VICTORIAN GAS PLANNING REPORT

Gas Transmission Network Planning for Victoria

2013

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Purpose

AEMO publishes the Victorian Gas Planning Report in accordance with Rule 323 of the National Gas Rules.

This publication is based on information available to AEMO at 30 September 2013, although AEMO has endeavoured to incorporate more recent information where practical.

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

Revision History

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EXECUTIVE SUMMARY

The 2013 Victorian Gas Planning Report (VGPR) provides information about the Victorian Declared Transmission System (DTS) performance during 2012 and winter 2013, including maximum supply and demand. It also provides a capacity assessment of the DTS for the next five years (2014–18), known as the outlook period, to support forecast demand.

Information on committed augmentations to the DTS, and emerging DTS capacity limitations and their potential solutions are also covered in this report. The VGPR is used by market participants and government to assist in market, operational, and investment decisions. The 2013 VGPR confirms there are no significant DTS supply or withdrawal increases for winter 2014.

Peak demand

The 2013 peak gas demand[1] day for Victoria occurred on 24 June 2013 with a total demand of 1,200.4 terajoules (TJ). This was made up of system demand (1,081.7 TJ); gas-powered generation (GPG) demand (85.2 TJ) due to a Yallourn Power Station outage; and export demand through Culcairn (33.5 TJ).

The system met all demand and pressure requirements with gas supply of approximately 1,226.3 TJ, including 21.4 TJ of liquefied natural gas (LNG) for that day. Injections higher than the total demand were required because beginning-of-day linepack was below target.

System capacity

System capacity (1,349 TJ per day) is expected to remain materially unchanged for winter 2014. Minor system capacity change occurs due to the interactions between the major pipelines and overall injections and withdrawals. As long as peak day system demand is less than 1,349 TJ per day and there are sufficient injections into the Longford to Melbourne Pipeline (LMP), system capacity is sufficient to meet demand for the five-year outlook period.

Annual gas system consumption

Over the outlook period, annual gas system consumption[2] (excluding GPG and exports) is forecast to remain materially unchanged at 202 petajoules (PJ) per year for 2014 and 2015, before increasing to 209 PJ by 2018. This reflects an average annual growth rate of 0.7%, revised up from 0.3% in AEMO's 2012 Victorian Gas Medium Term Outlook (MTO) over the period.

Average consumption for residential, small commercial, and small-to-medium industrial customers (Tariff V) is forecast to increase by 1.1% per year (revised up from 0.8% in 2012) while the annual average large commercial and industrial customer (Tariff D) consumption is forecast to remain flat (revised up from a decline of 0.6% in 2012).

Both the 1-in-2 and 1-in-20 annual peak day system demands are forecast to increase at an average annual rate of 0.9% over the outlook period. In particular:

- 1-in-2 peak day system demand is forecast to increase from 1,155 TJ per day in 2014 to 1,195 TJ per day in 2018.
- 1-in-20 peak day system demand is forecast to increase from 1,277 TJ per day in 2014 to 1,322 TJ per day in 2018.

The current system capacity of 1,349 TJ per day is sufficient to satisfy the 1-in-20 peak day system demand during the forecast period. While there is sufficient supply and DTS capacity to meet peak day system demand, gas supply and system capacity are tight, particularly when GPG and increased exports to New South Wales are included.

[1] Demand refers to capacity or gas flow on a hourly or daily basis.
[2] Consumption refers to gas usage over a monthly or annual period.

The Winchelsea compressor will increase system capacity in 2015, which will in turn support increased exports to New South Wales via Culcairn. Updated system capacity modelling for winter 2015 will be provided in the March 2015 VGPR.

GPG consumption

GPG consumption is expected to grow at an average annual rate of 0.3 PJ per year over the outlook period to 3.9 PJ in 2018, revised down from the 0.8 PJ forecast in AEMO's 2012 MTO. The reduced forecast is based on lower electricity consumption and changes in energy policy. The 0.3 PJ growth is expected to occur during the summer months.

These GPG levels are lower than experienced in the past, notably 2007 when GPG consumption was particularly high at 36 PJ.

Supply capacity

Total production capacity at the Longford Gas Plant and the Iona Underground Gas Storage (UGS) is not expected to change for winter 2014. The system capacity of 1,349 TJ per day is met by gas supplied into the LMP and the South West Pipeline (SWP).

The LMP capacity including BassGas injections remains at 1,030 TJ per day. Longford and VicHub injections have not been modelled above 940 TJ per day based on historical performance and expected flows on the Eastern Gas Pipeline (EGP) to New South Wales.

SWP capacity has increased slightly to 367 TJ per day for a 1-in-20 peak day in winter 2014 due to operational changes in the system. This capacity is dependent on operating conditions, pressures, and demand on the SWP. This capacity remains less than the combined production capacity of Iona UGS, and the other Port Campbell gas plants and injection facilities. The Winchelsea compressor will increase SWP capacity to 429 TJ per day for winter 2015.

This report highlights a substantial decrease in retailer contracted gas supply from 2018, which indicates that a number of retailers have not committed to gas supply agreements beyond 2017. Production facility forecasts indicate sufficient supply capacity over the outlook period, including 2018. AEMO assumes that supply will eventually be contracted to meet Victorian demand and New South Wales export requirements.

Victorian gas exports

Victorian Northern Zone gas exports to New South Wales via the Culcairn interconnection increased by 46% to 7.2 PJ during winter 2013 compared to winter 2012 (4.9 PJ). This follows the Euroa compressor commissioning in late 2012.

The report signals a 145% increase in exports to New South Wales via Culcairn from winter 2015, subject to the APA Group looping sections of the Wollert to Barnawartha Pipeline. This will increase export capacity by 67 TJ per day (from 46 TJ to 113 TJ per day). The Northern Zone 1-in-20 peak day export capacity is expected to increase by 11 TJ per day for winter 2014 to 57 TJ per day following the completion of the first expansion phase during the first half of 2014.

Detailed capacity information for this second expansion phase of up to 113 TJ per day will be available in the 2015 VGPR.

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CHAPTER 1 - INTRODUCTION

1.2 Background

The 2013 Victorian Gas Planning Report (VGPR) supports participant planning and investor decision-making in the Victorian gas market by providing a five-year (2014-18) maximum supply and demand outlook as well as a capacity assessment of Victorian Declared Transmission System (DTS) for the next five years.

The forecasts in this report incorporate recent information from winter 2013 to assess the adequacy of the DTS for the next five years.

This report includes:

- Information about gas transmission system performance for calendar year 2012 and winter 2013.
- An overview of the DTS capacity as a whole (system capacity).
- An overview of individual pipeline capacities.
- Results of modelling scenarios that simulate credible operational scenarios with the potential to create operational challenges and identify system constraints. These modelling scenarios test situations that may require load curtailment in the most severe cases and identify the absolute limits of system capacity.
- Information about gas consumption and supply over the five-year outlook.
- Information about the short-term DTS demand and supply forecast for 2014 by month.
- Information about committed augmentations and their impacts. Committed augmentations are those where proponents have secured the necessary land and planning approvals; have entered into contracts for finance and purchasing equipment; and construction has either commenced or a firm date has been set.
- Information about scheduled maintenance that affects gas supply and system capacity availability.
- AEMO's approach to planning for the Victorian DTS.

Changes since 2012

AEMO continues to review how it presents network planning information to provide stakeholders with more timely and focused information.

The 2013 VGPR consolidates and replaces information previously contained in the Victorian Annual Planning Report (VAPR), Victorian Gas System Adequacy (VGSA), Victorian Gas Medium Term Outlook (MTO), Victorian Gas Declared Transmission Capacity, and Victorian Gas Planning Approach publications. The next VGPR will be published in March 2015, then every two years. It will use the demand forecasts incorporating winter 2014 actual conditions.

This consolidation provides a single document for stakeholders while still providing annual planning review information to meet AEMO's obligations under Rule 323 of the National Gas Rules (NGR).

VAPR Rules obligations

Rule 323 of the NGR[3] requires that AEMO publish an annual DTS planning review by 30 November each year. AEMO sought a letter of No-Action from the Australian Energy Regulator (AER) to delay publication until 30 December 2013 (at the latest). This request sought to improve alignment between the Victorian gas planning documents, and to allow analysis based on the most recent winter demand data.

[3] Australian Energy Market Comission. *National Gas Rules, Rule 323*. Available at: http://www.aemc.gov.au/Gas/National-Gas-Rules/Current-Rules.html. Viewed: 11 December 2013.

This proposal was discussed and endorsed in principle by both the APA Group (as the DTS Service Provider) and the Gas Wholesale Consultative Forum, and agreed to by the AER on 30 April 2013.

Figure 1-1 shows the arrangement of documents for 2012 and Figure 1-2 shows the improved arrangement for 2013 and future publications.

Figure 1-1 — Suite of gas planning documents in 2012

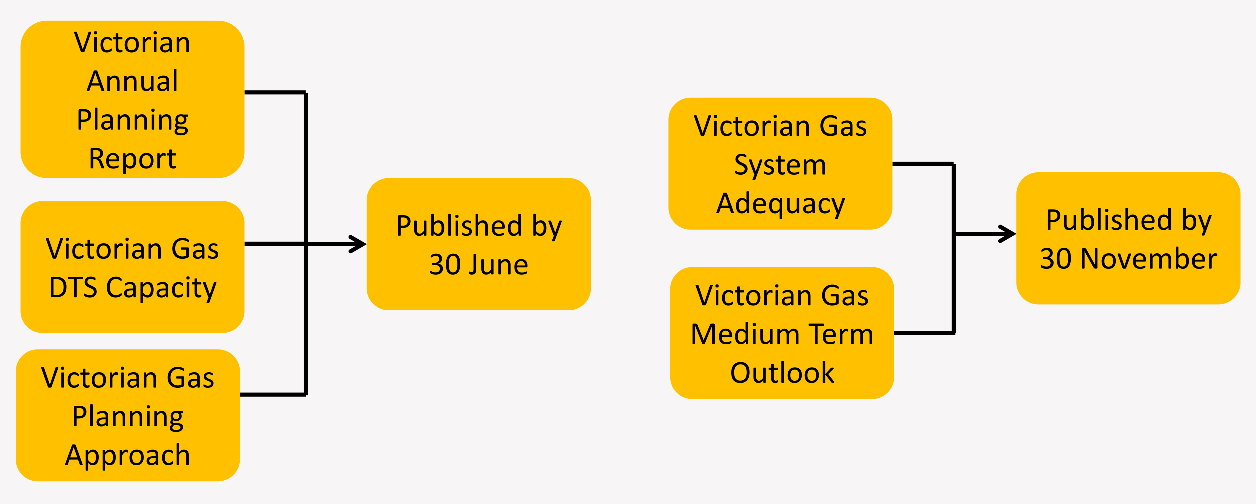
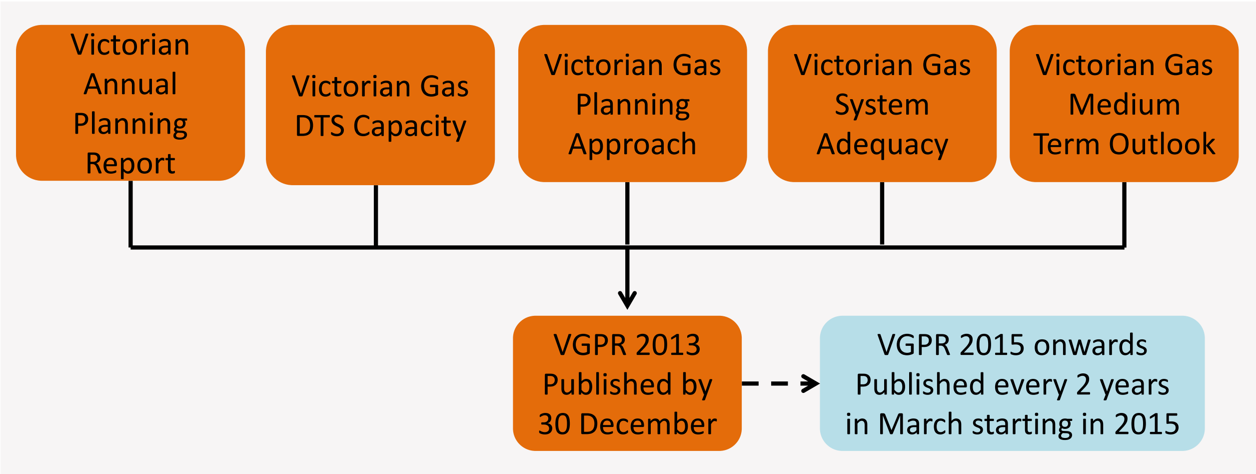


Figure 1-2 — Victorian Gas Planning Report (VGPR) 2013



1.3 Gas planning

AEMO operates the Victorian DTS, and the APA Group owns and maintains it. Third party asset owners maintain and augment the associated network infrastructure including production facilities and interconnected pipelines. AEMO provides planning advice about network constraints, capability, and development proposals to support the final investment decisions and investment of market participants.

Figure 1-3 provides a high-level map of the Victorian gas transmission system including the DTS (in orange) and other gas transmission pipelines.

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Figure 1-3 — Victorian gas transmission system

Victorian gas planning approach

The 2013 VGPR considers the following:

- Forecasts for peak day, peak hour, and annual gas consumption.
- Forecasts for peak day and annual gas supply.
- Expansions or extensions to the DTS, known as augmentations.
- An assessment of overall supply, demand, and capacity.
- Acceptable pressure ranges.
- Information about gas storage.

For more information, see Appendix A.

1.4 Content and structure of the 2013 VGPR

The executive summary provides an overview of the key messages and findings in relation to the VGPR.

Chapter 1 - Introduction, provides information about the 2013 VGPR.

Chapter 2 Gas transmission performance, provides information about the DTS performance during 2012 and the 2013 winter.

Chapter 3 Declared transmission system capacity, provides current information about individual pipeline capacities and the DTS capacity as a whole (system capacity).

Chapter 4 Gas demand forecast, provides short- and medium-term gas demand forecasts for the DTS.

Chapter 5 Gas supply forecast, provides short- and medium-term gas supply forecasts for the DTS.

Chapter 6 Gas transmission adequacy, system maintenance, and augmentations provides information on the supply–demand balance, maintenance and plant outages for the DTS.

Attachment A Victorian gas planning approach, provides an overview of the planning methodology, assumptions and criteria used in the modelling scenarios.

Attachment B Compressor availability, provides information about compressor requirements and availability for 2014.

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Chapter 2 GAS TRANSMISSION PERFORMANCE

Summary

This chapter provides information about the Victorian Declared Transmission System (DTS) performance throughout 2012 and to 30 September 2013. It includes performance information specific to the 2012 and 2013 winter periods (May–September), and historical information from the Gas Bulletin Board.

There were no supply and demand or system security issues throughout the 2012 and 2013 winter periods. Although the winter was generally mild, there were nine cool days from 19 June 2013; Victoria's total gas demand was around 1,000 TJ a day during this period.

The 2013 peak day occurred on 24 June 2013 with a total demand of 1,200.4 TJ/d which is 6.5% higher than 2012 (1,126.5 TJ) and a total supply of 1,226.3 TJ including 21.4 TJ of liquefied natural gas (LNG) was injected into the DTS.

Gas-powered generation (GPG) consumption for winter 2013 was 1.2 PJ—the lowest for the last seven years and a drop of 22.8% compared to 2012. However, there were higher-than-expected levels of GPG consumption in June 2013 as a result of an outage of the Yallourn Power Station. LNG was injected as peak shaving gas to support GPG demand during the Yallourn Power Station outage as this coincided with the largest week of system demand since 2008. A total of 0.04 PJ of LNG was injected into the DTS during that week; the only LNG used during the 2013 winter period.

Gas exports via Culcairn increased from 4.9 PJ to 7.2 PJ, a 46% increase over winter 2012. Total gas export demand for winter 2013 was 7.2 PJ (33.5% higher than in 2012), largely due to increased demand from New South Wales. The total export demand was offset by lower 2013 BassGas withdrawals of 0.01 PJ (0.2 PJ in 2012).

Pipeline flow analysis showed that for both years, the Longford to Melbourne Pipeline (LMP) is was under-utilised during the winter peak, while the South West Pipeline (SWP) was constantly close to capacity.

2.1 The Victorian gas network

2.1.1 The Declared Transmission System

The DTS comprises pipelines extending from Longford in eastern Victoria, to Portland in the south-west, and northwards to Culcairn in New South Wales. The main DTS pipelines include:

- The Longford to Melbourne Pipeline (LMP), which extends from Longford to Dandenong and Pakenham to Wollert.
- The South West Pipeline (SWP), which extends from Port Campbell to Lara (near Geelong) and its continuation, the Brooklyn to Lara Pipeline (BLP).
- The Brooklyn to Corio[4] Pipeline (BCP), which interconnects with the SWP at Lara.
- The Northern System, which extends from Wollert to Barnawartha (near Wodonga) then onward to Culcairn[5] and from Wandong to Bendigo and Carisbrook.

[4] Located close to Geelong.
[5] Including the New South Wales –Victoria (NSW-VIC) Interconnect, which comprises the section from Barnawartha to Culcairn pipeline.

- The Brooklyn to Ballan pipeline (BBP), which extends from Brooklyn to Ballarat via Ballan, and includes the Ballan Pipeline that is a limited capacity interconnect between the BBP and the Wandong to Bendigo pipeline.
- The Western Transmission System (WTS), which extends from Port Campbell to Portland.

The DTS receives gas via the following injection points:

- Longford Gas Plant, located near Sale, which is owned and operated by ExxonMobil and BHP Billiton. The plant extracts gas from the Bass Strait gas fields in the Gippsland Basin.
- VicHub, which is an injection and withdrawal point located adjacent to the Longford Gas Plant. VicHub is part of the Eastern Gas Pipeline (EGP) that transports Victorian gas to New South Wales.
- BassGas, which is an injection and withdrawal point located at Pakenham, and supplies gas from the Yolla gas field via the Origin-operated Lang Lang Gas Plant. This point also supplies the Jemena South Gippsland Gas Pipeline (which is not part of the DTS).
- Iona Gas Plant, which is an injection and withdrawal point located near Port Campbell. Gas flows to and from Melbourne via the SWP. Pipeline withdrawals are used to fill the Iona Underground Gas Storage (UGS) facility and for export to South Australia via the South East Australia (SEA) Gas pipeline. Gas from the Santos-operated Casino, Henry, and Netherby gas fields are also processed at the Iona Gas Plant.
- Otway Gas Plant, located near Port Campbell, is supplied from the Origin-operated Thylacine and Geographe gas fields. Gas injections into the DTS at this point are limited due to pressure limitations; however, the Otway Gas Plant is a major source of supply for the SEA Gas and Mortlake injection points.
- SEA Gas, located adjacent to the Iona and Otway gas plants, supplies from the Iona, Minerva, and Otway gas plant into the DTS. These gas supplies can also supply the Mortlake power station pipeline.
- Mortlake[6], also located adjacent to the Iona and Otway gas plants. Injection are also received from linepack[7] in the Mortlake power station pipeline.
- Culcairn, which is an injection and withdrawal point located in southern New South Wales. Gas flows to and from New South Wales via the NSW–VIC Interconnect.
- Dandenong LNG facility, where LNG is liquefied, stored, vaporised, and injected into the DTS as required, usually for peak demand management.

2.1.2 Non-DTS Pipelines

- The Melbourne Ring Main (MRM): Extends from Dandenong to Keon Park to Brooklyn. It supplies gas around the Metropolitan area and is predominantly owned by the three distribution companies.
- The Eastern Gas Pipeline (EGP): The EGP transports gas from the Gippsland Basin in Victoria to supply the Sydney Short Term Trading Market (STTM) and several other centres including Wollongong and Canberra. The primary source of gas supply is the Longford Gas Plant, which is also a primary source for Victoria. Gas supply to the EGP also includes the Orbost Gas Plant.[8]
- Tasmanian Gas Pipeline (TGP): The TGP transports gas from the Gippsland Basin in Victoria to Bell Bay in Tasmania supplying gas to both industry and townships in the state. The pipeline is owned by Tasmanian Gas Pipeline Pty. Ltd and sources their gas predominately from Longford Gas Plant. [9]
- SEA Gas Pipeline: The SEA Gas pipeline transports gas from the plants at Port Campbell to supply the Adelaide STTM and other centres in South Australia including Mount Gambier.[10]

[6] This does not include Mortlake Power Station.
[7] Linepack is the pressurised gas stored in transmission pipelines.
[8] Jemena. *Eastern Gas Pipeline*. Available at: http://jemena.com.au/what-we-do/assets/eastern-gas-pipeline/. Viewed: 11 December 2013.
[9] Tasmanian Gas Pipeline. *Pipeline*. Available at: http://www.tasmaniangaspipeline.com.au/pipeline/. Viewed: 11 December 2013.
[10] SEA Gas. *Our High-Pressure Gas Pipeline Sytem*. Available at: http://www.seagas.com.au/our-pipeline-system.php. Viewed: 11 December 2013.

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- NSW – VIC Interconnect: This interconnect transports bi-directional gas between New South Wales and Victoria at Culcairn.[11]
- Carisbrook to Horsham Pipeline: This pipeline, owned and operated by Gas Pipelines Victoria, is connected to the DTS at Carisbrook and supplies the towns of Ararat, Stawell, and Horsham in western Victoria.
- South Gippsland Gas Pipeline: This pipeline is connected to the BassGas pipeline at Lang Lang and supplies the towns of Lang Lang, Korumburra, Leongatha, Inverloch, and Wonthaggi.

2.1.3 Pipeline capacity

Detailed information about system capacity, pipeline capacity, and factors that affect normal pipeline operating boundaries is in Chapter 3 . A summary of the individual pipeline maximum capacities is as follows:

- LMP capacity is 1,030 TJ/d, which can be met by Longford and VicHub injecting 970 TJ/d and BassGas injecting 60 TJ/d. Maximum LMP capacity without BassGas injecting is 990 TJ/d.
- SWP capacity is 367 TJ/d under 1-in-20[12] peak day conditions. On lower demand days SWP capacity is reduced due to reduced offtake from this pipeline and capacity limitations at the Brooklyn end-of-line facility.

  This capacity does not include Western Transmission System demand of 17 TJ/d, which increases the injection capacity at Iona to 384 TJ/d.

  Capacity has increased from the 353 TJ/d reported in the 2012 Victorian Gas DTS Capacity Report[13], and Iona injections have increased from 370 TJ/d due to operational changes in the system. Further detail about the operational changes can be found in Chapter 3 .

  SWP capacity is expected to increase further in winter 2015 with the commissioning of Winchelsea Compressor Station. More information about current and future SWP capacity can be found in Chapter 3 .
- The NSW–VIC Interconnect capacity at Culcairn is currently 120 TJ/d for import and 46 TJ/d for export under 1-in-20 peak day conditions as previously published in Victorian Gas DTS Medium Term Outlook[14] in 2012.

  An increase in industrial load during winter 2014 north of Springhrust Compressor Station would have reduced this capacity to 42 TJ/d; however, the first stage of the Northern System expansion will result in an overall export capacity increase of 11 TJ/d to 57 TJ/d under 1-in-20 peak day conditions.

  Interconnect export capacity is expected to increase further for winter 2015 to 113 TJ/d on a 1-in-20 peak day. More information on this is in Chapter 3 .

Overall DTS system capacity depends on the location of these pipeline system injections and withdrawals because these three supply pipelines can supply more gas than the modelled maximum capacity of the system, which is 1,349 TJ/d. The commissioning of the Winchelsea Compressor Station and increased exports via the NSW–VIC Interconnect will increase the system capacity. More information will be provided in the 2015 VGPR.

2.2 Historical gas demand

Total demand refers to the sum of system demand, GPG demand, and export demand.

System demand refers to demand from Tariff V and Tariff D customers (covering the industrial, commercial, and residential sectors) excluding GPG. For more information about Tariff V and Tariff D demand, see Chapter 4 .

[11] APA Group. *New South Wales*. Available at: http://www.apa.com.au/our-business/energy-infrastructure/new-south-wales.aspx. Viewed: 11 December 2013.
[12] For more information regarding a 1-in-20 peak day, refer to Chapter 4 .
[13] AEMO. *Victorian Gas DTS Capacity*. Available: http://aemo.com.au/Gas/Planning/Victorian-Gas-DTS-Capacity. Viewed: 11 December 2013.
[14] AEMO. *2012 Victorian Gas DTS Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013.

Winter 2013 generally lacked very cold weather conditions, with the exception of nine days commencing 19 June 2013. On these days, Victoria experienced total demand of over 1,000 TJ every day, which included the largest total gas demand day of 1,200.4 TJ on 24 June. The last occurrence of similar sustained demand was in 2008. Despite this, there were no supply and demand or system security issues.

2.2.1 Peak day demand

Peak day system demand in 2013 was 1,081.7 TJ/d on 24 June 2013 with an Effective Degree Day (EDD) of 11.87. This is below the 1-in-2 and the 1-in-20 peak day weather standards found in the 2012 Victorian Gas DTS Medium Term Outlook[15] which are as follows:

- 1,149 TJ for a 1-in-2 peak day on a day with EDD of 14.21.
- 1,270 TJ for a 1-in-20 peak day on a day with EDD of 16.49.

Peak day system demand in 2012 was 1,091.5 TJ/d on 9 August 2012 with an EDD of 12.35. This is below the 1-in-2 and 1-in-20 peak day weather standards found in the 2011 GSOO Attachment[16] which are as follows:

- 1,162 TJ for a 1-in-2 peak day on a day with EDD of 14.55.
- 1,280 TJ for a 1-in-20 peak day on a day with EDD of 16.80.

Peak gas day total demand in 2013 was 1,200.4 TJ, which is 6.5% higher than 2012 (1,126.5 TJ). This is the highest peak day demand experienced since 2008 but is less than the record set in 2007 when demand reached 1,283.1 TJ.

The DTS met total demand without the need for curtailment; however, peak shaving LNG injections were required to maintain system security on 24 June 2013. Maximum demand is weather dependent, and weather conditions on 24 June 2013 were milder than the peak day forecast conditions used for network planning.

Table 2-1 lists the breakdown of total demand for 2013 and 2012 peak days.

Table 2-1 — Peak day demand, 2013 and 2012

Demand Source[a]		24 Jun 2013 TJ/d	% of total demand	9 Aug 2012 TJ/d	% of total demand
System demand		1081.7	90.1	1091.5	96.9
GPG demand[b]		85.2	7.1	0.0	0.0
Export	Iona[c]	0.0	0.0	0.0	0.0
	BassGas	0.0	0.0	2.2	0.2
	Culcairn	33.5	2.8	32.8	2.9
	SEA Gas	0.0	0.0	0.0	0.0
	VicHub	0.0	0.0	0.0	0.0
Total demand		**1200.4**	**100.0**	**1126.5**	**100.0**

a. Export and GPG demand can vary from day to day, and can differ from one peak to another. This is due to changes in their drivers, which include GPG-related prices and contracts in the National Electricity Market (NEM), and New South Wales gas market conditions. Analysis of these drivers is beyond the scope of the VGPR.

b. For more information about GPG demand, see Section 2.2.3.

c. Iona withdrawals are delivered to Iona UGS reservoirs, or exported to South Australia.

[15] AEMO. *2012 Victorian Gas DTS Medium Term Outlook.* Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013.

[16] AEMO. *Victorian Gas Declared Transmission Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2011-Gas-Statement-of-Opportunities/Attachment. Viewed: 11 December 2013.

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2.2.2 Annual consumption

Total consumption for nine months to 30 September 2013 was 172.1 PJ. Total winter period consumption including gas export to New South Wales via Culcairn was 121.8 PJ; 6.5% lower than 2012 (130.2 PJ).

System consumption

System consumption for winter 2013 was 113.4 PJ; 8.2% lower that winter 2012 (123.4 PJ). Average winter system demand for 2013 was 740.8 TJ; 8.1% lower than 2012 (806.6 TJ).

GPG consumption

Total GPG consumption for winter 2013 was 1.2 PJ, compared to 1.6 PJ for winter 2012; a drop of 22.8%. See Section 2.2.3 for more information regarding GPG consumption.

Export demand

Export consumption for winter 2013 was 7.2 PJ; 36.7% higher than winter 2012 (5.28 PJ). The exports represent actual physical flows from the DTS, either via the Iona UGS facility, the New South Wales – VIC Interconnect, or supplies to South Gippsland towns. Total exports for the 2013 winter period were:

- 7.2 PJ via Culcairn (4.9 PJ in 2012); an increase of 46%.
- 0.02 PJ via Iona (0.02 PJ in 2012). This reflects the net Iona withdrawals and does not include WTS demand. There was no change during between winter 2012 and winter 2013 as Iona mostly withdraws during summer. Total Iona withdrawals for the nine months to 30 September 2013 were 1.16 PJ; total Iona withdrawals for the 12 months to 31 December 2012 were 0.85 PJ. This shows that Iona withdrawals are increasing.
- 0.01 PJ via BassGas (0.2 PJ in 2012). The high 2012 withdrawals at the BassGas were due to the Lang Lang Gas Plant being offline for maintenance during 2012.

There have been no physical DTS exports via VicHub since 2010 and SEA Gas has not physically withdrawn gas from the DTS since it was being commissioned in late 2003.

Table 2-2 lists the breakdown of consumption for nine months from 1 January to 30 September 2013 and calendar year 2012. It also compares the 2013 and 2012 winter periods.

Table 2-2 — Annual consumption in 2013[17] and 2012

Demand source		9 months to September 2013 (PJ)	May to September 2013 (PJ)	12 months to December 2012 (PJ)	% of total consumption	May to September 2012 (PJ)	% of total consumption
System demand		156.1	113.4	206.7	92.9	123.4	94.7
GPG consumption		2.5	1.2	3.2	1.4	1.6	1.2
Export	Iona	1.2	0.02	0.9	0.4	0.02	0.02
	BassGas[a]	0.02	0.01	0.4	0.2	0.3	0.2
	Culcairn	12.4	7.2	11.3	5.1	4.9	3.8
	SEA Gas	0.0	0.0	0.0	0.0	0.0	0.0
	VicHub	0.0	0.0	0.0	0.0	0.0	0.0
Total consumption		172.1	121.9	222.5	100.0	130.2	100.0

a. This is a withdrawal at BassGas to supply the South Gippsland towns when BassGas is offline during maintenance in 2012.

[17] Annual demand in 2013 is partial and is nine months from 1 January to 30 September 2013.

2.2.3 Gas-powered generation consumption

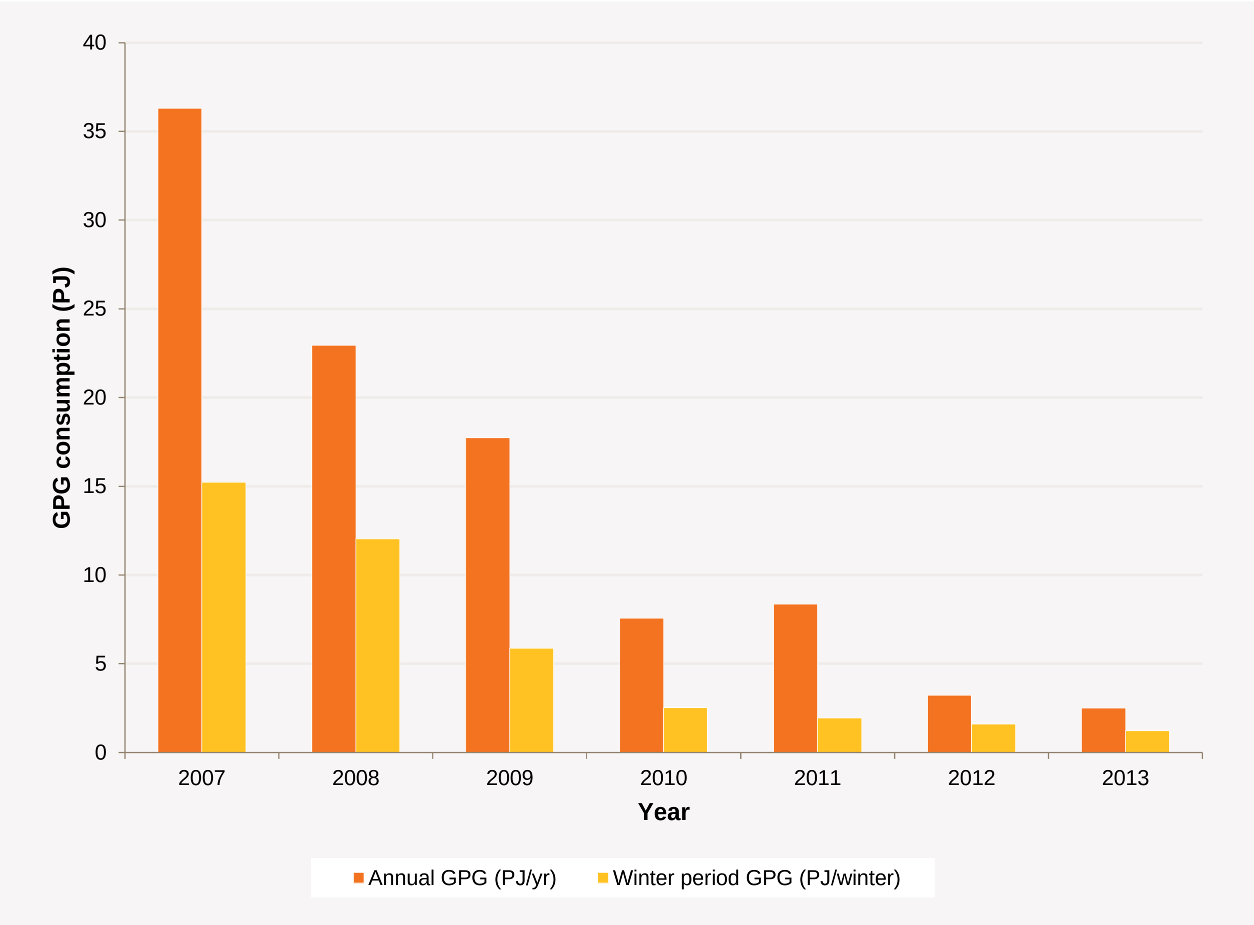
GPG consumption for the winter period 2013 was 1.2 PJ; the lowest for the last seven years and a 22.8% decrease on the 1.6 PJ in winter 2012.

Figure 2-1 shows the annual GPG consumption for the seven-year period from 2007 to 2013. GPG consumption for 2013 includes the nine months to 30 September 2013. In 2012, GPG consumption was 3.2 PJ.

Annual GPG gas consumption correlates strongly with the requirement for electricity capacity support; GPG operates at times of peak electricity demand and when conventional generation is unavailable (due to maintenance) or when there are low levels of renewable generation (such as wind).

The significantly higher GPG consumption in 2007 was largely due to drought-induced hydroelectric and coal-fired generation capacity limitations, leading to an increased reliance on GPG to meet electricity demand. Reasons for the downward trend of DTS-connected GPG consumption over the last seven years are: the recovery in hydroelectric generation and coal-fired power station cooling water storages, the increase in alternative electricity supplies (both wind and solar), and an increase in non-DTS connected GPG such as Mortlake.

Figure 2-1 — Annual GPG consumption from 2007 to 2013[18]



[18] Annual GPG consumption for 2013 is partial and is nine months from 1 January to 30 September 2013.

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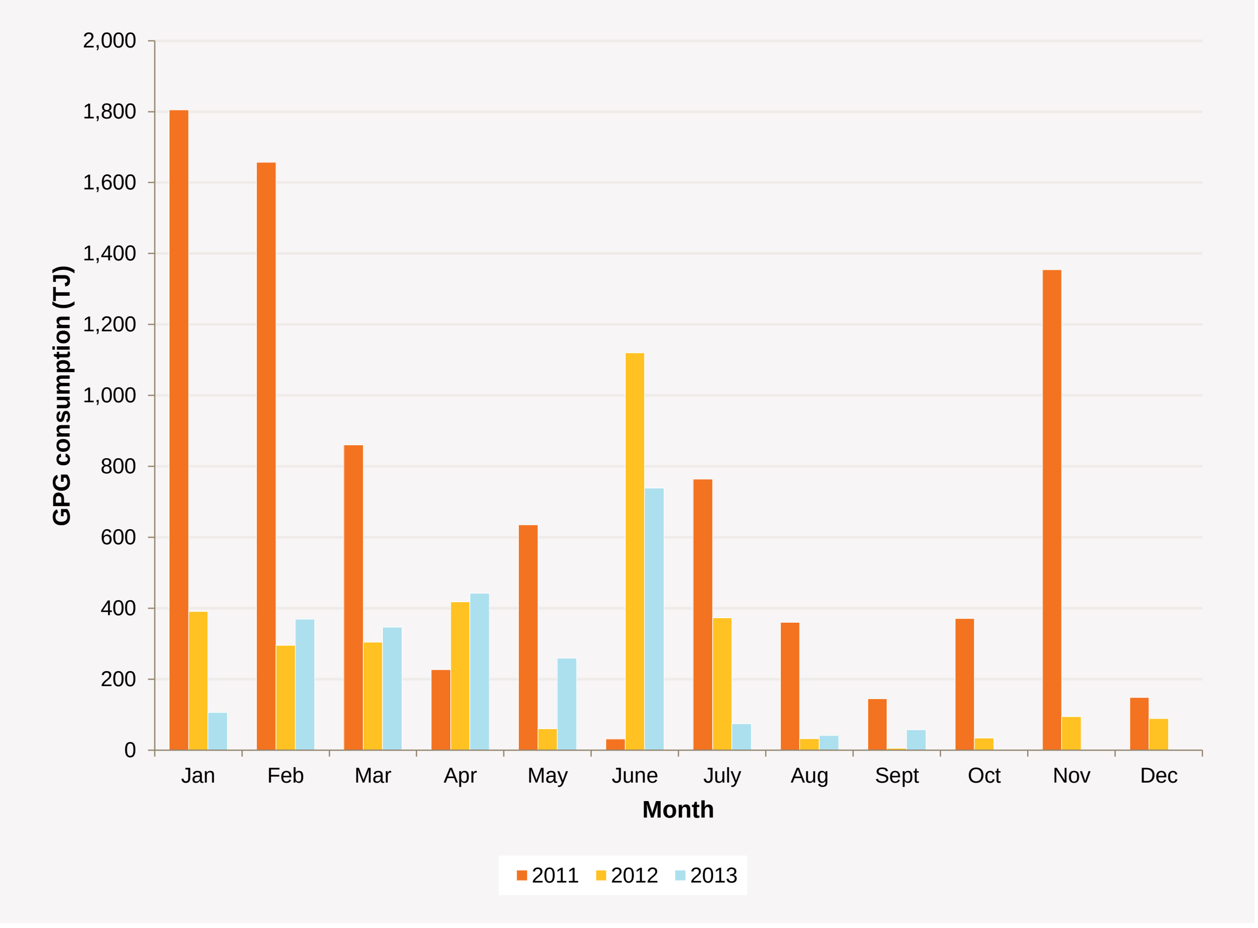
Figure 2-2 shows monthly GPG consumption for the three-year period from 2011 to 2013. Demand for 2013 shows data only to 30 September 2013. The noticeably higher levels of GPG consumption in June 2012 and 2013 compared to the other winter months reflects the flooding of Yallourn coal mine (June 2012) and the outage of a number of coal-fired generating units at Yallourn Power Station (June 2013).

Figure 2-2 — Monthly GPG consumption from 2011 to 2013



2.3 Historical gas supply

2.3.1 Daily production and pipeline flows

This section presents a summary of Gas Bulletin Board production and pipeline flow data in conjunction with additional AEMO data relevant to the Victorian DTS.

For more information about the data used in this section, see the Gas Bulletin Board website.[19]

Pipeline flows

Key pipeline flows are supplied from the Port Campbell and Gippsland production facilities.

19 National Gas Market Bulletin Board. *Gas Bulletin Board*. Available at: http://gasbb.com.au/. Viewed: 11 December 2013.

