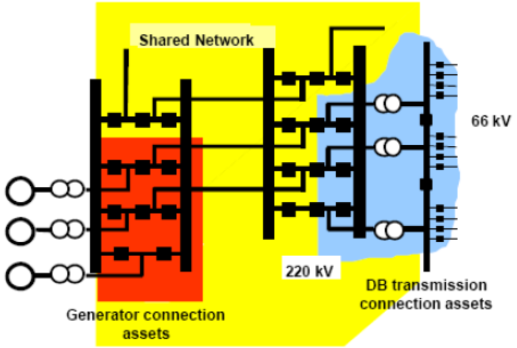
5 The five DBs are: Jemena Electricity Networks (Vic) Ltd, CitiPower, Powercor Australia, United Energy, and SPI Electricity. SPI Electricity is owned by the SP AusNet Group, a diversified energy infrastructure business that also owns and operates the Victorian electricity transmission system. Throughout this document “SPI PowerNet” refers to the transmission business of SP AusNet and “SPI Electricity” refers to the distribution business of SP AusNet.

6 The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single point. This network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.

7 VENCorp’s responsibilities for planning and directing the augmentation of the Victorian electricity transmission shared network were transferred to AEMO on 1 July 2009.

Figure 1: Shared network and connection assets in a notional network



(Source: *VENCorp Electricity Annual Planning Review*, 2009, page 17)

These planning arrangements are aimed at fostering efficient and coordinated development of transmission connection facilities and the downstream sub-transmission and distribution systems. The DBs are best placed to determine the optimum level of investment in, and configuration of, distribution system capacity and transmission connection capacity, having regard to:

- the needs and preferences of the end consumers of electricity;
- the relative costs and benefits associated with alternative distribution, sub-transmission and transmission connection development strategies, and alternative strategies that would deliver a level of supply reliability in accordance with consumers' needs; and
- the direct and indirect incentives (and penalties) faced by the DBs in relation to the reliability of their distribution networks and the transmission connection facilities that they plan.

The transmission planning responsibilities of AEMO are set out in section 50C(1) of the National Electricity (South Australia) (National Electricity Law—Australian Energy Market Operator) Amendment Act 2009. Under that act, AEMO's functions include:

> "to plan, authorise, contract for, and direct, augmentation of the declared shared network", where the declared shared network is defined as "the adoptive jurisdiction's [in this case, Victoria's] declared transmission system excluding any part of it that is a connection asset within the meaning of the Rules".

In accordance with clause 5.14.1(a)(1) of the Rules, AEMO and the DBs undertake joint planning to ensure the efficient development of the shared transmission and distribution networks and the transmission connection facilities. To formalise these arrangements, the parties have agreed a Memorandum of Understanding (MoU). The MoU sets out a framework for cooperation and liaison between AEMO and the DBs with regard to the joint planning of the shared network and connection assets in Victoria. The MoU sets out the approach to be applied by AEMO and the DBs in the assessment of options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and shared transmission network. Under the MoU, the DBs and AEMO have agreed that joint planning projects should be assessed by applying the Regulatory Investment Test for Transmission.

The DBs also liaise regularly with SPI PowerNet, the owner of the Victorian transmission system, to coordinate their transmission connection augmentation plans with SPI PowerNet's asset renewal and replacement plans.

1.3 DBs' obligations as transmission connection planners

1.3.1 Victorian regulatory instruments

Clause 14 of each DB's Distribution Licence states:

> "The ***Licensee*** is responsible for planning, and directing the augmentation of, ***transmission connection assets*** to assist it to fulfil its obligations [to offer connection services and supply to customers] under clause 6."

The licence defines "transmission connection assets" as:

> "those parts of an electricity transmission network which are dedicated to the connection of customers at a single point, including transformers, associated switchgear and plant and equipment."

In accordance with their obligations under clause 3.1(b) of the Electricity Distribution Code, the DBs plan and direct the augmentation of the transmission connection assets in a way which minimises costs to customers taking into account distribution losses and transmission losses.

Clause 3.4 of the Electricity Distribution Code states:

"3.4.1 Together with each other distributor, a distributor must submit to the Commission a joint annual report called the 'Transmission Connection Planning Report' detailing how together all distributors plan to meet predicted demand for electricity supplied into their distribution networks from transmission connections over the following ten calendar years.

3.4.2 The report must include the following information:

(a) the historical and forecast demand from, and capacity of, each transmission connection;

(b) an assessment of the magnitude, probability and impact of loss of load for each transmission connection;

(c) each distributor's planning standards;

(d) a description of feasible options for meeting forecast demand at each transmission connection including opportunities for embedded generation and demand management and information on land acquisition where the possible options are constrained by land access or use issues;

(e) the availability of any contribution from each distributor including where feasible, an estimate of its size, which is available to embedded generators or customers to reduce forecast demand and defer or avoid augmentation of a transmission connection; and

(f) where a preferred option for meeting forecast demand has been identified, a description of that option, including its estimated cost, to a reasonable level of detail.

3.4.3 Each distributor must publish the Transmission Connection Planning Report on its website and, on request by a customer, provide the customer with a copy. The distributor may impose a charge (determined by reference to its Approved Statement of Charges) for providing a customer with a copy of the report."

The Electricity Distribution Code was amended in March 2008 to include an additional provision (clause 3.1A) relating to the security of supply of the Melbourne CBD. This provision describes the circumstances in which the *Melbourne CBD distributor* (currently CitiPower) is required to prepare a *CBD security of supply upgrade plan* and also sets out the required scope of that plan. In particular, the *CBD security of supply upgrade* plan must:

(a) specify strengthened security of supply objectives for the Melbourne CBD and a date or dates by which those objectives must be met;

(b) specify the capital and other works proposed by the *Melbourne CBD distributor* in order to achieve the security of supply objectives for the Melbourne CBD that are specified in the plan; and

(c) meet the regulatory test (which is discussed in further detail in section 1.3.2 below).

This provision establishes a separate planning process that applies to the Melbourne CBD only.

Given that this Transmission Connection Planning Report covers the whole of Victoria, it should acknowledge the existence of any CBD security of supply upgrade plan without unnecessarily duplicating that plan and the supporting analysis. Details of the CBD security of supply upgrade plan are available from CitiPower's website at the following address:

http://www.citipower.com.au/Electricity_Networks/CitiPower_Network/CBDSupply/

The upgrade will protect Melbourne's electricity supply from a prolonged blackout should there be major failures (i.e. the loss of two or more 66 kV subtransmission elements) within the electricity networks supplying this area. The relevant transmission connection works (namely, the establishment of a new 66 kV source of supply at Brunswick Terminal Station) are a separate project, but are related to the CBD upgrade project. Following further consultation by AEMO and CitiPower in 2011 on the options for addressing emerging constraints at three terminal stations currently servicing CitiPower's distribution network in the Melbourne CBD and surrounding suburbs, a final report was published. The final report confirmed that:

- The preferred option is an upgrade of the existing Brunswick Terminal Station (BTS) to 66 kV supply with 220 kV and 66 kV indoor gas insulated switchgear.

- CitiPower and AEMO propose to implement the preferred option and expect that the additional capacity provided by the upgrade of BTS to a 66 kV terminal station will be available from 2016.

Further details on this matter are available from AEMO's website at http://www.aemo.com.au/Consultations/Network-Service-Provider/Joint/Proposed-Augmentation-for-Melbourne-Inner-Suburbs-and-CBD-Supply, or by contacting the CitiPower officer listed on page 5 of this report.

1.3.2 National Electricity Rules

Part B of Chapter 5 of the Rules[8] sets out provisions governing the planning and development of networks. These provisions require, amongst other things, Transmission and Distribution Network Service Providers to:

- prepare and publish annual planning reports;
- consult with interested parties on the possible options, including but not limited to demand side options, generation options and market network service options to address the projected network limitations;
- undertake analysis of proposed network investments using the Regulatory Investment Test for Distribution (formerly the regulatory test) or the Regulatory Investment Test for Transmission, as appropriate.

As noted in section 1.2, the DBs and AEMO have agreed that subject to the thresholds set out in the Rules, joint planning projects involving transmission connection and distribution investment should be assessed by applying the Regulatory Investment Test for Transmission (RIT-T). This agreement is consistent with clauses 5.16.3(a)(2) and (6) of the Rules, which requires RIT-T proponents to apply the RIT-T to projects to augment transmission connection facilities where the estimated capital cost of the most expensive technically and economically feasible option to address the identified need exceeds $5 million. It is noted that in circumstances where a transmission connection augmentation project is not a joint project, then the assessment of that project may be undertaken by the relevant DB(s) under the Regulatory Test for Distribution.

Clause 5.13.2 of the Rules requires Distribution Network Service Providers to publish a Distribution Annual Planning Report (DAPR). The DAPR must contain the information specified in schedule 5.8 of the Rules, unless that information is provided in accordance with jurisdictional electricity legislation.

Pursuant to clause 5.13.2(d) of the Rules, this Transmission Connection Planning Report presents the information on transmission connection planning required under schedule 5.8. The table below lists the relevant clause of schedule 5.8, and provides a cross reference to the section of this report where the required information is presented.

Table 1A: Schedule 5.8 requirements addressed in this report

Schedule 5.8 clause	Matters addressed	Where the information is presented in this report
S5.8(b)(1)	A description of the forecasting methodology used	Section 2
S5.8(b)(2)(i), (iv), (v), (vi), (vii), (viii), and (ix)	Load forecasts and forecasts of capacity	Section 3, Section 4.6 and individual Risk Assessments for each terminal station

8 Version 59 of the Rules was in force at the time of preparing this report (November 2013).

Schedule 5.8 clause	Matters addressed	Where the information is presented in this report
S5.8(b)(3)	Forecasts of future transmission-distribution connection points and any associated connection assets	The Executive Summary, and individual Risk Assessments for each terminal station
S5.8(h)	The results of joint planning undertaken with Transmission Network Service Providers	Section 1.2 describes joint planning arrangements. The Executive Summary, and individual Risk Assessments for each terminal station describe the results of joint planning.
S5.8(i)(1)	The results of joint planning undertaken with other Distribution Network Service Providers	As above.

1.3.3 Reliability incentive scheme (s-factor) for the Distribution Businesses

Under the Distribution Determination and Service Target Performance Incentive Scheme (STPIS) that applies from 1 January 2011, each DB's price control contains an s-factor which provides a revenue bonus when service performance is better than performance targets, and a penalty when service performance is worse than performance targets. The operation of the s-factor relates to the distribution network, and therefore is not directly relevant to the reliability of the transmission system. However, under clause 3.3(a)(6) of the STPIS, the DBs are exposed to financial penalties if load interruptions are caused by a failure of transmission connection assets where the interruptions are due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning. The financial incentive under these arrangements reinforces the DBs' responsibilities with respect to transmission connection planning, which are set out in the Distribution Licences and the Electricity Distribution Code.

1.3.4 SPI PowerNet's role in delivering connection services

The transmission connection assets are located within terminal stations which are owned, operated, and maintained by the TNSP (Transmission Network Service Provider), SPI PowerNet. The DBs have limited direct control over the performance of connection assets under their connection agreements with SPI PowerNet. However, the revenue cap applied to SPI PowerNet contains a Service Target Performance Incentive Scheme (STPIS) applicable specifically to SPI PowerNet as TNSP and developed in accordance with clause 6A.7.4 of the National Electricity Rules. The STPIS aims to balance the incentive for SPI PowerNet to minimise expenditure with the need to maintain and improve reliability for customers, by providing SPI PowerNet with a financial incentive to maintain or improve service levels.

1.4 Matters to be addressed by proponents of "non-network" alternatives

One of the purposes of this document is to provide information to proponents of non-network solutions (such as embedded generation or demand management) to emerging network constraints. As noted in further detail in Chapter 2 below, the DBs aim to develop their networks and the associated transmission connection assets in a manner that minimises total costs (or maximises net economic benefit). To this end, proponents of non-network solutions to the emerging network constraints identified in this report are encouraged to lodge expressions of interest with the relevant DB(s).

Proponents of non-network proposals should make initial contact with the relevant DB as soon as possible, to ensure that sufficient time is available to the DB to fully assess feasible network and non-network potential solutions, having regard to the lead times associated with the evaluation, planning and implementation of various options. Indicative timeframes for the network solutions are provided in the summary table of the Executive Summary.

To assist in the assessment of non-network solutions, proponents are invited to make a detailed submission to the relevant DB. This submission should be informed by earlier discussions with the relevant DB, and should include all of the following details about the proposal:

1. proponent name and contact details;
2. a detailed description of the proposal;
3. electrical layout schematics;
4. a firm nominated site;
5. capacity in MW to be provided and number of units to be installed (if applicable);
6. fault level contribution, load flows, and stability studies (if applicable);
7. a commissioning date with contingency specified;
8. availability and reliability performance benchmarks;
9. network interface requirements (as agreed with the relevant DBs);
10. the economic life of the proposal;
11. banker / financier commitment;
12. proposed operational and contractual arrangements that the proponent would be prepared to enter into with the relevant DBs;
13. any special conditions to be included in a contract with the responsible DBs; and
14. evidence of a planning application having been lodged, where appropriate.

All proposals must satisfy the requirements of any applicable Codes and Regulations.

In addition, as a general rule of thumb, any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent(s) of the non-network project. Some non-network alternatives such as embedded generation may raise issues relating to fault level control. In particular, connection of additional embedded generators will result in an increase in fault levels. Therefore fault level mitigation measures may be required because of the installation of embedded generation, in which case it would be equitable and efficient for the proponents of such projects to bear the costs of fault level mitigation works.

It is noted that regulatory arrangements governing the terms and conditions for connection to the distribution network are subject to change. In particular:

- On 14 June 2012, the AEMC initiated the rule change process in relation to a rule change proposed by ClimateWorks Australia, Seed Advisory and the Property Council of Australia. The rule change request states that it seeks to make a more timely, clearer and less expensive process for connecting embedded generators to distribution networks. On 27 June 2013, the AEMC published its draft determination. A final determination on the rule change proposal is expected by 19 December 2013. Further details are available at the AEMC's webpage at:

  http://www.aemc.gov.au/Electricity/Rule-changes/Open/connecting-embedded-generators.html

- Guideline 15 (Connection of Embedded Generation) issued by the Victorian Essential Services Commission is expected to be rescinded once the National Energy Customer Framework is implemented in Victoria.

1.5 Implementing Transmission Connection Projects

In the absence of any commitment by interested parties to offer "non-network" solutions (such as embedded generation or demand side management), the process to implement the preferred network solution will commence. A brief description of the implementation process for network solutions and the issues involved is presented below.

1.5.1 Land Acquisition

Network solutions may require land acquisition. The process of land acquisition for new terminal stations may be complex especially in metropolitan areas. Land acquisition issues and processes are beyond the scope of this document.

A limited number of vacant sites, currently owned by SPI PowerNet, have been reserved for possible future terminal station development in Victoria. DBs would need to seek SPI PowerNet's consent to use any reserved land for transmission connection development.[9]

The granting of a town planning permit on lands reserved for future terminal station development is by no means certain. In some municipalities, town planning approval may also be required for network augmentation on existing developed sites.

1.5.2 Connection Application to AEMO

In accordance with the requirements of Chapter 5 of the Rules, a connection application to AEMO for new transmission connection points is required. As noted in section 1.2, the 220 kV assets that form part of the Victorian shared transmission network would fall under the planning jurisdiction of AEMO. Hence, issues associated with 220 kV switching arrangements and connection to the shared transmission system would need to be clarified at the connection application stage so that the requirements of the DBs and AEMO can both be met.

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9 Electricity Industry Guideline No. 18 (*Augmentation and Land Access Guidelines*) issued by the ESC on 1 April 2005 may govern access to such sites, in some circumstances. See: http://www.esc.vic.gov.au/getattachment/95b01c40-b945-4b31-8ff2-fa164fa76bc0/Guideline-18-Final-Guidelines-2005.pdf

For augmentations to existing connection points, a connection application to AEMO may still be required so that the effect on the shared transmission network, if any, can be taken into consideration. In some cases, AEMO and the relevant DBs may undertake a public consultation process in relation to the proposed development. In addition, AEMO's requirements regarding any augmentation of shared transmission network assets must be finalised through a joint planning process involving AEMO and the relevant DBs. These activities can increase the lead time for delivery of augmentations by some months.

1.5.3 Connection Application to SPI PowerNet

It is most likely that establishment of new transmission connections, or augmentation of existing transmission connections will require interface to transmission assets owned by SPI PowerNet. In accordance with the negotiating framework issued by SPI PowerNet, an initial "Connection Inquiry" outlining the broad scope of service sought should be submitted to SPI PowerNet, followed by a "Connection Application" when the scope of the service has been accurately defined in consultation with AEMO and the relevant DB(s).

1.5.4 Contestable procurement of transmission connection works

In relation to the question of the DBs' obligations to competitively procure transmission connection services, page 3 of the ESC's June 2002 *Information Paper- Cost Recovery Issues for the Proposed Cranbourne Terminal Station*, states:

> "Distributors have no specific regulatory obligation to conduct competitive tendering of transmission connection asset augmentations. However, in meeting their Electricity Distribution Code obligation to minimise costs to customers, distributors would normally competitively tender such works."

It is noted that Part H of Chapter 8 of the National Electricity Rules contains provisions relating to the competitive sourcing of augmentations, however those provisions relate to the procurement by AEMO of augmentations to the shared network.

1.5.5 Town Planning Permit

For greenfield sites, DBs may need to engage the services of experienced town planning consultants, because very extensive planning requirements are generally laid down by local planning authorities. In most cases, the town planning permit application would need to be accompanied by extensive supporting documents such as:

- flora and fauna study;
- archaeological and cultural assessment;
- noise study;
- electromagnetic field (EMF) assessment;
- traffic analysis;
- layouts and elevation plans; and
- landscaping and fencing.

The choice of appropriate town planning consultants is very important, as they may need to provide expert witness statements to the Victorian Civil and Administrative Tribunal

(VCAT) if objections to the transmission connection application are received. Due to the possibility of simultaneous shared network development by AEMO on the same site, it may become necessary to invite AEMO to participate in the town planning process at the same time so that both the council and the public are made aware of the entire proposed development on the site.

For augmentation to existing transmission connection assets, the requirement for a town planning permit varies from council to council, and depends on the extent of the proposed work. SPI PowerNet is likely to be the initiator of the planning permit application for augmentation work at an existing terminal station.

1.5.6 Public Consultation Strategy

A key aspect of the public consultation strategy is the positive engagement of various stakeholders in the project from the initial stages of the development. The strategy may include:

- distribution of leaflets that provide information on the proposal in clear, concise, non-technical language to every nearby resident;
- presentations to the councillors of the local municipality and the local members of parliament; and
- public consultation such as display stands in local shopping centres to highlight the need for such a project and the resultant benefits to the community, and invitation of public comments on the proposal.

Feedback from stakeholders is then considered in the design of the transmission connection work to ensure the resultant project is acceptable to the local community.

1.5.7 Project Implementation

As noted in section 1.3.1, the DBs are required by the Distribution Code to augment the transmission connections in a way which minimises costs to customers taking account of distribution losses. This can be achieved by a variety of means, including competitive tendering and cost benchmarking.

Transmission connection augmentation works will be arranged by the relevant DBs in accordance with the requirements of any applicable guidelines in force[10].

1.5.8 Project lead times

The lead-time required for the implementation of connection asset augmentation projects depends on the number of interdependent activities involved in the project, and varies from between 3 to 5 years.

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10 As already noted, page 3 of the ESC's June 2002 *Information Paper- Cost Recovery Issues for the Proposed Cranbourne Terminal Station*, states:

> "Distributors have no specific regulatory obligation to conduct competitive tendering of transmission connection asset augmentations. However, in meeting their Electricity Distribution Code obligation to minimise costs to customers, distributors would normally competitively tender such works."

The critical path activities in the delivery of such projects include the following:

- Finalisation of any requirements for shared network augmentation due to planned connection asset augmentation works. These requirements are assessed through the joint planning process, which involves AEMO, SPI PowerNet and the DBs in Victoria.

- Procurement of a planning permit in relation to the proposed works. In order to obtain planning consent for proposed works, the statutory planning requirements of the local council(s) must be met, and community expectations must be addressed. For connection asset augmentations involving either major augmentations on an established site or the development of new terminal station(s) on new site(s), a period of at least 24 to 36 months is required for land planning and associated community issues to be resolved. The timely completion of this task requires effective coordination and cooperation between AEMO, SPI PowerNet and the DBs through the joint planning process in Victoria.

- After completing the above two tasks successfully, the next important tasks are:

    - Finalisation of the scope of works;

    - Preparation of cost estimates (including invitation to tender if the project is contestable); and

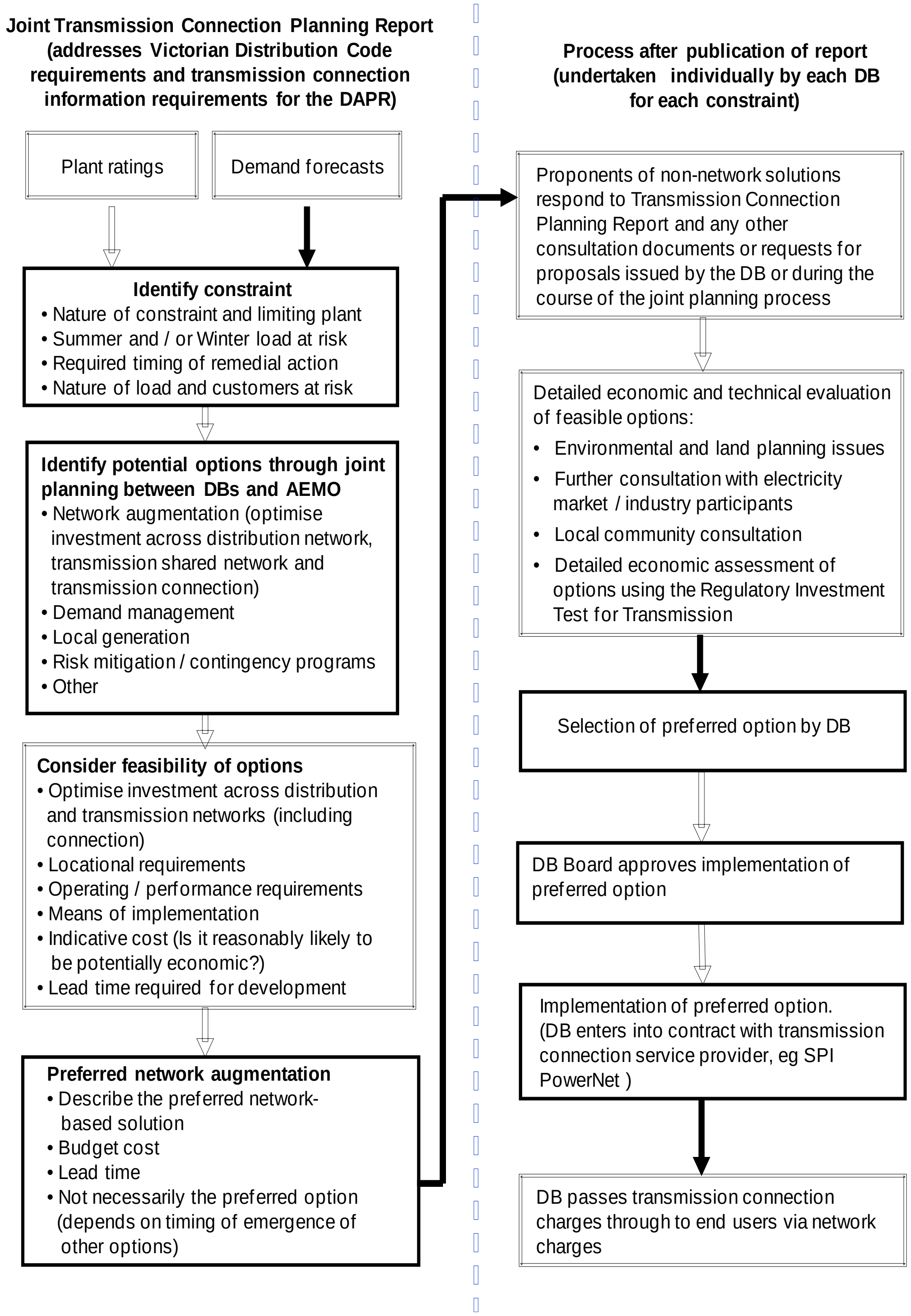
    - Finalisation and execution of all contracts and agreements between distribution and transmission network service providers after obtaining all the necessary internal business approvals.

Once the project contracts are signed, the next important task is the delivery of the project itself, including installation and commissioning of the assets into service. SPI PowerNet's recent experience indicates that the lead-time required for the delivery of a connection asset augmentation involving power transformers is between 18 and 24 months. In some cases, issues identified during testing of completed units have resulted in further delays. In view of this, for planning purposes it is assumed that approximately 24 months would be required to install and commission power transformers from the time that a commercial contract is signed between the parties to complete the project works.

1.6 Overview of Transmission Connection Planning Process

The flow chart below provides a summary of the transmission connection planning and augmentation process under the regulatory framework which presently applies to the Victorian DBs.

PROCESS FLOW CHART: TRANSMISSION CONNECTION PLANNING



2 PLANNING STANDARDS

2.1 Planning standard applying to transmission connection assets

Clause 3.4.2(c) of the Electricity Distribution Code requires this report to set out the planning standards applying to transmission connection assets. The planning standard applied by the DBs is the Regulatory Investment Test for Transmission (RIT-T), the purpose of which is set out in clause 5.16.1(b) as follows:

> "To identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."

Clause 5.10.2 of the Rules defines "reliability corrective action" as follows:

> "Investment by a Transmission Network Service Provider or a Distribution Network Service Provider in respect of its transmission network or distribution network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options."

The terms "applicable regulatory instruments" is defined in the Rules as follows:

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

Applicable regulatory instruments in Victoria includes:

(a) the Electricity Industry Act 2000 (EI Act);

(b) all regulations made and licences (Licences) issued under the EI Act;

(c) the Essential Services Commission Act 2001 (ESCV Act);

(d) all regulations and determinations made under the ESCV Act;

(e) all regulatory instruments applicable under the Licences; and

(f) the Tariff Order made under section 158A(1) of the Electricity Industry Act 1993 and continued in effect by clause 6(1) of Schedule 4 to the Electricity Industry (Residual Provisions) Act 1993, as amended or varied in accordance with section 14 of the EI Act.

Further background information on this planning standard, and the probabilistic planning approach applied by the DBs for the purpose of evaluating net market benefits is set out below.

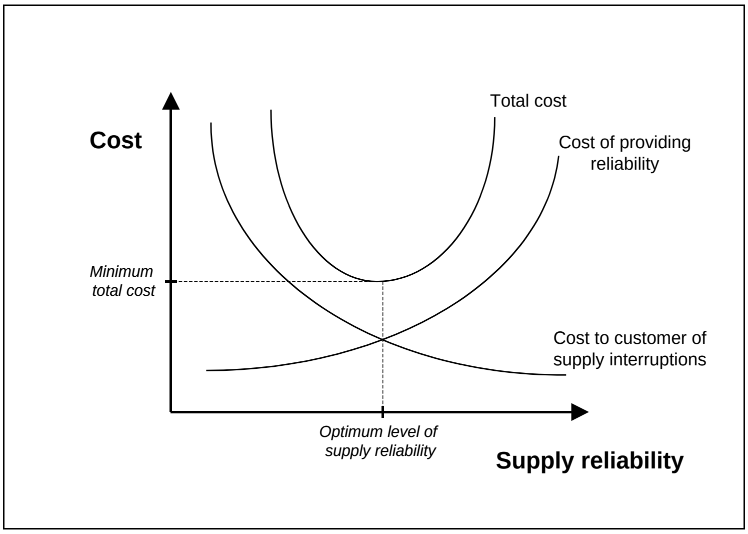
2.2 Overall objective of transmission connection planning

The planning standards and criteria applied in network development are a significant determinant of network-related costs. Costs associated with transmission connection facilities can be considered to be comprised of two parts:

- the direct cost of the service (as reflected in network charges and the costs of losses); and
- indirect costs borne by customers as a consequence of supply interruptions caused by network faults and / or insufficient network capacity.

In establishing and applying their planning standards and investment criteria, the DBs aim to develop transmission connection facilities in an efficient manner that minimises the total (direct plus indirect) life-cycle cost of network services. This basic concept is illustrated in Figure 2 below.

Figure 2: Balancing the direct cost of service and the indirect cost of interruption



In accordance with the requirements of the RIT-T, the DBs' transmission connection investment decisions aim to maximise the net present value to the market as a whole, having regard to the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.

2.3 Overall approach to transmission planning and investment evaluation

In some Australian jurisdictions, deterministic planning standards (for instance, "N-1") are applied in transmission system development. In Victoria however, pursuant to section

50C of the National Electricity Law, AEMO applies a probabilistic approach[11] to planning the shared transmission network[12].

Under the probabilistic approach, the deterministic N-1 criterion is relaxed, and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. The application of this approach can lead to the deferral of transmission capital works that might otherwise proceed if a deterministic standard were strictly applied. This is because:

- in a network planned in accordance with the probabilistic approach, there may be conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
- under these conditions, the value of the energy that is *expected* to be not supplied is not high enough to justify additional investment, taking into account the probability of a forced outage of a particular element of the transmission network.

However, implicit in the use of a probabilistic approach is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available terminal station capacity will be insufficient to meet actual demand and significant load shedding could be required.

In Victoria, the jurisdiction has not set deterministic standards applying to transmission connection assets. In light of this, and the requirements of the RIT-T, the DBs apply probabilistic planning and economic investment decision analysis to transmission connection assets, subject to meeting the technical and other standards set out in the Rules and other applicable regulatory instruments[13].

2.4 Valuing supply reliability from the customers' perspective

In order to determine the economically optimal level and configuration of connection capacity (and hence the supply reliability that will be delivered to customers), it is necessary to place a value on supply reliability from the customer's perspective.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Nonetheless, there is information available (principally, surveys designed to estimate the costs faced by consumers as a result of electricity supply interruptions) that provides a guide as to the likely value.

AEMO's Final Report titled National Value of Customer Reliability, published on 19 January 2012[14] explained that:

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11 A copy of the Victorian transmission planning criteria can be obtained from AEMO's web site at: http://www.aemo.com.au/en/Gas/Planning/Related-Information/Policies-and-Procedures/~/media/Files/Other/planning/0400-0047%20pdf.ashx

12 The "shared transmission network" is the Victorian transmission system, excluding the transmission facilities that connect the distribution networks (and the generators) to the high voltage network. The distribution businesses, are responsible for the planning and development of the transmission facilities that connect their distribution networks to the shared transmission network. These arrangements are set out in the distribution licences issued by the ESC.

13 These instruments include, without limitation, the Victorian Electricity Distribution Code.

14 The report is available from AEMO's website at the following address: http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Policies-and-Procedures/~/media/Files/Other/planning/0400-0055%20pdf.ashx

"The value of a reliable supply of electricity is a key part of understanding the relative economic merits of alterations to the electricity network. In probabilistic transmission planning, a Value of Customer Reliability or VCR is needed to value the benefit of a proposed augmentation project that is expected to reduce unserved energy in the future, so that this benefit can be compared to the costs of the augmentation. In deterministic transmission planning, a VCR may be used to value the partial market benefit of reducing the likelihood of having unserved energy in the future.

Therefore the value that consumers place on a reliable supply of electricity plays a vital role in the transmission planning process as the valuation of reliability is a key element to the social benefit of network augmentations."

In correspondence dated 10 October 2013, AEMO advised that the following Victorian VCR values, by sector, apply for 2013.

Table 1: 2013 Victorian VCR estimates by sector

Sector	VCR for 2013 ($/kWh) (Source: AEMO, 10 October 2013)
Residential	$27.19
Commercial	$113.05
Agricultural	$147.76
Industrial	$44.93
Composite- all sectors[15]	**$63.09**

Clause 5(c) of the RIT-T[16] states:

"the market benefit must include … changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers".

The accompanying RIT-T Application Guidelines published by the AER do not prescribe a particular value of electricity to consumers. However, page 63 of the Guidelines states:

"Examples of reasonable estimates of the value of electricity to consumers include:

- The market price cap (or Value of Lost Load, VoLL) – at 1 June 2010 VoLL is $10,000/MWh but will increase to $12,500/MWh from 1 July 2010.
- The Value of Customer Reliability (VCR) used by AEMO for network planning in Victoria. The VCR used by AEMO in the 2009 Victorian Annual Planning Report (VAPR) is $55,000/MWh."

AEMO is currently undertaking a review of a national VCR, with the aim of producing region-specific VCRs for use in revenue regulation, planning and operational purposes in the National Electricity Market. Further information is available from http://www.aemo.com.au/Consultations/National-Electricity-Market/Value-of-Customer-Reliability-Issues-Paper

15 The Victorian composite VCR was calculated by the DBs based on the following composition of total Victorian load: 34% residential; 1% agricultural; 34% commercial; and 31% industrial.

16 The RIT-T (version 1) was published by the AER in June 2010 and came into effect on 1 August 2010. Further details are available at: http://www.aer.gov.au/node/8865

In considering the appropriate VCR to apply in network investment evaluation, the Victorian DBs favour the application of the VCR estimate as opposed to the VoLL wholesale market price cap. This is because the VCR attempts to reflect the marginal value of supply reliability to customers, whereas the VoLL applies in the wholesale market, and its rationale is more closely linked to management of risk in that market.

In applying the VCR, it should be recognised that VCR is a composite (or weighted average) measure of customer interruption costs:

- for a wide range of different customers; and
- across a wide range of interruption durations (up to 24 hours).

VCR is a simple single ratio derived from an estimate of interruption costs and a notional quantity of energy not consumed as a result of the interruption. The single VCR number attempts to represent a very complex, multi-dimensional set of variables.

A further limitation of the concept of the "composite" or average VCR is the variability of the marginal value of unsupplied energy across different customer groups. This is illustrated in the sector VCR values that underpin the Victorian composite VCR of $63,090 per MWh for 2013, as shown in Table 1 above.

The wide range of sector VCR values has potentially significant implications for transmission connection investment decisions, especially where the composition of the load supplied from a potentially constrained terminal station is dominated by a particular sector.

For instance, the load within the Melbourne CBD is comprised predominantly of commercial sector load, which has an estimated VCR of around $113,000 per MWh. That VCR is nearly twice the composite VCR for Victoria as a whole. These observations suggest there is a reasonable case for the application of sector-specific VCR values in transmission connection investment analysis, where a constraint affects a readily identifiable group of consumers.

This report provides details of the VCR values used for each terminal station, based on the sector VCR estimates provided by AEMO and set out in Table 1 above.

2.5 Application of the probabilistic approach to transmission connection planning

The probabilistic planning approach involves estimating the probability of a plant outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint,[17] and therefore
- whether it is economic to augment terminal station capacity to reduce expected supply interruptions.

[17] The energy that would not be supplied in the event of an interruption is valued in accordance with the approach outlined in Section 2.3 above.

The quantity and value of energy at risk is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of terminal station augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available terminal station capacity will be insufficient to meet actual demand and significant load shedding could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic plant failure leading to extended periods of plant non-availability; and
- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

3 HISTORIC AND FORECAST DEMAND

In its capacity as the planner of the Victorian shared transmission network, AEMO produces consolidated terminal station demand forecasts each year, based on data provided by the DBs. The forecasts that form the basis of this report are consistent with those published by AEMO in its report titled *Terminal Station Demand Forecasts for 2013/14 to 2023/24*. AEMO's report includes a description of the methodology used in developing the forecasts. The report also includes details of generation capacity of known embedded generating units. A copy of the report is available from AEMO's web site at:

http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.

4 RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

4.1 Preamble

This section presents an overview of the magnitude, probability and impact of loss of load at each transmission connection, in accordance with the requirements of clause 3.4.2(b) of the Electricity Distribution Code.

The assessment presented is not a detailed planning analysis, but a high-level description of the expected balance between capacity and demand over the forecast period. Data presented in this high-level analysis may indicate an emerging major constraint. Therefore, this high-level assessment provides a means of identifying those terminal stations where further detailed analysis of risks and options for remedial action, in accordance with RIT-T, is required.

It is emphasised that this high-level analysis focuses on risks to supply reliability that relate to the capacity and reliability of transformers only. There are typically risks to supply reliability associated with the performance and capacity of smaller plant items. However, these smaller items involve relatively low capital expenditure, the deferral of which is unlikely to entail a sufficiently high avoided cost to justify the employment of non-network alternatives.

In addition, capital expenditure is required from time to time to address fault level issues. This expenditure is driven chiefly by mandatory health and safety standards, and does not relate to terminal station capacity, per se. Fault level issues are therefore not within the scope of this report, however, the analysis of feasible and preferred options for increasing capacity will, where appropriate have due regard to issues relating to fault level control[18].

The following key data are presented in this section for each Terminal Station:

- ***Energy at risk:*** For a given demand forecast, this is the amount of energy that would not be supplied from a terminal station if a major outage[19] of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months (as discussed in section 4.4 below), and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer.

- ***Expected unserved energy:*** For a given demand forecast, this is the energy at risk weighted by the probability of a major outage of a transformer. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year, taking into account the very low probability that one transformer at the station will not be available for 2.6 months because of a major outage.

Risk assessments for each individual terminal station provide estimates of energy at risk and expected unserved energy based on the 50th percentile and 10th percentile demand

[18] Some non-network alternatives such as embedded generation may raise issues relating to fault level control. A further discussion of this issue is set out in Section 1.4 of this report.

[19] The term “major outage” refers to an outage that has a mean duration of 2.6 months, typically due to a significant failure within the transformer. The actual duration of an individual major outage may vary from under 1 month up to 9 months. Further details are provided in section 4.4 below.

forecasts set out in Section 3. Consideration of energy at risk and expected unserved energy at these two demand forecast levels provides:

- an indication of the sensitivity of these two parameters to temperature over the Summer peak period; and

- an indication of the level of exposure to supply interruption costs at higher temperature and demand conditions (namely, 10th percentile levels).

As already noted, this information provides an aid to identifying the likely timing of economically-justified augmentations or other actions. However, the precise timing of augmentation or any other non-network solutions aimed at alleviating emerging constraints will be a matter for more detailed analysis that takes into account all relevant factors, including the uncertainty of temperature outcomes and the impact of temperature on demand at the particular terminal station.

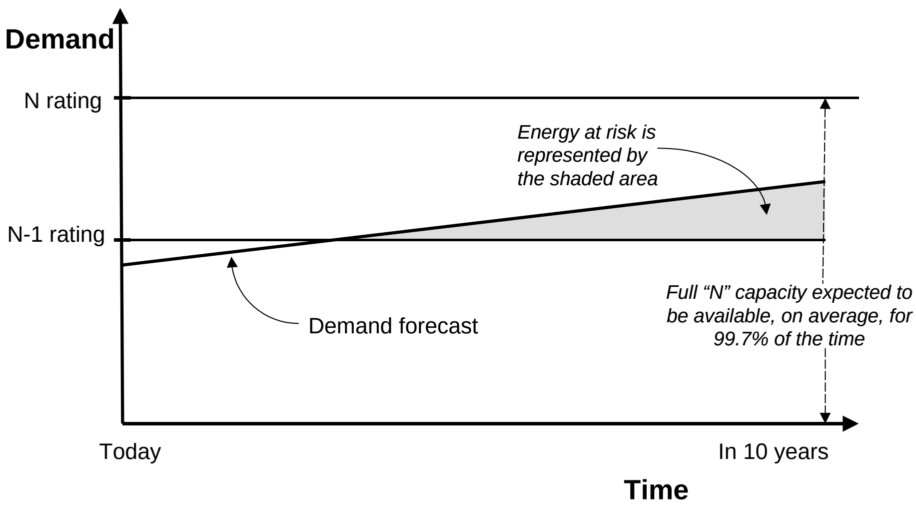
In interpreting the information set out in this report, it is important to recognise that the 50th percentile demand forecast relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50% probability of being higher than the 50th percentile demand forecast.[20]

4.2 Interpreting "energy at risk"

As noted above, "energy at risk" is an estimate of the amount of energy that would not be supplied if one transformer was out of service due to a major failure during the critical loading season(s), for a given demand forecast.

The capability of a terminal station with one transformer out of service is referred to as its "N minus 1" rating. The capability of the station with all transformers in service is referred to as its "N" rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted is the diagram below.

Relationship between N rating, N-1 rating and energy at risk



20 Conversely, there is also a 50% chance that actual demand will be lower than the forecast in any one year.

4.3 Assessing the costs of transformer outages

As noted in Section 4.1, for a given demand forecast:

- "energy at risk" denotes the amount of energy that would not be supplied from a terminal station if a major outage of a single transformer occurs at that station in that particular year, and no other mitigation action is taken; and
- "expected unserved energy" is the energy at risk weighted by the probability of a major outage of a single transformer.

In estimating the expected cost of connection plant outages, this report considers the first order contingency condition ("N minus 1") only. It is recognised that in the case of terminal stations that consist of two transformers, there is a significant amount of energy at risk if both transformers are out of service at the same time, due to a major outage. Some interested parties have therefore suggested that the analyses presented in this report should be expanded to include consideration of the costs of major outages under N-1 (first order contingency) and N-2 (second order contingency) conditions.

The DBs have carefully considered these suggestions, and concluded that it is not necessary for the analyses presented in this report to be extended to include consideration of second order contingency conditions. The principal reason for this is that the value of expected unserved energy associated with second order contingencies would be unlikely to be sufficiently high to justify the advancement of any major augmentation, compared to the augmentation timing that is economically justified by an analysis that is limited to considering first order contingencies. The Appendix contains a detailed example which illustrates this point.

However, in undertaking a detailed economic evaluation of network investment, the DBs agree that the quantity and value of energy at risk associated with higher order contingencies should be considered. These higher order contingencies are unlikely to affect the likely timing of the required investment, which is the primary focus of this report.

4.4 Base reliability statistics for transmission plant

Estimates of the expected unserved energy at each terminal station must be based on the expected reliability performance of the relevant transformers. The basic reliability data for terminal station transformers has been established and agreed with the asset owner, SPI PowerNet. The base data focuses on:

- the availability of the connection point main transformers; and
- the probability of a major problem forcing these plant items out of service for an average period of 2.6 months. This does not include minor faults that would result in a transformer being unavailable for a short period of time (ranging from a few hours up to no more than two days).

The basic reliability data adopted for the purpose of producing this report is summarised in the following table. It is derived from the statistical data collected in a survey carried out in 1995 for the Australian CIGRE Panel 12 on Transformer Reliability, with support from SPI PowerNet, the owner of the connection assets.

Major plant item: Terminal station transformer		Interpretation
Major outage rate for transformer	1.0% per annum	*A major outage is expected to occur once per 100 transformer-years. Therefore, in a population of 100 terminal station transformers, you would expect one major failure of any one transformer per year.*
Weighted average of major outage duration	2.6 months	*On average, 2.6 months is required to repair the transformer and return it to service, during which time, the transformer is not available for service.*
Expected transformer unavailability due to a major outage per transformer-year	0.01 x 2.6/12 = 0.217% approximately	*On average, each transformer would be expected to be unavailable due to major outages for 0.217% of the time, or 19 hours in a year.*

In an email dated 22 November 2013, SPI PowerNet's Principal Engineer, Strategic Network Planning confirmed that the transformer outage rate data and the average transformer repair time assumptions adopted in this report are reasonable, for the purpose of preparing the transmission connection asset risk assessments. SPI PowerNet also advised that the use of average transformer outage data may not accurately represent the specific outage risks associated with individual transformers at particular locations over particular time periods. SPI PowerNet has provided the DBs with further information on asset failure risks on a station-by-station basis where such information is available. This information has been taken into account in the preparation of risk assessments for each terminal station. It is noted that such information is also taken into account in the preparation by SPI PowerNet of its asset replacement plans, and that the DBs strive to coordinate terminal station augmentation works with SPI PowerNet's replacement plans.

Further details regarding the estimation of the weighted average duration of "major outages" are provided in the Appendix. The Appendix also sets out an example demonstrating the calculation of the "Expected Transformer Unavailability" for a terminal station with two transformers, using the basic reliability data contained in this section.

4.5 Availability of spare transformers

In an email dated 22 November 2013, SPI PowerNet's Principal Engineer, Strategic Network Planning confirmed that the metropolitan and country spare 220/66 kV transformers are available for the forthcoming summer period. The metropolitan spare transformer is stored at Keilor Terminal Station, whilst the country spare transformer is stored at South Morang Terminal Station. SPI PowerNet confirmed that:

> "SPI PowerNet took the initiative to purchase these spares in part to ensure consistency with good Electricity Industry practice. This assessment was made on the basis of considering similar integrated transmission utilities, and their approach to transformer spares holding to cover both periodic maintenance activities and forced transformer outages. As a consequence these spares have been purchased to allow the provision of connection services according to our obligations. This service is achieved through an integrated asset management approach that includes not only providing an alternative for transformers which are unavailable for service, but also to support essential maintenance activities including refurbishment programs.

> SPI PowerNet confirms that it will aim to install the spare transformers to replace a unit exposed to long term outage within one calendar month. It must be stressed that while it is considered that such a time frame can generally be achieved it is not appropriate to provide a guaranteed time for the temporary replacement. The individual and unique circumstances of each transformer failure have the potential to result in either a greater or lesser time requirement. More importantly a timeframe of this order could only be achieved if the spare transformer is not being used at another location at the time of the failure."

SPI PowerNet has advised that, subject to the availability of the relevant spare transformer:

- The metropolitan spare transformer is suitable for use at the following stations: Altona, Brooklyn, Cranbourne, East Rowville, Fishermans Bend, Geelong, Heatherton, Keilor, Malvern, Richmond, Ringwood, South Morang, Springvale, Tyabb, Thomastown, Templestowe, and West Melbourne.

- The rural spare transformer is suitable for use at the following stations: Ballarat, Bendigo, Geelong, Glenrowan, Horsham, Kerang, Mount Beauty, Morwell, Red Cliffs, Shepparton, and Terang.

Given the uncertainty regarding the availability of spare transformers at any particular time, the DBs have decided that for the purpose of this report, the potential availability of the spare transformers will not be directly taken into account in the (probabilistic) estimation of expected unserved energy. Instead, the detailed risk assessment for each terminal station will:

- estimate the expected unserved energy for a major outage of a single transformer (namely an outage with an average outage of 2.6 months); and

- where a spare transformer can be deployed to replace the out-of-service transformer, this option will be identified as one of the operational solutions to mitigate the severity (that is, duration) of a major outage.

4.6 Treatment of Load Transfer Capability

For many terminal stations there is some capability to transfer load from one terminal station to adjacent terminal stations using the distribution network. The amount of load that can be transferred varies from minimal amounts at most country terminal stations to significant amounts at some urban terminal stations. Load transfers are able to be made at 66 kV and/or 22 kV and lower voltage levels.

In the event of a transformer failure at a terminal station load could be transferred away (where short-term transfer capability is available) and this would reduce the unserved energy and the impact of an outage. Following careful consideration, the DBs have decided that for the purpose of this report, short-term load transfer capability will not be taken into account directly in the estimation of expected unserved energy in the event of a major failure of a transformer[21]. Instead, where short-term load transfer capability is available at an individual terminal station, the risk assessment for that station will identify

[21] The one exception is Wemen Terminal Station, which is the only single transformer station considered in this report. The risk assessment for Wemen takes into account post-contingent load transfer capability, in order to provide a more accurate assessment of expected unserved energy in the event of a major outage of the single transformer at that station.

this as one of the operational solutions to mitigate the severity of a major outage. If investment can be undertaken to provide permanent load transfer capability to reduce risk at the station, then this will be identified in the risk assessment as an option for alleviating constraints at the station. Therefore whilst the risk assessments set out in this report adopt a simplified analytical approach in terms of considering load transfer capability, the more detailed system studies and economic evaluations (including RIT-T assessments) that are undertaken by DBs prior to committing to a particular project do explicitly consider load transfer capability.

Consistent with the approach outlined in section 4.5 above the analytical approach applied in relation to transfer capability reduces the complexity of the initial analysis of expected unserved energy prepared for this report.

4.7 Detailed risk assessments and options for alleviation of constraints, by terminal station

Set out on the following pages are the detailed risk assessments and a description of the options available for alleviation of constraints, for each individual terminal station. The assessments, by station, are set out in alphabetical order. For each station, the network augmentation requirements (if any) and the estimated annual costs of the augmentation works are identified. This cost estimate provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation.

However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. For example, a non-network solution that defers a network augmentation from 2017 to 2020 is less valuable today than one which defers a network augmentation from, say, 2014 to 2017. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

In addition, any potential proponents of non-network solutions to emerging constraints should note that the lead time for completion of a major network augmentation (such as the development of a new station, or the installation of a new transformer) can easily be up to two to three years, taking into account the need to obtain local authority planning consent[22]. In view of this consideration, the individual risk assessment commentaries for each terminal station will:

- identify the estimated lead time for delivery of the preferred network solution; and/or
- identify the latest date by which the relevant DB(s) will generally require a firm commitment from proponents of non-network alternatives, in order to be confident that the network augmentation can be displaced or deferred without compromising supply reliability in the future.

4.8 Interpreting the dates shown in the risk assessments

All charts and tables in the following risk assessments present data on a calendar year basis. However, the narrative within some of the risk assessments may refer to composite years; for instance “2014/15”, or “summer of 2014/15”.

22 Section 1.5 provides a more detailed description of the processes and timeframes involved in implementing transmission connection projects.

References to composite years may be made in risk assessments relating to summer peaking stations. In these cases, the peak annual demand would typically be expected to occur around mid to late summer (that is, early in the calendar year, say, from late January to March).

Therefore, where a risk assessment refers to a peak demand occurring in a composite year (such as 2014/15, for instance), the peak would typically be expected to occur in the second year (in this example, 2015), and the relevant data for 2014/15 would be shown in the accompanying tables and charts as 2015.

APPENDIX: ESTIMATION OF BASIC TRANSFORMER RELIABILITY DATA AND SAMPLE OF EXPECTED TRANSFORMER UNAVAILABILITY CALCULATION

1. Estimation of basic transformer reliability data

The basic transformer reliability data adopted for the risk assessment is estimated as follows:

Based on historic data, a major outage is expected to occur once per 100 transformer-years (reflecting a 1% per annum failure rate). Therefore, in a population of 100 transformers, you would expect one major failure of any one transformer per year.

The mean duration of a major failure is derived from the following data:

	PROPORTION OF MAJOR FAILURES	MEAN OUTAGE DURATION
Costly Major Failures[23]	0.4 of failures	5.0 months
Other Major Failures	0.6 of failures	1.0 month

Mean duration of a major failure = (0.4*5.0 months) + (0.6*1.0 month) = **2.6 months**

2. Sample of expected transformer unavailability calculation

This appendix sets out an example demonstrating the calculation of the "Expected Transformer Unavailability" for a terminal station with two transformers, using the basic reliability data contained in Section 4.4.

Expected transformer unavailability due to major outage per transformer-year (Refer to Section 4.4 for the base reliability statistics)	A	0.217%
Number of transformers	B	2
Expected unavailability of one transformer (probability of being in state N-1)	**C=A*B**	**0.434%**
Expected unavailability of both transformers (probability of being in state N-2)[24]	**D=A*A**	**0.00047%**

23 The costly major failures are those that would result in repair costs greater than 2% of the replacement value of the failed transformer, with a relatively long duration of outage for repair.

24 The coincident outages of two transformers are considered to be "independent events". This means that the failure of one transformer is assumed to not affect the availability of the other.

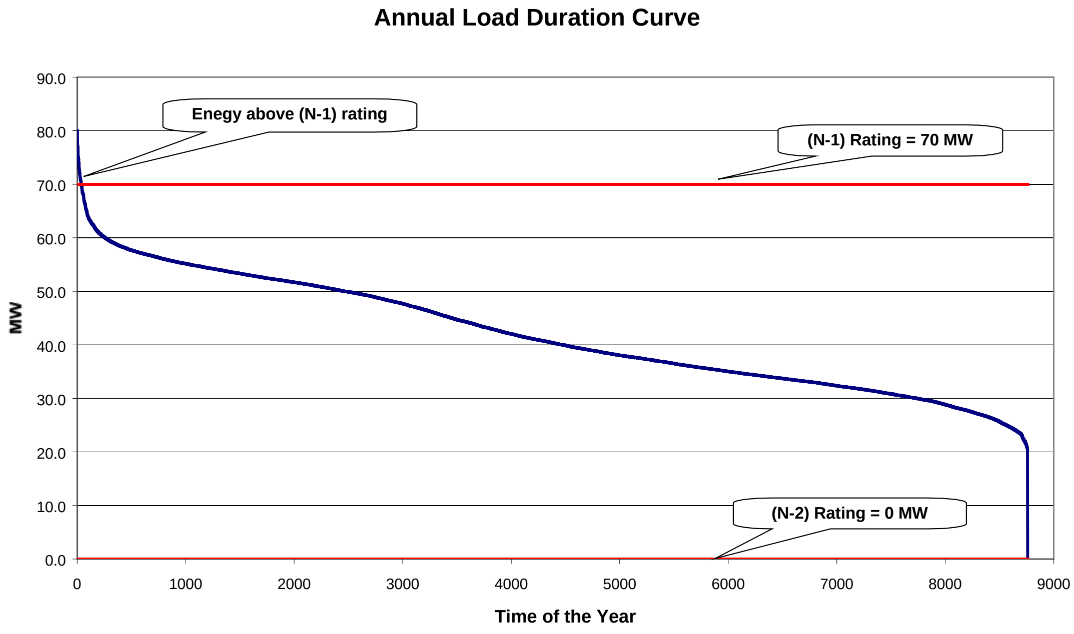
Example Calculation

The following example is used to illustrate the methodology to calculate "Expected Unserved Energy" for a 2-transformer terminal station, given the following data and the load duration curve shown below:

Required Data:

- Maximum Demand = 80 MW
- (N-1) Rating = 70 MW
- (N-2) Rating = 0 MW
- Annual Maximum Demand Growth Rate = 3.0%
- Annual Energy Growth Rate = 1.5%
- VCR = $60,000 per MWh[25]

Risk assessment results for first and second order contingencies (i.e. one and two transformers out of service, respectively) over 10 years are presented for this example. It is assumed that the shape of the load duration curve will not change over the forecast period. Detail calculations are shown for the first year.



Risk Assessment Calculations for the first year

Energy at risk for an N-1 contingency is determined as the area below the load duration curve, but in excess of the N-1 rating, as shown above. For this example, this is given by:

- Energy above N-1 Rating in year 1 = 132 MWh

25 A VCR of $60,000 per MWh is used for illustrative purposes only.

Similarly, energy at risk for an N-2 contingency is determined as the area below the load duration curve, but in excess of the N-2 rating:

- Energy above N-2 Rating in year 1 = 367,877 MWh

First Order Contingency (N-1):

Expected Unserved Energy	= (Energy above N-1 Rating) * (N-1 Probability) = (132 MWh) * (0.434%) = 0.6 MWh
Customer Value	= (Expected Unserved Energy) * (VCR) = (0.6 MWh) * ($60,000 per MWh[26]) = $36,000

Second Order Contingency (N-2)

Expected Unserved Energy	= (Energy above N-2 Rating) * (N-2 Probability) = (367,877 MWh) * (0.00047%) = 1.7 MWh
Customer Value	= (Expected Unserved Energy) * (VCR) = (1.7 MWh) * ($60,000 per MWh) = $102,000

Based on the data set out above, the expected unserved energy and corresponding customer value can be calculated for each year over the next 10 years. The results of these calculations are summarised and presented in the table and chart below. The following conclusions can be drawn from the results:

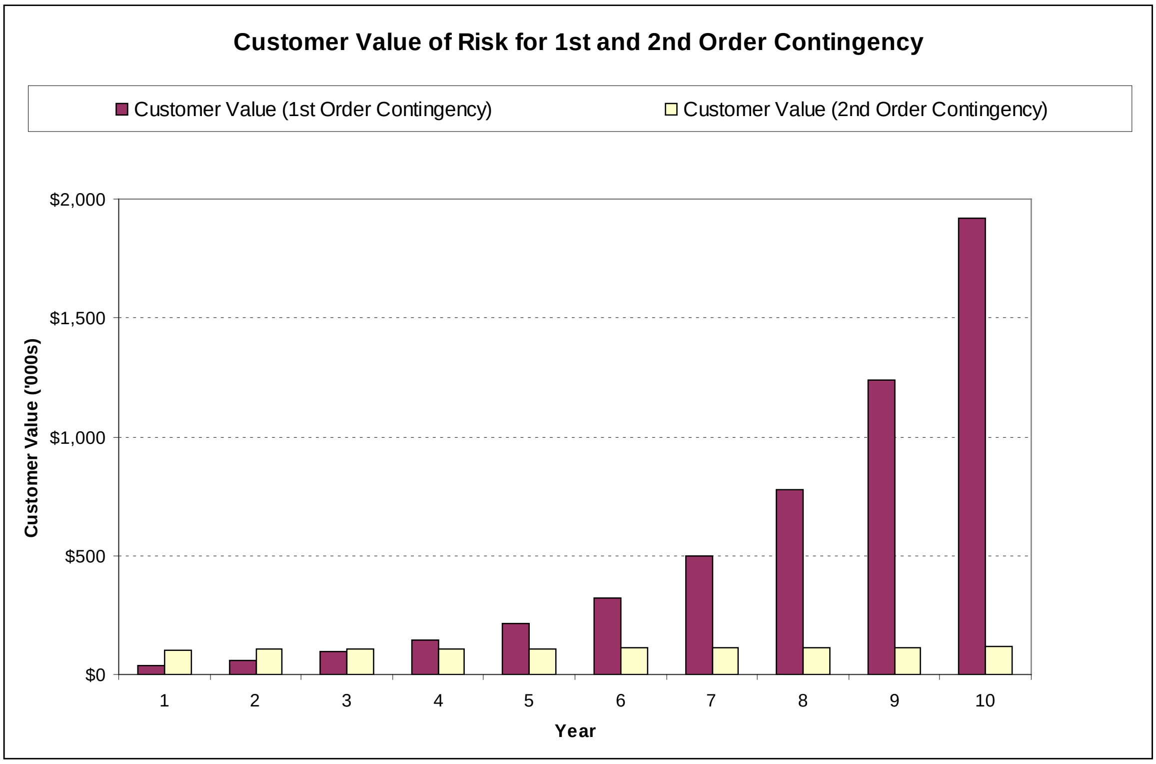
- The value of expected unserved energy for a 2nd order contingency is comparable to the value of expected unserved energy for a 1st order contingency in the earlier years (when the peak demand is roughly the same as the N-1 rating at the station). However, the combined total value of unserved energy for first and second order contingencies in those early years is highly unlikely to economically justify a large capital investment, such as the installation of a new transformer.

- Over the ten year planning horizon, the value of expected unserved energy for a 1st order contingency grows at a much faster rate than the value of expected unserved energy for a 2nd order contingency.

- The value of expected unserved energy associated with 2nd order contingencies only would be unlikely to be sufficiently high to economically justify any major augmentation. Hence, if a terminal station was expected to remain within its N-1 rating over the planning period, major augmentation (such as the installation of a third transformer) would not be economically justified.

- In undertaking a detailed economic evaluation of network investment, the quantity and value of energy at risk associated with higher order contingencies should be assessed. However, for the purpose of providing an indication of the likely timing of the need for new investment, it is sufficient to consider the expected unserved energy associated with first order contingencies only.

[26] A VCR of $60,000 per MWh is used for illustrative purposes only.


