VICTORIAN GAS PLANNING REPORT

DECLARED TRANSMISSION SYSTEM PLANNING FOR VICTORIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO publishes this Victorian Gas Planning Report in accordance with rule 323 of the National Gas Rules. This publication is generally based on information available to AEMO as at 31 January 2017. More recent information may have been included where practical.

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Acknowledgement

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

Version control

Version	Release date	Changes
1	9/03/2017	New document

EXECUTIVE SUMMARY

The *Victorian Gas Planning Report* (VGPR) provides an assessment of supply and demand, and pipeline capacity adequacy, for the Victorian gas declared transmission system (DTS) over the next five years (2017–21, called the outlook period). Registered participants in the Victorian declared wholesale gas market (DWGM) provide AEMO with confidential forecasts to prepare the VGPR. The VGPR provides forecast information for the total system and by system withdrawal zone (SWZ), as required by the National Gas Rules (NGR).

This document complements AEMO's *Gas Statement of Opportunities* (GSOO)[1] , which assesses wider gas supply adequacy in eastern and south-eastern Australia.

Key findings

- The Victorian gas supply demand balance is forecast to continue to tighten. Victorian supply shortfalls may occur if market participants do not carefully manage their gas portfolio, including storage balances.
- Producers have advised AEMO of a large decline in Victorian gas production during the 2017–21 outlook period.
  - Gippsland annual production is forecast to reduce by 34%, returning production to pre-2016 levels. Maximum daily production capacity is forecast to reduce by 27%.
  - Port Campbell annual production is forecast to reduce by 81%, due to some offshore fields ceasing production. Maximum daily production capacity is forecast to reduce by 81%.
- The reduced maximum daily gas production capacity will increase Victoria's reliance on supply from the Iona Underground Gas Storage (Iona UGS) facility during winter. An expansion of Iona UGS has been proposed by the facility owner.
- Reduced Port Campbell production will increase the amount of gas that must flow from Longford via the South West Pipeline (SWP) to refill Iona UGS outside of winter. Due to the existing SWP capacity limitation towards Port Campbell, refilling of Iona UGS is uncertain for winter 2018 and is unlikely for each subsequent winter from 2019 onwards.
  - AEMO has identified this as a threat to system security. Under the NGR, AEMO can direct the curtailment of large gas users that impact the filling of storage. AEMO does not have the power to direct investment to remove the SWP capacity limitation.
  - Expansion of the SWP capacity towards Port Campbell is required to ensure Iona UGS is refilled prior to each winter. Failure to refill Iona UGS during the summer, when demand is lower, may result in Victorian gas supply shortfalls during the following winter.
- Gas supply from Victoria to South Australia and New South Wales is expected to reduce, due to the forecast fall in Victorian gas production. Supply to these states is expected to reduce more in winter due to inventory limitations on gas stored at Iona UGS. The 2017 GSOO contains information regarding potential shortfalls.
- Due to the changing nature of gas consumption, peak day demand is increasing at some DTS offtake points into distribution networks. This creates locational and linepack[2] adequacy issues, and decreases the DTS's capability to provide gas for gas-powered generation (GPG).

[1] AEMO. 2017 GSOO. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
[2] Linepack is gas in pipelines – it is important to provide gas storage, and also to maintain gas pressure.

Actual demand and consumption trend

The annual gas consumption[3] trend since 2010, shown in Table 1, demonstrates an overall decline due to industrial closures.

Weather is the other major factor that causes variations in annual consumption. Data from the Bureau of Meteorology shows that 2016 was the fourth warmest year on record for Victoria. The only warmer years were 2005, 2013, and 2014. Colder winters have higher gas consumption, and milder winters have lower, which emphasises the need for market participants to have sufficient flexibility in their gas supply portfolios. Winter[4] 2015 was Victoria's coldest winter since 1989.

Table 1 Annual gas consumption and peak gas total demand

	2010	2011	2012	2013	2014	2015	2016
Annual system consumption (petajoules (PJ))	220	217	211	200	195	208	204
Annual GPG consumption (PJ)	8	8	3	3	4	3	4
Actual peak total demand (terajoules per day (TJ/d))	1,197	1,154	1,092	1,165	1,214	1,179	1,187

The 2016 peak demand day for Victoria occurred on Friday 24 June 2016. The total demand[5] of 1,187 terajoules (TJ) was all system demand, with no GPG occurring on that day. This was 8 TJ more than the highest demand day in 2015, but lower than the 1,214 TJ total demand on 1 August 2014.

Actual peak day system demands have not decreased, because residential winter demand growth has offset industrial closures. Peak day system demand has a low correlation to annual consumption (as it is possible to have a cold snap during a mild winter). Table 1 shows that 2014 had the lowest annual consumption in the seven-year period, due to it being Victoria's warmest year on record. Despite this, 2014 had the highest peak day gas demand over the same period.

Peak system demand forecast

The DTS peak system demand is forecast to decline in the outlook period, as shown in Table 2. This is mostly due to the combination of projected industrial load reductions, inner city consumers switching from gas to electric appliances, and a generally warming climate.

Table 2 Peak day system demand forecast, 2017–21

Forecast value (TJ/d)	2017	2018	2019	2020	2021
1-in-2 peak system demand[A]	1,198	1,190	1,181	1,170	1,162
1-in-20 peak system demand[A]	1,310	1,301	1,292	1,280	1,271

A) A 1-in-2 forecast is expected, on average, to be exceeded once in two years. A 1-in-20 forecast is expected, on average, to be exceeded once in 20 years.

Peak day supply adequacy

Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 peak system demand day, and to support forecast DTS-connected GPG demand out to 2021 (the VGPR outlook period). The forecast peak day system demand and supply is in Table 3.

Gas production supply by maximum daily quantity (MDQ)[6] is classified as:

- 'Available' supply – firm contracted gas supply from production and storage facilities.

[3] Demand refers to capacity or gas flow on an hourly or daily basis. Consumption refers to gas usage over a monthly or annual period.
[4] Winter is defined in the gas industry as 1 June to 30 September.
[5] Total demand is equal to the sum of system demand and GPG, but excludes exports.
[6] The MDQ is the maximum daily quantity of gas that a customer can request or take on any one day under the terms of a supply contract with a production or storage facility operator. MDQs can vary by month or season.

- 'Prospective' supply – uncontracted production and storage facility capacity that is available to be contracted by market participants.

Table 3 Peak day production supply, 2017 – 21

Forecast value (TJ/d)	2017	2018	2019	2020	2021
Total available MDQ supply	1,816	1,363	1,343	1,277	711
Total available and prospective MDQ supply	1,816	1,615	1,585	1,539	1,346

As production declines, there will be limited gas available in Victoria to export to New South Wales and South Australia on a peak demand day. Possible gas supply shortfalls for South Australia and New South Wales are explored further in the 2017 GSOO.

Additional peak day supply may be available from:

- The Dandenong Liquefied Natural Gas (LNG) facility (87 TJ per day (TJ/d) firm capacity[7]). This is a peak shaving gas supply facility with a limited inventory (600 TJ) that needs to be utilised sparingly during winter.
- Depending on market and upstream pipeline conditions, imports into the Victorian Northern Interconnect (VNI) via Culcairn (125 TJ/d).
- The Tasmanian Gas Pipeline (TGP) connection into the Longford to Melbourne Pipeline (LMP), called TasHub, which was commissioned in November 2016. TasHub is expected to be used as a small storage facility, similar to the Dandenong LNG facility. It can supply up to 120 TJ/d on peak demand days if there is sufficient linepack in the TGP.

The operator of the Iona UGS facility is proposing to increase its injection capacity into the SWP and its withdrawal capacity from the SWP. This would offset some of the Port Campbell production capacity decline, although the SWP transportation capacity to refill Iona UGS storage reservoirs is constrained until the augmentation to increase this capacity is completed (currently proposed for 2018).

Annual supply adequacy

Victorian gas producers have advised AEMO of a large decline in production over the five-year outlook period, due to the depletion of offshore gas fields. Forecast total annual consumption and production supply is summarised in Table 4. Historical and forecast production quantities are shown in Figure 1.

The GPG demand forecasts in this document have been updated to include the impact of the Hazelwood Power Station closing by 31 March 2017.

Annual GPG consumption is forecast to decrease after 2018, as shown in Table 4, due to an expected increase in renewable energy generation to support the Victorian Renewable Energy Target (VRET) and the Federal Large-scale Renewable Energy Target (LRET). If the renewable generation does not come online as projected, GPG consumption is expected to be higher than this forecast.

Table 4 Forecast annual consumption and production supply, 2017–21

Forecast values (PJ)	2017	2018	2019	2020	2021
Annual system consumption	196	194	192	190	188
Annual GPG consumption	19	21	13	9	10
Total annual consumption	214	215	205	198	198
Total production supply	420	322	291	291	242

[7] LNG firm capacity is 100 tonnes per hour for 16 hours.

Gippsland annual production, which includes the Longford and Lang Lang gas plants, is forecast to reduce by approximately 23% from 345 petajoules (PJ) in 2017 to 266 PJ in 2018, then a further 14% to 228 PJ out to 2021. The initial 79 PJ decline between 2017 and 2018 would return Gippsland production to pre-2016 levels.