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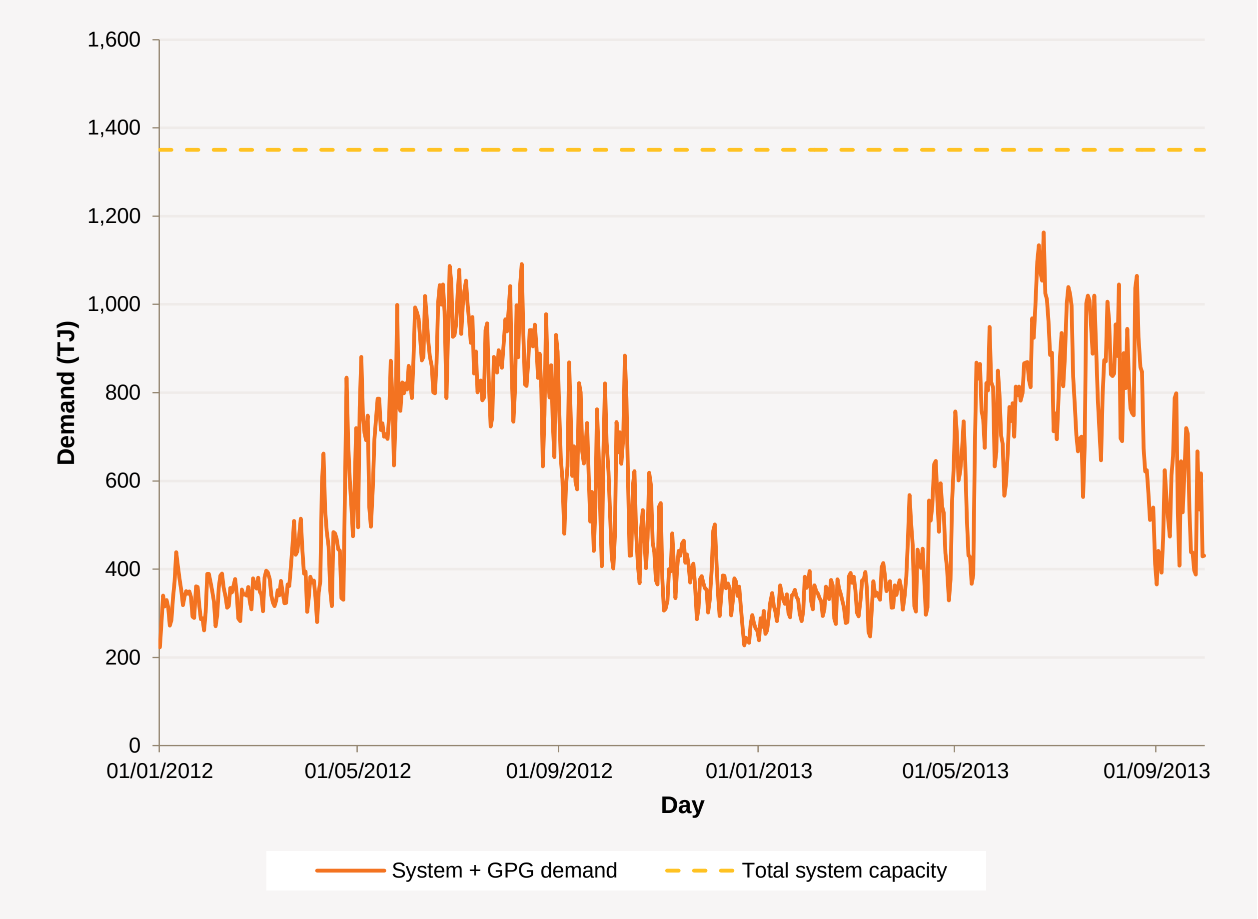
Figure 2-3 shows the daily DTS demand from 1 January 2012 to 30 September 2013 including GPG demand, and excluding export demand. The figure demonstrates strong overall seasonality (the variation between summer and winter) with a clear winter peak.

It shows that DTS demand varies from day to day due to changes in weather (which drives system demand), GPG demand, and day of the week (weekends have lower demand). Daily demand variations result in the need to reschedule system injections and withdrawals to ensure adequate linepack at the beginning-of-day while also ensuring that there is sufficient space in the system to accommodate additional gas if demand was lower than forecast.

Figure 2-3 — Daily DTS demand (excluding export demand) from 1 January 2012 to 30 September 2013



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The majority of DTS gas supply flows are through the Longford Melbourne Pipeline (LMP) and the South West Pipeline (SWP), whereas flows through the NSW–VIC Interconnect, SEA Gas, the EGP, and the Tasmanian Gas Pipeline (TGP) demonstrate how much Victorian gas flows to other states.

Figure 2-4 shows LMP and SWP flows to Melbourne for the three-year period from 1 January 2012 to 30 September 2013. The LMP supplies the majority of gas consumed in the DTS, with strong seasonality demonstrated by peak flows in winter and substantially reduced flows in summer. The decrease in Longford injections in winter 2013 were the result of BassGas returning to service and due to a warmer winter than in 2012.

The 2013 injections into the SWP were similar to 2012, with a very slight overall decrease of 0.3%, again due to the return of BassGas and the warmer winter. Physical gas withdrawals at to Iona via the SWP (which includes WTS demand) increased in 2013. With the increase in flows delivered from Brooklyn to Iona from year to year, AEMO and the APA Group are working together to understand and overcome possible transportation constraints.

Figure 2-4 — Daily LMP and SWP flows to Melbourne, 1 January 2012 to 30 September 2013

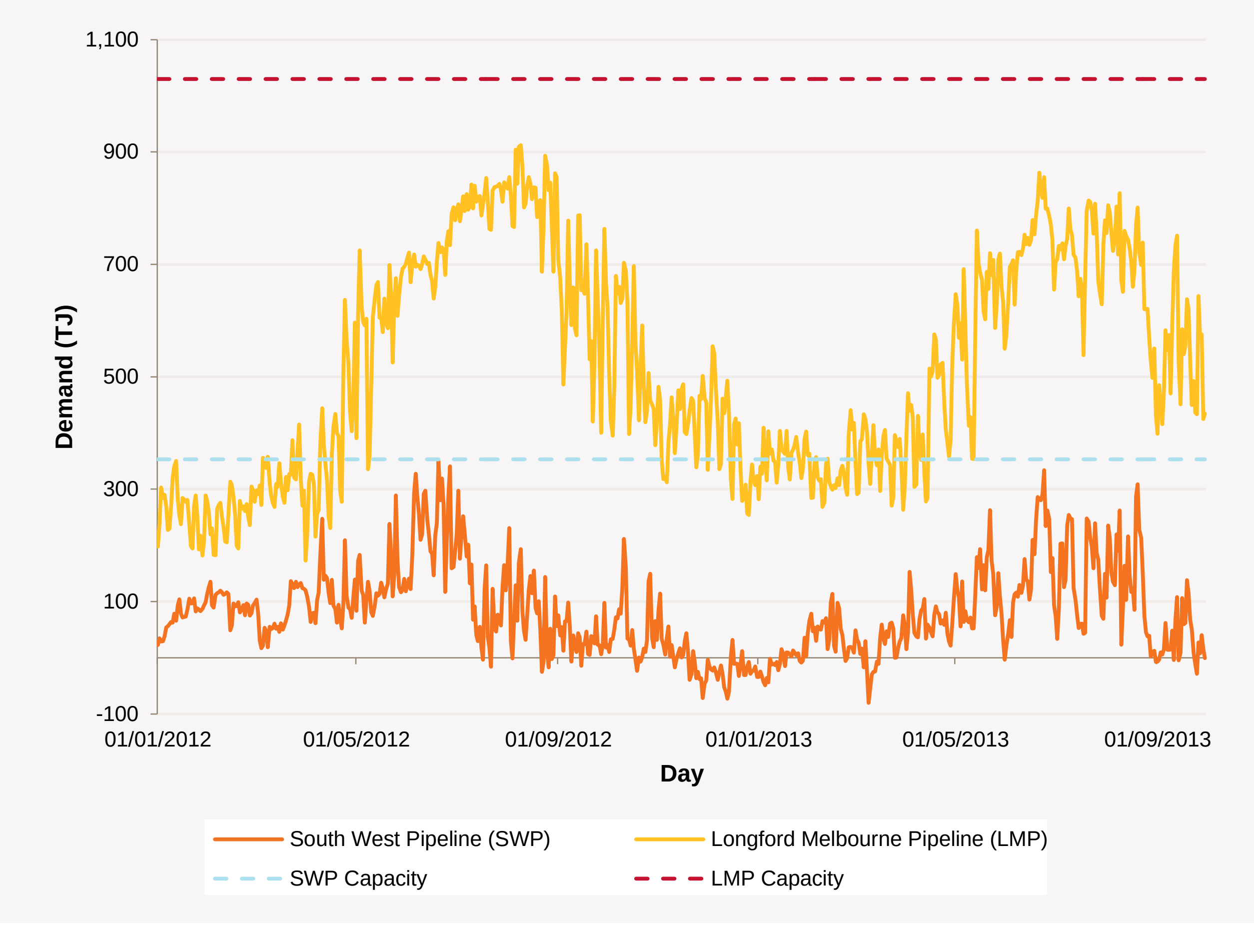

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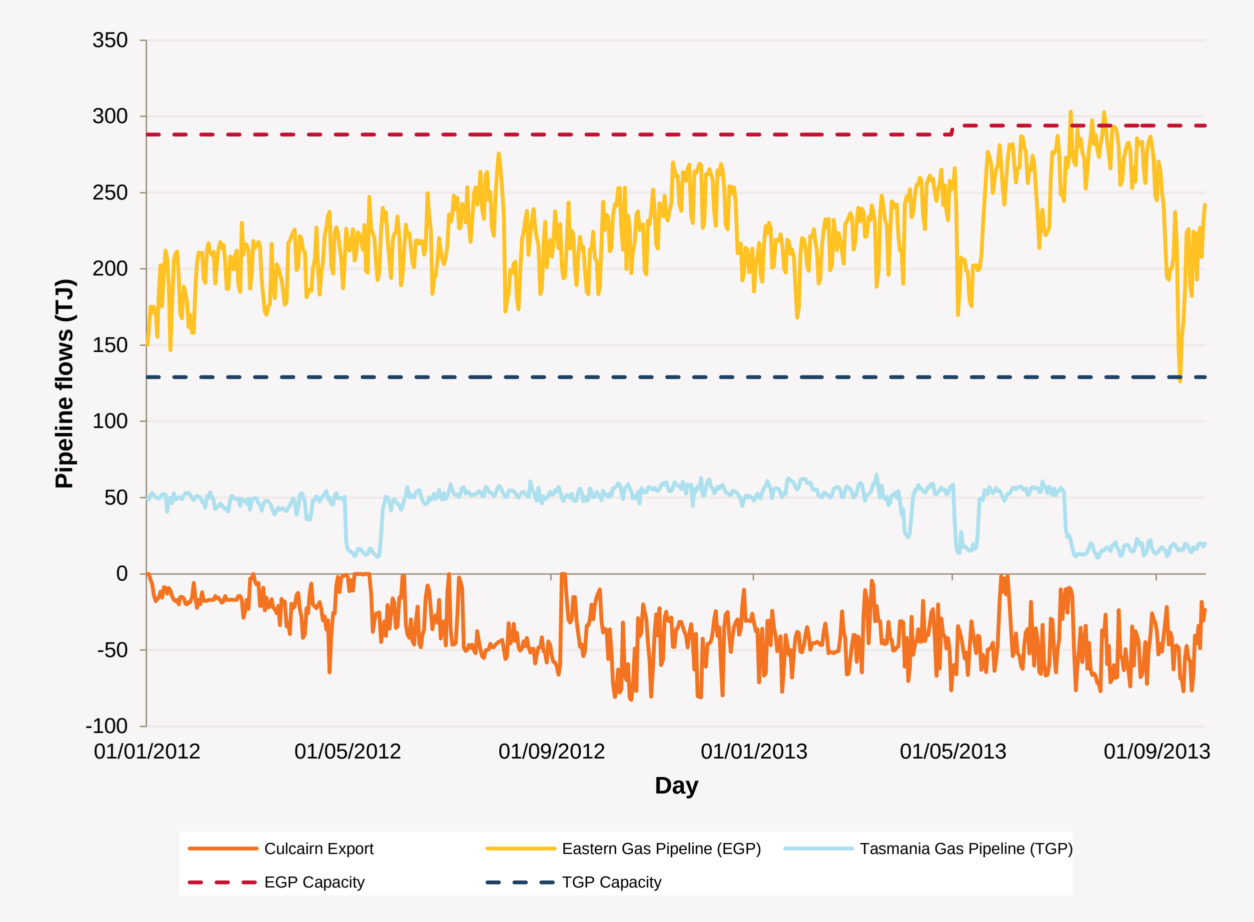
Figure 2-5 shows the daily Eastern Gas Pipeline (EGP), Tasmanian Gas Pipeline (TGP) and Culcairn export flows from 1 January 2012 to 30 September 2013. The figure shows the increase in daily Culcairn export flow with the commissioning of the Euroa compressor in winter 2012. Culcairn export capacity is dependent on system demand on the day and is therefore not shown on the figure. Pipeline flows on the EGP include gas supply from Orbost.

The EGP has generally higher flows during the winter months (resulting from New South Wales heating demand) as well as an increase during summer, which coincide with increased GPG demand in New South Wales. The flow on EGP has increased in winter 2013 compared to winter 2012 with flows reaching pipeline capacity. The TGP flows appear to flow more steadily over the period with no obvious seasonality. AEMO believes the reduction of pipeline flows on the TGP since July 2013 is the result of reduction in generation from the Tamar Valley power station.[20]

Figure 2-5 — Daily Culcairn export, EGP and TGP flows, 1 January 2012 to 30 September 2013



[20] The Mercury. *Tamar Valley power station stalls despite multi-million dollar contracts*. Available at: http://www.themercury.com.au/news/tasmania/tamar-valley-power-station-stalls-despite-multi-million-dollar-contracts/story-fnj4f7k1-1226739869707. Viewed: 11 December 2013.

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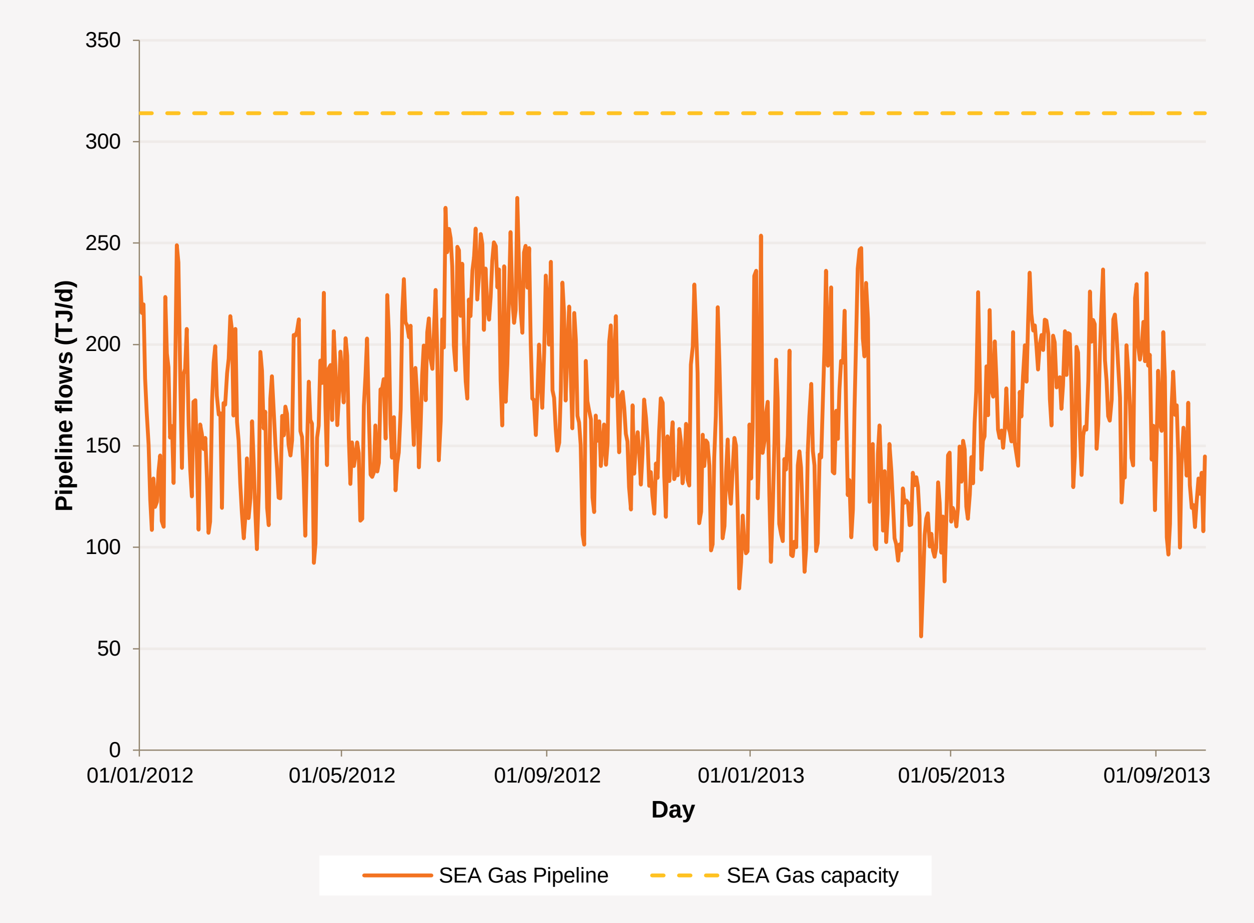
Figure 2-6 shows SEA Gas pipeline flows from Port Campbell from 1 January 2012 to 30 September 2013. The SEA Gas pipeline flows appear to follow a similar pattern as the EGP, increasing to support winter heating demand and summer GPG demand.

Figure 2-6 — Daily SEA Gas pipeline flows from Port Campbell, 1 Jan 2012 to 30 Sept 2013



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Gas production

Figure 2-7 shows gas production in the Gippsland System Withdrawal Zones (SWZ) (including the Longford and Lang Lang gas plants) from 1 January 2012 to 30 September 2013.

The seasonality demonstrated by the Longford Gas Plant relates to the same seasonality and winter peaking shown by pipeline flows. Figure 2-7 shows that during winter 2012, when the Lang Lang gas plant was offline for maintenance, Longford gas production increased compared to winter 2013 when Lang Lang Gas Plant was back online.

Figure 2-7 — Gippsland SWZ production, 1 January 2012 to 30 September 2013

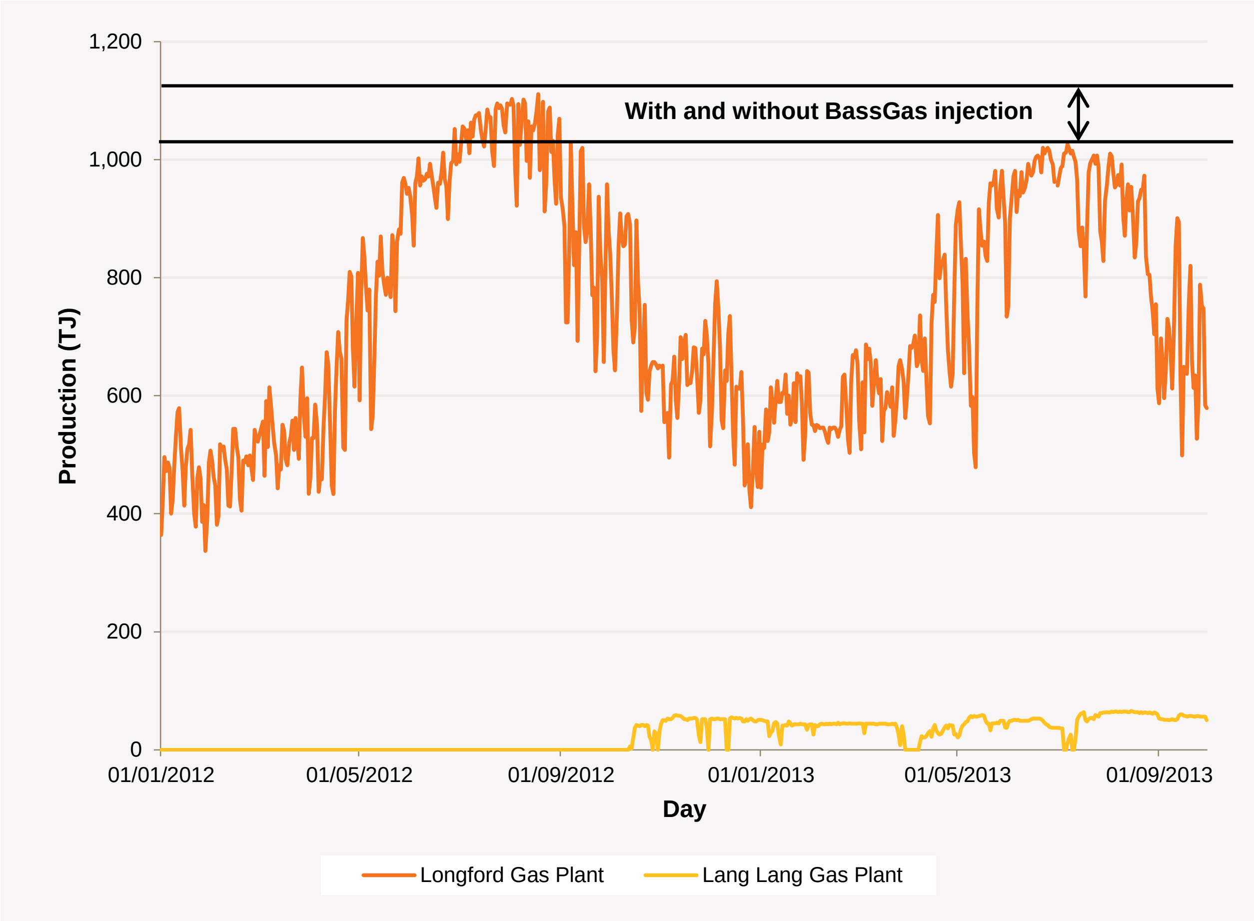

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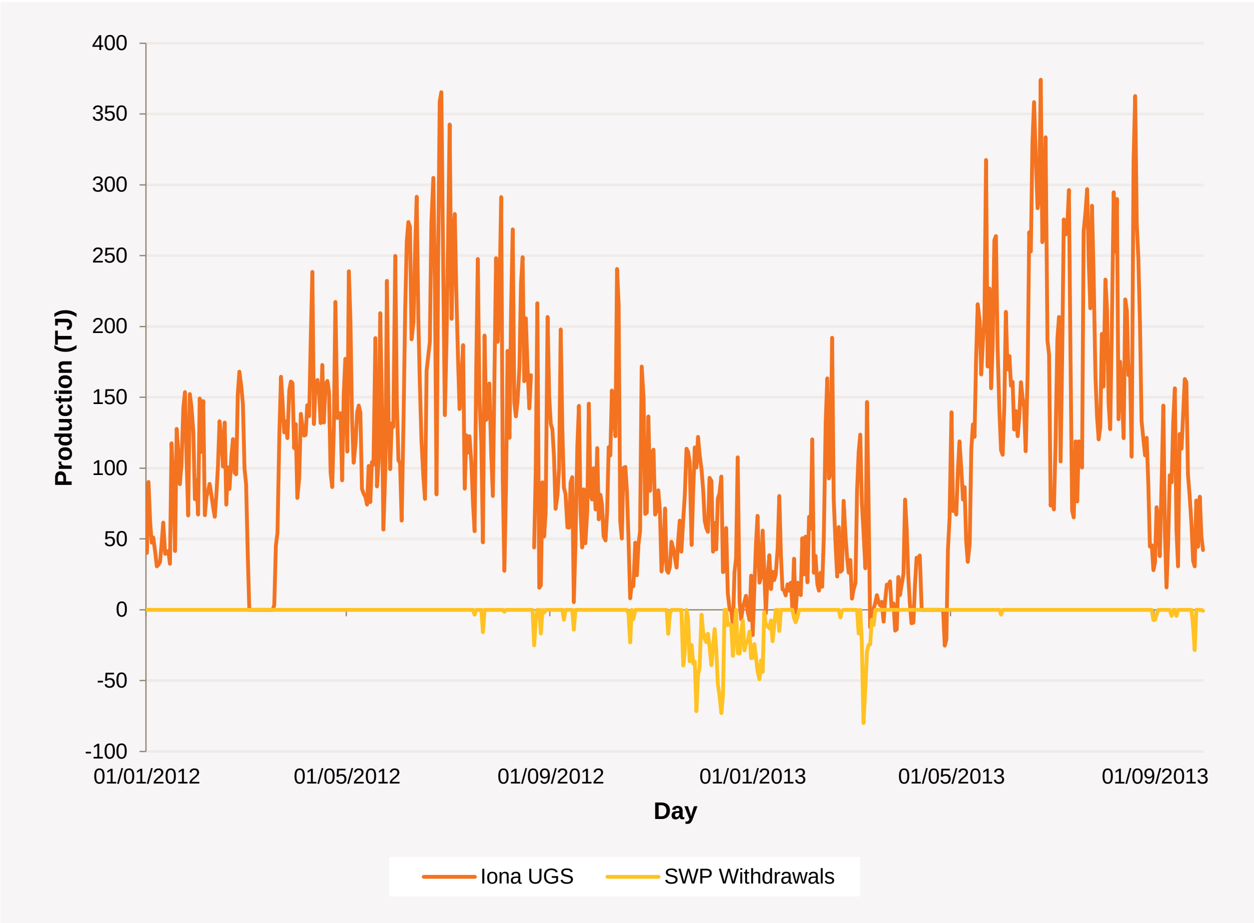
Figure 2-8 shows Iona Underground Gas Storage (UGS) production and SWP withdrawals from 1 January 2012 to 30 September 2013.

The figure shows that SWP withdrawals are higher than Iona UGS production which indicates that gas is withdrawn from the DTS and injected into either Mortlake or the SEA Gas pipeline. These withdrawals occur over the summer months.

Figure 2-8 — Iona UGS production and SWP withdrawals, 1 January 2012 to 30 September 2013



2.3.2 Peak day supply

The 2013 peak day occurred on 24 June, with total supply (including LNG) of 1,226.3 TJ injected into the DTS to meet demand and pressure requirements. Injections were higher than the 1200.4 TJ total demand because beginning-of-day linepack was below target and the end-of-day linepack was higher than target due to overnight demand being lower than forecast.

The 2012 peak day occurred on 9 August 2012, with total supply (including LNG) of 1,122.2 TJ injected into the DTS to meet demand and pressure requirements. Demand was similar to actual injections, meaning there was only a small change in linepack.

Table 2-3 lists the breakdown of supply for the peak day in 2013 and 2012.

Table 2-3 — Peak day gas supply, 2013 and 2012

Injection point	24 Jun 2013 (TJ)	% of total supply	9 Aug 2012 (TJ)	% of total supply
Longford	733.6	59.8	829.9	74.0
VicHub	78.9	6.4	80.1	7.1
BassGas	42.9	3.5	0.0	0.0
Total Longford, VicHub and BassGas	**855.5**	**69.8**	**910.0**	**81.1**
Iona UGS	314.8	25.7	207.7	18.5
SEA Gas	34.6	2.8	2.5	0.2
Otway	0.0	0.0	0.0	0.0
Total Iona, SEA Gas and Mortlake	**349.4**	**28.5**	**210.2**	**18.7**
Culcairn	0.0	0.0	0.0	0.0
Total (excluding LNG)	**1204.9**	**98.3**	**1120.2**	**99.8**
LNG	21.4	1.7	2.0	0.2
Total (including LNG)	**1226.3**	**100.0**	**1122.2**	**100.0**

2.3.3 Annual supply

Victorian gas market supplies totalled 222.2 PJ for the 12 months to 31 December 2012. Gas market supplies total up to 171.5 PJ for the nine months to 30 September 2013. Most gas supply was from the Gippsland area, with Longford and VicHub supplying 83.3% of total supply during winter 2013. BassGas supplies were low in 2012 due to the gas plant being offline for maintenance. Mortlake started injecting gas into Victoria, with a total injection of 0.7 PJ over the 2013 winter period. This resulted in reduced injections from SEA Gas.

In winter 2012, Culcairn showed 0.1 PJ net injection into Victoria and has not shown any net injection into Victoria for winter 2013.

A total of 0.04 PJ of LNG was injected into the DTS in 2013. LNG was dispatched twice, for the purpose of peak shaving, on 21 and 24 June 2013. These two days were the two largest demand days for the year and coincided with a Yallourn Power Station outage which contributed to 122 TJ and 85 TJ of GPG gas consumption on 21 and 24 June 20131 respectively.

Table 2-4 lists the breakdown of supply in calendar year 2012 and the nine months to September 2013.

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Table 2-4 — Annual and winter period gas supply in 2013[21] and 2012

Injection point	9 months to September 2013 (PJ)	May to September 2013 (PJ)	12 months to December 2012 (PJ)	% of total supply	May to September 2012 (PJ)	% of total supply
Longford	127.7	88.1	169.4	76.3	102.4	78.6
VicHub	5.7	4.6	13.6	6.1	7.2	5.6
BassGas	12.1	7.8	3.6	1.6	0.00	0.00
Total Longford, VicHub and BassGas	**145.5**	**100.5**	**186.6**	**84.0**	**109.6**	**84.2**
Iona UGS	16.7	15.1	25.6	11.5	15.8	12.1
SEA Gas	8.5	4.3	9.4	4.2	4.5	3.5
Otway	0.00	0.00	0.3	0.2	0.00	0.00
Mortlake	0.7	0.7	0.00	0.00	0.00	0.00
Total Iona, SEA Gas, and Mortlake	**25.92**	**20.1**	**35.3**	**15.9**	**20.3**	**15.6**
Culcairn	0.00	0.00	0.1	0.1	0.1	0.1
Total (excluding LNG)	**171.4**	**120.5**	**222.1**	**99.9**	**130.1**	**99.9**
LNG	0.04	0.04	0.1	0.1	0.1	0.1
Total (including LNG)	**171.5**	**120.6**	**222.2**	**100.00**	**130.2**	**100.00**

2.4 Comparison of winter period historical consumption and supply

Figure 2-9 and Figure 2-10 shows the components of consumption and supply for winter 2012 and winter 2013. The left bar for each month shows DTS withdrawals including system demand, GPG consumption and exports, and the right bar shows DTS supply by injection point. Gas supply from Mortlake and Otway is minimal and has been combined with SEA Gas.

[21] Annual gas supply in 2013 is partial and is from 1 January to 30 September 2013.

Figure 2-9 — Winter period consumption and supply comparison, 2012

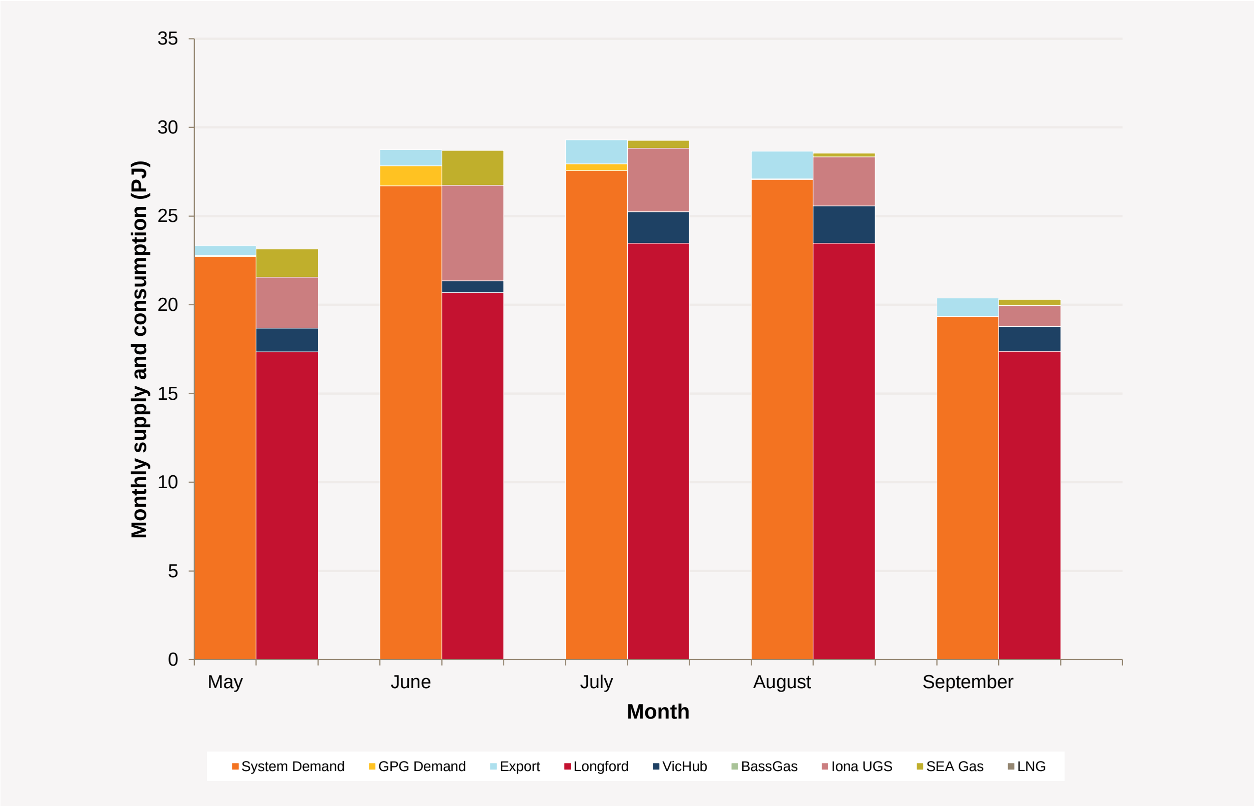
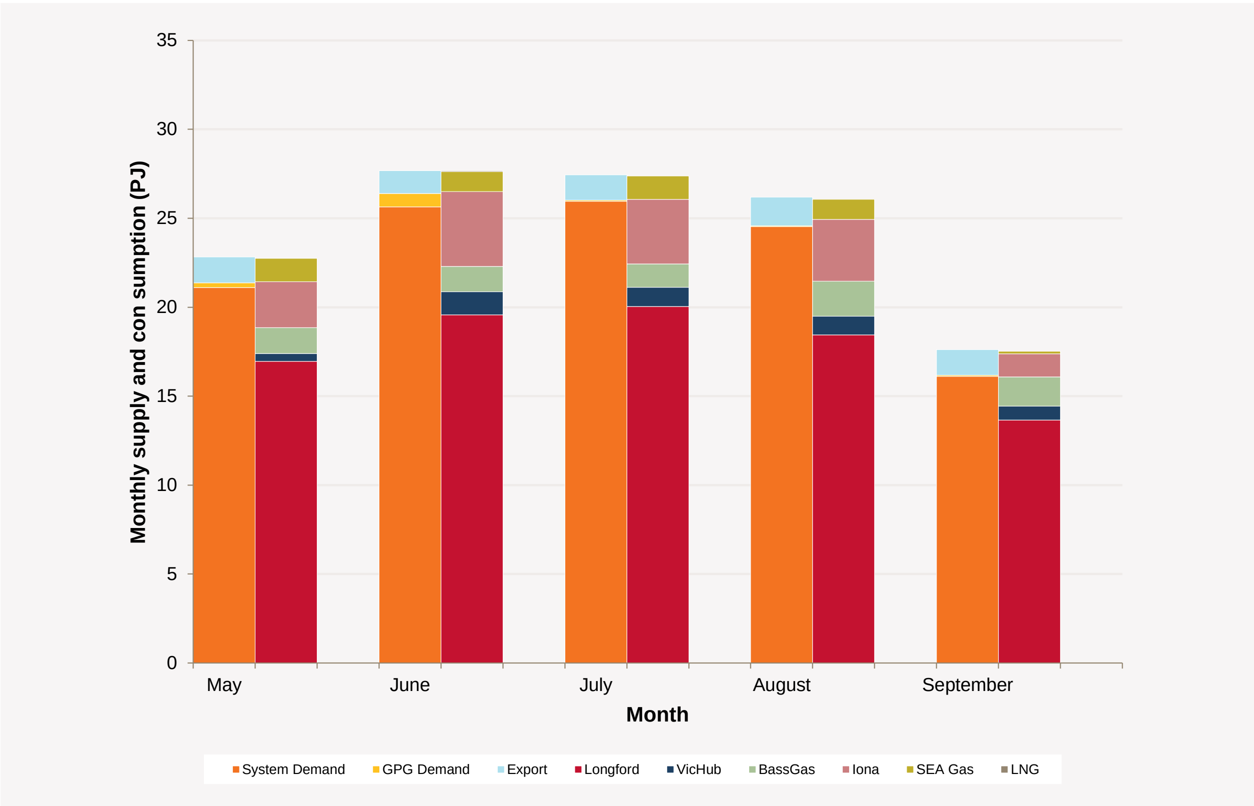


Figure 2-10 — Winter period consumption and supply comparison, 2013



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Chapter 3 DECLARED TRANSMISSION SYSTEM CAPACITY

Summary

This chapter presents an overview of the gas Declared Transmission System (DTS), individual pipeline capacities, the capacity of the DTS as a whole (system capacity), and background information on the factors that contribute to or limit pipeline and system capacity.

Based on current pipeline capacity, there is sufficient capacity in the DTS to meet demand as long as system demand is less than 1,349 TJ/d.

South West Pipeline (SWP) capacity has increased slightly for winter of 2014 to 367 TJ per day for a 1-in-20 peak day. The Winchelsea compressor, which will be in place by winter 2015, will further increase the SWP capacity to 429 TJ/d.

Increased capacity is required to meet increased in gas exports to New South Wales. The APA Group will loop (install a second parallel pipeline) sections of the Wollert to Barnawartha Pipeline. This will increase winter peak export capacity by 145% to 113 TJ/d.[22] The looping will be conducted in stages before winter 2015. Export capacity is expected to increase to 57 TJ/d for winter 2014.

This chapter also looks at how the system performs under different system demand and operating conditions. Depending on conditions, gas-powered generation (GPG) can rapidly deplete linepack in pipelines, potentially putting the system at risk. The modelling shows the system is able to support GPG demand within certain thresholds. For example, on a 1-in-2 day, the system is able to support 50 TJ/d GPG demand but curtailment may occur if GPG demand is 100 TJ/d, and it would almost certainly occur if GPG demand exceeded 150 TJ/d.

3.1 System capacity

This section provides information about modelled system capacity based on the maximum pipeline injections and pipeline operating limits for each of the main DTS pipelines. Information about modelled capacities and normal operating limits of individual pipelines is included in Section 3.2.

System capacity takes into account the interactions between the main DTS pipelines and is defined as the total quantity of gas that can be injected into the DTS on a gas day (6.00 am to 6.00 am).

The minimum pipeline pressures required for maintaining system security are provided in the Wholesale Market System Security Procedures (Victoria).[23] AEMO uses these requirements in its DTS capacity modelling.

[22] AEMO calculated this TJ/d figure by multiplying the previously published export capacity of 46 TJ/d by 145%, which is the capacity increase announced by APA Group.

[23] AEMO. Declared Wholesale Gas Market Rules and Procedures. Available at: http://aemo.com.au/Gas/Policies-and-Procedures/Declared-Wholesale-Gas-Market-Rules-and-Procedures. Viewed: 11 December 2013.

3.1.1 Injection points, main gas DTS pipelines, and typical gas flow

In Figure 3-1 the location of each system injection point is shown as an orange triangles and the storage facility is shown as a blue pentagons. The figure also shows the main DTS pipelines including:

- The Longford to Melbourne Pipeline which is the bulk transfer pipeline from both the Longford to Dandenong Pipeline and the Pakenham to Wollert Pipeline.
- The SWP (and the Brooklyn to Lara Pipeline) which is the bulk transfer pipeline from Iona to Brooklyn.
- The Northern System which is the bulk transfer pipeline from Wollert to Culcairn.
- The WTS which is the continuation of the DTS west of Iona to Portland and Hamilton.

Section 2.1 provides more detailed information about each injection point and main pipeline.

3.1.2 DTS system withdrawal zones

The DTS comprises six system withdrawal zones (SWZ): Gippsland, Western, Northern, Melbourne, Geelong, and Ballarat. These are shown in Figure 3-1. AEMO develops consumption and demand forecasts for each SWZ as well as the DTS as a whole.

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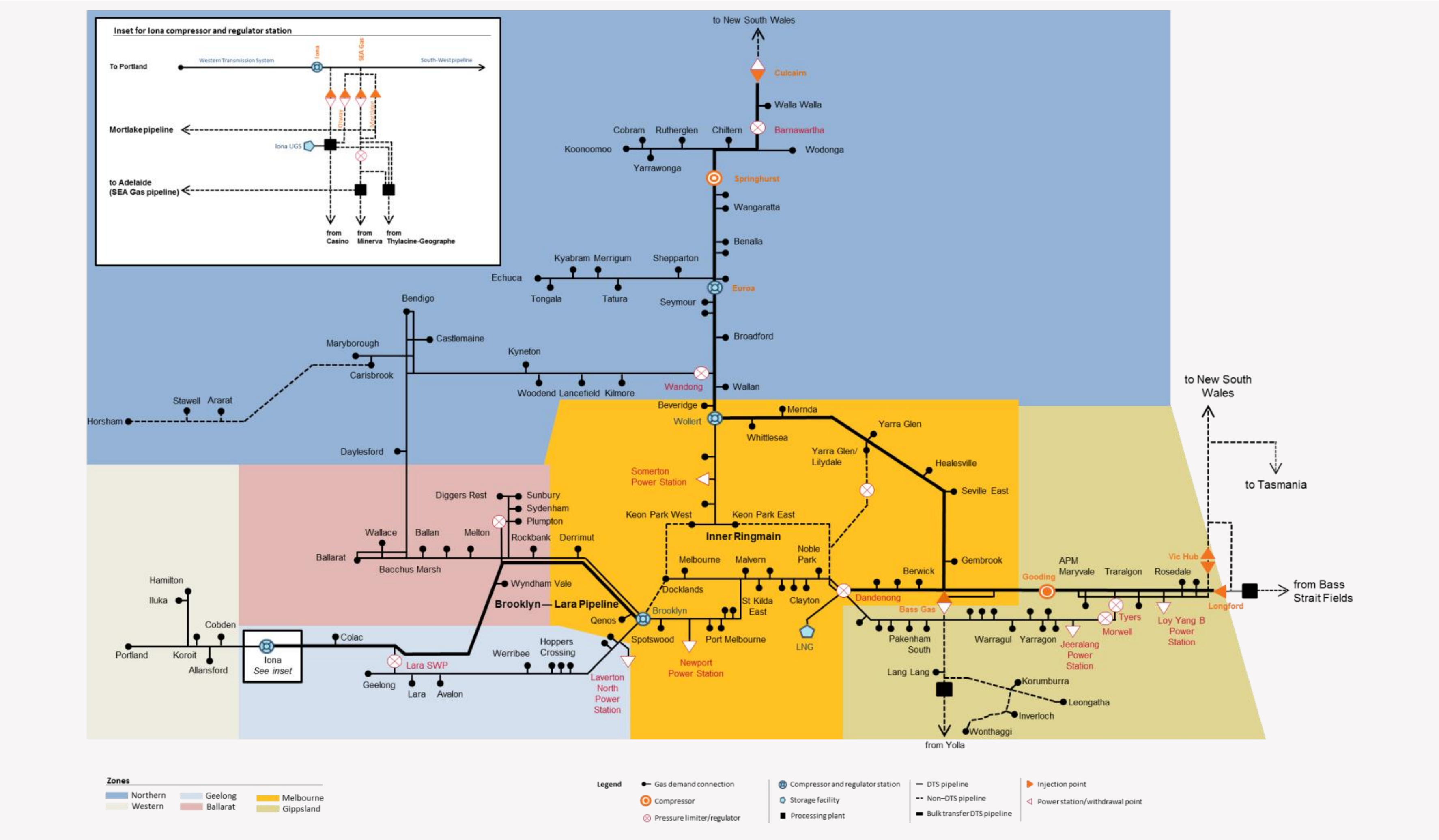
Figure 3-1 — System Withdrawal Zones[24]



24 AEMO. *Victorian Gas Planning Report*. Available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning-Report. Viewed: 12 December 2013.