Customer Value of Risk for 1st and 2nd Order Contingency
Customer Value (1st Order Contingency)
Customer Value (2nd Order Contingency)
Customer Value ('000s)
$2,000
$1,500
$1,000
$500
$0
1
2
3
4
5
6
7
8
9
10
Year

Summary of Risk Assessment Results for a 2-Transformer Terminal Station Example

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Maximum Demand	**80.0**	**82.4**	**84.9**	**87.4**	**90.0**	**92.7**	**95.5**	**98.4**	**101.3**	**104.4**
N-1 Risk Assessment										
• Rating	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
• Demand above Rating	10.0	12.4	14.9	17.4	20.0	22.7	25.5	28.4	31.3	34.4
• Energy above Rating	132	231	374	565	838	1,253	1,914	3,003	4,759	7,393
• Probability	0.433%	0.433%	0.433%	0.433%	0.433%	0.433%	0.433%	0.433%	0.433%	0.433%
• Expected Unserved Energy	0.6	1.0	1.6	2.4	3.6	5.4	8.3	13.0	20.6	32.0
• Customer Value ($)	36k	60k	96k	144k	216k	324k	498k	780k	1236k	1920k
N-2 Risk Assessment										
• Rating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
• Demand above Rating	80.0	82.4	84.9	87.4	90.0	92.7	95.5	98.4	101.3	104.4
• Energy above Rating	367,877	373,395	378,996	384,681	390,452	396,308	402,253	408,287	414,411	420,627
• Probability	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%	0.00047%
• Expected Unserved Energy	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	2.0
• Customer Value ($)	102k	108k	108k	108k	108k	114k	114k	114k	114k	120k

ALTONA/BROOKLYN TERMINAL STATION (ATS/BLTS) 66kV

Altona/Brooklyn Terminal Station (ATS/BLTS) 66 kV comprises two terminal stations in close proximity, connected by strong sub-transmission ties. The ATS/BLTS 66 kV supply area includes Altona, Brooklyn, Laverton North, Tottenham, Footscray and Yarraville. The stations supply both Jemena Electricity Network and Powercor customers.

Background

ATS consists of three 150 MVA 220/66 kV transformers with the 2-3 66 kV bus tie circuit breaker locked open to manage fault levels. Under these arrangements, only one ATS 150 MVA 220/66 kV transformer operates in parallel with the BLTS system. With the BLTS rebuild project being progressed by SP PowerNet, two 55 MVA 220/66 kV transformers have been retired and one new 150 MVA 220/66 kV transformer has been commissioned in service supplying the 66 kV buses in parallel with one existing 150 MVA 220/66kV transformer. The aging 150 MVA 220/66 kV transformer was replaced with a new unit in 2013.

A 66/22 kV transformer and 35 MVA phase angle regulator connects the BLTS 66 kV bus to the BLTS 22 kV bus. This tie will be retired as part of the rebuild project. A synchronous condenser connected to the BLTS 66 kV bus controls the 220 kV voltage.

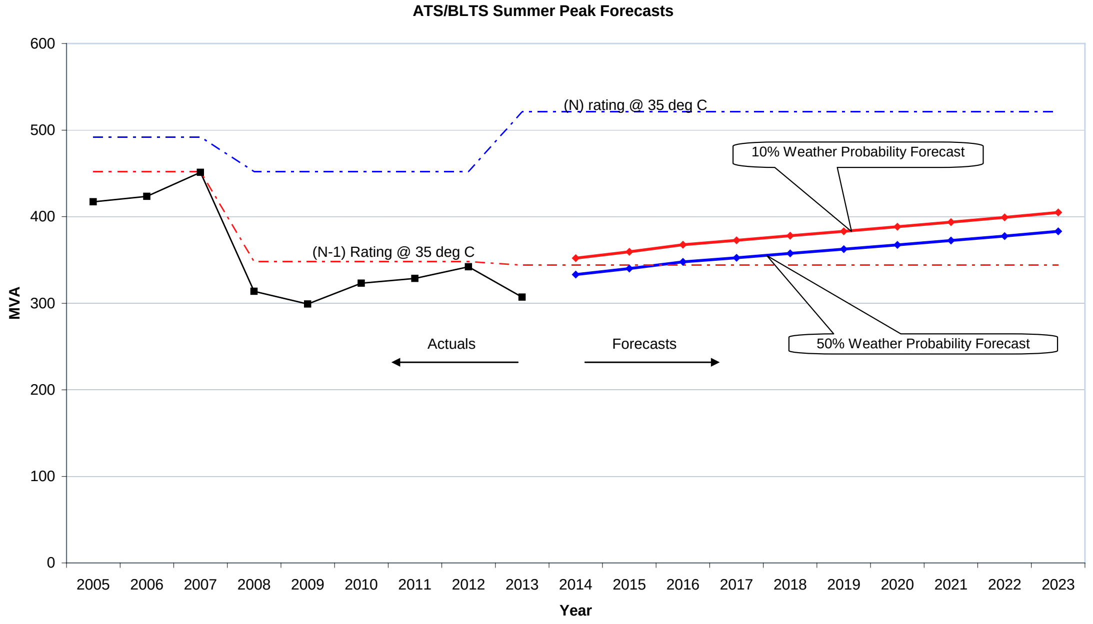
Magnitude, probability and impact of loss of transformer (N-1 System Condition):

The load characteristic for ATS/BLTS substation is of a mixed nature, consisting of residential and industrial applications. The peak load demand on the entire ATS/BLTS 66 kV network reduced from 309 MW in summer 2012 to 285 MW in summer 2013. A major customer (Qenos) installed a 22.5 MW gas generator in January 2013 and load was reduced from ATS-BLTS due to the generation. This load reduction due to the generation is reflected in the load forecasts.

It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.93.

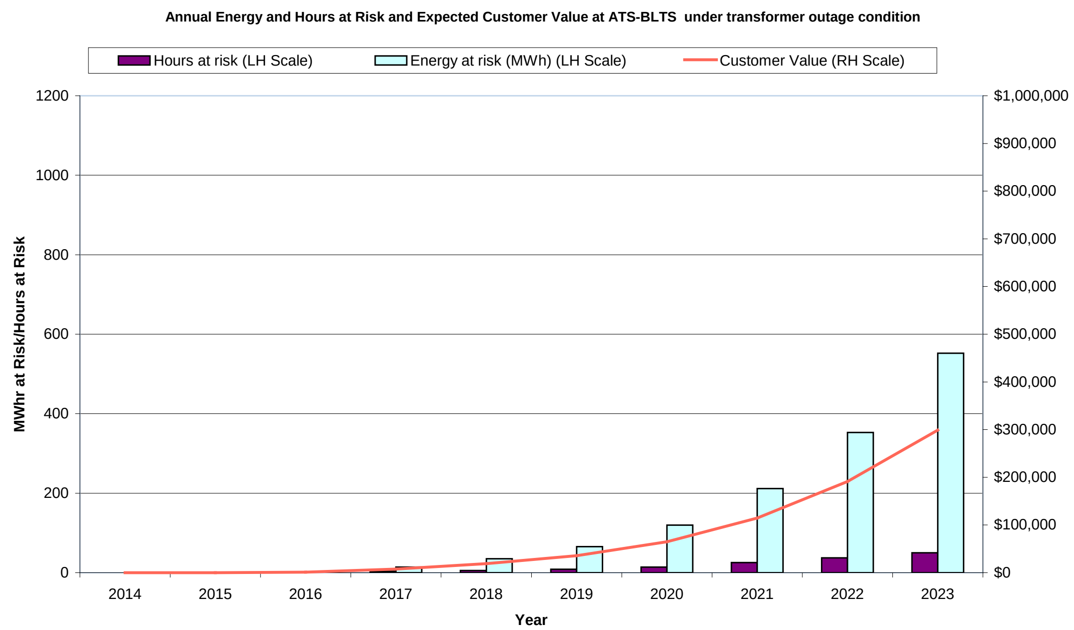
The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature. As explained above, the forecast is affected by the introduction of the Qenos embedded generator in summer 2012-13.



The “N” rating on the chart indicates the maximum load that can be supplied from ATS-BLTS with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from ATS-BLTS with one 150 MVA transformer out of service.

The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand until after 2023. However, if there is a forced transformer outage during peak load periods from 2016 onwards, there is insufficient capacity to supply the forecast demand at the 50th percentile temperature at ATS-BLTS and some customers might be affected.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

As noted above, there will be sufficient capacity at the station to supply all customer demand until 2023 under system normal condition for the 50th percentile demand forecast. However from 2016 onwards, for a major outage of one transformer at ATS-BLTS 66 kV over the summer peak load period; there would be insufficient capacity at the station to supply all customer demand.

For a major outage of one transformer at ATS-BLTS 66 kV, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 50 hours in summer 2023. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 552 MWh in 2023. The estimated value to consumers of the 552 MWh of energy at risk is approximately $46 million (based on a value of customer reliability of $83,315/MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at ATS-BLTS in 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $46 million.

It is emphasised however, that the probability of a major outage of one of the three 150 MVA transformers occurring over the year is very low at about 1% per annum, while the expected unavailability per transformer per annum is 0.217%. When the energy at risk (552 MWh for 2023) is weighted by this low probability, the expected unsupplied energy is estimated to be around 3.6 MWh. This expected unserved energy is estimated to have a value to consumers of around $299,100 (based on a value of customer reliability of $83,315/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 2,564 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $214 million. The corresponding value of the expected unserved energy is approximately $1.39 million.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	552	$46 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	3.6	$0.3 million
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	2,564	$214 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	16.7	$1.39 million

1 The value of unserved energy is derived from the sector values given in Table 2.1 of, weighted in accordance with the composition of the load at this terminal station.

Possible Impact on Customers

System Normal Condition (All 3 transformers in service)

Applying the 50th percentile demand forecast, it is anticipated that there will be sufficient capacity to serve all customers connected to Brooklyn Terminal Station over the 10 year planning horizon.

N-1 System Condition

If one of the ATS-BLTS 220/66 kV transformers is taken off line during peak loading times, causing the Terminal station rating to be exceeded, the OSSCA[2] load shedding scheme which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within transformer capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with Jemena Electricity Network's and Powercor's, operational procedures.

Possible load transfers away to ATS West, BATS and KTS terminal stations in the event of a transformer failure at ATS/BLTS total 20.7 MVA in summer 2014.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the ten year planning horizon:

1. The most likely long term viable solution for the next stage of augmentation will be to transfer loads from Laverton North zone substation to proposed new Truganina zone substation in 2017, resulting in ATS-BLTS being offloaded to the proposed Deer Park terminal station.

2. Capacitor banks connected to the ATS-BLTS 66 kV bus, may substitute for some capacity augmentation.

3. Embedded generation. An alternative option to the network solution could be the establishment of an embedded generator, suitably located in the area that is presently supplied by ATS-BLTS.

4. Demand Management. Another alternative option could be the introduction of demand management to reduce the magnitude of the summer peak demands under network emergencies. This might involve the introduction of interruptible load, negotiated with customers at reduced prices, with an agreement that the load can be interrupted during times of network constraint.

Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at ATS-BLTS, it is proposed to transfer loads from ATS-BLTS to the proposed future Deer Park Terminal Station. This work is not expected to be undertaken before 2017. The cost associated with these load transfers will be part of the proposed future Truganina zone substation project.

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[2] Overload Shedding Scheme of Connection Asset.

[3] Transmission Operations Centre.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

Altona/Brooklyn Terminal station

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor Network – 60.2% Jemena Electricity Network – 39.8%

	MW	MVA	
Normal cyclic rating with all plant in service		521	
Summer N-1 Station Rating:		344	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:		388	

Station: ATS-BLTS Sum 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	333.2	340.0	347.7	352.6	357.6	362.5	367.4	372.5	377.7	383.0
50th percentile Winter Maximum Demand (MVA)	304.9	311.4	318.8	323.2	327.7	332.1	336.6	341.2	345.9	350.7
10th percentile Summer Maximum Demand (MVA)	352.1	359.4	367.6	372.6	378.0	383.1	388.4	393.7	399.2	404.8
10th percentile Winter Maximum Demand (MVA)	311.7	318.3	325.8	330.3	334.9	339.4	344.0	348.7	353.5	358.4
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	2.4	14.3	35.2	65.6	119.5	211.5	353.0	552.0
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	1.5	3.8	5.5	8.8	14.3	25.5	37.3	50.3
N-1 energy at risk at 10% percentile demand (MWh)	14.0	48.5	132.8	234.8	396.9	609.2	899.5	1297.9	1834.8	2564.1
N-1 hours at risk at 10th percentile demand (hours)	3.8	6.3	14.5	26.0	37.8	50.8	71.0	96.3	125.5	164.8
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.02	0.09	0.23	0.43	0.78	1.37	2.29	3.59
Expected Unserved Energy at 10th percentile demand (MWh)	0.09	0.32	0.86	1.53	2.58	3.96	5.85	8.44	11.93	16.67
Expected Unserved Energy value at 50th percentile demand	$0	$0	$1,309	$7,730	$19,081	$35,536	$64,726	$114,519	$191,144	$298,958
Expected Unserved Energy value at 10th percentile demand	$7,583	$26,279	$71,908	$127,178	$214,950	$329,930	$487,112	$702,873	$993,653	$1,388,557
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$2,275	$7,884	$22,489	$43,564	$77,842	$123,855	$191,442	$291,025	$431,897	$625,838

Notes:

1 "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.

2 "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.

3 "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.

4 "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.

5 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

6 The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled Victorian Electricity Planning Approach, published on 9 July 2012

(see www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach)

ALTONA WEST TERMINAL STATION (ATS West) 66kV

Altona Terminal Station 66 kV comprises three 150 MVA 220/66 kV transformers. For reliability and maintenance of existing supply requirements, the station is configured so that one transformer operates in parallel with the BLTS system, and is isolated from the other two transformers via a permanently open 2-3 bus tie CB at ATS. This electrically separates the two systems and effectively creates two separate terminal stations. These stations are referred to as ATS/BLTS and ATS West (ATS bus 3 & 4).

Background

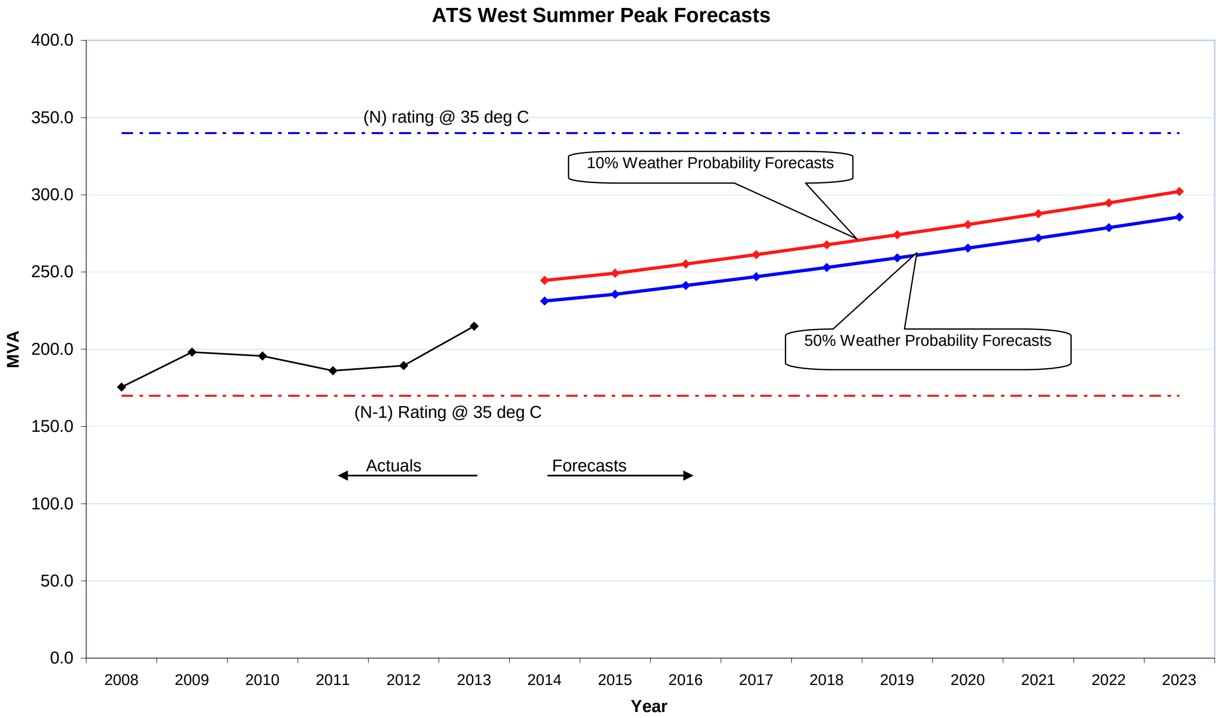
The ATS West 66 kV supply area includes Laverton, Laverton North, Altona Meadows, Werribee, Wyndham Vale, Mount Cottrell, Eynesbury, Tarneit, Hoppers Crossing and Point Cook. The station supplies Powercor customers, as well as Air Liquide, a company supplied directly from the 66 kV bus at ATS.

Since the system reconfiguration between ATS/West and ATS/BLTS prior to summer 2008, growth in summer peak demand on the 66 kV network at ATS West has averaged around 2.1% per annum. The peak load on the station reached 198.5 MW in summer 2013.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.93.

ATS West is summer peaking with high demand occurring over a four month period. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the stations operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.



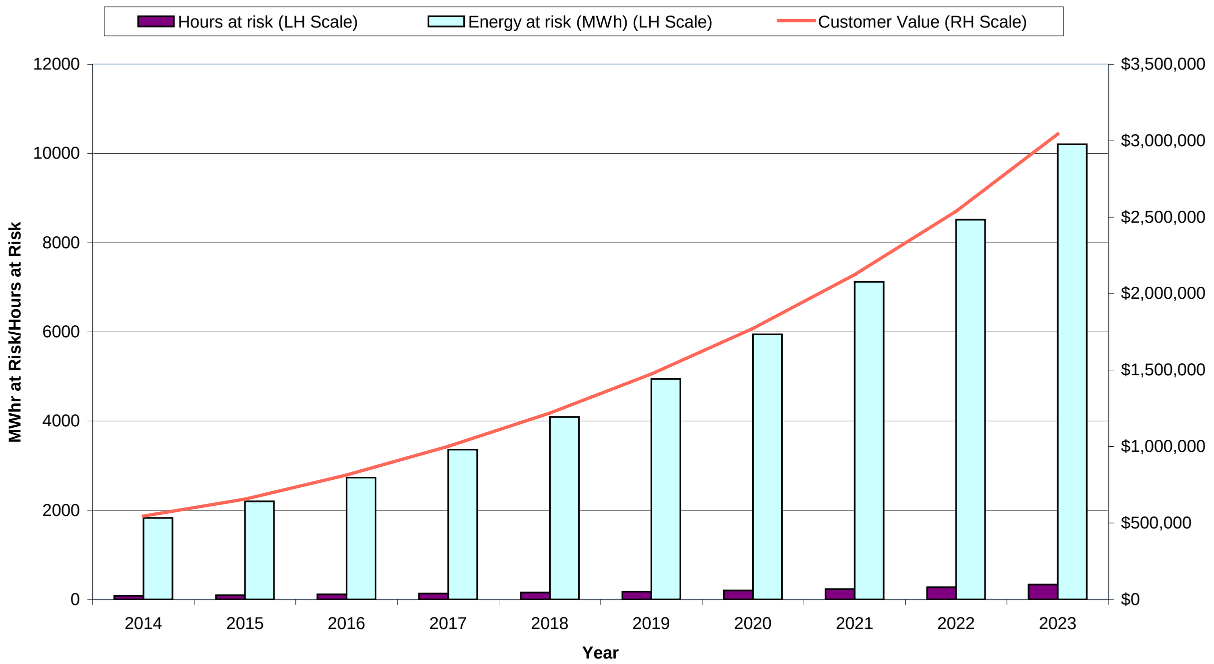
The “N” rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

The graph above shows that from 2014 onwards, there is insufficient capacity to supply the forecast demand at 50th percentile temperature at ATS West if a forced outage of a transformer occurs. The station summer load prediction is 36% above its N-1 rating in 2014 and this increases to 68% over in 2023.

Magnitude, probability and impact of loss of transformer (N-1 System Condition):

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

Annual Energy and Hours at Risk at ATS West on existing transformers



Comments on Energy at Risk

For an outage of one transformer at ATS West 66 kV, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 203 hours in summer 2020. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 5,946 MWh in 2020. The estimated value to consumers of the 5,946 MWh of energy at risk is approximately $409 million (based on a value of customer reliability of $68,794/MWh)[1]. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at ATS West in 2020 would be anticipated to lead to involuntary supply interruptions that would cost consumers $409 million.

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

It is emphasised however, that the probability of a major outage of one of the two 150 MVA transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (5,946 MWh for 2020) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 25.8 MWh. This expected unserved energy is estimated to have a value to consumers of $1.8 million (based on a value of customer reliability of $68,794/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2020 is estimated to be 9,588 MWh. The estimated value to consumers of this energy at risk in 2020 is approximately $660 million. The corresponding value of the expected unserved energy is $2.9 million.

These key statistics for the year 2020 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	5,946	$409 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	25.8	$1.8 million
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	9,588	$660 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	41.6	$2.9 million

Possible Impact on Customers

System Normal Condition (Both transformers in service)

Applying the 50th percentile and 10th percentile demand forecasts, there is sufficient capacity at Altona West Terminal Station to meet all demand when both transformers are in service.

N-1 System Condition

If one of the 150 MVA 220/66 kV transformers at ATS West is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[2] automatic load shedding scheme which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with Powercor's operational procedures after the operation of the OSSCA scheme.

Possible load transfers away to ATS/BLTS and KTS terminal stations in the event of a transformer failure at ATS West total 9.4 MVA in summer 2014.

2 Overload Shedding Scheme of Connection Asset.

3 Transmission Operation Centre.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Install additional transformation capacity and reconfigure 66 kV exits at ATS. This would result in the station being configured so that three transformers are supplying the ATS West load, and one transformer will continue to provide capacity to the ATS/BLTS system.

2. Establishment of a new Deer Park terminal station with proposed Truganina zone substation to offload Laverton (LV) and Werribee (WBE) zone substations and ATS West terminal station. This option has been assessed in a Regulatory Test report for the proposed Deer Park Terminal station, which was published in April 2012, and is also subject to further planning work in relation to the proposed Truganina zone substation, with both proposed projects expected to be completed in 2017.

3. Demand reduction: There is an opportunity to develop innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of potential demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing of any network capacity augmentation.

4. Embedded generation, connected to the ATS 66 kV bus, may substitute capacity augmentations.

Preferred network option(s) for alleviation of constraints

In the absence of a new Terminal Station at Deer Park in 2017 and any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at ATS, it is proposed to install additional transformation capacity and to reconfigure 66 kV exits at ATS.

On the basis of the 50^{th} percentile demand forecast scenario, the installation of an additional transformer and the 66 kV exit reconfiguration works at ATS would not be expected to be economic before 2020. Before 2020 the completion of Deer Park Terminal Station and the proposed Truganina zone substation will allow a portion of the load from LV and WBE zone substations to be permanently transferred away. This will alleviate some of the risk at ATS West.

The capital cost of installing additional transformation capacity and reconfiguring 66 kV exits at ATS is estimated to be in excess of $18 million. The cost of establishing, operating, and maintaining the new transformer and reconfigured subtransmission lines would be recovered from network users through network charges, over the life of the assets. The estimated total annual cost of the preferred network option is $1.8 million.

This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years. Sections 1.5 and 1.6 of this report provide further background information to proponents of non-network solutions to emerging constraints.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy should the Deer Park Terminal Station not proceed in this timeframe.

Altona West Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

	MW	MVA	
Normal cyclic rating with all plant in service		340	via 2 transformers (Summer peaking)
Summer N-1 Station Rating:	158	170	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	176	187	

Station: ATS WEST Sum 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	231.2	235.7	241.3	247.0	253.0	259.1	265.5	272.0	278.7	285.7
50th percentile Winter Maximum Demand (MVA)	169.5	172.4	176.3	180.3	184.5	188.8	193.3	197.9	202.7	207.7
10th percentile Summer Maximum Demand (MVA)	244.5	249.2	255.1	261.2	267.5	274.0	280.7	287.6	294.7	302.1
10th percentile Winter Maximum Demand (MVA)	172.4	175.4	179.3	183.5	187.7	192.1	196.6	201.3	206.2	211.2
N-1 energy at risk at 50% percentile demand (MWh)	1829.7	2201.8	2732.0	3359.1	4091.3	4946.3	5946.1	7125.1	8514.2	10209.7
N-1 hours at risk at 50th percentile demand (hours)	84.8	98.3	115.8	133.8	155.3	176.3	203.3	234.0	274.8	336.5
N-1 energy at risk at 10% percentile demand (MWh)	3321.9	3912.0	4735.2	5693.8	6804.7	8095.6	9587.6	11331.4	13434.7	16073.7
N-1 hours at risk at 10th percentile demand (hours)	125.0	141.0	162.5	184.5	209.0	237.0	271.0	312.3	370.3	448.0
Expected Unserved Energy at 50th percentile demand (MWh)	7.93	9.54	11.84	14.56	17.73	21.43	25.77	30.88	36.90	44.24
Expected Unserved Energy at 10th percentile demand (MWh)	14.40	16.95	20.52	24.67	29.49	35.08	41.55	49.10	58.22	69.65
Expected Unserved Energy value at 50th percentile demand	$0.55M	$0.66M	$0.81M	$1.00M	$1.22M	$1.47M	$1.77M	$2.12M	$2.54M	$3.04M
Expected Unserved Energy value at 10th percentile demand	$0.99M	$1.17M	$1.41M	$1.70M	$2.03M	$2.41M	$2.86M	$3.38M	$4.00M	$4.79M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.68M	$0.81M	$0.99M	$1.21M	$1.46M	$1.76M	$2.10M	$2.50M	$2.98M	$3.57M

Notes:
1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

BALLARAT TERMINAL STATION (BATS) 66kV

Ballarat Terminal Station (BATS) 66 kV consists of two 150 MVA 220/66 kV transformers and is the main source of supply for 66,085 customers in Ballarat and the surrounding area. The station supply area includes Ballarat CBD and Ararat via the interconnected 66 kV tie with Horsham Terminal Station (HOTS).

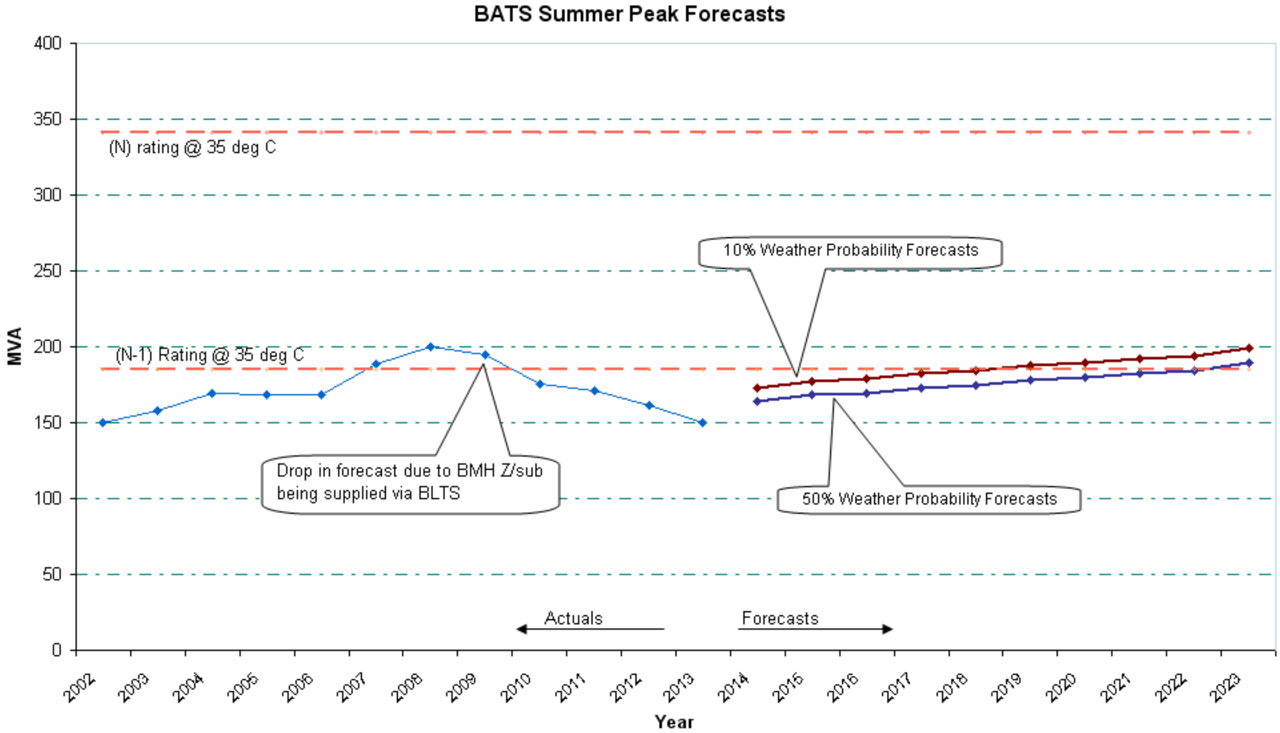
Magnitude, probability and impact of loss of load

Growth in summer peak demand at BATS has averaged around -10 MW (-5.6%) per annum (without BMH zone substation) over the last 5 years. The peak load on the station reached 146 MW in summer 2013. It is noted that summer 2012/13 was a relatively mild summer and a small contribution of embedded generation resulted in lower than usual maximum demands observed at the station. This is reflected in the growth rate referred to above.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.95.

The graph below depicts the 10th and 50th percentile maximum demand forecasts together with the stations operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.



The (N) rating on the chart indicates the maximum load that can be supplied from BATS with all transformers in service.

In July 2008, BMH zone substation load was from BATS to BLTS, resulting in a reduction in demand at BATS, as shown in the above chart.

The chart shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service under 50th percentile forecast conditions. Under 10th percentile forecast conditions, there is load at risk from 2019 onwards which can be managed utilising load transfers away to HOTS in the order of 10 MVA. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years

BENDIGO TERMINAL STATION (BETS) 22 kV

Bendigo Terminal Station (BETS) 22 kV consists of two 75 MVA 235/22.5 kV transformers supplying the 22 kV network ex-BETS. These two transformers have been in service since mid 2013 and they have enabled the separation of the 66 kV and 22 kV points of supply, and the transfer of load from the existing 230/66/22kV transformers. This configuration is the main source of supply for 19,500 customers in Bendigo and the surrounding area. The station supply area includes Marong, Newbridge and Lockwood.

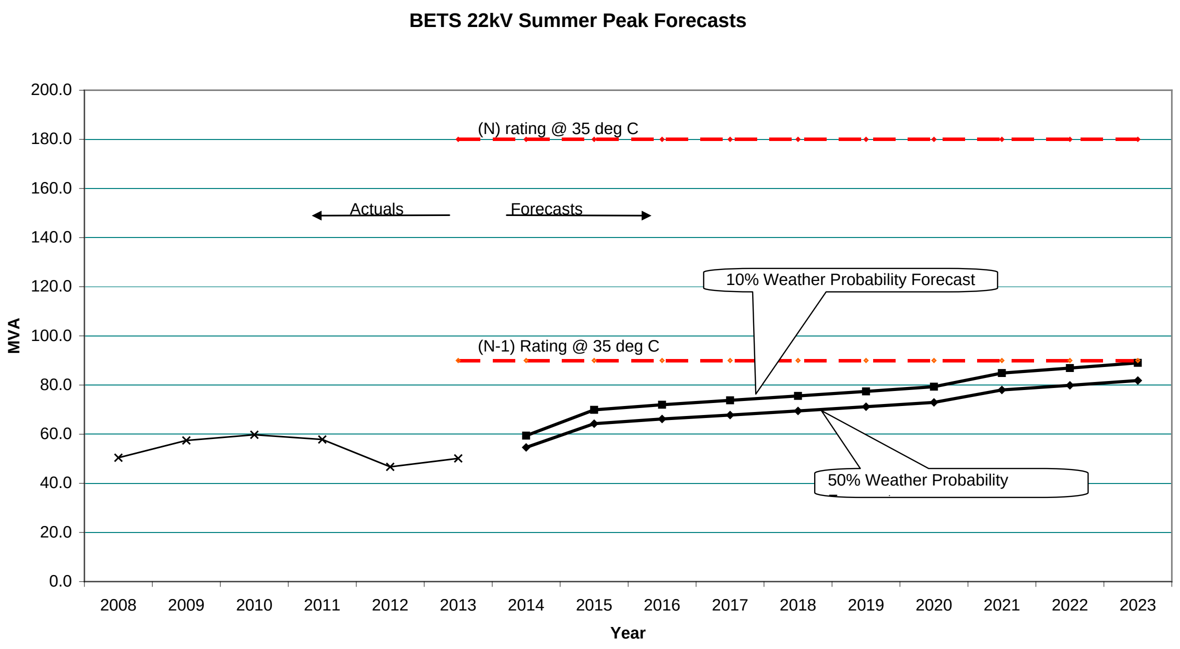
Magnitude, probability and impact of loss of load

BETS 22 kV demand is summer peaking. Growth in summer peak demand on the 22 kV network at BETS has averaged around -0.1 MW (-0.1%) per annum over the last 5 years. The peak load for the 22 kV network now on the station reached 48.9 MW in summer 2013.

It is estimated that:

- For 13 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.98.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.



The (N) rating on the chart indicates the maximum load that can be supplied from BETS with all transformers in service. Exceeding this level will initiate automatic load shedding by SPI PowerNet's automatic load shedding scheme.

The graph shows that there is sufficient capacity at the station to supply all the 50th percentile demand expected over the forecast period to 2023, even with one transformer out of service. Load at risk after 2023 for the 10th percentile demand scenario can be managed by transferring load to BETS 66 kV. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

BENDIGO TERMINAL STATION (BETS) 66 kV

Background

In mid 2013, SPI PowerNet commissioned 2x75 MVA 220/22 kV transformers to pick up the 22 kV load from the tertiary of the existing 230/66/22 kV transformers. The 66 kV and 22 kV points of supply at Bendigo Terminal Station are now segregated and supplied from separate transformers.

With the asset renewal plan at BETS being progressed by SPI PowerNet, two 70/57/51 MVA 230/66/22 kV transformers have been retired and one new 150 MVA 220/66 kV transformer has been commissioned in service supplying the 66 kV buses in parallel with one existing 125/125/40 MVA 230/66/22 kV transformer in 2013. These transformers provide the main source of 66 kV supply for 61,329 customers in Bendigo and the surrounding area. The station supply area includes Bendigo CBD, Eaglehawk, Charlton, St. Arnaud, Maryborough and Castlemaine.

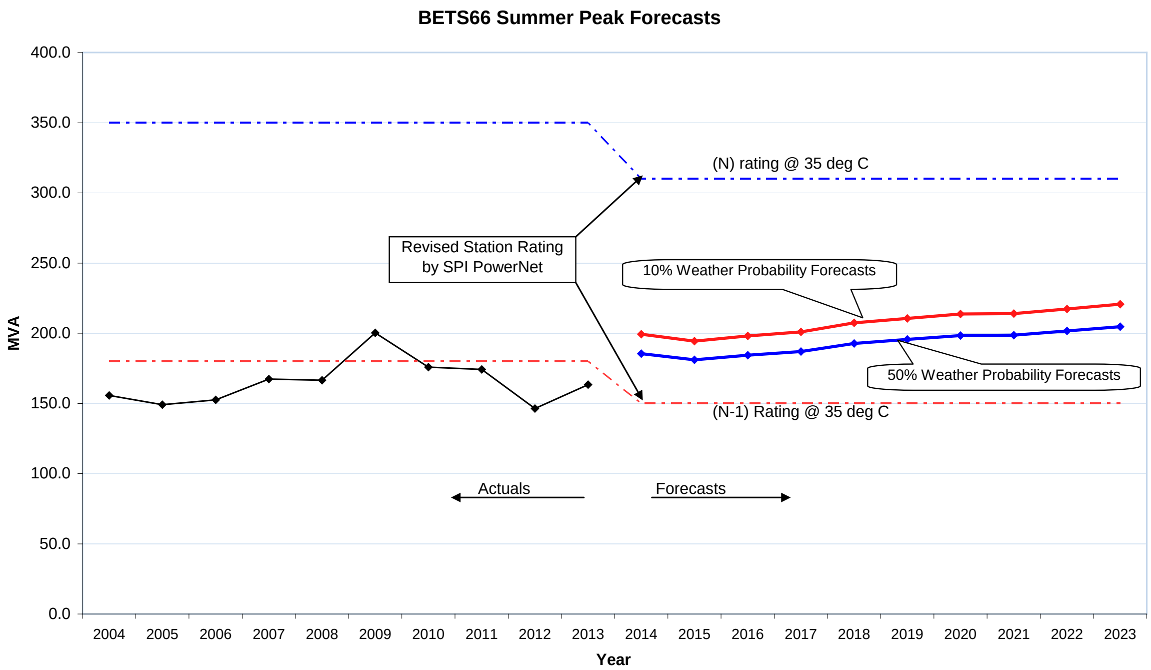
Magnitude, probability and impact of loss of load

Growth in summer peak demand at BETS 66 kV has averaged around -0.2 MW (-0.1%) per annum over the last 5 years. The peak load on the station reached 161.6 MW in summer of 2013.

It is estimated that:

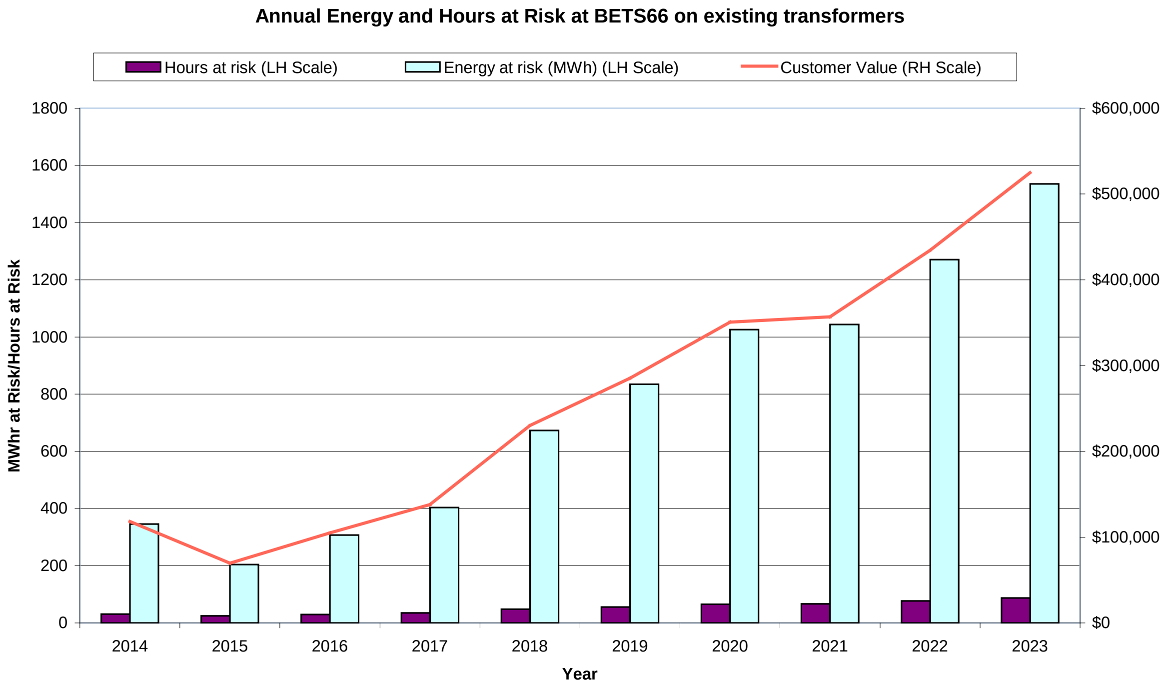
- For 12 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at time of peak demand is 0.99.

BETS 66 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperatures.



The (N) rating on the chart indicates the maximum load that can be supplied from BETS with all transformers in service. Exceeding this level will initiate automatic load shedding by SPI PowerNet's automatic load shedding scheme.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For a major outage of one transformer at BETS 66 kV during the summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 87.5 hours in 2023. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 1,535 MWh in 2023. The estimated value to consumers of the 1,535 MWh of energy at risk is approximately $121.1 million (based on a value of customer reliability of $78,887/MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at BETS 66kV in 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $121.1 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (1,535 MWh for 2023) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 6.7 MWh. This expected unserved energy is estimated to

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

have a value to consumers of around $0.52 million, (based on a value of customer reliability of $78,887/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 3,493 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $275.6 million. The corresponding value of the expected unserved energy is approximately $1.2 million.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	1,535	$121.1 million
Expected unserved energy at 50th percentile demand	6.7	$0.52 million
Energy at risk, at 10th percentile demand forecast	3,493	$275.6 million
Expected unserved energy at 10th percentile demand	15.1	$1.19 million

If one of the 230/66/22 kV transformers at BETS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[2] automatic load shedding scheme which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with Powercor's operational procedures after the operation of the OSSCA scheme.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the next ten year planning horizon:

1. Implement a contingency plan to transfer 13.8 MVA of load away to BETS 22 kV in the event of loss of a transformer at BETS 66 kV.

2. Install an additional 150 MVA 220/66 kV transformer at BETS 66 kV.

3. Demand reduction: There is an opportunity for voluntary demand reduction to reduce peak demand during times of network constraint. The amount of demand reduction would be taken into consideration when determining the optimum timing for the capacity augmentation.

4. Embedded generation, connected to the BETS 66 kV bus, may defer the need for an additional 220/66 kV transformer at BETS 66 kV.

[2] Overload Shedding Scheme of Connection Asset.

[3] Transmission Operation Centre.

Preferred option(s) for alleviation of constraints

As already noted, a contingency plan to transfer 13.8 MVA of load to BETS 22 kV will be implemented in the event of the loss of one of the BETS 220/66 kV transformer.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at BETS 66 kV, it is proposed to install an additional 150 MVA 220/66 kV transformer at BETS 66 kV. However, it is expected that the additional capacity will not be economically justified during the forecast period.

The capital cost of installing an additional transformer at BETS is estimated to be $12 million. The cost of establishing, operating and maintaining an additional transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $1.2 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation. Sections 1.5 and 1.6 of this report provide further background information to proponents of non-network solutions to emerging constraints.

Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for rural areas (refer to Section 4.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

Bendigo Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)
Normal cyclic rating with all plant in service 322 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating: 150.0 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 171.0 MVA

Station: BETS Sum 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	171.9	166.7	170.6	173.6	180.4	183.6	186.9	187.2	190.6	194.1
50th percentile Winter Maximum Demand (MVA)	125.6	121.1	123.1	124.4	129.3	130.6	132.0	131.2	132.6	134.0
10th percentile Summer Maximum Demand (MVA)	187.9	182.2	186.5	189.9	197.2	200.8	204.4	204.7	208.4	212.2
10th percentile Winter Maximum Demand (MVA)	129.5	124.9	127.0	128.3	133.4	134.8	136.2	135.3	136.8	138.2
N-1 energy at risk at 50% percentile demand (MWh)	346.0	203.9	307.3	403.5	672.8	834.5	1025.8	1043.7	1270.6	1535.1
N-1 hours at risk at 50th percentile demand (hours)	31.0	24.5	29.5	34.8	48.3	55.8	65.3	66.8	76.8	87.5
N-1 energy at risk at 10% percentile demand (MWh)	1100.6	770.5	1011.2	1231.2	1818.8	2156.0	2536.4	2571.3	3004.1	3493.4
N-1 hours at risk at 10th percentile demand (hours)	68.5	52.3	64.0	74.8	97.5	110.5	123.5	124.5	138.8	153.5
Expected Unserved Energy at 50th percentile demand (MWh)	1.50	0.88	1.33	1.75	2.92	3.62	4.45	4.52	5.51	6.65
Expected Unserved Energy at 10th percentile demand (MWh)	4.77	3.34	4.38	5.34	7.88	9.34	10.99	11.14	13.02	15.14
Expected Unserved Energy value at 50th percentile demand	$0.12M	$0.07M	$0.11M	$0.14M	$0.23M	$0.29M	$0.35M	$0.36M	$0.43M	$0.52M
Expected Unserved Energy value at 10th percentile demand	$0.38M	$0.26M	$0.35M	$0.42M	$0.62M	$0.74M	$0.87M	$0.88M	$1.03M	$1.19M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.20M	$0.13M	$0.18M	$0.22M	$0.35M	$0.42M	$0.51M	$0.51M	$0.61M	$0.73M

Notes:

1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means “ energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50^{th} and 10^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

BROOKLYN TERMINAL STATION (BLTS) 22 kV

The Brooklyn Terminal Station (BLTS) 22 kV supply area includes Altona, Brooklyn, Laverton North, Tottenham, Footscray and Yarraville. The station supplies both Jemena Electricity Network and Powercor customers.

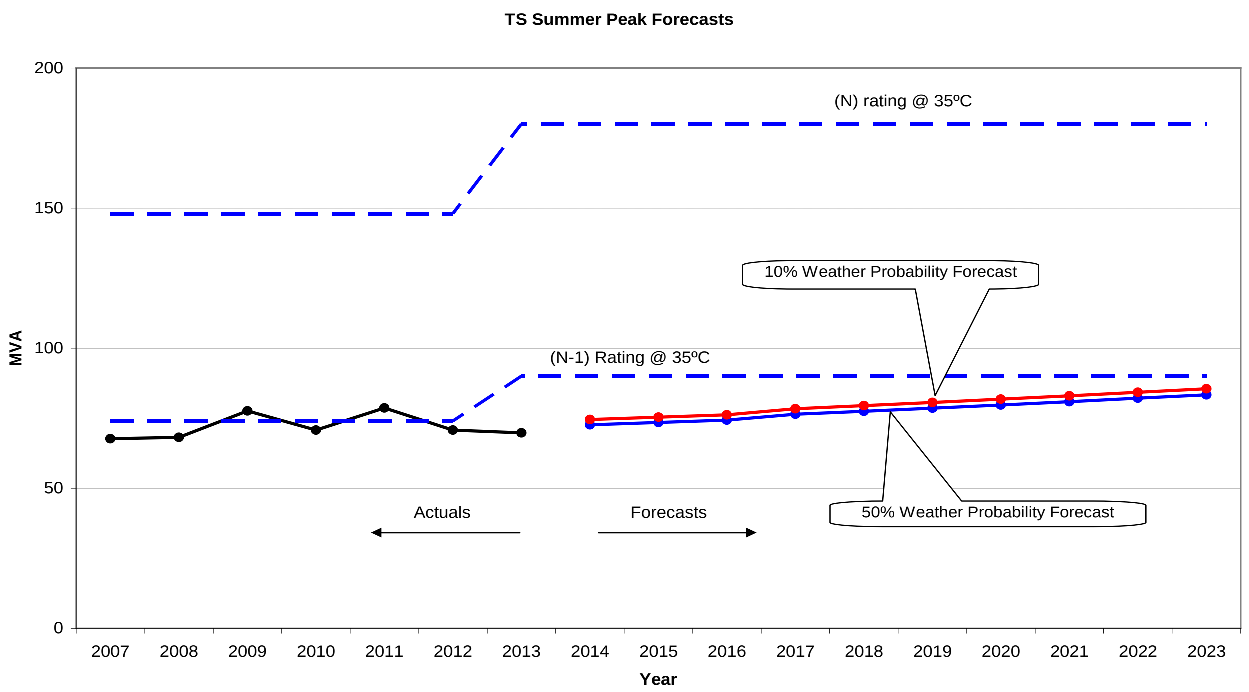
Background

Brooklyn Terminal Station (BLTS) 22 kV is being rebuilt by SP PowerNet during 2012-13 with the existing two 60 MVA 220/22 kV transformers plus a 35 MVA 66/22 kV tie transformer/phase angle regulator (PAR) being retired and replaced by two new 75 MVA 220/22 kV transformers namely L1 & L3. This configuration is the main source of supply for 6,800 customers in Brooklyn and the surrounding area.

The load characteristic for BLTS 22 kV substation is of a mixed nature, consisting of residential and industrial applications. In recent years, the industrial load has declined in the area; however this has been offset by the some growth from residential developments. Growth in summer peak demand on the 22 kV network at BLTS is expected to rise at an average of around 1.6% per annum over the next ten years. The peak load demand on the entire BLTS 22 kV network reached 59.6 MW in summer 2013. It is estimated that:

- For 14 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the time of peak demand is 0.85.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.



The “N” rating on the chart indicates the maximum load that can be supplied from BLTS 22 kV Terminal Station with all transformers in service. The “N-1” rating on the chart is the load that can be supplied with one 75 MVA transformer out of service.

The above graph shows that there is adequate capacity to meet the anticipated maximum load demand until 2023.

As previously noted, there has been a decline in industrial land use in the area in recent years, resulting in the rezoning of some industrial land for commercial and residential use. About 3000 lots of medium to low load density housing are being planned to be developed in this area, and depending on the scale and rate of actual development in the future, station load growth may increase from the current projected rate of 1.6% per annum to 3% per annum.

BRUNSWICK TERMINAL STATION 22 kV (BTS 22 kV)

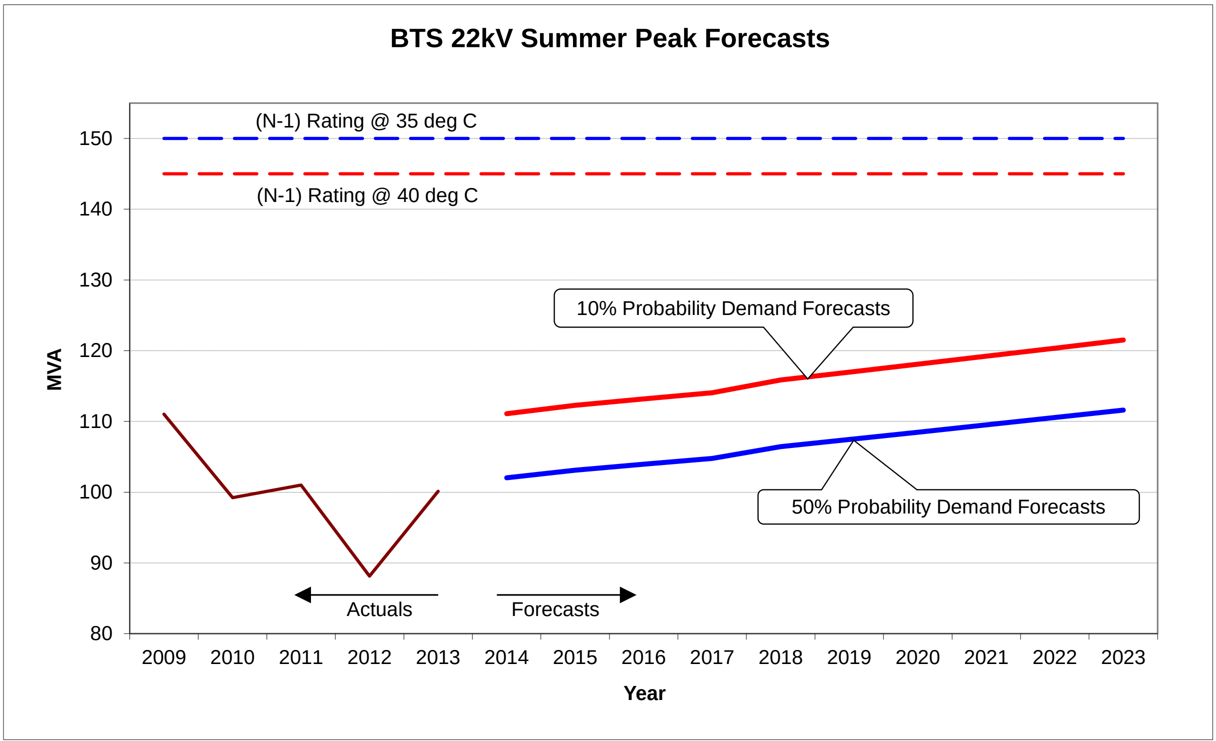
BTS 22 kV is a terminal station shared by Jemena Electricity Networks (58%) and CitiPower (42%). It is located in an inner northern suburb of Melbourne, operating at 220/22 kV and supplying areas including Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds.

Magnitude, probability and impact of loss of load

BTS 22 kV is a summer critical station. Following completion of the station refurbishment by SPI PowerNet in early 2007, BTS 22 kV has three 75 MVA transformers operating in parallel. It is estimated that:

- For 12 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at the time of peak demand is 0.92.

The graph below depicts the BTS 22 kV operational “N-1” rating (for an outage of one transformer) at ambient temperatures of 35°C and 40°C, and the 50th and 10th percentile summer maximum demand forecasts.



The graph shows there is sufficient station capacity to supply all anticipated loads and that no customers would be at risk if a forced transformer outage occurred at BTS 22 kV over the forecast period. Accordingly, no capacity augmentation is planned at BTS 22 kV over the next ten years.

BRUNSWICK TERMINAL STATION 66 kV (BTS 66 kV)

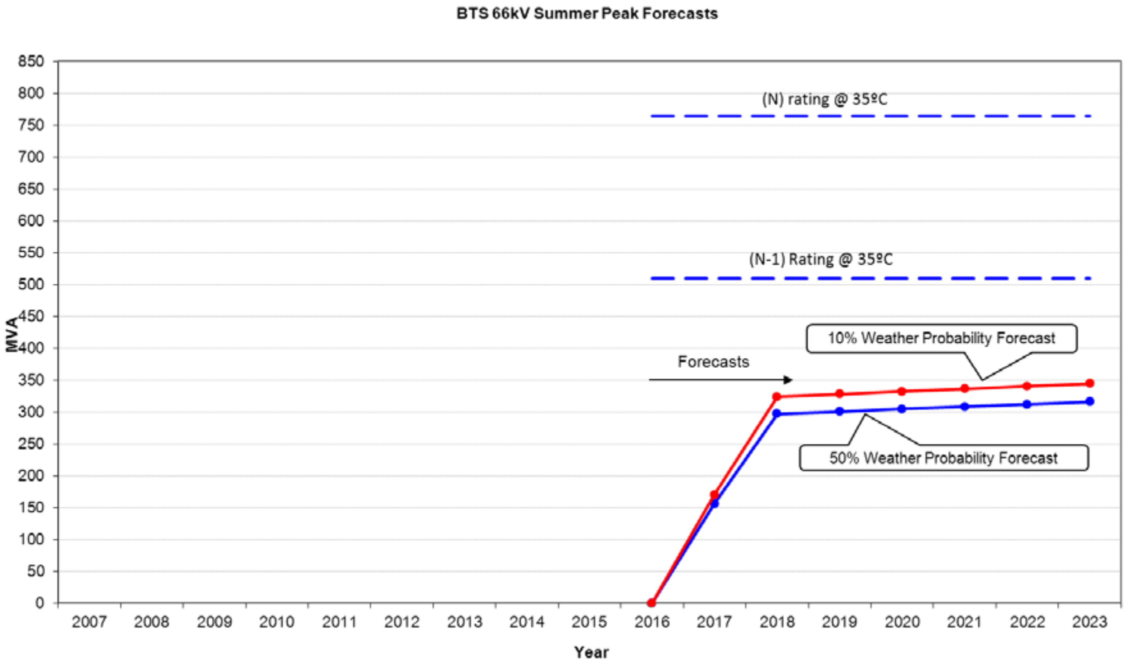
BTS 66 kV will be a new 66 kV source of supply, to be established with 3 x 225 MVA 220/66 kV transformers. BTS 66 kV is a committed project and is expected to be established in 2015/16 to reinforce the security of supply to the northern and inner suburbs and the Central Business District areas, and to provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood.

Magnitude, probability and impact of loss of load

The initial BTS load will include transfers of load from WMTS 66 kV. The BTS demand will be summer peaking. Subsequent load transfer projects amounting to approximately 140 MVA from RTS 66 kV in 2018 have now been approved, and are reflected in the graph below.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35 deg C ambient temperature.

The peak load on the station is expected to reach 149.6 MW in summer 2017 with a station load power factor of 0.96. The number of hours per year in which 95% of peak load is expected to be reached under the 50th percentile demand forecast is estimated to be 7 hours.



The graph shows that there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service.

CRANBOURNE TERMINAL STATION (CBTS)

Magnitude, probability and impact of loss of load

Cranbourne terminal station (CBTS) was originally commissioned with two 150 MVA 220/66 kV transformers in 2005 to reinforce the security of supply for United Energy and SPI Electricity customers and to off-load East Rowville terminal station. In order to supply the growing electricity demand in the area, a third 150 MVA 220/66 kV transformer was commissioned in 2009.

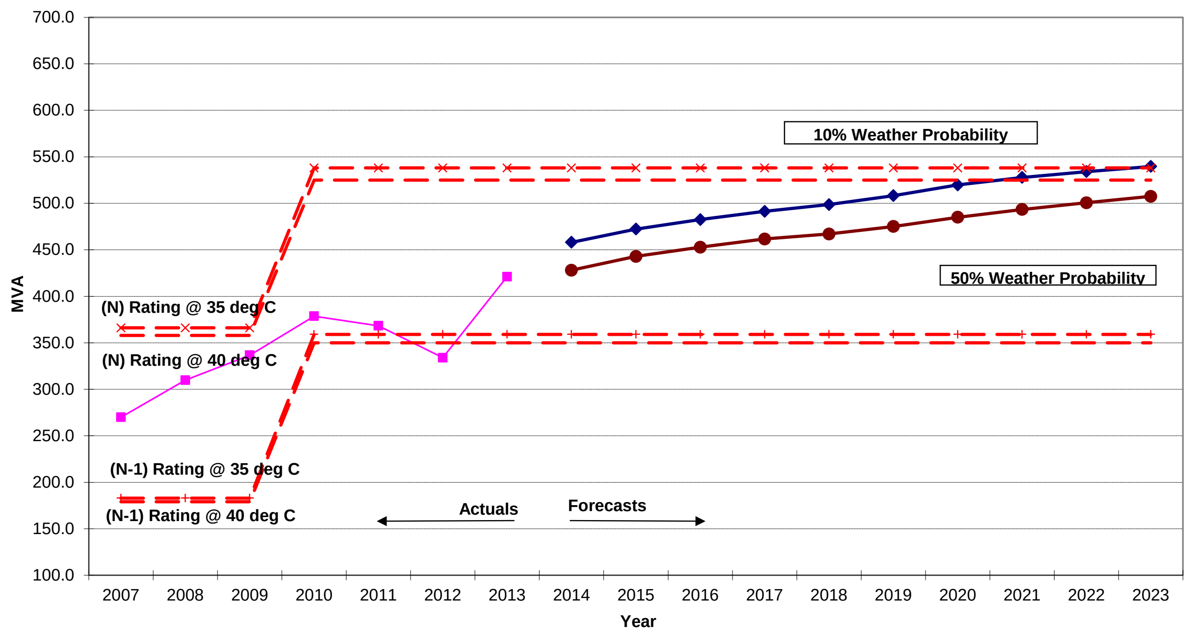
The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west. The electricity distribution networks for this area are the responsibility of both SPI Electricity (59%) and United Energy (41%).

The summer peak demand at CBTS 66 kV has increased by 150 MW, equivalent to an annual growth rate of 8%, between 2007 and 2013. The peak load on the station reached 402.4 MW (421.1 MVA) in summer 2012/13. The station load has a power factor of 0.956 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak load for 2 hours per annum.