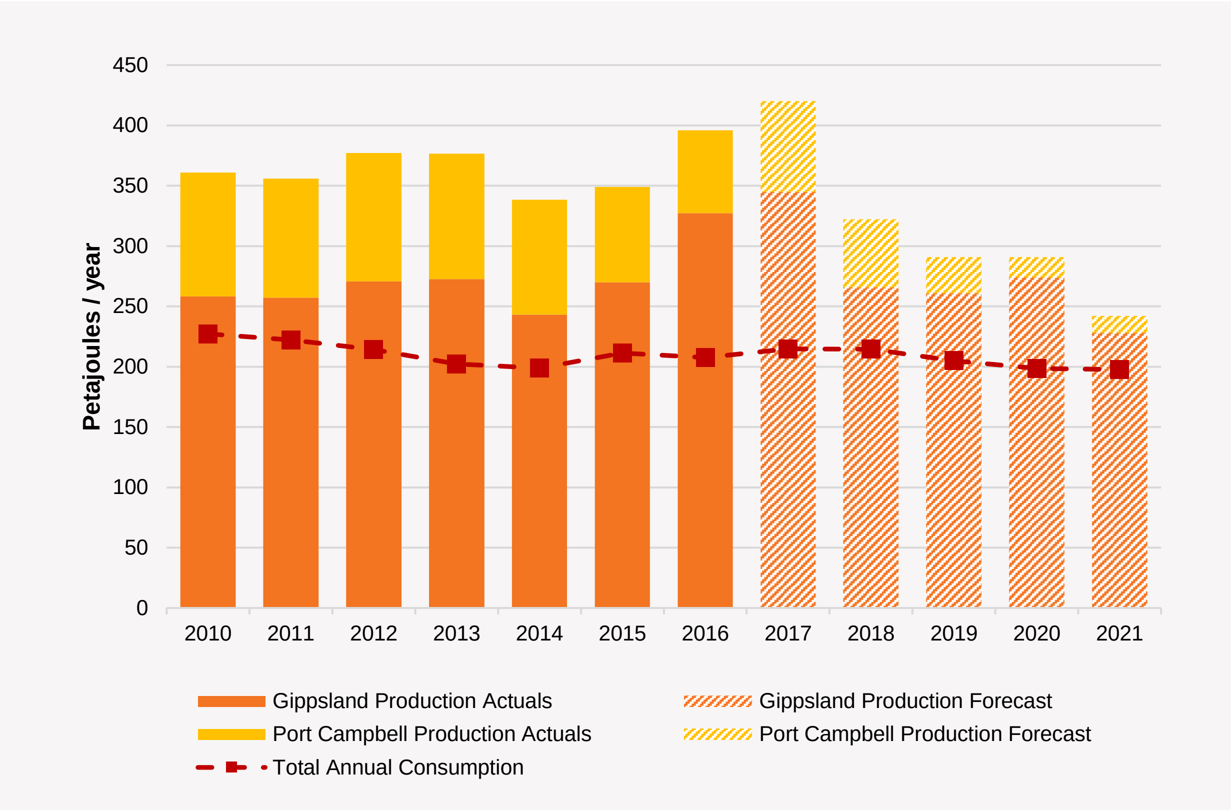
Port Campbell production, which includes the Otway and Minerva gas plants and the Casino development (processed via the Iona UGS facility), is in steep decline, with offshore fields at or near end-of-life. Total Port Campbell production is forecast to reduce by 81%, from 76 PJ in 2017 to 14 PJ in 2021.

If Victorian production continues to decline after 2021:

- Gas flows to New South Wales and South Australia are expected to reduce further.
- If Victorian annual production falls below the DTS annual consumption, Victoria will need to become a net importer of gas from outside the state.

Broader gas supply adequacy across eastern and south-eastern Australia is discussed further in the 2017 GSOO.

Figure 1 Annual production (petajoules per year) by location



Increased reliance on gas storage

While Victorian daily supply capacity is sufficient to meet peak day demand, declining production is putting the supply demand balance at increased risk. This places a higher reliance on gas storage inventory to supply winter gas requirements.

Refilling of Iona UGS for winter 2018 is uncertain, due to the forecast decrease in Port Campbell production and limitations on the SWP capacity towards Port Campbell. The SWP capacity limitation is expected to worsen, due to a forecast increase in GPG demand following the Hazelwood closure. Operation of the Laverton North Power Station further exacerbates the transportation limitation, because the SWP capacity reduces by the amount of gas this power station uses.

Iona UGS refilling for winter 2019 is unlikely, without an expansion of the SWP or an increase in Port Campbell production. This may result in winter gas supply shortfalls for Victoria. AEMO has identified this as a threat to system security.

The DTS service provider has proposed an expansion of the SWP that would be completed during 2018 to address this constraint. This is included in its 2018–2022 Access Arrangement submission to the Australian Energy Regulator (AER). Construction may need to be fast-tracked to support Iona UGS refilling for winter 2018.

Under the NGR, AEMO can take short term operational measures, including curtailment[8], to address threats to system security. Ultimately these measures are limited by the available supply of gas and transportation capacity of the DTS. AEMO does not control the capital investment that is required to remove DTS capacity limitations.

Changing gas demand and consumption profiles

Gas is supplied into the DTS at a constant rate. Linepack (gas stored in the DTS pipelines) is used to supply the peak hourly demands, which are higher than the rate of gas supply into the DTS.

Peak day demand profiles have become more 'peaky', due to industrial and commercial demand (which is flat) being replaced by residential demand (which peaks during the morning and evening). This is causing larger morning and evening peak gas flows out of the DTS into the distribution networks.

These increased peak gas flows are:

- Reducing the amount of DTS linepack that is available to support unforecast increases in demand due to weather forecast error.
- Reducing the capability of the DTS to support increased GPG demand, which also tends to be highest during the morning and evening peak periods. Investment in additional DTS linepack capacity may be needed to support increased GPG demand in Victoria, if GPG demand is higher than the levels forecast by AEMO.

Outside of winter, monthly and annual gas consumption is decreasing due to reduced commercial and industrial gas usage. Energy conservation measures, such as solar-boosted hot water, also reduce residential gas consumption during summer.

Market participants need to have flexible gas supply portfolios to support Victorian peak winter gas demands that can exceed 1,200 TJ/d, and summer gas demands of less than 300 TJ/d.

Increasing gas demand in growth areas is creating locational issues

Demand is increasing at some distribution connection points, particularly in the outer Melbourne residential growth areas:

- The distributor at the Melton South connection point has requested a higher supply pressure during winter due to population-driven demand increases.
- Expansion work is required to support increased commercial and residential demand in Warragul, where a pressure breach occurred in winter 2014. This breach had the potential to interrupt gas supply in the distribution system. AEMO forecasts show that if investment is not implemented by winter 2019 to support these demand increases, there is a high likelihood of localised curtailment being required during a peak demand day. AEMO has identified this as a threat to system security.

[8] Curtailment is the controlled interruption of an end user's supply of gas at its delivery point that occurs when AEMO intervenes in the DWGM or issues an emergency direction.

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CHAPTER 1. INTRODUCTION

The *Victorian Gas Planning Report* (VGPR) outlines system adequacy of the Victorian declared transmission system (DTS), shown in Figure 2, to supply peak day demand and annual consumption over a five-year outlook period (2017–21).

The VGPR contains:

- An update of pipeline capacities.
- An analysis of system adequacy.
- A review of historical performance during winter 2016.

The 2017 VGPR also covers:

- Emerging DTS capacity limitations, with potential solutions.
- Information on committed augmentations to the DTS.

Detail on this report's scope is in Section 1.4.

All times in this report are Australian Eastern Standard Time (AEST).

1.1 The Victorian Declared Transmission System

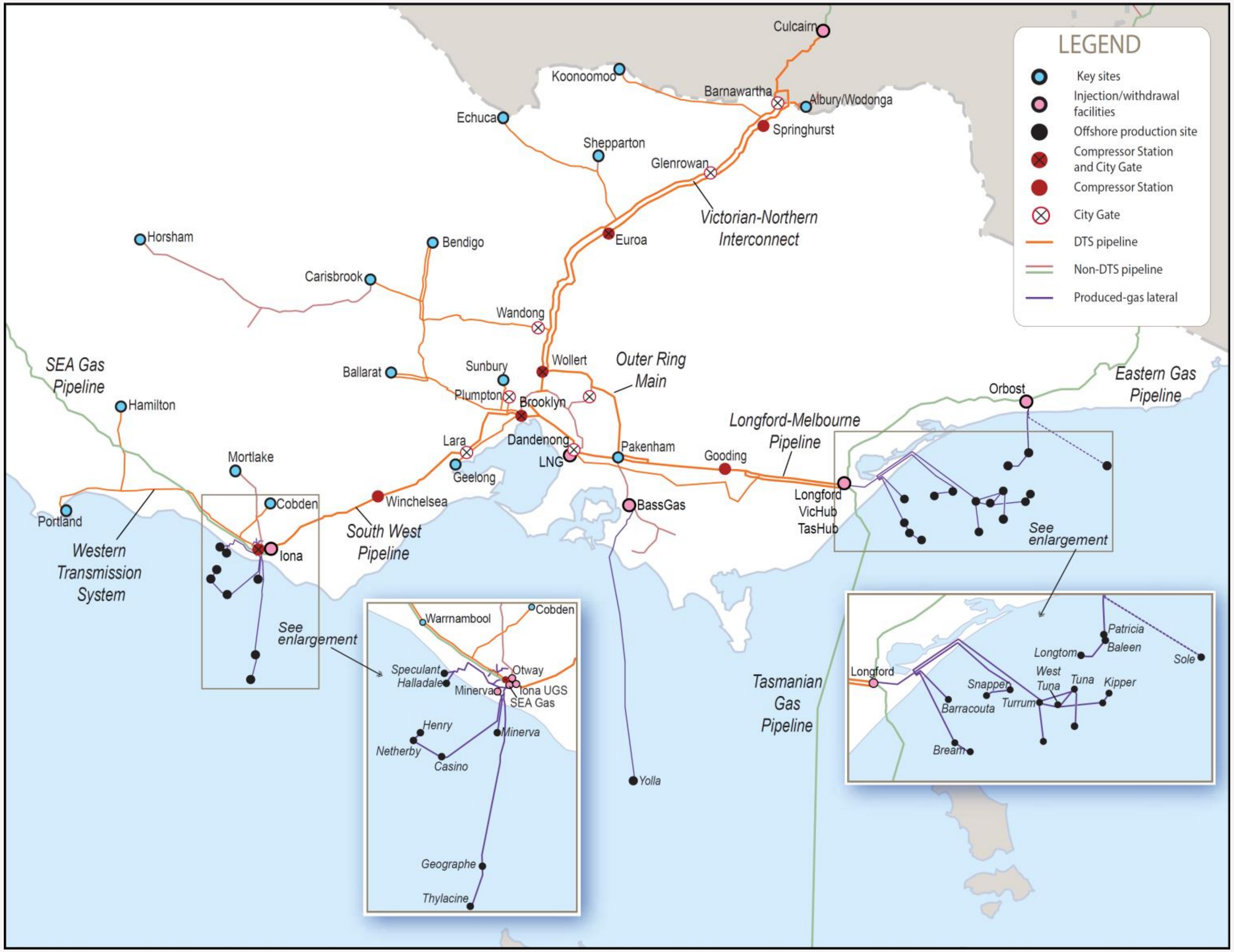
The DTS supplies natural gas to the vast majority of Victorian households and businesses. It transports gas from Longford in the east, to and from Culcairn in the north (connecting to the New South Wales transmission system) and Port Campbell in the west (connecting to South Australia, Otway and Minerva gas production facilities, and the Iona Underground Gas Storage (UGS) facility).

Figure 2 provides a high-level map of the Victorian gas transmission system, including the DTS (in orange) and other gas transmission pipelines.

The DTS comprises six system withdrawal zones (SWZs), defined in Appendix E:

- Ballarat.
- Geelong.
- Gippsland.
- Melbourne.
- Northern.
- Western (Western Transmission System, WTS).