3.1.3 Modelled system capacity

Injections are limited by the ability of the system to transport gas to demand areas. For this reason DTS system capacity is less than the sum of the capacities from all the individual pipelines. System capacity also depends on system conditions including demand, linepack, load distribution, and injection locations and amounts.

Figure 3-2 shows the DTS system capacity as a function of Iona injections and the LMP capacity under a simplified scenario with the following conditions:

- Culcairn export flow is assumed to be zero.
- There is no GPG demand.
- LNG injection is zero.
- Iona operates at up to 9,500 kPa.
- WTS demand of 17 TJ/d.
- No Winchelsea compressor.[25]

Figure 3-2 shows how system capacity varies with Iona injection (vertical axis) and LMP capacity (horizontal axis). The solid blue line shows the DTS operating boundary, where capacity is constrained by pipeline operating limits. The diagonal dashed lines show how a constant system capacity trajectory can be made up by different levels of Iona injection and LMP capacity. System capacity is limited to the feasible operational region within the solid line.

For example, a 900 TJ/d demand level can be met by 900 TJ/d of Longford injections and no Iona injections at one end of the range, to 600 TJ/d of Longford injections and 300 TJ/d of Iona injections at the other.

System capacity increases as pipeline injections at Iona and Longford increase. Maximum system capacity of 1,349 TJ/d is attained when the LMP capacity is at 1,030 TJ/d. This includes 970 TJ/d injection from the Longford gas plant and VicHub, and 60 TJ/day injections from BassGas. Because Iona injection and LMP capacity interact with each other, in the case of maximum LMP capacity, Iona injection is limited to 319 TJ/d.

When Iona is injecting at maximum capacity of 384 TJ/d, LMP capacity is limited to 950 TJ/d. This results in a reduced system capacity of 1,334TJ/d. When LMP capacity exceeds 950 TJ/d, Iona injection must be reduced proportionately.[26]

The 1-in-2 peak day system demand is forecast to increase from 1,155 TJ/d in 2014 to 1,195 TJ/d in 2018, and 1-in-20 peak day system demand is forecast to increase from 1,277 TJ/d in 2014 to 1,322 TJ/d in 2018. There is sufficient system capacity to meet peak system demand even if LMP capacity or SWP capacity is at maximum.

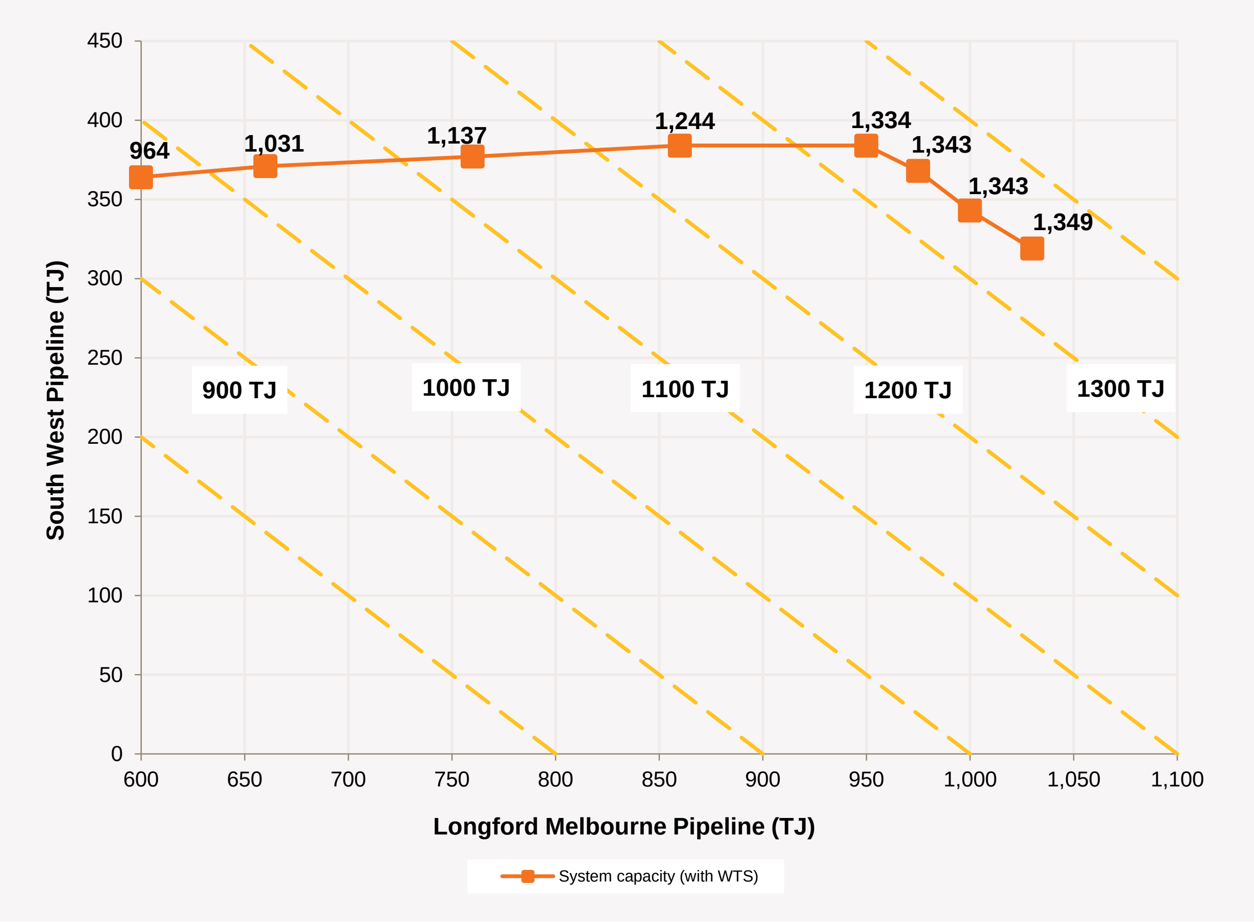
Total system capacity has decreased from the previously published 2012 Victorian DTS capacity of 1,350 TJ/d (without WTS demand) due to peakier load profiles in the forecast demand. This results from increased residential (Tariff V) demand, which is a peaky load, and reduced industrial (Tariff D) demand, which has a flatter profile. Peakier loads deplete more linepack for the same system demand, resulting in lower system capacity. AEMO will conduct further modelling of this issue for the 2015 VGPR.

Additional exports through Culcairn could increase the LMP and/or the Iona injection (post Winchelsea compressor), and therefore increasing system capacity. However, on a peak winter day, LNG injections are expected to be required to support export.

[25] The Winchelsea compressor is expected to be operational in winter 2015. Therefore, studies for system capacity with the Wincheslea compressor have not been conducted but will be conducted and published in the VGPR.

[26] This is due to a back-off effect that forces a reduction of gas injections, and is due to system conditions and pipeline network topology. System capacity is less than the sum of the LMP and the Iona injection, which is 1,349 TJ/d.

Figure 3-2 —DTS total system demand capacity



3.2 Modelled pipeline capacities

This section provides modelling information about individual pipeline capacities and the factors that affect pipeline normal operating boundaries.

Table 3-1 provides a summary of the currently allowable maximum pipeline injections, withdrawals, and operating boundaries. Nominal values are used, but reference is also made (where appropriate) to the range of injections for different operating conditions. These capacities assume a flat profile (a constant injection rate) for gas supply injections and a winter peak demand profile (unless otherwise specified).

Sections 3.2.1 to 3.2.6 provide more information about the allowable maximum injections, normal pipeline operating boundaries, and other factors that influence the capacity for each pipeline.

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Table 3-1 — Pipeline injections, withdrawals, and operating boundaries

Pipeline	Allowable maximum pipeline injections (TJ/d)	Normal pipeline operating range (TJ/d)	Comment
Longford to Melbourne	1,030	990–1,030	Longford to Melbourne pipeline capacity is 990 TJ/d with coincident injections from the Longford Gas Plant and VicHub. This capacity increases to 1,030 TJ/d with further coincident injections from BassGas (at Pakenham). These capacities are based on Longford pressures not exceeding 6,750 kPa. When BassGas is injecting and when pipeline capacity is reached, injections at Longford need to be reduced in the ratio of 1 to 3 to compensate. For more information, see Section 3.2.1.
South West Pipeline (from Iona)	367	300–367	SWP injection rates at Iona depend on pipeline pressure and Geelong SWZ demand. Maintaining WTS supply security requires the following winter operating pressure at the beginning-of-day at Iona: • Up to 9,500 kPa enables injections of 367 TJ/d on a 1-in-20 peak day into SWP. • 8,000 kPa enables injections of approximately 300 TJ/d on a 1-in-2 demand day into SWP. For more information, see Section 3.2.2.
South West Pipeline (to Iona)	129[a]	38–129	Allowable withdrawals at Iona (which occur mostly during summer) fall when the Laverton North Power Station is operating. During winter, Iona withdrawal capacity is greatly reduced and (due to market forces) Iona is expected to inject. For more information, see Section 3.2.3.
NSW-VIC Interconnect (imports)	120	35–120	Imports of 120 TJ/d are possible when the Young (Centaur) compressor, the Springhurst compressor, and the Euroa compressor are operating, and with the Wagga Wagga loop. For more information, see Section 3.2.4.
NSW-VIC Interconnect (exports – summer)	86	Up to 86	The first stage of the Northern System expansion is expected to be completed by winter 2014. Summer export capacity will be 86 TJ/d. Summer exports are expected to increase further with additional pipeline looping to be constructed prior to winter 2015. For more information, see Section 3.2.5.
NSW-VIC Interconnect (exports – winter)	57	57–72	On a 1-in-20 peak day in 2014, the first expansion stage is expected to increase Culcairn exports to 57 TJ/d under ideal DTS linepack, pressure, and compressor operating conditions. However, on winter days with lower demand (e.g., 1000 TJ/d), the system could export up to 72 TJ/d. Higher DTS demand reduces its capacity to export through Culcairn. Important operational considerations include intraday linepack management and the potential for using peak shaving gas. Additional pipeline looping will be constructed prior to winter 2015 to further increase New South Wales export capacity. For more information, see Section 3.2.5.

Pipeline	Allowable maximum pipeline injections (TJ/d)	Normal pipeline operating range (TJ/d)	Comment
Western Transmission System	28	17–28	WTS injections of 17 TJ/d to 22 TJ/d at Iona are possible when utilising the Iona compression with suction pressures of 4,000 kPa to 4,300 kPa. This can increase to 28 TJ/d with sufficient injections by the facilities at Iona, which results in a higher pressure supply into the WTS. For more information, see Section 3.2.6.

a. This refers to maximum withdrawals from Iona rather than maximum injections into the SWP.

3.2.1 Longford to Melbourne pipeline

Pipeline injections and withdrawals

Maximum injections into the Longford to Melbourne pipeline 990 TJ/d when injections are solely from the facilities at Longford. Assumptions underpinning this level of injections include the following:

- Injections are from the Longford gas plant and VicHub only.
- There are no injections from BassGas.
- There are favourable operating conditions (for example, sufficient beginning-of-day linepack).
- All compressors and other transmission assets are available.

The LMP capacity assessment assumes a Longford Gas Plant operating pressure of up to 6,750 kPa. High pressures at Longford, especially prior to morning or evening peak, can cause the Longford Gas Plant to reduce injections. BassGas injections of 60 TJ/d increase the LMP injection capacity to a maximum of 1,030 TJ/d. When BassGas is injecting and pipeline capacity is reached, injections at Longford need to be reduced in the ratio of 1 to 3.

GPG use in the Latrobe Valley increases the LMP capacity. This reduces the amount by which the Longford injection needs to be reduced.

Pipeline operating boundary – contributing factors

Several factors affect the pipeline operating boundary:

- System linepack and Longford pressures.
- Gooding and Wollert compressor station operations.
- GPG demand in the Latrobe Valley.

3.2.2 South West Pipeline (from Iona)

Pipeline injections and withdrawals

Current operating strategy is to target an optimum linepack that maintains a consistent average linepack independent of daily flow along the pipeline. Under high flow conditions, upstream pressure at the Iona end is high and downstream pressure at Brooklyn is low. Under lower flow conditions the difference between upstream and downstream pressure is reduced.

Maintaining linepack under high flow conditions is particularly challenging for the SWP due to the pressure drop along the pipeline that occurs and the variability of injections scheduled at Iona. Injections can be as high as 300 TJ/d on one day and less than 100 TJ/d the next. During winter, Iona withdrawals are sometimes scheduled overnight if system injections are significantly higher than actual demand.

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Pipeline operating boundary – contributing factors

Several factors affect the pipeline operating boundary:

- Demand uncertainty.
- Linepack management requirements.
- Beginning-of-day pressure at Iona.
- System demand.
- GPG consumption at Newport and Laverton North.
- Intermittent sources of significant gas demand in the Geelong zone.

The current SWP capacity (from Iona to Lara), which is the amount of gas that can be transported from Iona towards Melbourne under 1-in-20 peak day operational conditions, has been increased from 353 TJ/d (published in the 2012 Victorian Gas DTS Capacity Report[27]) to 367 TJ/d. This is due to reduced operating pressures at the Wollert City Gate, connection of Western Outer Ring Main (WORM) Stage 1 (Plumpton PRS (Pressure Reduction Station)) to the Brooklyn Lara Pipeline, and recalibration of the Victorian network model in February 2013.

SWP capacity will increase to 429 TJ/d for a 1-in-20 peak day by winter 2015 with the commissioning of the Winchelsea compressor. Modelling has shown that pipeline capacity differs under different operating conditions such as system demand and operating pressures.

This SWP capacity figure is for pipeline flow towards Melbourne and does not include the WTS. Therefore, total Iona injections are the sum of SWP flow and WTS demand. A WTS demand of 17 TJ/d would allow total system injection at Iona of 446 TJ/d.

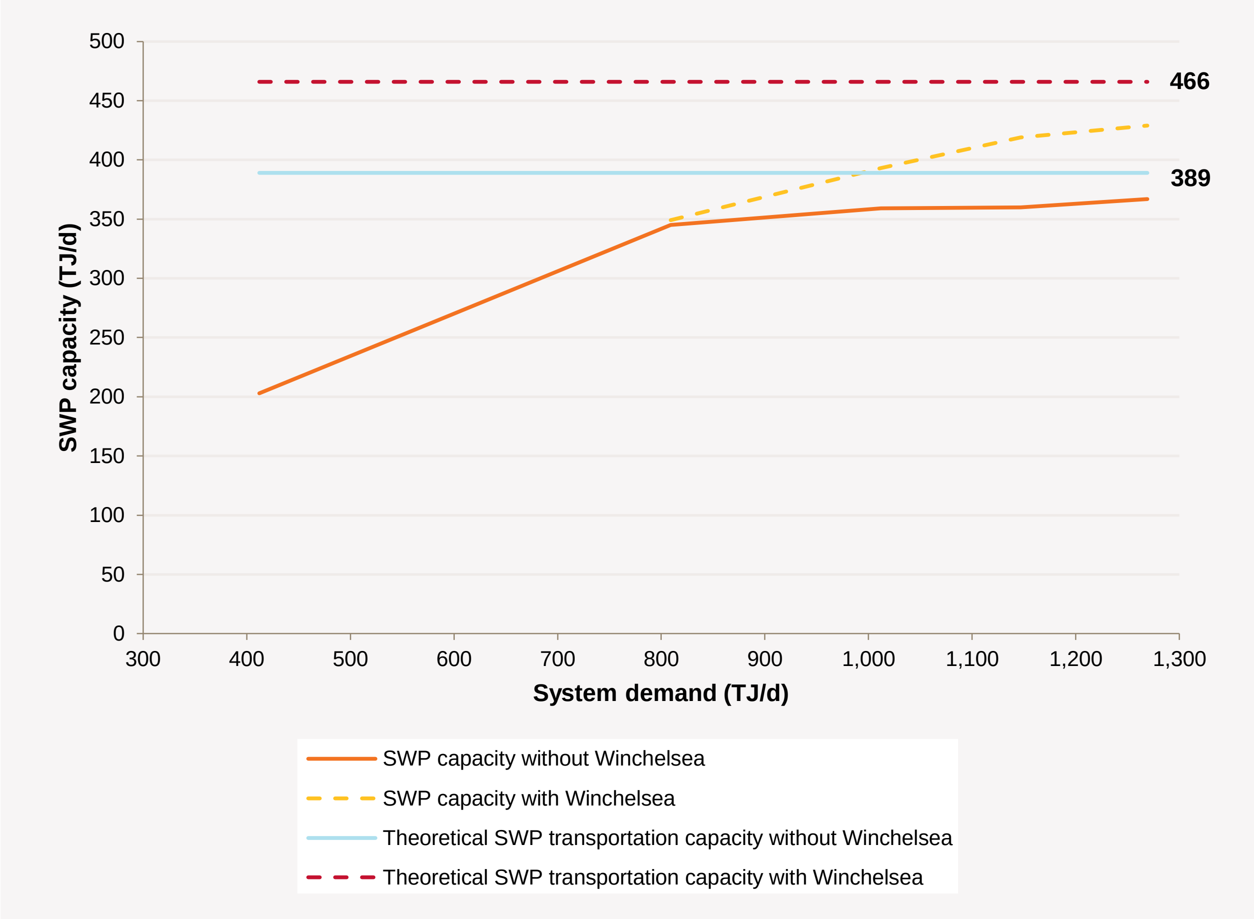
Figure 3-3 shows the relationship between system demand and SWP injections at Iona on different system demand days. This injection capacity is not constant, and decreases as system demand reduces. These capacities can be achieved with a maximum pressure at Iona of 9,500 kPa. The dashed line shows SWP capacity increases with the Winchelsea compressor in operation.

Figure 3-3 also shows the SWP's theoretical transportation capacity if it is not limited by downstream demand. Similarly it shows that the SWP capacity reduces and can even be limited on days with low system demand. This is not considered likely to occur given that Iona Underground Gas Storage (UGS) injections peak during winter to support peak demand, and it usually withdraws gas on low demand days.

AEMO's modelling assumptions are detailed in Appendix A.

[27] AEMO. *Victorian Gas DTS Capacity*. Available at: http://aemo.com.au/Gas/Planning/Victorian-Gas-DTS-Capacity. Viewed: 11 December 2013.

Figure 3-3 — SWP capacity with varying system demand days



Allowing the SWP to operate at pressures approaching its maximum allowable operating pressure (MAOP) also enables increased injections; however, high pipeline pressures create operational issues for the DTS.

For example, warmer-than-expected weather and consequent lower daily demand increase the risk of high pressures in the system, especially overnight. The inability to shift linepack quickly into the SWP (using compression at Brooklyn) if SWP injections decrease overnight can cause high operational pressure at Longford. This may cause a reduction in Longford Gas Plant injections.

Figure 3-4 shows the relationship between SWP capacity and maximum operating pressure at Iona. The SWP can transport up to 387 TJ/d under ideal conditions on a day with system demand of a 1-in-20 peak day if the pipeline is operating at its MAOP of 10,200 kPa at Iona. The SWP transportation capacity in Figure 3-4 is based on a 1-in-20 peak day. The SWP transportation capacity decreases with lower system demand.

For operational reasons, it is considered impractical to operate the pipeline at this pressure. Taking into account pressure variations throughout the day, the SWP can normally transport 367 TJ/d based on a maximum operating pressure of 9,500 kPa at Iona on a 1-in-20 peak day. The dashed line shows SWP capacity with Winchelsea compressor in place.

Assumptions from the modelling can be found in Attachment A.

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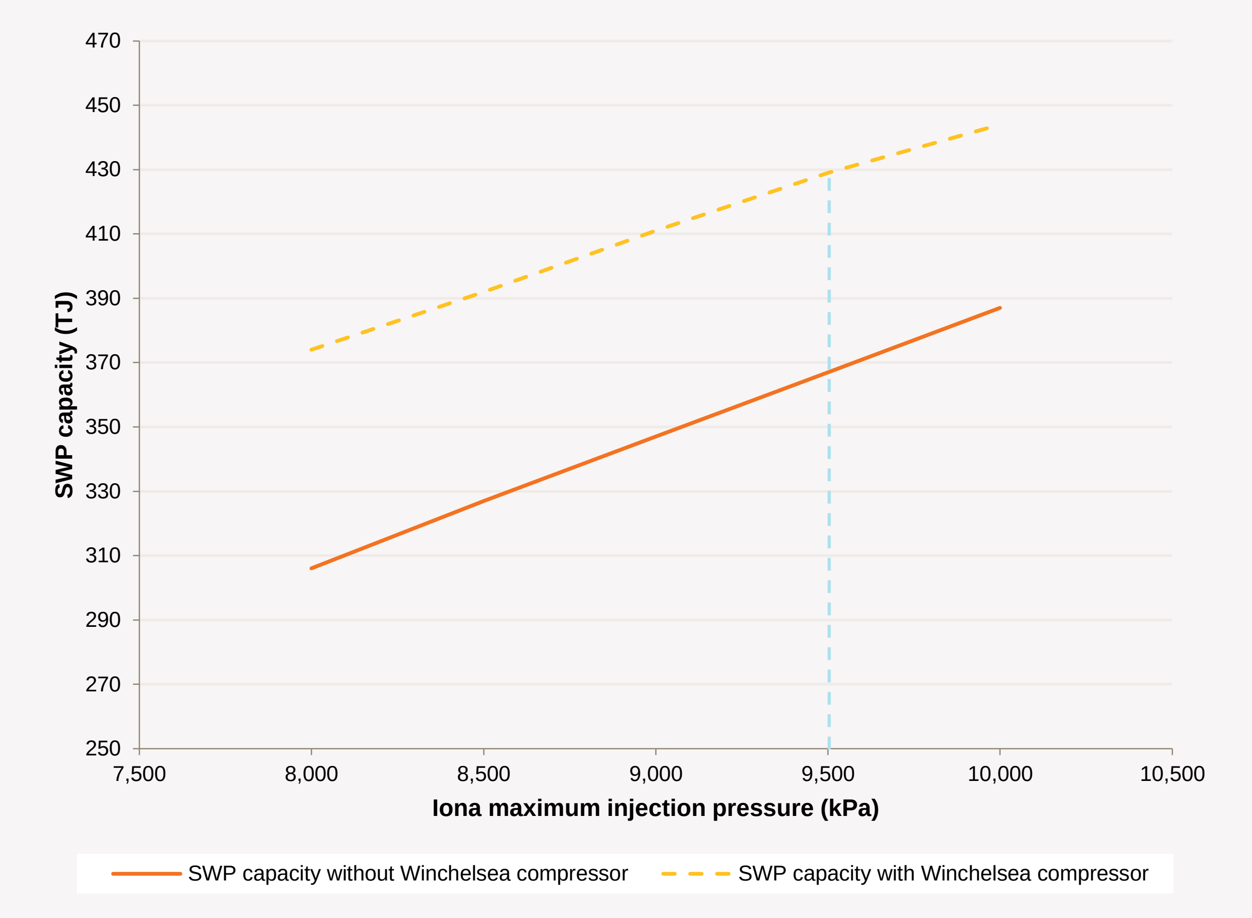
Figure 3-4 — SWP capacity with varying Iona pressure



3.2.3 South West Pipeline (to Iona)

Pipeline injections and withdrawals

Net pipeline withdrawal capacity at Iona currently depends on the throughput of the Brooklyn Compressor Station. Based on a 400 TJ/d demand day and compressor station capacities, the maximum modelled withdrawals from the SWP at Iona are as follows:

- 108 TJ/d with Units 11 and 12 operating, and a minimum pressure of 4,300 kPa at Iona.
- 31 TJ/d if only Unit 11 is available.
- 46 TJ/d if only Unit 12 is available.

Several factors may lead to a future requirement to transport increased amounts of gas to Iona:

- Increased SEA Gas flows to South Australia as Moomba gas is diverted to LNG exports (in the medium term).
- Increased utilisation of the Iona UGS to meet system demand, which will require additional gas to fill the storage reservoirs.
- Reduced production from the Otway Basin (such as the Casino, Minerva, Geographe, and Thylacine gas fields) as the gas fields are consumed.

The Iona net withdrawal values used are the quantities that can be withdrawn at Iona. WTS demand is already accounted for in the modelling.

Figure 3-5 shows the effect of different levels of system demand and different minimum Iona pressures on the ability to withdraw gas at Iona. The modelling assumes there is no gas flow to Newport and Laverton North power stations.

Modelling simulations for the summer period indicate a reduction in withdrawal capability at Iona of approximately 1 TJ/d for every 10 TJ/d of GPG demand at Newport, and 10 TJ/d for every 10 TJ/d of GPG demand at Laverton North.

Pipeline operating boundary – contributing factors

Several factors affect the operating boundary (for possible net Iona withdrawals):

- Demand downstream of Brooklyn (including the Laverton North Power Station, and the Geelong Zone).
- Sunbury pipeline demand if supplied from BLP.
- Ballarat zone demand (for high demand days only).
- Minimum operational pressure requirements at Iona.
- GPG demand at Newport, which reduces gas flow to Brooklyn.

During the shoulder seasons, minimum pressure requirements at Iona to ensure adequate SWP linepack are:

- Approximately 4,300 kPa (depending on system conditions).
- An increase to 4,500 kPa to provide the additional linepack to meet a 1-in-20 peak demand day on the WTS.

These figures allow for a possible load increase from the Laverton North Power Station if gas is withdrawn at Iona.

Future increases in Iona's minimum pressure targets may be required for at least part of the year to:

- Provide sufficient SWP security margins to ensure WTS supply security.
- Help manage Iona withdrawals together with Laverton North Power Station generation.

Maintaining a higher pressure at Iona will lead to a reduced supply of gas at Iona for withdrawal.

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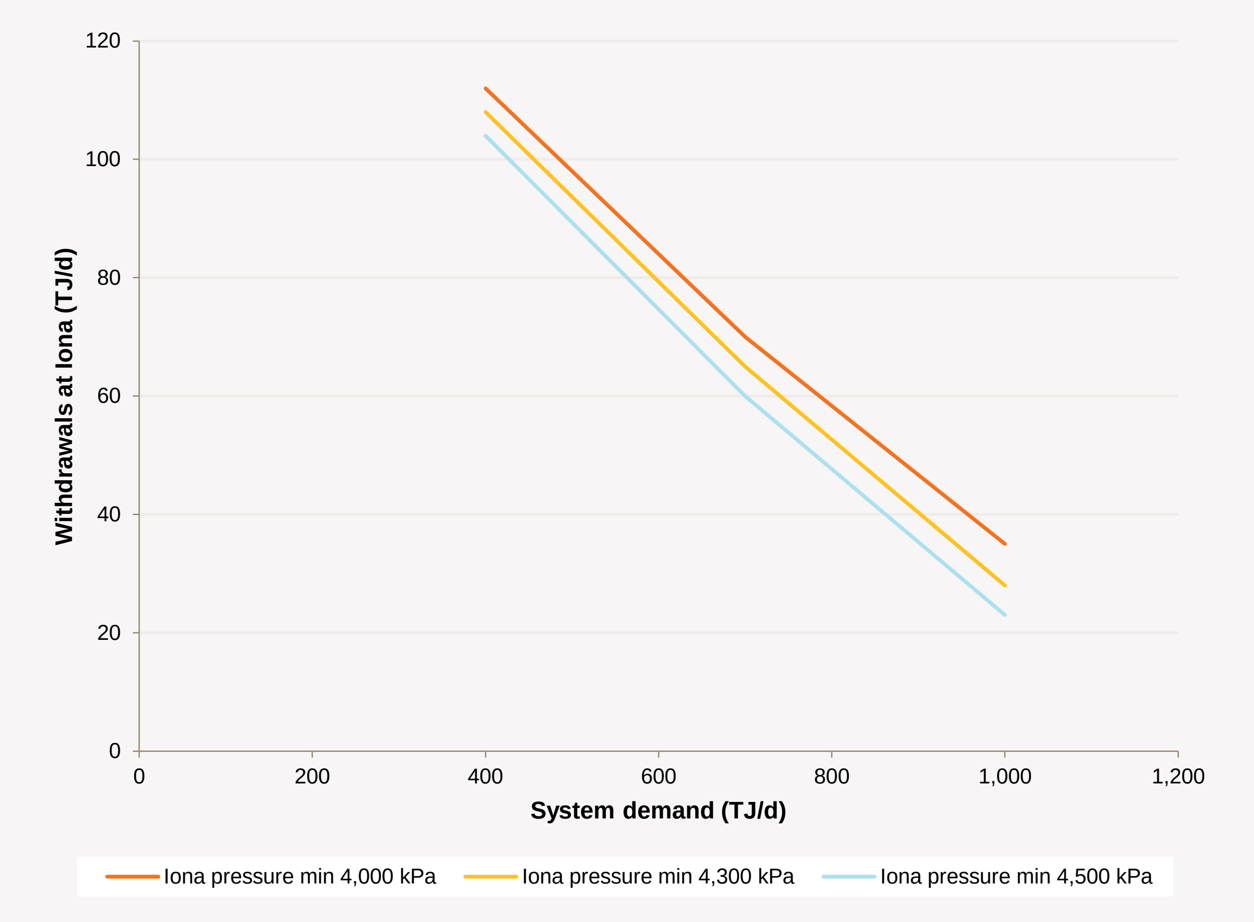
Figure 3-5 — Withdrawals at Iona as a function of system demand



3.2.4 New South Wales – Victoria Interconnect (imports)

Pipeline injections and withdrawals

When the Young[28], Springhurst, and Euroa compressors are operating and the Wagga Wagga loop[29] (between Young and Culcairn in New South Wales) is also operating, the maximum Culcairn import (supply into Victoria) capacity is 120 TJ/d. Culcairn compressors are not bi-directional so they are not used for import.

Figure 3-6 shows that increasing system demand also increases the capacity to import gas through Culcairn. The modelling assumes:

- The Young compressor has adequate power to operate at a constant discharge pressure of 8,500 kPa.
- The Springhurst compressor is operating.
- The Euroa compressor is operating.
- The Uranquinty Power Station is not in operation.
- The pressures in the DTS are set up to maximise imports through Culcairn.

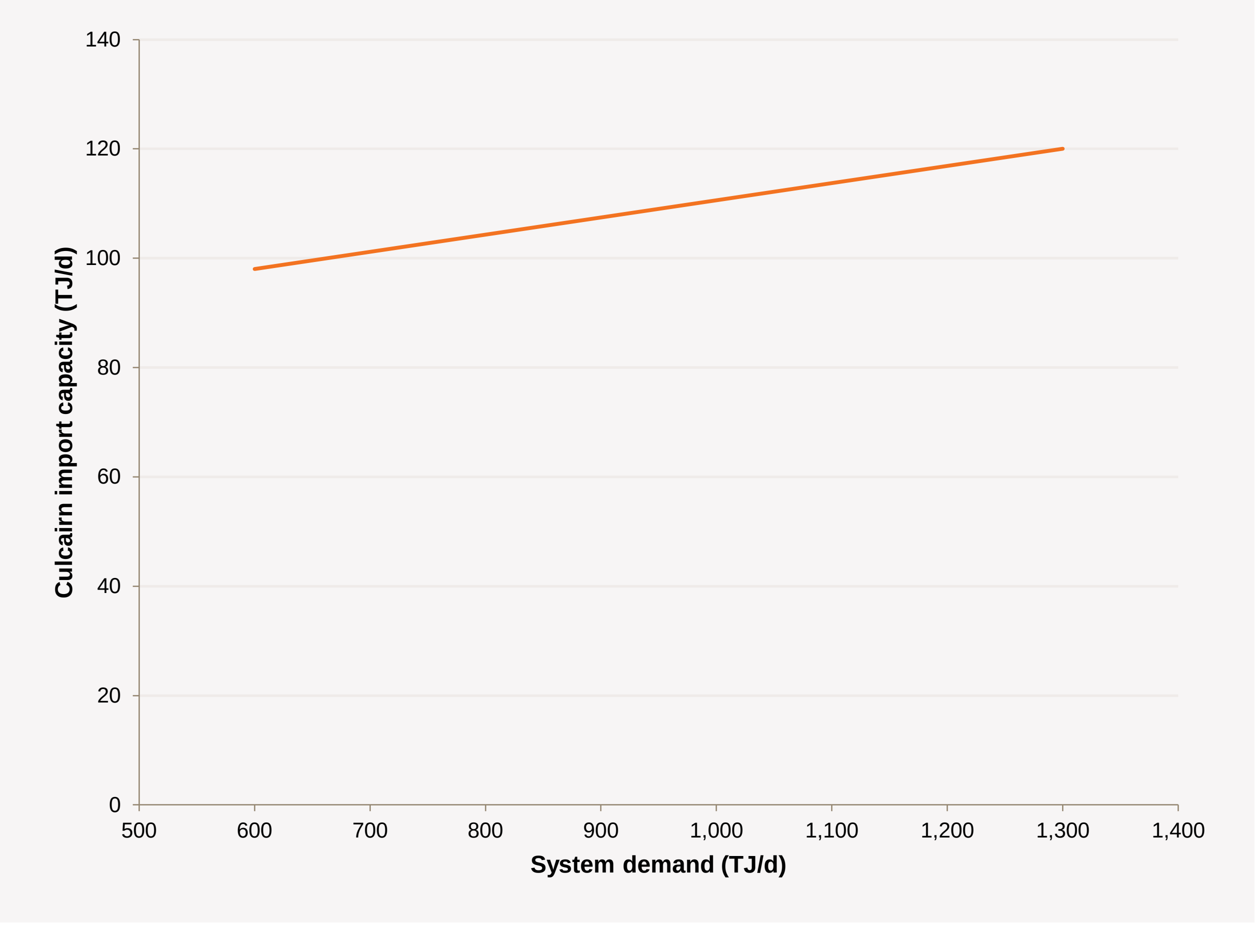
[28] Young is in NSW about 130 km northwest of Canberra.
[29] Pipeline duplication between Bethungra and Wagga Wagga.

Pipeline operating boundary – contributing factors

Several factors affect the operating boundary:

- DTS demand in Victoria and system demand in New South Wales.
- GPG demand at the Uranquinty Power Station.
- Operational constraints (linepack and compressor availability) in New South Wales.
- Northern Zone linepack.

Figure 3-6 — Imports from New South Wales through Culcairn



3.2.5 New South Wales – Victoria Interconnect (exports)

Pipeline injections and withdrawals

There are two Centaur 50 compressors installed at Wollert CS and one at Springhurst CS. Addition of a Centaur 50 compressor at Euroa in 2012 increased export capacity to New South Wales. Both the Euroa and Springhurst compressors can compress gas bi-directionally.

Figure 3-7 shows the relationship between Culcairn export capacity via the NSW-VIC Interconnect and total DTS demand. These exports can be achieved with a minimum modelled pressure of 6,000 kPa at Culcairn.

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The orange line shows current Culcairn export capacity at 46 TJ/d based on AEMO's 2012 Victorian Gas Medium Term Outlook forecast.[30] Load growth north of the Springhurst CS from winter 2014 onwards will decrease Culcairn export capacity to 42 TJ/d, demonstrated by the yellow line.

On 4 November 2013, the APA Group announced that it will expand the NSW-VIC Interconnect. The expansion will increase compression capacity at Culcairn and loop sections of the Wollert to Barnawartha in the Victorian DTS. The aggregate effect of the expansion will be to increase firm peak winter gas flow capacity from the Victorian DTS into the Moomba Sydney Pipeline by 145%. This expansion is intended to increase export capacity by 67 TJ/d from 46 TJ/d to 113 TJ/d on a 1-in-20 peak system demand day. It will commence this year and be completed by winter 2015.[31]

The first stage of the expansion is due for completion by winter 2014 and will increase Culcairn export capacity to 57 TJ/d. This is shown in the blue dashed line in Figure 3-7.

In accordance with Rule 329 of the National Gas Rules, AEMO will work closely with the APA Group to develop and agree the export capacity once the looping locations are confirmed by the APA Group. The capacities will be published in the 2015 VGPR.

Pipeline operating boundary – contributing factors

A series of factors affect the NSW-VIC Interconnect operating boundary:

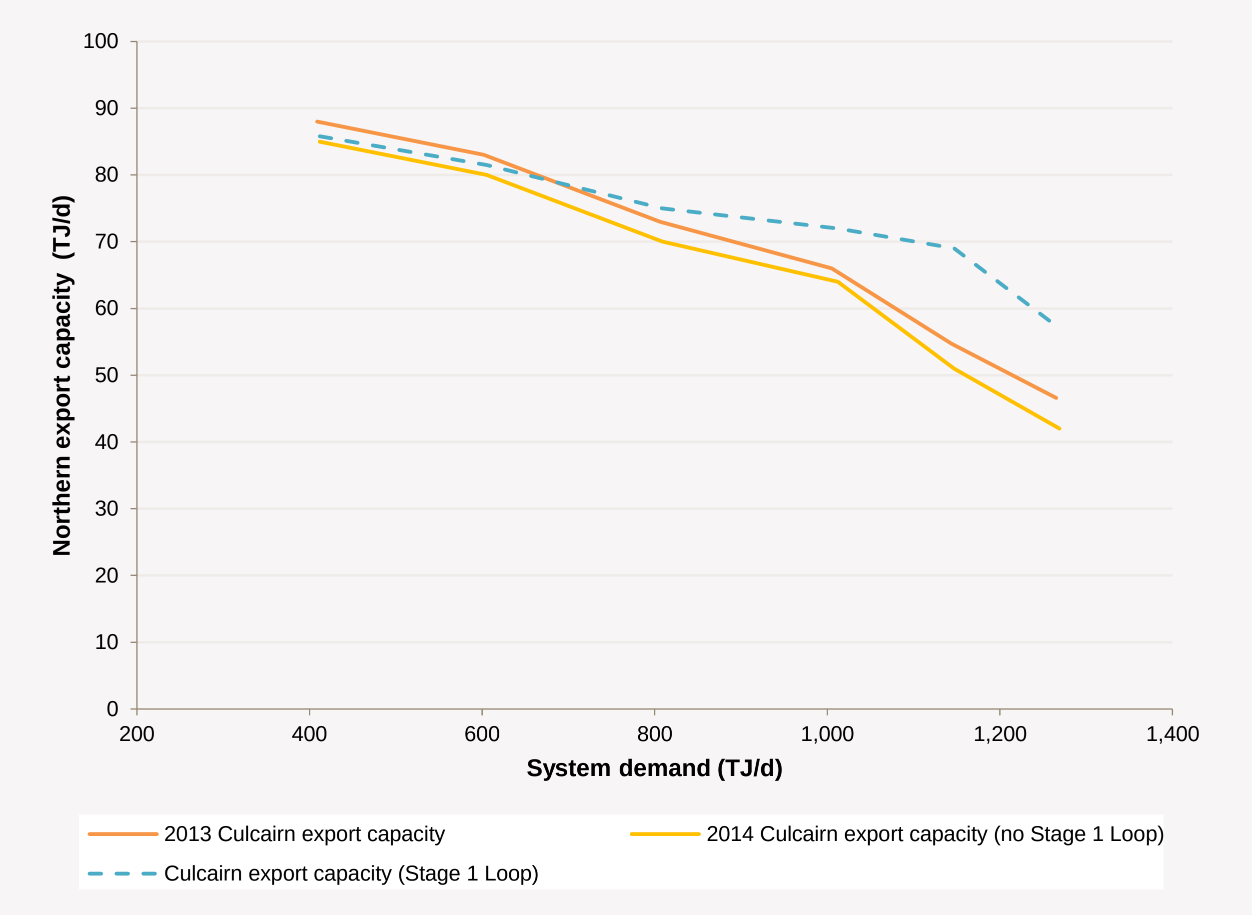
- Pressures required at Culcairn for the compressors on the New South Wales side of the Interconnect.
- Demand levels in the DTS.
- Wollert CS, Euroa CS, and Springhurst CS availability.
- LMP linepack.
- Requirement for peak shaving gas (i.e., LNG scheduled for very cold winter weather conditions).

In winter, the ability to export from Victoria to New South Wales declines due to higher peak winter demand in the DTS including in northern Victoria. Different operating pressure requirements at Culcairn also cause the export flow to vary.

[30] AEMO. *2012 Victorian Gas DTS Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013.

[31] The APA Group. *APA to further expand VIC NSW interconnect*. Available at: http://www.apa.com.au/investor-centre/news/asxmedia-releases/2013/apa-to-further-expand-vic-nsw-interconnect.aspx. Viewed: 11 December 2013.