The risk of interruption to CBTS 66 kV supplies, for a single contingency event was assessed as being unacceptable in 2010. A Request For Information (RFI) was published by SPI Electricity, United Energy and Australian Energy Market Operator (AEMO) in March 2011 to seek non-network alternatives to this emerging constraint. Two offers were received, one for demand management and one for connecting embedded generation. SPI Electricity and United Energy commenced negotiation with the generation proponent to establish a network support contract that would allow the installation of the fourth 220/66kV 150 MVA transformer to be deferred. However the forecast demand growth rate has significantly declined due to weaker economic conditions, appliance energy efficiency, rooftop solar generation and the impact of increases in the cost of electricity. This has deferred the economic timing for the installation of a fourth transformer or a network support contract as demonstrated later in this risk assessment.

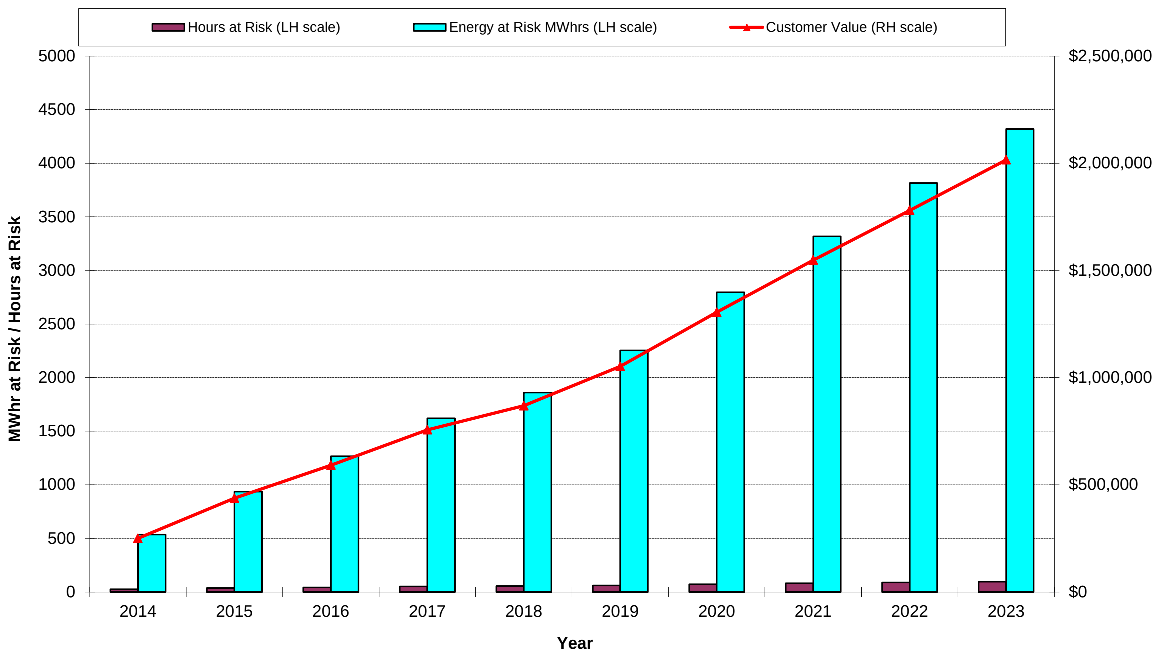
The precise timing and nature of the augmentation or network support option are yet to be determined. Accordingly, the following risk assessment is for the current configuration with three transformers.

CBTS 66 kV is a summer peaking station and is expected to be loaded above its “N-1” rating in summer. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s expected operational “N” rating (all transformers in service) and the “N-1” rating at 35°C as well as 40°C ambient temperature.



The "N" rating on the chart indicates the maximum load that can be delivered from CBTS 66 kV with all transformers in service. Exceeding this level will initiate SPI PowerNet's automatic load shedding scheme.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the "N-1" capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



CBTS is not expected to be loaded above its "N-1" rating under 50th percentile or 10th percentile winter maximum demand forecasts during the ten year planning horizon.

Comments on Energy at Risk

For an outage of one 220/66 kV transformer at CBTS, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 96 hours in 2022/23. The energy at risk under "N-1" conditions is estimated to be 4,320 MWh in 2022/23. The estimated value to consumers of the 4,320 MWh of energy at risk is approximately $310 million (based on a value of customer reliability of $71,791/MWh)[1]. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one 220/66 kV transformer at CBTS for the entire duration of the summer of 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers $310 million.

It is emphasised however, that the probability of a major outage of one of the transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (4,320 MWh) is weighted by this low unavailability, the expected unserved energy is estimated to be around 28.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $2.0 million (based on a value of customer reliability of $71,791/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of moderate temperatures occurring in each year. Under higher temperature conditions (that is, at the 10th percentile level), the energy at risk in 2022/23 is estimated to be 7,142 MWh. The estimated value to consumers of this energy at risk in 2022/23 is approximately $513 million. The corresponding value of the expected unserved energy is $3.3 million.

These key statistics for the year 2022/23 under "N-1" outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	4,320	$310 million
Expected unserved energy at 50th percentile demand	28.1	$2.0 million
Energy at risk, at 10th percentile demand forecast	7,142	$513 million
Expected unserved energy at 10th percentile demand	46.5	$3.3 million

If one of the 220/66 kV transformers at CBTS is taken off line during peak loading times and the N-1 station rating is exceeded, the Overload Shedding Scheme for Connection Assets (OSSCA)[2] which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within ratings of available plant. In the event of OSSCA operating, it would automatically shed up to 150 MVA of load, affecting up to 58,000 customers in 2013/14. Any load reductions that are in excess of the minimum amount required to limit load to the rated

[1] The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

[2] OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

[3] Transmission Operations Centre

capability of the station would be restored at zone substation feeder level in accordance with United Energy's and SPI Electricity's operational procedures after the operation of the OSSCA scheme.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint.

1. Implement contingency plans to transfer load to adjacent terminal stations: Both SPI Electricity and United Energy have established and implemented the necessary plans that enable load transfers under contingency conditions via emergency 66 kV ties to the adjacent terminal stations at East Rowville (ERTS 66 kV), Tyabb (TBTS 66 kV) and Heatherton (HTS 66 kV). The emergency 66 kV ties can be in operation within 2 hours and have a combined capability to transfer up to 150 MVA of load. Transfers using the 22 kV distribution network are also able to transfer a further 55 MVA.

2. Establish a new 220/66 kV terminal station: SPI Electricity expects that a new terminal station in the Pakenham area (with a site yet to be acquired) will be required in around 10 to 20 years to service load growth in the region. This development will help to off-load CBTS as well as addressing constraints on the existing 66 kV sub-transmission network from CBTS to the Pakenham area. SPI Electricity will carry out planning studies to assess whether this option is economic, and if so, to determine the optimal timing of any investment. An alternative would be to develop a new terminal station on a reserved site in North Pearcedale. The North Pearcedale site, however, is not located within the growth area and is considered suboptimal at this time.

3. Install a 4th 220/66 kV transformer at Cranbourne Terminal Station: The site has provision for a 4th transformer and implementing this option is relatively straight forward, however it would require 66 kV lines to be re-arranged so that the station can operate with split 66 kV buses in order to maintain fault levels within equipment ratings.

4. Install two new 50 MVAr 66 kV capacitor banks: CBTS currently does not have 66 kV capacitor banks and the station operates with a power factor around 0.96 lagging in summer. Installing two 50 MVAr 66 kV capacitor banks will help to reduce the net MVA supplied by the transformers by approximately 20 MVA and would defer the network augmentation by one year. AEMO have also been considering installing capacitors at CBTS to support the transmission network and any opportunity to install 66 kV capacitors at CBTS to provide benefits in both areas will be identified through joint planning with AEMO.

5. Demand Management: United Energy and SPI Electricity have developed a number of innovative network tariffs that encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and the subsequent change in load pattern and will be taken into consideration when determining the optimum timing for the capacity augmentation.

6. Embedded Generation: Embedded generation, with a capacity in the order of 20 MW, connected to the CBTS 66 kV bus, will defer the need for augmentation by one to two years.

Preferred network option for alleviation of constraints

Although SPI Electricity and United Energy have commenced the process of addressing the supply risks at CBTS, as discussed earlier the recent reduction in demand forecasts indicate that these activities can be deferred. The preferred option of network support and then the installation of a fourth 150 MVA 220/66 kV transformer can be deferred until 2021 based on the latest forecasts. The installation of two new 50 MVar 66 kV capacitor banks at CBTS could be economic earlier if they also supported the needs of the transmission network.

Prior to implementing any augmentation option it is proposed to implement the following temporary measures to cater for an unplanned outage of one transformer at CBTS under critical loading conditions:

- maintain contingency plans to transfer load to adjacent terminal stations;
- fine-tune the OSSCA scheme settings to minimise the impact on customers of any automatic load shedding that may take place; and
- subject to the availability of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer Section 4.5), this spare transformer can be used to temporarily replace a failed transformer.

The capital cost of installing a fourth 150 MVA 220/66 kV transformer at CBTS is estimated to be $20 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2 million. This cost provides a broad upper bound for the maximum annual network support payment which may be available to embedded generators or customers to reduce forecast demand, and to defer or avoid the transmission connection component of this augmentation. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

CRANBOURNE TERMINAL STATION
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (41%) and SPI Electricity (59%)

Normal cyclic rating with all plant in service 538 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Rating 359 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating 411 MVA

Station: CBTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	428.0	442.9	452.7	461.6	467.0	475.1	485.0	493.4	500.6	507.5
50th percentile Winter Maximum Demand (MVA)	333.7	342.1	349.4	356.1	362.7	369.1	374.6	378.9	382.5	386.9
10th percentile Summer Maximum Demand (MVA)	458.1	472.3	482.5	491.3	498.6	508.3	519.7	527.8	534.1	539.6
10th percentile Winter Maximum Demand (MVA)	343.6	351.9	359.0	365.5	371.9	378.2	383.6	387.7	390.9	395.3
N - 1 energy at risk at 50th percentile demand (MWh)	536	937	1,267	1,620	1,861	2,254	2,796	3,318	3,815	4,320
N - 1 hours at risk at 50th percentile demand (hours)	26	36	43	50	55	62	72	81	89	96
N - 1 energy at risk at 10th percentile demand (MWh)	2,326	2,944	3,443	3,908	4,323	4,903	5,647	6,222	6,699	7,142
N - 1 hours at risk at 10th percentile demand (hours)	45	53	59	64	69	74	84	91	97	102
Expected Unserved Energy at 50th percentile demand (MWh)	3.5	6.1	8.2	10.5	12.1	14.7	18.2	21.6	24.8	28.1
Expected Unserved Energy at 10th percentile demand (MWh)	15.1	19.2	22.4	25.4	28.1	31.9	36.8	40.5	43.6	46.5
Expected Unserved Energy value at 50th percentile demand	$0.25M	$0.44M	$0.59M	$0.76M	$0.87M	$1.05M	$1.31M	$1.55M	$1.78M	$2.02M
Expected Unserved Energy value at 10th percentile demand	$1.09M	$1.38M	$1.61M	$1.83M	$2.02M	$2.29M	$2.64M	$2.91M	$3.13M	$3.34M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.50M	$0.72M	$0.90M	$1.08M	$1.21M	$1.42M	$1.71M	$1.96M	$2.19M	$2.41M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

DEER PARK TERMINAL STATION (DPTS) 66 kV

Deer Park Terminal Station (DPTS) 66 kV is a proposed future terminal station located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is required to offload both transformer groups at KTS by Nov 2017 to avoid excessive load at risk and load exceeding 'N' ratings of plant at KTS in summer 2017/18. It is planned to transfer SU (Sunshine) zone substation from KTS (B1,2,5) transformer group and MLN (Melton) zone substation from KTS (B3,4) group to the new DPTS. Also, by 2018 there will be significant load at risk on the SBY/MLN 66 kV loops and transferring MLN to DPTS will also defer a large amount of augmentation work on these lines.

DPTS will also supply a nearby new zone substation, Truganina (TNA) which is required by November 2017 to offload nearby LV (Laverton), LVN (Laverton North), SU and WBE (Werribee) zone substations, and to augment supply to the fast-growing western suburbs of Melbourne.

The transfer of load from LV and LVN zone substations which are supplied from ATS West and ATS/BLTS terminal stations respectively also defers augmentation at those terminal stations.

DPTS is planned to be constructed with two 225 MVA 220/66 kV transformers. The initial load is forecast to be 213 MVA and rising to 248 MVA by 2023 due to the high load growth of the western suburbs of Melbourne and additional transfers from LV and WBE zone substations. The power factor of the load is expected to be 0.98. At this time it is not possible to provide a forecast of the number of hours per year that 95% of peak load is expected to be reached.

DPTS will connect into the existing KTS-GTS 220 kV lines which presently pass through the site.

Powercor, Jemena Electricity Networks and AEMO published a regulatory test analysis of the proposed Deer Park Terminal station in May 2012. A copy of the report is available at http://www.powercor.com.au/West_Metro_SubTransmission/. The analysis in that report used the 2011 terminal station load forecasts and recommended the commissioning of a new terminal station at Deer Park by November 2016. The latest 2013 terminal station load forecasts have recently have been used in an updated risk analysis for Keilor Terminal Station in this Transmission Connection Planning Report and it is recommended that Deer Park Terminal Station be commissioned by November 2017 for service during the summer of 2017/18.

EAST ROWVILLE TERMINAL STATION (ERTS)

ERTS is the main source of supply for much of the outer south-eastern corridor of Melbourne. The geographic coverage of the area supplied by this station spans from Scoresby in the north to Lyndhurst in the south, and from Belgrave in the east to Mulgrave in the west. The electricity supply network for this large region is split between United Energy (UE) and SPI Electricity (SPIE).

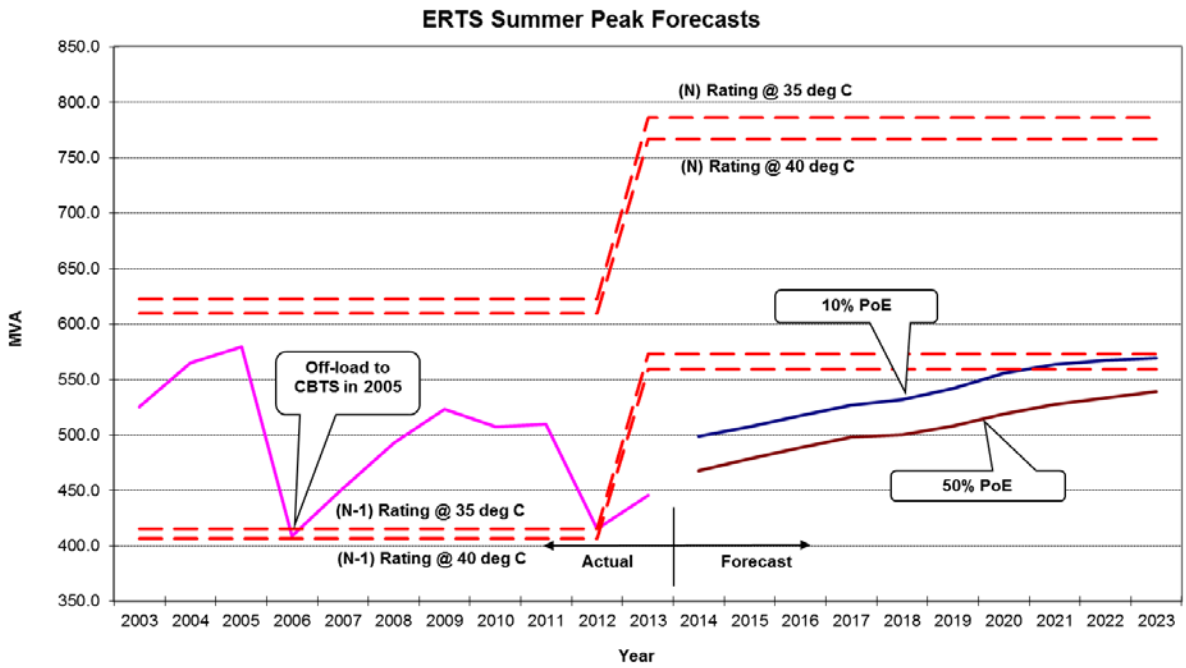
ERTS 66 kV is a summer critical station. The station reached its highest recorded peak demand of 504.9 MW (523.4 MVA) in summer 2008-09 under extreme weather conditions. The recorded demand in summer 2012-13 was 429.9 MW (445.4MVA). Four embedded generation schemes over 1 MW are connected at ERTS 66 kV.[1]

The risk of supply interruption at ERTS 66 kV, for a single contingency event was assessed as being unacceptable in 2007, and the establishment of a fourth 150 MVA 220/66 kV transformer at ERTS 66 kV was identified as the most economic network solution by both SPI Electricity and United Energy as part of the Regulatory Test. As a result, a new fourth transformer was installed at ERTS and commissioned in January 2012.

Prior to the installation of a fourth transformer, Cranbourne (CBTS) terminal station was established in 2005 to off-load ERTS.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile total summer maximum demand forecasts together with the station's expected operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.



[1] The maximum demand forecasts adopted in this risk analysis considers the impact of the five generation schemes. Each generation scheme and its contributions during peak demand periods are presented in the 2013 Terminal Station Demand Forecasts, available at: http://aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.

The N rating on the graph indicates the maximum load that can be supplied from ERTS with all transformers in service. Exceeding this level will require manual load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the overall demand at ERTS remains below its N rating within the 10 year planning period. However, the 10th percentile overall summer demand is forecast to exceed the station's N-1 rating at 40°C from summer 2020-21. The 50th percentile overall summer demand is expected to remain within the N-1 rating for the entire planning period.

The station load is forecast to have a power factor of 0.958 at times of peak demand. The demand at ERTS is expected to exceed 95% of the 50th percentile peak demand for approximately 8 hours per annum.

With the commissioning of the fourth transformer in 2012, the ERTS 66 kV bus was split into two bus groups (B12 and B34) containing two transformers in each group during normal operation in order to reduce the 66 kV fault level.

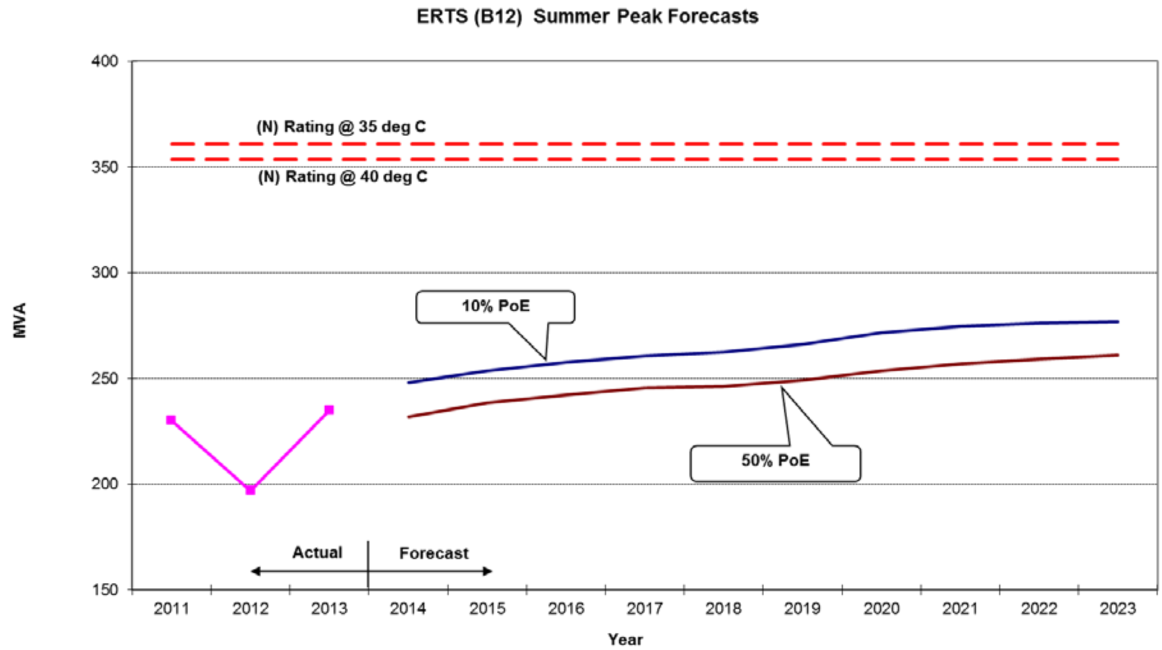
In the event of a transformer outage, the normally open 66 kV bus tie circuit breaker will automatically be closed to share the demand across the other three transformers. The following sections discuss the demand on these two bus groups under normal operating conditions.

Transformer group ERTS (B12) Summer Peak Forecasts

This bus group supplies UE's Mulgrave and Lyndale zone substations and SPIE's Ferntree Gully and Belgrave zone substations.

The graph below depicts the ERTS (B12) bus group rating with both transformers in service ("N" rating), the historical demand and the 10th and 50th percentile summer maximum demand forecasts.

The graph indicates that both the 10th and 50th percentile forecast maximum demands connected to the bus group ERTS (B12) are below its N rating for the entire planning period. Therefore, the maximum demand at ERTS (B12) bus group is not expected to exceed its total capacity under normal operation at any time over the 10 year planning period.



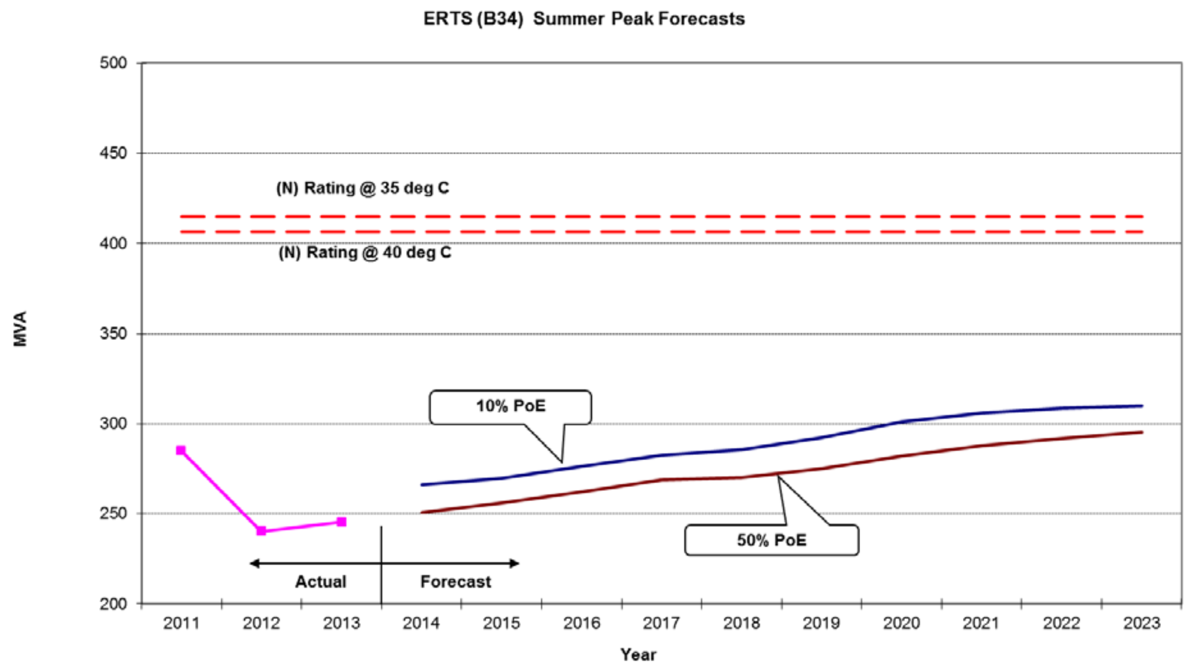
Transformer group ERTS (B34) Summer Peak Forecasts

This bus group supplies UE's Dandenong South, Dandenong and Dandenong Valley zone substations and SPIE's Hampton Park zone substation.

The graph below depicts the ERTS (B34) bus group rating with both transformers in service ("N" rating), the historical demand and the 10th and 50th percentile summer maximum demand forecasts.

A slight reduction of demand in bus group ERTS (B34) is anticipated prior to summer 2014-15 as a result of transferring approximately 6 MW from ERTS to HTS following the commissioning of the new Keysborough Substation.

The graph indicates that the forecast demand connected to the bus group ERTS (B34) is below its N rating for the full planning period. Therefore, it is not expected that the connected demand will exceed the total capacity of the bus group under normal operation at any time over the 10 year planning period.



Comments on Energy at Risk

After installing the fourth transformer, there is sufficient capacity to supply the total demand for an outage of one transformer at ERTS within the 10 year planning period based on the demand forecast at the 50th percentile temperature. Therefore, there is no energy at risk under the 50th percentile demand scenario at ERTS.

However, by 2023, there will be insufficient capacity at the station to supply all the demand at the 10th percentile temperature for about 2 hours in that year. The energy at risk at the 10th percentile temperature under N-1 condition is estimated to be 10 MWh in 2023. The estimated value to consumers of the 10 MWh of energy at risk is approximately $730,000 (based on a value of customer reliability of $76,244/MWh)[2]. In other words, at the 10th

[2] The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at ERTS in 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $730,000.

It is emphasised however, that the probability of a major outage of one of the four transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (10 MWh) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.08 MWh. This expected unserved energy is estimated to have a value to consumers of around $6,300 (based on a value of customer reliability of $76,244/MWh).

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	0	$-
Expected unserved energy at 50th percentile demand	0	$-
Energy at risk, at 10th percentile demand forecast	10	$730,000
Expected unserved energy at 10th percentile demand	0.08	$6,300

If one of the 220/66 kV transformers at ERTS is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[3] load shedding scheme which is operated by SPI PowerNet's TOC[4] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's and SPI Electricity's operational procedures after the operation of the OSSCA scheme.

In the event of ERTS supply at maximum loading periods, and based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would shed about 100 MVA of load, affecting approximately 35,000 SPIE customers.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement contingency plans to transfer load to adjacent terminal stations. Both United Energy and SPI Electricity have established and implemented the necessary infrastructure and plans that enable load transfers under contingency conditions via emergency 66 kV subtransmission ties to Springvale Terminal Station and Ringwood Terminal Station, respectively. The emergency 66 kV tie to Ringwood Terminal Station can be in operation within 2 hours and has the capacity to transfer up to 40 MVA of load. The emergency 66 kV tie to Springvale Terminal Station has the capacity to transfer up to

3 Overload Shedding Scheme of Connection Asset.
4 Transmission Operation Centre

68 MVA of load. A further 60 MVA can be transferred using the 22 kV distribution network. However, the magnitude of the available load transfer will depend on the configuration of the network at the time of an emergency.

2. Transfer Hampton Park (HPK) zone substation from ERTS to Cranbourne Terminal Station (CBTS). This would require 15 kilometres of new 66 kV lines between CBTS and HPK as well as new 66 kV line circuit breakers at CBTS.

3. Establish a new 220/66 kV terminal station. A terminal station site in Dandenong has been reserved for possible future electrical infrastructure development to meet customers' needs in the area. The establishment of a new terminal station at Nar Nar Goon would also enable ERTS to be offloaded.

Preferred network option for alleviation of constraints

Implement the following temporary measures to cater for an unplanned outage of one transformer at ERTS under critical loading conditions:

- maintain contingency plans to transfer load quickly to adjacent terminal stations;
- fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any automatic load shedding that may take place; and
- subject to the availability of the SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at ERTS, it is proposed to off-load ERTS by transferring Dandenong South zone substation onto a new terminal station in Dandenong.

On the present forecasts this transfer to off-load ERTS is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

EAST ROWVILLE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (72%) and SPIE (28%)
Station operational rating (N elements in service): 786 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Rating: 573 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 656 MVA

Station: ERTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	468	479	489	498	500	508	519	528	534	539
50th percentile Winter Maximum Demand (MVA)	380	388	395	400	405	411	415	417	417	420
10th percentile Summer Maximum Demand (MVA)	499	507	518	527	532	542	555	563	567	570
10th percentile Winter Maximum Demand (MVA)	395	403	409	414	419	424	428	430	429	432
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N-1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	2	5	10
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	1	2	2
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Expected Unserved Energy value at 50th percentile demand	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k
Expected Unserved Energy value at 10th percentile demand	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$1k	$4k	$6k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$1k	$2k

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

FISHERMAN'S BEND TERMINAL STATION 66 kV (FBTS 66 kV)

FBTS 66 kV is a terminal station shared by both CitiPower (currently 91%) and Powercor (currently 9%). It is a summer critical station consisting of three 150 MVA 220/66 kV transformers supplying the Docklands areas and an area south-west of the City of Melbourne bounded by the Yarra River in the north and west, St Kilda/Queen's Roads in the east and Hobsons Bay in the south. The main supply areas include Docklands and Southbank of the Central Business District planning areas, Port Melbourne, Fisherman's Bend, Albert Park, Middle Park and St Kilda West.

As part of its asset renewal program, SPI PowerNet plans to replace the B1 transformer with a new 150 MVA 220/66 kV transformer unit after 2020.

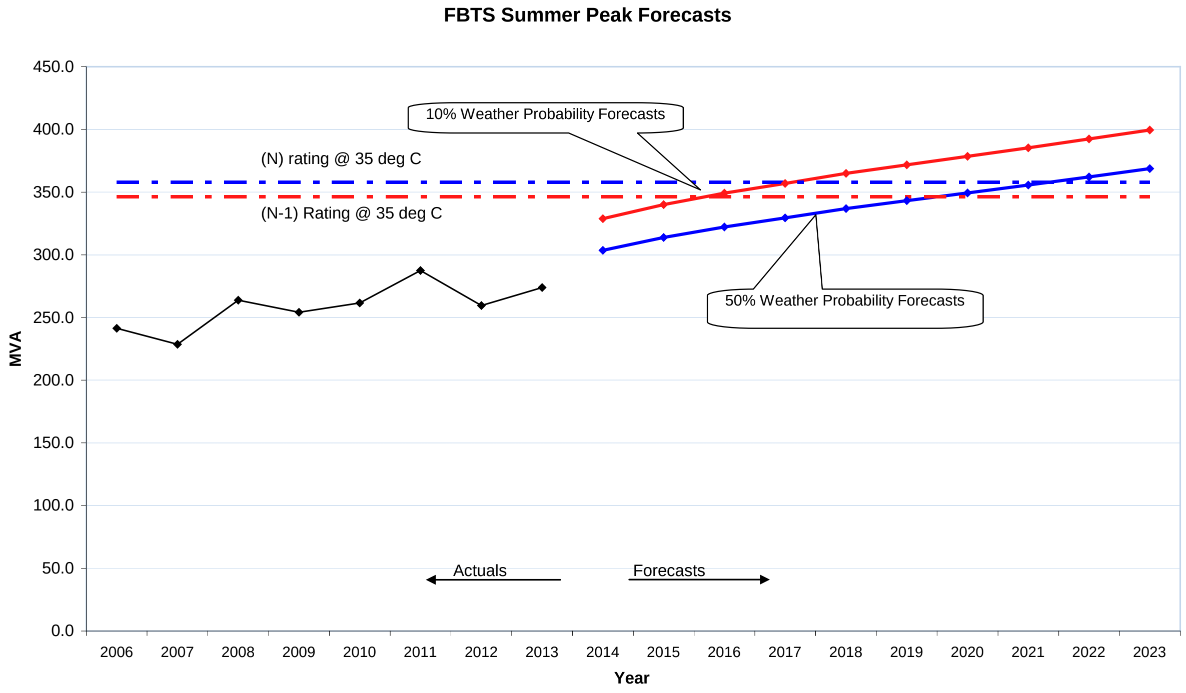
The peak load on the station reached 242.1 MW in summer 2013. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.96.

Magnitude, probability and impact of loss of load

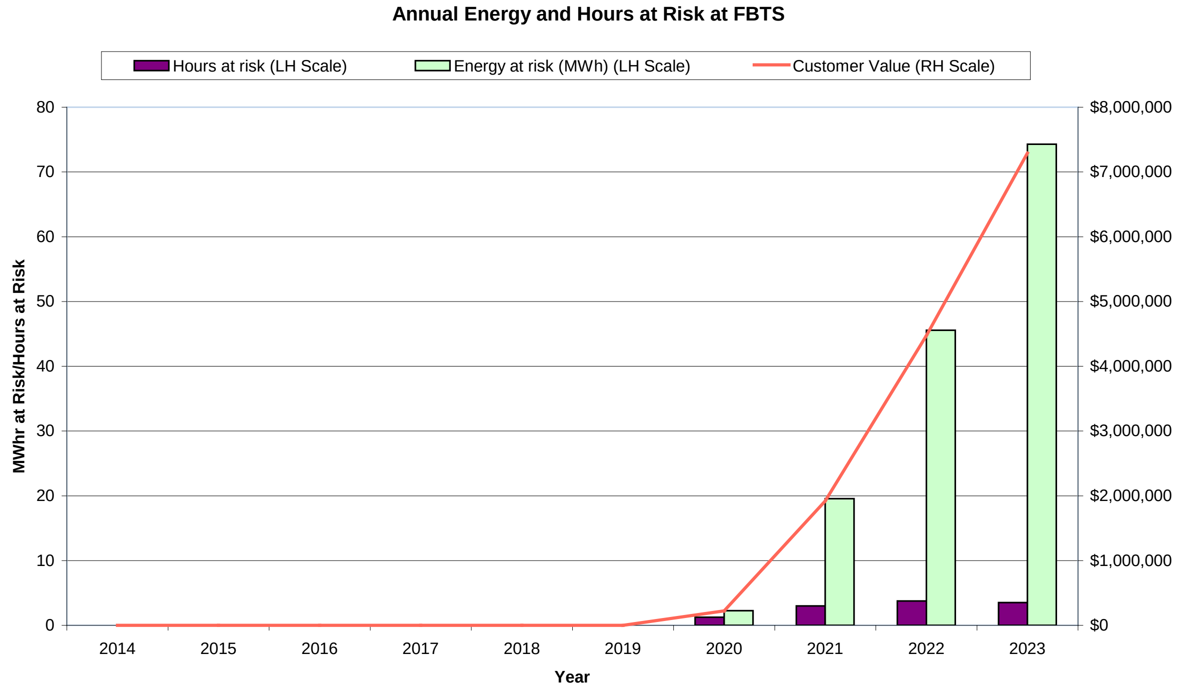
To facilitate voltage control on the main transmission network in the Melbourne metropolitan area, a 125 MVA synchronous compensator has been installed at FBTS. Given the high total fault current contribution from the synchronous compensator, together with the fault current contribution of existing embedded generators (totalling 17 MW of generating capacity) under earth fault conditions, one of the three 220/66 kV transformers at FBTS is operating on "Normal Open Auto-close" duty. Under this arrangement, one transformer operates on hot stand-by and it can be automatically switched into operation if there is a forced outage of any one of the two normal running transformers. This arrangement is required to maintain the 66 kV fault level to within the terminal station fault rating. With this transformer operating arrangement, the N rating is approximately equal to the N-1 rating (i.e. equal to the capacity of two transformers), thus imposing a restriction that the terminal station should not be loaded beyond the N capacity of two transformers at any time.

The graph below depicts the 10th and 50th percentile maximum demand forecasts during the summer periods over the next ten years, together with the station's operational N and N-1 ratings. The forecast demand includes the effects of any future load transfer works that have been committed.



The graph shows that there would be insufficient capacity at FBTS 66 kV to supply the forecast 10th percentile and 50th percentile demands by around 2016 and 2020 respectively.

The bar chart below depicts the energy at risk (under normal system conditions with one transformer on "Normal Open Auto-close" duty) for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the rated capacity under both N and N-1 conditions. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

With the existing transformer operating arrangement at FBTS, it is expected that by around 2020, there will be insufficient capacity to supply all demand at the 50th percentile temperature under N and N-1 conditions. Under these operating arrangements, the expected unserved energy is equal to the energy at risk, whenever loading exceeds the capacity of two transformers.

By 2020, the energy at risk and the expected unserved energy under N and N-1 conditions is about 2.3 MWh at the 50th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for about 1.3 hours in that year. The estimated value to consumers of this energy at risk in 2020 is approximately $0.22 million (at a value of customer reliability of $98,151 per MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, the existing load forecast for 2020 implies a level of involuntary supply interruption that would cost consumers approximately $0.22 million.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the energy at risk in 2020 is estimated to be 144.6 MWh. The estimated value to consumers of this energy at risk in 2020 is approximately $14.2 million.

These key statistics for the year 2020 under both N and N-1 conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	2.3	$0.22 million
Expected unserved energy at 50th percentile demand	2.3	$0.22 million
Energy at risk, at 10 percentile demand forecast	144.6	$14.2 million
Expected unserved energy at 10th percentile demand	144.6	$14.2 million

If the total station load exceeds the N and N-1 station ratings, the OSSCA[2] load shedding scheme which is operated by SP AusNet's NOC[3] will act swiftly to reduce the load in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower's and Powercor's operational procedures.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

[2] Overload Shedding Scheme of Connection Asset.

[3] Network Operation Centre.

1. Contingency plans could be put in place to transfer load to the adjacent terminal stations via the 11 kV distribution networks under transformer outage conditions. This option can defer major capital augmentation works until after the current ten-year planning period, but it requires the following work to be carried out to mitigate the risk of supply interruption and/or to alleviate the emerging constraint in the meantime:

    - Increase the N rating to the normal three-transformer capacity level of about 520 MVA (i.e. with all the three transformers operating on load) such that the station could be loaded up to beyond the N-1 rating under normal conditions.

      The N rating could be increased to near the normal three-transformer capacity level and the ‘hot standby’ transformer could be connected by removing the “Normal Open Auto-close” duty on the 66 kV transformer circuit breaker and implementing a “Normal Open Auto-close” facility on a 66 kV bus tie circuit breaker instead of on the transformer circuit breaker. Under these arrangements, the normal open bus tie circuit breaker will be automatically closed upon loss of any one of the three transformers. It should be noted however that this arrangement affects supply reliability to customers supplied from the one transformer bank as there will be a momentary interruption to supply before the 66 kV bus tie breaker closes. The total budget cost of these works is estimated to be in the order of $520,000.

2. Installation of a fourth 150 MVA 220/66 kV transformer is a longer term option to address the emerging constraint at FBTS. However, this still requires the fault level reduction work described in Option 1 to be completed before the option is feasible.

3. Embedded generation in the order of 20 MVA, will help to defer the need for augmentation by one year.

Preferred option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at FBTS 66 kV, or any other identified better network solutions, it is proposed to increase the station N rating to the normal three-transformer capacity, to defer any major capital augmentation works until after the current ten-year planning period by taking the following action:

1. Prior to summer 2020, operate all three existing transformers by implementing a “Normal Open Auto-close” facility on a 66 kV bus tie circuit breaker instead of on the transformer and rearrange the 66 kV lines between 66 kV buses for fault level control. Timing of the need for this work will be monitored closely pending the development of the Fisherman’s Bend rezoned precinct and Webb Dock, and will depend on future load increases.

2. Implementing the following measures to cater for an unplanned outage of one transformer at FBTS 66 kV under critical loading conditions:

- Maintain contingency plans to transfer load via HV distribution networks to the adjacent terminal stations;

- Fine-tune the OSSCA scheme settings in conjunction with NOC to minimise the impact on customers of any load shedding that may take place; and

- Subject to the availability of the SP AusNet spare 220/66 kV transformer for metropolitan areas (refer Section 4.5), this spare transformer can be used to temporarily replace the failed transformer, and so minimise the transformer outage period.

The estimated total terminal station capital cost associated with this option is approximately $520,000. The estimated total annual cost of this network augmentation is approximately $52,000. This cost provides a broad upper bound indication of the maximum network support payment which may be available to embedded generators or customers to reduce forecast demand, and to defer or avoid the transmission connection component of this augmentation. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging constraints.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

FISHERMAN'S BEND TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: CitiPower (Currently 91%); Powercor (currently 9%)
Station operational rating (N elements in service): 358 MVA via 3 transformers with one transformer on "Normal Open Auto-close" duty [Note 7] (Summer peaking)
Summer N-1 Station Rating: 309.3 MW (346.2 MVA) [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 355.8 MW (390.0 MVA)

Station: FBTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	303.6	313.8	322.2	329.5	336.9	343.2	349.4	355.7	362.2	368.8
50th percentile Winter Maximum Demand (MVA)	243.8	250.9	257.3	263.4	269.7	274.6	279.5	284.6	289.8	295.1
10th percentile Summer Maximum Demand (MVA)	328.9	340.0	349.1	357.0	365.0	371.8	378.5	385.4	392.4	399.6
10th percentile Winter Maximum Demand (MVA)	250.9	258.2	264.8	271.1	277.6	282.6	287.7	292.9	298.2	303.7
Annual N - 1 energy at risk at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	2.3	19.6	45.6	74.3
Annual N - 1 energy at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	1.3	3.0	3.8	3.5
Annual N - 1 energy at risk at 10th percentile demand (MWh)	0.0	0.0	2.0	25.5	60.2	95.4	144.6	230.3	357.4	504.1
Annual N - 1 energy at risk at 10th percentile demand (hours)	0.0	0.0	1.0	3.5	3.3	5.0	7.5	9.3	14.8	20.0
Expected Annual Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	2.3	19.6	45.6	74.3
Expected Annual Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	2.0	25.5	60.2	95.4	144.6	230.3	357.4	504.1
Expected Annual Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.22M	$1.92M	$4.47M	$7.29M
Expected Annual Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.20M	$2.50M	$5.90M	$9.36M	$14.2M	$22.6M	$35.1M	$49.5M
Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.06M	$0.75M	$1.77M	$2.81M	$4.41M	$8.13M	$13.7M	$19.9M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)
7. The N and N-1 ratings are approximately equal due to the restriction of "Normal Open Auto-close" transformer duty. The N rating will be increased to about 520MVA when the restriction is removed.

FRANKSTON TERMINAL STATION (FTS)

FTS is a 66 kV switching station. FTS was originally supplied from East Rowville terminal station (ERTS) and transferred to Cranbourne terminal station (CBTS) in May 2005. The station is now supplied via three 66 kV supply routes from CBTS. There are no embedded generation schemes connected at FTS 66 kV.

United Energy upgraded its existing CBTS-CRM 66 kV line in 2009. This increased the summer thermal rating of the line from 930 A to 1125 A at 35ºC.

Arrangements relating to the ownership of assets supplying FTS, as well as the ratings of those assets are listed in the table below.

66kV Supply Route to FTS	Thermal Rating @ 35°C	Ownership
CBTS-FTS #1	825 Amp	Transmission connection asset owned by SPI PowerNet
CBTS-FTS #2	825 Amp	Transmission connection asset owned by SPI PowerNet
CBTS-CRM-(FTN/LWN)-FTS	1125 Amp	Distribution system assets owned by United Energy

Magnitude, probability and impact of loss of load

The various 66 kV supply routes and ownership arrangements mean that the risk assessment for FTS is more complicated than for other terminal stations. As far as transmission connection assets are concerned, load flow studies indicate that the lowest N-1 rating of FTS during summer corresponds to the outage of CBTS-CRM 66 kV line which is limited by the combined thermal rating of CBTS-FTS No.1 and CBTS-FTS No.2 66 kV lines.

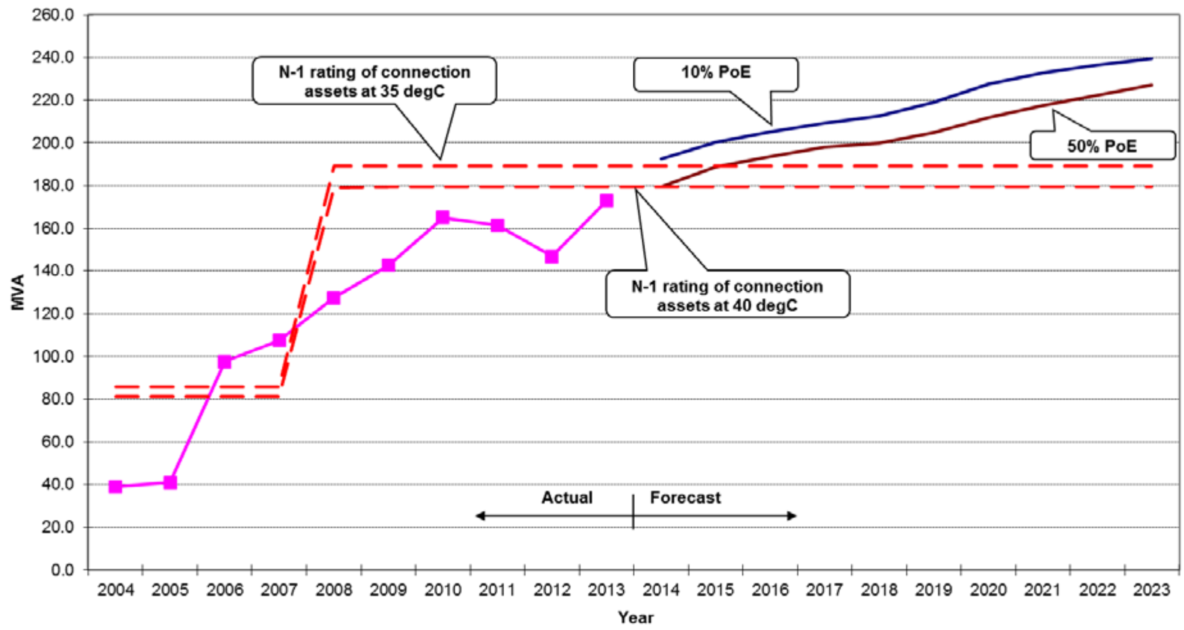
The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational (N-1) rating at 35°C as well as 40°C ambient temperature.

The N-1 rating on the chart indicates the maximum load that can be supplied from FTS with the CBTS-CRM 66 kV line out of service. If the ratings of SPI PowerNet's CBTS-FTS 66 kV lines are exceeded, SPI PowerNet's automatic load shedding scheme would be initiated to trip the remaining 66 kV lines. This would result in loss of electricity supply to all customers connected at FTS until the lines are re-energised with sufficiently reduced demand level to avoid further overloading.

The graph below indicates that both the 10th percentile and 50th percentile maximum demand is expected to exceed the N-1 rating (at 40°C) from summer 2013-14.

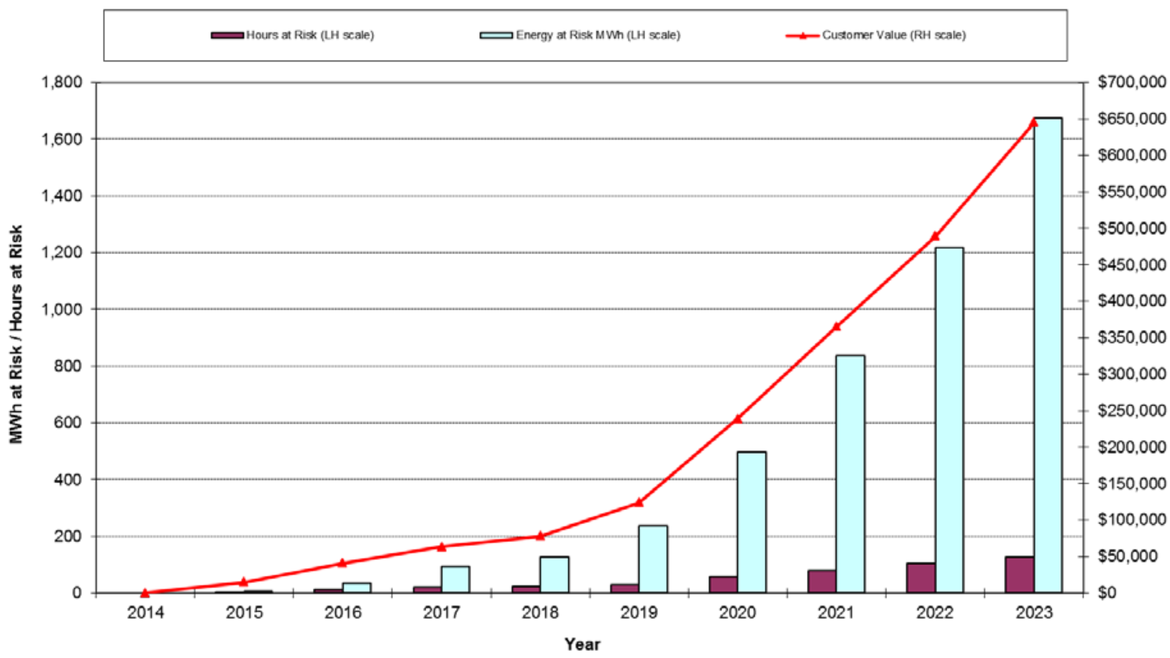
The station load is forecast to have a power factor of 0.95 at times of peak demand. The demand at FTS is expected to exceed 95% of the 50th percentile peak demand for approximately 6 hours per annum.

FTS Summer Peak Forecasts



The bar chart below depicts the energy at risk for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

Annual Energy and Hours at Risk at FTS (Single Contingency Only)



Comments on Energy at Risk

For an outage of the CBTS-CRM 66 kV line, there will be insufficient capacity at FTS to supply all the connected demand at the 50th percentile temperature beyond summer 2014-15. To protect assets from overload, load shedding will be required to ensure that the loading of the two CBTS-FTS 66 kV lines owned by SPI PowerNet do not exceed their rating. The total estimated duration of the constraint under N-1 is about 128 hours in 2023. The total energy at risk above the N-1 rating is estimated at 1,676 MWh in summer 2023. The estimated value to consumers of the 1,676 MWh of energy at risk is approximately $122.5 million (based on a value of customer reliability of $73,113/MWh)[1].

If load shedding is not undertaken to manage the loading of the two CBTS-FTS 66 kV lines within their ratings, SPI PowerNet will protect its assets by tripping both CBTS-FTS 66 kV lines. Hence there is a risk of the total supply to FTS being disconnected for an outage of the CBTS-CRM 66 kV line during high demand periods when the total connected load exceeds the N-1 rating. In such an event, it is expected that the two CBTS-FTS 66 kV lines can be re-energised within two hours after ensuring sufficient demand reduction to maintain the demand within the CBTS-FTS 66 kV line ratings. The mean duration of a CBTS-CRM 66 kV line outage (repair time) is assumed to be 24 hours for the balance of the load at risk.

It is emphasised however, that the probability of an outage of a 66 kV line is low. The outage rate for the CBTS-CRM 66 kV line is estimated to be 0.9 per annum and that of CBTS-FTS 66 kV lines are estimated to be 0.7 per annum.

When the energy at risk is weighted by these low failure rates and adjusted for the mean duration of the outage, the expected unserved energy is estimated to be around 8.8 MWh in 2023. This expected unserved energy is estimated to have a value to consumers of around $0.65 million (based on the value of customer reliability of $73,113/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 2,379 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $174.0 million. The corresponding value of the expected unserved energy is around $1.0 million.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	1,676	$122.5
Expected unserved energy at 50th percentile demand	8.8	$0.65M
Energy at risk, at 10th percentile demand forecast	2,379	$174.0
Expected unserved energy at 10th percentile demand	13.8	$1.0M

1 The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV subtransmission and 22 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from FTS is assessed at 32.2 MVA for summer 2013-14.

2. Upgrade CBTS-FTS #1 and CBTS-FTS #2 66 kV circuits. The preliminary assessments revealed that this option would require complete rebuilding of these two lines as the existing assets are not designed to carry additional mechanical load.

3. Improve the operating power factor during the peak demand periods at the zone substations (Carrum, Frankston and Langwarrin) supplied through FTS where technically feasible by installing switched capacitors.

4. Establish a new 66 kV line out of CBTS to augment the existing 66 kV loop.

5. Establish a new 66 kV loop from CBTS to supply a new 66/22 kV zone substation in the Skye / Carrum Downs area and offload the existing 66 kV loop.

6. Demand Side Management: United Energy has developed a number of innovative network tariffs that encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and the subsequent change in load pattern, and will be taken into consideration when determining the optimum timing for any future capacity augmentation or other action.

7. Embedded generation, in the order of 4 MVA, connected to the network supplied by FTS 66 kV bus, will help to defer the need for augmentation by one year. Given the capacity constraints in the distribution network, the preferred location for such generation support is the area supplied by Carrum (CRM) zone substation.

Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at FTS, it is proposed to:

1. Install additional switched capacitors at zone substation or distribution feeder level to improve the operating power factor.

2. Maintain contingency plans to transfer load quickly to adjacent terminal stations; and

3. Establish a new 66 kV loop from CBTS to supply a new 66/22 kV zone substation in the Skye / Carrum Downs area and offload the existing 66 kV loop.

On the present forecasts, it is unlikely that Option 3 will be economical before December 2021. The capital cost of establishing a new 66 kV loop is estimated to be $15.5 M. The estimated total annual cost of this network augmentation is approximately $1.6 M. This cost provides a broad upper bound indication of the maximum network support payment which may be available to embedded generators or customers to reduce forecast demand, and to defer or avoid the transmission connection component of this augmentation. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging constraints.

Until the long term solution is implemented, it is proposed to implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions via the distribution network. Transfer capability away from FTS 66 kV onto adjacent terminal stations is assessed at 32.2 MVA. The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

FRANKSTON TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)
Normal cyclic rating with all plant in service 236 MVA via all 66kV lines (Summer peaking)
Summer N-1 Loop Rating: 189 MVA and 194 MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines respectively [See Note 1]
Winter N-1 Loop Rating: 247 MVA and 201 MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines respectively

Station: FTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	180	189	194	198	200	205	212	218	222	227
50th percentile Winter Maximum Demand (MVA)	151	155	158	162	165	169	172	175	176	179
10th percentile Summer Maximum Demand (MVA)	192	200	205	209	213	219	227	233	236	240
10th percentile Winter Maximum Demand (MVA)	156	159	162	165	169	172	175	177	179	181
N-1 energy at risk at 50th percentile demand (MWh)	0	6	35	95	126	236	498	838	1,219	1,676
N-1 hours at risk at 50th percentile demand (hours)	0	4	11	20	22	29	57	80	105	128
N-1 energy at risk at 10th percentile demand (MWh)	23	86	147	251	307	487	870	1,317	1,808	2,379
N-1 hours at risk at 10th percentile demand (hours)	4	11	18	32	37	48	78	107	136	164
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.2	0.6	0.9	1.1	1.7	3.3	5.0	6.7	8.8
Expected Unserved Energy at 10th percentile demand (MWh)	0.3	0.9	1.4	2.3	2.7	3.8	6.0	8.4	11.0	13.8
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.02M	$0.04M	$0.06M	$0.08M	$0.12M	$0.24M	$0.36M	$0.49M	$0.65M
Expected Unserved Energy value at 10th percentile demand	$0.02M	$0.06M	$0.10M	$0.17M	$0.20M	$0.28M	$0.44M	$0.62M	$0.80M	$1.01M
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.01M	$0.03M	$0.06M	$0.09M	$0.11M	$0.17M	$0.30M	$0.44M	$0.58M	$0.75M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

GEELONG TERMINAL STATION (GTS) 66kV

Geelong Terminal Station (GTS) 66 kV consists of four 150 MVA 220/66 kV transformers. Due to the excessive fault levels associated with all four transformers operating in parallel the following strategies have been adopted:

(a) Prior to 2012 the B3 transformer operated as a hot standby with a normally open auto close scheme on its 66 kV circuit breaker.

(b) In 2012 the 66 kV loop lines were rearranged so that the B3 transformer could be placed in service with the 66 kV bus tie circuit breaker between 66 kV buses 2&3 normally open. Under system normal, 66 kV buses 1&2 are supplied via B1 and B2 transformers and 66 kV buses 3&4 are supplied via B3 and B4 transformers. For loss of a transformer, the normally open 66 kV bus tie circuit breaker between buses 2&3 is closed.

GTS is the main source of supply for over 135,590 customers in Geelong and the surrounding area. The station supply area includes Geelong, Corio, North Shore, Drysdale, Waurn Ponds and the Surf Coast.

Magnitude, probability and impact of loss of load

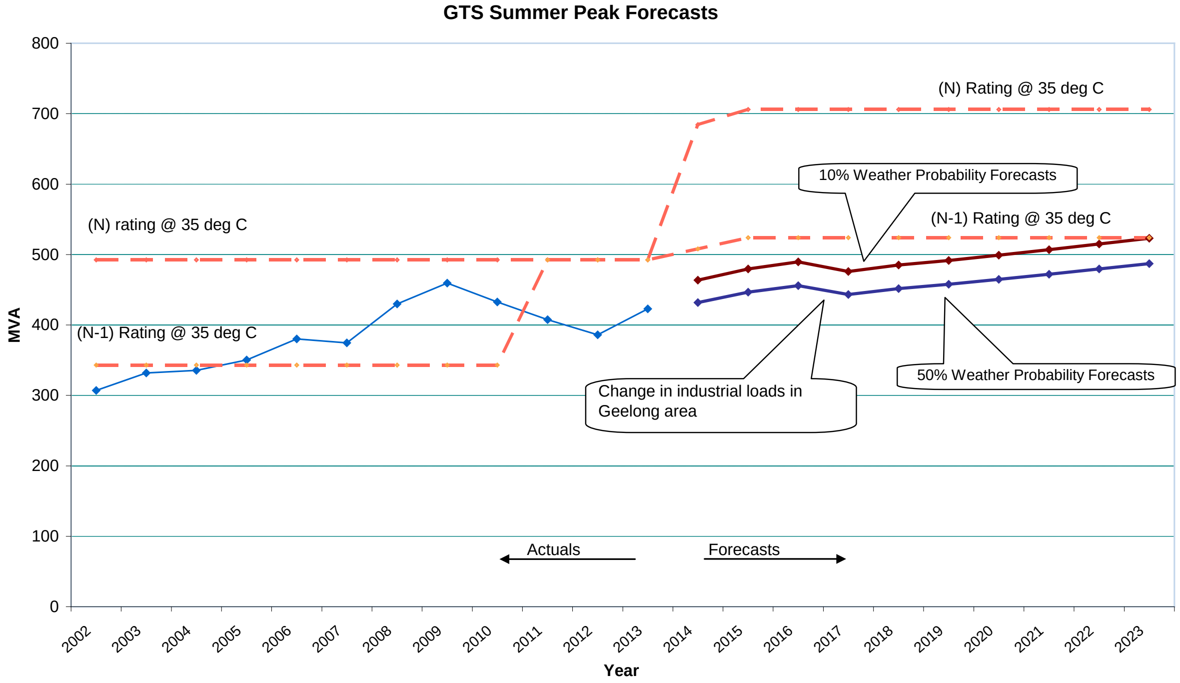
Growth in summer peak demand at GTS has averaged around -1.43 MW (-0.1%) per annum over the last 5 years. The peak load on the station reached 413.8 MW in 2013. It is noted that summer 2012/13 was a relatively mild summer that produced lower-than-usual daily maximum demands. During the warmer summer of 2009 station demand peaked at 437 MW.

It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.97

GTS 66 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.

As part of the SPI PowerNet asset renewal program, the B3 transformer was replaced in 2013, and the B1 transformer is due to be replaced in 2014. The B4 transformer is scheduled to be replaced in 2022.



The (N) rating on the chart indicates the maximum load that can be supplied from GTS with four transformers in service. Exceeding this level will initiate automatic load shedding by SPI PowerNet's automatic load shedding scheme.

Under system normal conditions (i.e. with four transformers available for service) and under (N-1) transformer outage conditions for the 10th and 50th percentile demand forecasts, it is estimated that over the ten year outlook period, there will be sufficient capacity to supply all load at the station. There is expected to be a change in the industrial customer mix in the area over the next four years, and this in addition to recent refurbishment works at GTS will mean that the forecast load growth is not expected to exceed capacity.