Figure 2 Map of the Victorian Declared Transmission System



1.2 Winter 2016 review

In 2016, the peak system demand day for Victoria occurred on Friday 24 June 2016.

The system demand for the day was 1,187 terajoules (TJ), with an effective degree day (EDD)[9] of 13.95. There were 9.1 TJ of Culcairn imports and no demand from gas-powered generation (GPG).

The DTS experienced 13 days when system demand exceeded 1,000 terajoules per day (TJ/d) during the winter period (1 June to 30 September).

The key observations from the 2016 winter are:

- Average system demand of 855 TJ/d, which is lower than 977 TJ/d in 2015.
- Participants withdrew 2 petajoules (PJ) at the Iona node, utilising available capacity on the South West Pipeline (SWP) to withdraw during lower demand in the winter period, which has not occurred in previous years.
- Average daily flow to New South Wales via the Victorian Northern Interconnect (VNI) of 38 TJ/d, which is less than the average flows exported in 2015 (63 TJ/d).
- There was 1.4 PJ of DTS-connected GPG demand during the winter period.
- The highest total demand day of 1,187 TJ/d is the second highest in the last five years, 2014 being the highest of 1,213 TJ on 1 August 2014.

The cumulative total EDD for the winter 2016 was 999. This is 10% lower than the total EDD of 1,113 for winter 2015, which was the coldest winter in 26 years.

A total of 2,356 tonnes (129 TJ) of liquefied natural gas (LNG) was scheduled for injection into the DTS during winter 2016. None of this LNG was scheduled for peak shaving purposes, which is the scheduling of LNG injections to maintain system pressures during periods of very high gas demand.

A total of 64.9 TJ (or 1,196 tonnes) peak shaving LNG was injected on 1 October 2016 to maintain system security during a Longford Gas Plant outage.

1.3 Gas planning in Victoria

1.3.1 Roles and responsibilities

AEMO operates the Victorian DTS and provides information about gas supply and demand, system constraints, capability, and development proposals, to assist in the efficient planning and development of gas markets and facilities.

The DTS service provider, APA Group, owns and maintains the DTS assets. As the asset owner, APA controls the capital investment in the DTS through the Access Arrangement process[10] with the Australian Energy Regulator (AER).

Third party asset owners maintain and augment associated infrastructure, including production and storage facilities, and interconnected pipelines.

1.3.2 Planning basis and definitions

AEMO prepares and publishes a planning review (in the form of the VGPR) once every two years by 31 March, in accordance with rule 323 of the National Gas Rules (NGR).

[9] EDD is a measure of coldness that includes temperature, sunshine hours, wind speed, and seasonality. Each gas day is assigned an EDD value based on the weather conditions.
[10] See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2018-22.

In accordance with rule 324 of the NGR, participants are required to provide AEMO with forecast information. Under rule 324(6), AEMO must keep this forecast information confidential.

In producing the VGPR, AEMO assesses the DTS supply and system adequacy to meet a forecast 1-in-2 and 1-in-20 peak system demand day over the outlook period (2017–21):

- A **1-in-2 forecast** is defined as a peak day gas demand forecast with a 50% probability of exceedance (POE). This is equivalent to a 50% peak day for electricity planning. It means the forecast is expected, on average, to be exceeded once in two years, and is considered the most probable forecast.
- A **1-in-20 forecast** is defined as a peak day gas demand forecast for severe weather conditions, with a 5% POE. This is equivalent to a 95% peak day for electricity planning. It means the forecast is expected, on average, to be exceeded once in 20 years.

AEMO must also assess:

- The adequacy of the DTS transmission capacity on a peak system demand day.
- The impact of GPG demand on a forecast 1-in-2 peak system demand day.

The *Gas Industry Act* and the *Gas Safety Act* impose obligations on network operators and owners relating to the reliability of gas supply. The reliability of gas supply refers to the continuity of supply to customers, with an unplanned loss of supply (or interruption) to a customer in any circumstance being regarded by Energy Safe Victoria (ESV) as a potentially dangerous and undesirable event.

AEMO uses these legislative requirements, along with the planning standard, to assess the Victorian DTS's adequacy to support peak demand days. This assessment is used to demonstrate what augmentations or additional gas supplies are required to minimise the risk of an unplanned loss of supply and subsequent risks to public safety.

1.4 Scope of the 2017 VGPR

The VGPR provides a five-year (2017–21) maximum supply and demand outlook, as well as a capacity assessment of the DTS.

The 2017 VGPR considers the following for the outlook period:

- Forecasts for peak daily demand, peak hourly demand, 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 system capacity.
- Acceptable DTS operating pressure ranges.
- Information about gas storage.

Specifically, this report includes:

- Information about the gas transmission system's performance for the calendar year 2016 and winter 2016.
- An overview of the DTS capacity as a whole (system capacity).
- An overview of individual DTS pipeline capacities.
- Information on the supportability of DTS-connected GPG on a 1-in-2 peak system demand day.
- Results of modelling to 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 outlook period.

- Information about the short-term (2017) DTS demand and supply forecast by month.
- Information about committed augmentations and their expected impacts. Committed augmentations are those where proponents have secured the necessary land and planning approvals and 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.
- Information about AEMO's approach to planning for the Victorian DTS.

CHAPTER 2. GAS DEMAND FORECAST

Key findings

- The forecast peak system demand for 2017 is the highest over the outlook period:
  - 1,198 TJ/d for a 1-in-2 peak system demand day.
  - 1,310 TJ/d for a 1-in-20 peak system demand day.
- Annual system consumption is forecast to decrease from 196 PJ in 2017 to 188 PJ in 2021.
- Annual GPG consumption is forecast to increase from 4 PJ in 2016, to 18 PJ in 2017 and 20 PJ in 2018, due to the March 2017 closure of Hazelwood Power Station. From 2019, the GPG consumption is forecast to decrease to 9.6 PJ in 2021, due to the forecast increase in renewable energy generation to support the Victorian Renewable Energy Target (VRET) and Federal Large-scale Renewable Energy Target (LRET).

Background

The VGPR uses forecasts from the latest *National Gas Forecasting Report* (NGFR) published in December 2016.[11,12] The demand forecasts include monthly values for 2017, and annual values over the outlook period, for:

- 1-in-2 peak system demand day forecast.
- 1-in-20 peak system demand day forecast.
- Annual consumption.

There have been some material changes in recent months impacting GPG forecast figures reported in the 2016 NGFR and the 2016 *National Transmission Network Development Plan* (NTNDP).[13] GPG consumption forecasts published in the VGPR used the NTNDP methodology, which examined a pathway of generation retirements based on assumed financial viability and announced intentions to close coal plant at the end of their technical life. The updated inputs into this model for the 2017 VGPR assumed the announced Hazelwood Power Station closure in March 2017[14], and the Portland Aluminium smelter continuing to operate due to the announced Federal and State Government support package.[15]

2.1 Peak day system demand forecast

This section reports the DTS forecasts of annual peak day system demand over the five-year outlook period from 2017, and monthly gas forecasts for January 2017 to December 2017. These forecasts are split by SWZ and are shown excluding GPG demand.

System demand is the forecast daily demand, which includes unaccounted for gas (UAFG) and excludes GPG demand.

System demand is split into the following:

- **Tariff V** demand, consisting of residential and small commercial customers normally consuming less than 10 TJ per year (TJ/y) of gas.

[11] AEMO. 2016 NGFR. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report
[12] The 2016 NGFR assumed the closure of the Portland smelter.
[13] AEMO. 2016 NTNDP. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.
[14] Engie. Media release: "Hazelwood to close in March 2017", 3 November 2016. Available at: http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf.
[15] Prime Minister of Australia. "Remarks at Alcoa Portland Aluminium Smelter", 20 January 2017. Available at: https://www.pm.gov.au/media/2017-01-20/remarks-alcoa-portland-aluminium-smelter.

- **Tariff D** demand, consisting of large commercial and industrial customers normally consuming more than 10 TJ/y of gas.

The VGPR uses the DTS peak day system demand forecasts from AEMO's 2016 NGFR, published in December 2016, which considered the VRET.

The peak day system demand forecasts are presented for the 1-in-2 peak day and 1-in-20 peak day standards.

2.1.1 Annual peak system demand

Peak day system demand is sensitive to weather, because it is primarily driven by gas consumption for heating.

The actual peak day system demand in winter 2016 was 1,186 TJ/d, as discussed in Chapter 1.

The 1-in-2 and 1-in-20 peak day system demand forecasts, summarised in Table 5, show a small projected decline over the outlook period, with an average annual decline of peak day demand of 0.77% and 0.75% respectively.

Forecast trends indicate the decline for peak demand, excluding GPG, will be driven mostly by the combination of projected industrial load reductions, and inner city customers switching from gas to electric appliances.

Tariff V demand is forecast to decrease, as growth due to new connections is projected to be offset by gas to electric appliance switching, and lower heating demand from a warmer climate.

GPG demand is not correlated with the same drivers as industrial, commercial, and residential peak demand, and is instead strongly influenced by conditions in the National Electricity Market (NEM). It therefore does not drive the 1-in-2 and 1-in-20 peak system demand maximums.

Annual peak day system demand by SWZ is detailed in Appendix B (Table 23 and Table 24).

Table 5 Annual 1-in-2 peak day demand forecast (TJ/d)

	2017	2018	2019	2020	2021	Annual average change (%)
Tariff V demand	944	938	935	928	920	-0.6%
Tariff D demand	254	252	246	242	242	-1.2%
System demand	1,198	1,190	1,181	1,170	1,162	-0.8%

Table 6 Annual 1-in-20 peak day demand forecast (TJ/d)

	2017	2018	2019	2020	2021	Annual average change (%)
Tariff V demand	1,053	1,047	1,044	1,037	1,027	-0.6%
Tariff D demand	257	254	248	243	244	-1.3%
System demand	1,310	1,301	1,292	1,280	1,271	-0.8%

2.1.2 Monthly peak day forecast

Table 7 shows forecast monthly peak day system demand for 2017. Peak day system demand is assumed to occur in the winter period, which runs from June to September. Monthly peak day system demand is influenced by weather conditions and seasonal industrial demand variations. Monthly peak day forecast demand by SWZ is shown in Appendix B (Table 27).