Figure 3-7 — Exports to New South Wales at 6,000 kPa minimum modelled pressure at Culcairn



3.2.6 Western Transmission System

Pipeline injections and withdrawals

The maximum modelled injections into the Western Transmission System (WTS) are 28 TJ/d. This assumes injections at Iona result in a WTS supply pressure of at least 7,500 kPa. This is not a firm capacity and maintaining this pressure requires high net injections at Iona over consecutive days.

Pipeline operating boundary – contributing factors

Factors affecting the WTS operating boundary include WTS load growth (given its fringe location), and the pressure at Iona.

Depending on SWP gas flows for the preceding day, Iona pressures may be high enough to supply WTS demand without using the Iona compressors. This usually occurs during winter.

The WTS has unique operational pressure requirements. In terms of WTS demand:

- Compression at Iona is required to meet moderate and peak demands when SWP pressures at Iona are relatively low.
- Without Iona compression, SWP's minimum pressure at Iona of 3,800 kPa is lower than the normal 4,500 kPa minimum operational requirement and limits supplies to approximately 10 TJ/d. This is only sufficient on days of low summer demand. With Iona compression, the 3,800 kPa minimum pressure at Iona enables a WTS supply of approximately 18 TJ/d.
- Peak WTS demand can occur in September and October due to the region's increased food and dairy processing plant activity, which is when the Iona UGS can also be in withdrawal mode.

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Peak WTS demand for the outlook period is forecast to be the same as 2012. However, if Iona is in withdrawal mode and SEA Gas or Mortlake is not injecting, the supply pressure at Iona will need to be maintained at approximately 4,500 kPa to maintain WTS security of supply on a 1-in-20 peak demand day.

If WTS demand increases or if the pressure at Iona cannot be maintained at 4,500 kPa, augmentation might be required. Possible augmentations include connecting the Brooklyn compressor directly to the Brooklyn to Lara Pipeline (BLP), which will result in a higher pressure at Iona; a connection to the SEA Gas pipeline; or additional WTS compression and looping.

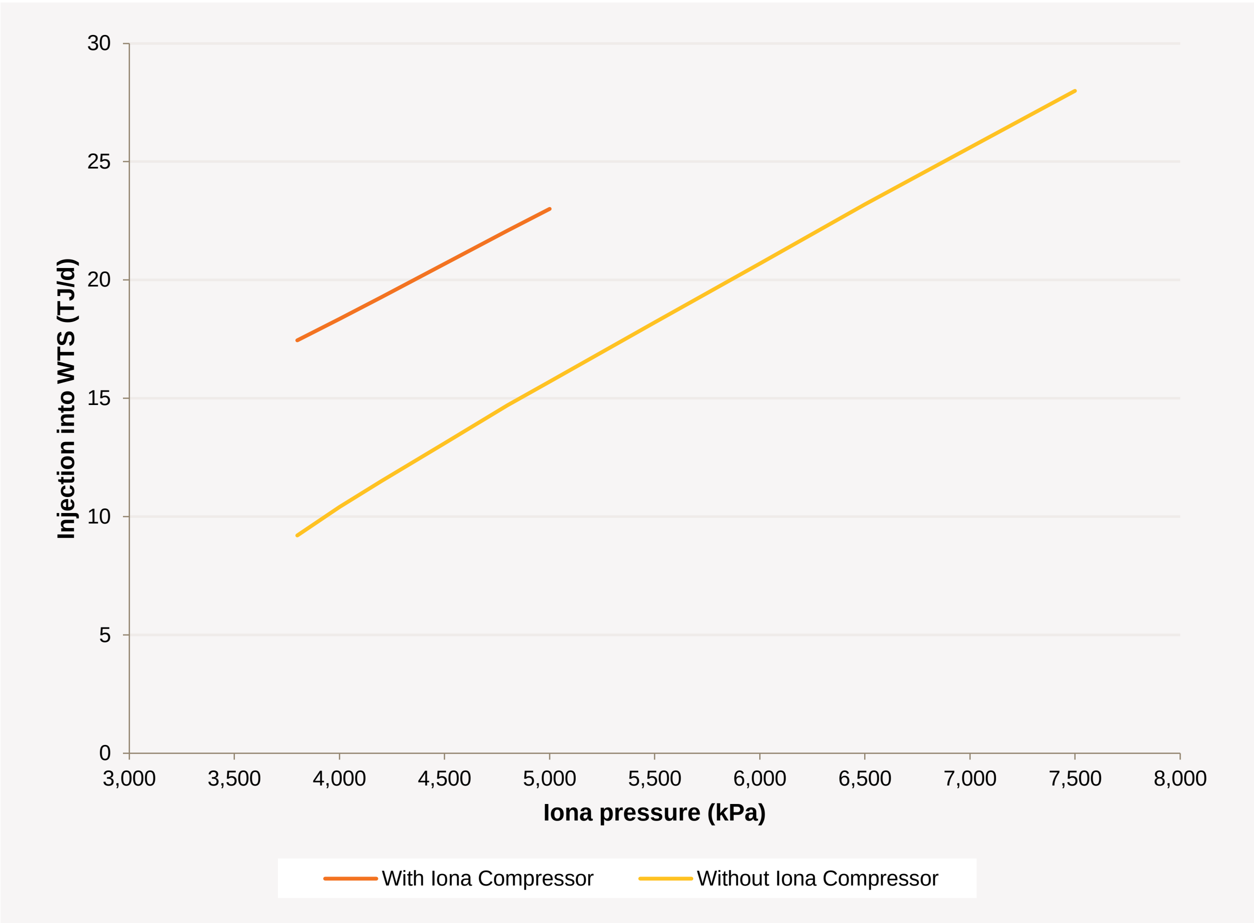
This forecast assumes that there are no injections at Iona, and that the Laverton North and Newport gas-powered stations are not operating. The market solution is to schedule participants to inject an appropriate quantity of gas at Iona to meet WTS demand.

When Iona UGS is not injecting gas, the WTS can be supplied with Gippsland gas via the Brooklyn Compressor Station (CS). Brooklyn compression can currently only increase the pressure at Iona to approximately 5,000 kPa over 12 to 24 hours if gas is not being withdrawn at Iona. This is due to the lack of a direct connection between the Brooklyn compressor discharge and the BLP. This pressure enables security of WTS supply on a moderate demand day without further compression at Iona.

WTS fringe minimum pressures at Portland and Hamilton can be maintained for 1-in-20 peak demand day conditions if the Iona compressor discharge pressure is approximately 6,500 kPa.

Figure 3-8 shows the relationship between injections into the WTS and the pressures at Iona.

Figure 3-8 — Western Transmission System injections and Iona pressures



3.3 Operational considerations

This section presents information about the operational (and other) factors that affect system capacity. It also describes the impact of within-day balancing on system capacity. The section also presents two modelling cases that would impact DTS system security.

3.3.1 Operational factors affecting system capacity

Beginning-of-day linepack

DTS linepack varies considerably during the day. It is drawn down from the start of the gas day when demand during the morning and evening demand peaks exceeds the constant hourly gas supply injection rate, and reaches a minimum around 10.30 pm. Overnight, injections exceed demand and linepack is replenished before the morning peak starts at around 6.00 am.

Demand forecast error

Daily demand forecast errors occur due to changes in the weather (which drives domestic heating demand) and unplanned changes to large loads, especially GPG. More generally:

- Higher gas consumption than forecast can result in a greater system linepack depletion through the day, which also reduces system capacity.
- Lower gas consumption than forecast can result in very high linepack and system pressures, which in the worst case could reduce system injections prior to the evening peak.

Section 3.3.2 presents two modelling cases outlining the impact demand forecast errors have on DTS system security.

Delivery pressure

Delivery or supply pressure drives gas through the pipeline. The higher the pressure, the higher the average level of linepack and effective system capacity.

Injection profiles

For operational reasons, gas production plants generally operate at a constant injection rates, with variations due to rescheduling. Under these conditions, system pressure varies throughout the day.

Maintaining a constant delivery pressure increases pipeline transport capacity. However, to achieve this, injection flows would vary continuously over the day; gas production plants prefer to avoid this as it is operationally more difficult and the required increased plant capacity may not be available.

Alternatively, an increase of approximately 4% in pipeline transport capacity can be achieved using profiled injections from Longford on high demand days. A profiled injection refers to higher injections in the first 12 hours of the gas day (6:00 am to 6:00 pm) and lower injections in the next 12 hours. Profiled injections improve system capacity.

Gas sources that can be injected for short periods during times of high demand, such as LNG, can greatly assist pipeline operators to maximise overall system capacity.

Demand profiles (temporal distribution)

During winter, demand peaks in the morning and evening (due to temperature-sensitive load) draw down linepack. More severe demand profiles, including the presence of spike loads such as GPG, deplete linepack at a much faster rate.

Spatial distribution of demand

System capacity is modelled using forecast load distributed across the system. If a specific load is located close to an injection point, the gas transport capacity is higher than if the load is located further away.

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Gas composition

Coal seam gas (CSG) has a lower heating value than conventional gas, so pipeline capacities will reduce from those currently modelled if CSG is used.

3.3.2 Modelling scenarios to assess the impact of operational factors

This section presents two scenarios which assess possible DTS operational challenges. The 2013 scenarios for this year focus on the impact that demand forecast error would have on DTS system security. The scenarios modelled are realistic and present conditions that would challenge the gas system.

- Scenario 1 – Impact of weather forecast error on the gas system.
- Scenario 2 – Impact of unscheduled GPG demand on the gas system.

Table 3-2 and Table 3-3 present scenario information its impact on the system.

Table 3-2 — Impact of weather forecast error on the gas system

Scenario 1	
Background	System demand was forecast to be a 1-in-2 day (1,155 TJ) but demand forecast errors have occurred due an incorrect weather forecast, meaning forecast system demand was closer to a 1-in-20 peak day (1,277 TJ). Culcairn initially exports at a 1-in-2 peak day capacity. A constraint is applied to Culcairn once the forecast error was realised. A reschedule occurs at 2.00 pm: • Iona injections increase at 2.00 pm. • Longford injection increase at 3.00 pm. LNG was scheduled to inject at 2.00 pm at the maximum of 100 t/h. This planning assumption is based on the contract rate of LNG vaporisation. In practice, LNG would be vaporised at a rate up to 180 t/h before curtailment is called.
Issue	Due to higher gas consumption than forecast, there was a greater-than-expected linepack depletion through the day. Low linepack means lower-than-expected system pressures and, in an extreme case, usable linepack plus peak shaving gas might be insufficient to meet demand for the evening peak.
Constraint	Dandenong City Gate minimum connection pressure breach.
Solution	• Longford profiling injection, or • Approximately 25 TJ/d of curtailment is required to maintain system security.
Trigger	Demand forecast error due to changes in weather.

Table 3-3 — Impact of unscheduled GPG demand on the gas system

Scenario 2	
Background	System demand for the day was forecast at 1000 TJ/d with no GPG demand forecast at the 6.00 am and 10.00 pm scheduling horizons. Culcairn was exporting to the modelled VGPR limit of 64 TJ/d (detailed in Section 3.2.5). At 12.30 pm, due to a loss in supply from a major power station in Victoria, electricity prices increase. This triggers all GPG to come online ***unscheduled*** at 1.00 pm at 70% of their maximum hourly capacity. A reschedule occurs at 2.00 pm: • Iona injection increase at 2.00 pm. • Longford injection increase at 3.00 pm. LNG was scheduled to inject at 2.00 pm at a maximum of 100 t/h.
Issue	Due to unscheduled GPG demand coming online, there was higher gas consumption than forecast, so there was greater linepack depletion through the day. Low linepack means that some injections will be used to recover linepack to normal levels and not be available to support demand.
Constraint	Dandenong City Gate minimum connection pressure breach.
Solution	Curtail GPG demand down to 50% of their maximum hourly capacity.
Trigger	Higher electricity prices triggered GPG to come online unscheduled.

3.3.3 Impact of within-day balancing on system capacity

This section presents information about within-day balancing requirements and managing linepack depletion, and the impact on system capacity.

Within-day balancing

Figure 3-9 and Figure 3-10 shows within-day supply, demand, and usable linepack. However, as within-day balancing is affected by pipeline capacity and usable system linepack, an examination of hourly supply and demand becomes critical.

In Figure 3-9 and Figure 3-10, the left hand vertical axis applies to supply and demand (TJ/h), and the right hand vertical axis applies to system linepack (TJ). The amount of usable system linepack varies from day to day, depending on operating conditions. In winter, beginning-of-day usable linepack is usually about 150 TJ to 160 TJ. Usable linepack is used to describe the concept of linepack used to meet the within-day imbalance between supply and demand. This is not a fixed value and varies from season to season and also is affected by export level.

In the example shown in Figure 3-9, it shows that system linepack is lower than the required minimum. This is the point at which the minimum system pressures are likely to be breached.

Figure 3-9 shows a day where total demand is high, and shows the impact on the system linepack with and without LNG.

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Key features in the figure include:

- Daily supply (excluding LNG) typically follows a flat injection profile over a 24-hour period, as production plants typically run most efficiently at a constant rate and have limited ability to increase rates over a short amount of time.
- An initial forecast at the beginning-of-day determines the rate of injection, which is then kept relatively constant for the rest of the day. Within-day adjustments are possible with rescheduling at 10.00 am, 2.00 pm, 6.00 pm, and 10.00 pm.
- Demand varies considerably through the day, increasing in the morning and evening due to gas heating, cooking, and hot water loads. Demand then decreases overnight due to reduced commercial and industrial demand, and reduced heating in homes. Any additional demand from GPG is usually concentrated around the morning and evening gas demand peaks, increasing the daytime swing in demand and tending to draw down system linepack.
- A typical day's system linepack profile results from an imbalance in hourly supply and demand levels. System linepack falls to a minimum at around 10.00 pm, and is rebuilt for the following morning. (Although AEMO aims to match supply and demand over 24-hours, this may not occur).
- Figure 3-9 shows the predicted linepack with no LNG injection. In this example, linepack is predicted to fall below the grey dashed line which is the critical linepack level ensuring that key system pressures are maintained.
- Figure 3-10 shows the linepack resulting from injecting LNG (circled in red). Capable of being injected at short notice (and in close proximity to the point of demand), LNG has several applications:
  - For within-day balancing (because it is the fastest way to supply gas to the DTS).
  - To maintain system pressures when system linepack is predicted to fall to an unacceptable level.

Profiling injections can reduce the volume of LNG required, but LNG is still a critical supply source on high demand days.

Normally, LNG is usually not injected until later in a gas day once demand forecasts and system linepack projections are firm. However, LNG may still be present in the first schedule issued for the day, if there are no errors in demand forecasts or weather forecasts, or if no other gas supply is available.

Breaches of system pressures are most likely to occur in the late evening (around 10.00 pm to 11.00 pm), when system linepack normally reaches a minimum.

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Figure 3-9 — Within-day supply, demand, and system linepack

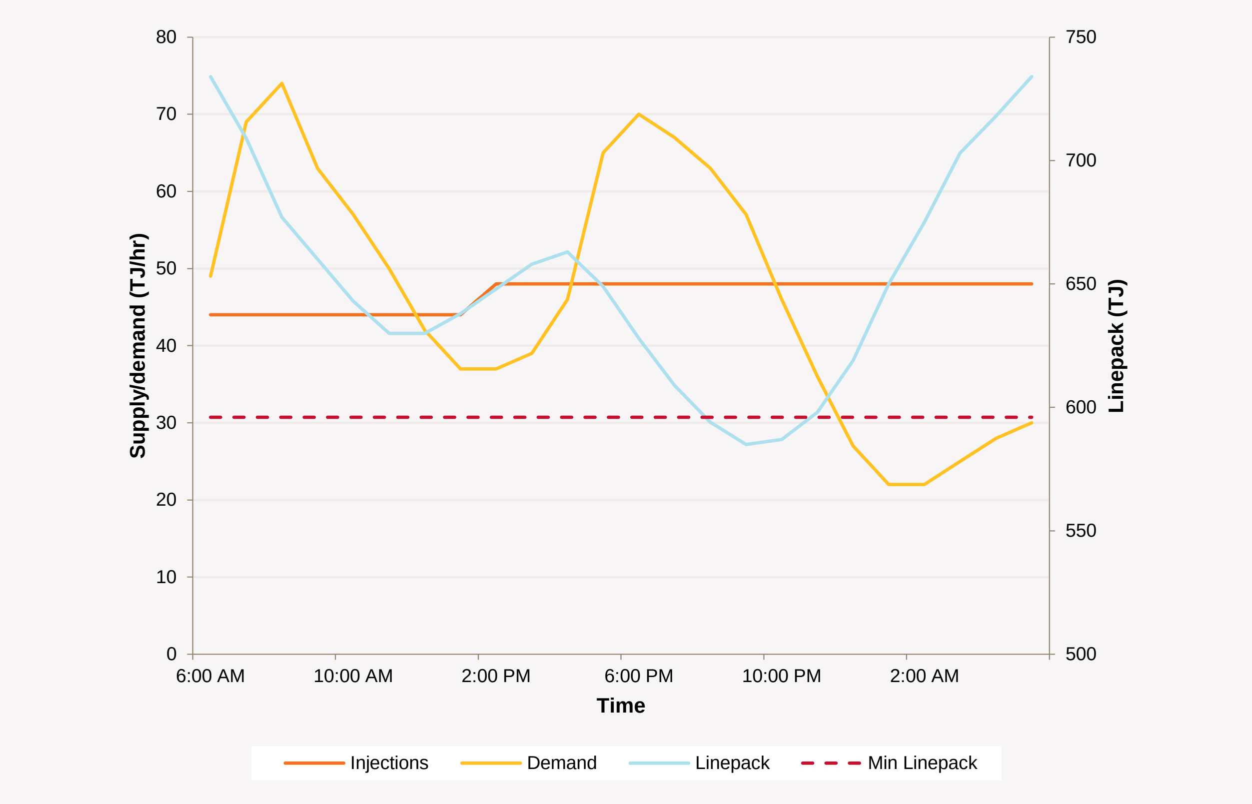
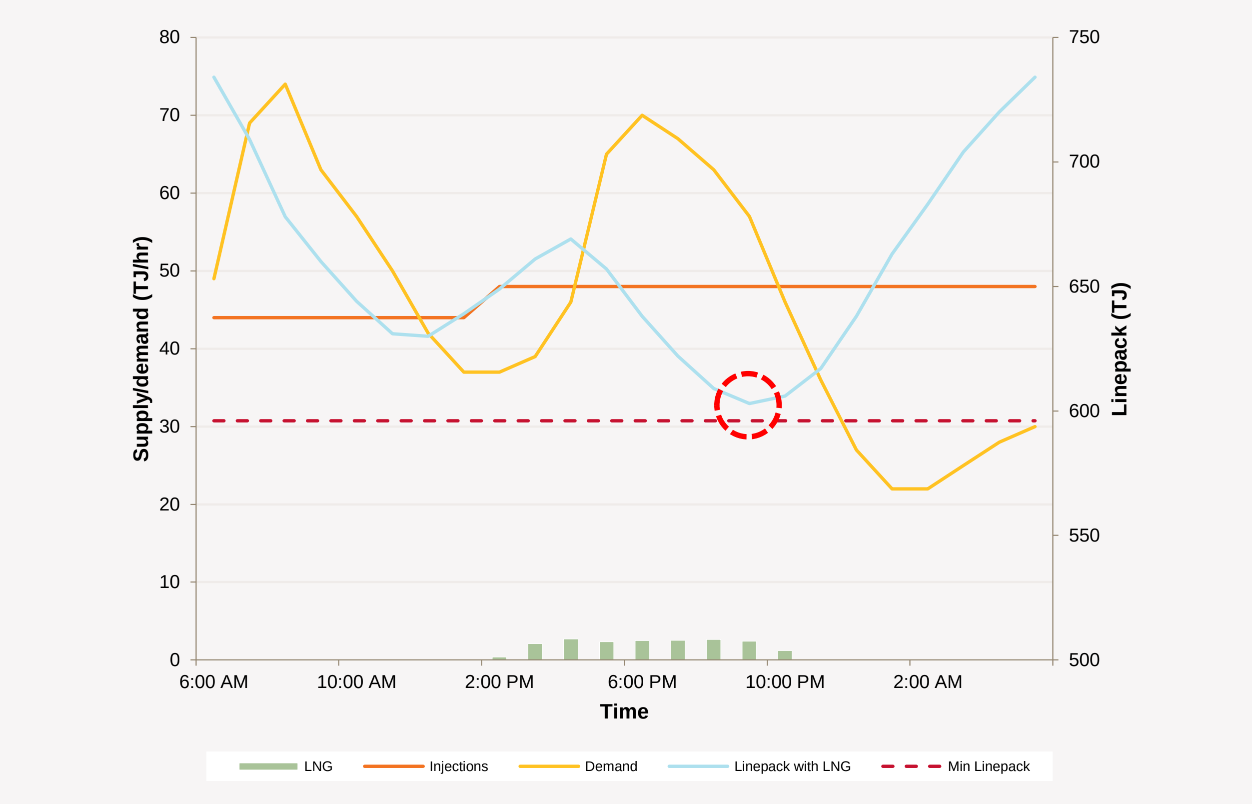


Figure 3-10 — Within-day supply, demand, and system linepack



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Managing linepack depletion

Several operational factors lead to the depletion of usable system linepack:

- Extreme demand with a normal demand profile.
- High demand with an extreme demand profile.
- Lower than planned beginning-of-day system pressures (low beginning-of-day linepack, usually due to a colder-than-forecast morning leading into a cold day).
- Demand from GPG, where this demand is usually concentrated in the first half of the gas day.
- GPG forecast errors, where demand is materially higher than forecast due to changes in National Electricity Market (NEM) schedules, including reschedules due to forced outages.
- System demand forecast error, where demand is materially higher than forecast, is usually due to colder weather than the original morning forecast.
- Supply problems when a producer or storage provider has not been able to meet scheduled injection rates, particularly in the first half of the gas day.
- Pipeline constraints.

In practice, combinations of these events can occur on any given gas day, causing uncertainty in the projections for the rest of the day, including the likelihood and magnitude of LNG use.

Methods for mitigating the impact of these events include:

- Use of non-uniform supply injection profiles that more closely resemble the demand profile to support system linepack. In practice, this involves a higher-than-average injection rate for the first half of each gas day so that, for example, 55% of the scheduled daily quantity is injected in the first 12 hours. This means that on a day with system demand of 1,200 TJ/d, an additional 60 TJ would be injected during the first half of the day as an alternative to LNG injection. This is equivalent to the contracted LNG capacity vaporised over an 11-hour period.
- Use of a higher end-of-day linepack target during periods of high demand. This is not always possible because higher linepack levels increase the probability of having to back-off supplies if demand is lower than expected.
- Improved demand forecasting performance would assist on very high demand days; however, this is unlikely given weather forecasting errors.
- Participant awareness of the within-day impact of changes to GPG levels, particularly if GPG demand is higher than advised at beginning-of-day. Generators, market participants, and AEMO could work more closely to improve the reliability and timeliness of these forecasts.

3.3.4 Other factors that can affect system capacity

Other factors that can affect system capacity include:

- The composition of injected gas at each injection point.
- Ground and ambient air temperatures.
- Minimum and maximum operating pressure limits at critical points throughout the system.
- Compressor station power and efficiency.
- Facility outages.

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3.4 Unscheduled and scheduled GPG demand

This section provides information about the relationship between unscheduled GPG demand, system demand and system linepack, and the relationship between scheduled GPG demand and system demand.

3.4.1 Unscheduled GPG demand

Depending on system demand and operating conditions on the day, scheduled or unscheduled GPG can rapidly deplete linepack, potentially risking system security. The potential maximum hourly quantity (MHQ) of GPG can be very high relative to the hourly demand from all other industrial and commercial gas customers.

Figure 3-11, shows system linepack for a typical peak winter day without GPG demand. Figure 3-12 shows system linepack for a typical peak winter day with unscheduled GPG demand.

In Figure 3-12, unscheduled GPG demand comes online at the rate of 22 TJ/hr from 1.00 pm for the next nine hours. The yellow line shows the increase in total supply from Longford, Iona, and LNG in the scheduling horizon to account for the GPG demand. The system linepack is predicted to fall below the minimum value (circled in red), which indicates that key system pressures are not maintained. This shows that the system does not have the capacity to support large levels of unscheduled GPG demand. To maintain key system pressures, GPG curtailment will occur.

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Figure 3-11 — System linepack for a typical peak winter day without GPG demand

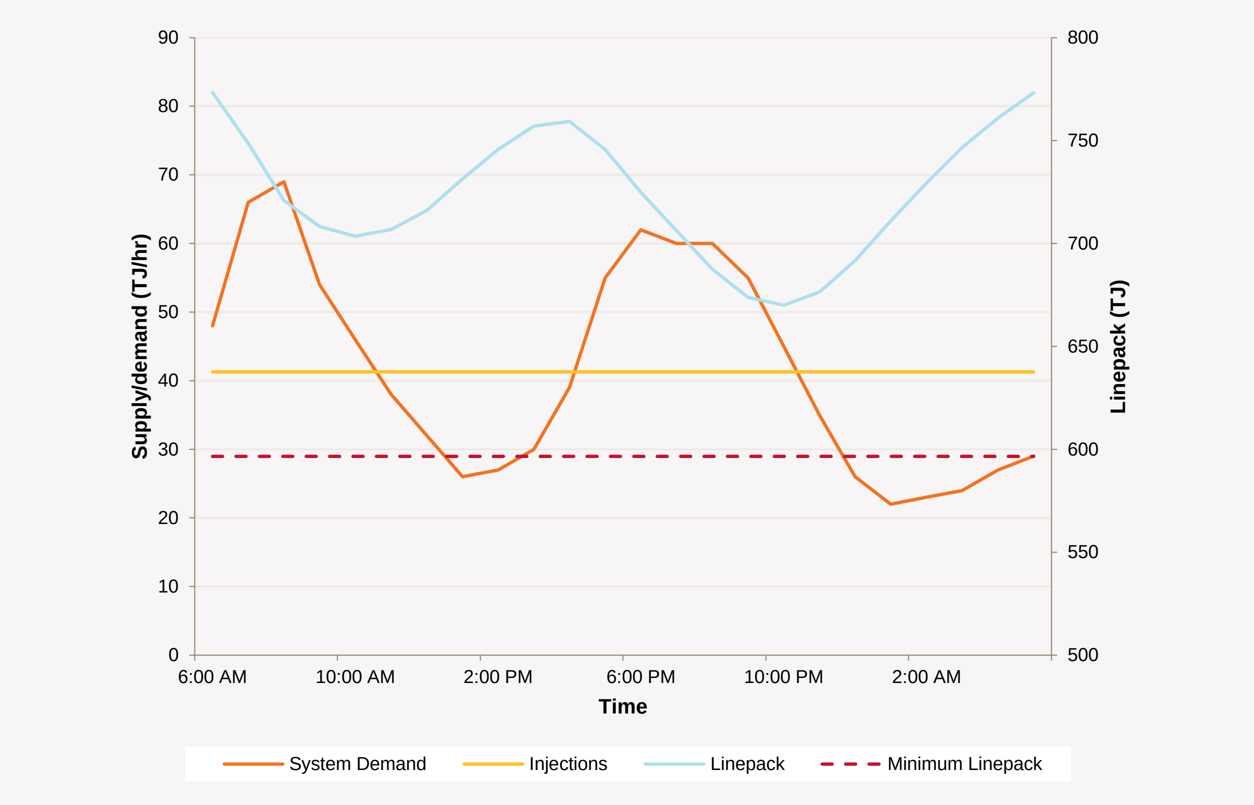
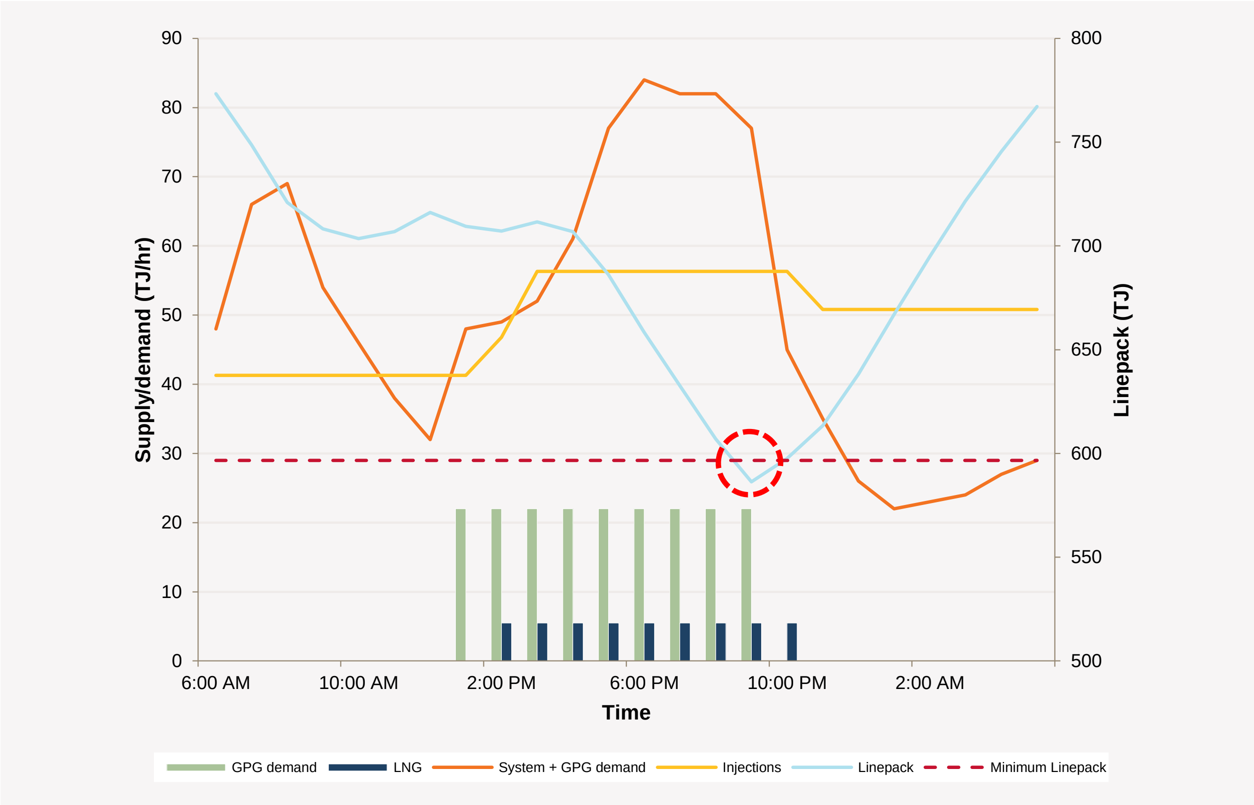


Figure 3-12 — Impact of unscheduled GPG demand on system linepack

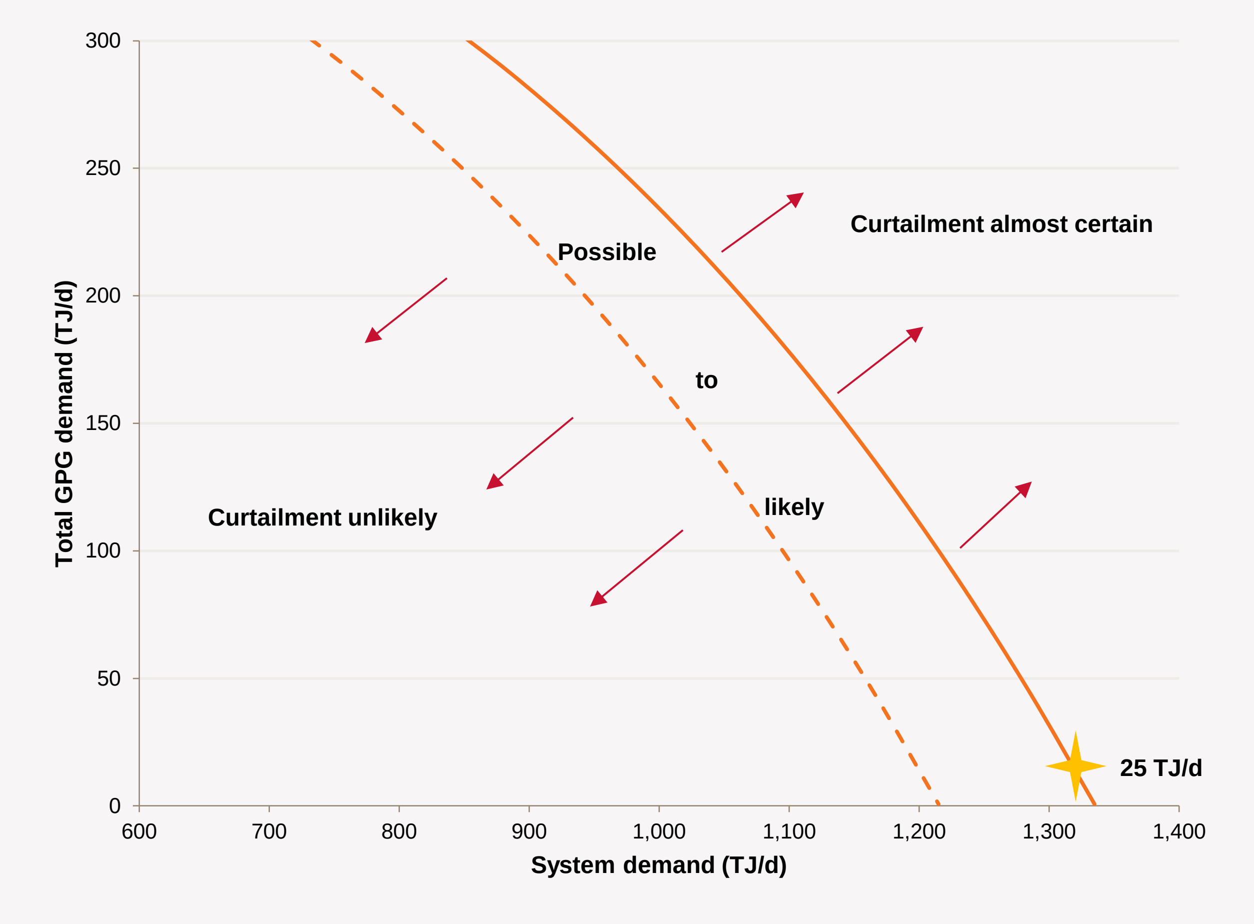


3.4.2 Scheduled GPG demand

This section provides information on the relationship between GPG demand, system demand, and curtailment limits. The total GPG demand in Figure 3-13 refers to GPG demand scheduled before the 6.00 am scheduling horizon for the system to be able to support the amount stated in the graph.

Figure 3-13 shows the system is able to support the scheduled quantity of GPG demand (shown by the dashed line). For anything between the dashed and solid line, curtailment might be possible subject to conditions and forecast errors on the day. Curtailment will occur for any GPG demand above the solid line. For example, on a 1-in-2 day, the system is able to support 50 TJ/d of GPG demand. Curtailment might occur if the GPG demand is 100 TJ/d, and it will almost certainly occur if GPG demand exceeds 150 TJ/d. With system demand of 1,305 TJ/d, GPG demand of greater than 25 TJ/d will be curtailed (indicated by the star).

Figure 3-13 — Relationship between scheduled GPG demand, system demand, and curtailment limits



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Chapter 4 GAS DEMAND FORECAST

Summary

While the Victorian Gas Planning Report (VGPR) presents a five-year outlook and AEMO's modelling is also based on a five-year outlook, the gas demand forecasts in this chapter cover a 10-year outlook (2014–23).

This chapter contains forecasts of annual system consumption, annual consumption for gas-powered generation (GPG), annual peak day system demand, and annual peak hour system demand for gas supplied through the gas Declared Transmission System (DTS) for the 10-year outlook.

Monthly system consumption, monthly peak day, and monthly peak hour demand for gas (including gas compressor fuel) for the 2014 calendar year are also included.

Between 2014 and 2018, annual gas system consumption plus annual gas consumption for DTS-connected GPG is forecast to increase by 3.1% to 211 PJ. Over the entire 10-year outlook it is forecast to increase by 7.2% to 219 PJ.

Residential and small industrial and commercial gas consumption is expected to increase annually from 0.9% in the 2012 forecasts to 1.0% in the 2013 forecasts. This reflects a slightly lower retail gas price profile (noting that gas prices are still forecast to increase, just at a slower rate than forecast in 2012), slight upward revisions for growth in residential dwellings between 2021 and 2023, and slight growth in household incomes.

Large commercial and industrial annual consumption is forecast to remain relatively flat over the 10-year outlook, averaging approximately 74 PJ per annum. This reflects the longer-term shift of the Victorian economy away from energy-intensive heavy industry.

GPG consumption is forecast to grow at an average annual rate of 0.3 PJ over the five-year outlook period, compared to 0.8 PJ per year in the 2012 DTS Medium Term Outlook (MTO) forecast. The revision down of the forecast is based on lower electricity demand and changes in energy policy. The growth is expected to occur during the summer months.

For the DTS (excluding DTS-connected GPG), both the 1-in-2 and 1-in-20 annual peak day system demand forecasts grow at an average annual rate of 0.8% over the 10-year outlook. For the period 2014 to 2018, annual peak day system demand is forecast to grow at an average annual rate of 0.9%.

4.1 Demand forecast methodology

4.1.1 Definition of demand forecast terms

Forecast and actual data in this chapter pertain to gas days starting at 6.00 am.

In this document, system demand includes:

- Tariff V customer demand: residential, small commercial and industrial customers nominally consuming less than 10 TJ/yr of gas.
- Tariff D customer demand: larger commercial and industrial customers nominally consuming more than 10 TJ/yr of gas.

Excluded from the definition of system demand are:

- Gas demand for GPG.
- Gas exports by pipeline to other states.
- Gas withdrawn for underground storage at Iona and withdrawn for conversion to LNG at the Dandenong LNG gas storage facility.

Distribution losses and gas compressor fuel are included in the forecasts, while losses from transmission pipelines are assumed to be zero.

Demand forecasts for this chapter were developed by the National Institute of Economic and Industry Research (NIEIR), using NIEIR's state and energy-industry based projection models.

4.1.2 Economic growth scenarios

The gas demand forecasts in this chapter were prepared using the following basis:

- AEMO's best estimate of the future direction of the major gas demand drivers.
- Designed to include any policy or other changes that can be predicted with reasonable certainty.
- Designed as a medium growth scenario.
- Include currently legislated carbon policies based on the Australian Treasury's core scenario.
- Use currently estimated rates of development of new technologies.

AEMO's Planning Assumptions webpage[32] provides detailed data sets used in AEMO's planning publications. The economic forecasts used in this chapter were largely based on economic forecasts from NIEIR prepared for AEMO in late 2012.[33]

4.1.3 Demand forecast methodology

This section outlines the methodology used to prepare the forecasts.

Annual DTS consumption forecasts for the 10-year outlook were prepared for each system withdrawal zones (SWZ)[34] for the following:

- Annual system consumption.
- Annual GPG consumption.
- Peak day system demand.
- Peak hour system demand.

Monthly forecasts for (including gas compressor fuel) the 2014 calendar year were also prepared for each SWZ for the following:

- Monthly gas system consumption.
- Monthly peak day gas system demand.
- Monthly peak hour system demand.

Annual consumption forecast approach

Annual system consumption forecasts, and forecasts for the industrial, commercial, and residential sectors, and each major industry group[35] were generated from econometric models. The model use key forecast economic inputs including:

- State-level industry specific output projections.
- Projections of state population, dwelling stocks, real household disposable income, gas prices, and the consumer price index.

[32] AEMO. *2013 Modelling Methodology and Assumptions*. Available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions. Viewed: 11 December 2013.

[33] AEMO. *Economic Outlook*. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013/NEFR-Supplementary-Information-2013. Viewed: 11 December 2013.

[34] Included gas demand from the Lang Lang area as part of the Gippsland SWZ.

[35] As defined by the Australian and New Zealand Standard Industry Classifications (ANZSIC).

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Other factors taken into account when preparing the forecasts include:

- A survey of major industrial users on planned expansions or reductions in gas consumption including gas cogeneration.
- Market information obtained from media reports.
- Federal and state government energy policies.
- Standard weather conditions[36] as Victorian gas demand is very sensitive to weather variations.

Residential gas demand is the largest component of Tariff V and is modelled using an end-use model that disaggregates residential gas usage into new and established dwelling demand. The residential forecasts incorporate the impact of real household disposable income and real gas prices.

Tariff V business gas demand forecasts are developed taking account of commercial output growth and movements in real gas prices.

Tariff D gas demand forecasts are developed on a per industry basis and account for forecast changes in output for each industry and changes in real gas prices.

The forecasts are then adjusted by NIEIR if required, taking into account input from their survey of major gas users, market information, and policies that might influence gas demand.

Annual system consumption forecasts by SWZ are generated by analysing historical Tariff D demand by industry sector and historical Tariff V demand to determine heating and non-heating loads in each SWZ.

Monthly demand forecast approach

Victorian monthly gas demand forecasts are based on standard weather conditions for monthly effective degree day (EDD) standards (see Section 4.1.4).

Forecast weather-normalised monthly profiles for each SWZ and for the total gas DTS are extracted from historical monthly consumption data. This is performed for Tariff D and V demand, while accounting for large load variations due to known expansions or closures at specific locations. The forecast monthly load profiles are used to derive monthly consumption forecasts from forecast annual system consumption in each SWZ. The SWZ forecasts are reconciled with the monthly system consumption forecasts for the DTS.