Comments on Energy at Risk

The graph above shows there is sufficient capacity at the station to supply all the 10th and 50th percentile demand expected over the forecast period to 2023, even with one transformer out of service. Load at risk over the forecast period beyond 2023, can be managed by transferring load away to TGTS in the event of a loss a transformer, after which there would be expected to be no unsupplied demand. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

GLENROWAN TERMINAL STATION 66 kV (GNTS 66 kV)

Glenrowan terminal station (GNTS) consists of one 125 MVA three phase transformer and one 110 MVA transformer formed by six single-phase 55 MVA units. The station is the main source of supply for a major part of north-eastern Victoria including Wangaratta in the north; to Euroa in the south; to Mansfield and Mt Buller in the east; and Benalla more centrally. SPI Electricity (SPIE) is responsible for planning the transmission connection and distribution networks for this region.

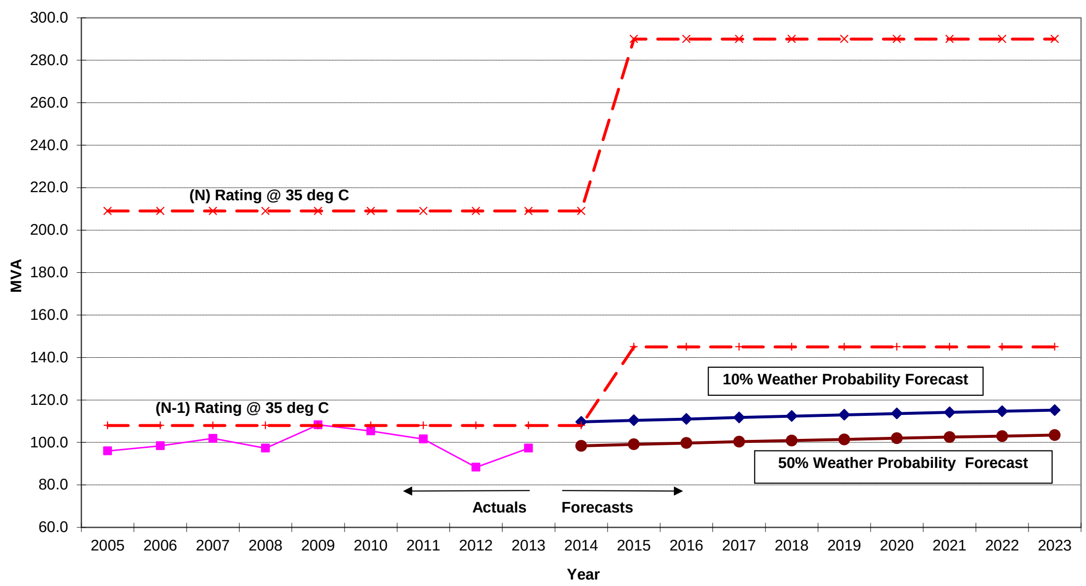
Magnitude, probability and impact of loss of load

GNTS has historically been a winter peaking station but more recently has had similar peak loading in both summer and winter. The rate of growth in both summer and winter peak demand at GNTS 66 kV has been low in recent years, and demand is forecast to continue to increase slowly at less than 1% per annum for the next few years. The peak load on the station reached 100 MW (101 MVA) in winter 2012 and 97 MW (98 MVA) in summer 2012/13. Demand is expected to exceed 95% of the 50th percentile peak load for 4 hours per annum. The station load has a power factor of 0.944 at maximum demand but load on the transformers has a power factor of 0.995 due to 66 kV capacitor banks installed at the station.

SPI PowerNet has commenced construction work to replace the 110 MVA transformer with a new three-phase 150 MVA 220/66kV transformer, which is the standard rating for new 220/66 kV connection transformers. This work will be completed before summer 2014/15 and will increase the capacity at the station, as shown below.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at an ambient temperature of 35°C.

GNTS 66 kV Summer Peak Demand Forecasts



The graph shows that in summer there is only a very small amount of energy at risk under 10th percentile summer conditons for the next summer prior to SPI PowerNet's completion of the transformer replacement project. There is no energy at risk under 50th percentile or 10th percentile loading conditions for the winter period for the next ten years. There is therefore not expected to be any need for augmentation over the ten year planning period.

HEATHERTON TERMINAL STATION (HTS)

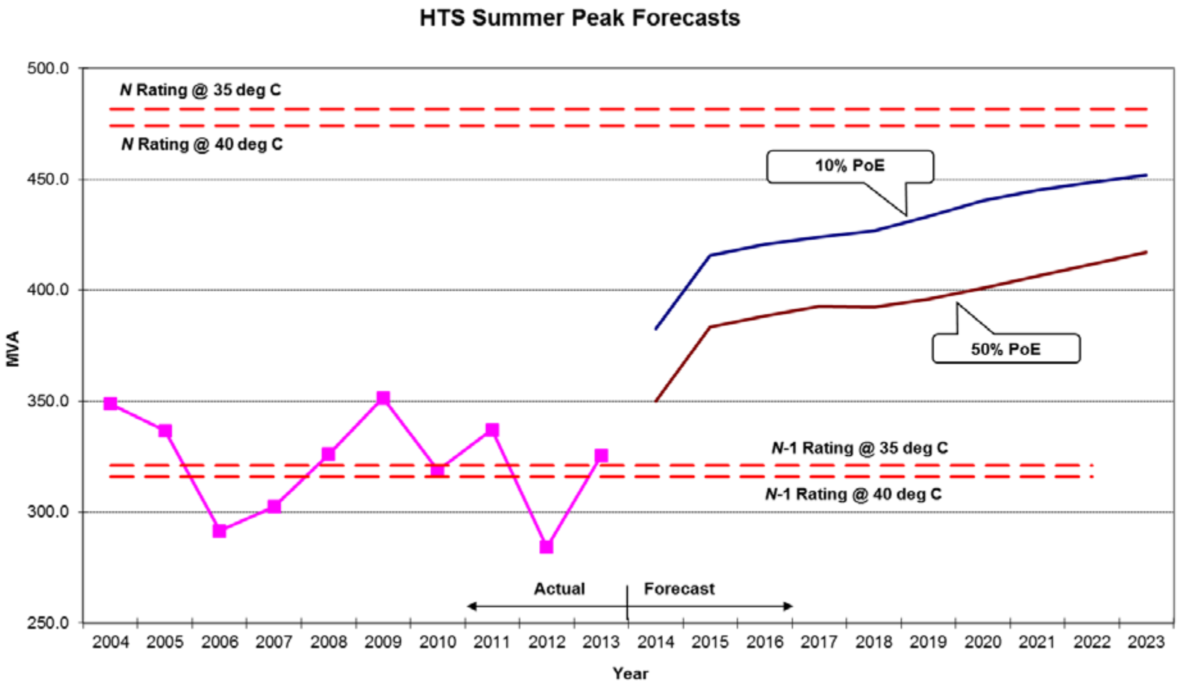
HTS is the main source of supply for a major part of the southern metropolitan area. The geographic coverage of the HTS supply area spans from Brighton in the north to Edithvale in the south.

HTS is a summer critical terminal station. The station reached its highest recorded peak demand of 341.1 MW (351.4 MVA) in summer 2008-09 under extreme weather conditions. The recorded demand in summer 2012-13 was 318 MW (325.4 MVA), which was 40 MW higher than the 2012 peak. There are no embedded generation schemes over 1 MW connected at HTS.

Major works completed to manage load at HTS over the last ten years have included establishment of a new terminal station at Cranbourne (CBTS) in 2005 to off-load HTS (and ERTS) prior to summer 2006. United Energy transferred approximately 48 MW away from HTS to CBTS in September 2005.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.

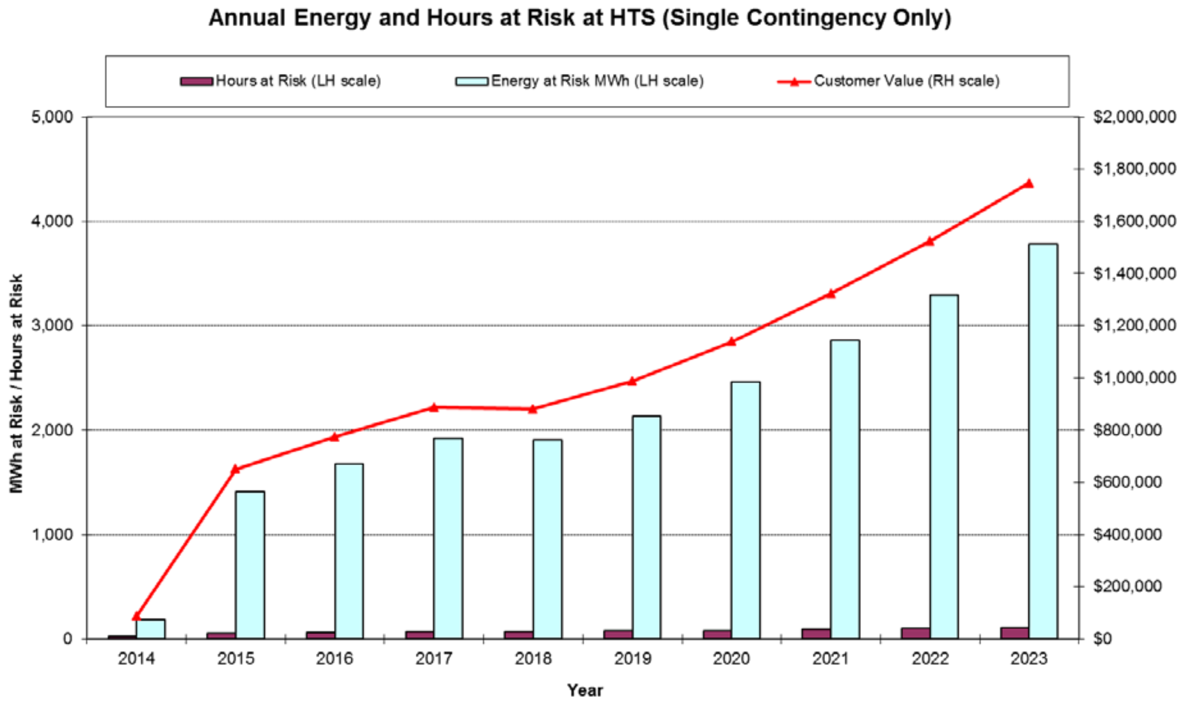


The N rating on the graph indicates the maximum load that can be supplied from HTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that both the 10th percentile and 50th percentile maximum demand is expected to exceed the (N-1) rating from summer 2013-14. The step increase in HTS demand in summer 2014-15 is due to the connection of the new Keysborough zone substation. With this development, approximately 24 MW will be transferred onto HTS from East Rowville Terminal Station (ERTS) and Springvale Terminal Station (SVTS).

The station load is forecast to have a power factor of 0.977 at times of peak demand. The demand at HTS is expected to exceed 95% of the 50th percentile peak demand for approximately 6 hours per annum.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For an outage of one transformer at HTS, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 108 hours in 2023. The energy at risk under N-1 conditions is estimated to be 1,727 MWh in summer 2023. The estimated value to consumers of the 3,779 MWh of energy at risk is approximately $270.5 million (based on a value of customer reliability of $71,568/MWh)[1]. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at HTS over the summer of 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $270.5 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (3,779 MWh in 2023) is weighted by this low unavailability, the expected unserved energy is estimated to be

[1] The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

around 24.4 MWh. This expected unserved energy is estimated to have a value to consumers of around $1.7 million (based on a value of customer reliability of $71,568/MWh). SPI PowerNet has indicated that all three of the transformers at HTS have an elevated failure rate due to the age and condition of the transformers. Therefore the expected unserved energy calculated above may underestimate the risk at this station. Given SPI PowerNet has plans in place to replace these transformers as part of its asset replacement program in 2017, the elevated failure rates are unlikely to advance any augmentation requirement at this terminal station.[2]

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 4,682 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $335 million. The corresponding value of the expected unserved energy is around $2.2 million.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	3,779	$270.5 million
Expected unserved energy at 50th percentile demand	24.4	$1.7 million
Energy at risk, at 10th percentile demand forecast	4,682	$335.1 million
Expected unserved energy at 10th percentile demand	30.2	$2.2 million

If one of the 220/66 kV transformers at HTS is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[3] load shedding scheme which is operated by SPI PowerNet's NOC[4] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's operational procedures after the operation of the OSSCA scheme.

In the case of HTS supply at maximum loading periods, and based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would shed about 80 MVA of load, affecting approximately 38,000 customers in 2013.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

2 Section 3.6 of the 2013 Victorian Annual Planning Report (VAPR) provides further information on SPI PowerNet's asset renewal program. It is available from: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/VAPR2013/Victorian_Annual_Planning_Report_2013_v2.ashx

3 Overload Shedding Scheme of Connection Asset.

4 Network Operations Centre

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV subtransmission and 22 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from HTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 37 MVA.

2. Install a fourth 220/66 kV transformer at HTS.

3. Replace the existing HTS 'B' transformers in 2017 as part of SPI PowerNet's asset replacement programme. The station's (N-1) rating after asset replacement is expected to be similar (or marginally higher) than the current level given SPI PowerNet intends to replace with like-for-like transformers.

4. Establish a new 220/66 kV terminal station in the Dandenong area to off-load HTS.

   Prior to 2011, the TCPR identified that a 4th transformer at HTS would be the preferred network option to alleviate the increasing load at risk. It has now been determined that this may not be the most economic option for the following reasons:

   - HTS is supplied on a radial double-circuit 220 kV transmission line from Rowville (ROTS) via Springvale (SVTS). The connected demand on these lines is presently reliant on emergency short time ratings to remain within the N-1 rating of the 220 kV circuits. Therefore the capacity provided by a fourth transformer at HTS may not be able to be utilised because of the 220 kV line constraints.

   - The anticipated timing of a 4th transformer at HTS coincides with a number of other significant sub-transmission and connection asset constraints in the Dandenong, Keysborough and Braeside areas, which a 4th transformer at HTS would not be able to resolve.

   - SPI PowerNet plans to replace the existing transformers, with like-for-like transformers, as part of their asset replacement programme and have indicated that the station N-1 rating is expected to be similar (or marginally higher) than the current level.

     Given these considerations, in early 2012 United Energy submitted a connection enquiry to AEMO for the establishment of a new connection point in the Dandenong area by 2023. Joint planning activities are now underway between the two organisations to quantify the risk of the emerging constraints in the area and to assess viable options for alleviating the constraints. This has included engaging consulting firm Sinclair Knight Merz to identify possible 220 kV transmission line routes. The capital cost of installing a new 220/66 kV terminal station in Dandenong is estimated to be in excess of $70 million. The cost of establishing, operating and maintaining the new assets would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $7 million.

     There has been a reduction in the maximum demand forecast at HTS and Springvale Terminal Station (SVTS) compared with last year's forecast, so the new terminal station is not likely to be economically justified before December 2025. Further analysis, including a Regulatory Investment Test for Transmission will be undertaken to determine the preferred option for addressing the constraints, but at this stage a new 220/66 kV terminal station in Dandenong is the preferred network option. In the absence of any significant increased capacity at HTS due to SPI PowerNet's transformer replacement, the need for and timing of the new terminal station in Dandenong will be confirmed through the Regulatory Investment Test for Transmission process.

Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at HTS, it is proposed to:

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at HTS under critical loading conditions:

   - maintain contingency plans to transfer load quickly to adjacent terminal stations;

   - fine-tune the OSSCA scheme settings in conjunction with NOC to minimise the impact on customers of any load shedding that may take place; and

   - subject to the availability of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. Establish a new 220/66 kV terminal station in the Dandenong area to off-load HTS

   On the present forecasts, the new terminal station in the Dandenong area is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

HEATHERTON TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)
Station operational rating (N elements in service): 482 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Rating: 321 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 351 MVA

Station: HTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	350	383	388	393	392	396	401	406	412	417
50th percentile Winter Maximum Demand (MVA)	294	296	298	300	302	305	308	313	319	323
10th percentile Summer Maximum Demand (MVA)	383	416	421	424	427	433	440	445	449	452
10th percentile Winter Maximum Demand (MVA)	302	304	305	307	310	313	317	322	328	332
N-1 energy at risk at 50th percentile demand (MWh)	187	1,409	1,677	1,920	1,906	2,138	2,462	2,861	3,297	3,779
N-1 hours at risk at 50th percentile demand (hours)	23	60	65	70	69	75	82	92	100	108
N-1 energy at risk at 10th percentile demand (MWh)	584	2,031	2,329	2,596	2,613	2,900	3,289	3,724	4,180	4,682
N-1 hours at risk at 10th percentile demand (hours)	33	67	74	80	80	85	94	100	110	117
Expected Unserved Energy at 50th percentile demand (MWh)	1.2	9.1	10.8	12.4	12.3	13.8	15.9	18.5	21.3	24.4
Expected Unserved Energy at 10th percentile demand (MWh)	3.8	13.1	15.0	16.8	16.9	18.7	21.2	24.1	27.0	30.2
Expected Unserved Energy value at 50th percentile demand	$0.09M	$0.65M	$0.78M	$0.89M	$0.88M	$0.99M	$1.14M	$1.32M	$1.52M	$1.75M
Expected Unserved Energy value at 10th percentile demand	$0.27M	$0.94M	$1.08M	$1.20M	$1.21M	$1.34M	$1.52M	$1.72M	$1.93M	$2.16M
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile vale + 0.3 x 10th percentile value	$0.14M	$0.74M	$0.87M	$0.98M	$0.98M	$1.09M	$1.25M	$1.44M	$1.65M	$1.87M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

HORSHAM TERMINAL STATION (HOTS) 66kV

Horsham Terminal Station (HOTS) 66 kV consists of two 100 MVA 235/67.5 kV transformers and is the main source of supply for some 36,372 customers in Horsham and the surrounding area. The station supply area includes Horsham, Edenhope, Warracknabeal and Nhill. The station also supplies Stawell via the inter-terminal 66 kV ties with Ballarat Terminal Station (BATS).

Magnitude, probability and impact of loss of load

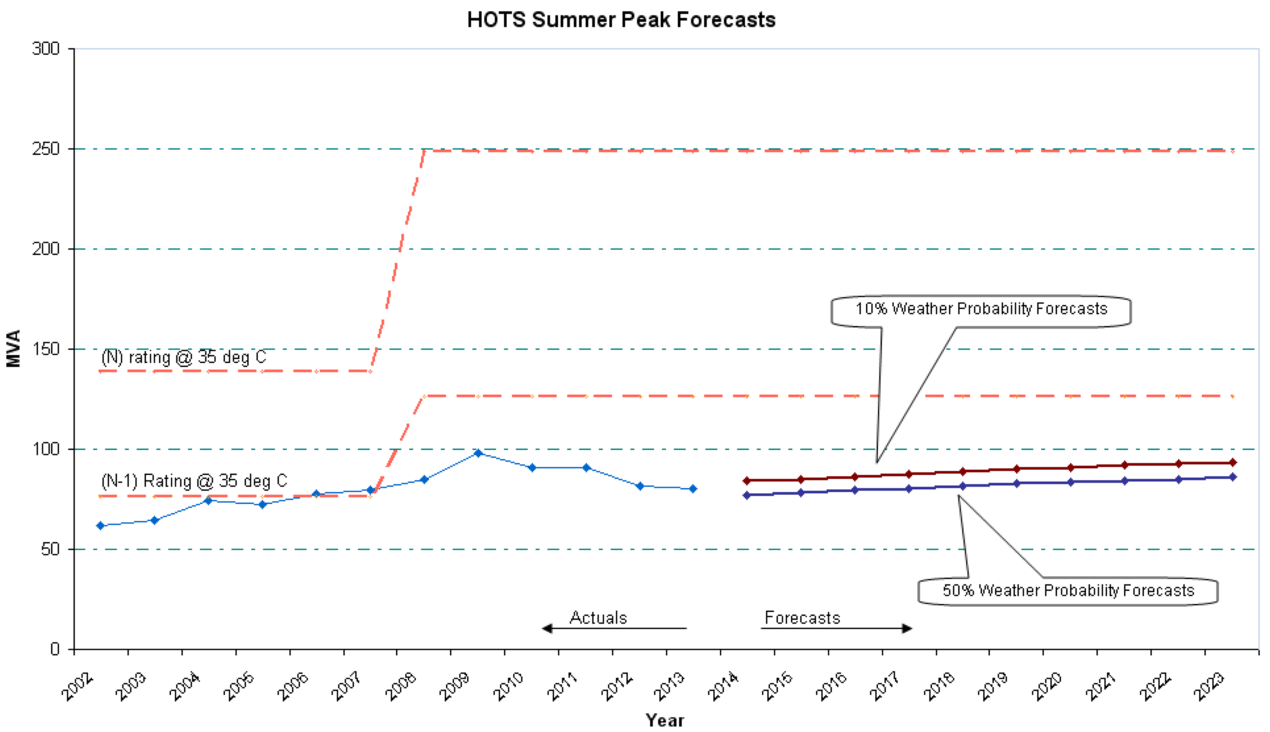
HOTS 66 kV demand is summer peaking. Summer peak demand at HOTS has reduced by an average of around -0.1 MW (-1.1%) per annum over the last 5 years. The peak load on the station reached 78.3 MW in summer 2013. It is noted that the 2012/13 summer was a relatively mild summer in comparison to previous years and therefore a lower than expected maximum demand was observed at the station. For average summer temperatures, a growth rate of 0.7% is reflected in the future peak forecast below.

It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.96.

In 2007, as part of its asset replacement program, SPI PowerNet replaced the existing two 70 MVA 235/67.5 kV transformers with 100 MVA units after approval from Powercor. The capacity increase delivered by these works is depicted in the step increase in the N and N-1 station rating shown in the graph below.

The graph depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.



The graph shows that there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

HEYWOOD TERMINAL STATION (HYTS) 22kV

Heywood Terminal Station (HYTS) 22 kV consists of two 70 MVA 500/275/22 kV transformers and is the source of supply to Midway, a wood chipper in the local area and the only large customer supplied from this supply point. A small number of domestic and farming customers along the line route are also supplied from this supply point.

Magnitude, probability and impact of loss of load

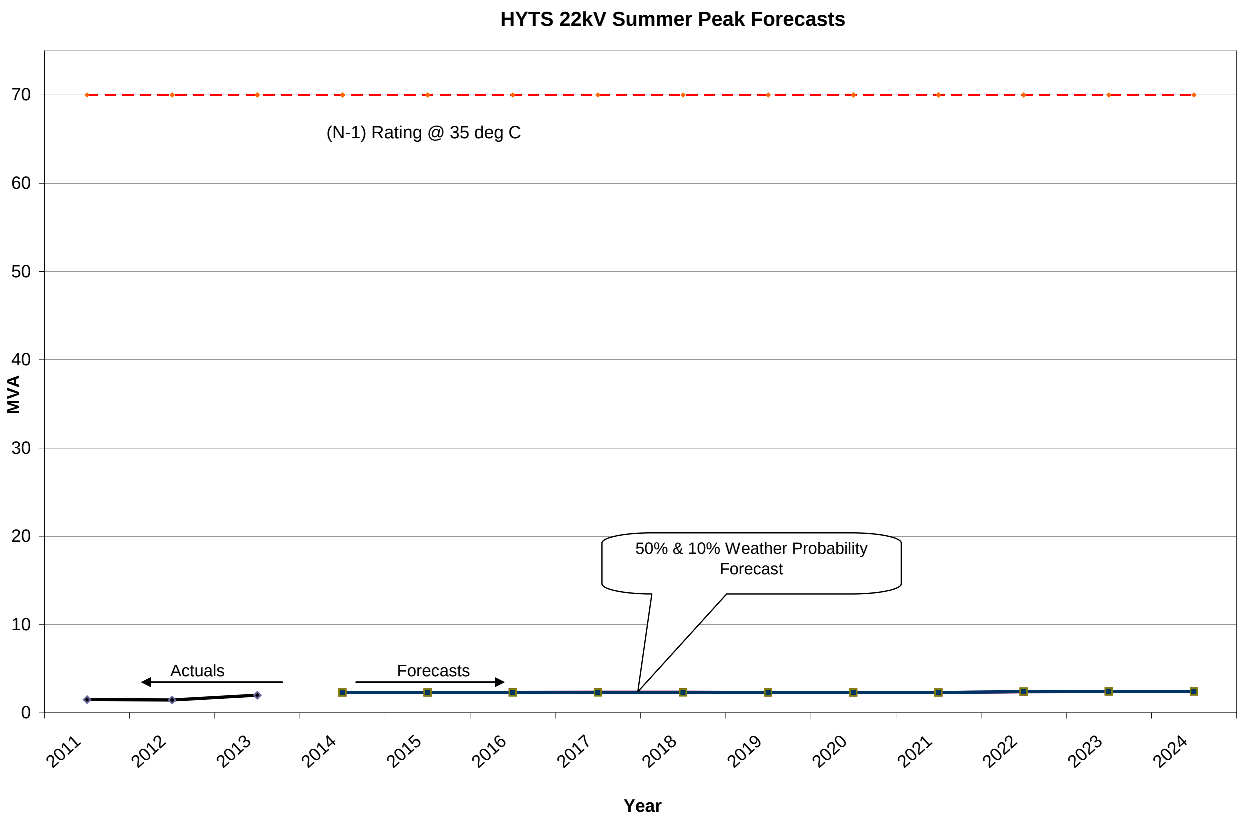
The peak load on the station reached 2.0 MW in summer 2013.

The 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on the existing 2 x 500/275/22 kV South Australian / Victorian interconnecting transformers. The supply is arranged so that one transformer is on hot standby (on its tertiary 22 kV), due to excessive fault levels.

It is estimated that:

- For 3 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.97.

The graph depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N-1" rating at 35°C ambient temperature.



The graph shows that there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

KEILOR TERMINAL STATION 66 kV (KTS 66 kV)

Keilor Terminal Station is located in the north west of Greater Melbourne. It operates at 220/66 kV and supplies a total of approximately 210,000 Jemena Electricity Networks and Powercor customers in the Airport West, St. Albans, Sunshine, Melton, Woodend, Pascoe Vale, Essendon and Braybrook areas.

Background

KTS has five 150 MVA transformers and is a summer critical station. Up until 2012, the station was operated with one of the five transformers, also known as KTS B5 transformer, in "hot standby" mode, with the then No. 2-3 66 kV bus tie circuit breaker open for the purpose of limiting the maximum prospective fault levels to within switchgear ratings. In the event of an outage of one of the four "normally on-load" transformers, the B5 unit would be connected in automatically. Therefore the "N" and "N-1" ratings were the same.

In 2012, the station was re-configured to enable the KTS B5 transformer to take load under system normal conditions. Under system normal conditions, the No.1, No.2 & No.5 transformers are operated in parallel as one group (KTS(B1,2,5)) and supply the No.1, No.2 & No.5 66 kV buses. The No.3 & No.4 transformers are operated in parallel as a separate group (KTS(B3,4)) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 3-5 and bus 1-4 tie circuit breakers are operated in the normally open position to limit the maximum prospective fault levels on the five 66 kV buses to within switchgear ratings.

For an unplanned transformer outage in the KTS(B3,4) group, the No.5 transformer will automatically change over to the KTS(B3,4) group. Therefore, an unplanned transformer outage of any one of the five transformers at KTS will result in both the KTS(B1,2,5) and KTS(B3,4) groups being comprised of two transformers each. Given this configuration, load demand on the KTS(B3,4) group must be kept within the capabilities of the two transformers at all times or load shedding will occur.

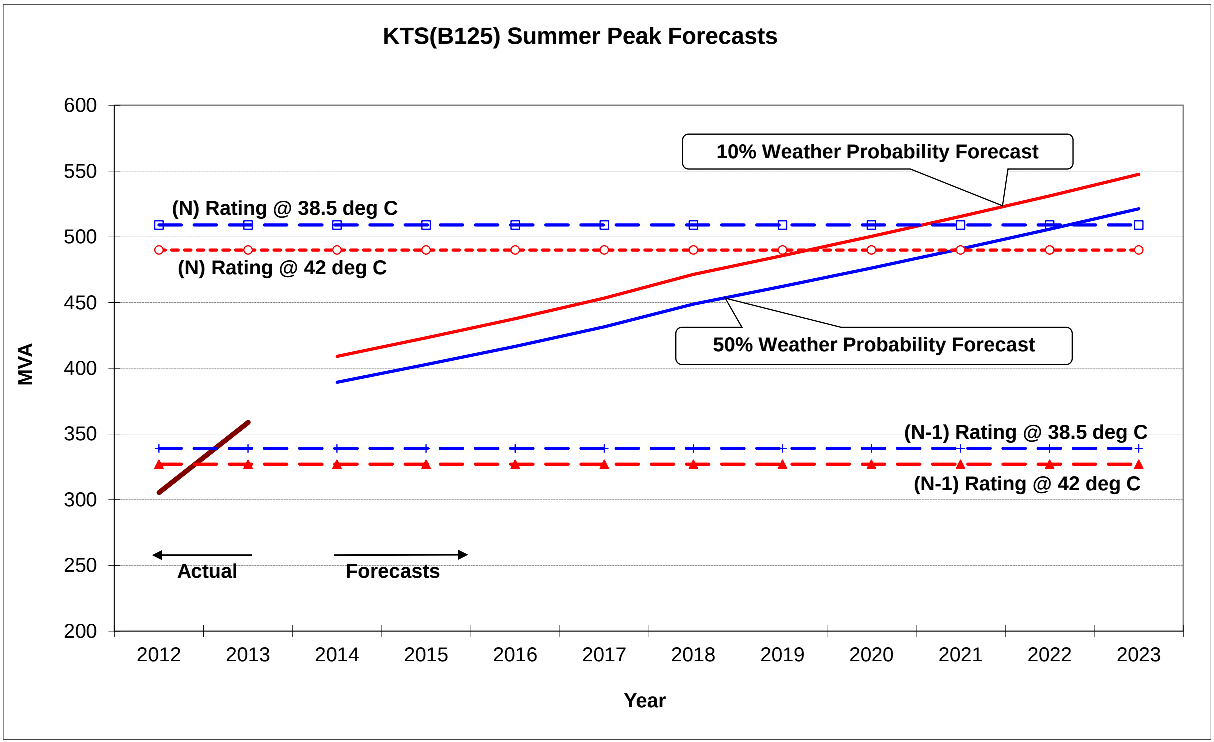
The following sections examine the two transformer groups separately.

Transformer group KTS (B1,2,5) Summer Peak Forecasts

The graph below depicts the KTS (B1,2,5) rating with all transformers (B1, B2 & B5) in service ("N" rating), and with one of the three transformers out of service ("N-1" rating), along with the 50th and 10th percentile summer maximum demand forecasts[1]. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at time of peak demand is 0.98.

[1] Note that station transformer output capability rating and transformers' loading is used.



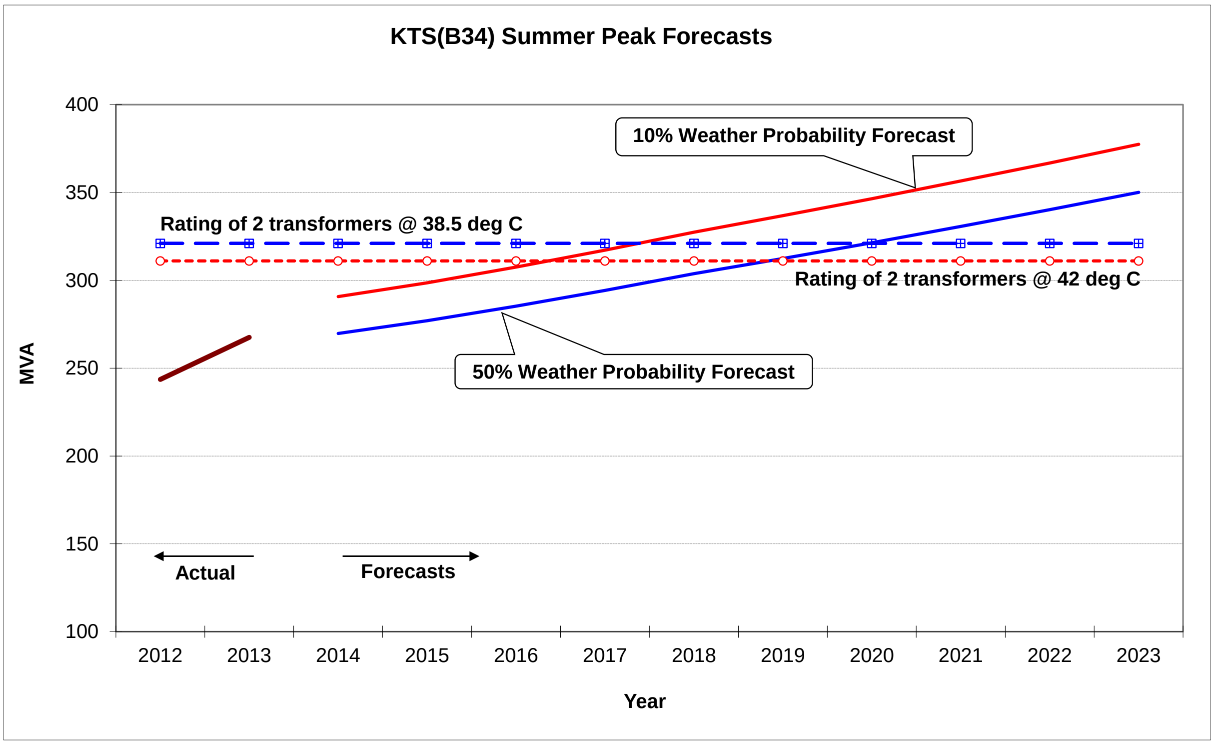
The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand until 2020. However, if there is a forced transformer outage during peak load periods from 2014 onwards, some customers would be affected.

Transformer group KTS (B3,4) Summer Peak Forecasts

The graph below depicts the summer maximum demand forecasts (for 50th and 10th percentile temperatures) for KTS (B3,4) and the corresponding rating with both transformers (B3 & B4) operating. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at time of peak demand is 0.95.

It shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand until 2017. As explained above, if an unplanned transformer outage in the KTS(B3,4) group occurs, the No.5 transformer will automatically change over to the KTS(B3,4) group. In effect, the N-1 and N ratings of the KTS(B3,4) group are equivalent. Thus there is sufficient capacity provided by the KTS(B3,4) group to meet the anticipated maximum demand until 2017, even under a transformer outage condition. From 2017 onwards, there is insufficient capacity to meet the anticipated maximum load demand at the 10th percentile level for the remainder of the forecast period. However, at the 50th percentile level, there is adequate capacity to meet the anticipated maximum load demand until 2021.

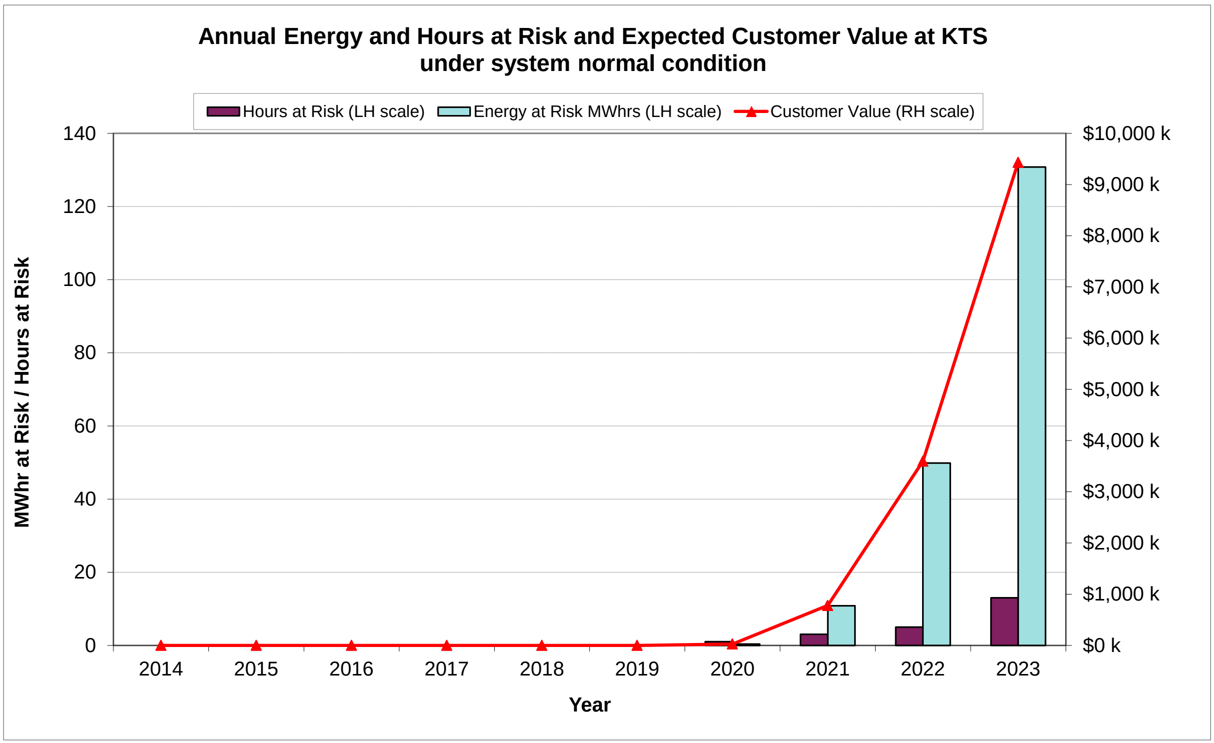


Magnitude, probability and impact of loss of load at KTS

The magnitude, probability and load at risk for the two transformer groups are considered together below.

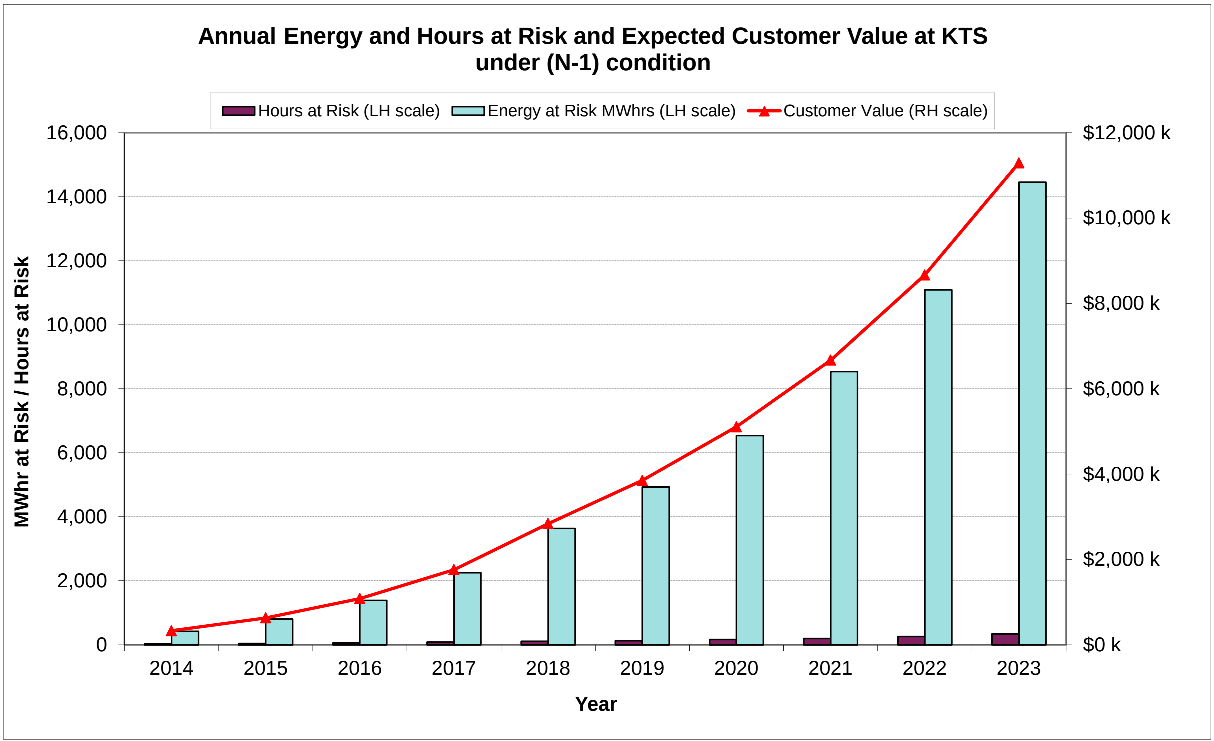
System Normal Condition (All 5 transformers in service)

The bar chart below depicts the energy that would not be supplied under system normal conditions for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N capability rating. The line graph shows the value to consumers of the unserved energy in each year, for the 50th percentile demand forecast in each year under system normal (N) condition. .



N-1 System Condition

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating for the KTS(B1,2,5) group. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk at KTS

There will only be sufficient capacity at the station to supply all customer demand until 2020 under system normal condition for demand below the 50th percentile demand forecast. For any peak demand reaching the 10th percentile forecast, all load will not be able to be supplied after 2017. However from 2014 onwards, for an outage of one transformer at KTS 66 kV over the summer peak load period, there would be insufficient capacity at the station to supply all customer demand.

By summer 2017/18, the energy that would not be supplied under a transformer outage (N-1 condition) on the KTS transformer groups is estimated to be 3,632 MWh for the 50th percentile demand forecast. Over the summer 2017/18 period, there would be insufficient capacity to meet demand for about 111 hours in that year for (N-1) condition. The estimated value to consumers of the 3,632 MWh of the energy not supplied is approximately $262 million (based on a value to customer reliability of $72,130/ MWh)[2]. In other words, at the 50th percentile summer demand level, and in the absence of any other operational response that might be taken to mitigate impacts on customers, a major outage of one transformer at KTS over the summer of 2017/18 would be anticipated to lead to involuntary supply interruptions that would cost consumers $262 million.

It is emphasised however, that the probability of a major outage of one of the five transformers is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (3,632 MWh) is weighted by this low transformer unavailability, the expected unserved energy (for loss of one transformer) is estimated to be around 39.3 MWh. The expected unserved energy is estimated to have a value to consumers of around $2.8 million.

It should also be noted that the above estimates are based on an assumption of demand up to the average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the customer demand increases significantly due to air conditioning loads. At the 10th percentile demand forecast, the energy that would not be supplied in the summer of 2017/18 for N and (N-1) conditions is estimated to be 67.9 MWh and 5,629 MWh respectively. The estimated value to consumers of this energy in the summer of 2017/18 for N and (N-1) conditions is approximately $4.9 million and $406.0 million respectively. The total corresponding value of the expected unserved energy is approximately $9.3 million.

[2] The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

These key statistics for the summer of 2017/18 under N and (N-1) outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy not supplied at 50th percentile demand forecast under N condition	0	$0
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	3,632.2	$262.0 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	39.3	$2.8 million
Total expected unserved energy at 50th percentile demand for N and N-1 conditions	39.3	$2.8 million
Energy not supplied at 10th percentile demand forecast under N condition	67.9	$4.9 million
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	5,629.0	$406.0 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	61.0	$4.4 million
Total expected unserved energy at 10th percentile demand for N and N-1 conditions	128.8	$9.3 million

Possible Impact on Customers

System Normal Condition (All 5 transformers in service)

Applying the 50th percentile demand forecast, it is anticipated that load shedding of 0.4 MVA in 2019/20 increasing to 41.4 MVA in 2022/23 would be required to limit the load to within the rated capacity of the station. This would affect approximately 127 customers in 2019/20, increasing to 13,800 in 2022/23, under system normal condition. This indicates that major action will be required during the forecast period to alleviate this emerging constraint.

N-1 System Condition

If one of the KTS 220/66 kV transformers is taken off line during peak loading times, causing the KTS (B1,2,5) rating to be exceeded, the OSSCA[3] load shedding scheme which is operated by SPI PowerNet's TOC[4] will act swiftly to reduce the loads in blocks to within transformer capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with Jemena EN's and Powercor's, operational procedures.

3 Overload Shedding Scheme of Connection Asset.
4 Transmission Operations Centre.

In the summer of 2017/18, at maximum loading periods, based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would automatically shed about 109.8 MVA of the KTS supply load. This would affect approximately 36,600 customers.

Applying the 50th percentile demand forecast, the energy at risk increases from 418.8 MWh in 2013/14 to 14,451.5 MWh in 2022/23. For the same period, the expected unserved energy increases from 4.5 MWh in 2013/14 to 156.6 MWh in 2022/23. This indicates that major action will be required during the forecast period to alleviate this emerging constraint.

Feasible options and preferred network option(s) for alleviation of constraints

The risk of supply interruption at Keilor Terminal Station (KTS) has been assessed as being very high for summer 2017/18[5]. The proposed network option that was identified by both Powercor and Jemena Electricity Networks (in the 2010 and 2011 Transmission Connection Planning Reports) as the most economic network solution is to:

- establish a new 220/66 kV terminal station at Deer Park and associated 66 kV sub-transmission lines by summer 2017/18 at an estimated capital cost of $125 million; and
- to transfer load from KTS(B1,2,5) and KTS(B3,4) groups to the new terminal station.

In addition to the proposed new 220/66 kV terminal station at Deer Park, Powercor and Jemena Electricity Networks are currently planning for the installation of a 100 MVAr capacitor bank on the KTS(B3,4) group by summer 2015/16 at an estimated capital cost of $6 million, to improve the power factor and address the emerging capacity limitation on the KTS(B3,4) group.

Powercor and Jemena Electricity Networks completed a public “Expression of Interest” process for non-network alternatives, via the publication of the Transmission Connection Planning Reports in 2010 and 2011. In 2011, Powercor and Jemena also provided potential proponents of non-network solutions with information on capacity constraints at KTS, supply risks and potential opportunities for provision of network support services. Early in 2012, Powercor, Jemena and AEMO completed a Joint Consultation Paper[6] and Joint Regulatory Test Report[7] in relation to the options for addressing the capacity constraints at KTS. A copy of the report is available at:

http://www.powercor.com.au/West_Metro_SubTransmission/

At the conclusion of the expression of interest and regulatory consultation process on 27 July 2012, no firm proposals for alternatives to the network augmentation had been received.

In the absence of any commitment by interested parties to offer non-network solutions, Powercor and Jemena Electricity Networks intend to proceed with the next stage of the process by implementing the proposed network solution- that is establishing a new 220/66 kV terminal station at Deer Park and associated 66 kV sub-transmission lines by summer

[5] The risk of supply interruptions at KTS has previously been assessed as being unacceptable for summer 2016/17 in the 2010 and 2011 Transmission Connection Planning Reports. However, with the 2012 and 2013 updated forecasts, the revised optimal timing for the proposed network solution is prior to summer 2017/18, based on an investment decision rule of maximising expected net market benefits.

[6] The Joint Consultation Paper was published on Jemena, Powercor and AEMO websites on 10 February 2012.

[7] The Joint Regulatory Test Report was published on Jemena, Powercor and AEMO websites on 1 May 2012.

2017/18 at an estimated capital cost of $125 million, to transfer load from KTS(B1,2,5) and KTS(B3,4) groups to the new terminal station. It is noted that the analysis of emerging constraints at KTS presented in the May 2012 Joint Regulatory Test Report assumed that the proposed 100 MVAr capacitor bank would be installed on the KTS(B3,4) group by the summer of 2013/14. Application of the latest demand forecasts indicates that this work can be deferred to 2015/16, as noted above.

In the meantime, the risk to supply reliability will be mitigated through the following temporary measures:

- Balance the load between the two bus groups at KTS so that the load on each bus group is kept below its N rating;
- maintain contingency plans to transfer load quickly, where possible, to adjacent terminal stations;
- fine-tune the OSSCA scheme settings in conjunction with SPI PowerNet to minimise the impact on customers of any automatic load shedding that may take place; and
- Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for urban areas (refer section 4.5), this spare transformer could be installed at KTS and used to temporarily replace a failed transformer.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

KEILOR TERMINAL STATION (KTS(B1,2,5) TRANSFORMER GROUP)[8]

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	Jemena EN (64%), Powercor (36%)
Normal cyclic rating with all plant in service	509 MVA at 50th percentile temperature and 490 MVA at 10th percentile temperature (Summer peaking)
Summer N-1 Station Transformer Rating:	339 MVA at 50th percentile temperature and 327 MVA at 10th percentile temperature [See Note 1 below for interpretation of N-1]
Winter N-1 Station Transformer Rating:	353 MVA

Station: KTS(B125) 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	389	403	417	432	449	462	476	491	506	521
50th percentile Winter Maximum Demand (MVA)	291	302	312	323	335	344	353	362	372	382
10th percentile Summer Maximum Demand (MVA)	409	423	438	453	472	486	500	516	531	548
10th percentile Winter Maximum Demand (MVA)	299	309	320	331	344	353	362	372	382	392
N-1 energy at risk at 50th percentile demand (MWh)	419	806	1,385	2,253	3,632	4,928	6,536	8,534	11,091	14,451
N-1 hours at risk at 50th percentile demand (hours)	26	39	58	82	111	127	162	198	258	340
N-1 energy at risk at 10th percentile demand (MWh)	1,645	2,230	2,987	4,021	5,629	7,339	9,466	12,093	15,276	19,173
N-1 hours at risk at 10th percentile demand (hours)	44	54	70	94	144	175	220	269	322	389
Expected Unserved Energy at 50th percentile demand (MWh)	5	9	15	24	39	53	71	92	120	169
Expected Unserved Energy at 10th percentile demand (MWh)	18	24	32	44	61	80	127	261	513	863
Expected Unserved Energy value at 50th percentile demand	$ 0.3 M	$ 0.6 M	$ 1.1 M	$ 1.8 M	$ 2.8 M	$ 3.9 M	$ 5.1 M	$ 6.7 M	$ 8.7 M	$ 12.2 M
Expected Unserved Energy value at 10th percentile demand	$ 1.3 M	$ 1.7 M	$ 2.3 M	$ 3.1 M	$ 4.4 M	$ 5.7 M	$ 9.2 M	$ 18.8 M	$ 37.0 M	$ 62.2 M
Expected Annual Unserved Energy value (using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value)	$ 0.6 M	$ 1.0 M	$ 1.5 M	$ 2.2 M	$ 3.3 M	$ 4.4 M	$ 6.3 M	$ 10.3 M	$ 17.2 M	$ 27.2 M

Notes:

1. "N-1" means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 38.5 degrees Centigrade and 42 degrees Centigrade (for 50th percentile value and 10th percentile value respectively) as this is the typical temperatures where 50% PoE loads and 10% PoE loads are likely to occur at KTS.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means " energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

[8] Note that risk assessment for this station is carried out using station transformers' rating and loading.

KEILOR TERMINAL STATION (KTS(B3,4) TRANSFORMER GROUP)[9]

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	Jemena EN (31%), Powercor (69%)
Normal cyclic rating with all plant in service:	321 MVA at 50th percentile temperature and 311 MVA at 10th percentile temperature (Summer peaking)
Summer N-1 Station Transformer Rating:	321 MVA at 50th percentile temperature and 311 MVA at 10th percentile temperature [See Note 1 below for interpretation of N-1]
Winter N-1 Station Transformer Rating:	344 MVA

Station: KTS(B34) 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	270	277	285	294	304	312	321	331	340	350
50th percentile Winter Maximum Demand (MVA)	214	219	225	231	238	244	250	256	262	268
10th percentile Summer Maximum Demand (MVA)	291	299	307	317	327	337	346	356	367	377
10th percentile Winter Maximum Demand (MVA)	221	227	233	239	246	252	258	264	271	278
N-1 energy at risk at 50th percentile demand (MWh)	-	-	-	-	-	-	0	11	50	119
N-1 hours at risk at 50th percentile demand (hours)	-	-	-	-	-	-	1	3	5	12
N-1 energy at risk at 10th percentile demand (MWh)	-	-	-	10	68	176	347	575	845	1,150
N-1 hours at risk at 10th percentile demand (hours)	-	-	-	2	10	15	23	27	31	34
Expected Unserved Energy at 50th percentile demand (MWh)	-	-	-	-	-	-	0	11	50	119
Expected Unserved Energy at 10th percentile demand (MWh)	0	0	0	10	68	176	347	575	845	1,150
Expected Unserved Energy value at 50th percentile demand	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ 0.0 M	$ 0.8 M	$ 3.6 M	$ 8.6 M
Expected Unserved Energy value at 10th percentile demand	$ - M	$ - M	$ - M	$ 0.8 M	$ 4.9 M	$ 12.7 M	$ 25.0 M	$ 41.5 M	$ 61.0 M	$ 82.9 M
Expected Annual Unserved Energy value (using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value)	$ - M	$ - M	$ - M	$ 0.2 M	$ 1.5 M	$ 3.8 M	$ 7.5 M	$ 13.0 M	$ 20.8 M	$ 30.9 M

Notes:

1. "N-1" means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 38.5 degrees Centigrade and 42 degrees Centigrade (for 50th percentile value and 10th percentile value respectively) as this is the typical temperatures where 50% PoE loads and 10% PoE loads are likely to occur at KTS.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is the same as "N-1 energy at risk" for this bus group.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) is the same as "N-1 hours per year at risk" for this bus group.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx) .

[9] Note that risk assessment for this station is carried out using station transformers' rating and loading.

KERANG TERMINAL STATION (KGTS) 66kV & 22kV

Kerang Terminal Station (KGTS) 66 kV and 22 kV consists of three 35 MVA 235/66/22 kV transformers and is the main source of supply for over 18,076 customers in Kerang and the surrounding area. The station supply area includes Kerang, Swan Hill and Cohuna.

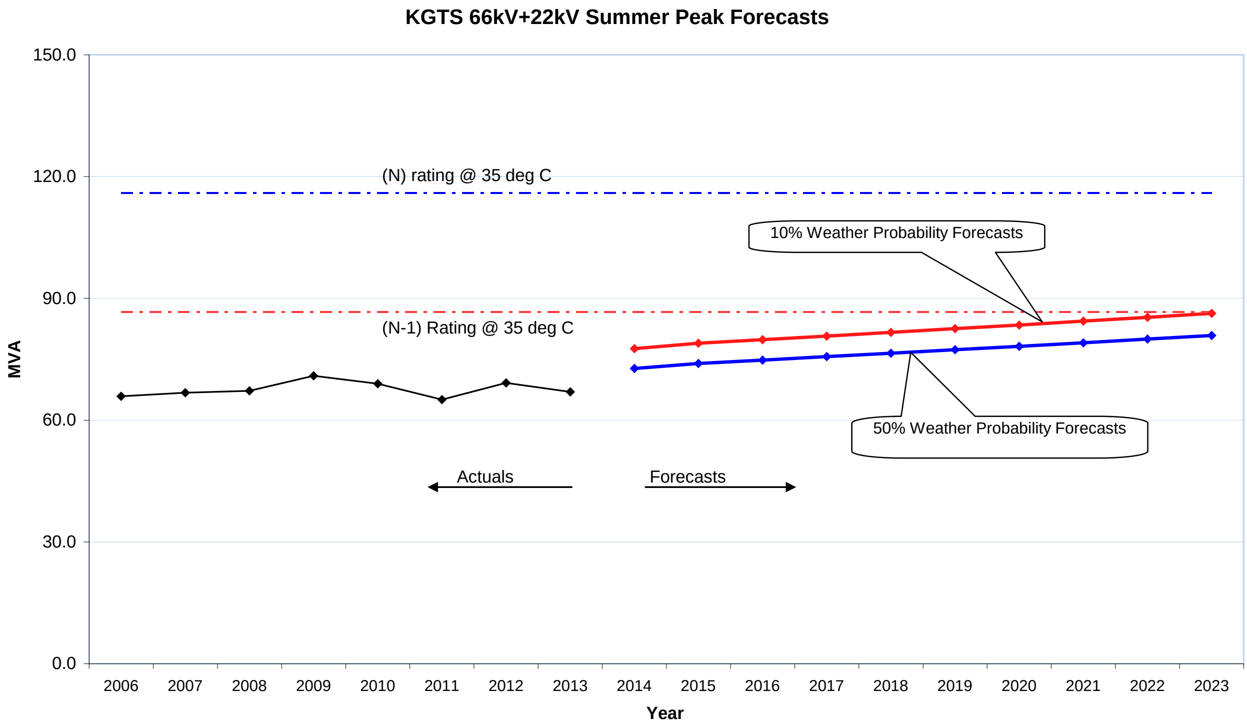
Magnitude, probability and impact of loss of load

Growth in summer peak demand at KGTS is expected to average around 0.9 MVA (1.48%) per annum over the next ten year forecast period. The peak load on the station reached 67.2 MVA (66 kV and 22 kV networks) in summer 2013.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 1.00.

KGTS 66 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.



The graph shows there is sufficient capacity at the station to supply all expected demand at the 50th percentile temperature, over the forecast period, even with one transformer out of service. There is no load at risk at the 10th percentile temperature even for the loss of a transformer. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

MALVERN 22 kV TERMINAL STATION (MTS 22 kV)

MTS 22 kV is the source of supply for over 12,000 customers in Burwood, Ashwood, Glen Iris, Mount Waverley and Surrey Hills.

The station underwent a refurbishment in 2007 when the asset owner, SPI PowerNet, replaced aged transformers and switchgear including protection and control equipment at the station. The project was part of SPI PowerNet's asset replacement program, and included replacement of the three old 45/55 MVA 220/22 kV transformers with two new 40/60 MVA 66/22 kV transformers. These transformers are supplied from existing 140/225 MVA 220/66 kV transformers at MTS (refer also to the Risk Assessment for MTS 66 kV).

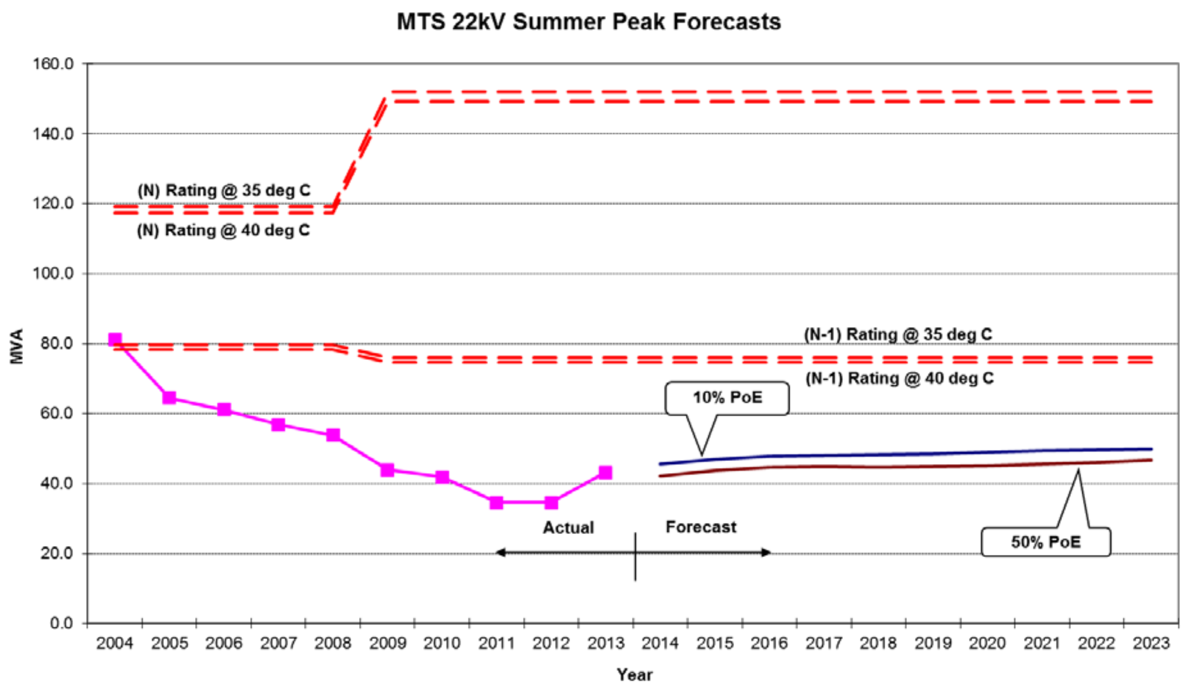
In addition to asset replacement works at MTS 22 kV by SPI PowerNet, two major 22 kV to 66 kV conversion projects initiated by United Energy (UE) on its network, resulted in load transfers from MTS 22 kV to MTS 66 kV being commenced in 2001. The reduction in station summer maximum demand from 89.3 MVA in 2001 to 34.5 MVA in 2011, shown in the graph below, is attributed to the conversion works by UE.