Table 7 Monthly peak day system demand (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	351	352	517	670	902	1,198	1,198	1,198	1,198	768	586	506
1-in-20	430	464	638	867	1,102	1,310	1,310	1,310	1,310	862	728	682

2.1.3 Peak hourly system demand forecast

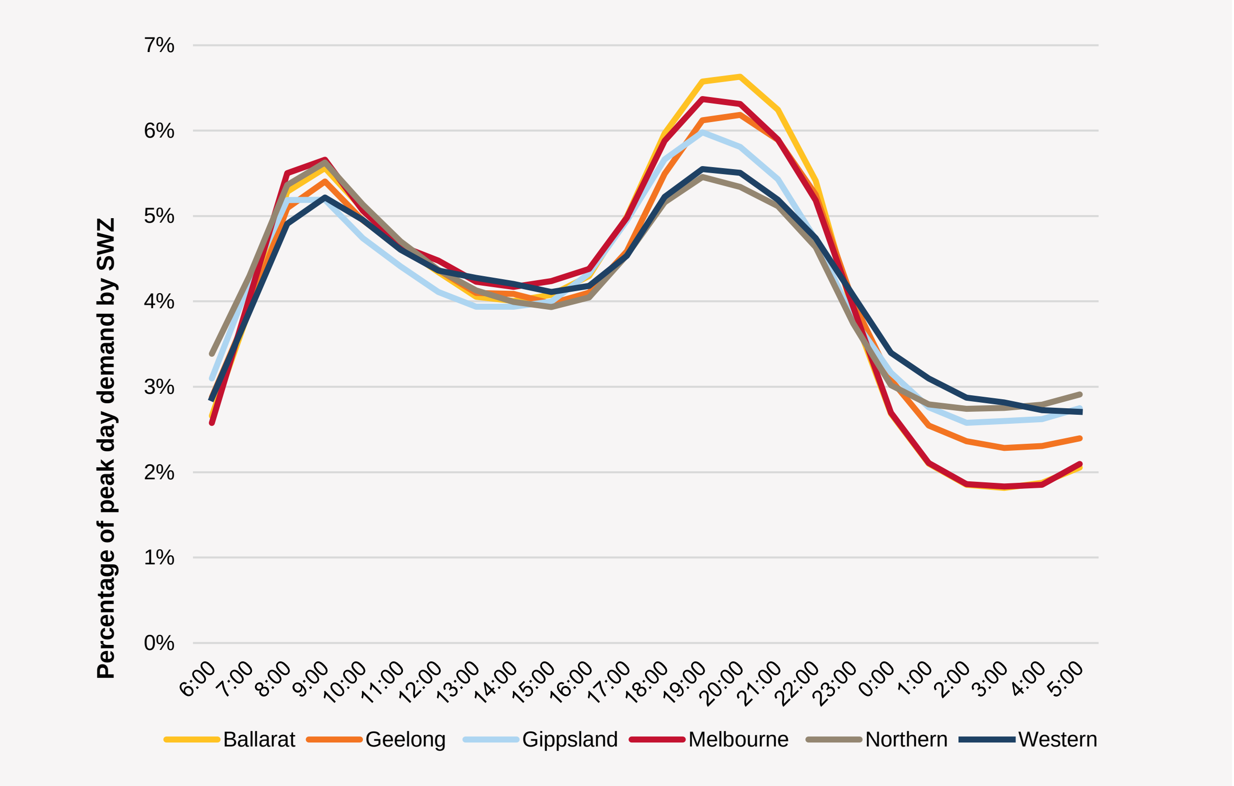
The peak hourly system demand forecast for each SWZ has been produced by applying the modelled winter peak demand profile at each Custody Transfer Meter (CTM) to the peak day system demand forecast, then aggregating for all CTMs in each SWZ.

The 1-in-20 peak hourly demand profiles by SWZ, shown in Figure 3, demonstrate that:

- The morning peak occurs between 7:00 am and 9:00 am, due to heating, hot water, and industry start-up.
- The evening peak occurs between 6:00 pm and 10:00 pm, due to residential gas heating and hot water usage.

Peak hourly system demand forecasts are presented in Appendix B (Table 25 and Table 28), for annual forecasts over the outlook period and monthly for January 2017 to December 2017.

Figure 3 Winter 1-in-20 peak hourly demand profiles by SWZ



2.2 Total consumption

This section presents forecasts of DTS total annual and monthly consumption, including a breakdown of system demand by SWZ and DTS-connected GPG demand. The annual system demand by SWZ, and by Tariff V and Tariff D, is included in Appendix B (Table 26).

Total consumption refers to all gas consumed within the DTS, including:

- System consumption, including compressor fuel gas and UAFG.
- GPG consumption (the adequacy of the DTS to support GPG demand is discussed in Chapter 5).

2.2.1 Annual consumption

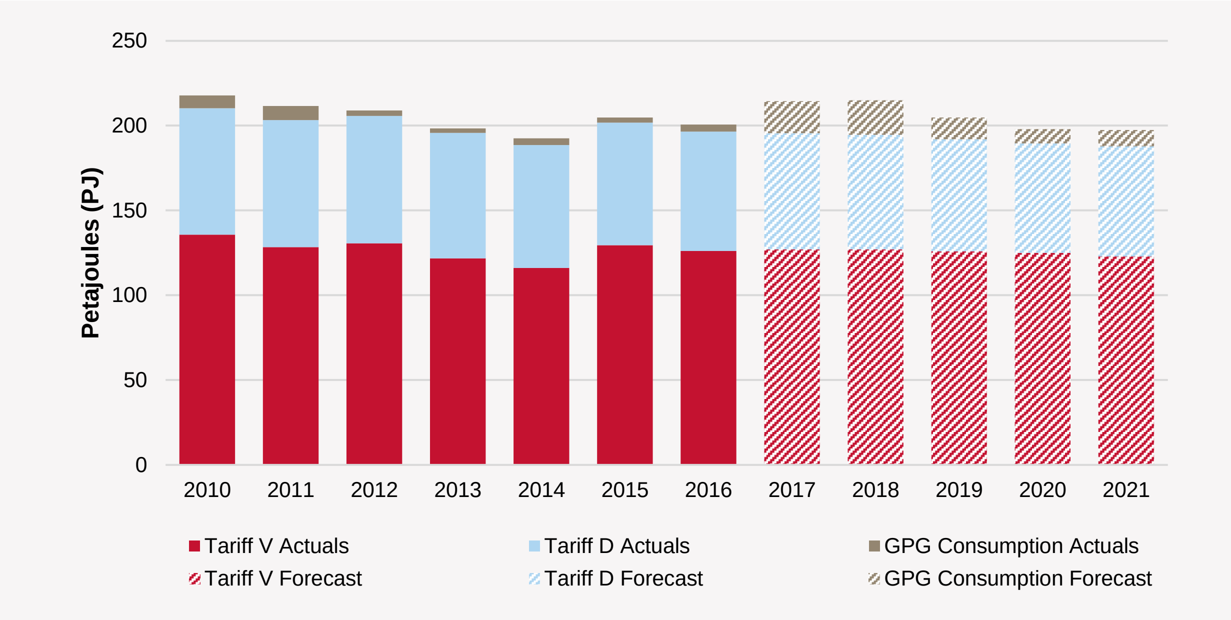
Annual gas consumption is forecast to fall from 215 PJ in 2017 to 198 PJ in 2021, shown in Table 8 and Figure 4:

- Tariff V annual consumption represents residential and small commercial demand, which over the outlook period projects a slight decline of 0.80%. Despite more people connecting to gas, total consumption is projected to decline slightly as new connections are offset by improved energy efficiency, customers in high density inner city regions switching from gas to electric appliances, and lower heating demand due to a generally warmer climate.
- Tariff D annual consumption is forecast to have a relatively greater reduction in annual consumption over the outlook period, of 1.40%. Tariff D annual consumption has similar dynamics to those of Tariff D peak day forecast, and the reduction in demand is primarily driven by projected industrial load reductions and increases in gas price.

Table 8 Total annual gas consumption (PJ/y)

	2017	2018	2019	2020	2021	Annual average change (%)
Tariff V	127	127	126	125	123	-0.8%
Tariff D	68.6	67.6	65.9	64.6	64.8	-1.4%
System consumption	196	195	192	190	188	-1.0%
GPG consumption	18.8	20.5	12.9	8.5	9.6	-12.4%
Total consumption	214	215	205	198	197	-2.0%

Figure 4 Historical and forecast total annual gas consumption, 2010 to 2021



Annual GPG consumption

Figure 4 highlights historical and forecast DTS-connected GPG consumption. Historically, GPG consumption has averaged 5 PJ per year, with the higher demand in 2010 and 2011 due to the drought conditions in most of southern Australia reducing the availability of hydroelectric generation and cooling water for coal-fired generation.

GPG consumption is forecast to increase from 4 PJ in 2016, to 19 PJ in 2017 and 21 PJ in 2018. This forecast is driven by the March 2017 closure of the coal-fired Hazelwood Power Station, and highlights the key role GPG is expected to play in balancing the output from intermittent renewable energy sources and playing a transitional role in the transformation of the generation mix towards a low carbon future.

Increased GPG consumption is forecast to continue through 2019–21, although to a lesser extent as the uptake of large-scale renewable energy is projected to become more established under VRET and the Federal LRET. If renewable generation does not come online as projected, GPG consumption over the outlook period is expected to exceed this forecast.

System consumption by SWZ

The forecast annual gas consumption by SWZ is shown in Table 9:

- In the Gippsland and Western SWZs, where there are higher proportions of Tariff D load relative to Tariff V load, there is greater forecast load decline.
- In SWZs with larger proportions of Tariff V load, such as Melbourne, Ballarat, and Geelong, gas usage is projected to decline at a slower rate.

This reflects the different rate of forecast decline for the market segments over the outlook period, with Tariff D load showing a greater relative decrease across all SWZs.

GPG consumption is shown in Table 9 to decrease over the outlook period in all SWZs except Gippsland. The increase in GPG consumption forecast in Gippsland is due to AEMO modelling a new DTS-connected GPG unit starting up in 2020 and increasing its generation and gas demand in 2021. This does not reflect a known project, but is assumed to be commissioned to support the forecast uptake in renewable generation.