Monthly system consumption forecasts are generated for the SWZs for Tariffs D and V separately. The forecasts are reconciled to take account of large load variations on the peak day profiles. Final forecasts for each SWZ are reconciled with the DTS monthly peak day forecasts.

Peak day system demand forecast approach

The peak day system demand forecast is determined by applying load factors[37] to the average daily demand, which are derived from the annual consumption forecasts. Regression analysis is used to determine the weather sensitivity of demand for each market segment. Peak day forecasts are then calculated for Tariff D and V separately. These are then added together to provide the DTS system demand forecast.

Winter peak day system demand is sensitive to weather conditions, with increased heating load expected on colder winter days. The peak day forecasts are presented for the following two weather standards:

- 1-in-2 peak day: This represents a milder standard, with weather conditions for the day expected to be exceeded once every two years, or a 50% probability of exceedence (POE).
- 1-in-20 peak day: This represents a more severe weather condition and is expected to be exceeded once in 20 years, or a 5% POE. This is the agreed planning standard for assessing gas supply adequacy and DTS transmission system capacity with APA Group.

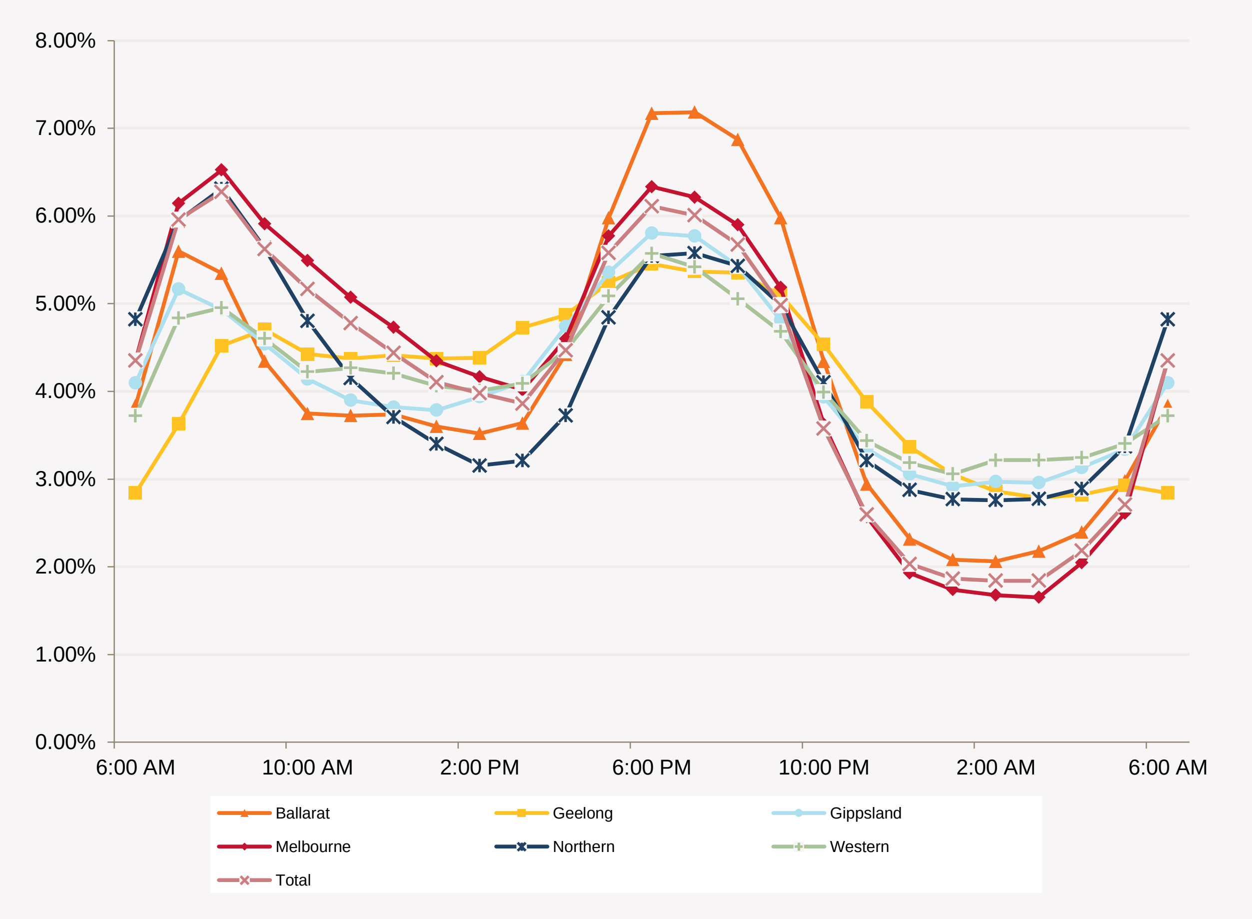
[36] AEMO. *2012 Review of Weather Standards for Gas Forecasting – Part 1 Victorian EDD Review*. Available at: http://www.aemo.com.au/Gas/Planning/Victorian-EDD-Weather-Standards-Review. Viewed: 11 December 2013.

[37] Defined as the ratio of the average daily demand to the peak day demand.

Peak hour system demand forecast approach

Winter peak day hourly demand profiles for each SWZ and the total system are shown in Figure 4-1. Demand peaks at around 8.00 am and again at around 6.00 pm primarily due to residential demand.

Figure 4-1 — Winter peak day hourly demand profiles by SWZ



The peak hour system demand forecasts for each SWZ are produced by applying the proportion of gas used in the peak hour on a selection of high demand days in the previous winter to the peak day forecasts. The growth rates are assumed to be the same as for the peak day forecasts.

Peak hour system demand forecasts are prepared for 1-in-2 and 1-in-20 peak day weather standards.

The peak hour demand forecasts in each SWZ are unlikely to coincide as peak hour demand in some SWZs occurs in the morning while in others it occurs in the evening. Evening peaks associated with residential gas heating usually occur between 6.00 pm and 7.00 pm. Morning peaks due to heating, hot water and industry start-up usually occur between 7.00 am and 8.00 am.

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4.1.4 Weather standards

AEMO reviewed the latest EDD weather standards in 2012.[38] For this report, fixed monthly EDD standards and monthly peak day 1-in-2 and 1-in-20 EDD standards were developed. These were used in AEMO's medium-to-long-term gas demand forecasts and will remain in place until the next AEMO EDD weather standards review.

Annual and peak EDD observed

The actual peak day system demand in 2013 was 1,081.7 TJ/d on Monday 24 June 2013, with an EDD of 13.08. This is below the 1-in-2 year peak day weather standard of 14.21 and the 1-in-20 year peak day weather standard of 16.49.

The second highest system demand reading of 1,049 TJ/d occurred on Tuesday 20 August 2013, with an EDD of 12.05.

Table 4-1 lists the annual EDD[39] and peak day EDD[40] actual for the calendar years from 2000 to 2012. Figure 4-2 shows a chart of the same information.

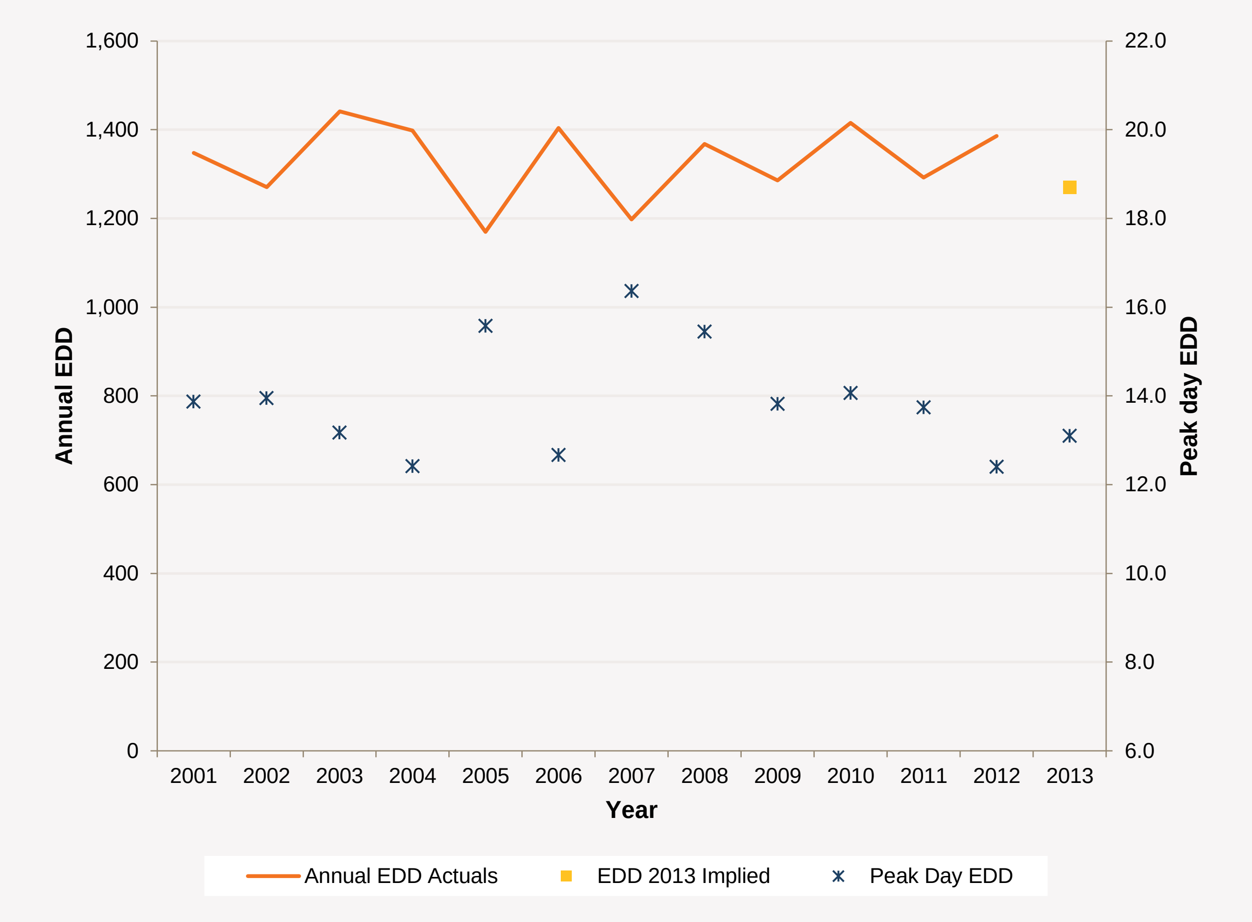
Table 4-1 — Annual EDD and peak day EDD actual from 2002 to 2013

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[a]
Annual EDD	1271	1441	1398	1170	1404	1198	1368	1286	1415	1292	1386	1270
Peak day EDD	13.9	13.2	12.4	15.6	12.7	16.4	15.4	13.8	14.1	13.7	12.4	13.1

a. Implied 2013 EDD includes the actual EDD from January to August 2013 and the forecast EDD from September to December 2013.

[38] AEMO. *2012 Review of Weather Standards for Gas Forecasting – Part 1 Victorian EDD Review*. Available at: http://www.aemo.com.au/Gas/Planning/Victorian-EDD-Weather-Standards-Review. Viewed: 11 December 2013.
[39] The annual EDD is a summation of all daily EDDs in a calendar year.
[40] The peak day EDD is the EDD on the maximum demand day of the year.

Figure 4-2 — Annual EDD and peak day EDD actual from 2000 to 2013



Monthly peak day EDD standards

Table 4-2 lists the existing monthly EDD standards, and the monthly peak day 1-in-2 and 1-in-20 EDD standards[41] used to develop gas demand forecasts in this chapter.

Table 4-2 — Monthly EDD standards and monthly peak day 1-in-2 and 1-in-20 EDD standards

Month	Monthly EDD standard	Monthly peak day 1-in-2 standard	Monthly peak day 1-in-20 standard
JAN	0.6	0.6	2.1
FEB	1.7	1.0	3.3
MAR	8.2	2.5	5.5
APR	56.8	5.7	8.8
MAY	163.0	9.6	12.9
JUN	252.5	14.21	16.49

[41] AEMO. *2012 Review of Weather Standards for Gas Forecasting – Part 1 Victorian EDD Review*. Available at: http://www.aemo.com.au/Gas/Planning/Victorian-EDD-Weather-Standards-Review. Viewed: 11 December 2013.

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Month	Monthly EDD standard	Monthly peak day 1-in-2 standard	Monthly peak day 1-in-20 standard
JUL	295.5	14.21	16.49
AUG	250.0	14.21	16.49
SEP	162.9	14.21	16.49
OCT	85.5	8.0	11.0
NOV	24.2	5.5	8.6
DEC	7.8	2.8	5.9

4.1.5 Relationship to the Gas Statement of Opportunities

In December 2013, AEMO published the 2013 Gas Statement of Opportunities (GSOO).[42] The GSOO presents forecasts of annual gas consumption and peak day gas demand for each eastern and south-eastern Australian region. The aggregate system level forecasts presented in this VGPR are higher those presented in the 2013 GSOO by less than 1% for annual gas consumption, and by up to 3% for peak day gas demand. Differences are attributable to:

- Different historic time series: The VGPR relies on historic demand data to the end of August 2013. The GSOO projections are based on historic demand data to the end of May 2013 to allow supply–demand modelling to be completed prior to the November release date. A warmer-than-average winter and lower-than-forecast industrial gas consumption across the DTS in 2013 partly contributes to VGPR forecasts being lower than those presented in the 2013 GSOO.
- Different regional classification: The GSOO presents projections for the entire state of Victoria, while the VGPR projections concern DTS zones.
- Different basis for peak day demand calculation: The peak day forecasts in the VGPR are calculated to coincide with the time of the DTS system peak. The peak day forecasts in the GSOO are calculated as the non-diversified sum of the individual GSOO zone peaks.

The next release of the VGPR and the GSOO will occur in March 2015, enabling improved consistency between them by addressing the factors described above. The forecasts will be presented independently in the inaugural National Gas Forecasting Report (NGFR) in December 2014 and will serve as an input into the GSOO and the VGPR.

4.2 Annual gas consumption forecasts

This section presents forecasts of DTS supplied gas consumption, including forecasts of:

- Annual system plus DTS-connected GPG consumption.
- Annual system consumption.
- Annual system consumption by SWZ.
- Annual DTS-connected GPG consumption.

[42] AEMO. *2013 Gas Statement of Opportunities.* Available at: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2011-Gas-Statement-of-Opportunities. Viewed: 11 December 2013

4.2.1 Annual system plus DTS-connected GPG forecast

Figure 4-3 and Table 4-3 show annual system plus DTS-connected GPG consumption forecasts.

Annual gas consumption is forecast to remain largely unchanged for 2014 and 2015 before increasing over the remainder of the 10-year outlook. Forecast average annual growth over the 10-year outlook is 0.8%, below the 1.1% average annual growth forecast last year in the 2012 Victorian Gas DTS Medium Term Outlook (MTO).[43]

Figure 4-3 — Annual system plus DTS-connected GPG forecast[44]

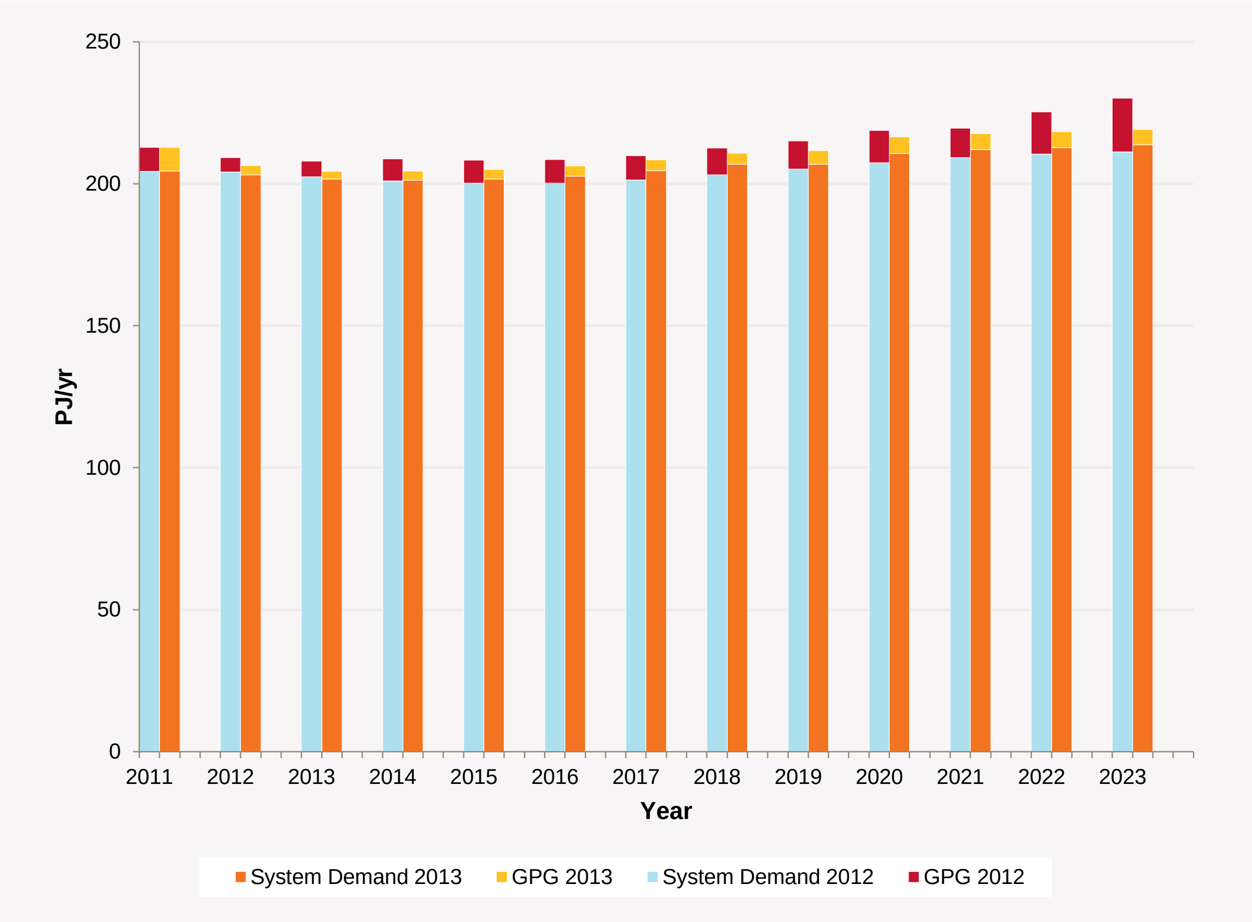

Table 4-3 — Annual system plus DTS-connected GPG consumption forecast (PJ/yr)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2013 forecast	System demand	202	201	202	203	205	207	209	211	212	213	214
	GPG demand	3	3	3	4	4	4	5	6	6	6	5
	Total	**204**	**204**	**205**	**206**	**208**	**211**	**214**	**217**	**218**	**218**	**219**

[43] AEMO. *2012 Victorian Gas DTS Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013

[44] 2011 and 2012 figures are based on actual data.

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		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2012 DTS MTO forecast	System demand	203	201	200	200	201	203	205	207	209	210	211
	GPG demand	5	8	8	8	9	9	10	11	10	15	19
	Total	**208**	**209**	**208**	**209**	**210**	**213**	**215**	**219**	**220**	**225**	**230**

4.2.2 Annual consumption forecasts (excluding GPG)

Table 4-4 shows forecast annual system consumption, which is forecast to fall from 202 PJ in 2013 to a minimum of 201 PJ in 2014. By 2018 annual system consumption is forecast to reach 207 PJ and grow further to 214 PJ by 2023.

Tariff D annual system consumption is forecast to remain relatively flat over the 10-year outlook, averaging around 74 PJ per annum. As a share of annual system consumption, Tariff D is forecast to fall from 37% in 2014 to 35% in 2023. This outlook reflects the longer-term structural shift of the Victorian economy away from energy-intensive heavy industry as well as lower gas demand stemming from:

- Increased competition from overseas imports that encourage consolidation of the manufacturing sector and result in lower gas demand.
- The impact of recent strong growth in business gas prices.
- The impact of currently legislated carbon policies that discourage carbon intensive activities and encourage increased energy efficiency measures.

Over the 10-year outlook, Tariff V forecast consumption grows steadily, at an average annual rate of 1.0% from 127 PJ in 2014 to 139 PJ in 2023. Over the five-year period 2014 to 2018, Tariff V consumption is forecast to grow at an average annual rate of 1.2%.

As a share of annual system consumption, Tariff V is forecast to increase from 63% in 2014 to 65% in 2023.

Tariff V demand is driven by assumed growth in population, residential dwelling growth, and household incomes, and is mitigated by improved gas appliance efficiency and increased reverse-cycle air conditioner usage for heating.

Growth in annual system consumption is also affected by residential and business gas price growth, as well as the relative price of gas compared to substitute energy sources, including electricity.

Table 4-4 — Annual consumption forecasts (excluding GPG), (PJ/yr)

	2013[a]	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth (%/yr)
2013 system consumption forecast												**2014–23**
	202	201	202	203	205	207	209	211	212	213	214	0.7
2013 system consumption forecast by market segment												**2014–23**
Tariff D	75	74	74	73	74	74	75	75	75	75	74	0.1
Tariff V	126	127	128	129	131	133	134	136	137	138	139	1.0
2012 system consumption forecast by market segment (2012 DTS Medium Term Outlook)												**2014–23**
Tariff D	79	77	76	75	75	76	76	77	77	77	77	-0.1
Tariff V	124	124	124	125	126	128	129	131	132	133	134	0.9
Total	**203**	**201**	**200**	**200**	**201**	**203**	**205**	**207**	**209**	**210**	**211**	**0.6**

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Comparison with 2012 annual system consumption forecasts

Table 4-4 and Figure 4-4 compare 2013 system consumption forecasts with those presented in 2012.[45] Over the 10-year outlook average annual growth in system consumption has been revised upwards from 0.6% in 2012 to 0.7% in 2013, driven by:

- An increase in forecast average annual growth in Tariff D from -0.1% in 2012 to 0.1% in 2013. This reflects a slight increase in the economic growth outlook for several industries (including chemicals, petroleum, coal, metal products, construction, and agriculture).
- An increase in forecast average annual growth in Tariff V from 0.9% in 2012 to 1.0% in 2013. This reflects a slightly lower retail gas price profile (noting that gas prices are still forecast to increase, just at a slower rate than forecast in 2012), slight upward revisions for growth in residential dwelling between 2021 and 2023, and slight upward revisions for growth in household incomes in 2016 and 2017.

Based on recent historical data, downward revisions have been made to the levels of Tariff D demand over the 10-year outlook. Industry sectors contributing to this include the chemicals sector (revised down by 1.3 PJ), the paper and wood sector (revised down by 1.1 PJ), and the food, beverages and tobacco sector (revised down by 0.7 PJ).

Conversely, as a result of higher-than-expected demand in 2013, upward revisions have been made to the levels of Tariff V demand over the 10-year outlook. This has resulted in Tariff V gas consumption of 126 PJ in 2023, which is 3.5% higher than the 2012 forecast.

As a combined result of these revisions to the levels of Tariff D and Tariff V consumption, annual energy for 2013 is estimated to be 0.8 PJ below that forecast in 2012.

[45] 2013 Planning Scenario forecasts are compared against the medium economic growth scenario as presented in the 2012 MTO.

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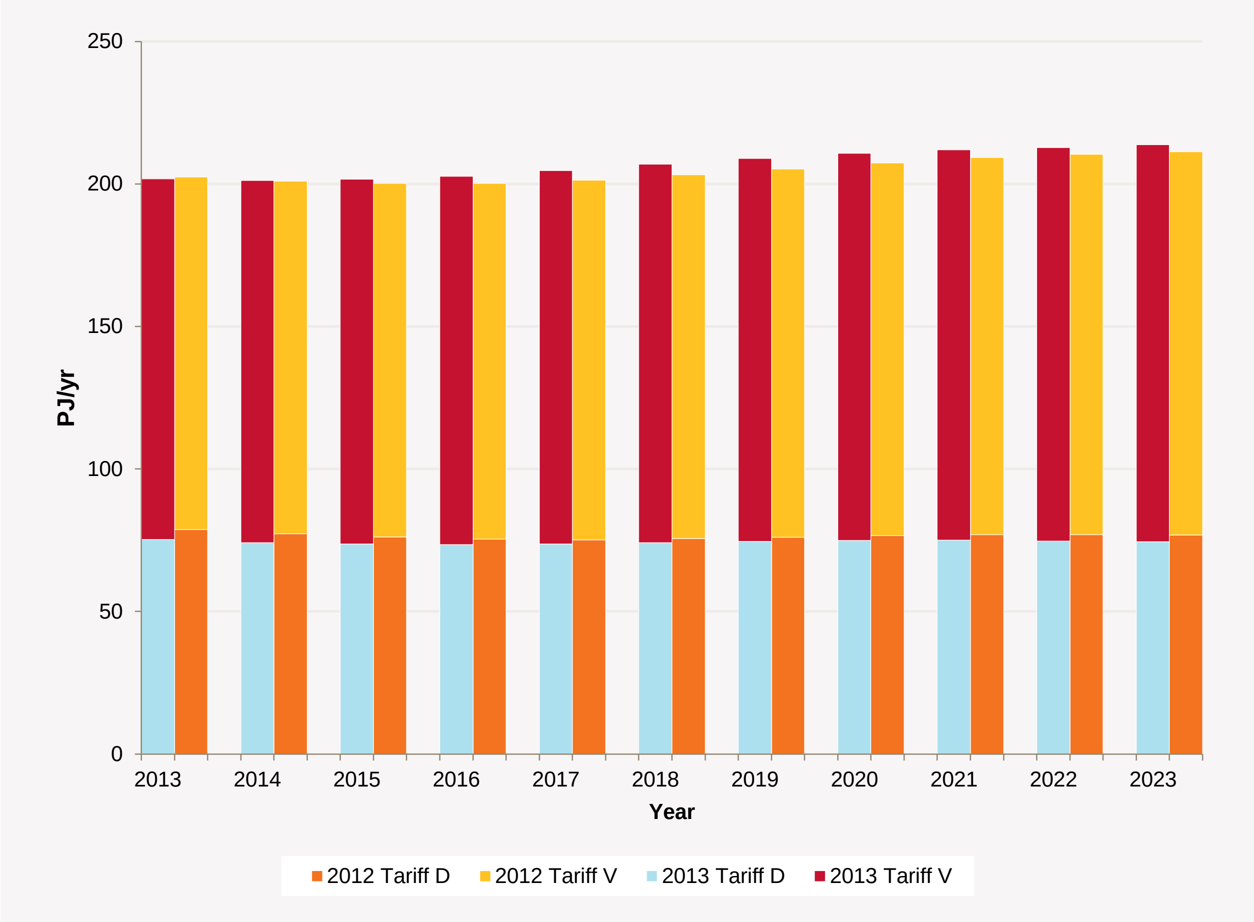
Figure 4-4 — Comparison of annual system consumption forecasts (excluding GPG)



Annual system consumption forecast by SWZ

Annual system consumption forecasts by SWZ are shown in Table 4-5 and Figure 4-5. The differences in growth rate between the six SWZs are primarily due to differences in the composition of demand between Tariff D and Tariff V, and the different forecast growth rates for these two market segments.

Reflecting the forecast slow growth in the Victorian manufacturing sector, SWZs with higher Tariff D demand relative to Tariff V demand (i.e., Geelong) have a negative growth rate, while those with a larger proportion of Tariff V demand (i.e., Northern and Ballarat) have positive growth rates.

Tariff V demand is projected to grow across all SWZs as growth in household dwelling numbers and household incomes lead to increasing retail gas connections. Additionally, retail gas price growth is assumed to moderate somewhat from the strong growth of recent years.[46]

Table 4-5 also compares the 2013 annual system consumption gas forecasts with those published in the 2012 MTO. The 2013 forecasts are 1.4 PJ/yr higher on average over the 10-year outlook.

[46] Australian Energy Regulator (AER). *A guide to the AER's review of gas network prices in Victoria*. Available at: http://www.aer.gov.au/sites/default/files/A%20guide%20to%20the%20AER%27s%20review%20of%20gas%20network%20prices%20in%20Victoria_2.pdf. Viewed: 11 December 2013.

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Table 4-5 — Annual system consumption forecast by SWZ (PJ/yr)

SWZ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth (%/yr)
2013 forecast												**2014–23**
Ballarat	8.9	8.9	9.0	9.1	9.2	9.3	9.4	9.6	9.6	9.7	9.8	1.0
Geelong	25.1	25.0	24.9	24.8	24.9	25.0	25.0	25.1	25.0	24.9	24.8	-0.1
Gippsland	15.4	15.4	15.3	15.3	15.3	15.4	15.5	15.6	15.6	15.7	15.7	0.2
Melbourne	129.7	129.3	129.9	130.9	132.4	134.0	135.5	136.8	137.9	138.6	139.4	0.8
Northern	18.2	18.2	18.2	18.3	18.5	18.7	19.0	19.2	19.3	19.4	19.5	0.8
Western	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5	0.4
Total system demand	**202**	**201**	**202**	**203**	**205**	**207**	**209**	**211**	**212**	**213**	**214**	**0.7**
2012 forecast (2012 Victorian Gas DTS Medium Term Outlook)												**2014–23**
Ballarat	8.8	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.3	9.4	9.4	0.8
Geelong	24.9	24.5	24.2	24.0	24.1	24.2	24.3	24.5	24.6	24.6	24.6	0.1
Gippsland	15.4	15.3	15.2	15.1	15.1	15.1	15.2	15.3	15.4	15.5	15.5	0.2
Melbourne	130.6	129.8	129.5	129.8	130.8	132.1	133.5	135.0	136.3	137.2	137.8	0.7
Northern	18.2	18.1	18.0	18.0	18.1	18.3	18.5	18.7	18.9	19.0	19.1	0.6
Western	4.5	4.5	4.4	4.4	4.4	4.5	4.6	4.6	4.7	4.7	4.7	0.5
Total system demand	**203**	**201**	**200**	**200**	**201**	**203**	**205**	**207**	**209**	**210**	**211**	**0.6**

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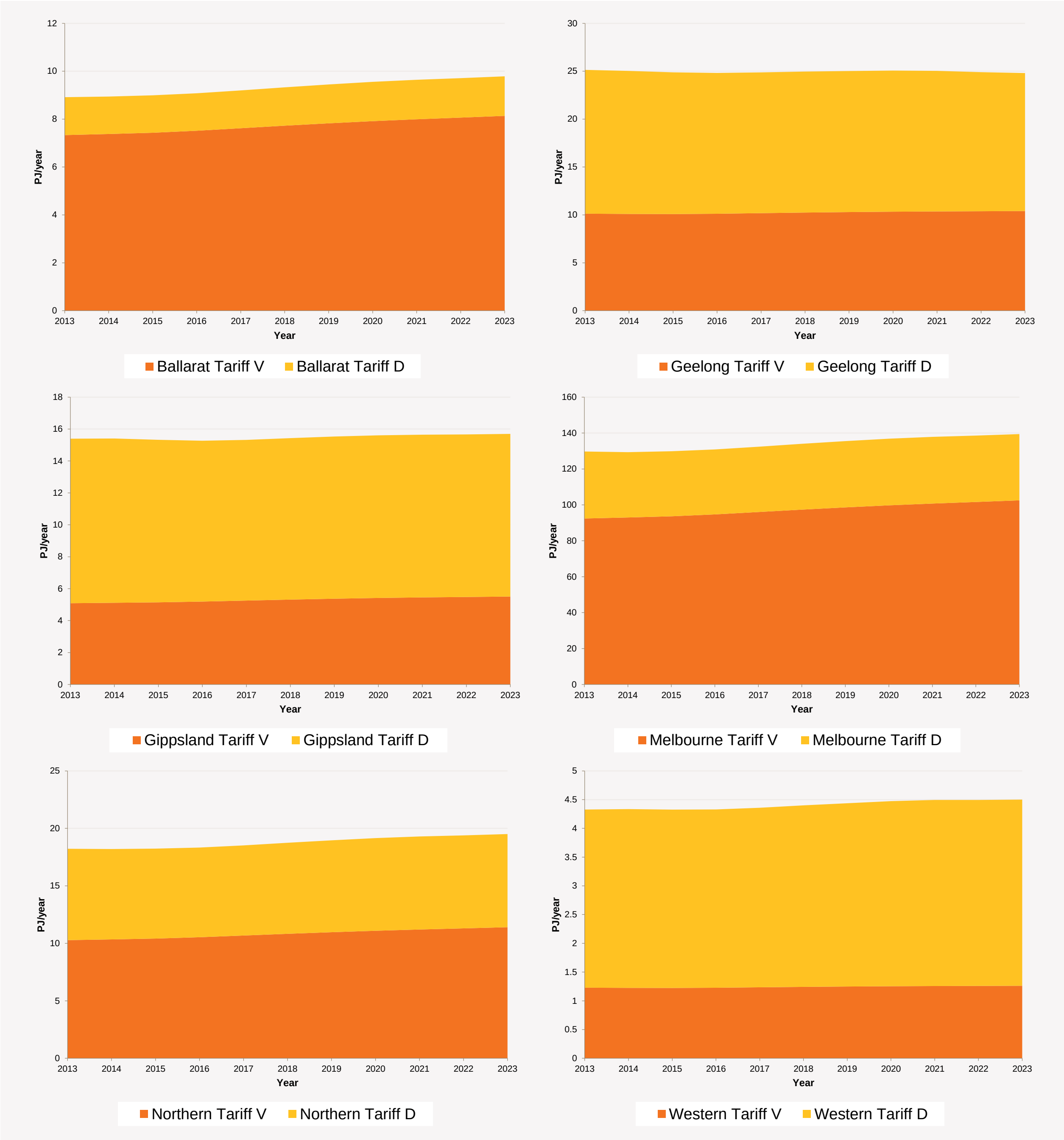
Figure 4-5 — Annual system consumption forecast by SWZ, by Tariff segment (PJ/yr)



4.2.3 Annual forecast of gas consumption for DTS-connected GPG

Annual forecasts of gas consumption for DTS-connected GPG are shown in Figure 4-6 and Table 4-6. Gas demand for GPG is forecast to be 2.6 PJ in 2013, down from the actual 3.2 PJ in 2012.

The gas powered generation (GPG) consumption forecast in this report is expected to grow at an average annual rate of 0.3 PJ per year over the five-year outlook period, compared to 0.8 PJ per year in the 2012 DTS Medium Term Outlook (MTO) forecast. By 2018, total gas consumption for DTS-connected GPG is forecast to be 3.9 PJ/yr rising to 5.4 PJ/yr by 2023, or approximately double that in 2013.

The underlying assumptions of the DTS-connected GPG demand forecasts have been updated since AEMO's 2012 Medium Term Outlook.[47] These updates include the impacts of the following developments:

- A lower annual generating requirement associated with the medium scenario outlined in AEMO's 2012 Electricity Statement of Opportunities.[48]
- Changes to carbon policy since the 2012 forecasts, including the removal of the carbon price floor. Through its exposure to the European carbon market, a lower forecast carbon price has increased the effective cost of GPG compared to other fuel types, including coal.

Figure 4-6 — Comparison of annual DTS-connected GPG consumption forecasts[49]

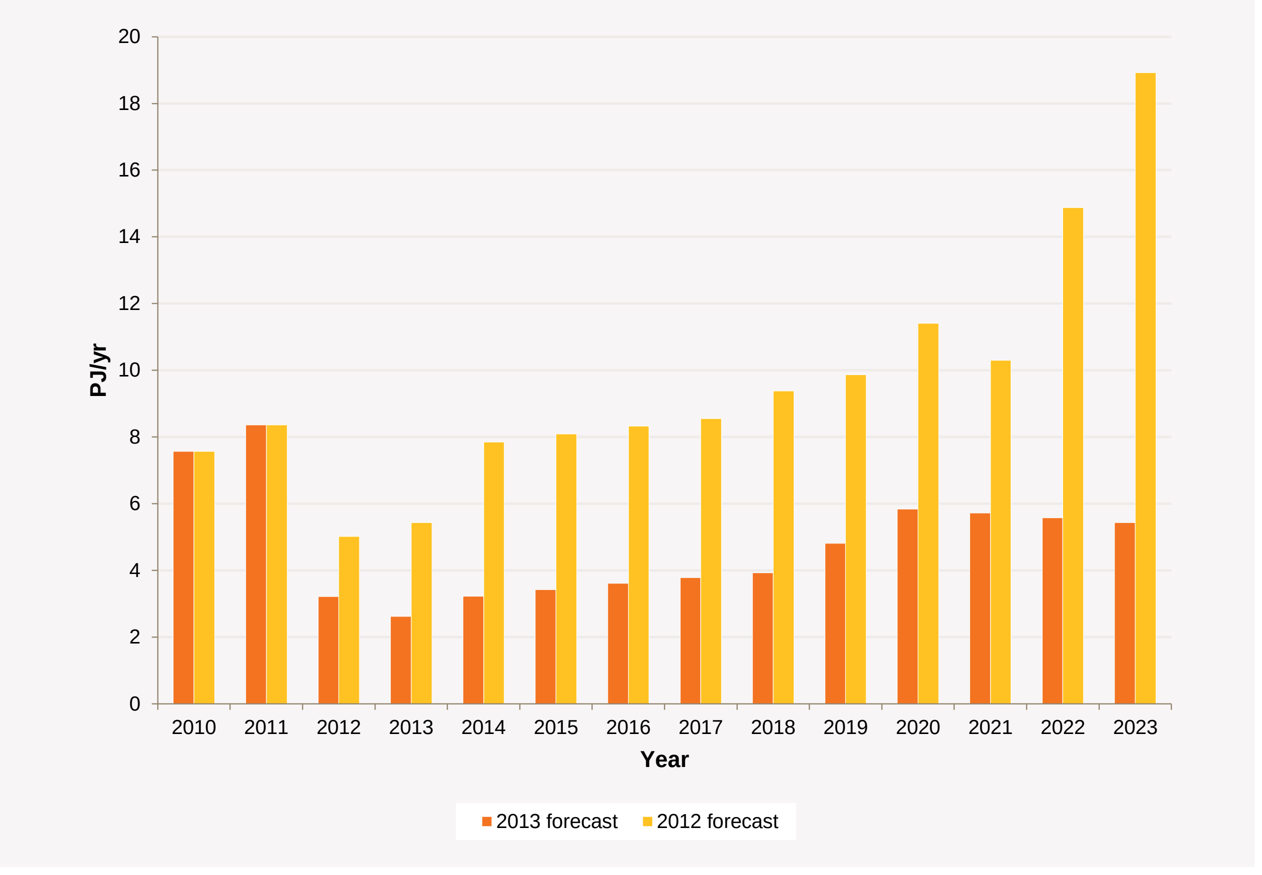


Table 4-6 — Annual DTS-connected GPG consumption forecast (PJ/yr)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2013 forecast											
Medium	2.6	3.2	3.4	3.6	3.8	3.9	4.8	5.8	5.7	5.6	5.4
2012 forecast (2012 Victorian Gas DTS Medium Term Outlook)											
Medium	5.4	7.8	8.1	8.3	8.6	9.4	9.9	11.4	10.3	14.9	18.9

[47] AEMO. *2012 Victorian Gas DTS Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013.
[48] AEMO. *2012 Electricity Statement of Opportunities*. Available at: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities. Viewed: 11 December 2013.
[49] 2010, 2011, and 2012 figures are based on actual data.

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4.3 Monthly gas system consumption forecasts

This section presents consumption forecasts for gas supplied through the DTS, including forecasts of:

- Monthly system consumption for 2014.
- Monthly system consumption by SWZ for 2014.

Monthly system consumption forecasts and monthly peak day and peak hour forecasts for 2014 are similar to the corresponding monthly forecasts for 2013, which were published in the 2012 Victorian Gas System Adequacy.[50]

4.3.1 Monthly system consumption forecasts

Table 4-7 shows the monthly system consumption forecasts for the period January to December 2014. These:

- Vary between 9.6 PJ/m and 16.0 PJ/m from January to April and October to December.
- Vary between 19.7 PJ/m and 27.4 PJ/m from May to September.
- Reach a maximum of 27.4 PJ/m in July, the forecast coldest month of the year.

Table 4-7 — Monthly system consumption forecasts for January-December 2014 (PJ/m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System consumption	10.5	9.6	11.2	14.0	20.3	24.5	27.4	25.0	19.7	16.0	12.1	10.9

Monthly system consumption forecasts by system withdrawal zones

Table 4-8 and Figure 4-7 show the monthly system consumption forecasts by SWZ from January to December 2014.