MTS 22 kV is a summer critical terminal station. The recorded demand in summer 2012-13 was 41.8 MW (43 MVA), which was approximately 8 MW higher than the summer 2011-12 peak. The station load has a power factor of 0.969 at times of peak demand. The demand at MTS 22 kV is expected to reach 95% of the 50th percentile peak demand for approximately 5 hours per annum.

There are no embedded generation schemes over 1 MW connected at MTS 22 kV.

Magnitude, probability and impact of loss of load

In addition to historical summer maximum demands, the graph depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.



On the present forecasts, it is projected that demand at MTS 22 kV will remain well within the (N-1) thermal rating over the next ten years, as shown above.

Hence, the need for augmentation of transmission connection assets at MTS 22 kV is not expected to arise over the next decade.

The table on the following page provides more detailed data on the station rating and demand forecasts.

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MALVERN TERMINAL STATION 22 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 152 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating: 76 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 84 MVA

Station: MTS 22kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	42.0	43.7	44.5	44.9	44.7	44.8	45.1	45.6	46.1	46.6
50th percentile Winter Maximum Demand (MVA)	35.1	35.8	36.3	36.7	37.0	37.3	37.9	38.3	38.7	39.0
10th percentile Summer Maximum Demand (MVA)	45.5	46.9	47.8	48.0	48.1	48.5	49.0	49.4	49.6	49.8
10th percentile Winter Maximum Demand (MVA)	38.0	38.9	39.3	39.9	40.2	40.4	41.0	41.7	42.4	42.8
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N-1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

MALVERN 66 kV TERMINAL STATION (MTS 66 kV)

MTS 66 kV is the main source of supply for over 75,000 customers in Elsternwick, Caulfield, Carnegie, Malvern East, Ashburton, Chadstone, Oakleigh, Ormond, Murrumbeena, Hughesdale and Bentleigh East.

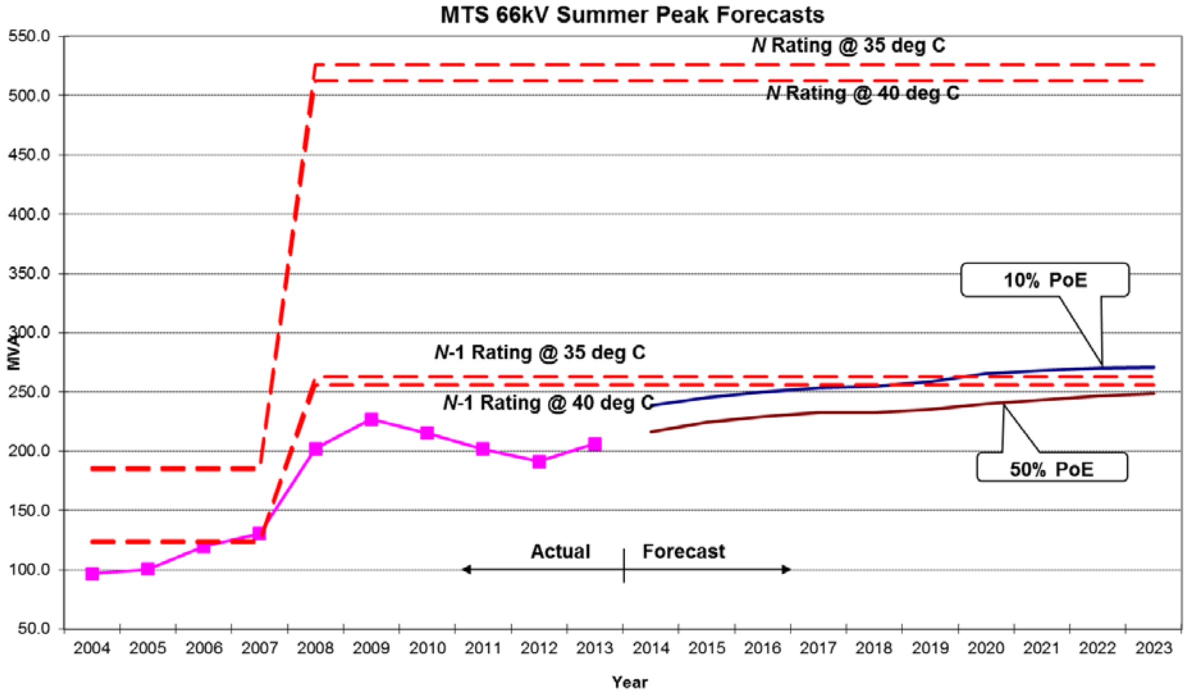
The station underwent a refurbishment in 2007 when the asset owner, SPI PowerNet, replaced aged transformers and switchgear including protection and control equipment at the station. The project was part of SPI PowerNet's asset replacement program, and included replacement of the three old 45/55 MVA 220/66 kV transformers with two new 140/225 MVA 220/66 kV transformers. These transformers support the demand of both 66 kV and 22 kV networks ex MTS (refer also to the Risk Assessment for MTS 22 kV).

MTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 220 MW (227 MVA) in summer 2008-09 under extreme weather conditions. The recorded demand in summer 2012-13 was 201 MW (206 MVA), which was approximately 15 MW higher than the 2012 peak.

There are no embedded generation schemes over 1 MW connected at MTS 66 kV.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.



The N rating on the graph indicates the maximum load that can be supplied from MTS 66 kV with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph above shows that with one transformer out of service, the projected demand will remain within the N-1 capability rating for the 50th percentile demand forecast over the ten year planning horizon. However, the 10th percentile demand forecast is expected to exceed the (N-1) rating at 40°C from summer 2018-19.

The station load is forecast to have a power factor of 0.983 at times of peak demand. The demand at MTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for approximately 4 hours per annum.

Comments on Energy at Risk

For an outage of one transformer at MTS 66kV, there will be sufficient capacity at the station to supply all demand at the 50th percentile temperature within the 10 year planning horizon.

Under 10th percentile temperature conditions, the energy at risk under N-1 conditions is estimated to be 25 MWh in summer 2023. The estimated value to consumers of the 25 MWh of energy at risk is approximately $1.7 million (based on a value of customer reliability of $69,616/MWh)[1].

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. At the 10th percentile level, when the energy at risk, 25 MWh in 2023 is weighted by this low unavailability, the expected unserved energy is estimated to be 0.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $7,500.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	Nil	Nil
Expected unserved energy at 50th percentile demand	Nil	Nil
Energy at risk, at 10th percentile demand forecast	25	$1.7 million
Expected unserved energy at 10th percentile demand	0.1	$7,500

If one of the 220/66 kV transformers at MTS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[2] load shedding scheme which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's operational procedures after the operation of the OSSCA scheme.

In the case of MTS 66 kV supply at maximum loading periods, and based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would shed about 78 MVA of load, affecting approximately 27,600 customers.

1 The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station

2 Overload Shedding Scheme of Connection Asset.

3 Transmission Operations Centre

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV subtransmission and 22 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from MTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 19 MVA.

2. Install a third 140/225 MVA 220/66 kV transformer at MTS 66 kV.

   The capital cost of installing a 220/66 kV transformer at MTS 66 kV is estimated to be $20 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2 million.

On the present maximum demand forecasts, the third 220/66 kV transformer is not likely to be required within the ten year planning horizon.

Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at MTS 66 kV, it is proposed to:

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at MTS 66 kV under extreme loading conditions:

   - maintain contingency plans to transfer load quickly to adjacent terminal stations;

   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any automatic load shedding that may take place; and

   - Subject to the availability of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. Install a third 140/225 MVA 220/66 kV transformer at MTS 66kV.

   In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at MTS 66 kV, it is proposed to install a third 220/66 kV transformer at MTS. On the present forecasts, an additional 220/66 kV transformer is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

MALVERN TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 526 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating: 263 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 303 MVA

Station: MTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	217	224	229	233	232	235	240	243	246	249
50th percentile Winter Maximum Demand (MVA)	167	171	175	178	181	185	188	190	191	194
10th percentile Summer Maximum Demand (MVA)	239	245	250	253	255	259	265	268	270	271
10th percentile Winter Maximum Demand (MVA)	172	177	180	183	186	190	193	195	196	199
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N-1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	1	10	17	22	25
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	1	2	3	3	3
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.4k	$3.1k	$5.2k	$6.5k	$7.5k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.1k	$0.9k	$1.6k	$1.9k	$2.2k

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

MORWELL TERMINAL STATION 66 kV (MWTS 66 kV)

Morwell terminal station (MWTS) 66 kV is the main source of supply for a major part of south-eastern Victoria including Gippsland. It supplies Phillip Island, Wonthaggi, Leongatha in the west; Moe and Traralgon in the central area; to Omeo in the north; and to Bairnsdale and Mallacoota in the east. SPI Electricity (SPIE) is responsible for the transmission connection and distribution network planning for this region.

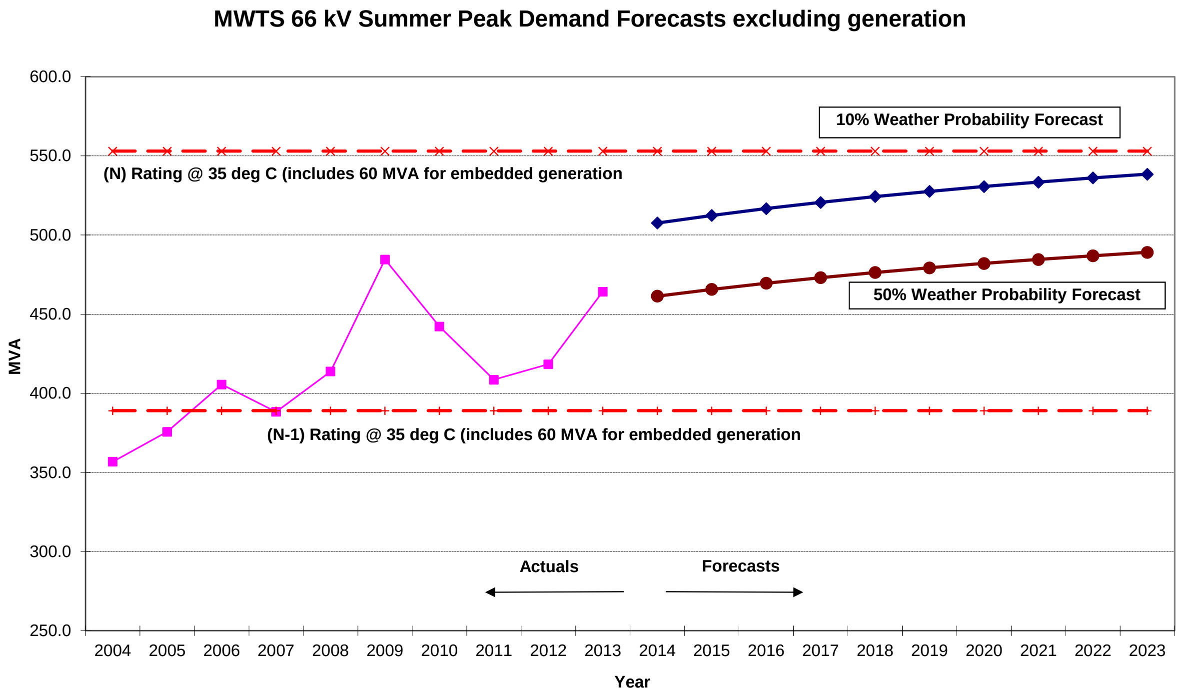
Magnitude, probability and impact of loss of load

MWTS 66 kV is supplied by two 165 MVA 220/66 kV transformers and one 150 MVA 220/66 kV transformer. SPI PowerNet plans to replace the No. 2 220/66 kV 165 MVA transformer with a new 220/66 kV 150 MVA unit in the next five years.

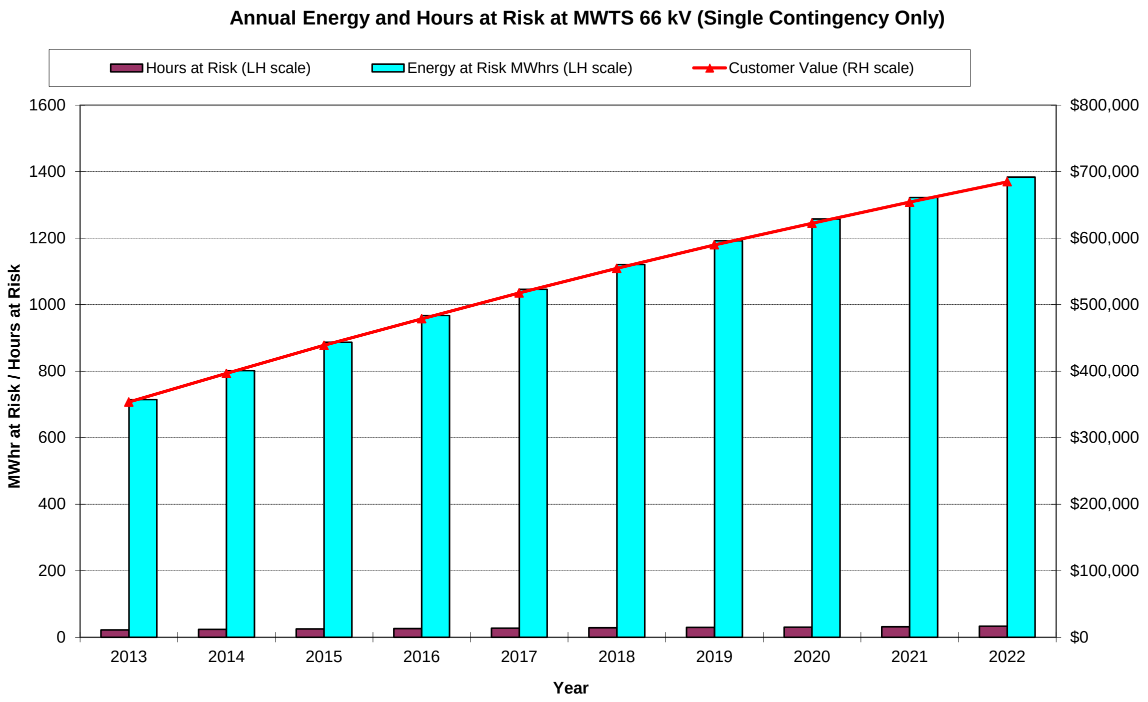
MWTS 66 kV is a summer peaking station which recorded a maximum demand of 452 MW (464 MVA) in early January 2013. The peak demand period is usually quite short coinciding with a few weeks of peak tourism from Christmas to early January along the east coast of Victoria. The maximum demand recorded is very dependent on weather in this short period. Growth in peak demand at MWTS 66 kV has averaged around 5 MW (1.5%) per annum over the last 6 years and is forecast to continue at this level for the next few years. The station load has a power factor of 0.974 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak load for 5 hours per annum.

The assessment of the energy at risk at MWTS 66 kV needs to take into account the significant levels of embedded generation which is connected to the MWTS 66 kV bus and directly offsets the loading on the 220/66 kV transformers at MWTS. The embedded generation includes the 75 MW Morwell Power Station (MPS), the 80 MW Bairnsdale Power Station (BPS), the 10 MW Traralgon Power Station and the Wonthaggi and Toora Wind Farms totalling 33 MW. The combined capacity of these generators totals 198 MW and during the summer 2012/13 peak demand an actual generation contribution of 64 MW was observed, which was low compared with previous years. Morwell power station has recently reduced output. In order to make a realistic assessment of the risk at MWTS the output from these embedded generators in assumed to be 60 MVA allowing 40 MVA for BPS (one unit of two in service), 15 MVA from MPS (typical recent summer output) and 5 MVA from the wind farms.

The “N–1” and “N” ratings shown on the graph below include the transformer capacity as well as the assumed 60 MVA contribution from embedded generation. For example the 389 MVA “N–1” rating includes the 329 MVA capacity of two 220/66 kV transformers and 60 MVA from the embedded generation. The graph also shows the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service plus 60 MVA from embedded generation) and the “N-1” rating at an ambient temperature of 35°C. The “N” rating on the chart indicates the maximum load that can be supplied from MWTS 66 kV with all transformers in service. Summer peak demand loading at MWTS is expected to exceed the station’s “N-1” rating for the entire planning period between 2013/14 to 2022/23.



The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the "N-1" capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



MWTS is not expected to be loaded above its "N-1" rating under 50th percentile or 10th percentile winter maximum demand forecasts during the 10 year planning horizon.

Comments on Energy at Risk (assuming embedded generation at 60 MVA)

As noted above the embedded generation is expected to be contributing 60 MVA over the peak demand period so the analysis below assumes this level of embedded generation output, although the total available capacity of the embedded generators is 198 MVA.

For an outage of one transformer at MWTS 66 kV over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 33 hours in summer 2022/23. The energy at risk under "N-1" conditions is estimated to be 1,384 MWh in summer 2022/23. The estimated value to consumers of the 1,384 MWh of energy at risk is approximately $105.4 million (based on a value of customer reliability of $76,129/MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any additional generation above the 60 MVA assumed in these studies, or any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at MWTS 66 kV over the summer of 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers $105.4 million.

It is emphasised however, that the probability of a major outage of one of the three transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (1,384 MWh for summer 2022/23) is weighted by this low unavailability, the expected unsupplied energy is estimated to be 9.0 MWh. This expected unserved energy is estimated to have a value to consumers of around $0.69 million, (based on a value of customer reliability of $76,129/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of moderate summer temperatures occurring in each year. Under higher summer temperature conditions (that is, at the 10th percentile level), the energy at risk in 2022/23 is estimated to be 3,684 MWh. The estimated value to consumers of this energy at risk in 2022/23 is approximately $280 million. The corresponding value of the expected unserved energy is approximately $1.83 million.

These key statistics for the year 2022/23 under "N-1" outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	1,384	$105 million
Expected unserved energy at 50th percentile demand	9.0	$0.69 million
Energy at risk, at 10th percentile demand forecast	3,684	$280 million
Expected unserved energy at 10th percentile demand	24.0	$1.83 million

If one of the 220/66 kV transformers at MWTS is taken off line during peak loading times and the "N-1" station rating is exceeded, then the Overload Shedding Scheme for Connection

1 The value of unserved energy is derived from the sector values given in Table 1 of section 2.3, weighted in accordance with the composition of the load at this terminal station.

Assets (OSSCA) which is operated by SPI PowerNet's TOC[2] to protect the connection assets from overloading[3], will act swiftly to reduce the load in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with SPI Electricity's operational procedures after the operation of the OSSCA scheme. If OSSCA operates at MWTS, it would shed about 110 MVA of load, affecting approximately 46,000 customers.

Comments on Energy at Risk (assuming BPS is available at full capacity)

The previous comments on the energy at risk are based on the assumption that there is only 40 MVA of generation from Bairnsdale Power Station and 20 MVA from other embedded generation available to offset the 220/66 kV transformer loading. The Bairnsdale Power Station (BPS) is contracted to provide network support over the night-time hot water demand peak at an output of up to 40 MVA, and during the afternoon peak demand period at an output of up to 20 MVA. BPS frequently generates up to its maximum output of 80 MVA during the summer period. In practice this embedded generation reduces the energy at risk over the summer period to lower levels than indicated above. If there was a major transformer failure it should be possible to contract additional generation over the peak period to minimise any load shedding required. There is no firm commitment that BPS generation will be available to offset transformer loading at MWTS; however the times of peak demand at MWTS generally coincide with periods of high wholesale electricity prices, resulting in a high likelihood that BPS will be generating. With BPS generating to its full capacity there would be much lower levels of energy at risk during the current planning period up to 2022/23.

The Morwell Power Station (MPS) is expected to operate at 15 MVA output for the next two years but is able to increase output to 50 MVA if required with two weeks notice. The longer term future of MPS is dependent on carbon pricing and is uncertain at this stage. Generation from MPS in excess of 15 MVA would reduce energy at risk levels at MWTS.

SP AusNet is also currently negotiating for the connection of further wind generation into the MWTS 66 kV network and this would further reduce the load at risk at MWTS.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Establish a new terminal station in or adjacent to the supply area of MWTS. A strategically selected location for a new terminal station could allow load to be transferred away from MWTS. Electricity supply options for the Pakenham area currently supplied from Cranbourne Terminal Station include the establishment of a new terminal station near Tynong, Pakenham or Nar Nar Goon in the next 10 years. This option would allow some MWTS load in West Gippsland to be transferred away from MWTS.

[2] Transmission Operation Centre.

[3] OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

2. Embedded generation: Bairnsdale Power Station normally provides 20 MVA over the night time peak but it can be called upon to provide up to 40 MVA at any time, and if available up to 80 MVA can be sought. The Morwell Power Station may also be able to increase output in the event of a transformer failure.

3. Install a fourth 220/66 kV transformer at MWTS: Installation of a 4^{th} transformer at MWTS is a technically feasible option. However, fault level constraints would make such a solution costly to implement.

4. Installation of Power Factor Correction Capacitors: As the station is currently running with a power factor of around 0.97 at the summer peak the use of additional capacitors to further improve the power factor and to reduce the MVA loading will bring only marginal benefits.

5. Load transfers: Only 5 MVA of load can be shifted away from MWTS using the existing 22 kV distribution network so this is option is unable to provide any significant ability to manage the risk at MWTS.

Preferred network option(s) for alleviation of constraints

The preferred options for alleviation of transformer loading constraints are:

1. Continue to ensure that an adequate level of the existing embedded generation (Bairnsdale Power Station) is available in case of a major transformer failure. (As already noted, SPI Electricity has entered into a network support agreement with Bairnsdale Power Station for up to 40 MVA of support.)

2. Depending on the electricity supply option chosen for the supply area between Cranbourne terminal station and MWTS, there is the possibility of transferring some MWTS load to a new terminal station.

3. Install a new fourth 220/66 kV transformer at MWTS. Installation of a fourth transformer at MWTS is not economic over the ten year planning horizon if a total contribution of 60 MVA from embedded generators is assumed.

4. Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for rural areas (refer section 4.5), this spare transformer can be used to temporarily replace a failed transformer.

The capital cost of installing a new fourth 220/66 kV 150 MVA transformer at MWTS is estimated to be $25 million, including works required to mitigate fault levels. The cost of establishing, operating and maintaining the transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2.5 million which provides a broad upper bound for the maximum annual network support payment which may be available to embedded generators or demand management proponents that defer or avoid the transmission connection augmentation which may otherwise be required beyond 2023. A non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for say 10 years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging network constraints.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy assuming embedded generation is contributing 60 MVA.

MORWELL TERMINAL STATION 66kV (MWTS 66)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	SPI Electricity (100%)
Normal cyclic rating with all plant in service	554 MVA via 3 transformers and embedded generation
Summer N-1 Station Rating (MVA):	389 MVA via 2 transformers and embedded generation
Winter N-1 Station Rating (MVA):	467 MVA via 2 transformers and embedded generation

Station: MWTS 66kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	461.4	465.7	469.6	473.1	476.3	479.3	482.1	484.6	486.9	489.1
50th percentile Winter Maximum Demand (MVA)	370.6	373.9	376.8	379.6	382.0	384.4	386.5	388.5	390.2	391.9
10th percentile Summer Maximum Demand (MVA)	507.6	512.4	516.7	520.6	524.3	527.6	530.6	533.4	536.1	538.4
10th percentile Winter Maximum Demand (MVA)	381.0	384.4	387.3	390.2	392.8	395.1	397.4	399.3	401.2	402.9
N - 1 energy at risk at 50th percentile demand (MWh)	715	802	887	967	1,046	1,121	1,192	1,258	1,322	1,384
N - 1 hours at risk at 50th percentile demand (hours)	21.8	23.4	24.9	26.2	27.4	28.4	29.4	30.3	31.5	33.3
N - 1 energy at risk at 10th percentile demand (MWh)	2,043	2,245	2,442	2,630	2,822	3,005	3,184	3,356	3,527	3,684
N - 1 hours at risk at 10th percentile demand (hours)	48.8	52.5	55.9	60.1	65.3	69.8	74.0	77.7	81.3	84.4
Expected Unserved Energy at 50th percentile demand (MWh)	4.7	5.2	5.8	6.3	6.8	7.3	7.8	8.2	8.6	9.0
Expected Unserved Energy at 10th percentile demand (MWh)	13.3	14.6	15.9	17.1	18.4	19.6	20.7	21.8	23.0	24.0
Expected Unserved Energy value at 50th percentile demand	$0.35M	$0.40M	$0.44M	$0.48M	$0.52M	$0.56M	$0.59M	$0.62M	$0.66M	$0.69M
Expected Unserved Energy value at 10th percentile demand	$1.01M	$1.11M	$1.21M	$1.30M	$1.40M	$1.49M	$1.58M	$1.66M	$1.75M	$1.83M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.55M	$0.61M	$0.67M	$0.73M	$0.78M	$0.84M	$0.89M	$0.94M	$0.98M	$1.03M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

MT BEAUTY TERMINAL STATION 66 kV (MBTS 66 kV)

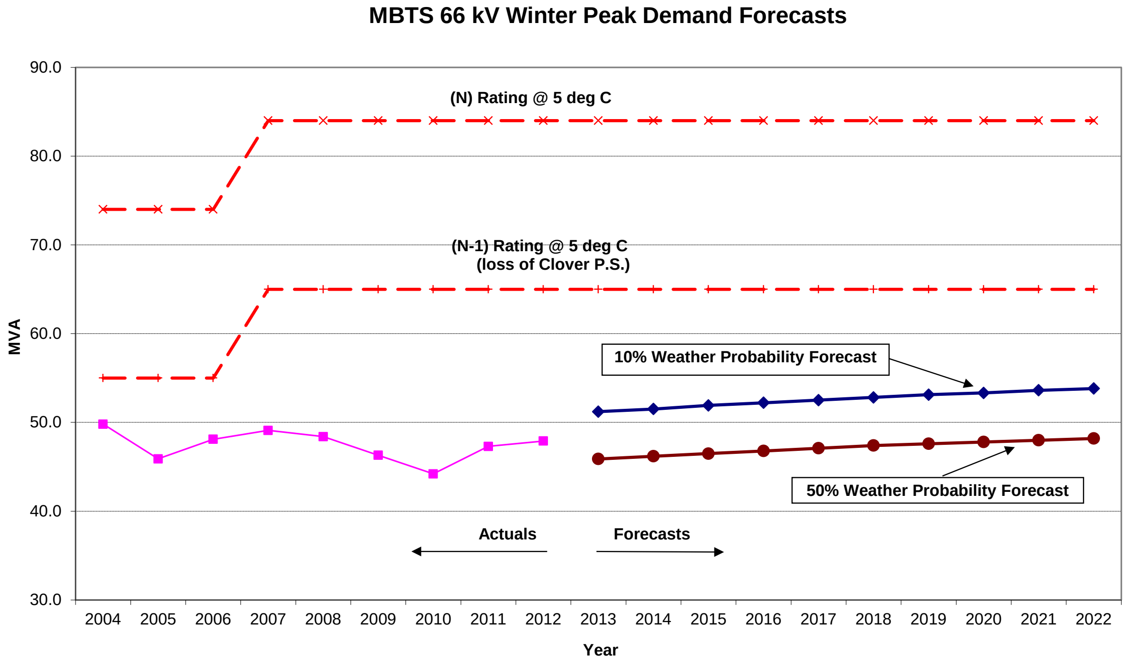
Mt Beauty terminal station is the main point of connection into the 220 kV electricity grid for Victoria's Kiewa hydro generation resources. The power stations include West Kiewa, McKay, Dartmouth, Clover and Eildon. MBTS is also the source of 66 kV supply for the alpine areas of Mt Hotham and Falls Creek along with the townships of Bright, Myrtleford and Mount Beauty. The station has two 220/66 kV 50 MVA transformers with one transformer in service and the other available as a hot spare that can be brought into service in approximately 4 hours. In addition, supply can also be taken from Clover Power Station and the 66 kV tie to Glenrowan terminal station via Myrtleford. It is SPI Electricity's responsibility to plan the electricity supply network for this region.

Magnitude, probability and impact of loss of load

MBTS is a winter peaking station and growth in winter peak demand on the MBTS 66 kV bus is expected to be approximately 0.9% per annum for the next few years. The peak load on the station reached 47.9 MVA in winter 2012. The station load has a power factor of 0.996 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak load for 8 hours per annum. The summer peak demand is approximately 75% of the winter peak.

In light of the current and expected future network configuration, and in keeping with the approach adopted by AEMO in its planning studies, the "N-1" scenario for MBTS is the loss of the 66 kV line to Clover power station.

The graph below depicts the 10th and 50th percentile winter maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at an ambient temperature of 5°C. With the forecast growth rates, MBTS 66 kV is not expected to reach its "N-1" winter station rating during 10 year planning horizon.



The above analysis does not include the possibility of loss of load for the short period of about 4 hours that it takes to change over from the in-service transformer to the hot spare transformer. The 66 kV tie line to Glenrowan terminal station can support about 25 MW of

MBTS load and this tie line is operated normally closed so if the load is below this limit there will not be any loss of customer load during a transformer outage. The Clover power station can generate around 26 MW and so any generation would also minimise the likelihood of the loss of customer load during a transformer outage.

It is recognised that at times of high demand and with low output from Clover power station a transformer outage at MBTS could result in the loss of some customer load for a short period of no more than 4 hours.

The energy at risk for a major transformer outage[1] in this situation (taking account of the limited 66 kV tie line capability) is significant at around 4,435 MWh in winter 2013 and rising to 5,906 MWh by 2022 However, given that the hot spare transformer can be made available within 4 hours, the expected outage duration in the case of a major transformer failure at MBTS is 4 hours (rather than 2.6 months). Accordingly, the probability of the transformer being unavailable in this particular case is only 0.000457%. The expected unserved energy at MBTS is therefore less than 0.1 MWh in 2022 and this is estimated to have a value to consumers of around $7,000 (based on a value of customer reliability of $71,609/MWh).[2] Full switching of the hot spare transformer with new 220 kV and 66 kV circuit breakers would eliminate this risk but this is estimated to cost around $2 million so it is not economic to carry out this work within the ten year planning horizon.

[1] In this report, “major transformer outage” means an outage that has a mean duration of 2.6 months.

[2] The value of unserved energy is derived from the sector values given in Table 1 of section 2.3, weighted in accordance with the composition of the load at this terminal station.

RED CLIFFS TERMINAL STATION (RCTS) 22kV

Red Cliffs Terminal Station (RCTS) 22 kV consists of two 35 MVA 235/66/22 kV transformers supplying the 22 kV network ex-RCTS. An additional 140 MVA 235/66/22 kV transformer operates normally open on the 22 kV bus with an auto-close scheme to close this transformer onto the 22 kV bus in the event of a failure of either of the other two transformers. This configuration is the main source of supply for 6,200 customers in Red Cliffs and the surrounding area. The station supply area includes Red Cliffs, Colignan and Werrimull.

Magnitude, probability and impact of loss of load

Growth in summer peak demand on the 22 kV network at RCTS has averaged around 1.3 MW (4%) per annum over the last 5 years. The peak load for the RCTS 22 kV network reached 35.9 MW in summer 2013.

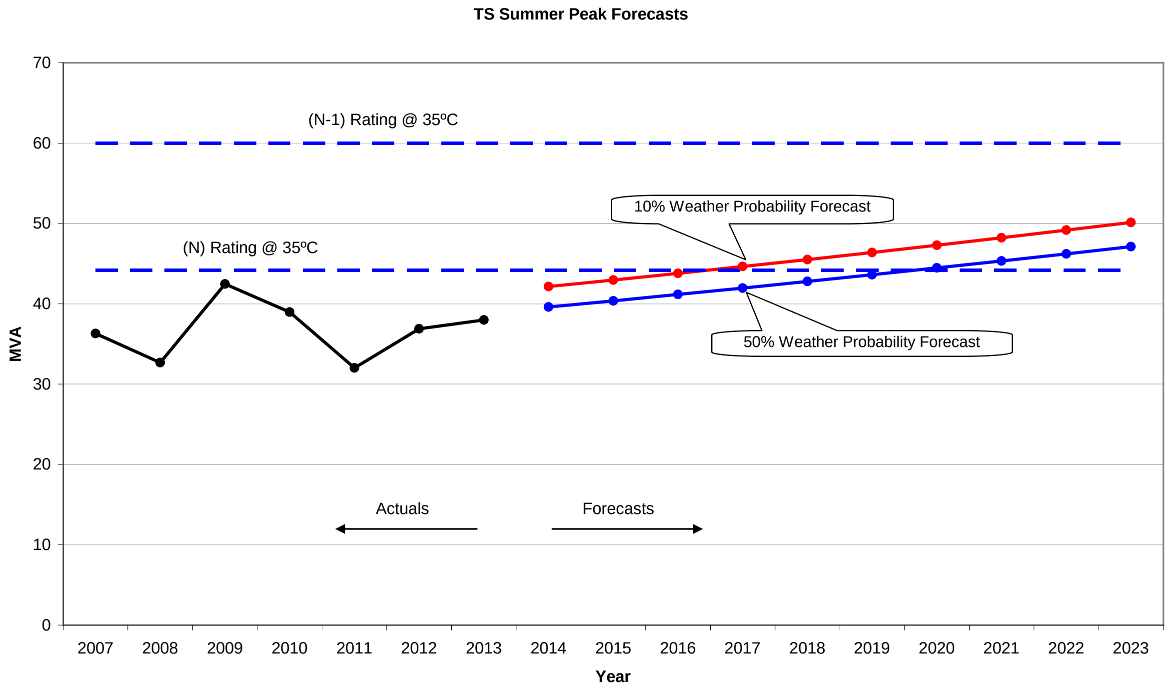
It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the peak time demand is 0.87.

As noted above, a 140 MVA 235/66/22 kV transformer operates normally open on the 22 kV bus with an auto-close scheme to close this transformer onto the 22 kV bus in the event of a failure of either of the other two transformers. The 140 MVA 235/66/22kV transformer can also be closed onto the 22 kV bus in the event that load exceeds 44.2 MVA, with the two 35 MVA transformer being switched out to maintain fault levels below the 13.1 kA limit. This arrangement results in the station's "N-1" capacity being higher than the "N" capacity.

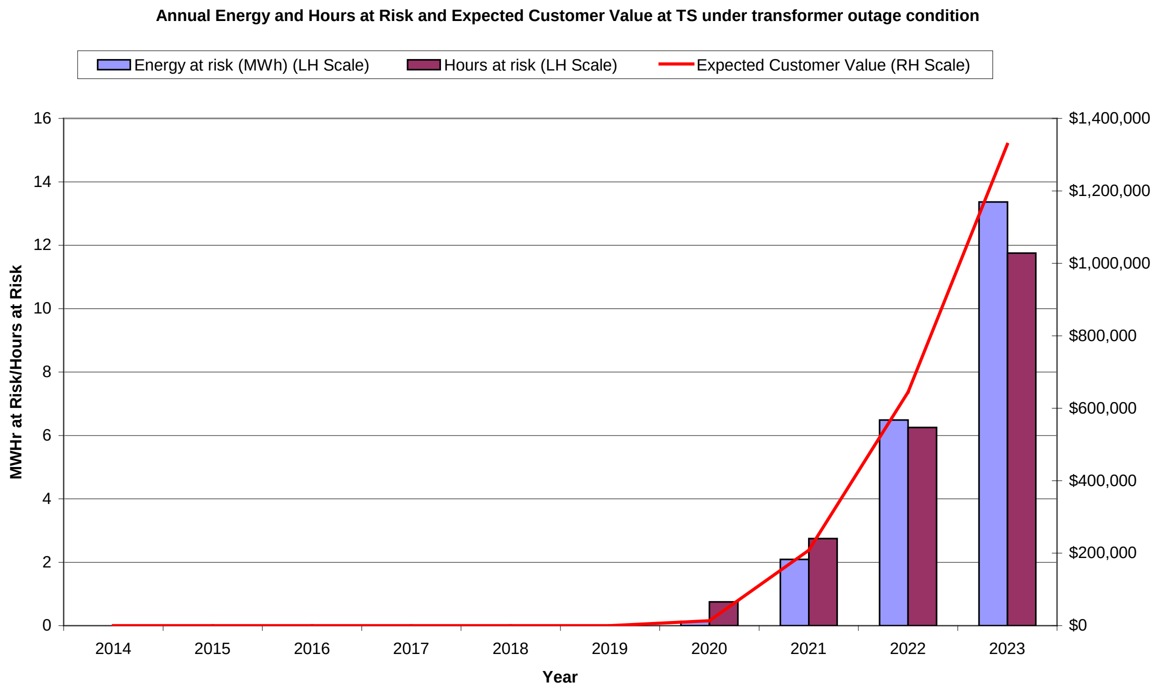
The N rating for RCTS 22 has been revised down by SPI PowerNet to 44.2 MVA (previously 55 MVA). This revised rating is lower due to the 22 kV connections from the two 35 MVA transformers being the limiting factor.

RCTS 22 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating and the "N-1" rating at 35°C ambient temperature.



The graph shows there is sufficient capacity at the station to supply all the 50th and 10th percentile demand expected over the forecast period when supplied from the two 35 MVA transformers (system normal) until 2017.

The bar chart below depicts the energy at risk when supplied from the two 35 MVA transformers (system normal) for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For system normal at RCTS 22 kV during the summer period, there will be insufficient capacity at the station to supply all demand at the 10th percentile temperature for about 3 hours in 2018. The energy at risk at the 10th percentile temperature under N conditions is estimated to be 2.9 MWh in 2018. The estimated value to consumers of the 2.9 MWh of energy at risk is approximately $0.28 million (based on a value of customer reliability of $99,407/MWh).[1] In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the system normal overload the impact of the system normal overload at RCTS 22kV in 2018 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $0.28 million.

These key statistics for the year 2018 under N conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	0	0
Expected unserved energy at 50th percentile demand	0	0
Energy at risk, at 10th percentile demand forecast	2.9	$0.28 million
Expected unserved energy at 10th percentile demand	2.9	$0.28 million

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the next ten year planning horizon:

- Transfer loads away to Mildura (MDA) zone substation.
- Demand reduction: There is an opportunity for voluntary demand reduction to reduce peak demand during times of network constraint. The amount of demand reduction would be taken into consideration when determining the optimum timing for any capacity augmentation.
- Contingency operation to switch in the 140 MVA 235/66/22kV transformer when load exceeds 44.2 MVA and switch out the two 35 MVA transformers. This is not a preferred option for permanent arrangement as all supplies including the 66 kV to BBD and NSW (Essential Energy) out of RCTS would be controlled by the 22 kV load at RCTS.
- Augment the transformer 22 kV connections on the two 35 MVA transformers to improve capacity under N.

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

Preferred option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at RCTS 22 kV the preferred option is to uprate the 22 kV connections on the two 35 MVA transformers. It is expected that this project will not be completed before 2018.

The capital cost to uprate the two 35 MVA transformers 22 kV connections at RCTS is estimated to be $0.3 million. The cost of uprating the 22 kV connections would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $0.03 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation. Sections 1.5 and 1.6 of this report provide further background information to proponents of non-network solutions to emerging constraints.

Load at risk over the forecast period before 2018 can be managed by the contingency operation to switch in the 140 MVA 235/66/22 kV transformer.

RCTS22 Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor - 100%

Normal cyclic rating with all plant in service 44.2 MVA

Summer N-1 Station Transformer Rating: 60 MVA

Winter N-1 Station Transformer Rating: 60 MVA

Station: RCTS22	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	39.6	40.4	41.2	42.0	42.8	43.6	44.5	45.3	46.2	47.1
50th percentile Winter Maximum Demand (MVA)	21.8	22.3	22.7	23.2	23.7	24.1	24.6	25.1	25.6	26.1
10th percentile Summer Maximum Demand (MVA)	42.1	43.0	43.8	44.6	45.5	46.4	47.3	48.2	49.2	50.1
10th percentile Winter Maximum Demand (MVA)	22.5	23.0	23.5	23.9	24.4	24.9	25.4	25.9	26.4	27.0
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.1	6.5	13.4
N hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.8	2.8	6.3	11.8
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.3	2.9	7.5	15.2	27.9	47.5	75.1
N hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	1.3	3.0	7.3	12.5	18.8	25.0	34.8
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	2.09	6.49	13.36
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.32	2.87	7.54	15.21	27.94	47.46	75.11
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.21M	$0.64M	$1.33M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.03M	$0.28M	$0.75M	$1.51M	$2.78M	$4.72M	$7.47M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.01M	$0.09M	$0.22M	$0.46M	$0.98M	$1.87M	$3.17M

Notes:

1. “N” means cyclic station transformer output capability rating for system normal operating arrangement. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N capability rating.
3. “N hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N capability rating.
4. “Expected unserved energy” means “ energy at risk” for system normal operating arrangement.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50^{th} and 10^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

RED CLIFFS TERMINAL STATION (RCTS) 66kV

Red Cliffs Terminal Station (RCTS) 66 kV consists of two 70 MVA and one 140 MVA 235/66/22 kV transformers supplying the 66 kV network ex-RCTS. This configuration is the main source of supply for 20,892 customers in Red Cliffs and the surrounding area. The station supply area includes Merbein, Mildura and Robinvale.

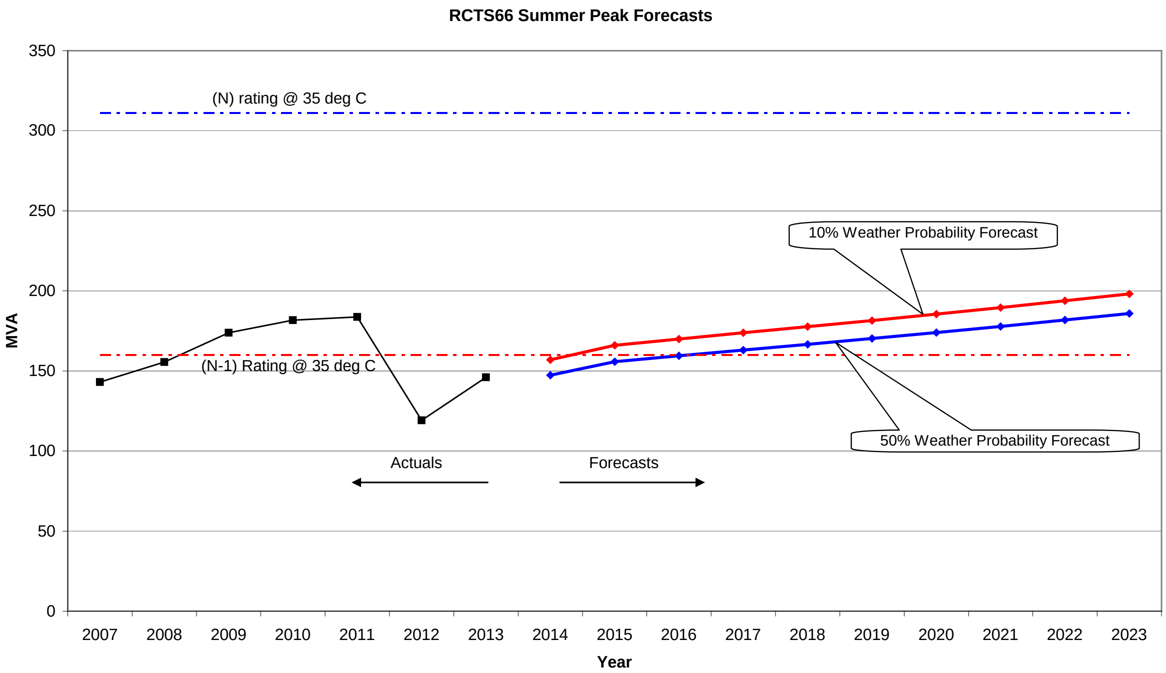
Magnitude, probability and impact of loss of load

RCTS 66 kV demand is summer peaking. In February 2012, part of the 66 kV network previously supplied from RCTS was transferred to the new Wemen Terminal Station (WETS). This is reflected in the reduction in actual demand in that year (shown in the chart below). The peak load for the 66 kV network now supplied from the station reached 145.6 MW in summer 2013.

It is estimated that:

- For 11 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.93.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.

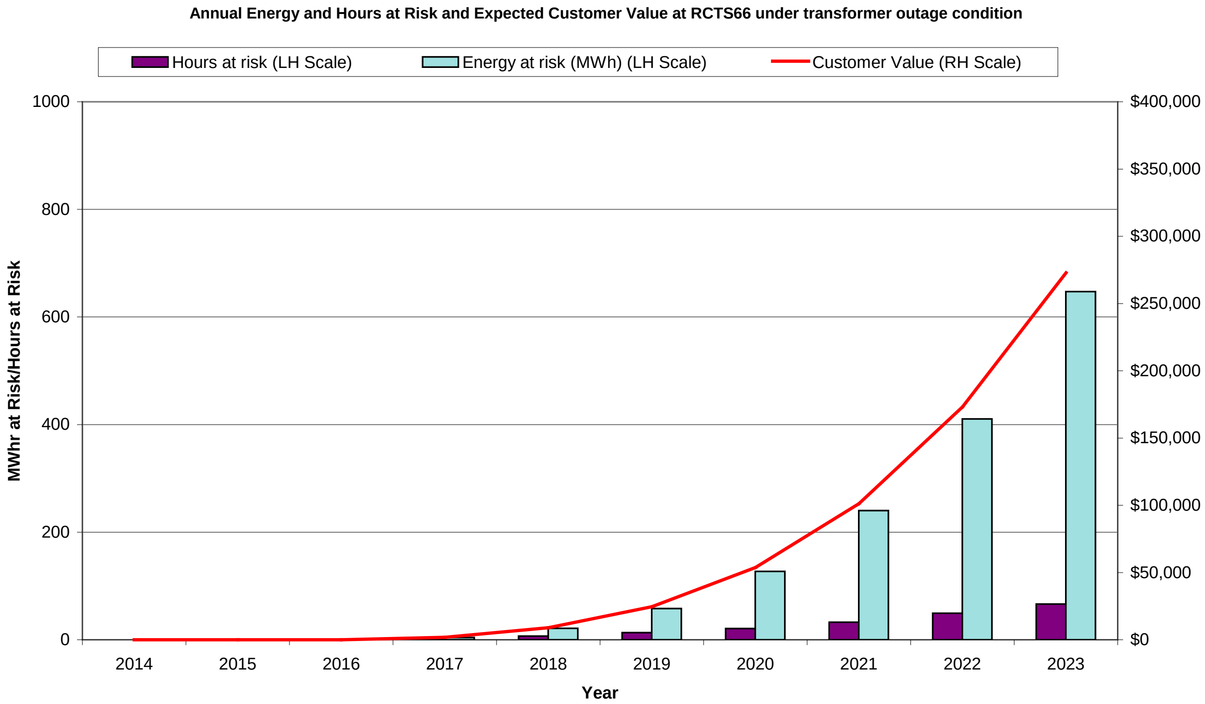


The (N) rating on the chart indicates the maximum load that can be supplied from RCTS with all transformers in service. Exceeding this level will initiate automatic load shedding by SPI PowerNet's automatic load shedding scheme.

The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand until 2023. However, if there is a forced transformer outage during peak load periods, from 2017 onwards there is insufficient capacity to supply the forecast demand at 50th percentile temperature at RCTS66 and some customers might be affected.

Magnitude, probability and impact of loss of transformer (N-1 System Condition):

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For a major outage of one transformer at RCTS 66 kV, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 66 hours in summer 2023. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 647 MWh in 2023. The estimated value to consumers of the 647 MWh of energy at risk is approximately $42 million (based on a value of customer reliability of $65,023/MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RCTS 66kV in 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $42 million.

It is emphasised however, that the probability of a major outage of one of the three transformers (two 70 MVA and one 140MVA) occurring over the year is very low at about 1% per annum, while the expected unavailability per transformer per annum is 0.217% per transformer. When the energy at risk (647 MWh for 2023) is weighted by this low probability, the expected unsupplied energy is estimated to be around 4.21 MWh. This expected unserved energy is

[1] The value of unserved energy is derived from the sector values given in Table 2.1 of, weighted in accordance with the composition of the load at this terminal station.

estimated to have a value to consumers of around $0.27 million (based on a value of customer reliability of $65,023/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average summer temperatures occurring in each year. At the 10th percentile temperature and demand level, the energy at risk in 2023 is estimated to be 1856 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $121 million. The corresponding value of the expected unserved energy is approximately $0.78 million.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	647	$42.1 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	4.2	$0.27 million
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	1,856	$120.7 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	12.1	$0.78 million

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the next ten year planning horizon:

1. Contingency transfer away of part of the load (in the order of 17.4 MVA in summer) to WETS and/or to RCTS 22 kV in the event of loss of a transformer at RCTS 66 kV. .

2. Replace one of the existing 70 MVA transformers with a new 140 MVA unit.

3. Embedded generation. An alternative option to the network solution could be the establishment of an embedded generator, suitably located in the area that is presently supplied by the RCTS 66 kV network.

4. Demand Management. Another alternative option could be the introduction of demand management to reduce the magnitude of the summer peak demands under network emergencies. This might involve the introduction of interruptible load, negotiated with customers at reduced prices, with an agreement that the load can be interrupted during times of network constraint.

Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at RCTS 66kV, it is proposed to replace one of the existing 70 MVA transformers with a new 140 MVA unit. On the basis of the 10th percentile demand forecast scenario, it is expected that the additional capacity will not be economically justified before 2023.

The capital cost of replacing an existing 70 MVA transformer at RCTS with a 140 MVA unit is estimated to be $12 million. The cost of establishing, operating and maintaining an additional transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $1.2 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation. Sections 1.5 and 1.6 of this report provide further background information to proponents of non-network solutions to emerging constraints.

Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for rural areas (refer to Section 4.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

RCTS66 Terminal Station

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

	MW	MVA
Normal cyclic rating with all plant in service		310
Summer N-1 Station Rating:		160
Winter N-1 Station Rating:		192

[See Note 1 below for interpretation of N-1]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	147.3	155.8	159.4	163.1	166.6	170.3	174.0	177.9	181.8	185.9
50th percentile Winter Maximum Demand (MVA)	94.5	101.3	103.1	104.9	106.7	108.5	110.3	112.2	114.2	116.2
10th percentile Summer Maximum Demand (MVA)	157.0	166.1	170.0	173.9	177.6	181.5	185.5	189.6	193.8	198.1
10th percentile Winter Maximum Demand (MVA)	96.0	102.9	104.7	106.5	108.4	110.2	112.1	114.0	116.0	118.0
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	4.3	21.2	58.2	127.3	239.9	410.6	647.1
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	2.8	6.8	13.3	20.8	32.5	49.5	66.3
N-1 energy at risk at 10% percentile demand (MWh)	0.0	18.5	57.3	131.6	246.4	420.1	660.4	974.0	1370.5	1856.1
N-1 hours at risk at 10th percentile demand (hours)	0.0	6.0	12.8	20.5	31.5	48.3	65.0	80.8	98.5	119.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.03	0.14	0.38	0.83	1.56	2.67	4.21
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.12	0.37	0.86	1.60	2.73	4.29	6.33	8.91	12.06
Expected Unserved Energy value at 50th percentile demand	$0	$0	$0	$1,828	$8,929	$24,518	$53,652	$101,151	$173,080	$272,781
Expected Unserved Energy value at 10th percentile demand	$0	$7,807	$24,154	$55,465	$103,856	$177,086	$278,390	$410,587	$577,743	$782,429
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0	$2,342	$7,246	$17,919	$37,407	$70,289	$121,073	$193,982	$294,478	$425,675

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled Victorian Electricity Planning Approach, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

RICHMOND TERMINAL STATION 22 kV (RTS 22 kV)

RTS 22 kV is a summer critical station equipped with two 165 MVA 220/22 kV transformers, providing supply to CitiPower's distribution network. The terminal station's supply area includes inner suburban areas in Richmond and Prahran and Melbourne City's Russell Place and surrounding areas. The station also provides supply to City Link and public transport railway substations east of the Central Business District. Due to uneven load sharing between the two 22 kV buses at RTS, the N rating is only slightly higher than the N-1 rating. The N-1 ratings are restricted by over-voltage limits on transformer tapping. A line drop compensator however, limits the overall 22 kV transformation output to 141 MVA for both summer and winter.

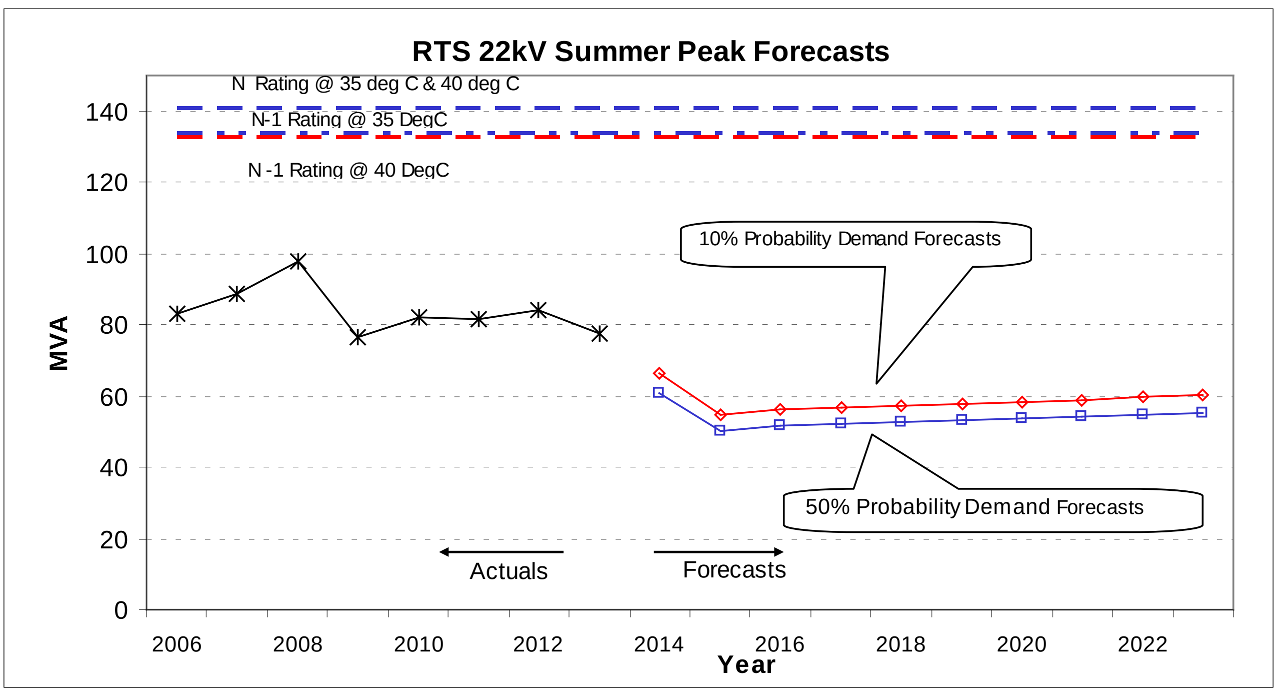
The peak load on the station reached 71.5 MW in summer 2013.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.92

Magnitude, probability and impact of loss of load

The graph below depicts the latest 10% and 50% probability maximum demand forecasts during the summer periods over the next ten years, together with the operational N and N-1 ratings for RTS 22 kV. The demand forecasts include the effects of future load transfer works that have been committed.



RTS 22 kV load reductions in 2014 and 2015 are due to load transfers to RTS 66 kV as part of the Prahran (PR) Zone Substation de-commissioning process.

The graph shows there is sufficient station capacity to supply all anticipated load, and that no customers would be at risk if a forced transformer outage occurred at RTS 22 kV over the forecast period. Accordingly, no capacity augmentation is planned at RTS 22 kV over the next ten years.

RICHMOND TERMINAL STATION 66 kV (RTS 66 kV)

RTS 66 kV is a summer critical station consisting of five 150 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (91%) and United Energy (9%), providing major supply to the Eastern Central Business District and wide-spread inner suburban areas in the east and south-east of Melbourne, including Fitzroy, Collingwood, Abbotsford, Richmond, North Richmond, Hawthorn, Camberwell, Gardiner, Toorak, Armadale, South Yarra, St Kilda, Elwood and Balaclava.

To limit fault levels, the five transformers at RTS 66 kV are split into two separate groups (1 & 2 bus group, and 3 & 4 bus group).

Following a hot summer period early in 2011, SPI PowerNet expressed concern regarding the operating temperature within the RTS 220/66 kV transformers. In order to avoid operating the RTS transformers at temperatures that would result in accelerated aging, and possibly imminent failure, SPI PowerNet has reviewed the RTS transformer summer cyclic ratings based on the latest RTS 66 kV load profile data and information on the transformer cooling effectiveness. These factors necessitated an average reduction of 6% to the transformer cyclic ratings across four of the transformers at an ambient temperature of 35 degrees C. SPI PowerNet also advised that its review confirmed that the station rating would be reduced further for ambient temperatures above 35 degrees C. SPI PowerNet has commenced an asset replacement project at RTS to replace the ageing transformers and other plant. SPI PowerNet has indicated that it expects the asset replacement project at RTS 66 kV to be completed by the end of 2017 during which time three 225 MVA transformers will replace the five existing 150 MVA transformers.

In December 2011, CitiPower made a connection application for the installation of a temporary 5th 220/66 kV transformer at RTS to reduce the potential for load shedding prior to the completion of the asset replacement work at RTS, or the transfer of load from RTS to new Brunswick Terminal Station. The temporary 5th transformer (B6) with dual secondary legs is now in service.

With B6 in service, under system normal conditions the No.1, No.4 & No.6 transformers (B1, B4 & B6) are operated in parallel as one group and supply the No.1 & No.2 buses. The No.2 & No.3 transformers (B2 & B3) are operated as a separate group and supply the No.3 & No.4 buses. B6 also supplies the No.3 & No.4 buses with a normally open secondary leg. For an unplanned outage of any one of B2 or B3 transformers, the normally open secondary leg of B6 will close automatically and the normally closed leg of B6 will open automatically. Under this scenario the load demand on the RTS12 group should be kept within the capabilities of the two transformers B1 & B4.

The following risk assessment is divided into two parts. Part 1 covers the period from 2013 to 2017, during which the asset replacement project will be undertaken. Part 2 covers the period from 2017 to 2023, after the asset replacement project is completed and there are three 225 MVA transformers in service at RTS.

Part 1: Period between 2013 to 2017 - with temporary transformer in service

Magnitude, probability and impact of loss of load from 2013 to 2017

As noted above, SPI PowerNet is undertaking asset replacement works at RTS, which are expected to be completed by the end of 2017. The risk assessment below covers the period to 2017, and reflects the impact of the temporary transformer in reducing the loads at risk at RTS.