Table 9 Total annual gas consumption (PJ/y) by SWZ

	SWZ	2017	2018	2019	2020	2021	Annual average change (%)
System consumption	Ballarat	9.6	9.5	9.5	9.4	9.3	-0.6%
	Geelong	21.2	21.2	20.8	20.7	20.7	-0.6%
	Gippsland	14.2	13.9	13.4	13.0	12.7	-2.8%
	Melbourne	127	126	125	124	123	-0.8%
	Northern	19.7	19.6	19.4	19.1	19.1	-0.8%
	Western	4.3	3.8	3.7	3.7	3.7	-3.8%
	System consumption	**196**	**194**	**192**	**190**	**188**	**-1.0%**
GPG consumption	Ballarat	-	-	-	-	-	-
	Geelong	7.9	7.7	4.3	2.0	2.2	-22.4%
	Gippsland	0.4	0.6	0.5	0.9	1.7	51.6%
	Melbourne	10.5	12.2	8.2	5.6	5.7	-11.8%
	Northern	-	-	-	-	-	-
	Western	-	-	-	-	-	-
	GPG consumption	**18.8**	**20.5**	**12.9**	**8.53**	**9.57**	**-12.4%**
Total consumption	Ballarat	9.6	9.5	9.5	9.4	9.3	-0.6%
	Geelong	29.1	28.9	25.1	22.7	22.9	-5.6%
	Gippsland	14.6	14.5	13.9	13.9	14.4	-0.3%
	Melbourne	138	138	133	130	129	-1.7%
	Northern	19.7	19.6	19.4	19.1	19.1	-0.8%
	Western	4.3	3.8	3.7	3.7	3.7	-3.8%
	Total consumption	**215**	**214**	**205**	**199**	**198**	**-2.0%**

2.2.2 Total monthly consumption

Monthly system consumption forecasts for January to December 2017, shown in Table 10, indicate:

- System demand variation within the winter period between 18.1 PJ per month (PJ/m) and 28.1 PJ/m from May to September, with the peak maximum in July.
- System demand variation outside the winter period between 8.47 PJ/m and 14.7 PJ/m from January to April and October to December.

Table 10 also shows DTS-connected GPG monthly demand forecast trends for 2017:

- The forecast spike in April 2017 (1.33 PJ) is driven by the retirement of Hazelwood Power Station at the end of March 2017 resulting in increased GPG usage to meet NEM demand.
- The forecast increase in GPG consumption in July and August 2017 (2.79 PJ and 2.31 PJ) is due to a combination of forecast NEM demand, and lower rooftop photovoltaic (PV) support in winter.

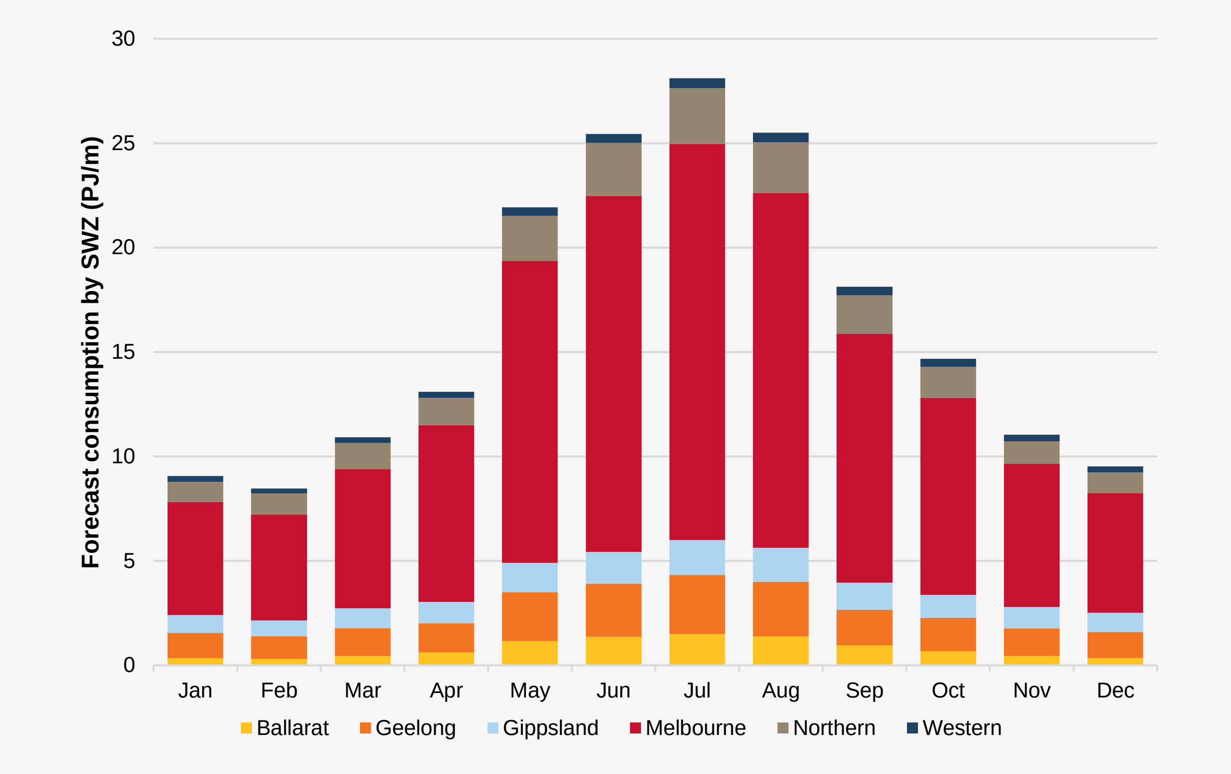
Table 10 Monthly gas consumption for 2017 (PJ/m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System demand	9.0	8.5	10.9	13.1	21.9	25.4	28.1	25.5	18.1	14.7	11.0	9.5
GPG demand	1.8	1.7	0.8	1.3	1.0	0.4	2.8	2.3	1.4	1.4	1.5	2.2
Total consumption	10.9	10.1	11.8	14.4	22.9	25.9	30.9	27.8	19.5	16.1	12.5	11.7

Figure 5 shows monthly system demand forecasts by SWZ (not including GPG), for Tariff D and Tariff V demand. Monthly system demand forecast figures by SWZ from January to December 2017, including GPG, are shown in Appendix B (Table 30).

Demand peaks across all zones for 2017 over the winter period are driven by peaking residential demand. SWZs with a greater relative composition of Tariff D demand show a flatter monthly demand profile, due to their demand being driven less by colder winter temperatures.

Figure 5 Monthly total consumption forecasts by SWZ for 2017 (PJ/m)



CHAPTER 3. GAS SUPPLY ADEQUACY

Purpose

This chapter outlines the available and prospective gas supply, and assesses the supply demand balance, on a peak system demand day and annual gas consumption basis. AEMO must publish aggregated gas supply capacities by SWZ that are derived from forecast data submitted by registered participants. These submissions are made in September 2016, however, AEMO includes any updated information provided to AEMO since that time. These requirements are set out in rules 323 and 324 of the NGR.

Key findings

- Tight supply demand balance is forecast, such that if market participants do not carefully manage their storage inventory and overall gas portfolio, supply shortfalls are possible from winter 2018.
- Producers have advised AEMO that Victorian gas production is forecast to decline during the 2017–21 outlook period.
  - Gippsland annual production is forecast to reduce by 34%, returning production to pre-2016 levels. Daily production capacity is forecast to reduce by 27% to 857 TJ/d.
  - Port Campbell annual and daily production is forecast to reduce by 81%, due to some offshore fields ceasing production.
- Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 year peak day system demand, and to support forecast GPG demand out to 2021. By 2021, there would be limited supply from Victoria available for New South Wales and South Australia on a 1-in-20 peak day.

3.1 DTS supply sources

3.1.1 Production facilities

DTS production capacity by supply source is reported by SWZ, shown in Table 11.

Table 11 DTS production facilities by SWZ

SWZ	Supply source	Project	Ownership
Gippsland	Longford Gas Plant	Gippsland Basin Joint Venture (GBJV)	• Esso Australia Resources, 50% • BHP Billiton, 50%
		Kipper Project[A]	• Esso Australia Resources, 32.5% • BHP Billiton, 32.5% • Mitsui E&P Australia, 35%
	Lang Lang Gas Plant	BassGas Project[B]	• Origin Energy, 42.5% • AWE, 35% • Toyota Tsusho, 11.25% • Prize Petroleum International, 11.25%
Port Campbell (Geelong)	Otway Gas Plant[B]	Otway Gas Project[B]	• Origin Energy, 67.23% • Benaris, 27.77% • Toyota, 5%
		Halladale/Speculant project	• Origin Energy, 100%
	Minerva Gas Plant	Minerva Joint Venture	• BHP Billiton, 90%[C] • Cooper Energy, 10%[D]
	Iona Gas Plant	Iona UGS	• Owned by QIC • Operated by Lochard Energy
		Casino Gas Project[E]	• Mitsui E&P Australia, 25% • Cooper Energy, 50% • AWE, 25 %

A) ExxonMobil. Available at: http://corporate.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/kipper-tuna-turrum. Viewed: 22 February 2017.
B) Origin Energy. Available at: https://www.originenergy.com.au/about/who-we-are/what-we-do/exploration-production.html. Viewed: 24 February 2017.
C) BHP Billiton. Available at: http://www.bhpbilliton.com/our-businesses/petroleum. Viewed: 24 February 2017.
D) Cooper Energy. Available at: http://www.cooperenergy.com.au/Upload/2017.01.10-Vic-Gas-Asset-completion.pdf. Viewed: 24 February 2017.
E) Mitsui & Co. Available at: https://www.mitsui.com/au/en/group/1216674_9223.html. Viewed: 24 February 2017.

3.1.2 Storage facilities

There are two storage facilities located in the DTS:

- Iona UGS, located in Port Campbell (Geelong zone), is discussed in Section 3.4.1.
- Dandenong LNG facility, located in the Melbourne zone, is discussed in Section 3.4.2.

3.1.3 Interconnected pipelines

There are four interconnected pipeline connections into the DTS:

- Eastern Gas Pipeline (EGP) via the VicHub connection point into the Longford to Melbourne Pipeline (LMP).
- Tasmanian Gas Pipeline (TGP) via the TasHub connection point into the LMP.
- Culcairn connection point into the VNI.
- South East Australia Gas (SEA Gas) Pipeline, which supplies into the SWP via the SEA Gas, Mortlake, and Otway connection points.

3.1.4 Future gas supply developments

Facility operators and market participants have advised AEMO that they will continue to evaluate investment in new supplies and are working to understand the current challenges and uncertainty in the market.

The following projects are expected to influence gas supply into the DTS:

- Gippsland Basin offshore development announced for the Sole Gas Project. This gas is to be processed at the Orbost Gas Plant. First gas is expected to be supplied in the March quarter of 2019.[16] This project will supply gas into the EGP, which may offset Longford gas flows on the EGP and make this Longford gas available to the DTS.
- The VNI is expanding for exports, but the import capacity will not change (discussed in Chapter 4).

No other facility operator has advised AEMO of its intention to develop further Victorian offshore gas reserves over the outlook period.

The Victorian Department of Economic Development, Jobs, Transport and Resources has formally advised AEMO that the *Resources Legislation Amendment (Fracking Ban) Bill 2016*, which is currently before the Victorian Parliament, specifies that the moratorium on onshore conventional gas does not apply to current or potential underground gas storage activities, subject to the activities being conducted under a current petroleum production licence and in accordance with a storage development plan approved under the *Petroleum Act*.