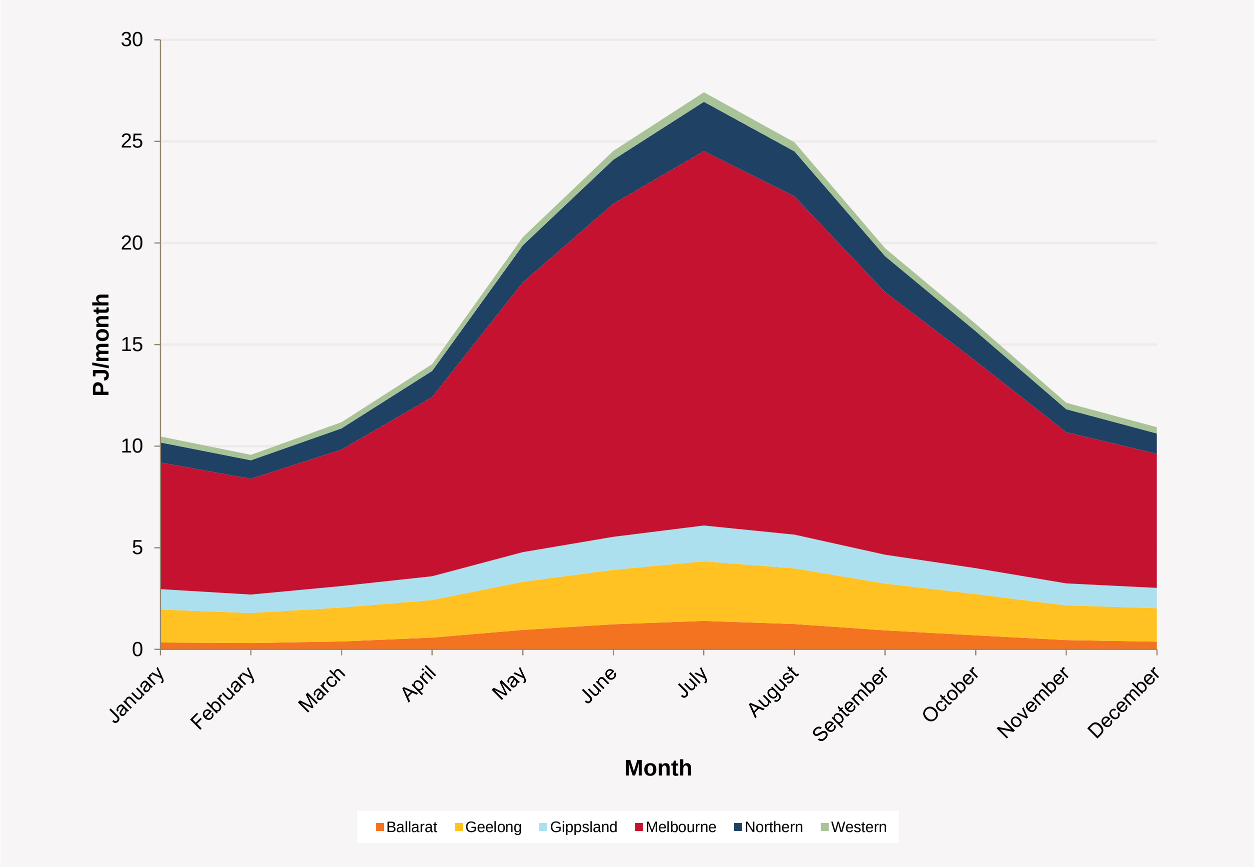
Monthly system consumption forecasts for 2014 for the Gippsland, Melbourne and Western SWZs show slight decreases compared to those forecasts for 2013 in the 2012 VGSA while slight increases are shown for the Ballarat, Geelong, and Northern SWZs.

Table 4-8 — Monthly system consumption forecasts by SWZ for 2014 (PJ/m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	0.3	0.3	0.4	0.6	1.0	1.2	1.4	1.2	0.9	0.7	0.5	0.4
Geelong	1.6	1.5	1.7	1.8	2.4	2.7	2.9	2.7	2.3	2.0	1.7	1.6
Gippsland	1.0	0.9	1.1	1.2	1.5	1.6	1.8	1.7	1.4	1.3	1.1	1.0
Melbourne	6.2	5.7	6.7	8.8	13.3	16.4	18.4	16.6	12.9	10.2	7.4	6.6
Northern	1.0	0.9	1.0	1.3	1.8	2.2	2.4	2.2	1.8	1.5	1.1	1.0
Western	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.3	0.3
System consumption	**10.5**	**9.6**	**11.2**	**14.0**	**20.3**	**24.5**	**27.4**	**25.0**	**19.7**	**16.0**	**12.1**	**10.9**

[50] AEMO. *Victorian Gas System Adequacy*. Available at: http://aemo.com.au/Gas/Planning/Victorian-Gas-System-Adequacy-2012. Viewed: 11 December 2013.

Figure 4-7 — Monthly system consumption forecasts by SWZ for 2014 (PJ/m)



4.4 Peak gas system demand forecasts

This section presents forecasts of demand for gas supplied through the DTS, including forecasts of:

- Annual 1-in-2 and 1-in-20 peak day system demand.
- Annual 1-in-2 and 1-in-20 peak day system demand by SWZ.
- Annual peak hour system demand by SWZ.
- Monthly 1-in-2 and 1-in-20 peak day system demand.
- Monthly 1-in-2 and 1-in-20 peak day system demand by SWZ.
- Monthly peak hour system demand by SWZ.

4.4.1 Winter peak day demand forecasts

Table 4-9 and Figure 4-8 show weather-normalised 1-in-2 and 1-in-20 peak day system forecasts for the 10-year outlook.

The actual peak day system demand in 2013 was 1,082 TJ/d, which occurred on 24 July. This is less than last year's 1-in-20 peak day system demand forecast of 1,270 TJ/d and last year's 1-in-2 forecast of 1,149 TJ/d. Actual annual peak day demand last exceeded the 1-in-2 forecast demand in 2010, and last exceeded the 1-in-20 forecast demand in 2007.

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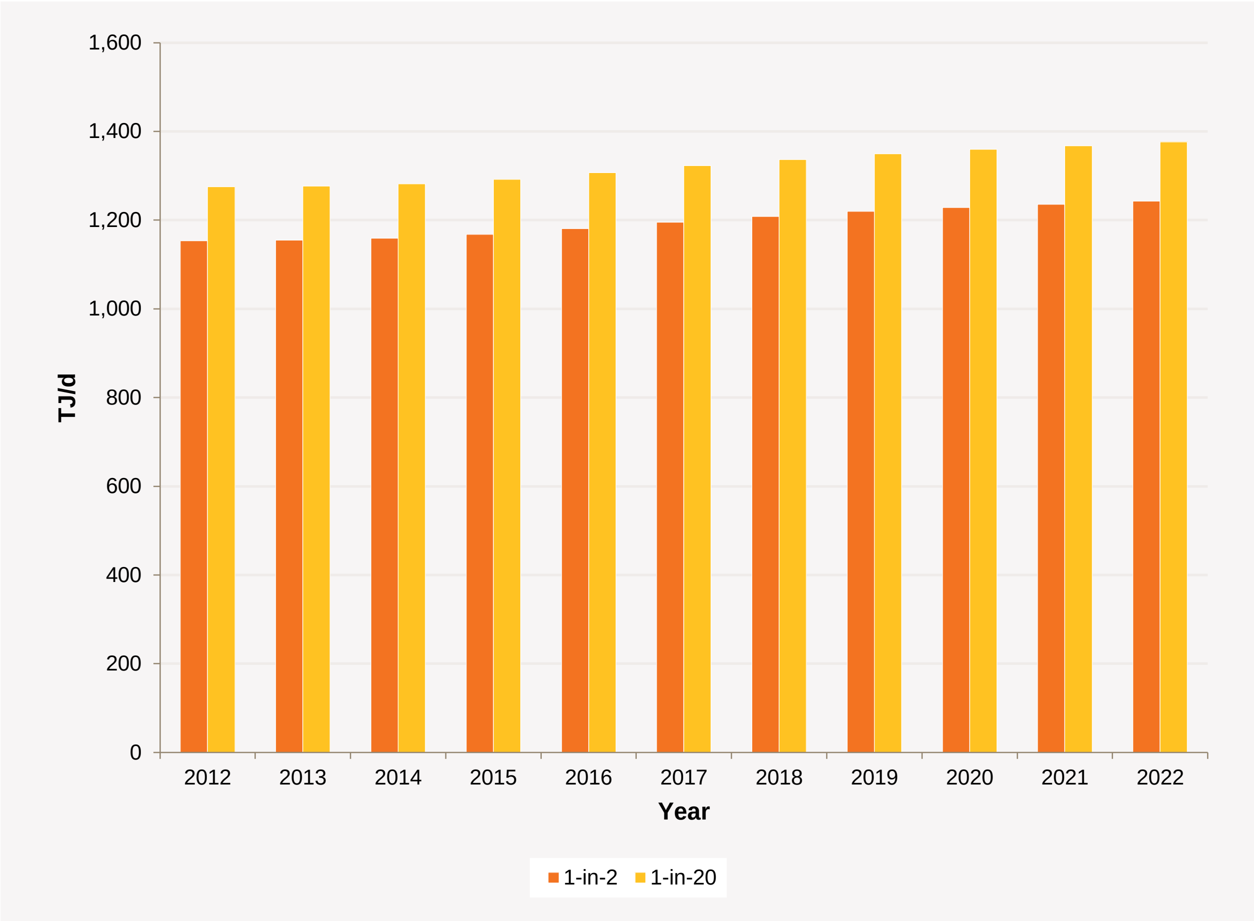
The 1-in-2 and 1-in-20 peak day system demand forecasts grow at an average annual rate of 0.9% to 2018 and an average annual rate of 0.8% over the entire 10-year outlook. Peak day system demand growth rates exceed the annual system demand growth rate of 0.7% over the 10-year outlook as a result of faster growing residential (Tariff V) gas demand being more sensitive to temperature than slower growing industrial (Tariff D) gas demand.

Figure 4-8 — Winter peak day system demand forecast



Additionally, Table 4-9 compares the 2013 forecast with the forecasts prepared for the 2012 MTO. Over the 10-year outlook, peak day system demand is forecast to grow at a marginally higher rate than was forecast in 2012, largely reflecting higher forecasts of annual gas system consumption.

Table 4-9 — Winter peak day system demand forecast, medium scenario (TJ/d)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth (%/yr)
2013 forecast												**2014–23**
1-in-2	1,153	1,155	1,159	1,168	1,181	1,195	1,208	1,219	1,228	1,235	1,243	0.8
1-in-20	1,275	1,277	1,282	1,292	1,307	1,322	1,337	1,350	1,360	1,368	1,376	0.8
2012 forecast (2012 Victorian Gas DTS Medium Term Outlook)												**2014–23**
1-in-20	1,270	1,265	1,264	1,268	1,278	1,291	1,306	1,320	1,334	1,344	1,351	0.7

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Winter peak day system demand forecasts by SWZ

Table 4-10, Table 4-11, and Figure 4-9 show the 1-in-2 and 1-in-20 peak day system demand forecasts by SWZ. The 2013 data point represents the actual 2013 peak day system demand, weather-normalised for 1-in-2 and 1-in-20 conditions.

As described above (see Section 4.2.2), the differences in the peak day growth rates between the SWZs are due to the different proportions of Tariff D and Tariff V demand in the SWZs, and the different growth rates forecast for these market segments over the 10-year outlook.

For comparative purposes, Table 4-10 and Table 4-11 also include the 1-in-2 and 1-in-20 peak day system demand forecasts published in last year's 2012 Victorian Gas DTS MTO.

Table 4-10 — Winter 1-in-2 peak day system demand forecast by SWZ (TJ/d)

SWZ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth (%/yr)
2013 forecast												**2014–23**
Ballarat	61	62	62	63	64	64	65	66	67	67	68	1.0
Geelong	116	116	115	115	116	116	116	116	117	116	116	0.0
Gippsland	68	68	68	68	68	69	69	70	70	70	70	0.4
Melbourne	788	789	793	801	811	821	831	840	847	853	859	1.0
Northern	103	103	103	104	105	106	108	109	110	110	111	0.9
Western	18	18	18	18	18	18	18	18	18	18	18	0.4
System demand	**1,153**	**1,155**	**1,159**	**1,168**	**1,181**	**1,195**	**1,208**	**1,219**	**1,228**	**1,235**	**1,243**	**0.8**
2012 forecast (2012 Victorian Gas DTS Medium Term Outlook)												**2014–23**
Ballarat	60	60	60	61	61	62	63	63	64	65	65	0.9
Geelong	111	109	109	109	109	110	111	112	112	113	113	0.4
Gippsland	69	69	68	68	68	69	69	70	71	71	71	0.4
Melbourne	790	787	787	789	797	805	815	823	833	840	844	0.8
Northern	101	101	101	101	102	103	104	105	106	107	108	0.7
Western	18	18	18	18	18	18	18	18	19	19	19	0.6
System demand	**1,149**	**1,144**	**1,143**	**1,146**	**1,155**	**1,167**	**1,180**	**1,193**	**1,205**	**1,214**	**1,220**	**0.7**

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Table 4-11 — 1-in-20 winter peak day system demand forecast by SWZ (TJ/d)

SWZ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth (%/yr)
2013 forecast												**2014–23**
Ballarat	69	69	70	70	71	72	73	74	75	75	76	1.0
Geelong	126	125	125	125	125	126	126	127	127	126	126	0.1
Gippsland	73	73	73	73	73	74	75	75	76	76	76	0.5
Melbourne	876	877	882	891	902	914	925	935	943	949	956	1.0
Northern	113	113	114	114	116	117	119	120	121	122	123	0.9
Western	19	19	19	19	19	19	19	19	19	19	19	0.4
System demand	**1,275**	**1,277**	**1,282**	**1,292**	**1,307**	**1,322**	**1,337**	**1,350**	**1,360**	**1,368**	**1,376**	**0.8**
2012 forecast (2012 Victorian Gas DTS Medium Term Outlook)												**2014–23**
Ballarat	68	68	68	68	69	70	70	71	72	73	73	0.9
Geelong	119	118	117	117	118	119	120	121	122	122	122	0.4
Gippsland	74	74	74	74	74	74	75	76	76	77	77	0.4
Melbourne	878	875	875	880	887	897	907	917	927	935	940	0.8
Northern	111	111	111	111	112	113	114	116	117	118	119	0.7
Western	19	19	19	19	19	19	19	19	20	20	20	0.7
System demand	**1,270**	**1,265**	**1,264**	**1,268**	**1,278**	**1,291**	**1,306**	**1,320**	**1,334**	**1,344**	**1,351**	**0.7**

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Figure 4-9 — Winter peak day system demand forecasts by SWZ (TJ/d)

4.4.2 Peak hour system demand forecasts

Table 4-12 shows 1-in-2 and 1-in-20 peak hour system demand forecasts by SWZ. The highest growth rates are seen in the Ballarat, Melbourne, and Northern SWZs.

As described above (see Section 4.2.2), the differences in the peak hour growth rates between the SWZs are due to the different proportions of Tariff D and Tariff V demand in the SWZs, and the different growth rates forecast for these market segments over the 10-year outlook.

Peak hour demands for individual zones are unlikely to occur at the same time across the SWZs, so annual peak hour system demand may be less than the actual highest hourly reading for each SWZ in each year.

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Table 4-12 — Peak hour system demand forecast by SWZ (TJ/hr)

	SWZ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average annual growth 2014-23 (%/yr)
1-in-2 peak hour	Ballarat	4.2	4.2	4.2	4.2	4.3	4.4	4.4	4.5	4.5	4.6	4.6	1.0
	Geelong	7.0	7.0	6.9	6.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0	0.0
	Gippsland	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	0.4
	Melbourne	50.8	50.9	51.2	51.7	52.3	53.0	53.6	54.2	54.7	55.0	55.4	1.0
	Northern	6.1	6.1	6.1	6.1	6.2	6.3	6.4	6.4	6.5	6.5	6.6	0.9
	Western	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.4
	System demand	**72.8**	**72.9**	**73.1**	**73.7**	**74.5**	**75.4**	**76.2**	**76.9**	**77.5**	**77.9**	**78.4**	**0.8**
1-in-20 peak hour	Ballarat	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1	5.2	1.0
	Geelong	7.6	7.5	7.5	7.5	7.5	7.6	7.6	7.6	7.6	7.6	7.6	0.1
	Gippsland	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.4	4.4	0.5
	Melbourne	56.5	56.6	56.9	57.5	58.2	59.0	59.7	60.3	60.8	61.2	61.7	1.0
	Northern	6.7	6.7	6.7	6.8	6.8	6.9	7.0	7.1	7.1	7.2	7.2	0.9
	Western	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.4
	System demand	**80.4**	**80.6**	**80.9**	**81.5**	**82.5**	**83.4**	**84.4**	**85.2**	**85.8**	**86.3**	**86.9**	**0.8**

Note: It is not appropriate to add up peak hour demand for each SWZ because all SWZs are not expected to coincide.

4.4.3 Monthly peak day demand forecasts

Table 4-13 lists the peak day system demand forecasts for the period January-December 2014.

Monthly peak day system demand is influenced by weather conditions and seasonal industrial demand variations.

Table 4-13 — Monthly peak day system demand forecasts for January-December 2014 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	425	446	527	698	908	1,155	1,155	1,155	1,155	822	688	543
1-in-20	505	570	688	865	1,084	1,277	1,277	1,277	1,277	983	854	709

For planning purposes, it is assumed that the 2014 peak day system demand may occur at any time in the June–September period. Peak day forecasts for the October–April period are based on monthly weather standards.

The 1-in-20 peak day system demand forecast:

- Is approximately10.6% higher than the forecast 1-in-2 peak day system demand during the period of most-likely peak demand (June–September).
- Ranges between 19.5% to 24.2% higher than the forecast 1-in-2 peak day system demand in the shoulder months (April, May, October, and November) due to greater variability in weather conditions in spring (October and November) and autumn (April and May).

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Monthly peak day demand forecasts by SWZ

By SWZ, during the period of most-likely peak demand (June to September), the 1-in-20 peak day system demand forecast is approximately:

- 12.3% higher than the forecast 1-in-2 peak day system demand in Ballarat.
- 8.4% higher than the forecast 1-in-2 peak day system demand in Geelong.
- 7.7% higher than the forecast 1-in-2 peak day system demand in Gippsland.
- 11.2% higher than the forecast 1-in-2 peak day system demand in Melbourne.
- 10.0% higher than the forecast 1-in-2 peak day system demand in Northern.
- 6.4% higher than the forecast 1-in-2 peak day system demand in Western.

Table 4-14 and Table 4-15 list the monthly peak day system demand forecasts for each SWZ for 2014 under 1-in-2 and 1-in-20 peak day conditions.

Consistent with the SWZ annual consumption forecasts, the differences in SWZ growth rates for the 1-in-2 and 1-in-20 peak day demand forecasts are due to the different proportions of Tariff D and V loads in each zone, and the different growth rates expected for these loads over the forecast period.

Table 4-14 — Monthly 1-in-2 peak day demand forecasts by SWZ for 2014 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	16	18	23	33	46	62	62	62	62	41	33	24
Geelong	58	60	66	80	96	116	116	116	116	89	79	67
Gippsland	37	38	41	48	57	68	68	68	68	54	48	42
Melbourne	262	277	335	459	610	789	789	789	789	548	452	347
Northern	41	43	50	64	82	103	103	103	103	75	63	51
Western	11	11	12	13	15	18	18	18	18	15	13	12
System demand	**425**	**446**	**527**	**699**	**908**	**1,155**	**1,155**	**1,155**	**1,155**	**822**	**688**	**543**

Table 4-15 — Monthly 1-in-20 peak day system demand forecasts by SWZ for 2014 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	21	25	33	44	57	69	69	69	69	51	43	34
Geelong	64	69	79	93	110	125	125	125	125	102	92	80
Gippsland	40	43	48	55	65	73	73	73	73	60	55	49
Melbourne	320	366	452	579	738	877	877	877	877	665	572	467
Northern	48	53	63	78	97	113	113	113	113	88	77	65
Western	12	12	13	15	17	19	19	19	19	16	15	14
System demand	**505**	**570**	**688**	**865**	**1,084**	**1,277**	**1,277**	**1,277**	**1,277**	**983**	**854**	**709**

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4.4.4 Monthly peak hour demand forecasts

Table 4-16 lists the monthly peak hour forecasts for 2014.

Table 4-16 — Monthly peak hour system demand for 2014 (TJ/h)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	21.9	25.1	29.0	45.5	58.7	72.9	72.9	72.9	72.9	51.3	41.6	30.7
1-in-20	26.1	32.1	37.9	56.3	70.1	80.6	80.6	80.6	80.6	61.3	51.7	40.1

Monthly peak hour demand forecasts by SWZ

Table 4-17 lists the peak hour forecasts for each month in 2014 for each SWZ. Peak hour demands for individual zones are unlikely to occur at the same time across the SWZs, so monthly peak hour system demand may be less than the actual highest hourly reading for each SWZ in each month.

Table 4-17 — Monthly peak hour demand forecast by SWZ for 2014 (TJ/h)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	Ballarat	0.9	1.1	1.5	2.4	3.3	3.9	3.9	3.9	3.9	2.8	2.2	1.5
	Geelong	2.7	3.0	3.4	4.5	5.8	7.3	7.3	7.3	7.3	5.2	4.3	3.4
	Gippsland	1.7	1.9	2.2	2.7	3.3	4.3	4.3	4.3	4.3	2.9	2.5	2.1
	Melbourne	14.1	16.1	19.7	30.7	40.3	49.8	49.8	49.8	49.8	35.4	28.7	20.7
	Northern	2.0	2.2	2.7	3.9	4.9	6.5	6.5	6.5	6.5	4.3	3.6	2.8
	Western	0.6	0.6	0.6	0.7	0.9	1.1	1.1	1.1	1.1	0.8	0.7	0.6
	System demand	**21.9**	**25.1**	**29.0**	**45.5**	**58.6**	**72.9**	**72.9**	**72.9**	**72.9**	**51.3**	**41.6**	**30.7**
1-in-20	Ballarat	1.2	1.6	2.1	3.1	4.0	4.4	4.4	4.4	4.4	3.5	2.9	2.2
	Geelong	3.0	3.5	4.1	5.3	6.6	7.9	7.9	7.9	7.9	5.9	5.0	4.1
	Gippsland	1.9	2.2	2.5	3.1	3.8	4.6	4.6	4.6	4.6	3.3	2.9	2.4
	Melbourne	17.2	21.3	26.5	38.7	48.8	55.4	55.4	55.4	55.4	42.9	36.3	27.9
	Northern	2.4	2.8	3.4	4.7	5.8	7.1	7.1	7.1	7.1	5.1	4.4	3.6
	Western	0.6	0.6	0.7	0.8	1.0	1.2	1.2	1.2	1.2	0.9	0.8	0.7
	System demand	**26.1**	**32.1**	**37.9**	**56.3**	**70.1**	**80.6**	**80.6**	**80.6**	**80.6**	**61.3**	**51.7**	**40.1**

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Chapter 5 GAS SUPPLY FORECAST

Summary

This chapter presents an overview of gas supplies and storage sources in the Declared Transmission System (DTS), peak and annual gas supply forecast information, and winter peak LNG requirements for the outlook period.

Peak and annual gas supply forecast information is provided by market participants in accordance with their obligations under National Gas Rules (NGR) 324. While the production facility forecasts provided indicate sufficient supply capacity over the outlook period, they show a substantial decrease in contracted gas supply from 2018. This indicates that a number of market participants have not committed to gas supply agreements beyond 2017. AEMO will monitor market participants' contract position and provide updates in the 2015 Victorian Gas Planning Report (VGPR).

There is sufficient liquefied natural gas (LNG) for a 1-in-2 or 1-in-20 peak day. Assuming export demand of 57 TJ/d for winter 2014 and 113 TJ/d from winter 2015 onwards (based on 2014–18 demand forecasts), the 87 TJ/d LNG capacity threshold is not exceeded regardless of GPG demand.

Market participants have indicated that Longford and Port Campbell gas is available to Victoria subject to DTS system demand, interstate commitments, and market conditions on the day. Longford gas may flow to Tasmania and New South Wales and Port Campbell gas flow might flow to South Australia depending on market conditions.

5.1 Gas supply and storage

This section describes individual gas supply sources and presents gas supply forecasts for the outlook period. This includes annual, monthly, and peak day supplies of gas transported through the DTS. Supplies are those that may be made available to the Victorian gas market, whether used or not.

Information on injection points is in Section 2.1.

The following two classifications of gas supply are used for planning purposes:

- "Available" supply is the aggregate contracted maximum daily quantities available to the market through commercial arrangements between market participants and gas producers or storage providers.
- "Prospective" supply is subject to market participants offering gas on the gas day, may depend on interconnecting pipeline operating conditions and contracts, and is therefore a less certain source of supply than "available".

Note: Although information in this chapter shows that for 2018, the majority of the gas supply is termed prospective instead of available, production capacity remains unchanged over the outlook period. AEMO will monitor market participants' contract position and provide the update in the 2015 VGPR.

5.1.1 Gippsland system withdrawal zone

The BassGas, Longford, and VicHub injection points are located in the Gippsland system withdrawal zone (SWZ) where gas can be injected into the DTS via the Longford to Melbourne Pipeline (LMP). The rate of gas injection might be limited by the LMP capacity.

As shown in Table 5-4, for 2014, market participants have advised that the winter peak day available supply from Gippsland is 1,027 TJ/d.

The Longford Gas Plant is the largest producer of gas for the Victorian market with plant capacity of 1,145 TJ/d. Market participants have advised that the plant capacity will remain unchanged for the outlook period.

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The Lang Lang Gas Plant has a capacity of 70 TJ/d. Participants have advised that the winter peak day available supply from BassGas flow is 67 TJ/d for the outlook period. Participants have indicated that there are no prospective supplies.

5.1.2 Geelong SWZ

The Iona, Mortlake, Otway, and South East Australia (SEA) Gas injection points are located near the township of Port Campbell in south-west Victoria in the Geelong SWZ. Gas can be injected into the DTS via the South West Pipeline (SWP) but may be limited by the transportation capacity of the SWP and the SEA Gas pipeline.

For 2014, market participants have advised that the winter peak available supply from Port Campbell (Iona, Mortlake, Otway, and SEA Gas injection points) is 550 TJ/d.

However, given that the Port Campbell gas can flow to either South Australia or into the Victorian DTS, market conditions may influence the quantity supplied to each market.

Participants have advised that Iona has a peak day plant processing and injection capacity of approximately 500 TJ/d for the outlook period; however, not all of this capacity is classified by market participants as available given market participants are constrained to the SWP capacity. There is no prospective gas indicated for the outlook period.

5.1.3 Northern SWZ

Participants have advised that supplies of 60 TJ/d will be available as supply from the Culcairn injection point over the outlook period with 5 TJ/d classed as prospective. The current import capacity from New South Wales is 120 TJ/d.

Although market participants have indicated available supplies at Culcairn, it has not had any net injections and has been in net withdrawals for 2013.

5.1.4 Melbourne SWZ

The Dandenong injection point is located near the Dandenong liquefied natural gas (LNG) storage facility at Dandenong City Gate, which is in the Melbourne SWZ. Refer to Section 0 for more information about the LNG storage facility.

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5.2 Annual gas supply forecast by SWZ

This section summarises forecast annual available and prospective supplies by SWZ and injection point or aggregated injection point. Refer to Section 5.1 for the definition of available and prospective supplies.

Market participants indicated that Longford and Port Campbell gas is available to Victoria subject to DTS system demand, interstate commitments and market conditions on the day. Longford gas may flow to Tasmania or New South Wales, and Port Campbell gas flow might flow to South Australia depending on market conditions.

Figure 5-1 shows forecast annual consumption (system consumption as well as DTS-connected GPG consumption) and available and prospective supply for supply–demand comparison. It shows that available supply exceeds demand up to 2017.

Figure 5-1 — Annual supply forecast compared with annual system consumption plus DTS-connected GPG consumption forecast

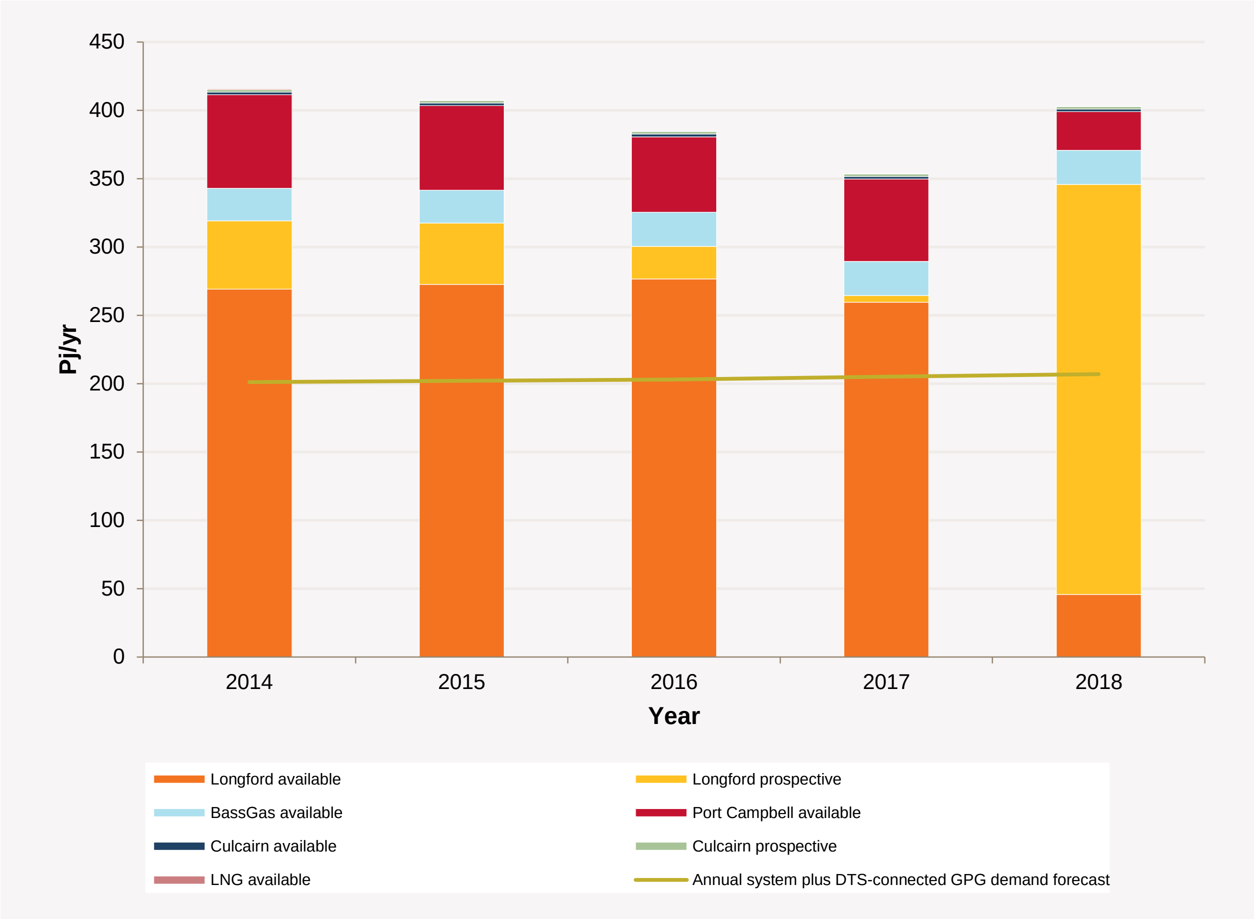

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Table 5-1 summarises the annual gas supply forecast provided by market participants. Data provided shows that available plus prospective gas supplies range from 350 to 420 PJ/yr over the outlook period.

Table 5-1 — Annual supply forecast by SWZ and injection point/or aggregated injection points (PJ/yr)

SWZ	Injection point	2014 (2012 MTO)	2014	2015	2016	2017	2018
Gippsland	Longford[a] available	278.8	269.0	272.5	276.5	259.5	45.8
	Longford prospective	54.8	50.0	45.0	24.0	5.0	300.0
	BassGas available	25.0	24.0	24.0	25.0	25.0	25.0
	BassGas prospective	0.0	0.0	0.0	0.0	0.0	0.0
	Total available	**303.8**	**293.0**	**296.5**	**301.5**	**284.5**	**70.8**
	Total available plus prospective	**358.6**	**343.0**	**341.5**	**325.5**	**289.5**	**370.8**
Geelong	Iona available	75.2	5.7	5.6	5.6	5.6	5.6
	Otway available		57.8	55.8	49.0	54.0	22.0
	Mortlake available		0.5	0.5	0.5	0.5	0.5
	SEA Gas available		4.3	0.0	0.0	0.0	0.0
	Geelong available	75.2	68.3	61.9	55.1	60.1	28.1
	Total available plus prospective	**78.0**	**68.3**	**61.9**	**55.1**	**60.1**	**28.1**
Northern	Culcairn available	2.0	2.0	2.0	2.0	2.0	2.0
	Culcairn prospective	1.8	1.8	1.8	1.8	1.8	1.8
	Northern available plus prospective	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**
Melbourne	LNG available[b]	0.5	0.6	0.28	0.06	0.06	0.06
Total available		381.5	363.9	360.7	358.7	346.7	101.0
Total prospective		59.4	51.8	46.8	25.8	6.8	301.8
Total available plus prospective		**440.9**	**415.7**	**407.5**	**384.5**	**353.5**	**402.8**

a. Longford includes gas supply from both the Longford gas plant and VicHub injection point.

b. LNG available is the LNG contracted by market participants.

5.3 Available monthly peak day gas supply forecasts for 2014

This section presents the available monthly gas supply forecast for January to December 2014.Table 5-2 lists the available monthly supply forecasts provided by market participants.

The quantities available at each system injection point are indicative of what may be made available to the DTS subject to pipeline constraints, commercial/term arrangements, DTS system demand, interstate commitments, and market price on the day.

In addition, supplies at each injection point have been adjusted to reflect plant maintenance outages (where possible), recall times, and ramp rates (where applicable). While producers are not obligated by the NGR to provide information to AEMO about their planned maintenance, there are ongoing consultations between AEMO and producers to ensure their maintenance will not pose a risk to DTS security.

Refer to Section 6.2 for maintenance information provided by market participants.

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Table 5-2 — Available monthly peak day gas supply forecast, January to December 2014 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Longford[a]	894[b]	896[b]	904[b]	905	938	956	961	960	937	924	904[b]	900[b]
BassGas	67	67	67	67	67	67	67	67	67	67	67	67
Port Campbell[c]	272	272	232[d]	359	360	367	367	367	367	359	359	345
Culcairn	60	60	60	60	60	60	60	60	60	60	60	60
LNG	0	87	87	87	87	87	87	87	87	87	87	87
Total supply	**1,293**	**1,382**	**1,350**	**1,478**	**1,512**	**1,537**	**1,542**	**1,541**	**1,518**	**1,497**	**1,477**	**1,459**

a. Longford includes gas supply from both the Longford gas plant and the VicHub injection point.

b. Maintenance is likely to occur during these months and will limit the available gas supply forecast to the plant capacity. There are frequent ongoing consultations between AEMO gas operations and the gas producers to ensure their maintenance will not pose a risk to DTS security.

c. Port Campbell includes gas supply from Iona Underground Gas Storage (UGS), SEA Gas, Otway, and Mortlake injection points. Port Campbell supply is subject to the net transportation capacity of the SWP and WTS.

d. Planned maintenance at Iona UGS will reduce injection into the SWP. SEA Gas, Otway and Mortlake can still inject into the SWP.

Table 5-3 summarises the monthly supply–demand outlook for 2014.

The monthly supply–demand outlook assumes:

- Monthly demand forecast for 2014 described in Chapter 4 .
- Culcairn is exporting and is set at the VGPR maximum export quantity for different system demand days as specified in Chapter 3 (This is based on historical data that shows Culcairn has been exporting the since 2012).
- GPG demand figures are based on the maximum GPG available on a 1,300 TJ day.
- Port Campbell supply is limited to the capacity of the pipeline and set at the VGPR capacity limit for different system demand days as specified in Chapter 3 .

Based on information provided by market participants in Table 5-2, there is sufficient supply to meet demand for 2014.

Table 5-3 — Monthly supply–demand outlook for 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-20 (TJ/d)	505	570	688	865	1,085	1,277	1,277	1,277	1277	983	854	709
Culcairn Export (TJ/d)	82.5	79	76	68.5	64	42	42	*28*	42	65	*58*	75
GPG Demand (TJ/d)	135	135	135	135	25	25	25	25	25	135	135	135
Total Demand (TJ/d)	**723**	**784**	**899**	**1,068**	**1,174**	**1,344**	**1,344**	**1,330**	**1,344**	**1,183**	**1,047**	**919**
Port Campbell (TJ/d)	272	272	232	359	360	367	367	367	367	359	359	345
BassGas (TJ/d)	67	67	67	67	67	67	67	67	67	67	67	67
Required Longford[a] supply without LNG (TJ/d)	384	445	600	642	747	910	910	896	910	757	621	507
With LNG (TJ/d)	0	87	87	87	87	87	87	87	87	87	87	87
Required Longford[a] supply with LNG (TJ/d)	**384**	**358**	**358**	**555**	**660**	**823**	**823**	**809**	**823**	**670**	**534**	**420**

a. Longford includes gas supply from both the Longford gas plant and VicHub injection point.

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5.4 Winter peak day gas supply forecast by SWZ

Figure 5-1 and Table 5-4 summarise forecast winter peak day available and prospective supplies by SWZ and injection point or aggregated injection points.

Figure 5-2 also shows forecast 1-in-2 and 1-in-20 peak day system demand (excluding GPG demand). It shows available supply exceeds peak day system demand; however, this comparison ignores transmission pipeline constraints. A more complete picture of supply capability including pipeline constraints is discussed in Chapter 6 .

Figure 5-2 — Peak day supply forecast compared with scenario demand

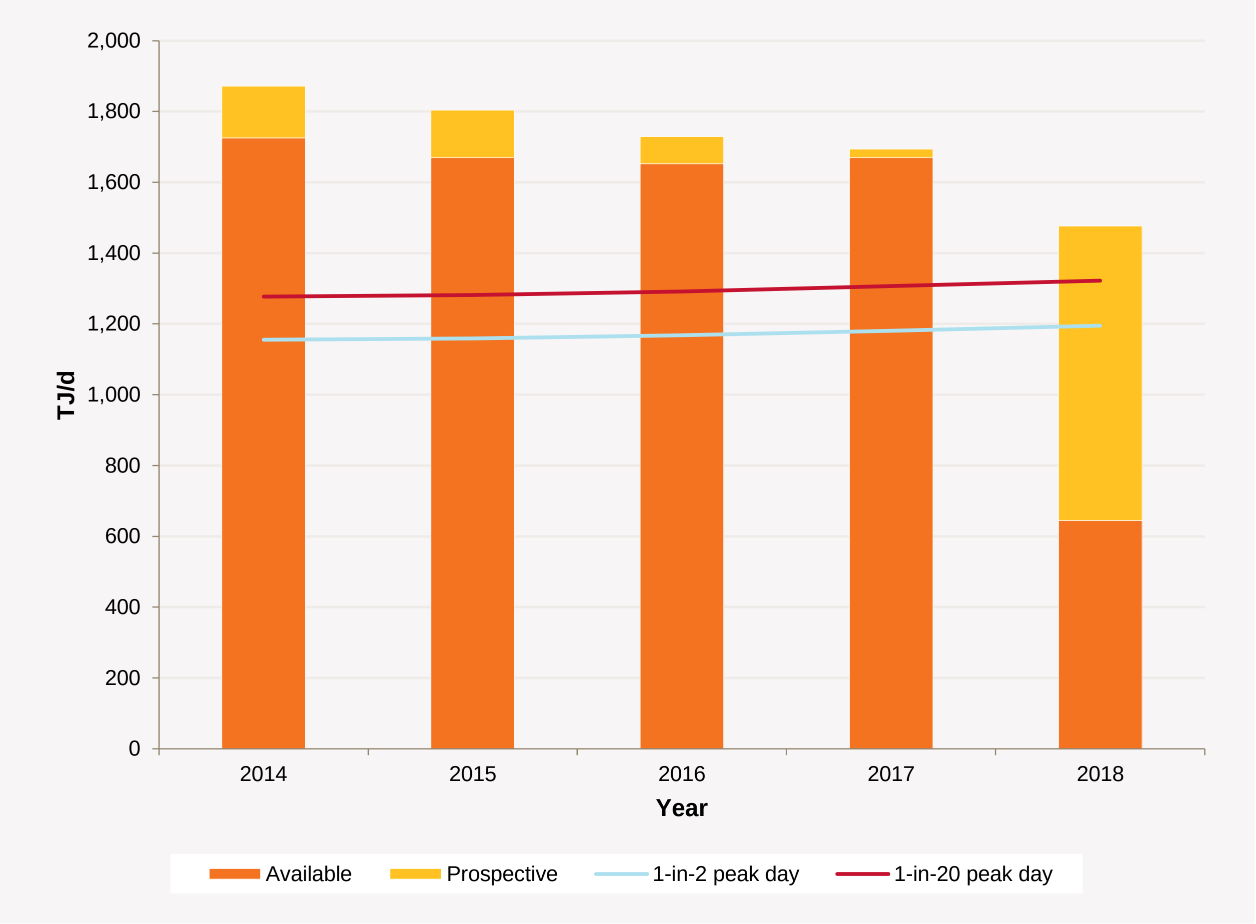

Table 5-4 also includes last year's peak day gas supply forecast for 2014. Compared with the 2014 forecast from the 2012 Gas MTO, available supply for 2014 has decreased by 120 TJ/d and total available supply plus prospective supply has decreased by 195 TJ/d. This decrease is largely due to market participants reporting their peak day supply for Port Campbell as constrained by SWP Allocated Maximum Daily Quantity (AMDQ).