RTS 1 & 2 66kV Bus Group Summer Peak Forecasts from __2013 to 2017__

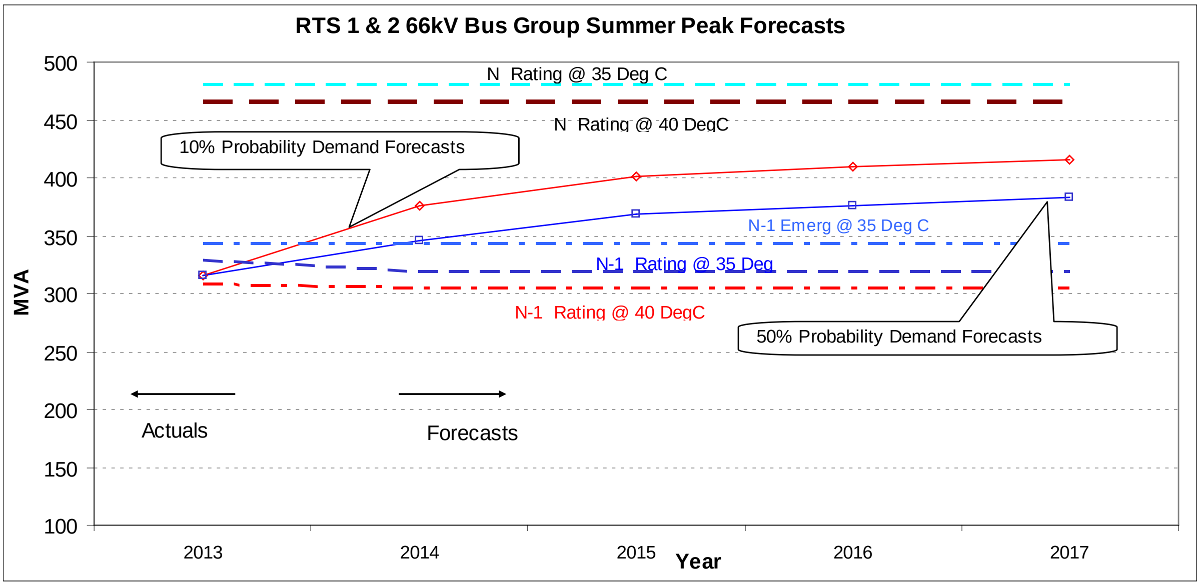
This bus group supplies Citipower's zone substations at Camberwell, Gardiner, Collingwood, North Richmond, Toorak, Armidale and Balaclava and United Energy's Gardiner zone substation.

The peak load on the RTS 1 & 2 Bus Group reached 304.9 MW in summer 2013.

It is estimated that:

- For 4 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

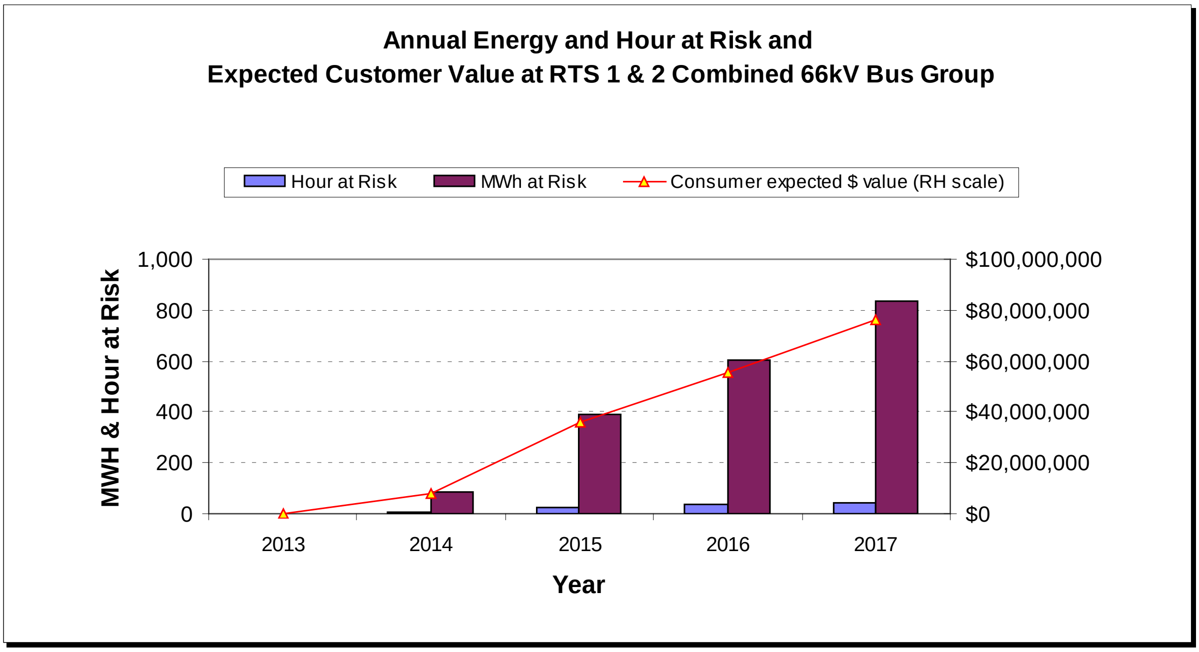
The graph below depicts the RTS 1 & 2 combined 66 kV bus group rating at 35 and 40 degrees under system normal (B1, B4 & B6 in parallel), along with the 50th and 10th percentile summer maximum demand forecasts for the bus group from summer 2013 to 2016. With the installation of the temporary 5th transformer, there is adequate capacity to supply the anticipated maximum load demand on this bus group while all transformers are in service.



Comments on Energy at Risk for RTS 1 & 2 66kV Bus Group for N-1 Condition from __2013 to 2017__

The bar chart below depicts the energy at risk with one transformer out of service (B6 out of service, B1 & B4 in parallel) for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

The load forecast reflects the committed projects to transfer load from RTS 22 kV to RTS 66 kV (following the decommissioning of Prahran zone substation).



For an outage of one transformer supplying 1 & 2 Bus Group at RTS 66 kV during the summer period, it is expected that there would be insufficient capacity to supply all demand at the 50th percentile temperature from 2014. This situation would also exist for an outage of a transformer on the 3 & 4 bus group as a transformer on the 1 & 2 group would automatically changeover to the 3 & 4 group.

For 2017, the energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 833 MWh. Under these conditions, there would be insufficient capacity to meet demand for approximately 46 hours in that year. The estimated value to consumers of this energy at risk in 2016 is approximately $76.3 million (based on a value of customer reliability of $91,586 per MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RTS 66 kV over the summer of 2016 would be anticipated to lead to involuntary supply interruptions that would cost consumers $76.3 million.

It is emphasised however, that the probability of a major outage of one of the five transformers at RTS 66 kV occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk in 2017 (833 MWh) is weighted by the low transformer unavailability, the expected unserved energy is estimated to be around 9.0 MWh. This expected unserved energy is estimated to have a value to consumers of approximately $0.8 million in 2017.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year[2]. Under 10th percentile summer temperature conditions, the energy at risk in 2017 is estimated to be 2,906 MWh. The estimated value to consumers of this energy at risk in 2017 is approximately $266.1 million. The corresponding value of the expected unserved energy is approximately $2.9 million.

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

2 As noted in Section 4.1, the 50th percentile demand forecast is used in each year.

These key statistics for the year 2017 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	833	$76.3 million
Expected unserved energy at 50th percentile demand	9.0	$0.8 million
Energy at risk, at 10th percentile demand forecast	2,906	$266.1 million
Expected unserved energy at 10th percentile demand	31.5	$2.9 million

If one of the transformers at RTS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, then the OSSCA[3] load shedding scheme which is operated by SPI PowerNet's TOC[4] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored where transfer capacity exists after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower and United Energy's operational procedures.

RTS 3 & 4 66kV Bus Group Summer Peak Forecasts from <u>2013 to 2017</u>

This bus group supplies CitiPower's zone substations in the Melbourne CBD and St Kilda and United Energy's Elwood zone substation.

The peak load on the RTS 3 & 4 Bus Group reached 241.0 MW in summer 2013.

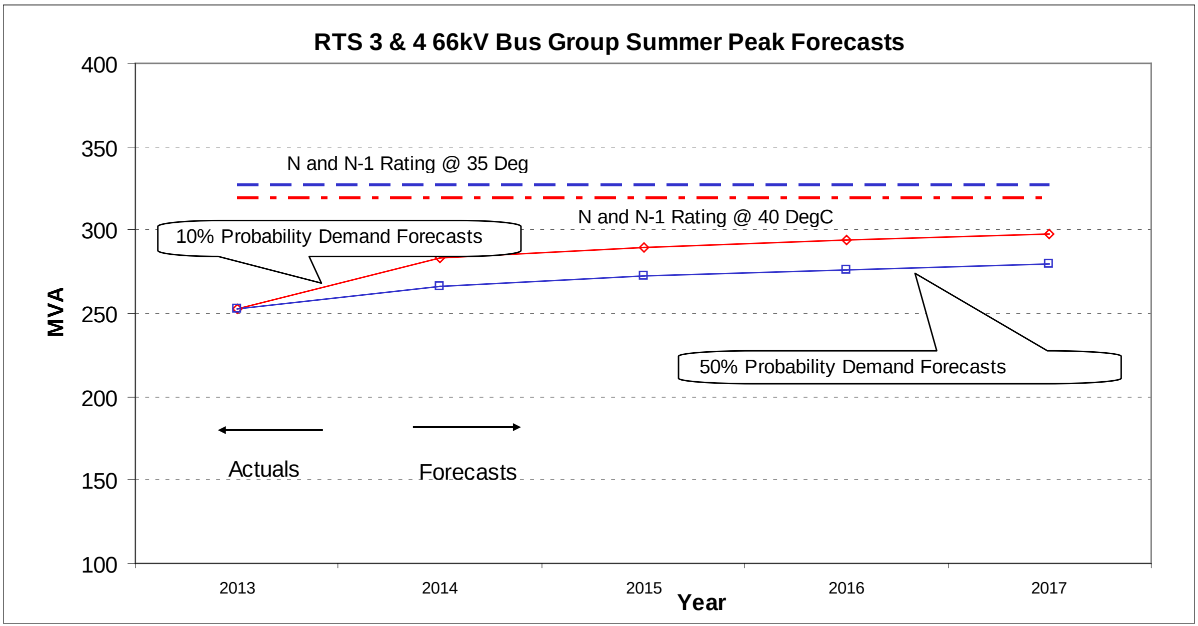
It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.953.

The graph below depicts the RTS 3 & 4 combined 66 kV bus group rating at 35 and 40 degrees under system normal (B2 & B3 in parallel), along with the 50th and 10th percentile summer maximum demand forecasts from summer 2013 to 2016. With the installation of the temporary 5th transformer, there is adequate capacity to supply the anticipated maximum load demand on this bus group while all transformers are in service.

3 Overload Shedding Scheme of Connection Asset.

4 Transmission Operation Centre.



<u>Comments on Energy at Risk for RTS 3 & 4 66 kV Bus Group for N-1 Condition from 2013 to 2017</u>

For an outage of one transformer supplying 3 & 4 Bus Group at RTS 66kV during the summer period, it is expected that there would be sufficient capacity to supply all the demand at the 50th percentile and the 10th temperatures on the RTS buses 3 and 4 combined 66 kV bus group until 2017.

RTS 66kV Total <u>in 2013</u>

The peak load on the station reached 545.7 MW in summer 2013.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.96.

<u>Part 2: Period between 2017 to 2023 - three 225 MVA transformers in service</u>

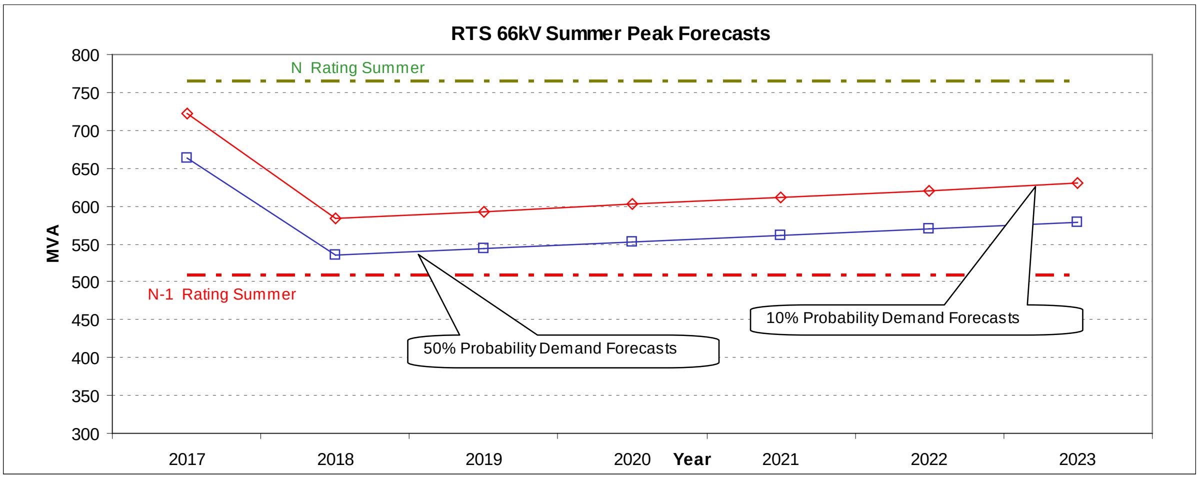
Magnitude, probability and impact of loss of load from 2017 to 2023

The risk assessment below addresses the period from 2017 to 2023, following the completion of the station asset replacement project. From 2017:

- there will be three 225 MVA transformers in service at RTS; and
- the 66 kV bus arrangement will be closed and all transformers will operate in parallel mode.

For this report, it is assumed that the station output ratings are 510 MVA for summer and 575 MVA for winter, based on typical data from existing similar stations. The ratings will be confirmed pending receipt of actual transformer test report information from the manufacturers.

The graph below depicts the total station N and N-1 rating at 35 and 40 degrees and the latest 10th and 50th percentile maximum demand forecast for the period from 2017 to 2023.

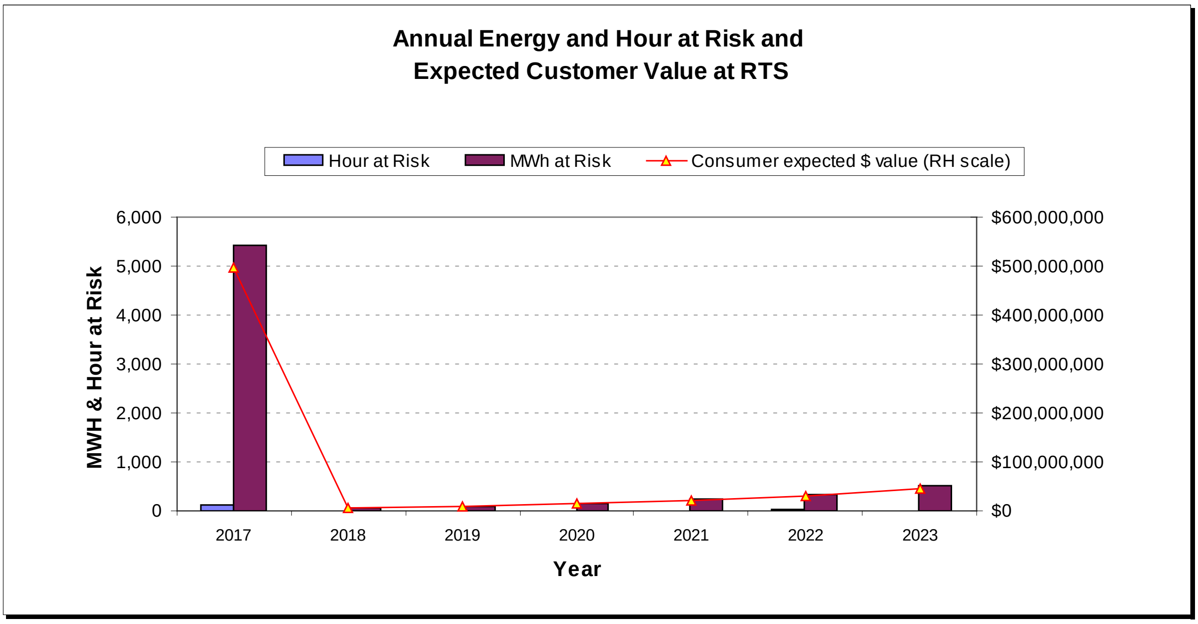


The graph shows that with all three transformers in service there will be sufficient capacity at RTS 66kV to supply the forecast 10th percentile and 50th percentile demands until 2022 and beyond.

The load forecast reflects the committed projects to transfer load from RTS 22 kV to RTS 66 kV (following the decommissioning of Prahran zone substation decommission), and the transfer of RTS 66 kV load to the new BTS 66 kV terminal station. The load at risk is reduced after load transfer to BTS 66 kV.

Comments on Energy at Risk from 2017 to 2023

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



For an outage of one transformer at RTS 66 kV during the summer period from 2018, it is expected that there would be insufficient capacity to supply all demand at the 50th percentile temperature.

For 2023, the energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 503 MWh. Under these conditions, there would be insufficient capacity to meet demand for approximately 25 hours in that year. The estimated value to consumers of this energy at risk in 2018 is approximately $46 million (based on a value of customer reliability of $91,586 per MWh).[5] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RTS 66 kV over the summer of 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $46 million.

It is emphasised however, that the probability of a major outage of one of the three transformers at RTS 66 kV occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk in 2023 (503 MWh) is weighted by the low transformer unavailability, the expected unserved energy is estimated to be around 3 MWh. This expected unserved energy is estimated to have a value to consumers of approximately $0.3 million in 2023.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year[6]. Under 10th percentile summer temperature conditions, the energy at risk in 2023 is estimated to be 2,581 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $236 million. The corresponding value of the expected unserved energy is approximately $1.5 million.

[5] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

[6] As noted in Section 4.1, the 50th percentile demand forecast is used in each year.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	503	$46 million
Expected unserved energy at 50th percentile demand	3	$0.3 million
Energy at risk, at 10th percentile demand forecast	2,581	$236 million
Expected unserved energy at 10th percentile demand	17	$1.5 million

If one of the transformers at RTS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, then the OSSCA[7] load shedding scheme which is operated by SPI PowerNet's TOC[8] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored where transfer capacity exists after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower and United Energy's operational procedures.

[7] Overload Shedding Scheme of Connection Asset.

[8] Transmission Operation Centre.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Permanent load transfer from RTS 66 kV to the proposed BTS 66 kV (Brunswick Terminal Station) connection point. This is part of the integrated plan for the proposed BTS 66 kV (Refer to the Risk Assessment Report for BTS 66 kV) and could be achieved by:

    - High voltage distribution load transfer from critical zone substations in the Central Business District areas supplied from RTS 66 kV to the upgraded zone substations supplied from the proposed BTS 66 kV commencing from 2015 to 2017[9].

    - Bulk subtransmission transfer of normal supply of a three-zone substation 66 kV subtransmission loop (about 135 MVA of load) from RTS 66 kV to the new BTS 66 kV by 2018, or alternatively:

    - Bulk subtransmission transfer of normal supply of MP zone substation (approximately 135 MVA) in the CBD from RTS 66 kV to the new BTS 66 kV by 2018.

2. A feasible option to provide added security to the CBD would involve CitiPower and United Energy working closely with SPI PowerNet to install an additional 220/66 kV 225 MVA transformer at RTS in conjunction with SPI PowerNet's RTS asset replacement program.

3. Demand Reduction: United Energy has developed a number of innovative network tariffs to encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and will be taken into consideration when determining the optimum timing for the capacity augmentation.

4. Embedded generation in the order of 150 MVA, would help to defer the need for augmentation.

5. Establishment of a new terminal station in the inner eastern suburban area to provide an extra point of supply would resolve the overloading problem. Acquisition of a new terminal station site at a suitable location would be required for this option. Planning requirements put this option outside the timeframe required.

6. CitiPower and United Energy intend to implement contingency plans between 2013 to 2017 to transfer bulk load at 66 kV from RTS 1 & 2 66 kV bus group to MTS and TSTS during emergency conditions only to meet peak load periods. The plan can also include 11 kV distribution network transfers and load management. These options reduce the security and reliability of the subtransmission network because many zone substations affected by 66 kV bulk transfers will be on radial supply for the duration of any contingency.

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9 Subject to SPI PowerNet delivering the project within the expected timeframe. Any delays resulting from unforeseen issues which are beyond the control of SPI PowerNet would affect the project delivery, and will be beyond the control of CitiPower.

Preferred option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at RTS 66 kV, or any other identified better network solutions, it is proposed to reduce load from RTS 66 kV permanently by transferring load away to the new BTS 66 kV. This transfer will be done via both the high voltage distribution and subtransmission networks from 2015[10] to 2017, which is in line with the integrated plan for the establishment of the new BTS 66 kV supply point.

Prior to the establishment of BTS, the following actions will be taken to mitigate supply interruption risk at RTS 66 kV under critical loading conditions:

- Contingency plans will be put in place between 2013/2014 to 2017/2018 to transfer bulk load at 66 kV from RTS 1 & 2 66 kV bus group to MTS and TSTS during emergency conditions. The plans may also include 11 kV distribution network transfers and load management.
- In conjunction with TOC, OSSCA scheme settings will be fine-tuned to minimise the impact on customers of any load shedding that may take place.
- Subject to availability, installation of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas could be undertaken to temporarily replace a failed transformer at RTS 66 kV.
- CitiPower is also implementing some demand management initiatives in this area.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy. In addition to the measures outlined above, CitiPower would welcome proposals from proponents of non-network solutions to provide network support services to reduce the load at risk at RTS 66 kV over the period to 2017. Proponents should contact Neil Gascoigne, Network Planning Manager, CitiPower / Powercor, on 9683 4472 for further details.

10 Subject to SPI PowerNet's timely delivery of the required works.

RICHMOND TERMINAL STATION 1 & 2 66 kV Bus Group

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this bus group:	CitiPower (91%), United Energy (9%)
Bus group summer operational rating (N elements in service):	481 MVA via 3 transformers in parallel
Bus group winter operational rating (N elements in service):	547 MVA via 3 transformers in parallel
Summer N-1 bus group rating	319 MVA via 2 transformers in parallel
Winter N-1 bus group rating:	353 MVA via 2 transformers in parallel

Station: RTS 1 & 2 66kV Bus Group	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	345.5	368.3	376.1	382.7	N/A	N/A	N/A	N/A	N/A	N/A
50th percentile Winter Maximum Demand (MVA)	282.9	302.3	307.2	311.6	N/A	N/A	N/A	N/A	N/A	N/A
10th percentile Summer Maximum Demand (MVA)	376.4	400.7	409.1	416.1	N/A	N/A	N/A	N/A	N/A	N/A
10th percentile Winter Maximum Demand (MVA)	297.1	302.7	307.9	313.3	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 50th percentile demand (MWh)	86	390	604	833	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 50th percentile demand (hours)	7	27	37	46	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 10th percentile demand (MWh)	612	1742	2334	2906	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 10th percentile demand (hours)	37	78	94	111	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy at 50th percentile demand (MWh)	0.9	4.2	6.6	9.0	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy at 10th percentile demand (MWh)	6.6	18.9	25.3	31.5	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value at 50th percentile demand	$0.1M	$0.4M	$0.6M	$0.8M	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value at 10th percentile demand	$0.6M	$1.7M	$2.3M	$2.9M	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.2M	$0.8M	$1.1M	$1.4M	N/A	N/A	N/A	N/A	N/A	N/A

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)
7. The N and N-1 ratings are approximately equal due to the restriction of "Normal Open Auto-close" transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.

RICHMOND TERMINAL STATION 3 & 4 66 kV Bus Group

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this bus group:	CitiPower (91%), United Energy (9%)
Bus group summer operational rating (N elements in service):	327 MVA via 2 transformers in parallel
Summer N-1 bus group rating	327 MVA via 2 transformers in parallel

Station: RTS 3 & 4 66kV Bus Group	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	266.0	272.0	276.4	279.9	N/A	N/A	N/A	N/A	N/A	N/A
50th percentile Winter Maximum Demand (MVA)	192.7	195.2	197.8	200.3	N/A	N/A	N/A	N/A	N/A	N/A
10th percentile Summer Maximum Demand (MVA)	282.2	286.9	290.3	293.7	N/A	N/A	N/A	N/A	N/A	N/A
10th percentile Winter Maximum Demand (MVA)	202.1	204.8	207.4	210.1	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Annual N - 1 energy at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value at 50th percentile demand	$0.0M	$0.0M	$0.0M	$0.0M	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value at 10th percentile demand	$0.0M	$0.0M	$0.0M	$0.0M	N/A	N/A	N/A	N/A	N/A	N/A
Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.0M	$0.0M	$0.0M	$0.0M	N/A	N/A	N/A	N/A	N/A	N/A

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled Victorian Electricity Planning Approach, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)
7. The N and N-1 ratings are approximately equal due to the restriction of "Normal Open Auto-close" transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.

RICHMOND TERMINAL STATION

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	CitiPower (91%), United Energy (9%)
Normal cyclic rating with all the plant in service	765 MVA via 3 x 225MVA transformers in parallel
Summer N-1 station rating	510 MVA via 2 x 225MVA transformers in parallel

Station: RTS 66kV Bus	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	N/A	N/A	N/A	664	536	544	553	562	570	579
50th percentile Winter Maximum Demand (MVA)	N/A	N/A	N/A	481	395	401	407	413	419	426
10th percentile Summer Maximum Demand (MVA)	N/A	N/A	N/A	722	583	593	603	612	621	630
10th percentile Winter Maximum Demand (MVA)	N/A	N/A	N/A	481	395	401	407	413	419	426
Annual N - 1 energy at risk at 50th percentile demand (MWh)	N/A	N/A	N/A	5426	58	95	152	229	339	503
Annual N - 1 energy at risk at 50th percentile demand (hours)	N/A	N/A	N/A	128	4	6	8	12	18	25
Annual N - 1 energy at risk at 10th percentile demand (MWh)	N/A	N/A	N/A	13601	609	865	1212	1596	2049	2581
Annual N - 1 energy at risk at 10th percentile demand (hours)	N/A	N/A	N/A	242	29	36	45	55	66	77
Expected Annual Unserved Energy at 50th percentile demand (MWh)	N/A	N/A	N/A	35	0	1	1	1	2	3
Expected Annual Unserved Energy at 10th percentile demand (MWh)	N/A	N/A	N/A	89	4	6	8	10	13	17
Expected Annual Unserved Energy value at 50th percentile demand	N/A	N/A	N/A	$3.2M	$0.0M	$0.1M	$0.1M	$0.1M	$0.2M	$0.3M
Expected Annual Unserved Energy value at 10th percentile demand	N/A	N/A	N/A	$8.1M	$0.4M	$0.5M	$0.7M	$1.0M	$1.2M	$1.5M
Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	N/A	N/A	N/A	$4.7M	$0.1M	$0.2M	$0.3M	$0.4M	$0.5M	$0.7M

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled Victorian Electricity Planning Approach, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)
7. The N and N-1 ratings are approximately equal due to the restriction of “Normal Open Auto-close” transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.

RINGWOOD TERMINAL STATION 22 kV (RWTS 22)

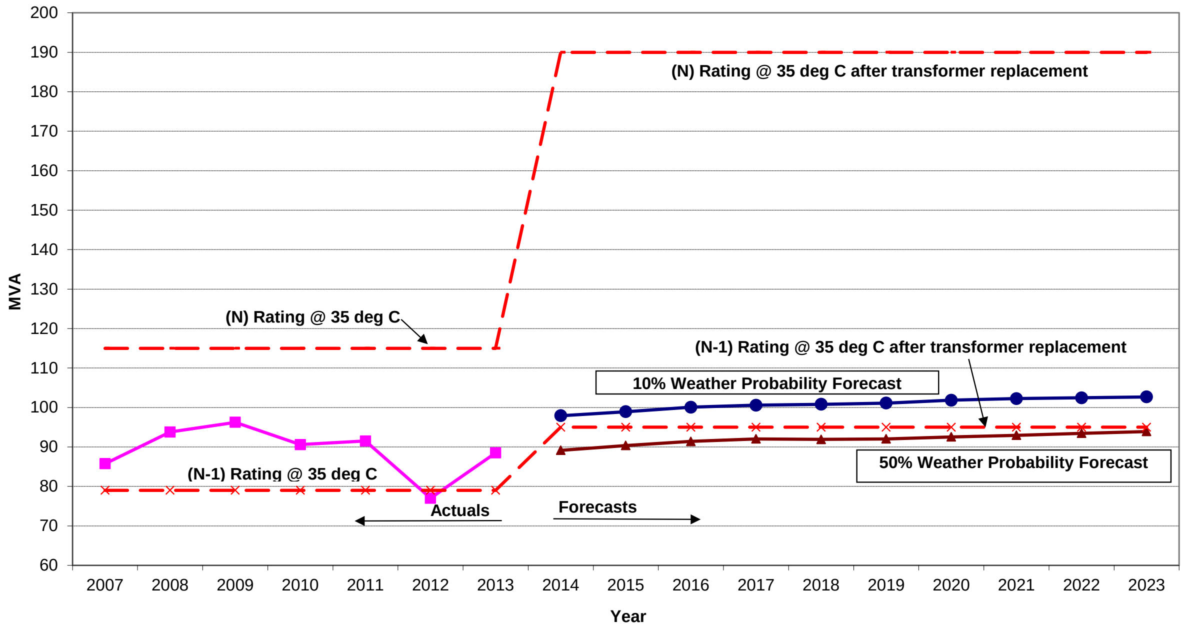
Ringwood terminal station consists of two separate components – the 66 kV component and the 22 kV component. The RWTS 22 kV component is now supplied by two 75 MVA 220/22 kV three-phase transformers following completion of SPI PowerNet's asset replacement project in 2013. RWTS 22 kV is the main source of 22 kV supply for the local area and for the commuter railway network. The geographic coverage of the station's supply area includes Ringwood, Mitcham, Wantirna and Nunawading. The electricity distribution networks for this area are the responsibility of both SPI Electricity (64%) and United Energy Distribution (36%).

Magnitude, probability and impact of loss of load

Peak loading at the station occurs in summer. Growth in summer peak demand at RWTS 22 kV is forecast to be around 0.5 MW (0.5%) per annum. The station recorded a peak demand of 84.3 MW (88.5 MVA) in the summer 2012/13. Demand is expected to exceed 95% of the 50th percentile peak load for 4 hours per annum. The station load has a power factor of 0.952 at maximum demand.

RWTS 22 kV is not expected to be loaded above its "N-1" rating under 50th percentile summer maximum demand forecasts during the ten year planning horizon. RWTS 22 kV is expected to be loaded above its "N-1" rating under the 10th percentile summer maximum demand forecasts. The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the station's "N-1" rating at an ambient temperature of 35°C.

RWTS 22 kV Summer Peak Demand Forecasts



The (N) rating on the chart shown above indicates the maximum load that can be supplied from RWTS 22 kV with all transformers in service.

RWTS 22 kV is not expected to be loaded above its "N-1" winter rating under 50th percentile or 10th percentile winter maximum demand forecasts during the ten year planning horizon.

Comments on Energy at Risk

For an outage of one transformer at RWTS 22 kV over the entire summer period, there will be sufficient capacity at the station to supply all demand at the 50th percentile temperature.

Under 10th percentile summer temperature conditions, there will be insufficient capacity at the station to supply all demand at the 10th percentile temperature for about 6 hours in 2022/23. The energy at risk in summer 2022/23 is estimated to be 16 MWh. This energy at risk is estimated to have a customer value of around $1.2 million, based on a value of customer reliability of $74,823/MWh[1]. In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, an outage of one transformer at RWTS 22kV over the summer of 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $1.2 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the duration of the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (16 MWh for summer 2022/23) is weighted by this low probability, the expected unsupplied energy is only 0.07 MWh, with an estimated value to consumers of around $5,100.

These key statistics for the year 2022/23 under “N-1” outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	0	$0
Expected unserved energy at 50th percentile demand	0	$0
Energy at risk, at 10th percentile demand forecast	16	$1.2 million
Expected unserved energy at 10th percentile demand	0.07	$5,100

If one of the 220/22 kV transformers at RWTS is unavailable during peak loading times and the N-1 station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by SPI PowerNet’s TOC[2] to protect the connection assets from overloading[3], will swiftly disconnect loads in blocks to within the ratings of available plant. In the event of OSSCA operating, it would automatically shed up to 10 MVA of load, affecting approximately 4,000 customers in 2012/13. Subsequently, loads will be manually matched to the rating of available plant in accordance with SPI Electricity’s and United Energy’s operational procedures after the operation of the OSSCA scheme.

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

2 Transmission Operation Centre.

3 OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging network constraint:

1. Implement contingency plans to transfer load to adjacent supply points

SPI Electricity has established and implemented the necessary plans that enable up to 11 MVA of load transfers via existing 22 kV feeders to adjoining zone substations. United Energy Distribution has the plans and capability to transfer an additional 15 MVA. This option reduces the interruption duration and load at risk resulting from a major transformer failure.

2. Install an additional transformer at RWTS 22 kV

The site has provision for a 3rd 220/22 kV transformer and implementing this option is relatively straight forward. Under the current transformer replacement project SPI PowerNet will also install a spare 75 MVA 220/22 kV transformer at RWTS in 2014 that could ultimately be used as a permanent third transformer.

3. Demand reduction

SPI Electricity is currently using an MVA tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak demand times. Up to 80% of the maximum demand at RWTS 22 kV is summer residential and commercial load, largely air conditioning.

United Energy Distribution has developed a number of innovative network tariffs to encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake, and will be taken into consideration when determining the optimum timing for the capacity augmentation.

4. Embedded generation

Embedded generation in the order of 5 to 10 MVA connected to the RWTS 22 kV bus may defer an augmentation by one or two years.

Preferred network option(s) for alleviation of constraints

1. Augmentation of the RWTS 220/22 kV transformer capacity with a third 75 MVA 220/22 kV transformer is the preferred option in the absence of a firm commitment for provision of network support services such as local generation or demand side management. These services would not be required prior to 2023 based on the present demand forecast.

2. In the meantime it is proposed to implement the following temporary measures to cater for an unplanned outage of one transformer at RWTS 22 kV under critical loading conditions:

   - maintain contingency plans to transfer load quickly to adjacent Zone Substations;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading;
   - Monitor the load growth to ensure the load at risk is within the forecast; and

- Engage in open discussions with commercial and industrial customers, demand management aggregators and embedded generator suppliers to ascertain the viability of these options in a cost and time efficient manner.

The capital cost of installing a new 220/22 kV transformer at RWTS 22 kV is estimated to be $15 million. The cost of establishing, operating and maintaining the transformer would be recovered from network users through network charges, over the life of the asset. In today's terms, the estimated total annual cost of this network augmentation is approximately $1.5 million. This cost provides a broad upper bound indication of the maximum annual network support payment which may be available to embedded generators or demand management proponents that defer or avoid this transmission connection augmentation which may be required beyond 2023. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for say ten years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging network constraints.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	SPI Electricity (64%) UED (36%)
Installed Transformer Capacity =	150 MVA
Normal cyclic rating with all plant in service	190 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating in MVA	95 MVA
Winter N-1 Station Rating in MVA	95 MVA

Station: RWTS 22kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	89.2	90.4	91.4	92.0	91.9	92.0	92.5	93.0	93.5	93.9
50th percentile Winter Maximum Demand (MVA)	69.8	70.4	70.8	70.9	71.1	71.3	71.4	71.6	71.9	72.5
10th percentile Summer Maximum Demand (MVA)	97.9	98.9	100.1	100.6	100.8	101.1	101.8	102.3	102.4	102.7
10th percentile Winter Maximum Demand (MVA)	75.3	76.1	76.4	76.6	76.8	77.1	77.3	77.5	77.8	78.4
N - 1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N - 1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N - 1 energy at risk at 10th percentile demand (MWh)	1	3	4.9	6.4	7.2	8.4	11.6	13.8	14.8	16.1
N - 1 hours at risk at 10th percentile demand (hours)	1	2	2.7	3.4	3.7	4.2	5.2	5.7	6.0	6.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

RINGWOOD TERMINAL STATION 66 kV (RWTS 66 kV)

Ringwood Terminal Station is the main source of supply for a major part of the outer eastern metropolitan area. The geographic coverage of the station's supply area spans from Lilydale and Woori Yallock in the north east; to Croydon, Bayswater and Boronia in the east; and Box Hill, Nunawading and Ringwood to the west. The electricity supply distribution networks for this region are the responsibility of both SPI Electricity (77%) and United Energy (23%).

Background

Ringwood terminal station consists of two separate components – the 66 kV component and the 22 kV component. The RWTS 66 kV component is supplied by four 150 MVA 220/66 kV transformers and peak loadings occur in summer. SPI PowerNet plans to replace the No. 4 220/66 kV transformer with a new 150 MVA unit in the next five years.

The existing four transformers are operated in two separate bus groups to limit the maximum prospective fault currents on the 66 kV buses within their respective switchgear ratings. Under network normal configuration, the No. 1 and No. 2 transformers are operated in parallel as one group (RWTS bus group 1-3) and supply the No.1 and No. 3 66 kV buses respectively. The No. 3 and No. 4 transformers are operated in parallel as another group (RWTS bus group 2-4) and supply the No.2 and No. 4 66 kV buses respectively. To configure the station as two separate bus groups, the 66 kV bus 1-2 and bus 3-4 tie circuit breakers are operated normally open.

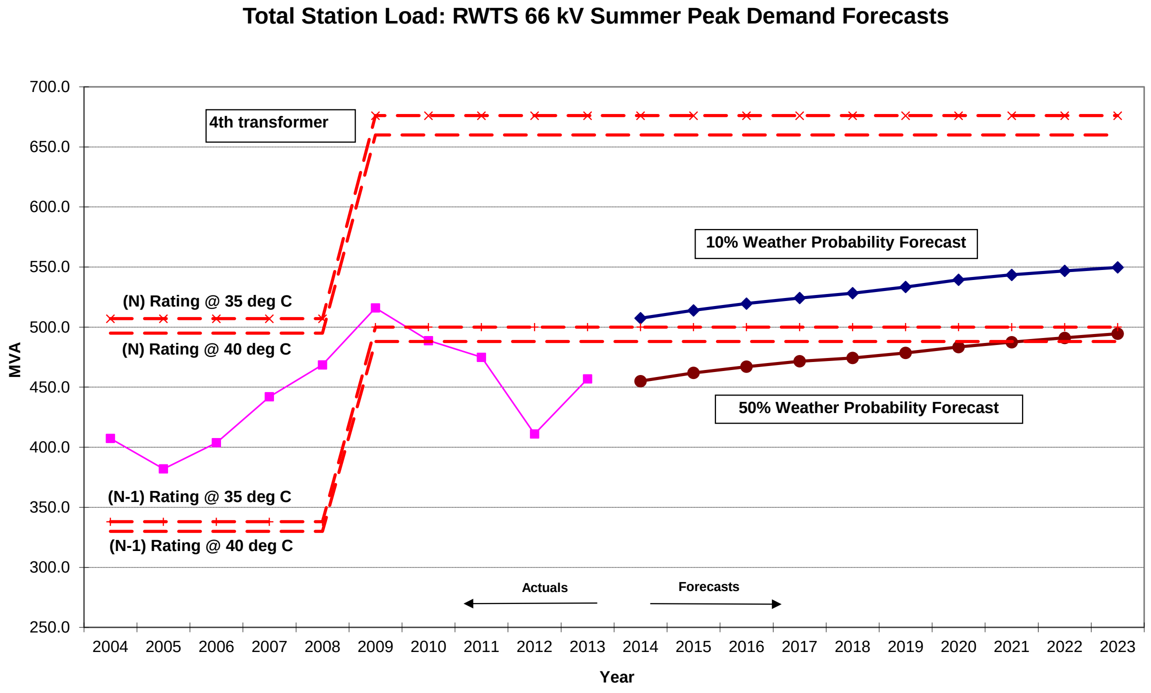
Given this configuration, load demand on the RWTS bus groups 1-3 and 2-4 must be kept within the capabilities of their respective two transformers at all times otherwise load shedding may occur. However, for an unplanned transformer outage in any of the two RWTS bus groups, an auto close scheme will operate resulting in parallel operation of the three remaining transformers.

Combined Summer Peak Demand forecasts for RWTS 66 kV -Total Station Load

Growth in summer peak demand at RWTS 66 kV has averaged around 8 MW (2%) per annum over the last eight years. The recorded peak demand in summer 2012/13 was 456 MW (457 MVA). The station load has a power factor of 0.970 at maximum demand but the load on the transformers has a power factor of 0.999 due to installed 66 kV capacitor banks. The demand is expected to exceed 95% of the 50th percentile peak load for 7 hours per annum. Forecast demand growth has significantly declined due to weaker economic conditions, appliance energy efficiency, rooftop solar generation and the impact of increases in the cost of electricity.

RWTS 66 kV is not expected to be loaded above its "N-1" rating under 50th percentile summer maximum demand forecasts during the ten year planning horizon. RWTS 66 kV is expected to be loaded above its "N-1" rating under the 10% percentile summer maximum demand forecast. The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the station's "N-1" rating at an ambient temperature of 35°C and 40°C.

The combined winter demand at RWTS 66 kV is not expected to reach the station's "N–1" winter rating during the ten year planning horizon.



RWTS Bus groups 1-3 and 2-4: Summer Peak Forecasts

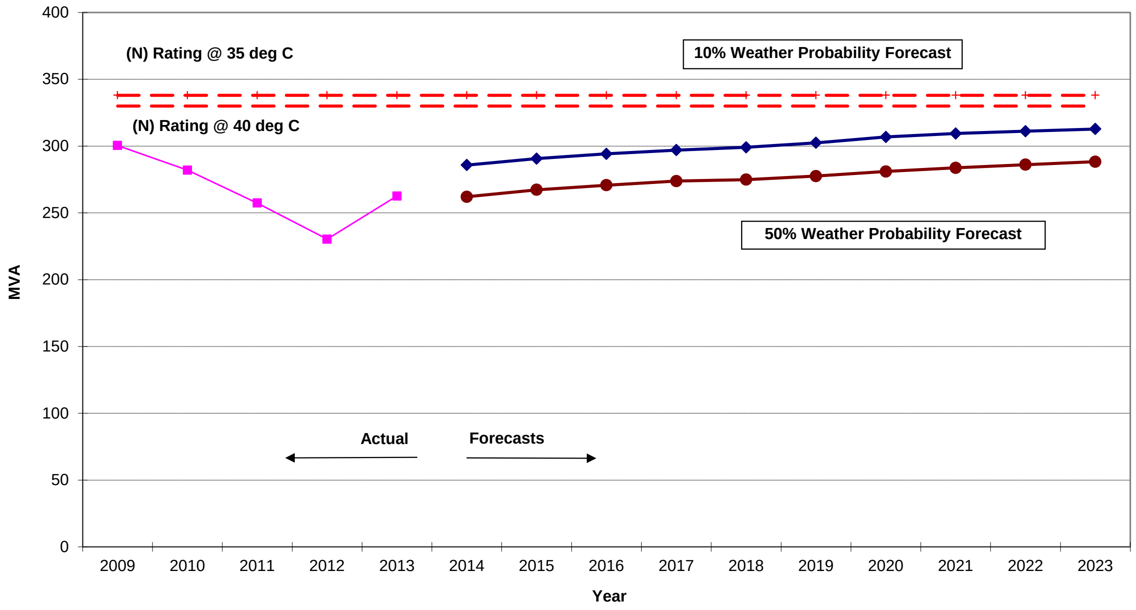
In addition to considering the station's total summer load under "N-1" conditions as shown above, it is essential to assess the risk of load shedding, if any, on the individual bus groups when both of their respective transformers are in service, i.e under "N" conditions.

RWTS Bus group 1-3: Peak demand at RWTS 66 kV bus group 1-3 occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under "N" conditions, the loading on this bus group at the 50th or 10th percentile temperature is forecast to remain within its "N" rating throughout the ten year planning horizon. This means that there is no expectation of load shedding being required to keep loading within plant ratings on this bus group under normal operating conditions during summer.

This bus group supplies United Energy's zone substations NW and BH, and SPI Electricity's zone substations RWN, LDL and WYK.

The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the bus group 1-3 rating at an ambient temperature of 35°C and 40°C.

Bus group 1/3: RWTS 66 kV Summer Peak Demand Forecasts

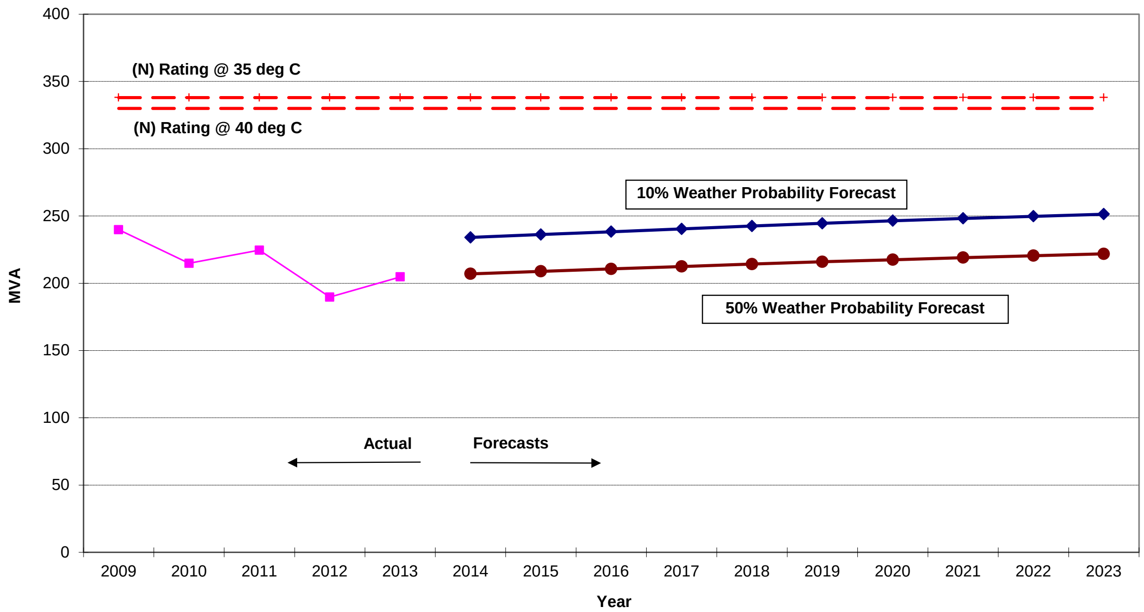


RWTS Bus group 2-4: Similar to bus group 1-3, the peak load at RWTS 66 kV bus group 2-4 also occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under "N" conditions, the loading on this bus group at the 50th or 10th percentile temperature is forecast to remain within its "N" rating throughout the ten year planning horizon. This means that there is no expectation of load shedding being required to keep loading within plant ratings on this bus group under normal operating conditions during summer.

This bus group supplies SPI Electricity's zone substations BRA, CYN and BWR, and feeder SRR to the 66 kV major customer Southern Rocycling.

The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the bus group 2-4 rating at an ambient temperature of 35°C and 40°C.

Bus group 2/4: RWTS 66 kV Summer Peak Demand Forecasts



Comments on Energy at Risk ("N – 1" for entire station)

Over the ten year planning period, for an outage of one transformer at RWTS 66 kV over the entire summer period, there will be sufficient capacity at the station to supply all demand at the 50th percentile temperature.

Under 10th percentile summer temperature conditions, there will be insufficient capacity at the station to supply all demand at the 10th percentile temperature for about 19 hours in summer 2022/23. The energy at risk in summer 2022/23 is estimated to be 383 MWh. This energy at risk has an estimated value to consumers of around $26.1 million (based on a value of customer reliability of $68,196/MWh)[1]. In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, an outage of one transformer at RWTS 66 kV over the summer of 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers $26.1 million.

It is emphasised however, that the probability of a major outage of one of the four transformers occurring over the duration of the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (383 MWh for summer 2022/23) is weighted by this low probability, the expected unsupplied energy is 3.3 MWh with an estimated value to consumers of around $0.23 million.

These key statistics for the year 2022/23 under "N-1" outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	0	$0 million
Expected unserved energy at 50th percentile demand	0	$0 million
Energy at risk, at 10th percentile demand forecast	383	$26.1 million
Expected unserved energy at 10th percentile demand	3.3	$0.23 million

If one of the 220/66 kV transformers at RWTS is taken off line during peak loading times and the N-1 station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by SPI PowerNet's TOC[2] to protect the connection assets from overloading[3], will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with SPI Electricity's and United Energy's operational procedures after the operation of the OSSCA scheme. It may be noted that in the event that OSSCA operates, it would shed about 100 MVA of load, affecting approximately 35,000 customers.

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

2 Transmission Operation Centre.

3 OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint and will be investigated by SPI Electricity, United Energy and AEMO in line with the Victorian Joint Planning Process:

1. Contingency plans to transfer load to adjacent terminal stations

Both SPI Electricity and United Energy have established and implemented the necessary plans to enable load transfers under contingency conditions via emergency 66 kV ties to the adjacent East Rowville and Templestowe terminal stations, respectively. The emergency 66 kV ties from RWTS 66 kV can be in operation within a few hours and have a transfer capability of approximately 50 MVA each. This option will substantially reduce the interruption duration and load at risk resulting from a major transformer failure. United Energy and SPI Electricity have the capability to transfer an additional 60 MVA at the 22 kV distribution feeder level.

2. Install new 66 kV Capacitor Banks on Bus Group 1-3

Installation of one new 50 MVAR 66 kV capacitor bank connected to 66 kV bus group 1-3 to alleviate the station loading levels may enable network augmentation to be deferred for one or two years.

3. Establish a new 220/66kV terminal station

There are vacant terminal station sites at Doncaster and Coldstream that could be utilised to construct a new terminal station to offload RWTS.

4. Install a fifth 220/66 kV transformer at RWTS

It is feasible to install a fifth transformer in the RWTS switchyard. There will be some unavoidable operational issues and difficulties in operating the station with five transformers. This option can be implemented in a shorter time frame compared with the new terminal station options, and would not require a reconfiguration of the 66 kV feeder exits to control the station fault levels.

5. Install a fourth 220/66 kV transformer at TSTS

It is feasible to install a fourth transformer in the nearby terminal station at Templestowe (TSTS) and build new 66 kV lines to allow load to be transferred away from RWTS.

6. Demand reduction

SPI Electricity is currently using a demand based (MVA) tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak times and thus reduce the station loading. Up to 50% of the maximum demand at RWTS 66 kV is summer residential load, largely air conditioning. With this existing load mix it is likely that demand reduction initatives can play a limited role in reducing the summer peak load at RWTS 66 kV.

United Energy has developed a number of innovative network tariffs to encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and will be taken into consideration when determining the optimum timing for the capacity augmentation.

7. Embedded generation

There is also potential for an additional 20 MVA of peak load embedded generation to be utilised to defer augmentation for 1 to 2 years.

Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at RWTS and under critical loading conditions:

   - maintain contingency plans to transfer load quickly to adjacent terminal stations;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading; and
   - subject to the availability of the SPI PowerNet spare 220/66kV transformer for the metropolitan area (refer section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at RWTS, it is propose to either:

   - Install a 66 kV Capacitor Bank on bus group 1-3 to defer a major augmentation; or
   - Install a fifth transformer at RWTS to meet the station's long term needs.

Whilst no decision has yet been made on a preferred network augmentation, a fifth transformer at RWTS is potentially the most likely economic option. This is unlikely to be required prior to 2023 based on the present demand forecast. The capital cost of installing a fifth transformer at RWTS is estimated to be $20 million in 2013 dollars. The cost of establishing, operating and maintaining this new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2 million. This cost provides a broad upper bound indication of the maximum annual network support payment which may be available to embedded generators or demand management initiatives that results in the deferral of this transmission connection augmentation which may otherwise be required beyond 2023. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging constraints.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

RINGWOOD TERMINAL STATION 66kV (RWTS 66)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	SPI Electricity (77%), UE (23%)
Normal cyclic rating with all plant in service	676 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Rating (MVA):	507
Winter N-1 Station Rating (MVA):	578

Station: RWTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	455.0	461.9	467.1	471.6	474.3	478.5	483.4	487.5	491.0	494.5
50th percentile Winter Maximum Demand (MVA)	360.6	364.6	368.0	371.3	374.5	377.8	380.5	382.8	384.6	386.8
10th percentile Summer Maximum Demand (MVA)	507.4	513.9	519.6	524.2	528.2	533.4	539.4	543.5	546.8	549.7
10th percentile Winter Maximum Demand (MVA)	380.9	384.9	388.4	391.6	395.0	398.2	401.4	404.0	406.3	408.7
N - 1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N - 1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N - 1 energy at risk at 10th percentile demand (MWh)	5	20	44	72	101	151	223	281	333	383
N - 1 hours at risk at 10th percentile demand (hours)	1	3	5	7	9	11	14	16	17	19
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.2	0.4	0.6	0.9	1.3	1.9	2.4	2.9	3.3
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.01M	$0.03M	$0.04M	$0.06M	$0.09M	$0.13M	$0.17M	$0.20M	$0.23M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.01M	$0.01M	$0.02M	$0.03M	$0.04M	$0.05M	$0.06M	$0.07M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

SHEPPARTON TERMINAL STATION (SHTS) 66 kV

Shepparton Terminal Station (SHTS) 66 kV consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 69,590 customers in Shepparton and the Goulburn–Murray area. The station supply area includes the towns of Shepparton, Echuca, Mooroopna, Yarrawonga, Kyabram, Cobram, Numurkah, Tatura, Rochester, Nathalia, Tongala, and Rushworth.

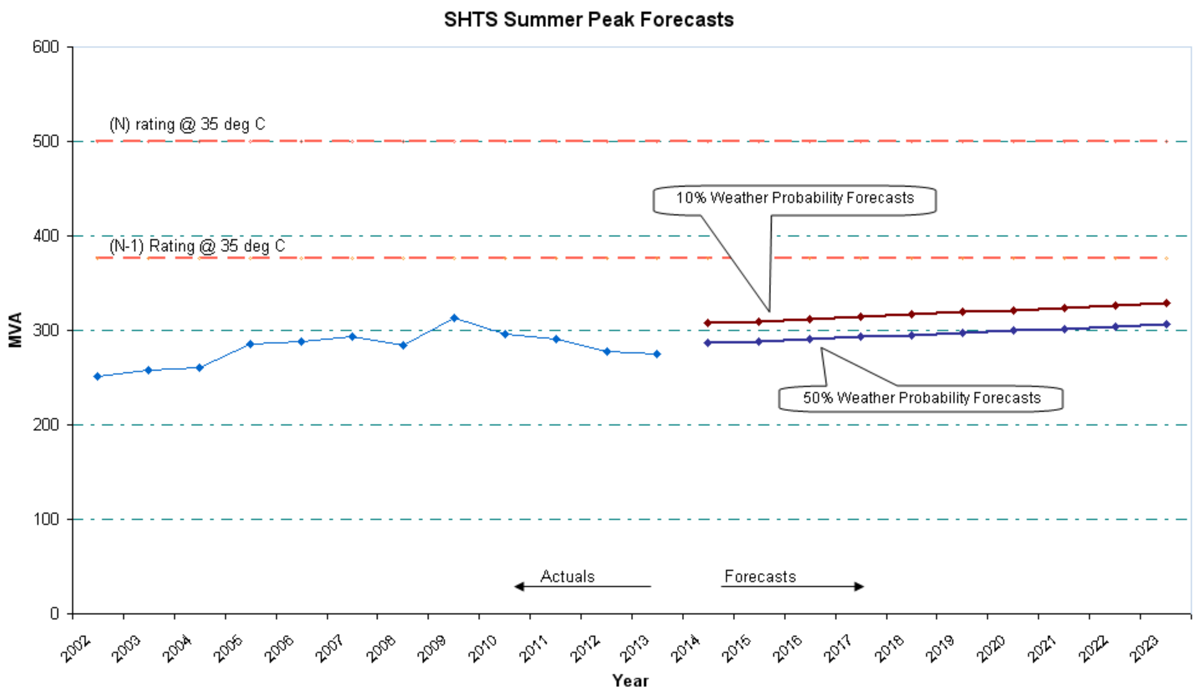
Magnitude, probability and impact of loss of load

Demand at SHTS is summer peaking. Growth in summer peak demand at SHTS has averaged around -1.9 MW (-0.5%) per annum over the last 5 years. Peak load on the station in the mild summer of 2013 reached 256 MW.

It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.96.

The chart below depicts the 10th and 50th percentile summer maximum demand forecast together with the station operational "N" rating (all transformers in service) and the "N−1" rating at 35°C ambient temperature.



The chart shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

SOUTH MORANG TERMINAL STATION (SMTS 66 kV)

Background

A 220/66 kV connection facility with two 220/66 kV 225 MVA transformers was established at the existing South Morang Terminal Station (SMTS) site in 2008. The re-arrangement of 66 kV loops with the establishment of SMTS resulted in the 140 MVA Somerton Power Station being connected to the SMTS 66 kV bus.

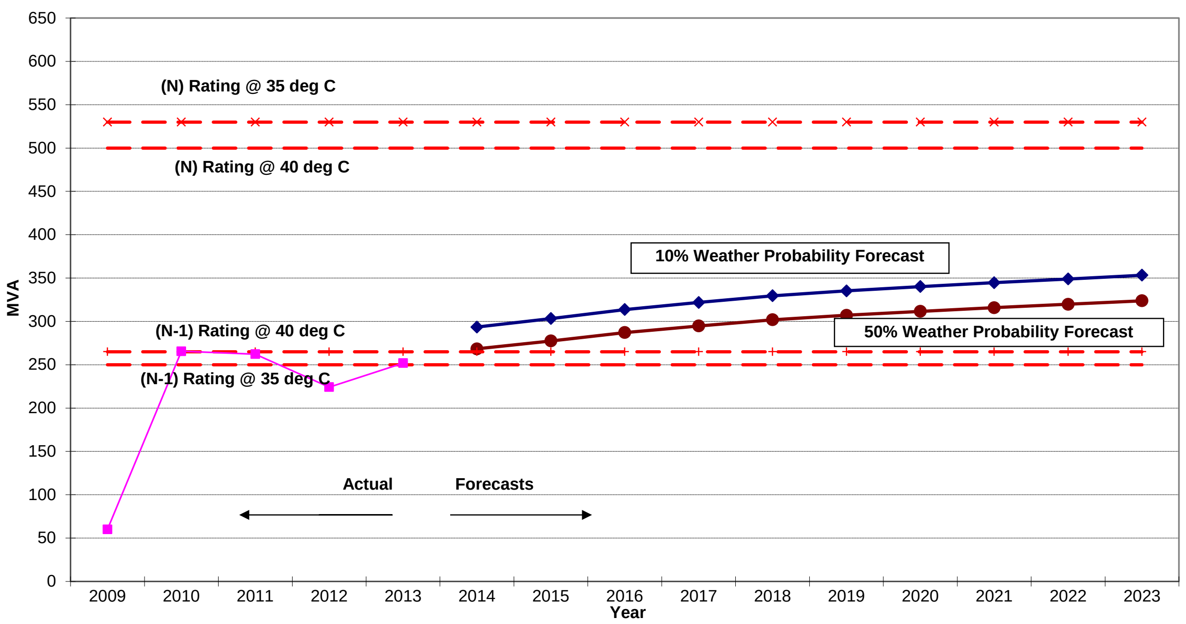
The geographic coverage of the area supplied by the new connection assets at SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south and from Doreen and Mernda in the east to Somerton and Craigieburn in the west. The electricity distribution networks for this area are the responsibility of both SPI Electricity (70%) and Jemena Electricity Networks (30%).