Underground gas storage operations (such as at Iona UGS) will continue to be subject to the conditions specified in the petroleum production licence covering the gas storage reservoirs for the facility. Current and future underground gas storage development will be in accordance with a storage development plan that is submitted and approved under the *Petroleum Act*.

3.2 Peak day supply and demand balance

This section lists the available peak day gas supply by source that is expected to be made available to the Victorian gas market over the 2017–21 outlook period. Information on SWZs and the corresponding gas supply sources is provided in Appendix E.

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

- ‘Available’ supply is firm contracted gas supply from production and storage facilities that is available to the market through commercial arrangements between market participants and the facility operator.
- ‘Prospective’ supply is production and storage facility capacity that is available to be contracted by market participants (but is not currently contracted, so is not considered to be “available” to supply the market).
- ‘Total supply’ is the sum of available and prospective supply, as well as firm capacity[17] LNG. This supply is subject to market participants contracting and offering the gas into the market on the day.

3.2.1 Annual peak day supply outlook

Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 peak day system demand, and to support forecast GPG demand through to 2021. Gas flows into interconnected pipelines supplying New South Wales and South Australia are expected to be reduced.

As Table 12 shows, the total available peak day production and storage facility gas supply capacity is forecast to decrease by 16% over the outlook period. These supply capacities do not include gas supplied from interconnected pipeline linepack.

[16] Cooper Energy. 2017. Quarterly Report December 2016. Available at: http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2017.01.25-Q2-FY17.pdf. Viewed: 20 February 2017.

[17] Firm capacity LNG refers to injections up to 100 tonnes/hr, and non-firm LNG is injections up to 180 tonnes/hr.

The supply capacities in Table 12 do not include gas supply limitations due to:

- DTS pipeline capacity limits, which are covered in Chapter 4.
- Production and storage facility capacity reductions due to unplanned maintenance or plant trips.
- Production and storage facility injections into pipelines that supply other states.

The availability of peak day gas supply capacity is reducing due to field depletion. No new gas supplies have been committed for supply into the DTS during the outlook period.

The forecast reduction of production maximum daily quantity (MDQ)[18] capacity is due to a decrease in total available and prospective peak day production capacity. The production capacity reductions are:

- Gippsland production MDQ capacity is forecast to decrease from 1,169 TJ/d in 2017 to 857 TJ/d by 2021.
- Overall Port Campbell MDQ capacity is forecast to decrease from 647 TJ/d in 2017 to 489 TJ/d in 2021.
  – Port Campbell production MDQ capacity is forecast to decrease from 257 TJ/d in 2017 to 49 TJ/d in 2021.
  – Port Campbell storage MDQ capacity is forecast to increase from 390 TJ/d in 2017 to 440 TJ/d in 2021. A larger expansion to 570 TJ/d has been proposed, but not committed (discussed in Section 3.4.1).

Table 12 Available peak day MDQ capacity by supply source (TJ/d), 2017–21

SWZ	Supply source	2017	2018	2019	2020	2021
Gippsland[A]	Available	1,169	816	807	750	272
	Prospective	0	202	192	212	585
	Total available and prospective	1,169	1,018	999	962	857
Port Campbell[B] (Geelong)	Available	647	547	536	527	439
	Prospective	0	50	50	50	50
	Total available and prospective	647	597	586	577	489
Melbourne	LNG	87	87	87	87	87
Total available		1,816	1,363	1,343	1,277	711
Total available and prospective		1,816	1,615	1,585	1,539	1,346
Total supply (including LNG)		1,903	1,702	1,672	1,626	1,433

A) These numbers only consider gas available to the DTS and do not include EGP only supply contracts.
B) Port Campbell includes Iona UGS (including Casino gas processing) and production facilities. These numbers include the total available gas to the DTS, South Australia, and Mortlake power station.

For 2017, the total daily available gas supply to the DTS is 1,816 TJ/d (see Table 12), from the Gippsland and Port Campbell production and storage facilities.

This total daily supply does not consider DTS pipeline capacity constraints, nor the DTS 1-in-20 peak day system capacity of 1,380 TJ/d without LNG injections and 1,500 TJ/d with LNG (discussed in Chapter 4).

[18] MDQ is the maximum daily quantity of gas that a customer can request or take on any one day under the terms of a supply contract with a production or storage facility operator. MDQs can vary by month or season.

3.2.2 Peak day supply outlook

A 1-in-20 peak system demand day supply outlook has been completed for 2017 (see Table 13) and 2021 (see Table 14). This analysis includes:

- Plant capacity, from the total available and prospective supply (shown in Table 12).
- DTS pipeline capacities (discussed in Chapter 4).
- Expected supply into the DTS to meet the 1-in-20 peak day system demand forecast based on historical peak day supply (discussed in Chapter 1).
- Remaining supply capacity on a 1-in-20 peak day system demand that is available to New South Wales, Tasmania, and South Australia.

The quantities available at each system injection point are indicative of supply available into the DTS, and are subject to pipeline constraints, commercial arrangements, system demand, and market price on the day.

This peak day supply analysis assumes that the full capacity of the Iona UGS facility is available, and not restricted due to low storage reservoir inventory.

VNI imports via Culcairn (up to 125 TJ/d) are not considered in the peak day outlook. This supply would depend on operational and market conditions in the New South Wales transmission system, including demand in southern New South Wales and the operation of Uranquinty Power Station.

Gas supply from the linepack of interconnected pipelines (SEA Gas, EGP, and TGP) is not included in the available peak day supply, because it would rely on sufficient pipeline linepack being maintained at all times.

2017 peak day outlook

The available supply on a 1-in-20 peak system demand day during winter 2017 is forecast to be similar to the gas supply available during winter 2016. Table 13 shows that there is forecast to be 593 TJ/d of spare capacity available to supply DTS GPG demand and to flow to other states.

Table 13 DTS capacities and expected supply on a 1-in-20 peak demand day, 2017 (TJ/d)

DTS supply sources		Plant capacity	Pipeline capacity	Expected supply	Remaining supply capacity
Gippsland		1,169	1,030	900	269
Port Campbell	To Melbourne	647	413	390	237
	To WTS[A]		28	20	
Melbourne	LNG storage	87	-	0	87
Total supply		**1,903**	**1,471**	**1,310**	**-**
1-in-20 system demand		1,310	1,310	1,310	-
Supply balance (TJ/d)		**+ 593**	**+ 161**	**-**	**+ 593**

A) WTS demand according to 2016 NGFR forecasts, which assumed a Portland aluminium smelter closure. Including the smelter demand would increase the WTS demand by approximately 2 TJ/d.

2021 peak day outlook

The analysis in Table 14 shows that there is only just sufficient supply available for a 1-in-20 peak system demand day during winter 2021. The remaining gas supply capacity has reduced from 593 TJ/d in 2017 to only 162 TJ/d in 2021. This 162 TJ/d of spare capacity is available to supply DTS GPG demand and to flow to other states.

In this forecast, maximum firm LNG is scheduled to enable some gas flow from Gippsland and Port Campbell to other states.

Table 14 DTS capacities and expected supply on a 1-in-20 peak demand day, 2021 (TJ/d)

DTS supply sources		Plant capacity	Pipeline capacity	Expected supply	Remaining supply capacity
Gippsland		857	1,030	776	81
Port Campbell	To Melbourne	489	412	390	81
	To WTS		28	18	
Melbourne	LNG storage	87	-	87	0
Total supply		**1,433**	**1,470**	**1,271**	**-**
1-in-20 system demand		1,271	1,271	1,271	-
Supply balance (TJ/d)		**+ 162**	**+ 199**	**-**	**+ 162**

3.3 Annual supply and demand balance

3.3.1 2017–21 available and prospective gas production forecast

This section lists the annual available and prospective gas supply sources for the outlook period. Included gas production is gas that is available, or could be made available, to the DTS from a production facility. The forecast does not take into account DTS storage facilities, because it is assumed that these are emptied then refilled to the same level each year.

The following three classifications of gas production are used for planning purposes:

- 'Available' supply is firm contracted gas supply from production that is available to the market through commercial arrangements between market participants and the facility operator.
- 'Prospective' supply is production that is:
  - Available to be contracted by market participants (so considered to be not available).
  - Firm production from a committed project (for example, a financial investment decision has been reached).
- 'Total supply' is the sum of available and prospective annual production quantities.

The annual available and prospective production by source for the outlook period is shown below in Table 15. It shows that total Victorian gas production is forecast to decline by 43%, from 420 PJ in 2017 to 242 PJ in 2021:

- Gippsland production available to the DTS is forecast to reduce by 35% from 345 PJ in 2017 to 228 PJ in 2021.
- Port Campbell production is forecast to reduce by 82% from 76 PJ in 2017 to 14 PJ in 2021, due to some offshore formations ceasing production. This will impact Iona UGS refilling, requiring supply from the Gippsland zone to supplement storage refilling requirements.

From winter 2018 onwards:

- A tight supply demand balance is forecast.
- If market participants do not carefully manage their storage and gas portfolios in 2017–18, a gas supply shortfall may occur.
- A combination of new production, increased storage development (UGS and/or LNG) and pipeline supply projects will be required to reduce the risk of a gas supply shortfall.

Table 15 Available gas production by zone (PJ/y), 2017–21

SWZ	Supply source	2017	2018	2019	2020	2021
Gippsland[A]	Available	345	229	224	220	93
	Prospective	0	37	37	54	135
	Total supply	345	266	261	274	228
Port Campbell (Geelong)[B]	Available	76	46	30	17	14
	Prospective	0	0	0	0	0
	Total supply	76	46	30	17	14
Total available		420	274	254	237	107
Total supply		420	311	291	291	242

A) Gippsland zone includes Longford GBJV, Longford Kipper Project and Lang Lang production facilities. The combined Longford number is gas available to the DTS and does not include EGP supply only contracts.
B) Port Campbell includes Iona UGS, Otway, and Minerva. These numbers include the total available gas to the DTS, South Australia, and Mortlake Power Station.

AEMO will continue to monitor changes in gas supply and will publish a VGPR Update if required.

3.4 DTS storage facilities

3.4.1 Iona Underground Gas Storage

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports GPG demand in South Australia via the SEA Gas Pipeline.

The current total Iona UGS storage reservoir capacity is 26 PJ. The current facility capacity is 435 TJ/d, including Casino production. The injection capacity into the storage reservoirs is 153 TJ/d. The facility has sufficient compression to withdraw 300 TJ/d from the SWP for injection into the storage reservoirs and into interconnected pipelines (SEA Gas and Mortlake).