Table 5-4 — Peak day supply forecast by SWZ and injection point (TJ/d)

SWZ	Injection Point	2014 (2012 MTO)	2014	2015	2016	2017	2018
Gippsland	Longford[a] available	986.2	960.8	925.7	930.7	930.7	165.7
	Longford[a] prospective	186.3	141.0	129.0	71.0	19.0	827.0
	BassGas available	67.0	67.0	67.0	67.0	67.0	67.0
	BassGas prospective	0.0	0.0	0.0	0.0	0.0	0.0

SWZ	Injection Point	2014 (2012 MTO)	2014	2015	2016	2017	2018
	Total available	**1,053.2**	**1,027.8**	**992.7**	**997.7**	**997.7**	**232.7**
	Total available plus prospective	**1,239.5**	**1,168.8**	**1,121.7**	**1,068.7**	**1,016.7**	**1,059.7**
Geelong	Port Campbell[b] available	645.2	550.5	530.0	508.0	525.0	265.0
	Port Campbell prospective	30.0	0.0	0.0	0.0	0.0	0.0
	Geelong available	645.2	550.5	530.0	508.0	525.0	265.0
	Total available plus prospective	**675.2**	**550.5**	**530.0**	**508.0**	**525.0**	**265.0**
Northern	Culcairn available	60.0	60.0	60.0	60.0	60.0	60.0
	Culcairn prospective	5.0	5.0	5.0	5.0	5.0	5.0
	Northern available plus prospective	**65.0**	**65.0**	**65.0**	**65.0**	**65.0**	**65.0**
Melbourne	LNG available	87.0	87.0	87.0	87.0	87.0	87.0
Total available		1,845.4	1,725.3	1,669.7	1,652.7	1,669.7	644.7
Total prospective		221.3	146.0	134.0	76.0	24.0	832.0
Total available plus prospective		**2,066.7**	**1,871.3**	**1,803.7**	**1,728.7**	**1,693.7**	**1,476.7**

a. Longford includes gas supply from both the Longford gas plant and VicHub injection point.

b. Port Campbell includes gas supply from Iona, SEA Gas, Otway and Mortlake injection points.

Table 5-5 summarises the peak day supply-demand outlook.

The peak day supply-demand outlook assumes:

- 1-in-20 peak day system forecast for the outlook period described in Chapter 4 .
- Culcairn is exporting the 1-in-20 peak day amount stated in Chapter 3 for the outlook period.
- GPG demand is 25 TJ/d for a 1,300 TJ/d.
- Port Campbell[51] supply is limited to the 1-in-20 peak day pipeline capacity.

Based on peak day supply forecast provided by market participants in Table 5-4, there is sufficient available and prospective supply to meet the outlook period.

Table 5-5 — Peak day supply–demand outlook

	2014	2015	2016	2017	2018
1-in-20 peak day system demand (TJ/d)	1,277	1,282	1,292	1,307	1,322
GPG demand (TJ/d)	25	25	25	25	25
Culcairn Export (TJ/d)	57	113	113	113	113
Total demand (TJ/d)	**1,359**	**1,420**	**1,431**	**1,445**	**1,460**
Port Campbell (TJ/d)	367	429	429	429	429

[51] Port Campbell includes gas supply from Iona, SEA Gas, Otway and Mortlake injection points.

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	2014	2015	2016	2017	2018
BassGas (TJ/d)	67	67	67	67	67
Without LNG (TJ/d)	0	0	0	0	0
Required Longford[a] supply without LNG (TJ/d)	925	924	935	949	964
With LNG (TJ/d)	87	87	87	87	87
Required Longford[a] supply with LNG (TJ/d)	**838**	**837**	**848**	**862**	**877**

a. Longford includes gas supply from both the Longford gas plant and VicHub injection point.

5.5 Liquefied Natural Gas (LNG)

The Dandenong LNG storage facility liquefies and stores LNG that is used as a source of gas on high demand days and at other times including maintaining system security in the event of a sustained supply loss or transmission failure.

The existing LNG facility has a storage capacity of 12,400 tonnes (680 TJ).[52] Approximately 10,929 tonnes (600 TJ) are available to market participants up to 31 January 2015 while 1,471 tonnes (81 TJ) are contracted to third party customers.

For developing forecasts, the assumptions involving the LNG storage facility include:

- The LNG tank is full or nearly full at the start of each winter.
- Vaporising capacity of up to 100 t/h is available over 16 hours for peak shaving.[53] This capacity equates to the vaporisation of 87 TJ/d, reflecting the contracted available rate for the outlook period. The LNG facility is able to vaporise 180 t/h at its maximum capacity.

Normally, LNG is not scheduled from the beginning-of-day, but is included in a reschedule later in the day.[54] For within-day balancing purposes, LNG only effectively supports DTS pressure when injected before 10.00 pm on the day it is required.

Given that LNG for peak shaving is only available over 11 hours, rather than the contracted time of 16 hours, peak day planning assumes that 60 TJ/d of LNG can be delivered for within-day balancing.[55] After 10.00 pm, further LNG injections only serve to increase the line-pack for the following day.

LNG liquefaction to replenish stock levels is planned on a monthly basis, with the potential to order liquefaction of up to 1,500 tonnes per month, averaging approximately 50 t/d or 2.7 TJ/d.

5.5.1 Peak day LNG requirements

This section presents an analysis of LNG requirements from the Dandenong LNG storage facility for peak day within-day balancing for the five-year forecast period.

Transmission constraints and pipeline operating boundaries limit the daily supply of gas available for injection. As a result, LNG may be required on high demand days to address within-day constraints due to limited pipeline capacity and useable linepack.

[52] The LNG Storage Provider has advised (as at September 2013) that 1 tonne of LNG has an energy equivalent of 54.9 GJ.
[53] This is based on the participant's firm LNG rate, which allows for an outage of one of three pumps and one of the three vaporiser units.
[54] Although LNG can be scheduled from the beginning-of-day, it is usually used on days when there has been a demand forcast error due to the weather being colder than forecast. This error becomes evident around 10.00 am.
[55] LNG is normally not scheduled from beginning-of-the-day, but is rescheduled later in the day. Therefore, the LNG used at a rate of 100 t/h over an 11-hour period (11.00 am to 10.00 pm) is 1,100 tonnes (60 TJ).

LNG use falls into one of three categories (the first two are modelled for this analysis):

- LNG required by operational response for within-day balancing, scheduled out of price-merit order[56] (to manage transmission constraints, supply, or transmission outages).
- LNG required by market response for supplementary supply on very high demand days, scheduled in price-merit order.
- LNG scheduled in price-merit order as an ordinary supply.

The Longford and Lang Lang gas plants generally have adequate supply and capacity over the summer months to support system demand, GPG demand, and withdrawals at Iona, Culcairn, and VicHub.

Table 5-6 and Table 5-7 present modelling results for 1-in-2 peak day LNG requirements with GPG demand and 1-in-20 peak day LNG requirements with and without GPG demand.

It is assumed that 60 TJ/d of LNG injection is available for within-day balancing. This may be required depending on the severity of the peak day profile and the beginning-of-day linepack conditions. It also assumed that a 1-in-20 peak day is correctly forecast either as a day+1 forecast or early in the morning on the day to commence LNG injections at the 10.00 am horizon. It does not take into account forecasting error situations or unexpected deteriorating weather conditions.

Overall, the modelling shows the following:

- During the forecast period, there is adequate LNG to meet demand. The LNG available for within-day balancing (60 TJ/d) is not exceeded for 1-in-20 peak days with GPG demand over the outlook period.
- Profiled injections (a profiled injection rate refers to higher injections for the first 12 hours of a gas day, with lower injections in the next 12 hours) have a significant effect in reducing the need for LNG.
- The major factor in the increase of the LNG requirement, compared to last year, is the increase in forecast peak day system demand.

Table 5-6 compares the LNG requirements:

- For a 1-in-2 peak day, with system demand based on the current five-year forecasts.
- With an assumed export of 68 TJ/d[57] for winter 2014 and 113 TJ/d[58] for winter 2015 at Culcairn.
- GPG demand based on an assumed 75 TJ/d.
- With injections at a flat and a profiled rate.

Table 5-6 — 1-in-2 peak day LNG requirement with GPG demand 2014-18 (TJ/d)

	2014	2015	2016	2017	2018
Forecast system demand	1,155	1,159	1,168	1,181	1,195
Culcairn export	68	113	113	113	113
Assumed GPG demand	100	100	100	100	100
LNG requirement for flat injection rate	44	52	56	63	69
LNG requirement for profiled injection rate	25	31	34	39	46

[56] When operator intervention is required for system security or safety, LNG is always scheduled from the lowest-priced LNG to the most expensive LNG (LNG price-merit order).
[57] Based on stage 1 Northern SWZ expansion completed by winter 2014. Refer to Section 3.2.5 for more information on the expansion.
[58] This is the 1-in-20 peak day number. AEMO has not modelled the export capacity for a 1-in-2 peak day. Northern export capacity with Northern SWZ expansion for various system demand days will be provided in 2015 VGPR.

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Table 5-7 compares the LNG requirements:

- For a 1-in-20 peak day, with system demand based on the current five-year forecasts.
- With an assumed export of 57 TJ/d[59] for winter 2014 and an estimated export of 113 TJ/d[60] from winter 2015 at Culcairn.
- With and without an assumed GPG demand of 25 TJ/d.
- With injections at a flat and a profiled rate.

Table 5-7 — 1-in-20 peak day LNG requirement 2014-18 (TJ/d)

	2014	2015	2016	2017	2018
Forecast system demand	1,277	1,282	1,292	1,307	1,322
Culcairn export	57	113	113	113	113
With assumed GPG demand 25 TJ/d					
LNG requirement for flat injection rate	43	54	59	67	75
LNG requirement for profiled injection rate	29	39	44	52	61
With no assumed GPG demand					
LNG requirement for flat injection rate	32	39	42	47	55
LNG requirement for profiled injection rate	11	20	24	30	36

Table 5-6 and Table 5-7 indicate that LNG requirements for the outlook period can be adequately supplied given the maximum LNG capacity for peak shaving is 87 TJ/d.

LNG requirements are higher than forecast in the 2012 Victorian Gas System Adequacy (VGSA) due to an increased forecast winter peak day system demand and increased export requirements.

In both the 1-in-2 and 1-in-20 peak day cases, profiled injection rates can be used to address within-day constraints and usable linepack by reducing the likelihood of curtailment by maintaining available LNG use if the situation continues to deteriorate.

5.5.2 Historical LNG use

LNG use has varied over the last 10 years. In 2007 it increased significantly as a result of the increase in GPG demand driven predominantly by the reduced availability of hydroelectric generation. The reduction in LNG use in 2008 and 2009 compared to previous years was partially due to commissioning of the Brooklyn to Lara Pipeline in 2008, which provides additional supply from the Otway Basin. In addition, operational tools have been developed to better forecast system conditions and LNG requirements, and market design changes have also contributed to the reduction in LNG usage. Table 5-8 lists the winter LNG use for the last 10 years.

The total LNG usage for 2012 winter period was 145 TJ. This usage is purely market related. LNG dispatch was not required for the purpose of peak shaving gas at any time in 2012. The higher injections of LNG in 2012 is possibly also due to its use as an alternative supply source to BassGas; the extended outage of BassGas during winter 2012 reduced available supply by approximately 50 TJ/d.

[59] Based on stage 1 Northern SWZ expansion completed by winter 2014. Refer to Section 3.2.5 for more information the expansion.
[60] Based on the Northern SWZ expansion completed by winter 2015, which would increase the 1-in-20 export capacity by 145%. Refer to Section 3.2.5 for more information on the expansion.

The total LNG usage for 2013 winter was 40 TJ. LNG dispatch was required twice for the purpose of peak shaving gas this winter on 21 and 24 June. These were the two largest demand days for 2013 and coincided with the Yallourn Power Station outage, which contributed to a large quantity of GPG consumption.

Table 5-8 — Historical winter LNG use (2004–13)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TJ	199	88	270	321	45	26	48	22	145	40
Tonnes	3,631	1,606	4,927	5,858	821	474	876	401	2,646	729

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Chapter 6 GAS TRANSMISSION ADEQUACY, SYSTEM MAINTENANCE, AND AUGMENTATIONS

Summary

Based on the modelled 1-in-20 peak day system demand forecast for the outlook period, no constraints have been identified in any of the system withdrawal zones (SWZs).

This chapter includes current planned maintenance for 2014 and the status of major committed and proposed transmission system augmentations.

Maintenance plans provided by market participants indicate no risk to Declared Transmission System (DTS) operation or security for 2014.

The committed DTS augmentations that AEMO uses in its transmission adequacy modelling are:

- The Wollert to Euroa to Springhurst partial looping on the Northern Zone to be commissioned by winter 2015.
- A new compressor station at Winchelsea on the South West Pipeline (SWP) to be commissioned by winter 2015.
- A gas cooling system for Brooklyn units 10 and 11.
- Iona Compressor Station reconfiguration.

These augmentations are detailed below.

6.1 System withdrawal zone transmission adequacy

This section summarises potential DTS constraints and operational challenges for the outlook period presented by Victorian gas SWZs.

For more information about gas SWZs, see the gas transmission maps in Chapter 2 .

6.1.1 Modelling scenarios

The modelling scenarios use the medium 1-in-20 peak day system demand forecasts presented in Chapter 4 . These forecasts also include compressor fuel usage. Over the five-year demand outlook period, peak day system demand forecast is now expected to grow at a faster rate than that provided in the 2012 Gas DTS Medium Term Outlook.[61] The reasons behind the increase in peak day system demand forecast are in Chapter 4 .

All scenarios assume up to 940 TJ/d of injection from Longford, 60 TJ/d from BassGas, and Iona makes up the balance to meet demand. Committed augmentations are taken into account in the modelling. LNG is used as needed up to the contracted rate of 60 TJ/d as per the planning standard.

Table 6-1 shows the medium 1-in-20 peak day system demand forecasts used in the modelling scenarios.

[61] AEMO. *2012 Victorian Gas DTS Medium Term Outlook*. Available at: http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/2012_Medium_Term_Outlook.pdf.ashx. Viewed: 11 December 2013.

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Table 6-1 — 1-in-20 peak day system demand forecast, medium scenario (TJ/d)

	2014	2015	2016	2017	2018
2013 VGPR Chapter 4					
1-in-20	1,277	1,282	1,292	1,307	1,322
2012 Victorian Gas Medium Term Outlook, Chapter 2 Demand Forecast					
1-in-20	1,265	1,264	1,268	1,278	1,291

6.1.2 Future GPG development modelling scenarios

GPG development during the outlook period can significantly affect the type and location of transmission constraints in the DTS. Based on the generation retirement and expansion modelling results prepared by AEMO for the 2013 National Transmission Development Plan (NTNDP)[62], there are no new GPG developments during the five-year outlook period. The only GPG demand assumed in the modelling scenarios is 25 TJ/d over a nine-hour period, which is the current planning standard for 1,300 TJ/d.

However, the installed maximum GPG capacity for the existing gas power stations is up to 22 TJ/hr.

6.1.3 Gas transmission constraints

Transmission constraints are identified when a part of the DTS experiences lower pressures than the minimum pressure obligations required by the Wholesale Market System Security Procedures (Victoria), Distribution Business Connection Deeds, the APA Group Connection Agreement, and the APA Group Service Envelope Agreement. The transmission constraints are grouped by gas SWZ for augmentations within the outlook period.

Based on the winter demand forecast for the outlook period, there are currently no constraints identified in any SWZ. Table 6-2 shows the gas transmission system adequacy by SWZ.

Table 6-2 — Gas transmission system adequacy by SWZ

SWZ	Constraints	Additional Information
Gippsland	No constraints identified.	The Longford Melbourne Pipeline (LMP) capacity is 1,030 TJ/d. Although available peak day gas supply forecast provided by market participants indicate approximately 1,000 TJ/d from Gippsland SWZ, the highest injection from Longford in the past three years is 940 TJ/d. The capacity of the pipeline is currently under-utilised. Longford and VicHub injections have not been modelled above 940 TJ per day based on historical performance and expected flows on the Eastern Gas Pipeline (EGP) to New South Wales. AEMO will validate and reassess their modelling assumptions before modelling commences.
Geelong	No constraints identified.	The South West Pipeline (SWP) capacity is 367 TJ/d. During high demand days, the pipeline is more likely to reach capacity as demonstrated by a number of Net Flow Transportation Constraints (NFTC) on the SWP during winter 2011 and 2012. Commissioning of Winchelsea Compressor Station by winter 2015 to increase the SWP capacity.

[62] AEMO. *2013 National Transmission Network Development Plan*. Available at: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2013/2013_NTNDP.pdf.ashx Viewed: 12 December 2013

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<table>
<tr><th>SWZ</th><th>Constraints</th><th>Additional Information</th></tr>
<tr><td>Northern</td><td>No constraints identified.</td><td>There has been high demand for gas export to New South Wales (NSW) for the past three years. It is highly unlikely to see high net injections from Culcairn in the future as there has been no net injection from Culcairn in 2013.
NSW-VIC Interconnect has reached export capacity limit on several occasions during winter and summer period 2012 and 2013.
The APA Group will loop sections of the Wollert to Barnawartha in the Victorian DTS. The aggregate effect of the expansion will be to increase firm peak winter gas export capacity from the DTS to NSW by 145%.
This expansion is intended to increase the export capacity by 67 TJ/d from 46 TJ/d to 113 TJ/d on a 1-in-20 peak system demand day. It will commence this year and be completed by winter 2015.
The first stage of the expansion is planned for completion by winter 2014 and will increase the Culcairn export capacity to 57 TJ/d.
Refer to Section 3.2.5 for further information.</td></tr>
<tr><td>Melbourne</td><td>No constraints identified.</td><td>Nil.</td></tr>
<tr><td>Ballarat</td><td>No constraints identified.</td><td>The upgrade on Plumpton PRS (Pressure Reduction Station) has allowed the Sunbury load to be supplied by Brooklyn Lara Pipeline (BLP). This has taken the load off the Brooklyn to Ballan pipeline which allows spare capacity in the pipeline.</td></tr>
<tr><td>Western</td><td>No constraints identified.</td><td>If there is no injection at Iona and the Brooklyn Compressor Station is not available, minimum pressures at Portland and Iluka will be breached during increased system load.
AEMO will manage the risk with ongoing consultations with market participants to ensure that the Brooklyn Compressor Station is available when Iona is not injecting.
Other solution includes:
• A new system injection point south of Hamilton to allow gas from SEA Gas pipeline to be injected into the WTS.
• Additional compression or looping of the WTS.</td></tr>
</table>

6.2 Maintenance and plant outages 2014

6.2.1 Gas DTS infrastructure

Table 6-3 lists the DTS maintenance schedules, infrastructure, and plant outages for 2014.

AEMO coordinates maintenance planning of the DTS, with the DTS system service provider, the interconnected pipeline service providers, and storage providers. To facilitate planning, the National Gas Rules (NGR) oblige the interconnected pipeline providers and storage providers give AEMO information about their planned maintenance. Table 6-3 and Table 6-4 summarise this information.

While producers are not obligated by NGR 324 to provide such information, AEMO's ongoing consultations with producers ensure that their maintenance will not pose a risk to system security.

Iona Underground Gas Storage (UGS) facility has a two-week planned maintenance outage in March 2014. The exact timing will depend on Longford injection rates and project progress.

Table 6-3 — Gas DTS maintenance, infrastructure, and plant outages for 2014

Infrastructure	Operational risk[b,c]	Description, primary role, and required maintenance
Brooklyn Compressor Station[a]	Low risk. Sufficient redundant compressors available during maintenance.	**Description:** One 850 kW compressor (Unit 8), one 950 kW compressor (Unit 9), two 2,850 kW compressors (units 10 and 11) and one 3,500 kW compressor (Unit 12). **Primary role:** Provides compression to the Brooklyn to Corio pipeline, SWP, and the Brooklyn–Ballarat pipeline. **Required maintenance:** With increased production of gas from the Otway fields, it is expected that the Otway Basin, rather than gas from Longford Gas Plant, will be used to replenish the Iona UGS. As a result, there will be less compression required at Brooklyn to replenish the Iona UGS. However, there will be increased Brooklyn compression to supply the GPG at Laverton North. Unit 8 – out of service for maintenance for 10 days mid-March. Unit 9 – out of service for maintenance for 10 days late-March to early-April. Unit 10 – out of service for maintenance for 10 days late-July. Unit 11 – out of service for maintenance for 10 days early-April. Unit 12 – out of service for maintenance for 10 days late-April. These outages are not expected to cause transmission constraints. Ongoing consultation between AEMO and the APA Group should enable maintenance to be carried out while minimising DTS security risks. Note: Brooklyn Unit 10 is a standby machine and is only operated if Unit 11 or Unit 12 is unavailable.
Gooding Compressor Station[a]	Low risk. Sufficient redundant compressors available during maintenance.	**Description:** Four 2,850 kW compressors (units 1, 2, 3, and 4). Since the station upgrade to dry seals in winter 2008, only two units have operated simultaneously due to improvements in operating efficiency. Three units were operated prior that, so one compressor is now available as a standby in case of failure. **Primary role:** Provides compression within the LMP when total Longford injection exceeds 720 TJ/d. **Required maintenance:** Unit 1 – out of service for maintenance for 10 days early-January. Unit 2 – out of service for maintenance for 10 days mid-January. Unit 3 – out of service for maintenance for 10 days early-February. Unit 4 – out of service for maintenance for 10 days mid-February. As the works will occur when Gooding compression is not required, these outages are not expected to cause transmission constraints.
Wollert Compressor Station[a]	Low risk. Sufficient redundant compressors available during maintenance.	**Description:** Two 850 kW compressors (units 1 and 3), one 950 kW compressor (Unit 2) and two 4,550 kW compressors (units 4 and 5). It is expected that one Centaur unit will operate to provide export to New South Wales with a second Centaur running for short period on peak days. **Primary role:** Provides compression to the Wollert to Wodonga pipeline and assists supply to the NSW-VIC Interconnect at Culcairn. Exports to New South Wales are generally not possible without Wollert compression. **Required maintenance:** Unit 1, 2 and 3 – out of service for maintenance for 5 days each in June. Unit 4 – out of service for maintenance for 10 days early-October. Unit 5 – out of service for maintenance for 10 days mid-October.

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Infrastructure	Operational risk[b,c]	Description, primary role, and required maintenance
Euroa Compressor Station	Low risk. Will reduce the export capacity to Culcairn.	**Description:** One 4,550 kW compressor (Unit 1). It is normally operated when the two Wollert compressor units and the Springhurst compressor combined are insufficient to meet export requirements. **Primary role:** Provides compression to the Euroa to Wodonga pipeline and assists supply to the NSW–VIC Interconnect at Culcairn. Exports to New South Wales can be increased with Euroa compression. **Required maintenance:** This compressor will out of service for general maintenance for 10 days in August. Export capacity to New South Wales is reduced during the maintenance period. For more information regarding export amounts during maintenance, refer to Appendix B.
Springhurst Compressor Station	Low risk. Will reduce the export capacity and pressure at Culcairn.	**Description:** One 4,550 kW compressor (Unit 1). **Primary role:** Provides compression for imports or exports via the NSW-VIC Interconnect. **Required maintenance:** This compressor will be out of service for general maintenance for 10 days in November. Export capacity to New South Wales is reduced during the maintenance period. Pressure of 6,000 kPa at Culcairn is not achievable during a Springhurst Compressor outage. Refer to Appendix B for more information regarding export amounts during maintenance.
Iona Compressor Station[a]	Low risk. Sufficient redundant compressor available.	**Description:** Two 300 kW reciprocating compressors (Units 1 and 2). **Primary role:** Provides compression to WTS from the SWP. **Required maintenance:** Alternate units will be out of service for 5 days in September. During this period, a standby compressor failure will limit Iona withdrawals to approximately 25 TJ/d to maintain a pressure of approximately 4,500 kPa at Iona and ensure supply to the WTS.
Dandenong LNG plant maintenance	Low risk. Sufficient supply available during maintenance period.	The LNG facility has a maximum vaporisation capacity of 180 t/h, requiring the availability of three vaporisers, three pumps, and one boil-off compressor. Failure of either a pump or a vaporiser can reduce capacity by 17% to 44%. The LNG contracted rate is 100 t/h for 16 hours, providing up to 87 TJ/d. This provides for plant redundancy in case of an outage of one pump and one vaporiser. The facility will undergo a two-week plant shutdown in January and general maintenance in May and November. The recall period (usually four hours) minimises DTS security risk. Annual vaporiser maintenance requires each unit to be out of service for four weeks during the low demand period in March, October, and November. Boil-off compressor maintenance does not affect vaporisation.
Pipeline inspection	Low risk. AEMO will manage the risk with ongoing consultations with market participants.	The following pipeline inspection (pigging) works are scheduled: Keon Park to Wollert 600mm pipeline. The timing of these works will depend on resource availability, suitable flows, and pressure conditions. The pigging is expected to be completed by winter 2014. Pigging is carried out on live pipelines but does not affect pipeline capacity.

a. At any time only one unit of a compressor station is scheduled for maintenance.

b. Refer to Appendix B for information on compressor requirements and availability for 2014.

c. The risk assessment in this column aligns with AS2885.1.

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In addition to compressor maintenance, scheduled compressor station maintenance takes place during the year. Compressor station maintenance does not normally require extensive equipment outages and has a rapid recall period (usually four hours).

6.2.2 Planned monthly infrastructure outages for 2014

Table 6-4 — APA Group planned maintenance and outages for 2014[a]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn Compressor Station												
Unavailable units			8 & 9	11 & 12			10					
Gooding Compressor Station												
Unavailable units	1 & 2	3 & 4										
Wollert Compressor Station												
Unavailable units						1, 2 & 3				4 & 5		
Euroa Compressor Station												
Unavailable units								1				
Springhurst Compressor Station												
Unavailable units											1	
Iona Compressor Station												
Unavailable units									1 & 2			
LNG facility												
LNG facility unavailable					Total facility						Total facility	
Vaporiser unavailable			Unit C							Unit A	Unit B	
Boil-off compressor unavailable		Unit B		Unit A								

a. Only including major maintenance and outages with a recall time longer than 24 hours.

Appendix B provides more detailed information on compressor availability in 2014. It also provides modelling information on the export capacity to Culcairn during Euroa or Springhurst compressor outage.

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6.3 Committed and proposed projects

6.3.1 Committed augmentations

The DTS constraints analysis in Section 6.1 assumes that committed augmentations will go ahead as planned. The following committed augmentations have been advised by the APA Group:

- Wollert to Euroa to Springhurst partial looping (162 km) to be commissioned by winter 2015. This partial looping will increase the export capacity to New South Wales by 145% of the current export capacity to 113 TJ/d. Stage 1 of the looping (27.8 km) is expected to be completed by winter 2014 and will increase the export capacity to 57 TJ/d.[63]
- A new compressor station at Winchelsea to be commissioned by winter 2015. The Winchelsea compressor (Taurus 60, (5,116 kW)) will increase the SWP capacity to 429 TJ/d during high system demand days.
- Upgrade of the cooling system from water cooling system to fin fan cooling system for Brooklyn units 10 and 11.
- Iona Compressor Station reconfiguration.

6.3.2 APA Group proposed projects

Table 6-5 shows projects submitted by the APA Group in 2013 to the Australian Energy Regulator (AER) for approval as part of their 2013–17 Access Arrangement. This list contains those projects which are related to capacity augmentation for growth and/or security of DTS supply. AEMO has not assessed these projects, and they are not assumed in AEMO's constraint modelling (unlike committed augmentations).

Table 6-5 — Projects proposed by the APA Group

Project	Description	Trigger	Expected completion
Western Outer Ring Main Stage 2	Construction of a 49.5 km DN500 pipeline interconnection between Plumpton to Wollert.	Security of supply in the event of a Longford supply loss.	2015 to 2020 and ongoing.
Wollert Compressor Station	Installation of a new 4.5 MW dry seal compressor and pressure limiter at Wollert.	To meet increasing demand.	2015 to 2020 and ongoing.
Kalkallo Project	Construction of a 4.5 km DN200 pipeline extension from the proposed WORM to Kalkallo.	Load growth in the Kalkallo area.	2015 to 2020 and ongoing.
Rockbank PRS	Installation of a pressure reduction station at Rockbank.	To maintain supply reliability to Ballarat in lieu of Brooklyn Compressor Unit 11.	2015 to 2020 and ongoing.
Warragul Looping	Construction of a 4.8 km DN150 pipeline looping of the Warragul lateral.	Load growth in the Warragul area contingent on demand increase.	2016.
Anglesea Pipeline Extension	Construction of a 15 km DN250 pipeline extension from the South West Pipeline to Anglesea.	Security of supply to the Geelong distribution network via a second custody transfer station.	2016.
Further Northern SWZ augmentation	Completed looping of Wollert to Euroa to Springhurst to Barnawartha.	An increase in exports through Culcairn.	2015 to 2020 and ongoing.
Further SWP expansion	Pipeline looping and/or up to two new compressor station sites each consisting of Taurus 60 and/or Centaur 50.	An increase in exports through Culcairn from Iona. An increase in flow on the SWP.	2015 to 2020 and ongoing.

[63] The Northern Zone expansion does not meet this criteria but is included as "committed" for the purposes of this report.

APPENDIX A – VICTORIAN GAS PLANNING APPROACH

Victorian gas planning criteria

Gas planning

The Victorian Gas Planning Approach describes AEMO's approach to planning Victoria's gas Declared Transmission System (DTS).

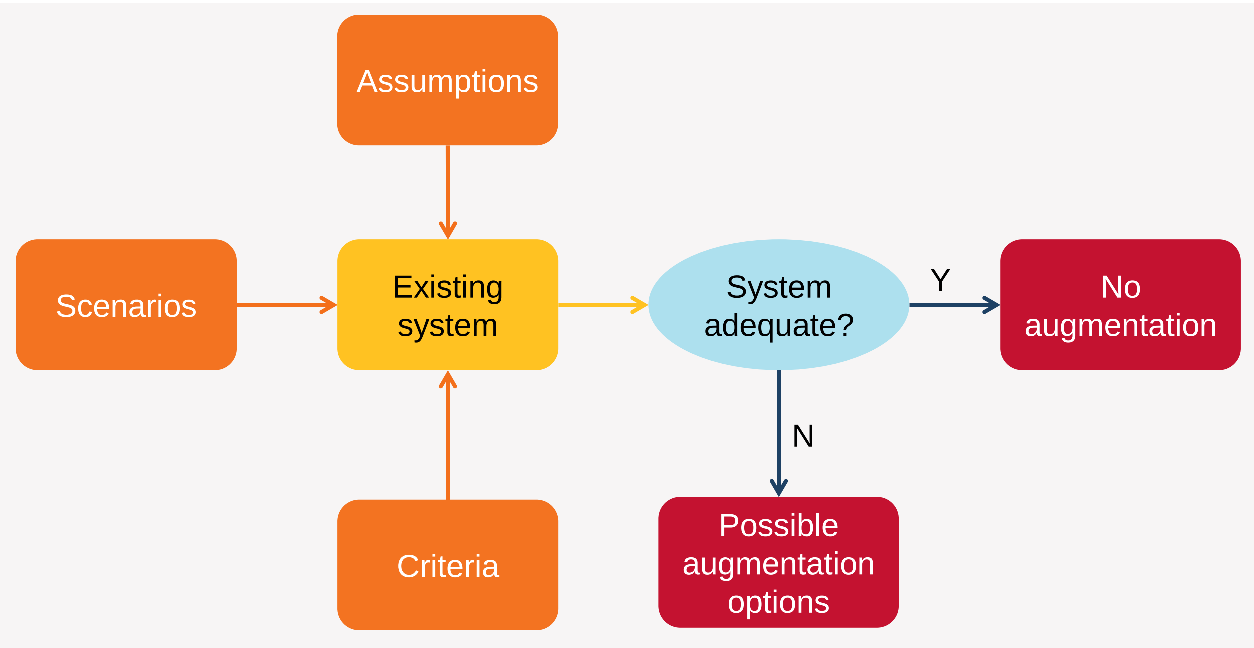
Gas planning criteria

AEMO's objective is to facilitate the most economically efficient expansion of the DTS as demand grows, while maintaining a safe and secure system (taking into account relevant uncertainties), and the timely provision of this information to the market.

A major requirement is for AEMO to forecast and report the adequacy of the gas supply and transmission capacity to meet anticipated demand. AEMO carries out detailed computer simulations of the DTS to analyse system adequacy.

Figure A-1 shows a high-level overview this process.

Figure A-1 — The Victorian gas planning process



When a DTS augmentation requirement is identified, AEMO publishes the information via the Victorian Gas Planning Report (VGPR) or a detailed planning report specific to that augmentation.

Planning reports

Figure A-2 shows AEMO's publications that contain gas-related information, the level of detail, and the planning outlook considered by each report. The VGPR's short-term outlook (five years) provides a good level of detail for identified augmentations and operational challenges. The Gas Statement of Opportunities (GSOO) has a longer-term, national outlook (20 years), and less detail about specific DTS issues.

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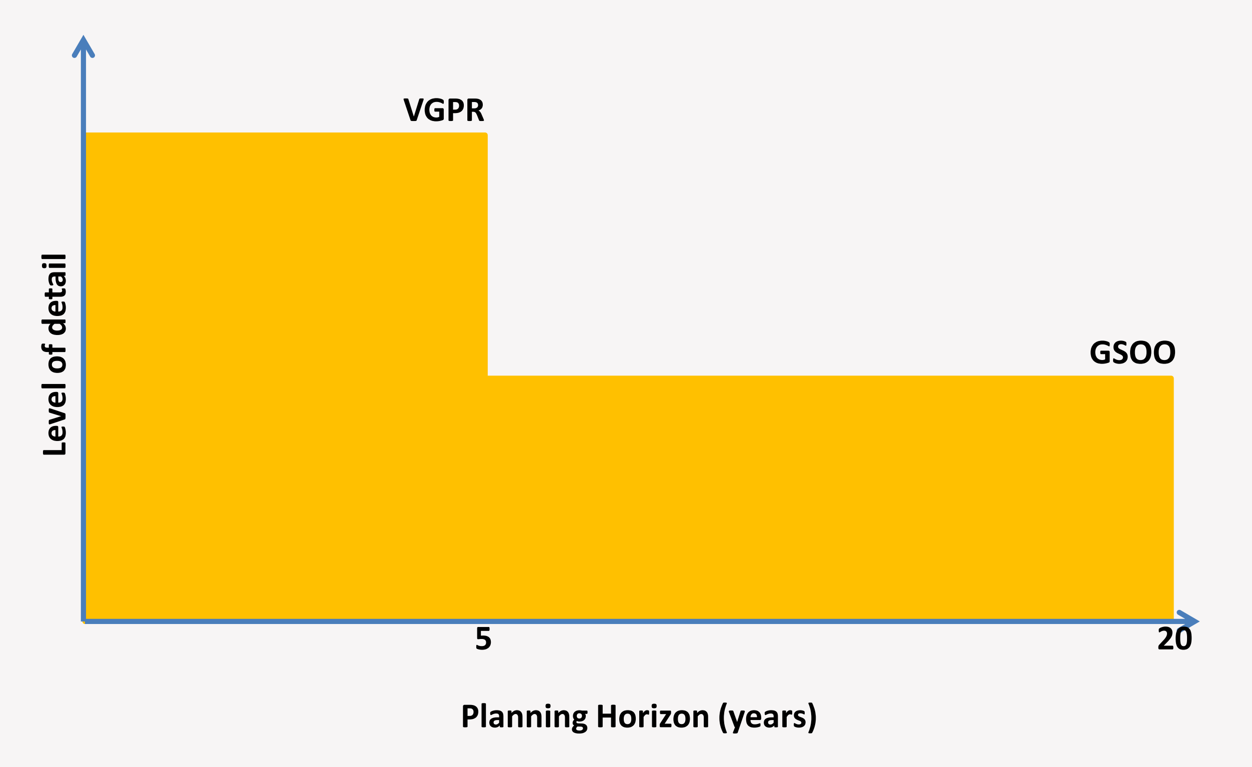
Figure A-2 — The span of gas planning context in AEMO publications



The gas planning cycle

In previous years, AEMO's gas planning cycle was tied to the Victorian Annual Planning Review (VAPR), which is published annually in June. This year, AEMO will publish the VGPR separately in December 2013; the VAPR is now purely an electricity transmission planning document.

Pending a final rule change from the Australian Energy Market Commission, the VGPR will be published every two years, with the next publication in March 2015. Publication in March allows AEMO to use forecasts that incorporate the previous winter's data, and aligns the forecasts with those used in the Gas Statement of Opportunites (GSOO) to provide greater consistency across AEMO's gas planning publications.

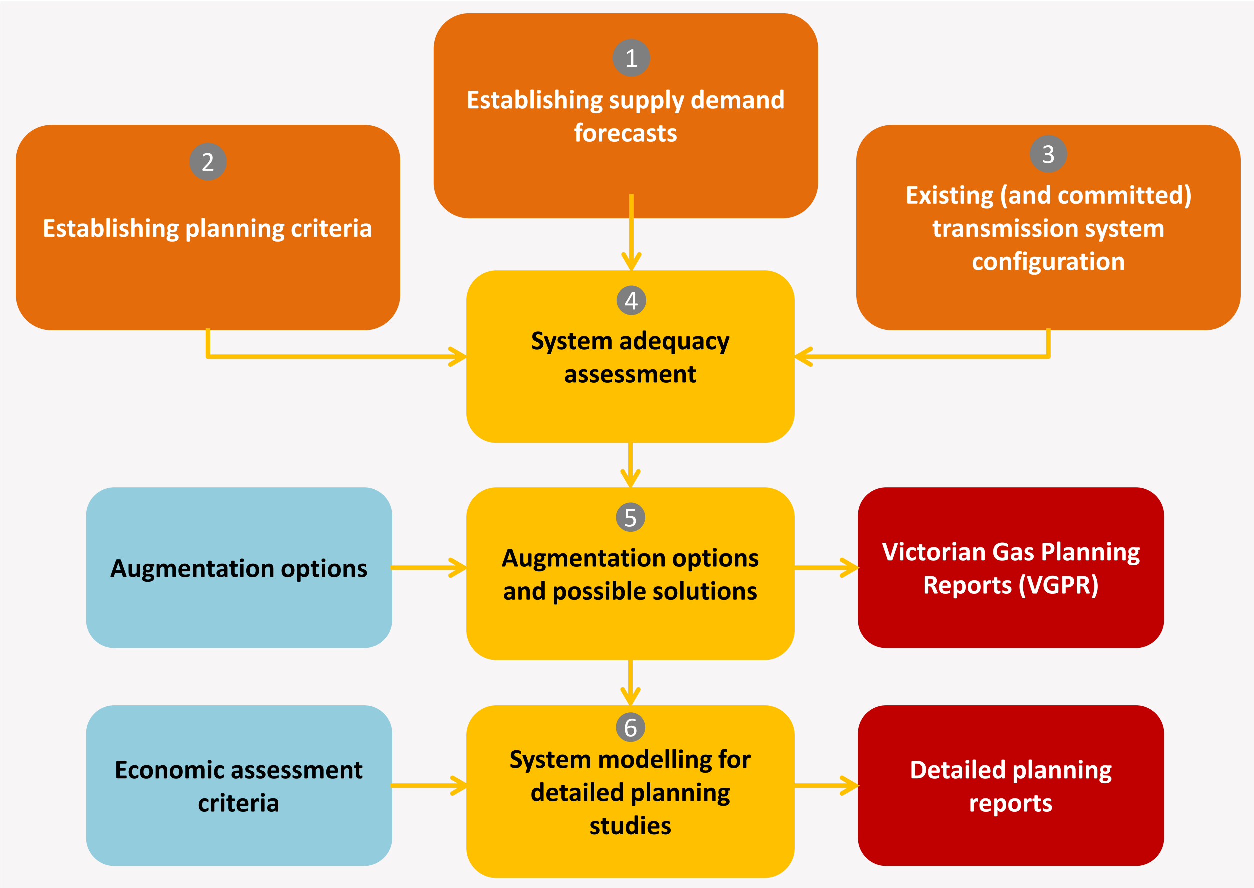
As a part of AEMO's obligation to review gas system adequacy, critical system pressures are also reviewed annually, and offtake pressure forecasts are prepared and provided to gas distributors prior to winter.

Planning methodology

AEMO's planning methodology involves a series of tasks that aim to assess planning assumptions involving supply, demand, and capacity. They establish the planning criteria and operating characteristic requirements to enable safe and reliable supply over the outlook period.

Figure A-3 shows a detailed description of AEMO's gas planning tasks and a high-level overview of the planning methodology.

Figure A-3 — Gas planning tasks



Establishing supply demand forecasts (step 1)

Planning assumptions consist of forecasts of gas supply, demand and other operational assumptions such as load profiles. These assumptions are validated based on historical data available in the database before commencing modelling work. As part of the VGPR process, five-year forecasts of peak day demand are prepared for each market sector, and for all system withdrawal zones (SWZ), based on a range of anticipated injection and withdrawal scenarios.

Establishing planning criteria (step 2)

The planning criteria address the operating characteristics that must be satisfied over the planning period if the system is to be capable of safe and reliable operation. These include the critical minimum pressures at key locations from the Wholesale Market System Security Procedures (Victoria) (previously called AEMO System Security Guidelines), and a range of other operating criteria that need to be satisfied, such as linepack targets.

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Existing (and committed) transmission system (step 3)

In conjunction with APA Group, AEMO creates and maintains the DTS models representing the current system configuration.

AEMO determines system capacity using a calibrated gas transmission system model (specifically, the Gregg Engineering WinFlow (steady state) and WinTran (transient) software modules).

AEMO's gas transmission system model is calibrated annually using actual winter metered gas injections and withdrawals on selected high and moderate demand days. Annual model calibration refines the model to ensure that it accurately simulates the observed pressures and flows throughout the DTS. The methodology and a set of assumptions and pipelines parameters are set out in the Guidelines for the Determination of the Victorian Gas Declared Transmission System Capacity document, jointly owned by AEMO and the APA Group.