SMTS is a summer peaking station which recorded a maximum demand of 248.1 MW (251.8 MVA) in summer 2012/13. The station load has a power factor of 0.985 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak demand for 4 hours per annum.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C as well as 40°C ambient temperature.

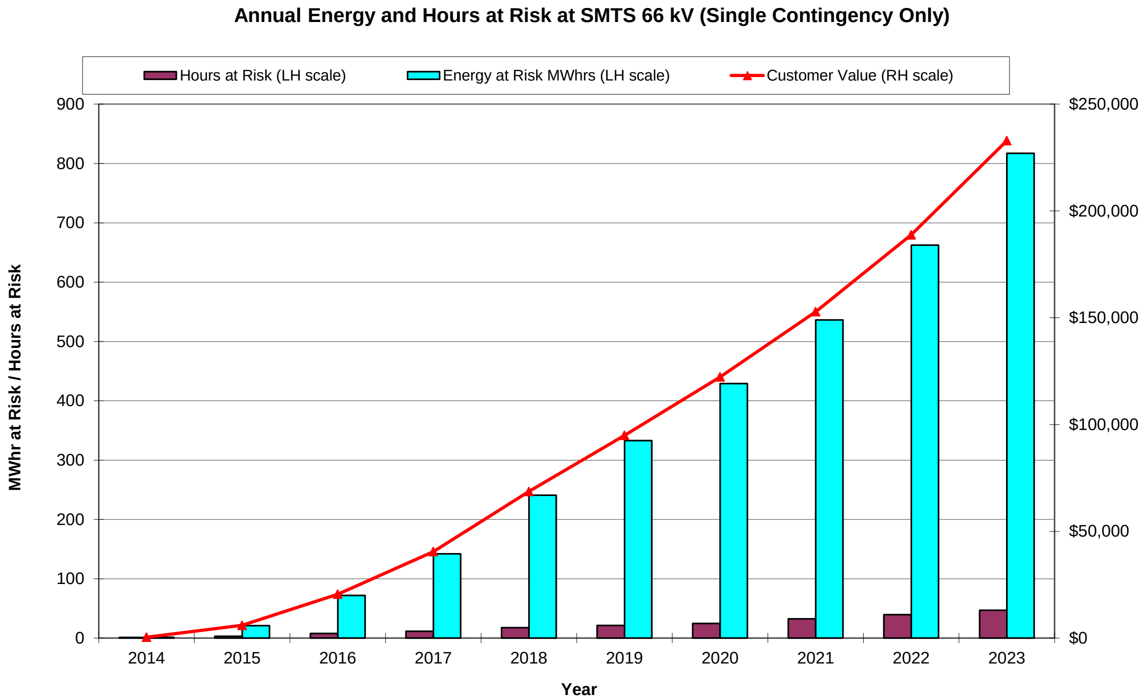
SMTS 66 kV Summer Peak Demand Forecasts



The "N" rating on the above chart indicates the maximum load that can be delivered from SMTS with both transformers in service.

With the projected growth in customer demand in the area, it is expected that SMTS will exceed its "N-1" rating in summer at the 50th percentile and 10th percentile summer demand forecasts, as shown in the graph above.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours each year that the 50th percentile demand forecast is expected to exceed the "N-1" capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



SMTS is not expected to be loaded above its "N-1" rating under 50th percentile or 10th percentile winter maximum demand forecasts during the 10 year planning horizon.

Comments on Energy at Risk assuming Somerton Power Station is unavailable

Assuming that Somerton Power Station is unavailable, then for an outage of one transformer at SMTS over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 47 hours in summer 2022/23. The energy at risk at the 50th percentile temperature under "N-1" conditions is estimated to be 817 MWh in 2022/23. The estimated value to consumers of the 817 MWh of energy at risk is approximately $53.7 million (based on a value of customer reliability of $65,781MWh)[1]. In other words, at the 50th percentile demand level, without any contribution from embedded generation and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at SMTS in 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers $53.7 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (817 MWh) is weighted by this low transformer unavailability, the expected unserved energy is estimated to be around 3.5 MWh. This expected unserved energy is estimated to

1 The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

have a value to consumers of around $0.23 million (based on a value of customer reliability of $65,781/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring in each year. Under higher temperature conditions (that is, at the 10th percentile level), the energy at risk in 2022/23 summer is estimated to be 2,671 MWh. The estimated value to consumers of this energy at risk in 2022/23 summer is approximately $176 million. The corresponding value of the expected unserved energy is approximately $0.76 million.

These key statistics for the year 2022/23 summer under "N-1" outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	817	$53.7 million
Expected unserved energy at 50th percentile demand	3.5	$0.23 million
Energy at risk, at 10th percentile demand forecast	2,671	$176 million
Expected unserved energy at 10th percentile demand	11.6	$0.76 million

If one of the 220/66 kV transformers at SMTS is taken off line during peak loading times and the "N-1" station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by SPI PowerNet's TOC[2] to protect the connection assets from overloading[3], will act swiftly to reduce the loads in blocks to within safe loading limits. In the event of OSSCA operating, it would automatically shed up to 40 MVA of load, affecting approximately 15,000 customers in 2013/14. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at feeder level in accordance with SPIE and Jemena's operational procedures after the operation of the OSSCA scheme.

Comments on Energy at Risk assuming Somerton Power Station is available

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 220/66 kV transformer loading. The Somerton Power Station (SPS) is capable of generating up to 140 MVA and this generation is connected to the SMTS 66 kV bus via the SMTS-ST-SSS-SMTS 66 kV loop. There is no firm commitment that generation will be available to offset transformer loading at SMTS; however it is most likely that the times of peak demand at SMTS will coincide with periods of high wholesale electricity prices, resulting in a high likelihood that SPS will be generating. If SPS is generating to its full capacity there would be no energy at risk at SMTS over the ten year planning horizon for the 50th percentile or 10th percentile summer maximum demand forecast.

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2 Transmission Operation Centre.

3 OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging capacity constraints:

1. Implement contingency plans to transfer load to adjacent terminal stations. SPI Electricity has established and implemented the necessary plans that enable up to 20 MVA of load transfers via existing 22 kV feeders to adjoining zone substations. Jemena has the plans and capability to transfer an additional 11 MVA. This option is able to partly reduce the interruption duration and load at risk resulting from a major transformer failure.

2. Install a third 225 MVA 220/66 kV transformer at South Morang Terminal Station (SMTS), which would also require the installation of fault limiting reactors.

3. Demand Management. SPI Electricity is currently using an MVA tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak demand times and thus reduce the station loading. Up to 50% of the maximum demand at SMTS 66 kV is expected to be summer residential load, largely air conditioning. With this existing load mix it is likely that demand reduction initiatives can play a limited role in reducing the peak summer load at SMTS 66 kV.

4. Embedded Generation. As mentioned above, the Somerton power station is connected to SMTS. A network support agreement with SPS or other generator connected to the SMTS 66 kV bus will help to defer the need for augmentation.

Preferred network option for alleviation of constraints

1. In the event that there are no firm commitments by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce future load at SMTS 66 kV, then it will be proposed to install a new third 220/66 kV transformer at SMTS 66 kV. The installation of the third transformer is not expected to be economically justified in the next ten years.

2. Implement the following temporary measures to cater for an unplanned outage of one transformer at SMTS under critical loading conditions until the new 220/66 kV transformer is commissioned:

   - maintain contingency plans to transfer load quickly to adjacent terminal stations;

   - rely on Somerton Power Station generation to reduce loading at SMTS 66 kV, and investigate the option of formalising a network support agreement with SPS;

   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading; and

   - subject to the availability of SPI PowerNet's (SPIP) spare 220/66 kV transformer for metropolitan areas (refer Section 4.5), this spare transformer can be used to temporarily replace the failed transformer. It is noted that SPIP only has a 150 MVA spare transformer, so the SMTS 66 kV capacity will be reduced under these emergency conditions.

   The capital cost of installing a new third 220/66 kV transformer at SMTS is estimated to be $22 million including the cost of installing three fault limiting reactors. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2.2 million. This cost provides a broad upper bound indication of the maximum annual network support payment which may be available to embedded generators or demand management initiatives that results in the deferral of this transmission connection augmentation which may otherwise be required beyond 2023. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, ten years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging network constraints.

The table on the following page provides more detailed data on the station rating, demand forecast, energy at risk and expected unserved energy assuming embedded generation is not available.

SOUTH MORANG TERMINAL STATION 66kV (SMTS 66)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	SPI Electricity (55%), Jemena Electricity Networks (45%)
Normal cyclic rating with all plant in service	530 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating (MVA):	265
Winter N-1 Station Rating (MVA):	294

Station: SMTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	268.3	277.4	287.1	294.7	301.9	307.1	311.6	315.8	319.7	323.8
50th percentile Winter Maximum Demand (MVA)	224.1	231.0	238.0	243.2	247.9	251.1	254.3	257.4	260.5	263.6
10th percentile Summer Maximum Demand (MVA)	293.4	303.3	313.7	321.8	329.6	335.2	340.1	344.6	349.0	353.3
10th percentile Winter Maximum Demand (MVA)	233.7	240.9	248.2	253.6	258.6	261.8	265.1	268.4	271.7	275.0
N - 1 energy at risk at 50th percentile demand (MWh)	2	21	72	142	241	333	429	536	663	817
N - 1 hours at risk at 50th percentile demand (hours)	1	3	8	12	18	21	25	33	40	47
N - 1 energy at risk at 10th percentile demand (MWh)	241	457	735	1,006	1,313	1,565	1,825	2,088	2,368	2,671
N - 1 hours at risk at 10th percentile demand (hours)	20	26	33	41	48	56	65	72	79	86
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.1	0.3	0.6	1.0	1.4	1.9	2.3	2.9	3.5
Expected Unserved Energy at 10th percentile demand (MWh)	1.0	2.0	3.2	4.4	5.7	6.8	7.9	9.1	10.3	11.6
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.01M	$0.02M	$0.04M	$0.07M	$0.10M	$0.12M	$0.15M	$0.19M	$0.23M
Expected Unserved Energy value at 10th percentile demand	$0.07M	$0.13M	$0.21M	$0.29M	$0.37M	$0.45M	$0.52M	$0.60M	$0.68M	$0.76M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.02M	$0.04M	$0.08M	$0.11M	$0.16M	$0.20M	$0.24M	$0.29M	$0.34M	$0.39M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.

SPRINGVALE TERMINAL STATION (SVTS)

Springvale Terminal Station (SVTS) is located in the south east of greater Melbourne. The geographic coverage of the station's supply area spans from Blackburn in the north to Keysborough in the south and from Wantirna South in the east to Riversdale in the west. The electricity supply network for this large region is split between United Energy (UE) and CitiPower (CP).

Background

SVTS was augmented with a new 150 MVA 220/66 kV transformer in 2006 to reinforce the security and reliability of supply for customers in the area. The station now has four 150 MVA 220/66 kV transformers and operates in a split bus arrangement. Under system normal conditions the No.1 & No.2 transformers (B1 & B2) are operated in parallel as one group (SVTS1266) and supply the No.1 & No.2 buses. The No.3 & No.4 transformers (B3 & B4) are operated in parallel as a separate group (SVTS3466) and supply the No.3 & No.4 buses. Connection between No.1 & No.4 buses is maintained via transfer buses No.5 & No.6. The 66 kV bus 2-3 and bus 4-5 tie circuit breakers are operated normally open to limit the fault levels on the 66 kV buses to within switchgear ratings. For an unplanned outage of any one of the four transformers, 66 kV bus 2-3 and bus 4-5 tie circuit breakers will close automatically and maintain the station in a 3-transformer closed loop arrangement. Given this configuration, the demand on the station will therefore need to be controlled as follows:

- Load demand on the SVTS1266 group should be kept within the capabilities of the two transformers B1 & B2 at all times.
- Load demand on the SVTS3466 group should be kept within the capabilities of the two transformers B3 & B4 at all times.
- Load demand on the total station should be kept within the capabilities of any three transformers when one transformer is out of service.

SVTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 478 MW (491 MVA) in summer 2008-09 under extreme weather conditions. The peak demand in summer 2012-13 was 428 MW (436 MVA). Two embedded generation schemes over 1 MW are connected at SVTS 66 kV.[1]

The magnitude, probability and load at risk for the two transformer groups are considered below.

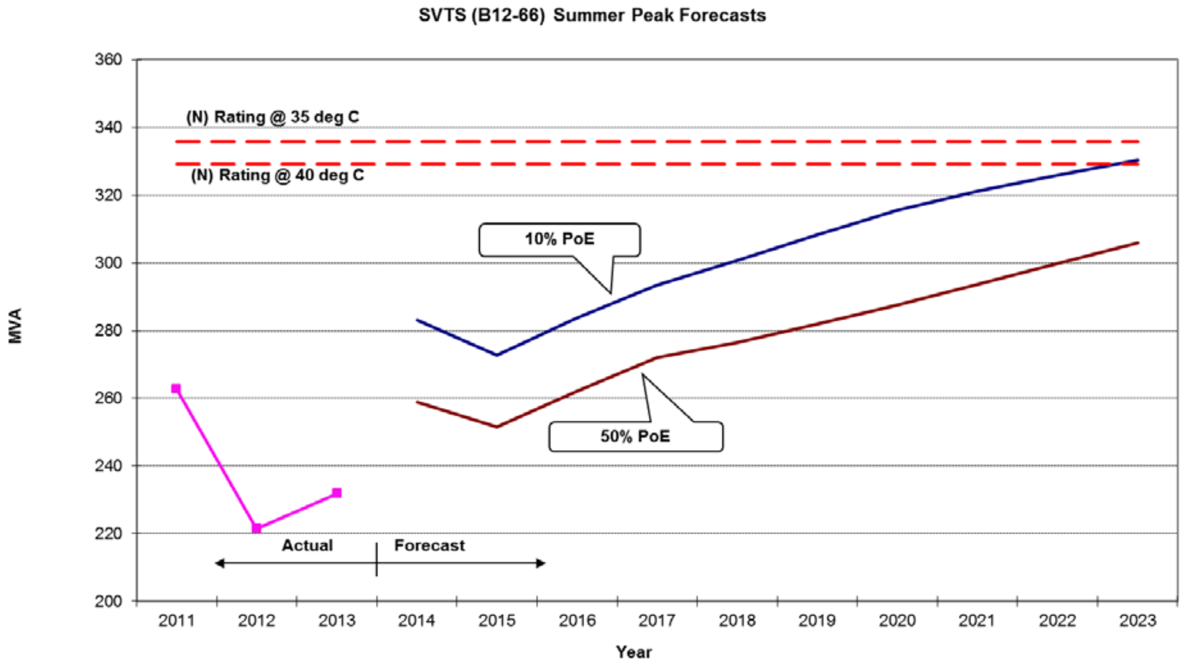
SVTS 1266 (B12) Bus Group Summer Peak Forecasts

This bus group supplies Noble Park, Springvale South, Clarinda, Oakleigh East, Springvale and Springvale West zone substations owned by United Energy. Two generation schemes over 1 MW are connected at SVTS 1266 (B12) bus group.[1]

The load at SVTS 1266 (B12) is forecast to have a power factor of 0.987 at times of peak demand.

The graph below depicts the 10th and 50th percentile summer maximum demand for SVTS1266 and the corresponding rating with both transformers in service.

[1] The maximum demand forecasts adopted in this risk analysis reflect the impact of the two generation schemes. Each generation scheme and its contributions during peak demand periods are presented in the 2013 Terminal Station Demand Forecast (TSDF), which is available at: http://aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria



The graph above shows that with both transformers in service, there is adequate capacity to meet the 50th percentile maximum demand for the entire planning period. However, the 10th percentile maximum demand is forecast to exceed the N rating at 40°C from summer 2022-23, beyond which time it is intended to balance the load between the two bus groups or transfer load away so that the load in each bus group is kept below its N rating.

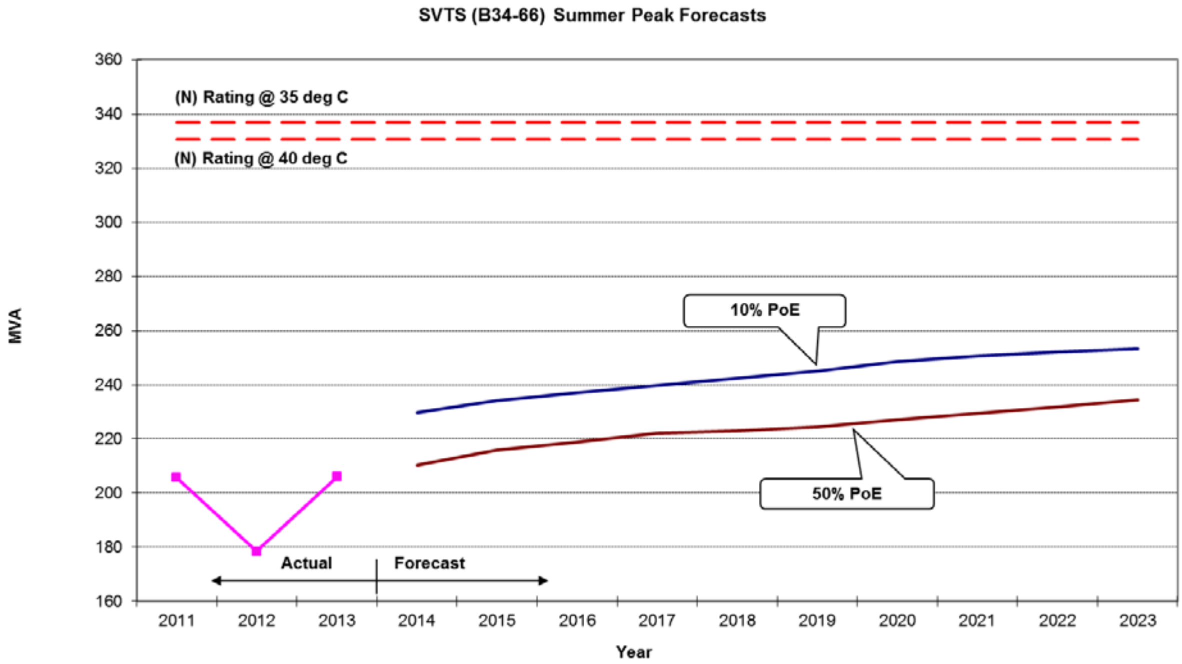
The recorded peak demand in summer 2012-13 for the SVTS 1266 group was 228 MW (232 MVA). The reduction in demand forecast in summer 2014-15 is a result of transferring approximately 18 MW from SVTS 1266 to HTS 66 kV with the commissioning of the new Keysborough zone substation.

SVTS 3466 (B34) Bus Group Summer Peak Forecasts

This bus group supplies East Burwood, Glen Waverley and Notting Hill zone substations owned by United Energy and Riversdale zone substation owned by Citipower. There are no embedded generation schemes over 1 MW connected at SVTS 3466 (B34) bus group.

The load at SVTS 3466 (B34) is forecast to have a power factor of 0.980 at times of peak demand.

The graph below depicts the 10th and 50th percentile summer maximum demand for SVTS3466 and the corresponding rating with both transformers in service.

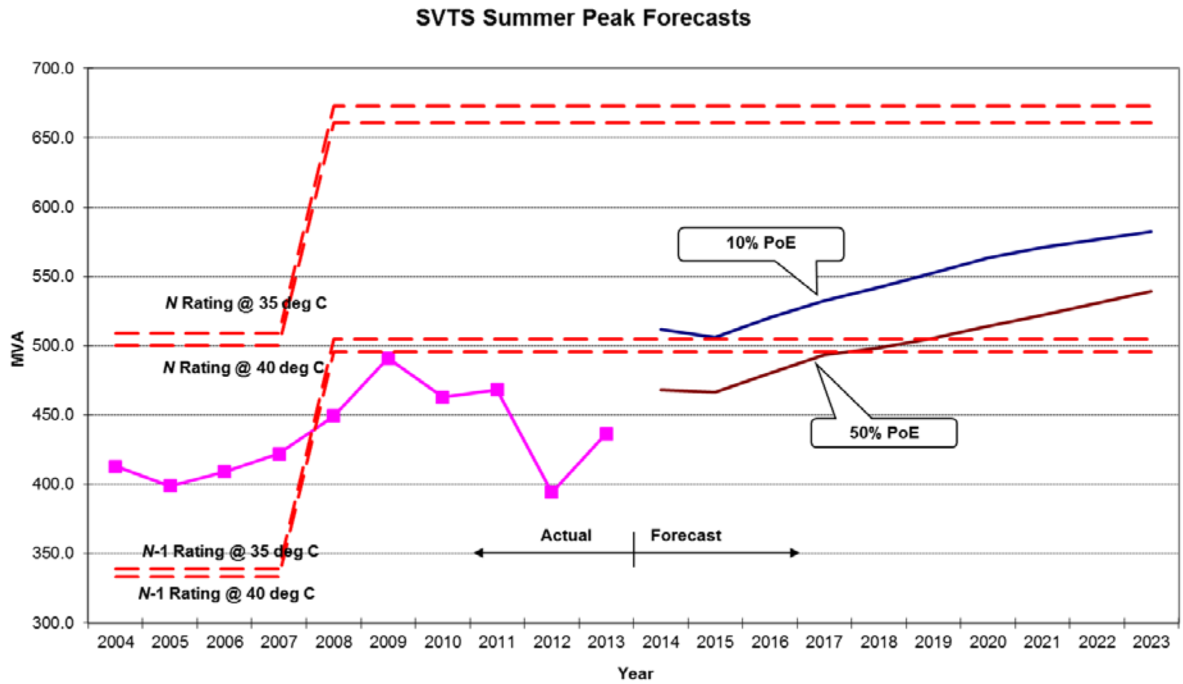


The graph above shows that with both transformers in service, there is adequate capacity to meet the anticipated maximum for the entire planning period.

The recorded peak demand in summer 2012-13 for the SVTS 3466 group was 201 MW (206 MVA).

Magnitude, probability and impact of loss of load

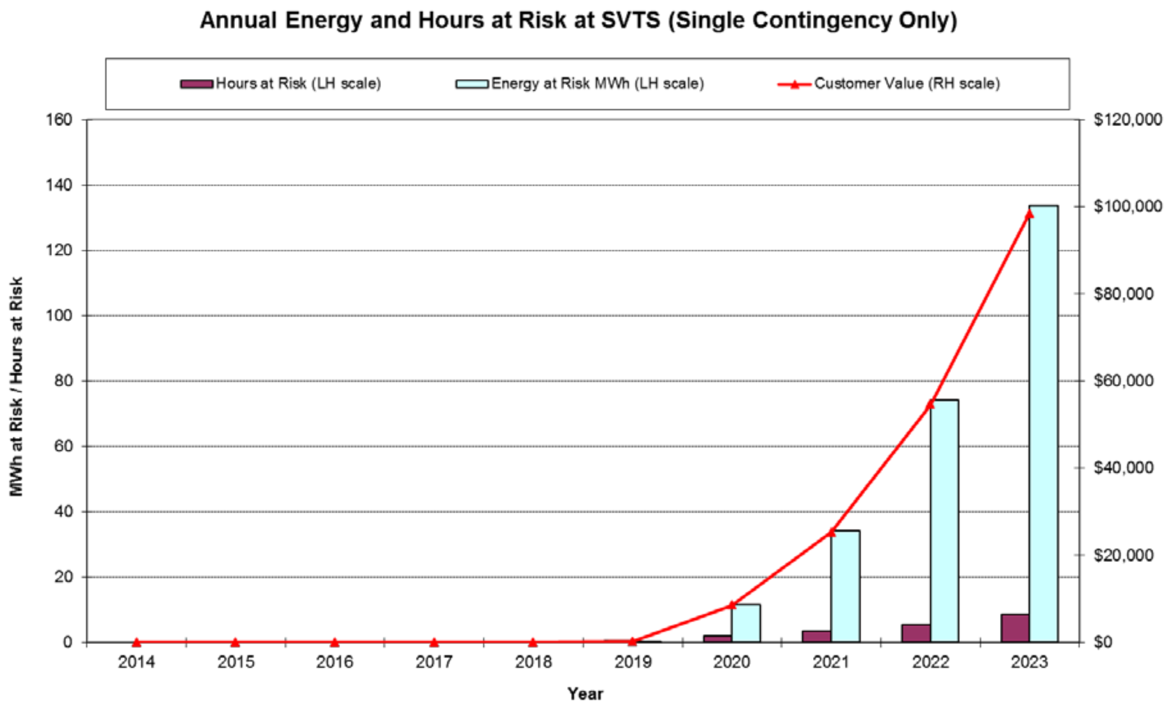
The graph below depicts the 10th and 50th percentile total summer maximum demand forecasts together with the station's expected operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.



The graph indicates that the demand at SVTS 66 kV remains below its N rating within the 10 year planning period. However, the 10th percentile overall summer maximum demand is forecast to exceed the station's N-1 rating from summer 2013-14, while the 50th percentile summer maximum demand is forecast to exceed its N-1 rating at 40°C from summer 2018-19.

The overall station load is forecast to have a power factor of 0.984 at times of peak demand. The demand at SVTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for approximately 6 hours per annum.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For an outage of one transformer at SVTS, it is expected that from 2019, there would be insufficient capacity at the station to supply all demand at the 50th percentile temperature.

By the end of the ten-year planning period in 2023, the energy at risk under N-1 conditions is estimated to be 134 MWh at the 50th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 9 hours in that year. The estimated value to customers of the 134 MWh of energy at risk in 2023 is approximately $11.4 million (based on a value of customer reliability of $85,402/MWh)[2]. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at SVTS over the summer of 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $11.4 million.

2 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (134 MWh in 2023) is weighted by this low unavailability, the expected unserved energy is estimated to be around 1.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $98,100 (based on a value of customer reliability of $85,402/MWh). SPI PowerNet has indicated that three of the four transformers at SVTS have an elevated failure rate due to the age and condition of the transformers. Therefore the expected unserved energy calculated above may underestimate the risk at this station. Given that SPI PowerNet plans to replace these transformers as part of its asset replacement program in 2019, the elevated failure rates are unlikely to advance any augmentation requirement at this terminal station.[3]

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 301 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $25.7 million. The corresponding value of the expected unserved energy is approximately $221,200.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	134	$11.4 million
Expected unserved energy at 50th percentile demand	1.1	$98,100
Energy at risk, at 10th percentile demand forecast	301	$25.7 million
Expected unserved energy at 10th percentile demand	2.6	$221,200

If one of the 220/66 kV transformers at SVTS is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[4] load shedding scheme which is operated by SPI PowerNet's NOC[5] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's and CitiPower's operational procedures after the operation of the OSSCA scheme.

In the case of SVTS supply at maximum loading periods, and based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would shed about 120 MVA of load, affecting approximately 23,000 customers in 2013.

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3 Section 3.6 of the 2013 Victorian Annual Planning Review provides further details of SPI PowerNet's asset renewal program. It is available from: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/VAPR2013/Victorian_Annual_Planning_Report_2013_v2.ashx

4 Overload Shedding Scheme of Connection Asset.

5 Network Operations Centre

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. Both United Energy and CitiPower have established and implemented the necessary plans that enable load transfers under contingency conditions via the 66 kV subtransmission and/or the high voltage 22 kV and 11 kV distribution networks. These plans are reviewed annually prior to the summer season. The total transfer capability away from SVTS 66 kV onto adjacent terminal stations via distribution network is assessed at 74 MVA.

2. Balance the bus group loads by transferring Clarinda and Oakleigh East zone substations from SVTS1266 to SVTS3466.

3. Establish a new 220/66 kV terminal station in the Dandenong area to off-load SVTS.

   In early 2012 United Energy submitted a connection enquiry to AEMO for the establishment of a new connection point in the Dandenong area by 2023. Joint planning activities are now underway between the two organisations to quantify the risk of the emerging constraints in the area and to assess viable options for alleviating the constraints. This has included engaging consulting firm Sinclair Knight Merz to identify possible 220 kV transmission line routes.

   The capital cost of installing a new 220/66 kV terminal station in Dandenong is estimated to be in excess of $70 million. The cost of establishing, operating and maintaining the new assets would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $7 million.

   Given the reduction in the maximum demand forecast at Heatherton Terminal Station (HTS) and SVTS compared with last year's forecast, the new terminal station is not likely to be economic before December 2025. Further analysis, including a Regulatory Investment Test for Transmission will be undertaken to determine the preferred option for addressing the constraints, but at this stage a new 220/66 kV terminal station in Dandenong is the preferred network option. The need for and the timing of the new terminal station in Dandenong will be confirmed through the Regulatory Investment Test for Transmission process.

4. Install a third 225 MVA 220/66 kV transformer at Malvern terminal station (MTS) to off-load SVTS.

5. Replace three of the four SVTS 'B' transformers in 2019, as part of SPI PowerNet's asset replacement programme.

   SPI PowerNet plans to replace the existing transformers, with like-for-like transformers, as part of its asset replacement programme. SPI PowerNet has indicated that the station N-1 rating is expected to be similar to (or marginally higher than) the current level.

6. Demand reduction: United Energy has developed a number of innovative network tariffs to encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and the subsequent change in load pattern and will be taken into consideration when determining the optimum timing for the capacity augmentation.

7. Embedded generation, in the order of 15 MVA, connected to the network supplied by the SVTS 66 kV bus, will help to defer augmentation in the area by one year.

Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at SVTS under critical loading conditions:

    - maintain contingency plans to transfer load quickly to adjacent terminal stations;
    - fine-tune the OSSCA scheme settings in conjunction with NOC to minimise the impact on customers of any automatic load shedding that may take place; and
    - subject to the availability of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. In the absence of any significant capacity increase at SVTS 1266 (B12) following asset replacement, and any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at SVTS, it is proposed to rebalance the bus group loads by transferring Clarinda and Oakleigh East zone substations from SVTS1266 to SVTS3466 by December 2022. On the present forecasts this would be required within the ten year planning horizon as the bus group load approaches the N rating. The capital cost of undertaking this rebalance is estimated to be $2.5 million.

    The estimated total annual cost of this network augmentation is approximately $0.25 million. This cost provides a broad upper bound indication of the maximum network support payment which may be available to embedded generators or customers to reduce forecast demand, and to defer or avoid the transmission connection component of this augmentation. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging constraints.

3. Establish a new 220/66 kV terminal station in the Dandenong area to off-load SVTS

    On the present forecasts, establishment of a new terminal station in the Dandenong area is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

SPRINGVALE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (94%) and CitiPower (6%)
Station operational rating (N elements in service): 673 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Rating: 505 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 560 MVA

Station: SVTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	468	467	480	493	498	505	514	522	530	539
50th percentile Winter Maximum Demand (MVA)	339	349	358	366	370	373	377	379	381	382
10th percentile Summer Maximum Demand (MVA)	512	506	520	532	542	552	563	571	577	582
10th percentile Winter Maximum Demand (MVA)	349	359	367	375	380	383	387	391	393	395
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	12	34	74	134
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	1	2	4	6	9
N-1 energy at risk at 10th percentile demand (MWh)	9	5	18	41	59	83	117	160	218	301
N-1 hours at risk at 10th percentile demand (hours)	1	1	1	2	3	3	5	7	9	13
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	1.1
Expected Unserved Energy at 10th percentile demand (MWh)	0.1	0.0	0.2	0.4	0.5	0.7	1.0	1.4	1.9	2.6
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.2k	$8.5k	$25.2k	$54.4k	$98.1k
Expected Unserved Energy value at 10th percentile demand	$6.7k	$3.6k	$13.1k	$29.9k	$43.0k	$60.8k	$85.6k	$117.1k	$160.2k	$221.2k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$2.0k	$1.1k	$3.9k	$9.0k	$12.9k	$18.4k	$31.7k	$52.8k	$86.1k	$135.0k

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx

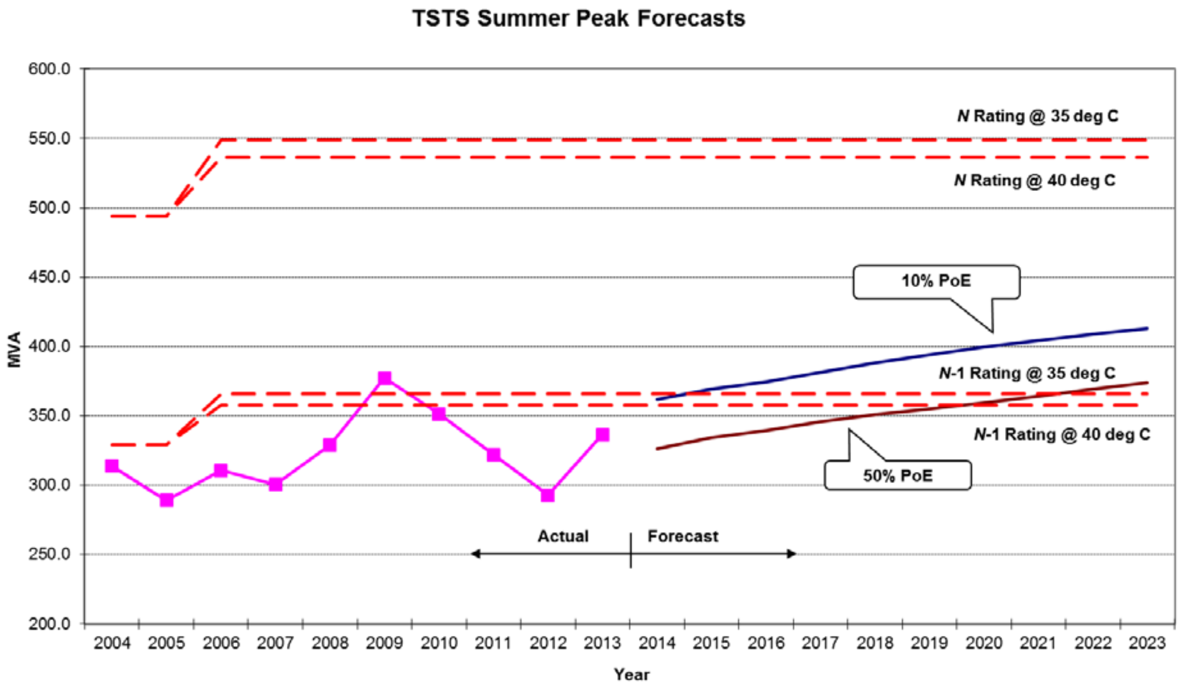
TEMPLESTOWE TERMINAL STATION (TSTS)

TSTS consists of three 150 MVA 220/66 kV transformers, and is the main source of supply for a major part of the north-eastern metropolitan area. The geographic coverage of the supply area spans from Eltham in the north to Canterbury in the south and from Mitcham in the east to Kew in the west. The electricity supply network for this large region is split between United Energy, CitiPower, SPI Electricity and Jemena Electricity Networks.

TSTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 357.6 MW (377.1 MVA) in summer 2008-09 under extreme weather conditions. The peak demand in summer 2012-13 was 325 MW (336.5 MVA). There are no embedded generation schemes over 1 MW connected at TSTS.

Magnitude, probability and impact of loss of load

The graph below depicts the 50th percentile summer maximum demand forecast together with the station's operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.

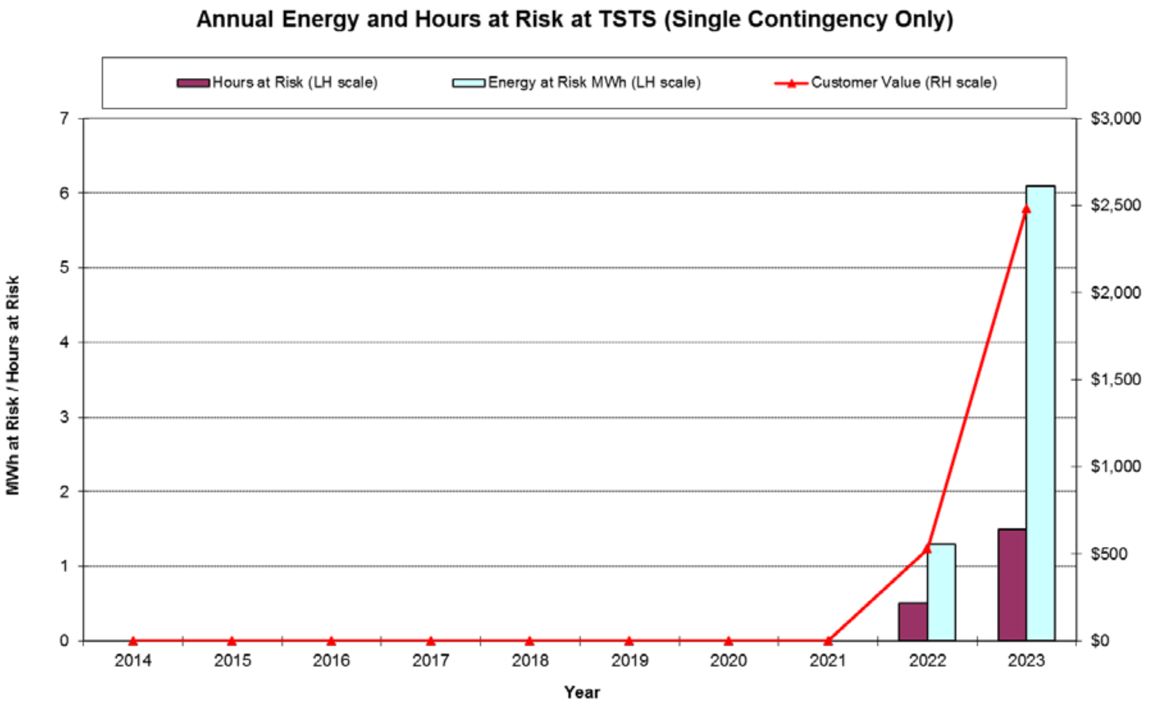


The N-1 rating at TSTS was restricted by over-voltage limits on transformer tapping until summer 2004. With the installation of a 50 MVAr capacitor bank at TSTS in December 2002 and improvement in the station power factor from 0.85 in 1994 to 0.91 in 2004, the station rating was subsequently reviewed and increased in 2004. The review, carried out by SPI PowerNet, indicated that the over-voltage limit on transformer tapping was no longer a constraint and could be removed. The N rating on the chart indicates the maximum load that can be supplied from TSTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the overall demand at TSTS remains below its N rating within the 10 year planning period. However, the 10th percentile overall summer demand is forecast to exceed the station's (N-1) rating at 40°C from summer 2013-14. The 50th percentile overall summer demand is expected to exceed its (N-1) rating at 40°C from summer 2019-20.

The demand at TSTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for approximately 3 hours per annum. The station load has a power factor of 0.961 at times of peak demand.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For an outage of one transformer at TSTS, it is expected that from summer 2019-20, there would be insufficient capacity at the station to supply all demand at the 50th percentile temperature.

By the end of the ten-year planning period in 2023, the energy at risk under N-1 conditions is 6 MWh at the 50th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 2 hours in that year. The estimated value to customers of the 6 MWh of energy at risk in 2023 is approximately $384,000 (based on a value of customer reliability of $62,993/MWh)[1]. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TSTS over the summer of 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $384,000.

It is emphasised however, that the probability of a major outage of one of the three transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (6 MWh in 2023) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.04 MWh. This expected unserved energy is estimated to have a value to consumers of around $2,500 (based on a value of customer reliability of $62,993/MWh). SPI PowerNet has indicated

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

that one of the three transformers at TSTS has an elevated failure rate due to the condition of the transformer. Therefore, the expected unserved energy calculated above may under-estimate the risk at this station. Given that SPI PowerNet plans to replace this transformer as part of its asset replacement programme in 2020, the elevated failure rates are unlikely to advance any augmentation requirements at this terminal station.[2]

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2023 is estimated to be 131 MWh. The estimated value to consumers of this energy at risk in 2023 is approximately $8.3 million. The corresponding value of the expected unserved energy is $53,500.

These key statistics for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	6	$384,000
Expected unserved energy at 50th percentile demand	0.04	$2,500
Energy at risk, at 10th percentile demand forecast	131	$8.3 million
Expected unserved energy at 10th percentile demand	0.8	$53,500

If one of the 220/66 kV transformers at TSTS is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA[3] load shedding scheme which is operated by SPI PowerNet's TOC[4] will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with each distribution company's operational procedures after the operation of the OSSCA scheme.

In the case of TSTS supply at maximum loading periods, and based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would shed about 70 MW of load, affecting approximately 20,000 customers in 2013.

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2 Section 3.6 of the 2013 Victorian Annual Planning Review provides further details of SPI PowerNet's asset renewal program. It is available from: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/VAPR2013/Victorian_Annual_Planning_Report_2013_v2.ashx

3 Overload Shedding Scheme of Connection Asset.

4 Transmission Operations Centre

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy, CitiPower, SPI Electricity and Jemena Electricity Networks have established and implemented the necessary plans that enable load transfers under contingency conditions. These plans are reviewed annually prior to the summer season. The total transfer capability away from TSTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 41 MVA.

2. Establish a new 220/66 kV terminal station. Two terminal station sites, one in Doncaster (DCTS) and another in Kew (KWTS), have been reserved for possible future electrical infrastructure development to meet customers' needs in the area. With established 220 kV tower lines to both sites, development of either of these sites could be economic depending upon the geographical location of additional customer load.

3. Install a fourth 150 MVA 220/66 kV transformers at TSTS. There is provision in the yard for an additional transformer.

   The capital cost of installing a 220/66 kV transformer at TSTS 66 kV is estimated to be $17 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $1.7 million.

On the present maximum demand forecasts, the fourth 220/66 kV transformer is not likely to be required within the ten year planning horizon.

Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at TSTS under critical loading conditions:

   - maintain contingency plans to transfer load quickly to adjacent terminal stations;

   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place; and

   - subject to the availability of SPI PowerNet's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. Install a fourth 150 MVA 220/66 kV transformers at TSTS.

   In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TSTS, it is proposed to install a fourth 220/66 kV transformer at TSTS. On the present forecasts, an additional 220/66 kV transformer is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

TEMPLESTOWE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (40%), CitiPower (27%), SPI Electricity (25%), Jemena (8%)
Station operational rating (N elements in service): 549 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Rating: 366 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 417 MVA

Station: TSTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	326	334	339	346	351	355	359	364	369	374
50th percentile Winter Maximum Demand (MVA)	250	253	258	263	265	267	270	273	275	278
10th percentile Summer Maximum Demand (MVA)	362	369	375	381	388	394	400	404	409	413
10th percentile Winter Maximum Demand (MVA)	259	262	267	271	275	276	279	282	285	288
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	1	6
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	1	2
N-1 energy at risk at 10th percentile demand (MWh)	2	7	15	29	45	60	76	93	111	131
N-1 hours at risk at 10th percentile demand (hours)	1	1	2	3	3	3	4	4	5	7
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.5k	$2.5k
Expected Unserved Energy value at 10th percentile demand	$0.8k	$2.8k	$6.2k	$11.8k	$18.2k	$24.5k	$30.7k	$37.7k	$45.1k	$53.5k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.2k	$0.8k	$1.9k	$3.6k	$5.5k	$7.3k	$9.2k	$11.3k	$13.9k	$17.8k

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. For 50th percentile value, the rating is at an ambient temperature of 35 degrees Centigrade. For 10th percentile value, the rating is at an ambient temperature of 40 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

TERANG TERMINAL STATION (TGTS) 66kV

Terang Terminal Station (TGTS) 66 kV consists of one 125 MVA transformer and one 150 MVA 220/66 kV transformer and is the main source of supply for over 76,663 customers in Terang and the surrounding area. The terminal station supply area includes Terang, Colac, Camperdown, Cobden, Warrnambool, Koroit, Portland and Hamilton.

Magnitude, probability and impact of loss of load

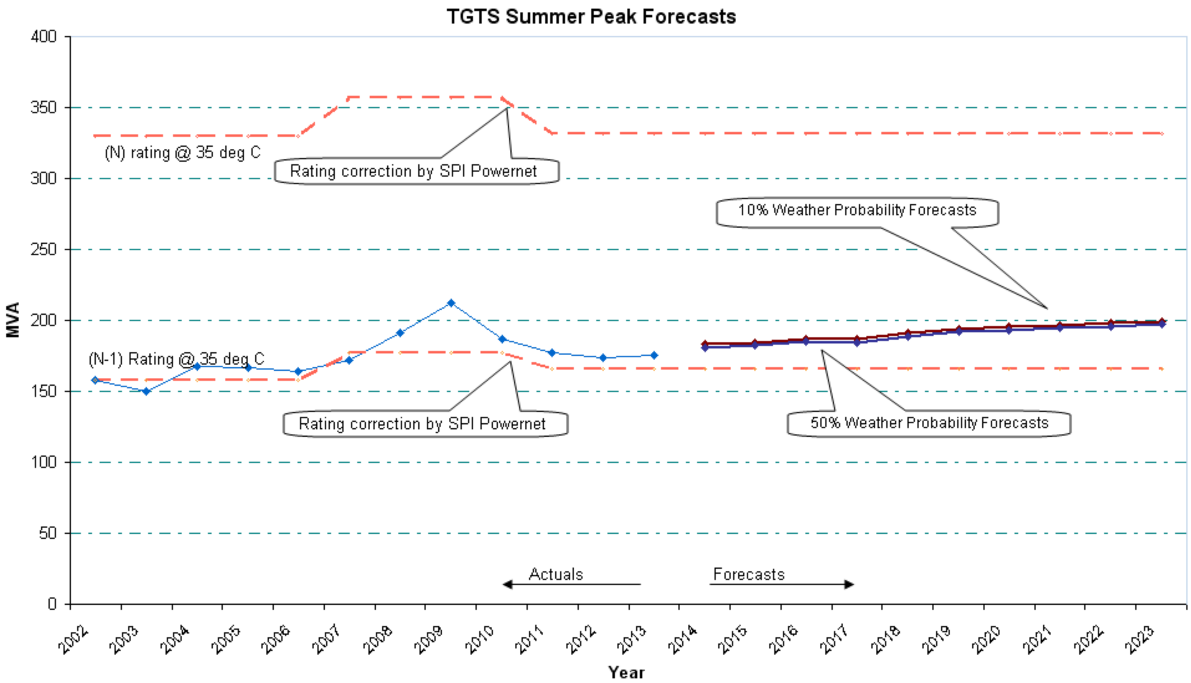
In 2007, as part of its asset replacement program, SPI PowerNet replaced the existing 1A and 1B 125 MVA single phase transformer bank at the station with a new 150 MVA three phase transformer unit. This has marginally increased the cyclic rating of the station as the previous cyclic rating was based on the rating of the 1A & 1B transformer bank (i.e. for loss of the #2 transformer). The station rating was further revised by SPI PowerNet in 2011. This step change in station cyclic rating is depicted in the graph below.

TGTS 66 kV demand is summer peaking but peaks can occur in spring depending upon the dairy industry load. Growth in summer peak demand at TGTS has averaged around -3.1 MW or -0.6% per annum over the last 5 years. The peak load on the station reached 173 MW in summer 2013 (after allowing for the effects on station load of a small contribution from embedded wind generation). It is noted that summer 2012/13 was a relatively mild summer. This is reflected in the growth rate referred to above.

It is estimated that:

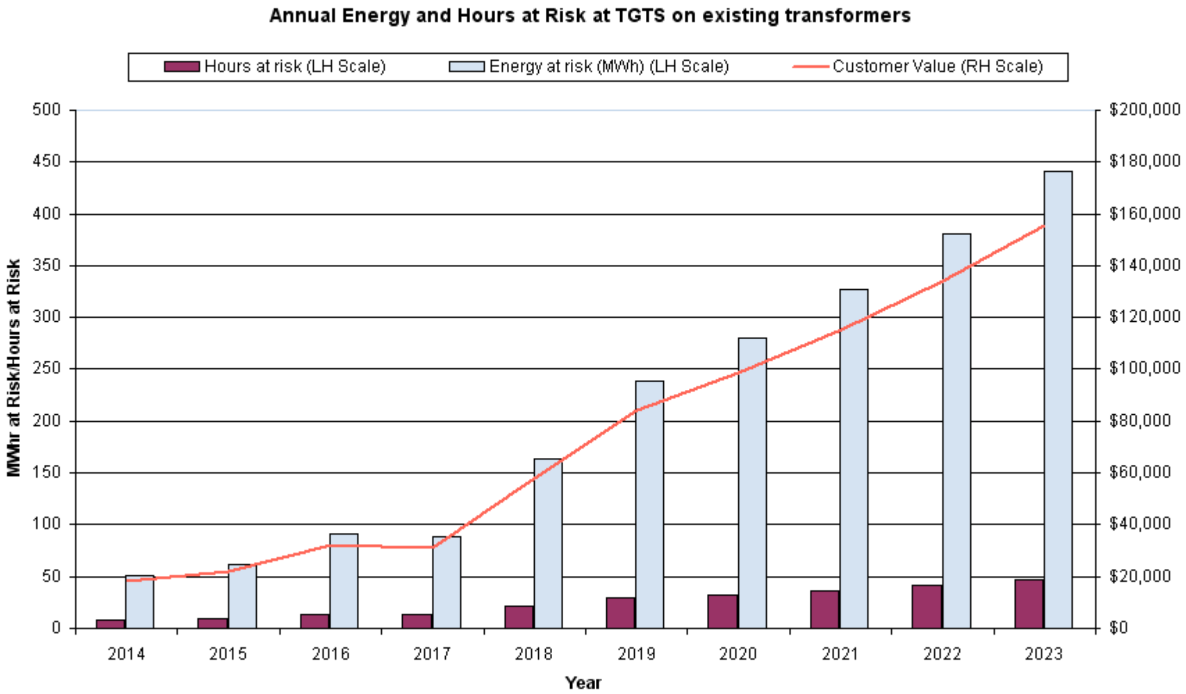
- For 4 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the stations operational “N” rating (all transformers in service) and the “N-1” rating at 35°C.



The (N) rating on the chart indicates the maximum load that can be supplied from TGTS with all transformers in service.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For an outage of one transformer at TGTS, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 46.3 hours in 2023. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 441 MWh in 2023. The estimated value to consumers of the 441 MWh of energy at risk is approximately $35.9 million (based on a value of customer reliability of $81,393 per MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TGTS in 2023 would be anticipated to lead to involuntary supply interruptions that would cost consumers $35.9 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, while the expected unavailability per transformer per annum is 0.217%. When the energy at risk (441 MWh for 2023) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 1.9 MWh. This expected unserved energy is estimated to

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

have a value to consumers of around $155,419 (based on a value of customer reliability of $81,393 per MWh).

Key statistics relating to energy at risk and expected unserved energy for the year 2023 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	441	$35.9 million
Expected unserved energy at 50th percentile demand	1.9	$155,419
Energy at risk, at 10th percentile demand forecast	779	$63 million
Expected unserved energy at 10th percentile demand	3.4	$274,942

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

- Replacing the #2 125 MVA 220/66 kV transformer at TGTS with a 150 MVA unit. For an indicative installation cost of $14 million this option will most likely prove to be uneconomic as it only provides a marginal increase in station capacity, hence necessitating additional capacity augmentation shortly afterwards.

- Installation of a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of $14 million.

- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.

- Embedded generation. Connection of wind farm generation into the 66 kV infrastructure ex-TGTS has been implemented. Codrington wind farm (18.2 MW) was commissioned in 2001 and this combined with Yambuk wind farm (30 MW) in 2005, Oakland's Hill wind farm (67.2 MW) in 2011 and Morton's Lane wind farm (19.5 MW) in 2012, provides a total wind generation capacity of 135 MW. Additional wind generation is being investigated in the area supplied by TGTS and this may defer any capacity augmentation planned for TGTS. Historically however, it has been observed that at times of peak demand, the level of wind generation has been relatively small.

Preferred option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TGTS, it is proposed to:

1. Install a third 220/66 kV transformer (150 MVA) at TGTS. On the basis of the medium economic growth scenario and 50th percentile weather probability, the transformer would not be expected to be required before 2023 to support the critical peak demand.

2. As a temporary measure, maintain contingency plans to transfer load quickly to the Geelong Terminal Station (GTS) by the use of the 66 kV tie lines between TGTS and GTS in the event of an unplanned outage of one transformer at TGTS under critical loading conditions. This load transfer is in the order of 15 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing their level of reliability;

3. Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for rural areas (refer Section 4.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The capital cost of installing a 150 MVA 220/66 kV transformer at TGTS is estimated to be $14 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $1.4 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

TGTS Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

	MW	MVA	
Normal cyclic rating with all plant in service		332	via 2 transformers (summer)
Summer N-1 Station Rating:	161	166	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	181	185	[See Note 7 below for revised rating]

Station: TGTS Sum 66kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	181.2	182.4	185.0	184.7	189.1	192.0	193.3	194.6	196.0	197.3
50th percentile Winter Maximum Demand (MVA)	183.6	184.7	187.2	187.7	191.1	193.9	195.1	196.3	197.5	198.7
10th percentile Summer Maximum Demand (MVA)	183.0	184.2	186.8	186.6	191.0	193.9	195.2	196.6	197.9	199.3
10th percentile Winter Maximum Demand (MVA)	192.8	193.9	196.5	197.1	200.7	203.6	204.9	206.1	207.4	208.7
N-1 energy at risk at 50% percentile demand (MWh)	51.1	61.9	91.5	88.6	163.8	238.8	280.0	326.7	380.2	440.7
N-1 hours at risk at 50th percentile demand (hours)	8.5	9.8	13.0	13.0	21.0	29.0	32.0	36.5	41.3	46.3
N-1 energy at risk at 10% percentile demand (MWh)	81.5	100.5	153.0	153.1	282.5	417.6	491.7	575.7	671.5	779.5
N-1 hours at risk at 10th percentile demand (hours)	13.5	15.5	21.3	21.5	35.8	48.5	55.3	63.5	71.3	81.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.22	0.27	0.40	0.38	0.71	1.03	1.21	1.42	1.65	1.9
Expected Unserved Energy at 10th percentile demand (MWh)	0.35	0.44	0.66	0.66	1.22	1.81	2.13	2.49	2.91	3.38
Expected Unserved Energy value at 50th percentile demand	$0.02M	$0.02M	$0.03M	$0.03M	$0.06M	$0.08M	$0.10M	$0.12M	$0.13M	$0.16M
Expected Unserved Energy value at 10th percentile demand	$0.03M	$0.04M	$0.05M	$0.05M	$0.10M	$0.15M	$0.17M	$0.20M	$0.24M	$0.27M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.02M	$0.03M	$0.04M	$0.04M	$0.07M	$0.10M	$0.12M	$0.14M	$0.16M	$0.19M

Notes:
1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.
7. The 1A & 1B 125 MVA single phase transformer bank was replaced by a 150 MVA three phase transformer unit in 2007 as part of SPI PowerNet's asset replacement program. This has marginally increased the summer and winter N-1 station ratings as shown above.

THOMASTOWN TERMINAL STATION 66 kV (TTS 66 kV)

Thomastown Terminal Station (TTS) is located in the north of greater Melbourne. It operates at 220/66 kV and supplies Jemena Electricity Networks and SPI Electricity customers in the Thomastown, Coburg, Preston, Watsonia, North Heidelberg, Lalor, Coolaroo and Broadmeadows areas.

Background

TTS has five 150 MVA transformers and is a summer critical station. Under system normal conditions, the No.1 & No.2 transformers are operated in parallel as one group (TTS(B12)) and supply the No.1 & No.2 66 kV buses. The No.3, No.4 & No.5 transformers are operated in parallel as a separate group (TTS(B34)) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 2-3 and bus 1-4 tie circuit breakers are operated open to limit the maximum prospective fault levels on the four 66 kV busses to within switchgear ratings.

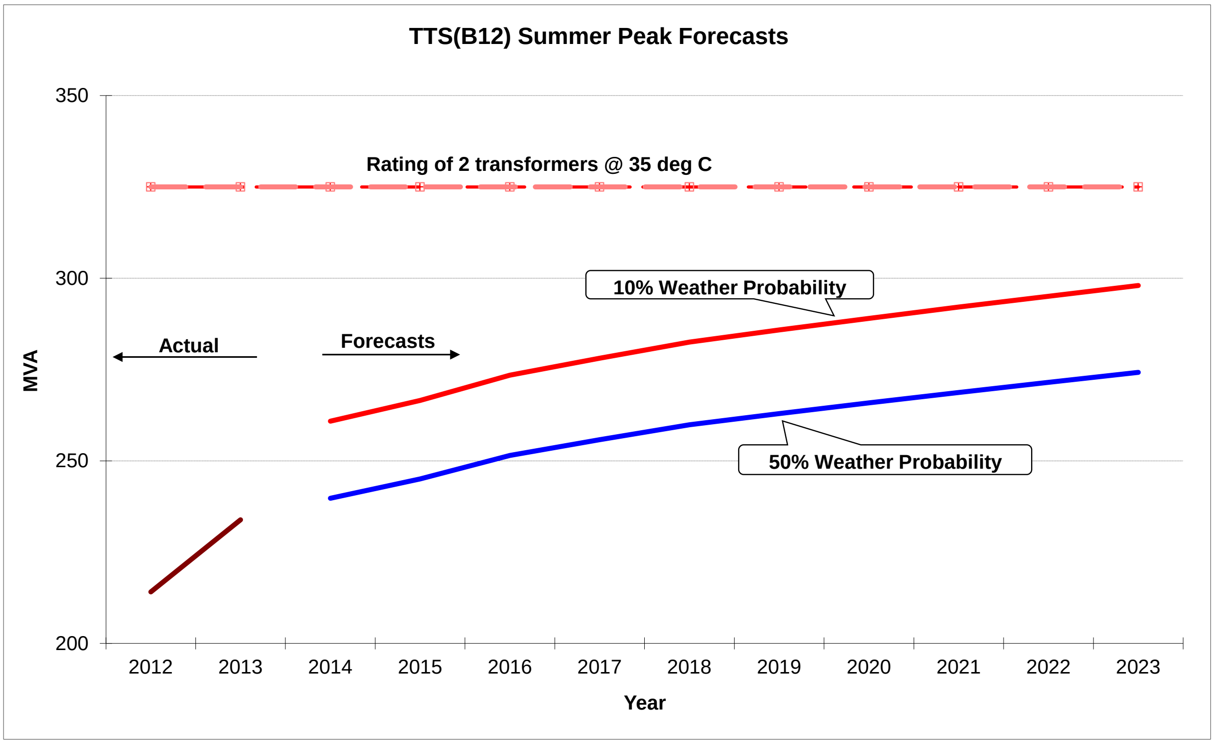
For an unplanned transformer outage in the TTS(B12) group, the No.5 transformer will automatically change over to the TTS(B12) group. Therefore, an unplanned transformer outage of any one of the five transformers at TTS will result in both the TTS(B12) & TTS(B34) groups being comprised of two transformers each. Given this configuration, load demand on the TTS(B12) group must be kept within the capabilities of the two transformers at all times or load shedding may occur.

Transformer group TTS (B12) Summer Peak Forecasts

The graph below depicts the summer maximum demand forecasts (for 50th and 10th percentile temperatures) for TTS (B12) and the corresponding rating with both transformers (B1 & B2) operating. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at the time of peak demand is 0.97.