Withdrawals from the SWP are restricted by the 104 TJ/d transportation capacity towards Port Campbell.

The Iona UGS facility operator has advised AEMO of plans to expand the reservoir withdrawal and injection capacity (as shown in Table 16). These expansion works include:

- Committed reservoir withdrawal capacity increase from 390 TJ/d to 440 TJ/d, and reservoir injection capacity increase from 153 TJ/d to 173 TJ/d, during 2017.
- Proposed further reservoir withdrawal capacity increase from 440 TJ/d to 570 TJ/d, and reservoir injection capacity increase from 173 TJ/d to 230 TJ/d, by the end of 2019 (shown in *italics*).

Table 16 Iona UGS proposed expansion plans (TJ/d)

Year	Max. reservoir withdrawal capacity	Max. Iona UGS Facility net injections in DTS[A]	Max. Iona reservoir injection capacity	Max. Iona UGS Facility net withdrawals from DTS[B]
2017	390	435	153	300
2018	440	440	173	400
2019	440	440	173	400
2020	*570*	*570*	*230*	*400*
2021	*570*	*570*	*230*	*400*

A) Net injection capacity into the DTS is reservoir withdrawal capacity plus production capacity.
B) Net withdrawal capacity is total quantity of gas that can be withdrawn from the DTS for reservoir injection plus injections into interconnected pipelines (the total quantity is limited by the compression capacity at the Iona UGS facility).

This proposed expansion would bring the overall capacity of the Iona UGS facility to 570 TJ/d by the end of 2019. The facility operator has also advised that this expansion could be contingent on whether there is an expansion of the SWP (discussed in Chapter 5).

3.4.2 LNG storage

The Dandenong LNG storage facility liquefies and stores natural gas to be used as a source of gas on high demand days. LNG injections into the DTS are also used to maintain system security in the event of a high unforecast demand or a supply disruption during a peak demand period.

The LNG facility has a storage capacity of 12,400 tonnes (680.8 TJ) with approximately 10,565 tonnes (580 TJ) of this capacity available to market participants. For forecasting and planning purposes, it is assumed that:

- The LNG storage capacity is full or nearly full at the start of each winter.
- Vaporisation capacity of up to 100 tonnes per hour (t/h), equivalent to 5.5 TJ/h, is available over 16 hours for peak shaving purposes. 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 (non-firm rate) capacity.

LNG is not usually scheduled from the beginning-of-day for peak shaving. It is usually included in an intraday schedule later in the day. LNG injected into the DTS is scheduled as either:

- Intraday peak shaving purposes required to maintain critical system pressures.
- A market response by market participants to balance their supply and demand during peak days.

Historical LNG trend

Over the last 10 years, LNG utilisation has varied during winter (see Table 17) and on an annual basis (see Table 18).

In 2007, LNG was used heavily as a result of increased GPG demand and SWP capacity limitations. This was predominantly due to the 2006–07 droughts[19] limiting the availability of hydroelectric generation and cooling water for coal generation. The reduction in LNG use in 2008 and 2009, compared to previous years, was partially due to the commissioning of the Brooklyn to Lara Pipeline (BLP) in 2008, which provided additional supply from the Port Campbell region.

Table 17 shows that there has been an increase of LNG storage utilisation over winter in the last two years since 2014. The increased utilisation of LNG during winter (shown in the percentage of tank capacity) could reduce the availability of peak shaving LNG if required to mitigate a threat to system security.

If the stock level is low, it cannot be filled quickly. Replenishing LNG stocks is planned on a monthly basis and the LNG facility has limited ability to refill over a short period. The maximum liquefaction rate is up to 1,500 tonnes a month (t/m), averaging approximately 50 tonnes a day (t/d) or 2.7 TJ/d.

Table 17 Historical winter LNG utilisation (2007 to 2016)

LNG	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
TJ	292	27.4	25.9	48.4	21.7	96.0	40.2	27.8	114	129
Tonnes	5,318	499	472	882	395	1,748	733	506	2,072	2,356
% of tank capacity[A]	43%	4%	4%	7%	3%	14%	6%	4%	17%	19%

A) This is based on a LNG tank capacity of 680.8 TJ, as provided by the DTS service provider.

[19] Australian Bureau of Statistics. 2006 Drought. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/a9ca4374ed453c6bca2570dd007ce0a4/ccc8ead2792bc3c7ca2573d200106bde!OpenDocument Viewed: 14 February 2017.

Table 18 shows that LNG usage has increased for the past four years, as LNG has been used as a supplementary supply due to a tightened east coast supply demand balance. The supply demand balance has also been impacted by a higher occurrence of unplanned plant outages and constraints.

These factors can lead to a higher gas price, which in turn can lead to more frequent market-scheduled LNG, as was seen in 2016.

In 2016, 64.9 TJ (or 1,196 tonnes) of peak shaving LNG was injected on 1 October 2016 to maintain system security during a Longford Gas Plant outage.

Table 18 Historical annual LNG utilisation (2007 to 2016)

LNG	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
TJ	444.6	260.5	72.7	60.5	86.1	144.9	42.2	68.0	175.3	237.5
Tonnes	8,098	4,745	1,324	1,102	1,568	2,639	768	1,239	3,193	4,327
% of tank capacity	65%	38%	11%	9%	13%	21%	6%	10%	26%	35%

CHAPTER 4. DECLARED TRANSMISSION SYSTEM PIPELINE CAPACITY

Purpose

This chapter defines the DTS pipeline capacities, for 2017 unless otherwise stated. These pipeline capacities will be used for the application of constraints in the DWGM, and to assess any proposed DTS service provider and facility operator maintenance plans.

Key findings

- SWP transportation capacity has decreased to 413 TJ/d towards Melbourne for winter 2017 due to industrial closures in the Geelong SWZ.
- An increase in VNI pipeline capacity to New South Wales via Culcairn, to 200 TJ/d on a 1-in-20 peak system demand day, is expected to be commissioned by winter 2017.
- The DTS peak day system capacity is 1,380 TJ/d without LNG and 1,500 TJ/d with LNG injections.

Background

The DTS consists of three major pipelines, and a number of laterals which supply metropolitan and regional Victoria. The major pipelines and capacities are summarised in Table 19.

Table 19 Summary of DTS pipeline capacities

Pipeline		Maximum capacity (TJ/d)	Comment
Longford to Melbourne		1,030	No change from previous years.
Victorian Northern Interconnect	To Melbourne	217	Limited to 125 TJ/d due a constraint in the New South Wales transmission network.
	To New South Wales via Culcairn	223	200 TJ/d on a 1-in-20 peak demand day.
South West Pipeline	To Melbourne	413	Excludes WTS demand. Reduces to 412 TJ/d in 2021 due to reduction in forecast 1-in-20 peak day demand.
	To Port Campbell	104	Excludes WTS demand.

4.1 Longford to Melbourne Pipeline

The LMP runs from the Esso Australia Longford Gas Plant to Dandenong City Gate (CG). It is supplied by Longford, VicHub, TasHub, and BassGas injection points.

The transportation capacity of the pipeline is 1,030 TJ/d when Longford injection pressure is 6,750 kilopascals (kPa), which is unchanged from previous VGPRs.

4.1.1 Tasmanian Gas Pipeline connection

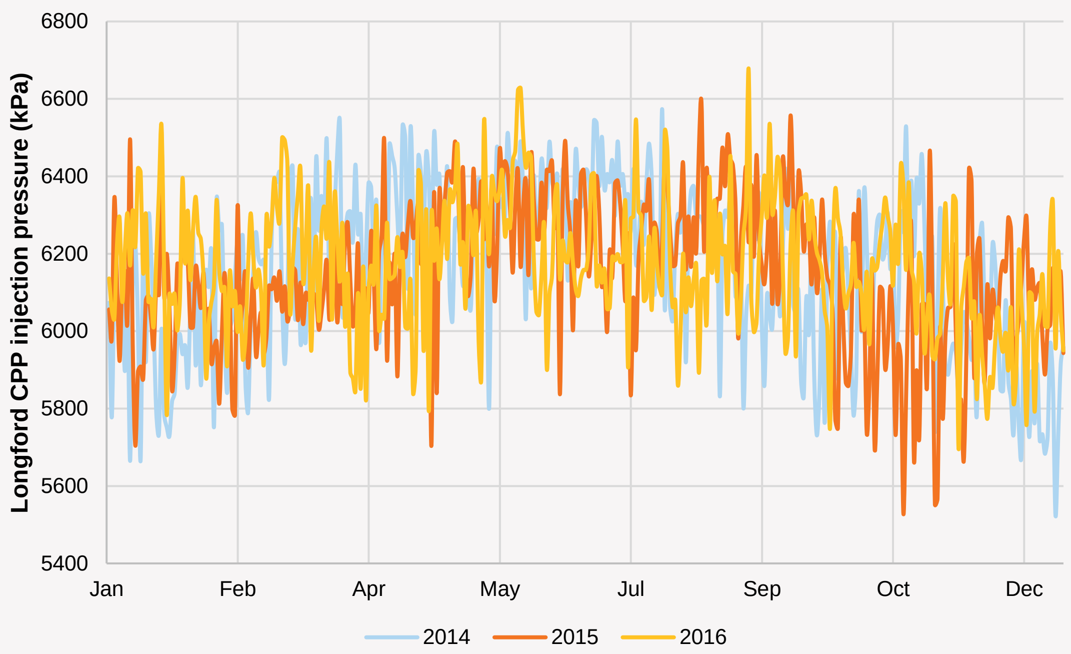
Commissioned in November 2016, the TasHub connection is a new connection to the DTS which enables injection of gas into the DTS from the TGP. TasHub has the capacity to inject 5.0 TJ/h, and up to 120 TJ/d, into the DTS.

The TasHub connection will not change the capacity of the LMP, but increases the likelihood that the LMP will reach capacity on high demand days. Increased compressor utilisation may be necessary, increasing fuel usage, to help manage pressure at the Longford Close Proximity Point (CPP)[20] and deliver gas to Dandenong CG and the Northern zone (via the outer ring main). The ramp rates of injections at the TasHub injection facility are limited, to minimise impact on Longford Gas Plant operation.

4.1.2 Longford CPP injection pressure

As discussed in Chapter 3, the Longford Gas Plant maximum injection pressure into the LMP has declined over time due to declining offshore field production. AEMO has worked with the Longford Gas Plant operator to manage the Longford injection pressures using compression at Gooding and Wollert, to reduce the occurrence of high pressure events at the Longford CPP (shown in Figure 6). High pressure events can impact Longford Gas Plant production, as Gas Plant 1 (GP1) does not have outlet compression on the connection into the LMP.