AEMO also establishes the expected gas transmission system configuration factors for the planning outlook:

- Committed augmentations and upgrades to the transmission system.
- New connections.
- Planned changes at injection points and storage facilities.
- Known operational constraints.

The APA Group provides notification about planned augmentations, upgrades, and changes. Planned changes to one part of the transmission system can cause constraints in other parts of the system. As a result, it may be necessary to evaluate some projects within inter-related groups, resulting in one project in a group being contingent on other projects also proceeding.

System adequacy assessment (step 4)

AEMO assess the system performance with the Gregg Engineering software and notifies the market about potential system constraints via the VGPR.

The gas flows and pressures in the DTS are modelled under a range of demand and supply scenarios over a five-year outlook.

A system constraint is identified when the secure system parameters are breached (representing a potential threat to system security).[64]

Augmentation options and possible solutions (step 5)

Where appropriate, AEMO evaluates potential solutions, which involves considering a number of possible options available to restore the system to a secure state:

- Augmentations or upgrades to the gas transmission system.
- Additional or new supply capacity and storage.
- Economic curtailment.

The adequacy assessment studies consider a range of solutions, to the extent this is feasible, given the availability of data and commercial confidentiality. However, given the outlook period and the use of less detailed analysis, the constraints and constraint solutions must be treated as indicative only.

[64] It is assumed that all pipeline facilities are available and operational.

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System modelling for detailed planning studies (step 6)

AEMO performs detailed planning studies (using deterministic[65] and probabilistic[66] mass-balance models) under the following circumstances:

- On request from APA Group to assist the review process for its access arrangements.
- When required to facilitate efficient augmentation investment identified by AEMO, and there has been insufficient initiative taken by the gas industry.
- On request by regulators or government agencies to independently review requirements for an augmentation or augmentations.

Based on screening study recommendations, AEMO will select the key constraints identified over the next five years, and prepare a more detailed evaluation, with a view to identifying the economically efficient solution, and facilitating the required investments.

The aim of these studies is to facilitate actual investments by providing rigorous and timely analysis that meets the standards required by the Australian Energy Regulator (AER) for regulatory approvals.

The planning reports for the detailed planning studies are published as required.

Planning assumptions

AEMO applies a series of network assumptions and conditions relating to the supply of gas to the DTS for modelling the capacity to supply.

Table A-1 to Table A-3 list the standard modelling assumptions used by AEMO.

Table A-4 and Table A-5 list the capacity modelling assumptions used by AEMO for South West Pipeline and Northern Zone export.

An additional modelling assumption involves injections into the DTS that reflect known injection point capabilities at each injection point.

To better reflect real-world conditions, the adequacy of the system to meet peak demand has been modelled using typical beginning-of-day (BoD) linepack[67] (lower than the linepack target) and surprise cold weather.[68]

Modelled maximum capacities can only be realised with reliable demand forecasting and operating conditions (on the day) that are similar to the model's assumptions. Extreme high demand days that test system capacity are often also surprise cold days, where scheduling is not optimum and maximum capacities cannot be realised. On peak days, the level of linepack and the BoD operating conditions are also critical. Modelled system capacity is based on pressures less than MAOP which optimise operational capabilities.

[65] Deterministic mass-balance modelling is used to evaluate the peak day requirement for LNG.

[66] Probabilistic mass-balance modelling is used to evaluate the benefits of carrying out a major augmentation by determining the reduction in LNG use and demand curtailment.

[67] The BoD target is 780 TJ being the total DTS linepack which includes both passive and active linepack.

[68] If BoD injections are lower than required for the actual demand (due to actual demand exceeding forecast demand), linepack is depleted more quickly than expected, until injections are rescheduled upwards.

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Supply assumptions

Table A-1 lists the assumptions relating to the supply of gas to the DTS.

Table A-1 — Gas DTS supply modelling assumptions

Supply assumptions and conditions	Notes
Longford injections at flat hourly profile.	Normal operating condition.
VicHub injections at flat hourly profile.	Normal operating condition.
Iona and SEA Gas injection at flat hourly profile.	Normal operating condition.
Heating Value 38.7 $MJ/m.^3$	Victorian gas standard properties.
New South Wales injection at Culcairn at flat hourly profile.	Normal operating condition.
Liquefied natural gas (LNG) contracted vaporisation rate at 100 t/h for 16 hours.	For peak shaving purposes to support critical system pressures, LNG is effective only up to 10.00 pm. Eleven hours LNG is assumed, equivalent to 60 TJ.

Demand assumptions

Table A-2 lists the assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table A-2 — Gas DTS demand modelling assumptions for 1-in-20 day

Network modelling assumptions and conditions	
Demand assumptions	**Notes**
Load profiles calculated by AEMO.	Calculated from historical flow data for each custody transfer meter.
Load distribution as per AEMO forecasts.	Based on historical custody transfer meter data and expected system configuration changes.
Supply to Horsham pipeline at Carisbrook..	Carisbrook to Horsham pipeline modelled with demand at Ararat, Stawell, and Horsham (connected in 1998). The minimum pressure requirement at Horsham is 1,200 kPa (SP AusNet design requirement).
Supply to Murray Valley (Chiltern Valley – Koonoomoo).	Pipeline commissioned in 1998.
Transmission unaccounted for gas (UAFG) determined at Longford.	Calculated from calibrated model data.
BOC liquefaction operating, let-down gas operating.	Full supply to this customer is normally required.
Existing gas powered generation (GPG) demand (open-cycle gas turbine (OCGT)).	A 25 TJ/d OCGT demand profile.[a]

a. The OCGT demand profile is from 12.00 pm till 9.00 pm.

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Analysis for the five years is based on a 1-in-20 peak day system demand forecast which is the agreed standard with APA Group. Tariff D and Tariff V[69] load changes are based on demand forecasts, existing GPG demand is based on GPG capacity for 1,300 TJ/d with historical load profiles and future GPG demand is based on known GPG development proposals, which are checked for consistency with electricity VAPR and APA Group for any committed connections to the DTS.

Export load is treated differently due to the need for consistency with any proposals that have been considered by APA Group, which are accounted for by the modelling.

Impact of operational factors modelling assumptions

Table A-3 lists the assumptions relating to operation of the DTS, and assist with the management of linepack and constraints specified in various agreements.

Table A-3 — Impact of operational factor modelling assumptions

Impact of operation factor modelling assumptions and conditions	
Operational assumptions	**Notes**
Maximum pressure at Longford 6,750 kPa.	To conform to normal operating practice. Assumed to peak momentarily at 6,750 kPa before reducing again. Longford injections begin to reduce when the pressure reaches 6,400 kPa and cannot be sustained at 6,750 kPa.
Iona maximum pressure 9,500 kPa and minimum pressure 4,500 kPa.	As per pipeline licences, operating agreements and practice.
Gas delivery temperature above 2 °C.	Gas Quality Regulations requirement.
Minimum pressure at Culcairn 6,000 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
Minimum pressure at Brooklyn–Lara Pipeline (BLP) CG inlet 4,500 kPa.	Pipeline design requirement for the BLP.
Minimum pressure at Brooklyn City Gate (BCG) inlet 3,200 kPa.	Normal operating condition.
Minimum pressure at Wollert City Gate (WCG) inlet 3,000 kPa.	Normal operating condition.
Minimum pressure at Dandenong City Gate (DCG) inlet 3,200 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
Maximum allowable operation pressure (MAOP) and delivery pressures in connection and service envelope agreements not infringed.	Service Envelope Agreement and Connection Deed requirements (for example, a minimum 3,100 kPa at the DCG).
BoD and end-of-day (EoD) linepack are equal.	For capacity modelling, mining of linepack not allowed.
BoD linepack 20 TJ below target.[70]	Used for lateral constraint modelling.
APA Group pipeline, regulator and compressor assets and operating conditions as specified in the Service Envelope Agreement.	Agreement between APA Group and AEMO.
BoD and EoD pressures similar at key network locations.	Required for system security.
Regulators, compressors, and valves are set to reflect operational guidelines.	Required for operational and system security reasons.

[69] Tariff D customers use more than 10 TJ/yr or 10 GJ/h. Tariff V customers are the small industrial and commercial users and residential customers.
[70] The normal BoD linepack target is 780 TJ which includes both passive and active linepack. In this case the BoD linepack is 760 TJ.

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Capacity modelling assumptions

Table A-4 lists the assumptions relating to South West Pipeline capacity modelling and Table A-5 lists the assumptions relating to Northern export capacity modelling. Under different operating conditions on the day, the capacity results will differ.

Table A-4 — SWP capacity modelling assumptions

SWP capacity modelling assumptions and conditions		
SWP capacity assumptions		**Notes**
Injections		Maximum injection from Iona and the rest will be supplied from Longford and/or BassGas for all cases.
GPG demand		No GPG demand for all cases.
Export demand		Export demand of 42 TJ/d (based on latest forecast) was used for all types of system demand as that is the minimum export that must be met on any system demand day up to 1-in-20 peak day.
Compressors		Compressors down rated according to information provided by APA Group for different system demand levels. For the case with Winchelsea compressor in place, the compressor was run with known compressor power.
Linepack		BOD and EOD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Iona	Maximum pressure is 9,500 kPa. Pressure not allowed to increase over the modelling period.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥ 1,150 TJ is set to 2,650 kPa.
	Wandong CG[71]	Minimum pressure is 3,500 kPa

Table A-5 — Northern export capacity modelling assumptions

Northern export capacity modelling assumptions and conditions	
Northern export capacity assumptions	**Notes**
Injections	Maximum injection from Longford does not exceed 900 TJ/d (max achieved in 2012). The rest will be supplied from Iona and/or BassGas for all cases.
GPG demand	GPG demand for all cases varied as agreed between AEMO and APA Group.
LNG	LNG was required to maintain system security for the 1-in-20 peak day system demand case.
Compressors	Compressors down rated according to information provided by APA Group for different system demand levels.

[71] Wandong CG pressure is varied on different system demand days in order to maximise capacity, taking into consideration the minimum pressure at Bendigo CG.

Northern export capacity modelling assumptions and conditions		
Northern export capacity assumptions		**Notes**
Linepack		BOD and EOD linepack are equal for system demand and Northern zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Culcairn	Modelled minimum pressure is 6,000 kPa for Northern capacity modelling cases. For maintenance planning cases, it is not possible to maintain 6,000 kPa without Springhurst operating.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1,150 TJ is set to 2,550 kPa. System demand ≥1,150 TJ is set to 2,650 kPa.
	Wandong CG[72]	Minimum pressure is 3,500 kPa

Due to DTS characteristics and the nature of operational practice, AEMO has to consider a number of operational factors that impact system capacity determinations.

Beginning-of-day linepack

Linepack is the pressurised gas stored in transmission pipelines throughout the DTS. Linepack varies considerably throughout the day, as it is drawn down from the start of the gas day to balance a fairly constant hourly injection rate with the morning and evening demand peaks. Linepack reaches a minimum by around 10.00 pm. Overnight, injections exceed demand and linepack is replenished until the start of the morning peak at around 6.00 am, when linepack is at its highest level.

Demand forecast error

Daily demand forecast errors occur due to changes in the weather, large loads varying from the initial forecast (such as GPG), and weather forecast errors.

When actual demand is higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system ability to meet demand.

When actual demand is lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the injection points, generally only after the 10.00 pm scheduling horizon, to avoid breaching upper operating limits.

Delivery pressure

Supply pressure drives gas through a pipeline. The higher the supply pressure, then the higher the average level of linepack and effective system capacity.

Injection profiles

For operational reasons, gas production plants generally operate at a fairly constant injection rate. Varying the injection rate to reflect demand throughout the day however can increase the ability to supply demand. In particular, an injection profile with a higher injection rate during the first half of the day can increase gas transport capability.

Gas sources that can be injected for short periods at times of high demand, such as liquefied natural gas (LNG), can assist overall system capacity.

[72] Wandong CG pressure is varied on different system demand days in order to maximise capacity, taking into consideration the minimum pressure at Bendigo CG.

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Demand profiles (temporal distribution)

During winter, peaking demand in the morning and evening (due to temperature-sensitive load) draws down system linepack. More severe demand profiles, including the presence of spike loads such as GPG, will deplete linepack at a faster rate.

Spatial distribution of demand

System capacity is modelled using the forecast load distributions across the DTS. If a specific load is located close to an injection point, the gas transport capability is higher than if the load is located further away.

Mass-balance modelling assumptions

Mass-balance modelling is used to test LNG usage and to evaluate major system augmentations. The Gregg Engineering software has been used to determine the linepack limits that are the basis of the mass-balance model and ensures the validity of this method of modelling. This section describes the assumptions used for the mass-balance modelling.

Table A-6 lists the planning assumptions for deterministic mass-balance modelling.

Table A-6 — Deterministic mass-balance modelling base case assumptions

Deterministic modelling conditions	Notes
System demand	1 in 20 peak day.
System demand profile	78.8% demand 6.00 am to 10.00 pm.
GPG demand profile	90% demand 6.00 am to 10.00 pm.
Forecasting error	6% under actual demand at 6.00 am schedule.
GPG forecasting error	15% under actual demand at 6.00 am schedule.
BoD system linepack	10 TJ below target.[73]
Supply reschedules	Effective 10.00 am, 2.00 pm, 6.00 pm, 10.00 pm.

Planning criteria

The planning criteria used in the DTS modelling are based on specified critical location and pressure obligations contained in distribution business (DB) Connection Deeds, Service Envelope Agreement (SEA), other connection agreements, and as specified by APA Group.

Critical location and pressure obligations

The minimum and maximum pressure obligations at critical system locations are defined in the Wholesale Market System Security Procedures (Victoria).[74] These limits are derived from agreements that AEMO has with the DBs and APA Group. Additional constraints are also applied for operational security purposes. If gas pressures fall below minimum pressure obligations at critical off-takes, there is a risk to the reliability of gas supply for users on the distribution networks (and directly connected customers).

[73] The normal BoD linepack target is 780 TJ which includes both passive and active linepack.
[74] AEMO. *Wholesale Market System Security Procedures (Victoria)*. Available at: http://www.aemo.com.au/Gas/Policies-and-Procedures/Declared-Wholesale-Gas-Market-Rules-and-Procedures. Viewed: 11 December 2013.

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AEMO operates the system to maintain connection pressure obligations across the DTS, where flows are within the limits specified in the relevant connection deed and agreement schedules. As gas demand increases, however, there is a risk that critical minimum pressures may be breached, potentially requiring customer curtailment to return the system to a secure state.

The system is in a secure state with the following conditions:

- The system is operating within the requirements of the gas quality procedures and breaches of the gas quality procedures do not require intervention by AEMO.
- There is no threat to public safety.
- There is no threat to the supply of gas to customers, and system pressures and flows are within and are forecast to remain within the agreed operating limits (see Table A-7).

Table A-7 lists key critical locations and associated pressure obligations (maximum allowable operating pressure (MAOP) and minimum operating pressure (MinOP)).

Table A-7 — Critical DTS locations

Location	Pressure obligation [kPa]			Comment
	MAOP	MinOP	Modelled	
Longford (with VicHub)	6,890	4,500		Pipeline licence pressure (6,750k Pa max for modelling)
Sale	6,895	5,000		DB Connection Deed – 4,800 kPa
Morwell City Gate (outlet)	2,760	2,700		SEA minimum outlet pressure
Warragul	2,760	1,400		AEMO-DB Connection Deed.
Pakenham South	2,760	1,400		AEMO-DB Connection Deed.
Dandenong Terminal Station (Morwell backup)	2,760	2,650		Maintaining the DCG Inlet Guideline Pressure ensures maintenance of the DTS Pressure Obligation
Dandenong Pressure Limiter Outlet (Morwell Backup)	2,760	1,400		SEA minimum pressure
Dandenong North	2,760	2,500		Maintaining the DCG Inlet Guideline Pressure ensures maintenance of the Dandenong North Pressure Obligation
Brooklyn (Melbourne-side)	2,760	1,700 1,800		Brooklyn compressor suction minimum pressure requirement DB Connection Deed – 1,700 kPa
Dandenong City Gate Inlet	6,890	3,000	3,200	SEA Minimum Inlet Pressure
Dandenong City Gate Outlet	2,760	2,700		SEA Minimum Outlet Pressure
Wollert Comp Station Inlet	6,890	3,000		SEA Minimum Inlet Pressure
Wollert Comp Station Outlet	8,800	3,000 @ Beveridge		Wollert–Wodonga pipeline licence pressure
Euroa Comp Station North	7,400	3,200	3,500	SEA Minimum Inlet Pressure
Euroa Comp Station South	8,800	3,200	3,500	SEA Minimum Inlet Pressure
Springhurst Comp Station Inlet	7,400	2,300	2,500	SEA Minimum Inlet Pressure
Springhurst Comp Station Outlet	7,400	2,300	2,500	SEA Minimum Inlet Pressure

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Location	Pressure obligation [kPa]			Comment
	MAOP	MinOP	Modelled	
Culcairn	10,200	2,700[a]	6,000	When gas is withdrawn at Culcairn (or 3,000 kPa for injections into the DTS from Culcairn)
Wollert CG	2,760	2,700	2,650 2,550	AEMO, APA and DBs have agreed to lower the pressure at Wollert CG to 2,650 kPa for demand days >1,150TJ and 2,550 kPa for demand days <1,150TJ.
Keon Park West	2,760	2,200		AEMO-DB Connection Deed.
Corio	7,390	2,300 w 1,900 s		7,390 kPa pipeline licence pressure. 2,300 kPa in winter, 1,900 kPa in summer, DB Connection Deed.
BLP	10,200	3,800		10,200 kPa pipeline licence pressure.
BLP City Gate Inlet	10,200	4,500		SEA Minimum Inlet Pressure
Iona (SWP)	10,200 7,400	3,800	9,500	10,200 kPa pipeline licence pressure. 7,400 kPa pipeline licence pressure. 3,800 kPa Operating Agreement.
Iona (WTS)	7,400/9,890	3,800		WTS has two pipeline licence pressures: 7,400 kPa (Iona-Paaratte) and 9,890 kPa
Iluka	9,890	2,500		
Portland	9,890	2,800		
Bendigo	7,390	3,000		
Maryborough	7,390	3,000		
Carisbrook	7,390	3,000		Pipeline agreement
Shepparton	7,400	2,400		
Wodonga	7,400	2,400		
Plumpton PRS	10,200/7,390	4,500		
Sunbury	7,390	2,000		
Ballarat	7,390	2,100		
Echuca	7,390	1,200		

a. The MinOP for Culcairn will be reviewed as part of the Northern SWZ expansion project

Seasonal variations in the DTS capacity

AEMO's planning methodology, assumptions, and system boundaries are for modelling under peak day conditions during winter as these are the most common DTS operating conditions analysed by AEMO and APA.

The need to determine export capacity for varied seasonal conditions has become necessary with the increase of export to New South Wales increasing during summer and shoulder periods.

AEMO and APA Group have discussed and agree on seasonal conditions such as load distribution and load profiles for these periods.

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The DTS characteristics change in summer and shoulder periods due to the following factors:

- Residential demand is reduced due to lower space heating needs.
- GPG load increases due to increasing electricity demand for air conditioning and relatively low gas price.
- Compressor stations have lower maximum compressor power available due to the downgraded performance of the gas turbines (and engines) in summer ambient temperature conditions.

When modelling summer or shoulder, some key system parameters need to be set differently from the winter assumptions.

These parameters have been discussed and agreed with APA as the need to determine the DTS capacity for various seasonal conditions has become necessary.

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APPENDIX B – COMPRESSOR AVAILABILITY

Compressor availability for 2014

Based on the compressor availability information provided by market participants, there are no issues for 2014. AEMO will mitigate system security risks by coordinating maintenance plans with the parties involved.

Table B-1 shows the compressor requirement and availability for 2014 where:

- "Available" is the number of compressors available taking into account maintenance.
- "Required" is the number of compressors, based on past requirements, to meet the 1-in-20 monthly demand forecast.
- "Redundant" equals the number of compressors "Available" minus the number of compressors "Required".

"Maintenance" is the number of compressors undergoing maintenance during the time period shown.

Table B-1— Compressor requirement and availability in 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gooding Compressor Station ***4 Centaurs @ 2,800 kW***												
Available	3	3	4	4	4	4	4	4	4	4	4	4
Required	0	0	2	2	2	3	3	3	3	2	0	0
Redundant	3	3	2	2	2	1	1	1	1	2	4	4
Maintenance	1	1	0	0	0	0	0	0	0	0	0	0
Brooklyn Compressor Station ***2 Centaurs @ 2,850 kW & 3,500 kW***												
Available	2	2	2	1	2	2	2	2	2	2	2	2
Required	2	2	2	2	2	2	2	2	2	2	2	2
Redundant	0	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	1	0	0	0	0	0	0	0	0
2 Saturns @ 850 kW &950 kW												
Available	2	2	1	2	2	2	2	2	2	2	2	2
Required	1	1	1	1	1	1	1	1	1	1	1	1
Redundant	1	1	0	1	1	1	1	1	1	1	1	1
Maintenance	0	0	1	0	0	0	0	0	0	0	0	0
Wollert Compressor Station ***3 Saturns @ 850 kW & 950 kW***												
Available	3	3	3	3	3	2	3	3	3	3	3	3
Required	0	0	0	0	0	0	0	0	0	0	0	0
Redundant	3	3	3	3	3	2	3	3	3	3	3	3
Maintenance	3	3	3	3	3	1	3	3	3	3	3	3
2 Centaurs @ 4,550 kW												

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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Available	2	2	2	2	2	2	2	2	2	1	2	2
Required	1	1	1	1	1	2	2	2	2	1	1	1
Redundant	1	1	1	1	1	0	0	0	0	0	1	1
Maintenance	0	0	0	0	0	0	0	0	0	1	0	0
Euroa Compressor Station ***1 Centaur @ 4,550 kW***												
Available	1	1	1	1	1	1	1	0	1	1	1	1
Required	1	1	1	1	1	1	1	1	1	1	1	1
Redundant	0	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	1	0	0	0	0
Springhurst Compressor Station ***1 Centaur @ 4,550 kW***												
Available	1	1	1	1	1	1	1	1	1	1	0	1
Required	1	1	1	1	1	1	1	1	1	1	1	1
Redundant	0	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	0	0	0	1	0
Iona Compressor Station ***2 Caterpillars @ 300 kW***												
Available	2	2	2	2	2	2	2	2	1	2	2	2
Required	1	1	1	0	0	0	0	0	0	0	1	1
Redundant	1	1	1	2	2	2	2	2	1	2	1	1
Maintenance	0	0	0	0	0	0	0	0	1	0	0	0

The two Brooklyn Saturn units (8 and 9) are used for low flow conditions and to support load in Ballarat when the Centaur units in the Brooklyn Compressor Station would provide excessive compression.

The two Brooklyn Centaurs are required year-round to maintain supply to the Laverton GPG and Iona underground gas storage (UGS) in the event of underground withdrawals if there is inadequate Iona injection. The Brooklyn Saturn units cannot maintain supply for either of these events and can only meet system demand. The Brooklyn Centaur Unit 10 can be made available by APA only when Centaur units 11 and 12 are both unavailable for an extended period of time.

Iona compressors are required in the event of sustained Iona UGS withdrawals and no SWP injections.

The Wollert Saturn units (1, 2 and 3) are used as back-ups only and are used when the Wollert Centaur units (4 and 5) are both unavailable and compression is required for system security in the Northern SWZ as they have a lower outlet pressure rating. They are also used to export to Culcairn when the Centaur units are unavailable. All three Saturn units combined have lower total power than one Centaur. Wollert requires two Centaur units during the winter period not to maintain system security but to meet Culcairn exports on 1-in-20 peak days.

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Likewise, the Euroa and Springhurst compressors are required to meet Culcairn exports; not to maintain system security. During maintenance at either Springhurst, Euroa, or on the Culcairn compressor, Culcairn exports are reduced. Modelling information regarding the amount available for export during maintenance can be found in the next section.

Export capacity during Northern SWZ compressor maintenance

Compressor and compressor station maintenance is scheduled throughout the year. During maintenance, compressors are normally out of service for several days. For this reason, during maintenance on either Springhurst or Euroa, Culcairn exports are reduced. When this happens AEMO sends a system-wide notice (SWN) to all market participants informing them of the reduction in export capacity.

This section provides information regarding the amount of export available when Springhurst or Euroa compressors have maintenance scheduled.

The minimum modelled pressure at Culcairn of 6,000 kPa is achieved at all levels of DTS demand using modelling scenarios with all three compressors available or with just Wollert and Springhurst compressors available. The minimum modelled pressure at Culcairn of 6,000 is not achievable in the modelling scenario with just Wollert and Euroa compressors available.

The modelling approach for this scenario is different in order to optimise Culcairn export capacity. This is done by accepting lower Culcairn operating pressures and using two Culcairn compressors to increase export capacity. Pressure that optimises the Culcairn export is shown in Figure B-1 and Figure B-2.

Figure B-1 shows the modelled export capacity to New South Wales with all three compressors available; with only Wollert and Springhurst compressors available; and, with only Wollert and Euroa compressors available. This is without the first stage of Northern SWZ expansion due to commence in 2014.

Figure B-2 shows the modelled export capacity with the first stage of expansion completed by winter 2014.

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Figure B-1— Exports to New South wales during Springhurst or Euroa compressor outage without stage 1 expansion

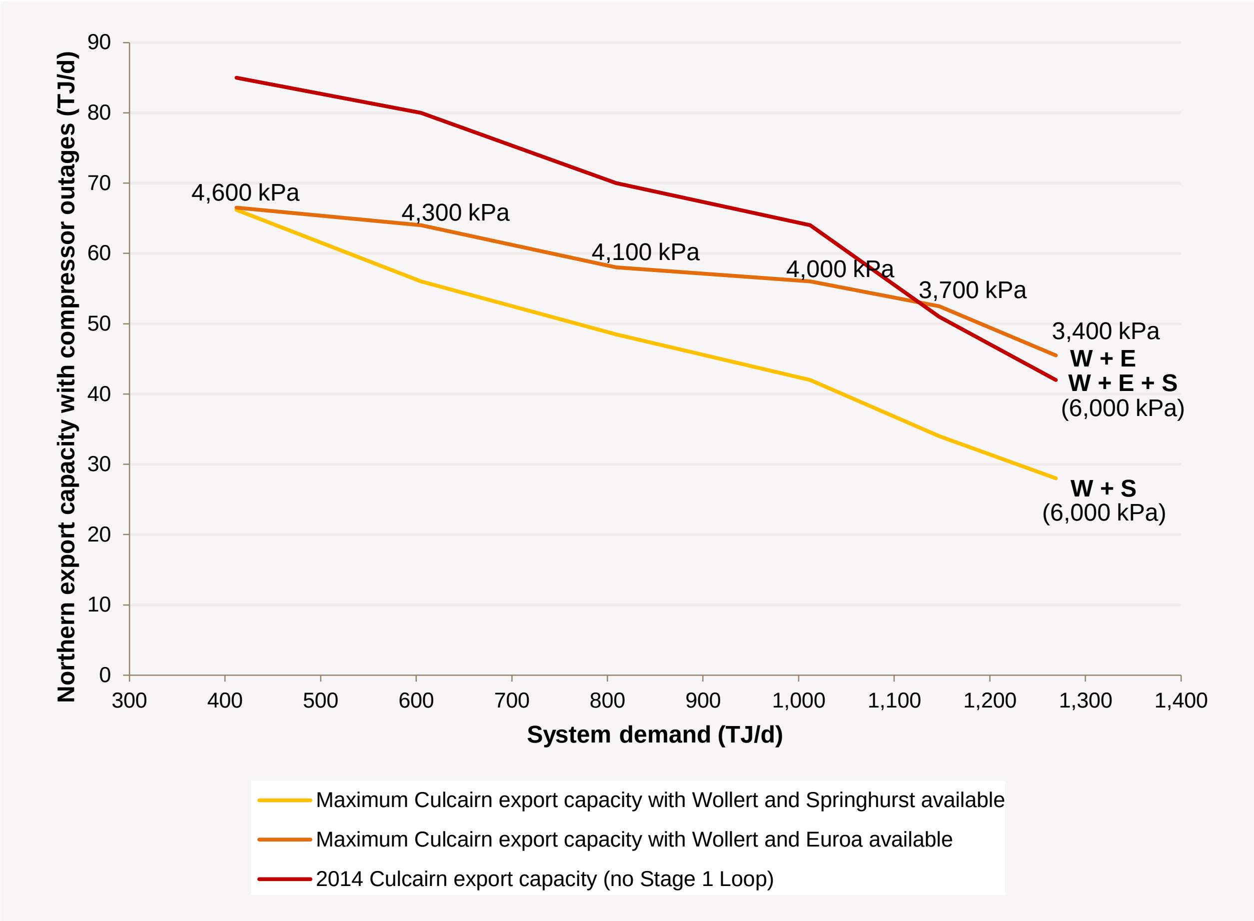

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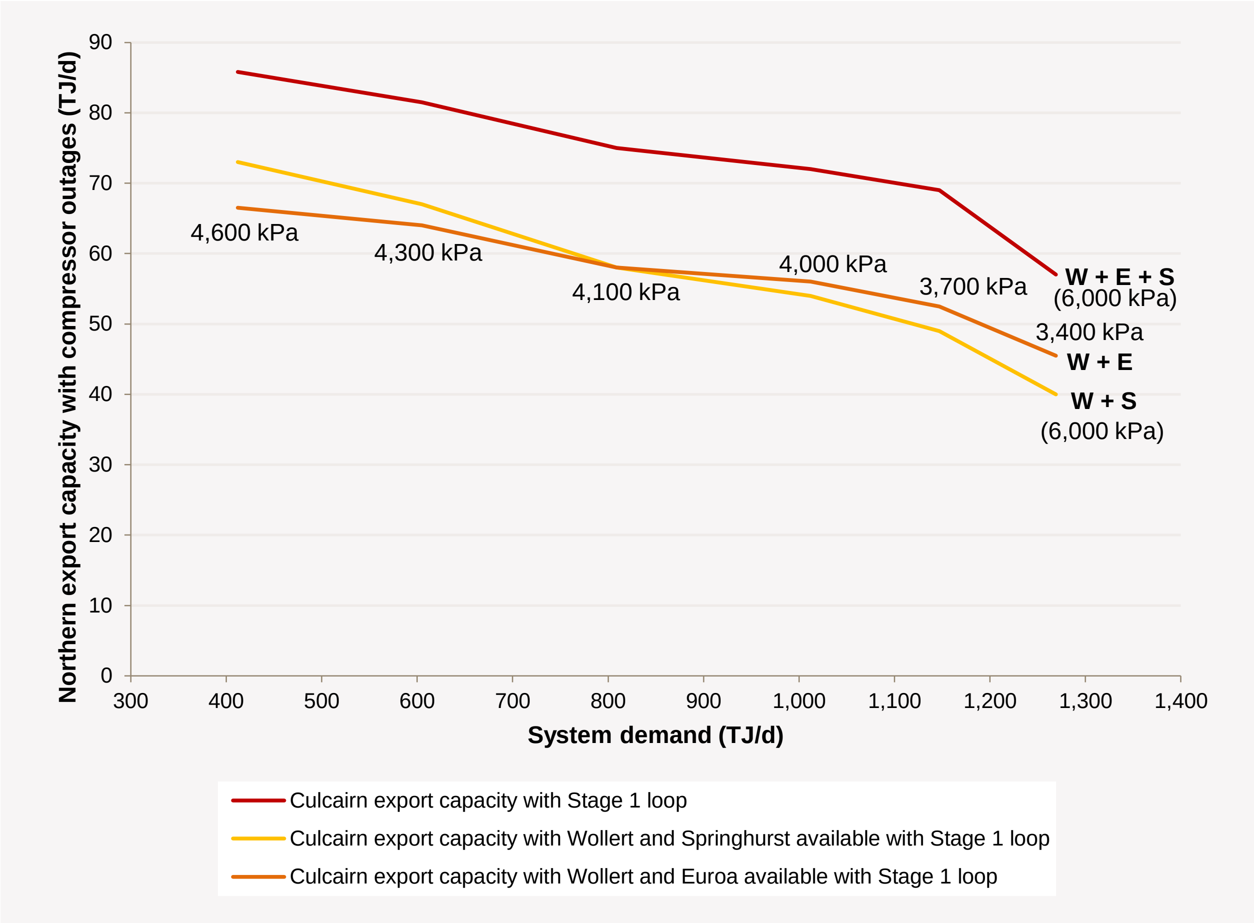
Figure B-2 — Exports to NSW during Springhurst or Euroa compressor outage with stage 1 expansion



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MEASURES & ACRONYMS

Measures

Abbreviation	Unit of Measure
EDD	Effective degree days
GJ	Gigajoules
HDD	Heating degree days
km	Kilometres
kPa	Kilopascals
kW	Kilowatts
MJ/m^3	Megajoule per cubic meter
MW	Megawatts
PJ	Petajoule
PJ/m	Petajoules per month
PJ/y	Petajoules per year
t	Tonne
t/d	Tonnes per day: a unit of LNG production
t/h	Tonnes per hour
TJ	Terajoule
TJ/d	Terajoules per day
TJ/h	Terajoules per hour
$	Australian dollars

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Acronyms

Acronyms	Unit of Measure
AEMO	Australian Energy Market Operator Ltd
AEST	Australian Eastern Standard Time
AER	Australian Energy Regulator
AMDQ	Allocated Daily Maximum Quantity
BBP	Brooklyn Ballan Pipeline
BCP	Brooklyn Corio Pipeline
BLP	Brooklyn–Lara Pipeline
CCGT	Combined Cycle Gas Turbine (a type of GPG)
DCG	Dandenong City Gate
DTS	Victorian gas Declared Transmission System
EGP	Eastern Gas Pipeline
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
NFTC	Net Flow Transportation Constraint
MAOP	Maximum allowable operating pressure
MHQ	Maximum Hourly Quantity
MRM	Melbourne Ring Main
MTO	Medium Term Outlook
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
OCGT	Open Cycle Gas Turbine (a type of GPG)
POE	Probability of exceedence
SEA	Service Envelope Agreement
SWP	South West Pipeline
SWZ	System withdrawal zone
TGP	Tasmanian Gas Pipeline
UGS	Underground gas storage
VAPR	Victorian Annual Planning Report
VGPR	Victorian Gas Planning Report
VGSA	Victorian Gas System Adequacy
WTS	Western Transmission System

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GLOSSARY

Definition	Description
1-in-2 peak day	Most probable peak day gas demand forecast, with a 50% probability of exceedence. This is expected, on average, to be exceeded once in two years (also known as the 50% peak day).
1-in-20 peak day	Peak day gas demand forecast for severe weather conditions, with a 5% probability of exceedence. This is expected, on average, to be exceeded once in 20 years (also known as the 95% peak day).
Augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
APA Group	Australia's largest natural gas infrastructure business, operating over 2000 km of gas transmission pipeline in Victoria.
Available	The aggregate contracted maximum daily quantities available to the market through commercial arrangements between market participants and gas producers or storage providers.
BassGas	See BassGas injection point.
BassGas injection point	Sources gas from the offshore Yolla gas field (Bass Basin) for supply to the Declared Transmission System (DTS), with treatment at the Lang Lang gas plant and injection into the DTS at Pakenham. Unless specified otherwise, "BassGas" refers to the BassGas injection point.
City gate	A distribution hub where gas is reduced in pressure before it enters the lower pressure, smaller diameter, distribution pipeline network.
Consumption	Usage of gas over monthly or annual period.
Culcairn	The location of the gas transmission network interconnection point between Victoria and New South Wales (NSW–VIC Interconnect).
Curtailment	The interruption of a customer's supply of gas at the customer delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
Customer	Any party who purchases gas and consumes gas at particular premises. Customers can deal through retailers or may choose to become market participants in their own right, and take on the retailing functions themselves.
Declared Transmission System	Owned by GasNet and operated by AEMO, the Declared Transmission System (DTS) refers to those aspects of the Victorian gas system that are a part of the declared network. According to National Energy Law, the DTS of an adoptive jurisdiction has the meaning given by the application Act of that jurisdiction and includes any augmentation of the defined declared transmission system.
Demand	Capacity or gas flow on a hourly or daily basis.

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Definition	Description
Degree Day	A commonly used temperature model for predicting gas demand for area/space heating.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, chill, and seasonality. The higher the number, the colder it appears to be and the more energy will be used for area heating purposes. Effective Degree Day is used to model the daily gas demand-weather relationship.
Export demand	Export demand includes withdrawal at VicHub, BassGas, SEA Gas, Iona and Culcairn.
Gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
Gas-powered generation	Where electricity is generated from gas turbines (combined cycle gas turbine, open cycle gas turbine).
Injection	The physical injection of gas into the transmission system.
Iona	See Iona injection point. The Iona gas plant processes conventional gas from the Casino, Henry, and Netherby gas fields. This gas, along with any gas withdrawn from underground gas storage, can flow from the Iona injection point into the Victorian Declared Transmission System via the South West Pipeline.
Iona injection point	The Iona injection point injects gas into the Victorian Declared Transmission System via the South West Pipeline. Unless other specified, Iona refers to the Iona injection point.
Linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
Liquefied Natural Gas	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.
Longford Melbourne Pipeline	The pipeline from Longford to Dandenong and Pakenham to Wollert.
Longford gas plant	The Longford gas plant, located near Sale in South Gippsland, processes gas from the Gippsland Basin and injects it into the DTS. It also supplies to New South Wales, the Australian Capital Territory, and Tasmania via the Eastern Gas Pipeline and the Tasmanian Gas Pipeline.
Longford ESSO injection point	Injects gas from the Longford Plant into the Declared via the Longford metering station and the Longford to Melbourne Pipeline.
Market participant	A person who is registered by AEMO and participates in declared wholesale gas market of an adoptive jurisdiction. The wholesale gasmarket involves the market operator, producers, storage providers, retailers, traders, market customers, declared transmission service provider, interconnected transmission pipeline service providers and distributors.

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Definition	Description
Maximum allowable operating pressure	The maximum pressure at which a pipeline is licensed to operate.
Minimum allowable operating pressure	The minimum pressure at which a pipeline is licensed to operate.
National Institute of Economic and Industry Research	A private economic research, consulting, and training group.
NSW–VIC Interconnect	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. The location of the flow measurement between the systems is Culcairn in New South Wales. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
Otway	See Otway injection point. Otway is the interconnection point for the South West Pipeline, Western Transmission System and SEA Gas pipelines; the underground gas storage; and the on-shore and offshore Otway Basin supplies.
Otway injection point	Injects gas from the Otway plant into the gas Declared Transmission System through the Otway, SEA Gas or Iona injection points. Unless specified otherwise, Otway refers to the Otway injection point.
Participant	A person registered with AEMO in accordance with the National Gas Rules (Victorian gas industry).
Peak day profile	The hourly profile of injection or demand occurring on a peak day.
Peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas.
Port Campbell	Port Campbell refers to the injection point hub into the South West Pipeline which includes gas supply from Iona, SEA Gas, Otway, and Mortlake injection points. Port Campbell supply is subject to the net transportation capacity of the SWP.
Prospective	Prospective supply is subject to participants offering gas on the gas day, and may depend on interconnecting pipeline operating conditions and contracts.
SEA Gas	See SEA Gas injection point. SEA Gas is the interconnection point between the SEA Gas pipeline and the gas Declared Transmission System at Iona.
SEA Gas injection point	The SEA Gas injection point, located near the township of Port Campbell in south-west Victoria, is the system injection point for gas from the offshore Minerva gas field and the Otway Basin, Geographe–Thylacine gas field supply developments, and the Mortlake pipeline. From this injection point, gas can be injected into the Declared Transmission System, the SEA Gas pipeline (for export to Adelaide), or the underground gas storage. Unless specified otherwise, SEA Gas refers to the SEA Gas injection point.
Shoulder season/period	The period between low (summer) and high (winter) gas demand. Includes calendar months April, May, October, and November.
South West Pipeline	The pipeline from Iona to Lara (Geelong) to Brooklyn.

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Definition	Description
Storage facility	A facility for storing gas, including the Liquefied Natural Gas storage facility and the Iona underground gas storage.
System capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • load distribution across the system • hourly load profiles throughout the day at each delivery point • heating values and the specific gravity of injected gas at each injection point • initial linepack and final linepack and its distribution throughout the system • ground and ambient air temperatures • minimum and maximum operating pressure limits at critical points throughout the system, and • powers and efficiencies of compressor stations.
System demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes GPG demand, exports, and gas withdrawn at Iona.
System injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
System withdrawal point	A gas Declared Transmission System connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
System withdrawal zone	Defined regions within the Victorian gas Declared Transmission System for which AEMO is required to publish demand forecasts. Each zone contains one or more system withdrawal point/s.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption > 10,000 GJ or MHQ > 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number.
Tariff V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users.
Tasmanian Gas Pipeline	The pipeline from Longford to Bell Bay in Tasmania.
Transmission	Long haul transportation of gas via high pressure pipelines.
Transmission constraint	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
Underground Gas Storage	The underground gas storage facility at Iona.
VicHub	See VicHub injection point. VicHub is the location of the interconnection between the Eastern Gas Pipeline and the gas Declared Transmission System at Longford, facilitating gas trading at the Longford hub.
VicHub injection point	VicHub, located near the Longford plant, has a gas Declared Transmission System injection point for gas from the Eastern Gas Pipeline. Unless specified otherwise, 'VicHub' refers to the VicHub injection point.

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Definition	Description
Western Transmission System (WTS)	Western Transmission System. The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the gas market and the gas Declared Transmission System.

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