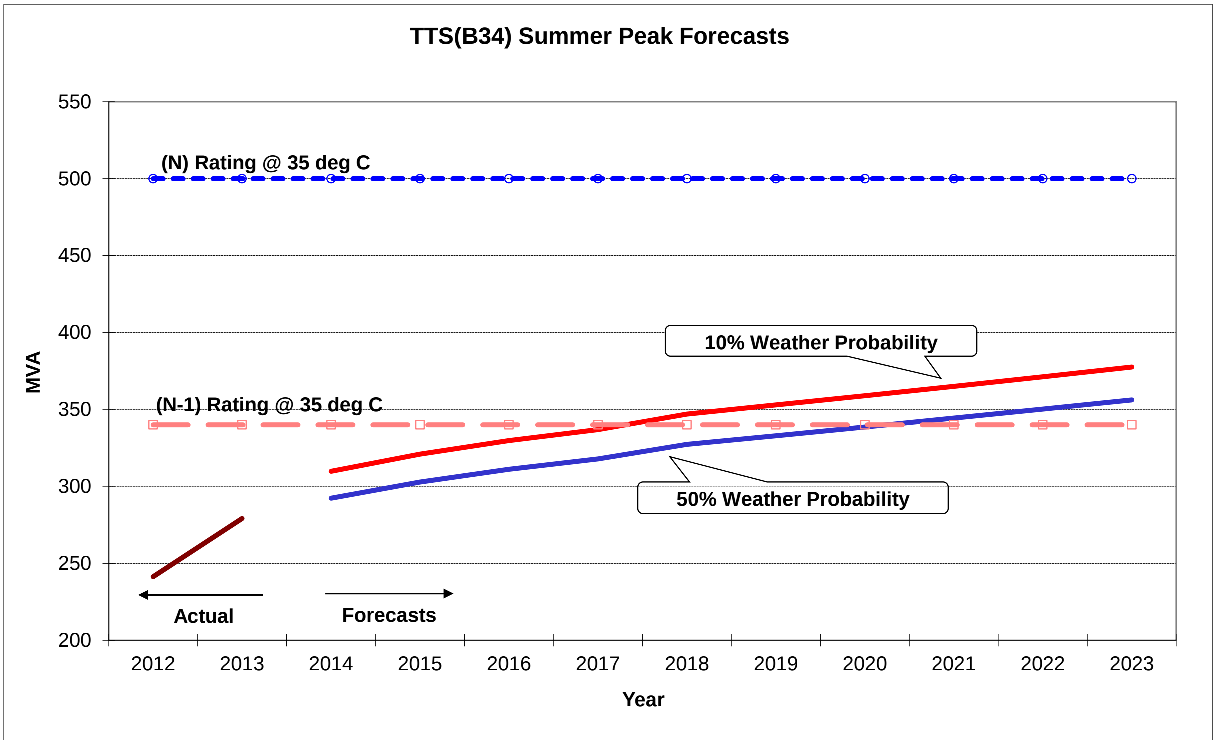
The graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. As explained above, if an unplanned transformer outage in the TTS(B12) group occurs, the No.5 transformer will automatically change over to the TTS(B12) group. In effect then, the N-1 and N ratings of the TTS(B12) group are equivalent. Thus there is sufficient capacity provided by the TTS(B12) group to meet the anticipated maximum demand for the entire forecast period, even under a transformer outage condition.



Transformer group TTS (B34) Summer Peak Forecasts

The graph below depicts the TTS (B34) rating with all transformers (B3, B4 & B5) in service ("N" rating), and with one of the three transformers out of service ("N-1" rating), along with the 50th and 10th percentile summer maximum demand forecasts. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at the time of peak demand is 0.91.



The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. However, if there is a forced transformer outage during peak load periods from 2018 onwards, some customers might be affected.

Magnitude, probability and impact of loss of load at TTS

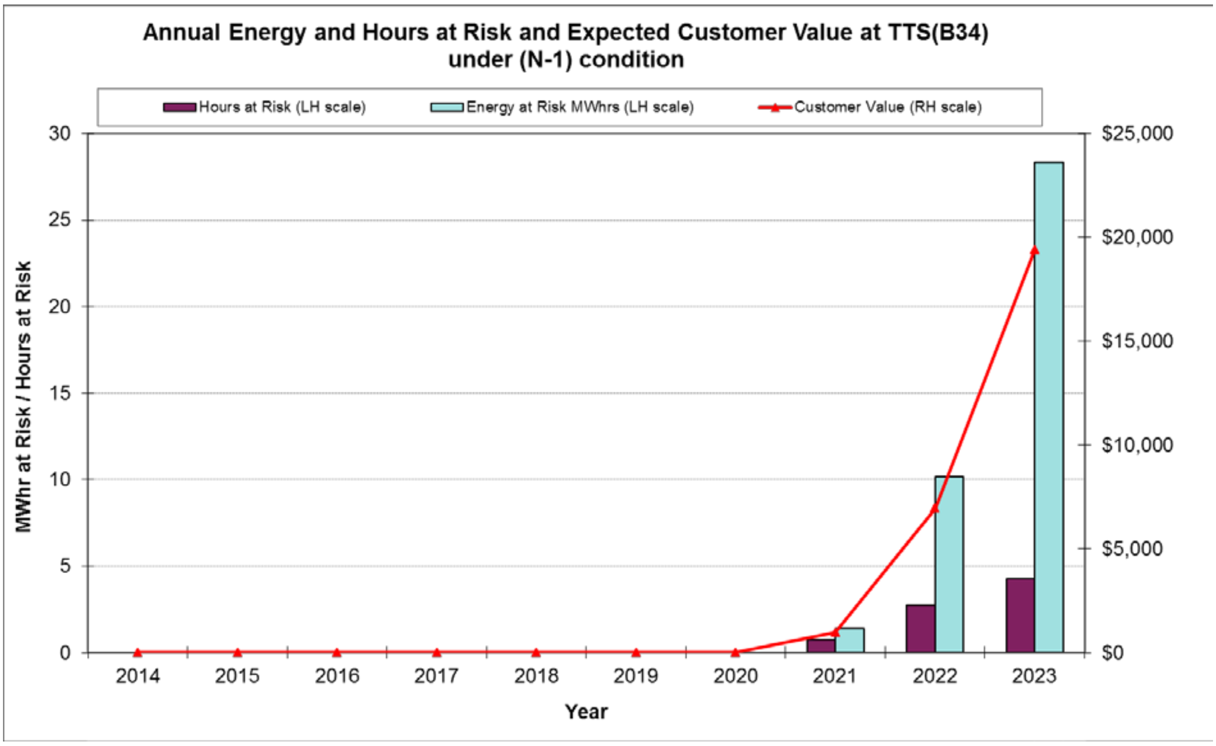
The magnitude, probability and load at risk for the two transformer groups are considered together below.

System Normal Condition (All 5 transformers in service)

There is no energy at risk under system normal condition at TTS.

N-1 System Condition

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating for the TTS (B34) group. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk at TTS

There will be sufficient capacity at the station to supply all customer demand for the entire forecast period under system normal condition for the 50th percentile demand forecast. However from 2021 onwards, for a transformer (N-1 condition) on the TTS (B34) group over the summer peak load period, there would be insufficient capacity at the station to supply all customer demand.

For summer 2022/23, the energy that would not be supplied for a transformer outage (N-1 condition) on the TTS(B34) group is estimated to be 28 MWh for the 50th percentile demand forecast. In the event of a major transformer outage over the summer 2022/23 period, there would be insufficient capacity to meet demand for about 4 hours in that year. The estimated value to consumers of the 28 MWh of energy that would not be supplied is approximately $1.8 million (based on a value of customer reliability of $63,090/MWh)[1]. In other words, at the 50th percentile summer demand level, and in the absence of any other operational response that might be taken to mitigate the impacts on customers, a major outage of one transformer at TTS over the summer of 2022/23 would be anticipated to lead to involuntary supply interruptions that would cost consumers $1.8 million.

It is emphasised however, that the probability of a major outage of one of the five transformers is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (28 MWh) is weighted by this low transformer unavailability, the expected unserved energy is estimated to be around 0.3 MWh. This expected unserved energy is estimated to have a value to consumers of around $19,000.

It should also be noted that the above estimates are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the customer demand increases significantly due to air conditioning loads. At the 10th percentile demand forecast, the energy not supplied in the summer of 2022/23 is estimated to be 368 MWh. The estimated value to consumers of this energy in the summer of 2022/23 is approximately $23.2 million. The corresponding value of the expected unserved energy is approximately $252,000.

These key statistics for the summer of 2022/23 under (N-1) outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	28	$1.8 million
Expected unserved energy at 50th percentile demand	0.3	$19,000
Energy at risk, at 10th percentile demand forecast	368	$23.2 million
Expected unserved energy at 10th percentile demand	4.0	$252,000

[1] The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

Possible Impact on Customers

System Normal Condition (All 5 transformers in service)

There is no load at risk under system normal condition for the entire forecast period for a 50th percentile demand forecast.

N-1 System Condition

There is no load at risk under an outage of one transformer at TTS until around 2021 for the 50th percentile demand forecast.

If one of the TTS 220/66 kV transformers is taken off line during peak loading times, causing the TTS (B34) rating to be exceeded, the OSSCA[2] load shedding scheme which is operated by SPI PowerNet's TOC[3] will act swiftly to reduce the loads in blocks to within transformer capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with Jemena Electricity Network's and SPI Electricity's operational procedures.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint towards the end of the ten year planning horizon:

1. Balance the load between the two bus groups at TTS so that the load in each bus group is kept below its respective N rating and implement a contingency plan to transfer load to adjacent terminal stations. Jemena Electricity Networks and SPI Electricity have established and implemented the necessary plans that enable load transfers under contingency conditions.

2. Establish a new 500/220/66 kV terminal station. Two terminal station sites, one in Donnybrook and another in Somerton, have been reserved for possible future electrical infrastructure development to meet customers' needs in the area.

3. Embedded generation. An alternative option to the network solution could be the establishment of an embedded generator, suitably located in the area that is presently supplied by TTS.

4. Demand Management. Another alternative option could be the introduction of demand management to reduce the magnitude of the summer peak demands under network emergencies. This might involve the introduction of interruptible load, negotiated with customers at reduced prices, with an agreement that the load can be interrupted during times of network constraint.

[2] Overload Shedding Scheme of Connection Asset. OSSCA is designed to protect against transformer damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

[3] Transmission Operations Centre.

Preferred network option(s) for alleviation of constraints

1. For summer 2020/21 and beyond, the exposure to energy at risk will be managed through the following measures within the TTS(B12) and TTS(B34) groups:

    - balance the load between the two bus groups at TTS so that the load on each bus group is kept below its respective N rating, however this will be reviewed on an annual basis;

    - maintain contingency plans to transfer load quickly to adjacent terminal stations;

    - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any automatic load shedding that may take place; and

    - Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for urban areas (refer to section 4.5), this spare transformer can be used to temporarily replace the failed transformer.

2. In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TTS, it is proposed to install a new 500/220/66 kV terminal station at either Donnybrook or Somerton. However, based on the present forecasts a new 500/220/66 kV terminal station is not likely to be economically justified within the ten year planning horizon. The capital cost of establishing a new 500/220/66 kV terminal station and associated 66 kV lines re-arrangement is estimated to be around $65 million.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

THOMASTOWN TERMINAL STATION (B12 TRANSFORMER GROUP)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: JEN (43%), SPI Electricity (57%)
Normal cyclic rating with all plant in service: 325 MVA (Summer peaking)
Summer N-1 Station Rating: 325 MVA [See note 1 below for interpretation on N-1]
Winter N-1 Station Rating: 356 MVA

Station: TTS (B12)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	240	245	251	256	260	263	266	269	272	274
50th percentile Winter Maximum Demand (MVA)	184	189	194	197	200	202	204	206	208	210
10th percentile Summer Maximum Demand (MVA)	261	267	273	278	283	286	289	292	295	298
10th percentile Winter Maximum Demand (MVA)	192	197	202	206	209	211	213	215	217	219
N -1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N -1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N -1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N -1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M
Expected Unserved Energy value at 10th percentile demand	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

THOMASTOWN TERMINAL STATION (B34 TRANSFORMER GROUP)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	JEN (100%), SPI Electricity (0%)	
Normal cyclic rating with all plant in service:	500 MVA	(Summer peaking)
Summer N-1 Station Rating:	340 MVA	[See note 1 below for interpretation on N-1]
Winter N-1 Station Rating:	397 MVA	

Station: TTS (B34)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	292	303	311	318	327	333	339	344	350	356
50th percentile Winter Maximum Demand (MVA)	239	247	254	259	267	271	275	278	282	286
10th percentile Summer Maximum Demand (MVA)	310	321	330	337	347	353	359	365	371	378
10th percentile Winter Maximum Demand (MVA)	247	256	263	268	276	280	284	288	292	296
N -1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	1	10	28
N -1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	1	3	4
N -1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	3	27	88	168	260	368
N -1 hours at risk at 10th percentile demand (hours)	0	0	0	0	5	11	15	17	20	24
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.3	1.0	1.8	2.8	4.0
Expected Unserved Energy value at 50th percentile demand	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ - M	$ 0.00 M	$ 0.01 M	$ 0.02 M
Expected Unserved Energy value at 10th percentile demand	$ - M	$ - M	$ - M	$ - M	$ 0.00 M	$ 0.02 M	$ 0.06 M	$ 0.11 M	$ 0.18 M	$ 0.25 M
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$ - M	$ - M	$ - M	$ - M	$ 0.00 M	$ 0.01 M	$ 0.02 M	$ 0.04 M	$ 0.06 M	$ 0.09 M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

TYABB TERMINAL STATION (TBTS)

TBTS consists of three 150 MVA 220/66 kV transformers, and is the main source of supply for over 115,000 customers on the Mornington Peninsula. The geographic coverage of the area spans from Frankston South in the north to Portsea in the south.

TBTS 66 kV is a summer critical station. Summer peak demand at TBTS generally occurs on days of high ambient temperature during the summer holiday period (from 25 December to the end of January). Given the peak demand at TBTS is directly related to air-conditioning use during the holiday periods along the costal belt of the Mornington Peninsula during summer, the peak is very sensitive to the maximum ambient temperature at this time. The station reached its highest recorded peak demand of 283.4 MW (298.0 MVA) on Thursday 29 January 2009 when the ambient temperature in Mornington reached 42ºC. The peak demand in summer 2012-13 was 269.3 MW (286.0 MVA). There are no embedded generation schemes over 1 MW connected at TBTS.

TBTS has exceeded its N-1 thermal rating since summer 2004 as the result of load transfers from East Rowville (ERTS) and Heatherton (HTS) terminal stations. Over the period since 2004, had a transformer outage occurred at TBTS, the capacity of the remaining transformer would have been insufficient to supply the total connected demand at TBTS. The amount of energy at risk has gradually increased over time with demand growth in the area. As a result, a Regulatory Test has since been undertaken, with a project initiated in 2011 to install a 150 MVA 220/66 kV third transformer. This transformer is expected to be commissioned by the 2013/14 summer.

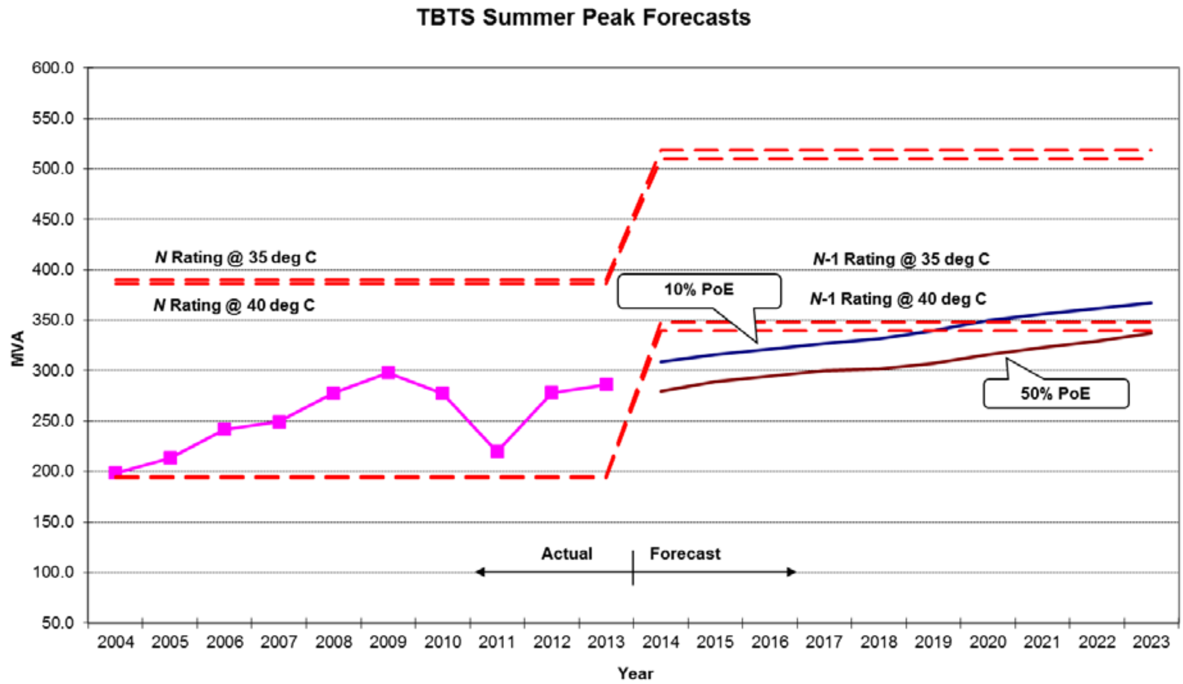
Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational N rating (all transformers in service) and the N-1 rating at 35°C as well as 40°C ambient temperature.

The N rating on the chart indicates the maximum load that can be supplied from TBTS with all transformers in service. Exceeding this level will initiate SPI PowerNet's automatic load shedding scheme.

The graph indicates that the demand at TBTS remains below its N rating within the 10 year planning period. However, the 10th percentile summer maximum demand is forecast to exceed the station's (N-1) rating from summer 2019-20. The 50th percentile summer maximum demand is expected to remain within the (N-1) rating for the entire planning period.

The station load is forecast to have a power factor of 0.967 at times of peak demand. The demand at TBTS is expected to exceed 95% of the 50th percentile peak demand for approximately 5 hours per annum.



Given the 50th percentile demand forecast is expected to remain below the N-1 rating of the station, no energy will be at risk for a single transformer outage based on the current 50th percentile demand forecast for the foreseeable future. The expected energy at risk under the 10th percentile demand forecast is not significant over the planning period. However, the load at risk after summer 2019-20 can be managed operationally by transferring load under contingency via the distribution network. Transfer capability away from TBTS onto adjacent terminal stations is assessed at 28 MVA which is expected to further reduce the expected energy at risk.

Therefore, no major demand related augmentation is planned at TBTS over the next ten years.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.

TYABB TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)
Station operational rating (N elements in service): 519 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Rating: 348 MVA via 2 transformers [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 397MVA via 2 transformers

Station: TBTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	279	289	294	300	302	307	315	323	330	337
50th percentile Winter Maximum Demand (MVA)	204	206	211	215	220	224	228	232	236	239
10th percentile Summer Maximum Demand (MVA)	308	316	322	327	332	339	350	356	362	367
10th percentile Winter Maximum Demand (MVA)	207	210	214	219	224	228	232	236	240	243
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N-1 energy at risk at 10th percentile demand (MWh)	1	0	0	0	0	0	16	31	49	70
N-1 hours at risk at 10th percentile demand (hours)	1	0	0	0	0	0	2	3	4	4
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.5
Expected Unserved Energy value at 50th percentile demand	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k	$0k
Expected Unserved Energy value at 10th percentile demand	$0k	$0k	$0k	$0k	$0k	$0k	$6k	$12k	$20k	$28k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0k	$0k	$0k	$0k	$0k	$0k	$2k	$4k	$6k	$8k

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)

WEMEN TERMINAL STATION (WETS)

Wemen Terminal Station (WETS) is a new station which was commissioned in February 2012. WETS consists of one 70 MVA 235/66 kV transformer supplying part of the 66 kV network previously supplied by RCTS. This configuration is the main source of supply for approximately 6,086 customers in the Wemen and Ouyen areas. The station supply area includes Wemen, Boundary Bend and Ouyen.

Magnitude, probability and impact of loss of load

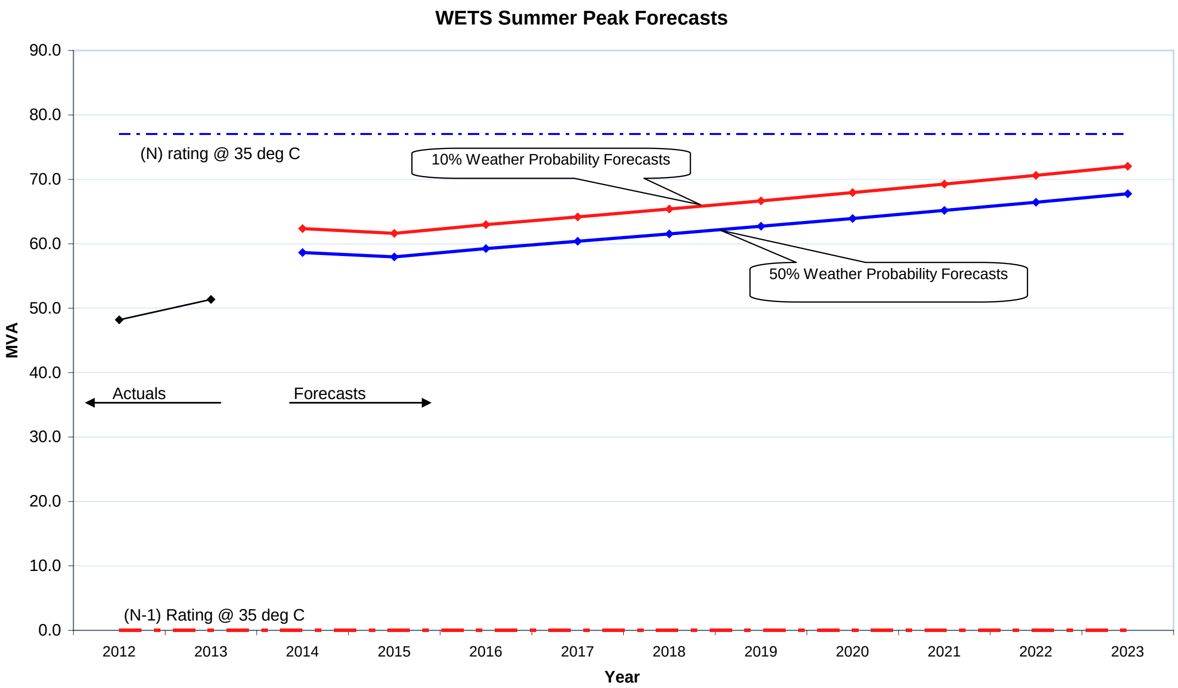
WETS demand is summer peaking. The peak load for the 66 kV network on the station reached 50.5 MW in summer 2013.

It is estimated that:

- For 10 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.

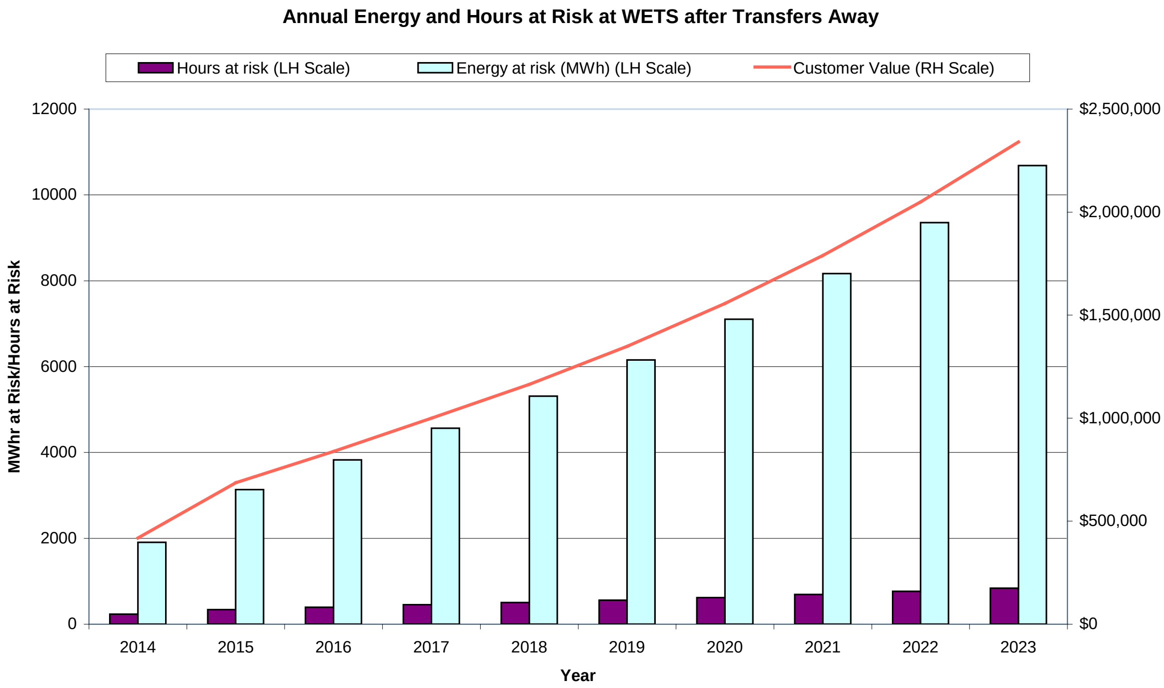
- The station load power factor at the time of peak demand is 0.98.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature. As WETS has only one transformer the "N-1" rating is zero.



The bar chart below depicts the energy at risk with the single transformer out of service, after implementation of the contingency plan to transfer 31 MVA of load away to RCTS, for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. As explained in section 4.6, the DBs have decided that for the purpose of the Transmission Connection Planning Report, short-term load transfer capability will not be taken into account directly in the estimation of expected unserved energy in the event of a major failure of a transformer. This approach has been adopted because it simplifies the presentation of information the risk assessment for each terminal station. The one exception to this approach is WETS, which is the only single transformer station considered in the Transmission Connection Planning Report. The risk assessment for WETS takes into account post-contingent load transfer capability, in order to provide a more accurate assessment of expected unserved energy in the event of a major outage of the single transformer at that station.

The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk

For a major outage of the single transformer at WETS a contingency plan will be implemented to transfer 31 MVA of load from WETS to RCTS. After taking this load transfer into account, there will be insufficient capacity at the station to supply all remaining demand at the 50th percentile temperature for about 504 hours in 2018. The energy at risk at the 50th percentile temperature under N-1 conditions, after load transfers, is estimated to be 5,313 MWh in 2018. The estimated value to consumers of the 5,313 MWh of energy at risk is approximately $537 million (based on a value of customer reliability of $101,101/MWh)[1]. In other words, at the 50th percentile demand level, after transferring load away but in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of the transformer at WETS in 2018 would be anticipated to lead to involuntary supply interruptions that would cost consumers $537 million.

It is emphasised however, that the probability of a major outage of the transformer occurring over the year is very low at 1% per annum, whilst the expected annual unavailability of the

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

transformer is 0.217%. When the energy at risk (5,313 MWh for 2018) is weighted by this low unavailability, the expected unsupplied energy is estimated to be 11.5 MWh. This expected unserved energy is estimated to have a value to consumers of around $1.16 million (based on a value of customer reliability of $101,100/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year[2]. Under 10th percentile summer temperature conditions, the energy at risk in 2018 is estimated to be 8,264 MWh. The estimated value to consumers of this energy at risk in 2018 is approximately $835 million. The corresponding value of the expected unserved energy is $1.81 million.

These key statistics for the year 2018 under N-1 outage conditions after 31 MVA of load transfers away are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast	5,313	$537 million
Expected unserved energy at 50th percentile demand	11.5	$1.16 million
Energy at risk, at 10th percentile demand forecast	8,264	$835 million
Expected unserved energy at 10th percentile demand	17.9	$1.81 million

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

- Installation of an additional 70 MVA 235/66 kV transformer at WETS.
- Demand reduction: There is an opportunity for voluntary demand reduction to reduce loading at the station during times of network constraint.
- Embedded generation, connected to the WETS 66 kV bus, may defer the need for capacity augmentation at WETS.

Preferred option(s) for alleviation of constraints

As already noted, a contingency plan to transfer 31 MVA of load to RCTS using the 66 kV network between WETS and RCTS will be implemented in the event of the loss of WETS which is a single transformer station.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at WETS, it is proposed to install an additional 70 MVA 235/66 kV transformer at WETS. On the basis of the 10th percentile demand forecast scenario, after transfers back to RCTS are taken into account, it is expected that the additional capacity will not be justified before 2018.

[2] As noted in Section 4.1, the 50th percentile demand forecast is used in each year.

The capital cost of installing an additional transformer at WETS is estimated to be $12 million. The cost of establishing, operating and maintaining an additional transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $1.2 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation. Sections 1.5 and 1.6 of this report provide further background information to proponents of non-network solutions to emerging constraints.

Subject to the availability of the SPI PowerNet spare 220/66 kV transformer for rural areas (refer to Section 4.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy. The energy at risk, hours at risk and expected unserved energy are after implementation of the contingency plan to transfer load to RCTS.

Wemen Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

Normal cyclic rating with all plant in service 77 MVA via 1 transformer
Summer N-1 Station Rating: 0 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 0 MVA

Station: WETS 66kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	58.7	58.0	59.2	60.4	61.5	62.7	63.9	65.2	66.4	67.7
50th percentile Winter Maximum Demand (MVA)	27.6	25.7	26.1	26.5	27.0	27.4	27.8	28.3	28.8	29.2
10th percentile Summer Maximum Demand (MVA)	62.3	61.6	63.0	64.2	65.4	66.7	68.0	69.3	70.6	72.0
10th percentile Winter Maximum Demand (MVA)	28.1	26.2	26.6	27.1	27.5	27.9	28.4	28.8	29.3	29.8
N-1 energy at risk at 50% percentile demand (MWh)	1908.0	3133.5	3828.1	4566.3	5312.9	6155.5	7106.1	8168.0	9356.3	10683.9
N-1 hours at risk at 50th percentile demand (hours)	234.3	337.8	396.0	453.5	504.3	557.3	619.0	692.8	763.5	840.3
N-1 energy at risk at 10% percentile demand (MWh)	3306.7	5147.9	6146.4	7203.3	8263.6	9448.4	10770.5	12246.8	13888.0	15711.8
N-1 hours at risk at 10th percentile demand (hours)	347.8	489.0	551.8	618.5	691.0	760.8	836.3	920.5	1015.5	1110.5
Expected Unserved Energy at 50th percentile demand (MWh)	4.13	6.79	8.29	9.89	11.51	13.34	15.40	17.70	20.27	23.15
Expected Unserved Energy at 10th percentile demand (MWh)	7.16	11.15	13.32	15.61	17.90	20.47	23.34	26.53	30.09	34.04
Expected Unserved Energy value at 50th percentile demand	$0.42M	$0.69M	$0.84M	$1.00M	$1.16M	$1.35M	$1.56M	$1.79M	$2.05M	$2.34M
Expected Unserved Energy value at 10th percentile demand	$0.72M	$1.13M	$1.35M	$1.58M	$1.81M	$2.07M	$2.36M	$2.68M	$3.04M	$3.44M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.51M	$0.82M	$0.99M	$1.17M	$1.36M	$1.56M	$1.80M	$2.06M	$2.35M	$2.67M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating after load transfers away.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating after load transfers away. As the WETS "N-1" rating is zero the load always exceeds the N-1 capacity before load transfers away.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx).

WEST MELBOURNE TERMINAL STATION 22 kV (WMTS 22 kV)

WMTS 22 kV is a summer critical station consisting of two 165 MVA 220/22 kV transformers, which supply CitiPower's distribution network. The terminal station provides major 22 kV supply to the West Melbourne area including Melbourne Docks, Docklands Areas, North Melbourne (including a railway substation), Parkville and Carlton, and the northern and western inner Central Business District and surrounding areas.

A new 66/11 kV zone substation (BQ) was established in 2011. BQ zone substation is supplied via WMTS 66 kV and partly offloaded WMTS 22 kV over 2012 – 2013. It is planned to supply BQ from Brunswick Terminal Station (BTS 66 kV) when that station is established.

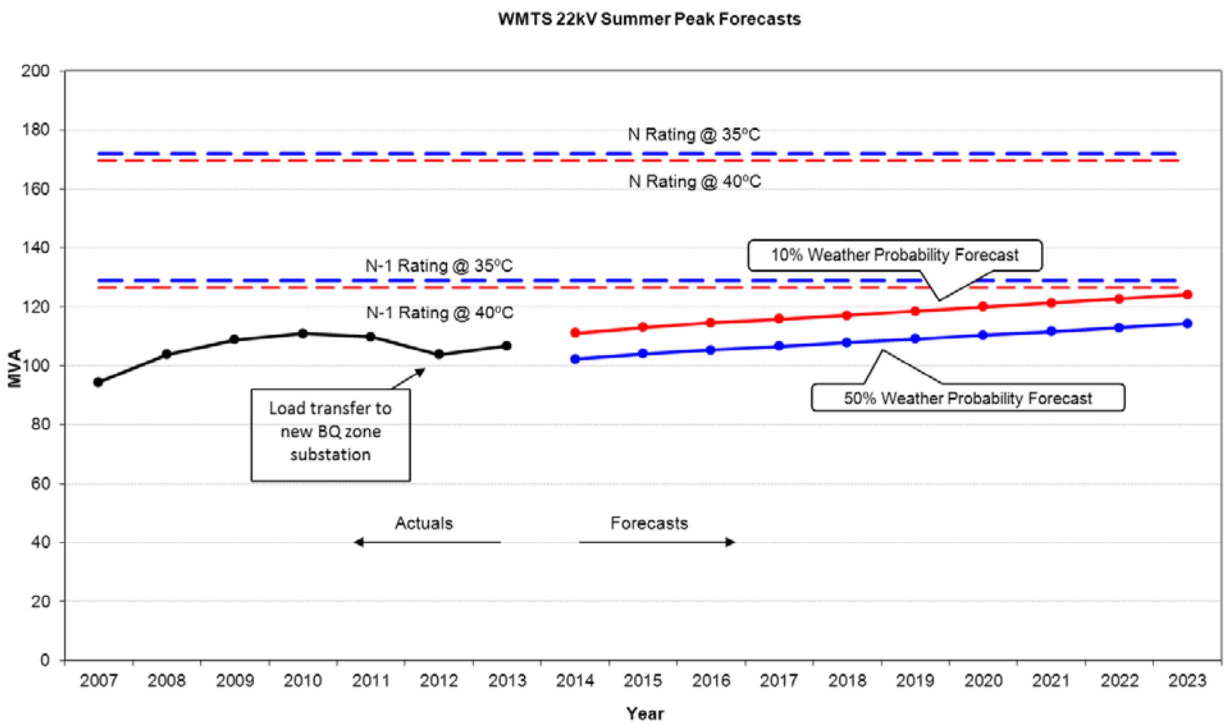
Further offloads from WMTS 22 are planned to occur to both BTS 66 (when established) and WMTS 66 within the next 5 to 10 years. These offloads are not committed and therefore are not shown in the WMTS 22 load forecast below.

The peak load on the station reached 97.6 MW in summer 2013. It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.91.

Magnitude, probability and impact of loss of load

The graph below depicts the station's operational N rating for all transformers in service and the N-1 rating (at 35 and 40 degrees ambient temperature), and the latest 10th and 50th percentile maximum demand forecasts for the next ten years. The N-1 ratings are restricted by over-voltage limits on transformer tapping.



The graph shows that there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

WEST MELBOURNE TERMINAL STATION 66 kV (WMTS 66 kV)

WMTS 66 kV is a summer critical station consisting of four 150 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (87.2%) and Jemena Electricity Networks (12.8%). The terminal station provides major supply to the western Central Business District, including Docklands areas, as well as the inner suburbs of Northcote and Brunswick West in the north, and Kensington, Flemington, Footscray and Yarraville in the west.

Following the commissioning of the fourth transformer in 2002, WMTS 66 kV is now operating with one of the four transformers on “Normal Open Auto-close” duty (i.e. on hot stand-by with a facility for automatic closing upon forced outage of any one of the three normal-running transformers). This arrangement facilitates control of the 66 kV fault level to within the terminal station fault rating. With this transformer operating arrangement, the N rating will be approximately equal to the N-1 rating (i.e. equal to the capacity of three transformers), thus imposing a restriction that the terminal station should not be loaded beyond the N-1 rating at any time.

Following the extremely hot summer in 2009, SPI PowerNet expressed concern regarding the operating temperature of the WMTS 220/66 kV transformers. In order to avoid operating the WMTS transformers at temperatures that would result in accelerated aging, SPI PowerNet has reduced the WMTS Terminal Station summer cyclic ratings by about 5.5% to 497 MVA at 35ºC ambient and about 10% to 463 MVA at 43ºC ambient. This has resulted in an appreciable increase in the load at risk at WMTS 66 kV.

As part of its asset renewal program, SPI PowerNet plans to replace three of the existing 150 MVA 220/66 kV transformer units (B1, B2 and B3) in 2016.

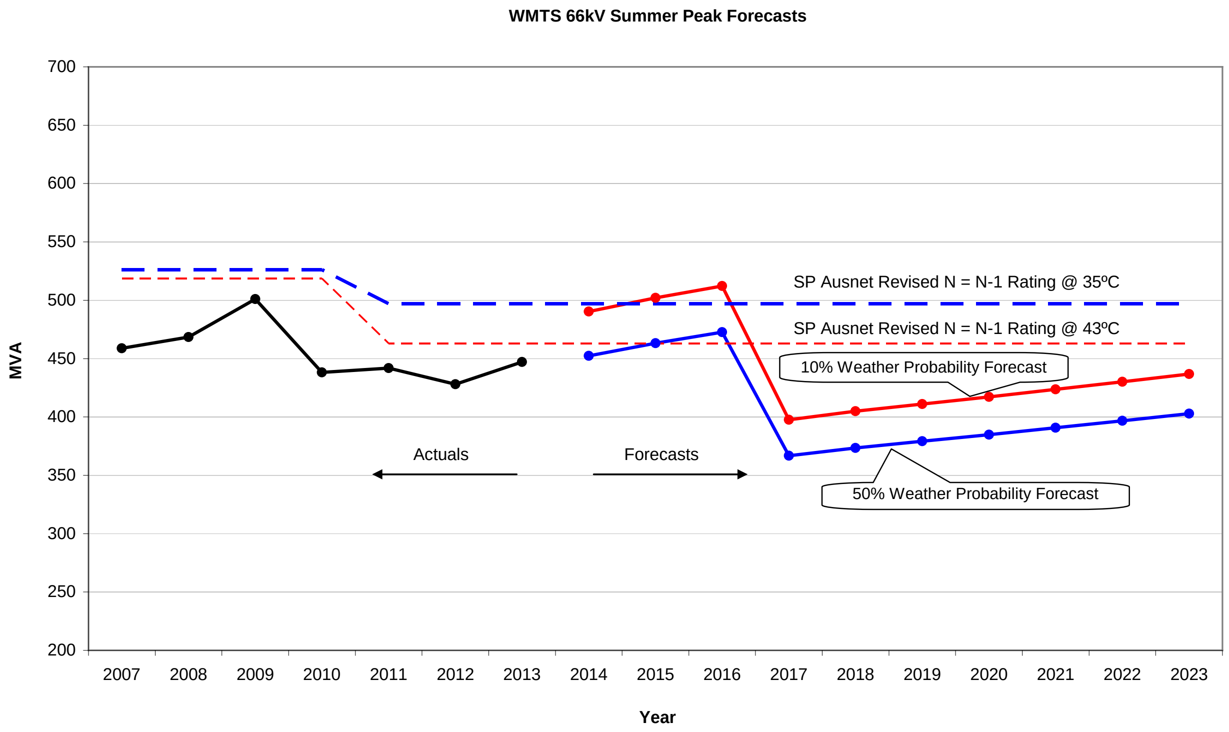
The peak load on the station reached 437.3 MW in summer (March) 2013.

It is estimated that:

- For 13 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.98.

Magnitude, probability and impact of loss of load

The graph below depicts the station’s N-1 rating (approximately equal to the N rating) at 35ºC and 43ºC, and the latest 10th and 50th percentile maximum demand forecasts during the summer periods over the next ten years. The forecast demands include the effects of future load transfer works which are planned to be undertaken after the establishment of BTS 66 kV in 2015/16. BTS 66 kV is now a committed project.



The graph shows that there would be insufficient capacity at WMTS 66 kV to supply the forecast 10% percentile demand by around 2014. Action may be required from 2013/14 to minimise the load at risk under N and N-1 conditions, until BTS 66 kV is established in 2015/16.

Comments on Energy at Risk

With the existing transformer operating arrangement at WMTS 66 kV, it is expected that there will be sufficient capacity to supply all demand at the 50th percentile temperature under both N and N-1 conditions. Under the present arrangements (with one of the four transformers operating with on "Normal Open Auto-close" duty), any expected unserved energy would be equal to the energy at risk, if loading exceeded the capacity of three transformers.

It should also be noted that the above is based on an assumption of average summer temperatures occurring in each year. Under 10th percentile level summer temperature conditions, the energy at risk in 2015 is estimated to be 255 MWh. The estimated value to consumers of this energy at risk in 2015 is approximately $25.4million.

These key statistics for the year 2015 under both N and N-1 conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	0	$0
Expected unserved energy at 50th percentile demand	0	$0
Energy at risk, at 10th percentile demand forecast	255	$25.4 million
Expected unserved energy at 10th percentile demand	255	$25.4 million

If the total station load exceeds the N and N-1 station ratings, the OSSCA[1] load shedding scheme which is operated by SPI PowerNet's NOC[2] will act swiftly to reduce the load in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to reduce load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower's and Jemena Electricity Network's operational procedures.

Prior to the establishment of the BTS 66 kV supply point in 2015/16, operational contingency plans are proposed to be implemented to reduce the energy at risk. These may include:

1. Temporary load transfer from WMTS to RTS (Richmond Terminal Station) via the 66 kV switching station in the Melbourne Central Business District. The magnitude of load that can be transferred to RTS 66 kV is a maximum of 80 MVA depending on the available spare capacity of the 66 kV subtransmission interconnecting network at the time of the emergency at WMTS 66 kV. No incremental cost would be required to achieve this load transfer capability. It is noted that utilising this switching to achieve the load transfers may require parts of the network to be de-energised, causing a momentary supply interruption to customers.

2. Utilise the capacity of the "Normal Open" 220/66 kV transformer to temporarily avoid exposure to load shedding by OSSCA under the 10th percentile summer ambient temperature conditions with no transformer outage. This can be done by dividing the load at one zone substation (about 130 MVA of load) into two sections and supplying one section of load from a single transformer and a single radial subtransmission cable.

3. Utilise 11 kV distribution transfer to FBTS and RTS.

Subject to availability, installation of SP AusNet's spare 220/66 kV transformer for metropolitan areas, to temporarily replace a failed transformer at WMTS 66 kV, will minimise any transformer outage period.

In addition to the measures outlined above, CitiPower would welcome proposals from proponents of non-network solutions to provide network support services to reduce the load at risk at WMTS 66 kV over the period to 2015 – 2016. Proponents should contact Neil Gascoigne, Network Planning Manager, CitiPower / Powercor, on 9683 4472 for further details.

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1 Overload Shedding Scheme of Connection Asset.

2 Network Operation Centre.

WEST MELBOURNE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: CitiPower (87%), Jemena Electricity Networks (13%)

Station operational rating (N elements in service): 497 MVA at 50th percentile temperature and 463 MVA at 10th percentile temperature (summer peaking) [See Note 7]

Summer N-1 Station Rating: 497 MVA at 50th percentile temperature and 463 MVA at 10th percentile temperature (summer peaking) [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating: 512.9 MW (570.0 MVA)

Station: WMTS 66kV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
50th percentile Summer Maximum Demand (MVA)	452.3	463.2	472.6	366.8	373.5	379.2	384.8	390.8	396.8	402.9
50th percentile Winter Maximum Demand (MVA)	325.1	336.6	342.0	261.3	266.4	270.7	275.1	279.7	284.3	289.0
10th percentile Summer Maximum Demand (MVA)	490.3	502.1	512.3	397.6	404.9	411.0	417.1	423.6	430.1	436.7
10th percentile Winter Maximum Demand (MVA)	330.4	342.0	347.6	265.5	270.7	275.1	279.5	284.2	288.9	293.6
N - 1 energy at risk at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N - 1 energy at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N - 1 energy at risk at 10th percentile demand (MWh)	112.5	255.0	461.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N - 1 energy at risk at 10th percentile demand (hours)	7.5	15.0	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	112.5	255.0	461.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M
Expected Unserved Energy value at 10th percentile demand	$11.2M	$25.4M	$46.0M	$0.0M	$0.0M	$0.0M	$0.00M	$0.0M	$0.0M	$0.0M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$3.36M	$7.62M	$13.8M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10th and 50th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx)
7. The N and N-1 ratings are approximately equal due to the restriction of "Normal Open Auto-close" transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.

WODONGA TERMINAL STATION (WOTS 66 kV and 22 kV)

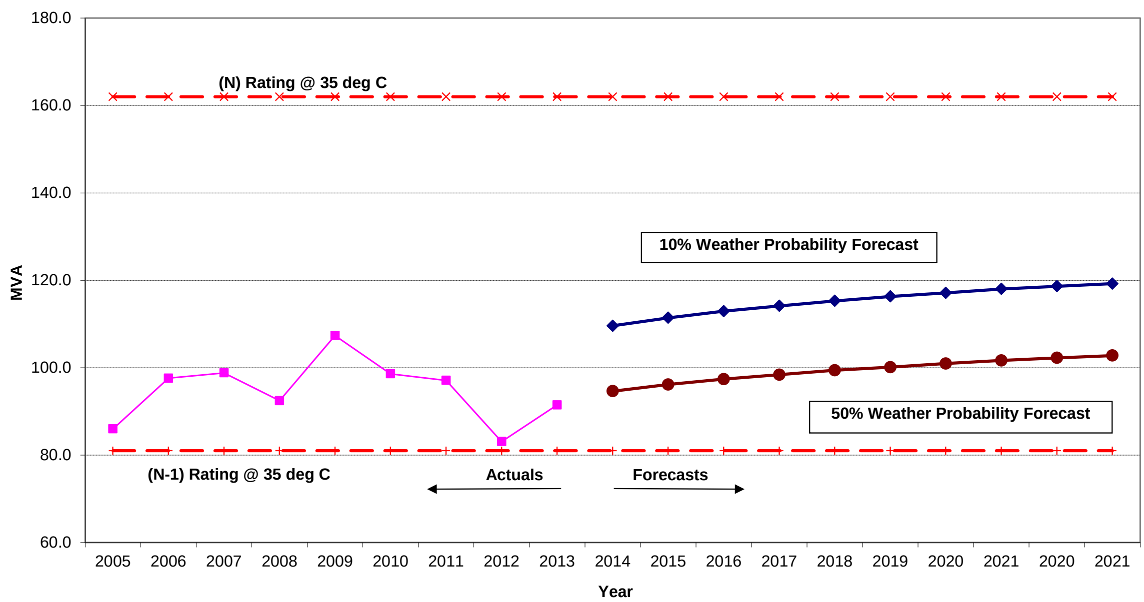
Wodonga terminal station is the main source of supply for a significant part of north-eastern Victoria. The supply is via two 330/66/22 kV three-winding transformers with a nominal rating of 75 MVA each. This terminal station supplies Wodonga centrally as well as the area from Rutherglen in the west to Corryong in the east. The Hume Power Station (HPS) is connected to the WOTS 66 kV bus and can supply up to 58 MVA into the WOTS 66 kV bus, offsetting the load on the transformers. SPI Electricity (SPIE) is responsible for planning the transmission connection and distribution network for this region.

Magnitude, probability and impact of loss of load

WOTS is a summer peaking station and growth in summer peak demand at WOTS 66 kV and 22 kV together has averaged around 0.5 MW (0.5%) per annum in recent years. The growth is forecast to continue at this level for the next few years. To accurately assess the transformer loading, the 66 kV and 22 kV loads need to be considered together because of the physical arrangement of the transformer windings. The recorded peak demand was 90.1 MW (91.5 MVA) in summer 2012/13. Demand is expected to exceed 95% of the 50th percentile peak load for 4 hours per annum. The station load has a power factor of 0.983 at maximum demand.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at an ambient temperature of 35°C. The combined 66 kV and 22 kV load at WOTS is not expected to reach the "N" summer station rating prior to 2022/23, but it presently exceeds the "N-1" rating at the 50th and 10th percentile summer demand level, and is forecast to continue to do so. Demand on the individual 66 kV and 22 kV windings is well within the ratings of the individual windings.

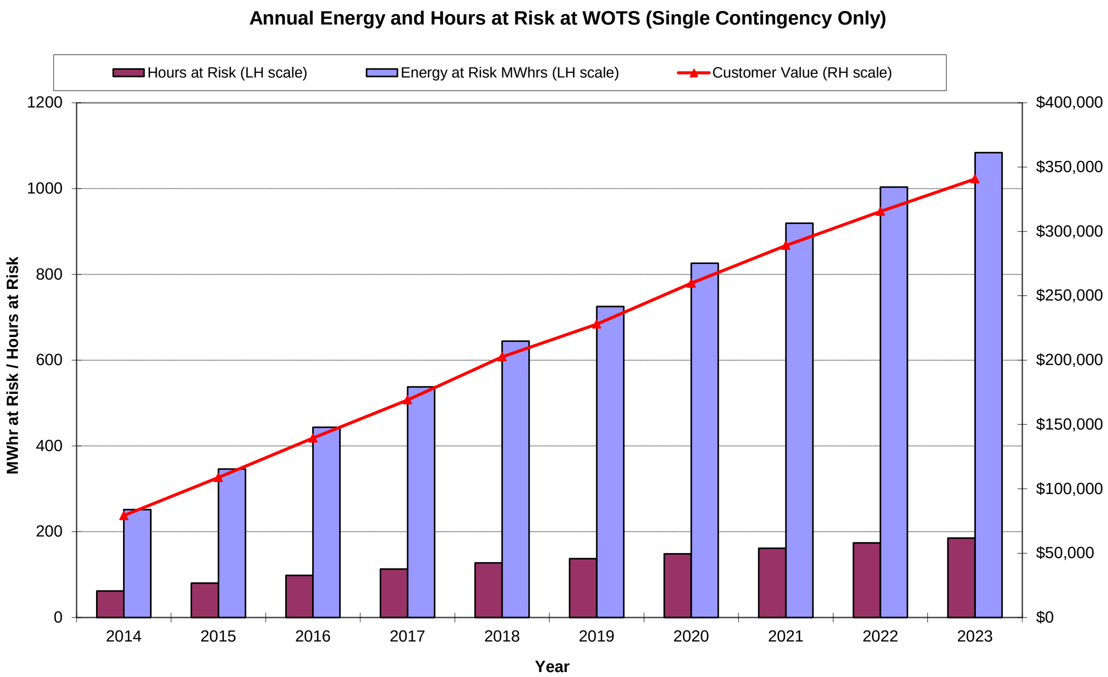
WOTS 66 kV and 22 kV combined Summer Peak Demand Forecasts



The combined 66 kV and 22 kV winter maximum demand at WOTS is less than the summer maximum demand and the winter rating is higher than the summer rating.

Forecast 50th percentile winter demand at WOTS 66 kV and 22 kV is not expected to exceed the "N -1" winter station in the next ten years but the 10th percentile load is expected to exceed "N – 1" rating by winter in 2019.

Nearly all of the energy at risk at WOTS occurs during the summer period so the comments below focus on the summer period. The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile summer demand forecast, and the hours each year that the 50th percentile summer demand forecast is expected to exceed the "N-1" capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



Comments on Energy at Risk - Assuming HPS generation is not available

As already noted, WOTS is a summer peaking station and most of the energy at risk occurs in the summer period so again the comments below focus on the energy at risk over the summer period. The analysis below is also based on the assumption that there is no generation available from the Hume Power Station to offset the 330/66/22 kV transformer loading.

For a major outage of any one of the two 330/66/22 kV transformers over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 185 hours in summer 2022/23. The energy at risk under "N-1" conditions is estimated to be 1,084 MWh in summer 2022/23. The estimated value to consumers of the 1,084 MWh of energy at risk is approximately $79 million (based on a value of customer reliability of $72,571/MWh).[1] In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a major outage of any one of the two 330/66/22 kV transformers at WOTS over the summer of 2022/23, it would be anticipated to lead to involuntary supply interruptions that would cost consumers $79 million.

[1] The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (1,084 MWh for summer 2022/23) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 4.7 MWh. This expected unserved energy is estimated to have a value to consumers of around $0.34 million (based on a value of customer reliability of $72,571/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under higher (10th percentile) summer temperature conditions, the energy at risk in 2022/23 is estimated to be 5,176 MWh. The estimated value to consumers of this energy at risk in 2022/23 is approximately $376 million. The corresponding value of the expected unserved energy is approximately $1.6 million.

These key statistics for the year 2022/23 under "N-1" outage conditions are summarised in the table below.

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	1,084	$79 million
Expected unserved energy at 50th percentile demand	4.7	$0.34 million
Energy at risk, at 10th percentile demand forecast	5,176	$376 million
Expected unserved energy at 10th percentile demand	22.5	$1.6 million

If one of the 330/66/22 kV transformers at WOTS is taken off line during peak loading times and the "N-1" station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is enabled by SPI PowerNet's TOC[2] to protect the connection assets from overloading[3], will act swiftly to reduce the loads in blocks to within safe loading limits. If OSSCA operation does occur, any load reductions that are in excess of the amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with SPI Electricity's operational procedures after the operation of the OSSCA scheme.

If OSSCA operates at WOTS, it would automatically shed about 60 MVA of load, affecting approximately 13,000 customers.

Comments on Energy at Risk - Assuming HPS generation is available

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 330/66/22 kV transformer loading.

2 Transmission Operation Centre.

3 OSSCA is designed to protect transformers against damage caused by overloads. Damaged transformers can take months to replace which can result in prolonged, long term risks to reliability of customer supply.

However, the generation from Hume Power Station (HPS) can be fed into the WOTS 66 kV bus. The power station is capable of generating up to 58 MVA. This output is expected to be restricted to 29 MVA for summer 2013/14 due to transformer replacement works currently underway at HPS. This generation can also be connected to the TransGrid 132 kV Network in New South Wales. The generation from HPS is dependent on water releases from Hume Dam for irrigation and the water level in the dam and can vary widely from year to year. There is presently no guarantee that generation from HPS will be available to offset transformer loading at WOTS. With HPS generating to its full capacity (taking into account its reduced output over the summer of 2013/14) there would be no energy at risk at WOTS over the ten year planning horizon for the 50^{th} or 10^{th} percentile summer maximum demand forecasts.

Feasible options for alleviation of constraints

The following are potentially feasible options for addressing constraints at this station:

1. Addition of Power Factor Correction Capacitors

The station is currently running with a power factor of around 0.98 at summer peak. At this power factor the use of additional capacitors to reduce the MVA loading would only provide marginal benefits.

2. Install a 3^{rd} 330/66/22 kV transformer at WOTS

Installation of a third transformer at WOTS is a relatively simple, technically feasible option for augmenting the station. The site can accommodate an additional 330/66/22 kV transformer.

3. Demand reduction

Sixty percent of the peak load is from Commercial and Industrial customers and SPIE will be looking into demand management through either special tariff incentives, or a demand management aggregator to asses these alternatives to network augmentation.

4. Embedded generation

As discussed above, subject to available water HPS can provide up to 58 MVA of network support to WOTS. SPI Electricity welcomes proposals from embedded generation proponents to establish a network support agreement to provide up to 30 MVA to the WOTS 66 kV bus to reduce energy at risk and defer the need for augmentation.

5. Load transfers

Only 1 MVA of load can be shifted away from WOTS using the existing distribution network so this option has limited ability to manage the risk at WOTS.

Preferred network option(s) for alleviation of constraints

1. SPI Electricity will seek expressions of interest by interested parties to offer network support services through local generation or through demand side management initiatives that would reduce future load at risk at WOTS 66 kV. Only in the absence of firm comittments would it be proposed to install a new third 330/66/22 kV transformer at WOTS 66 kV. On the basis of present forecasts, this is not expected to be required before 2023.

2. Before any network augmentation is planned, it is proposed to approach HPS and determine whether a network support agreement could be negotiated. Prior to any agreement with HPS being in place, the following temporary measures will be implemented to cater for an unplanned outage of any one of the 330/66/22 kV transformers at WOTS under critical loading conditions:

   - Fine-tune the OSSCA scheme settings to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading;

   - Monitor the load growth to ensure the load at risk is within the forecasts; and

   - Engage with commercial and industrial customers, demand management aggregators and embedded generator suppliers to ascertain the viability of these options in an efficient and timely manner.

The capital cost of installing a new 330/66/22 kV transformer at WOTS 66 kV is estimated to be $22 million. The cost of establishing, operating and maintaining the transformer would be recovered from network users through network charges, over the life of the asset. In today's terms, the estimated total annual cost of this network augmentation is approximately $2.2 million. This cost provides a broad upper bound indication of the maximum annual network support payment which may be available to embedded generators or customers to reduce forecast demand and defer or avoid this transmission connection augmentation which may otherwise be required beyond 2023. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for say 10 years. Sections 1.4 and 1.5 of this report provide further background information to proponents of non-network solutions to emerging network constraints.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy assuming embedded generation is not available.

WODONGA TERMINAL STATION 66kV and 22kV Loading (WOTS)
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:	SPI Electricity (100%)
Normal cyclic rating with all plant in service	162 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating (MVA):	81
Winter N-1 Station Rating (MVA):	87

Station: WOTS 66kV	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
50th percentile Summer Maximum Demand (MVA)	94.6	96.2	97.4	98.4	99.4	100.1	101.0	101.7	102.3	102.8
50th percentile Winter Maximum Demand (MVA)	75.5	76.8	77.9	78.8	79.5	80.2	80.9	81.5	81.9	82.3
10th percentile Summer Maximum Demand (MVA)	109.6	111.4	112.9	114.2	115.3	116.3	117.1	118.0	118.6	119.2
10th percentile Winter Maximum Demand (MVA)	82.5	83.9	85.1	86.0	86.9	87.7	88.3	88.9	89.4	89.9
N - 1 energy at risk at 50th percentile demand (MWh)	252	346	443	538	644	725	826	919	1,003	1,084
N - 1 hours at risk at 50th percentile demand (hours)	62	80	98	113	127	137	149	161	174	185
N - 1 energy at risk at 10th percentile demand (MWh)	2,631	3,037	3,402.8	3,709.8	4,008.9	4,283.4	4,520.0	4,791.9	4,987.9	5,178.4
N - 1 hours at risk at 10th percentile demand (hours)	256	281	302	318	333	351	369	390	404	418
Expected Unserved Energy at 50th percentile demand (MWh)	1.1	1.5	1.9	2.3	2.8	3.1	3.6	4.0	4.4	4.7
Expected Unserved Energy at 10th percentile demand (MWh)	11.4	13.2	14.8	16.1	17.4	18.6	19.6	20.8	21.6	22.5
Expected Unserved Energy value at 50th percentile demand	$0.08M	$0.11M	$0.14M	$0.17M	$0.20M	$0.23M	$0.26M	$0.29M	$0.32M	$0.34M
Expected Unserved Energy value at 10th percentile demand	$0.83M	$0.96M	$1.07M	$1.17M	$1.26M	$1.35M	$1.42M	$1.51M	$1.57M	$1.63M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.30M	$0.36M	$0.42M	$0.47M	$0.52M	$0.56M	$0.61M	$0.66M	$0.69M	$0.73M

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 10^{th} and 50^{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*, published on 9 July 2012 (see http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/Victorian_Electricity_Planning_Approach.ashx.