Figure 6 Historical daily maximum Longford CPP injection pressure 2014 –16



Managing the Longford CPP pressure is critical in shoulder periods. This is due to the lower injection rates and demand along the pipeline, which can limit the throughput of Gooding Compression Station (CS), as the compressors are designed for high flowrates during winter. TasHub injections will be managed to minimise impact on the Longford CPP pressure and Longford Gas Plant injections, with set ramp rates and utilisation of Gooding and Wollert compression as required.

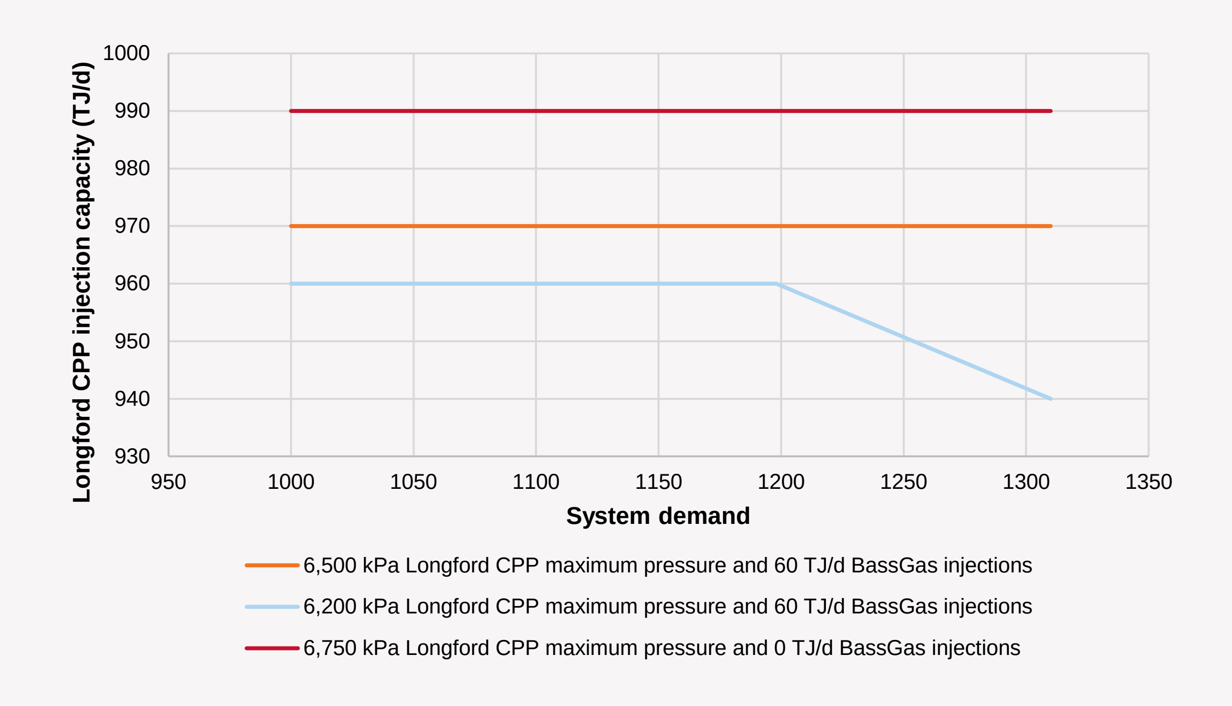
Figure 7 shows how reduced Longford injection pressure impacts injection capacity into the LMP. This modelling assessed the interactions between:

- Longford CPP injection capacity with maximum injection pressure at 6,200 kPa and 6,500 kPa, with 60 TJ/d of BassGas injections.
- Longford CPP injection capacity with maximum injection pressure at 6,750 kPa, and no BassGas injections.

[20] The Longford CPP consists of the following injection points: Longford, VicHub, and TasHub.

The base case for Longford injection pressure of 970 TJ/d at 6,750 kPa is not shown in Figure 7, because results are the same as the injection pressure case of 6,500 kPa with an LMP transportation capacity of 1,030 TJ/d for all system demands above 1,000 TJ/d.

Figure 7 Longford CPP injection capacity with varying conditions



Longford CPP injection pressure

The modelling assumed a flat injection profile of 60 TJ/d at BassGas and 970 TJ/d at Longford CPP. Modelling also included peak shaving LNG injections as required at the firm rate of 5.5 TJ/h on a 1-in-2 and 1-in-20 peak system demand day.

Analysis shows that at 6,500 kPa, the Longford CPP injection capacity remains at 970 TJ/d, however the LMP capacity is reduced once the injection pressure is limited to 6,200 kPa. The injection capacity is 960 TJ/d on a 1,000 TJ/d and a 1-in-2 peak demand day. It drops to 940 TJ/d on a 1-in-20 peak demand day.

The reduced LMP capacity is due to the inability to maintain supply into Melbourne through Dandenong CG and maintain critical system pressures.

To maintain 970 TJ/d Longford CPP injection capacity at a 6,200 kPa injection pressure, an augmentation would be required, such as:

- Additional compression, either internally at the Longford Gas Plant, or at the Longford metering station.
- Additional looping along the LMP.

Longford injection capacity with no BassGas injections

The Longford CPP injection capacity increases to 990 TJ/d without BassGas injections, as this changes the system dynamics and compressor utilisation. With no BassGas injections, the Gooding CS can operate at maximum power, which increases throughput due to lower linepack downstream of Gooding CS.

When BassGas injects into the LMP at Pakenham, this creates a back-off effect along the LMP. It increases the LMP linepack upstream of Gooding CS, which limits the throughput of the Gooding compressors.

Operation of Gooding CS

The Gooding compressors are configured as high flow, low differential pressure units. They are required to manage pressures along the LMP when Longford CPP injections are above 700 TJ/d. Due to its configuration, it is not possible to run Gooding compressors when Longford CPP injection levels are low.

If the operation of Gooding CS is not carefully managed, stopping the compressors can cause a rapid increase in Longford CPP pressure. This has the potential to reduce Longford injections and trip the Longford Gas Plant. To avoid this, Gooding compressors are typically shut down at times when pressure at the Longford CPP is not high.

Wollert CS is typically run in conjunction with Gooding CS to shift linepack into the Northern region to support demand and Culcairn exports. Wollert is configured differently to Gooding and is run at all times of the year.

4.2 South West Pipeline

The SWP is a bi-directional pipeline, which runs from the Port Campbell production facilities to Lara, then through the BLP to Brooklyn CG. It can also supply the Brooklyn to Corio Pipeline (BCP) through the Lara CG. Typically:

- In winter, the SWP flows towards Melbourne to support peak system demand days.
- In summer and shoulder seasons, the SWP flows towards Port Campbell to support Iona UGS reservoir refill and flows to South Australia via the SEA Gas pipeline.

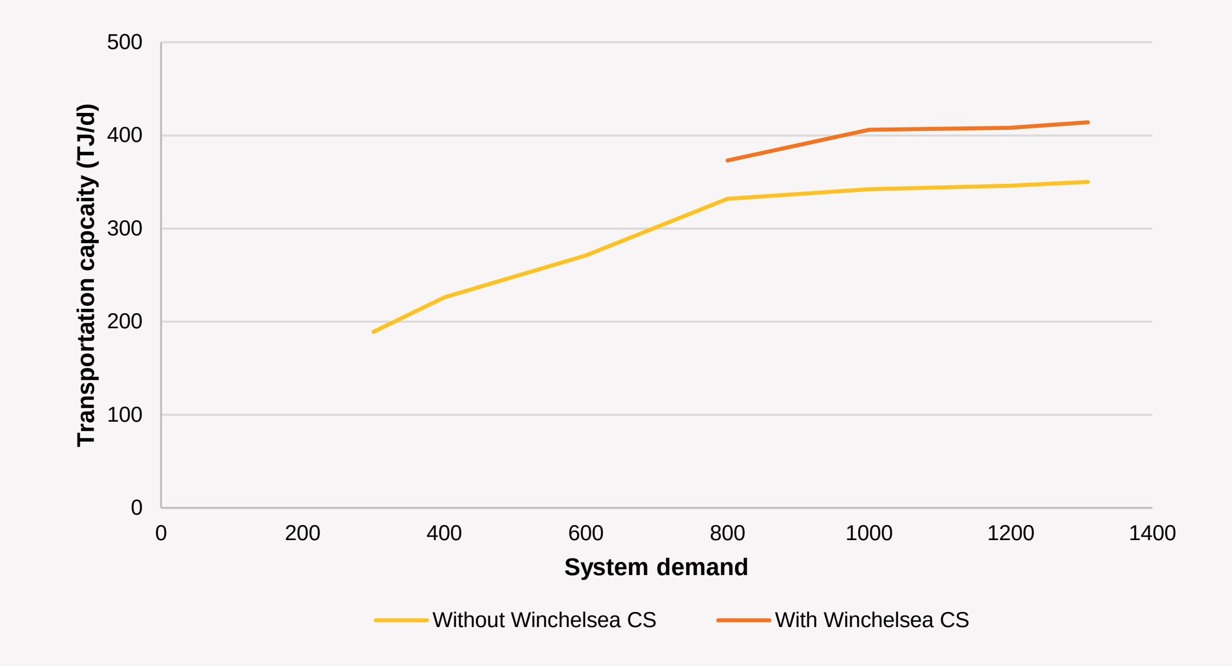
This section outlines the pipeline capacity with the current configuration of the SWP. The SWP constraint issue and expansion options are discussed in Chapter 5.

4.2.1 South West Pipeline to Melbourne

Figure 8 shows the SWP to Melbourne transportation capacity[21] with injections at the Iona CPP[22], which is dependent on system demand and therefore maximised on peak demand days. The Winchelsea CS is typically operated to increase transportation capacity on system demand days of 800 TJ/d and above.

[21] SWP transportation capacity to Melbourne is the total Iona CPP injections minus WTS demand.
[22] Iona CPP includes the following injection and withdrawal points: Iona, SEA Gas, Mortlake, and Otway.

Figure 8 South West Pipeline to Melbourne transportation capacity



The SWP transportation capacity has decreased from 429 TJ/d in 2016 to 413 TJ/d due to decline in demand by 15 TJ in the Geelong SWZ on a 1-in-20 peak demand day. The decline in demand is due to Tariff D closures in this region (see Chapter 2), and results in reduced SWP capacity for all system demand conditions.

The transportation capacity will decrease further to 412 TJ/d in 2021, due to the lower forecast 1-in-20 peak demand day (see Chapter 2).

Factors that may alter SWP transportation capacity are:

- An increase in capacity on peak demand days, with the proposed lateral to support Anglesea demand (see Chapter 5 for more information).
- A decrease in capacity with any further decreases in forecast demand on the SWP.

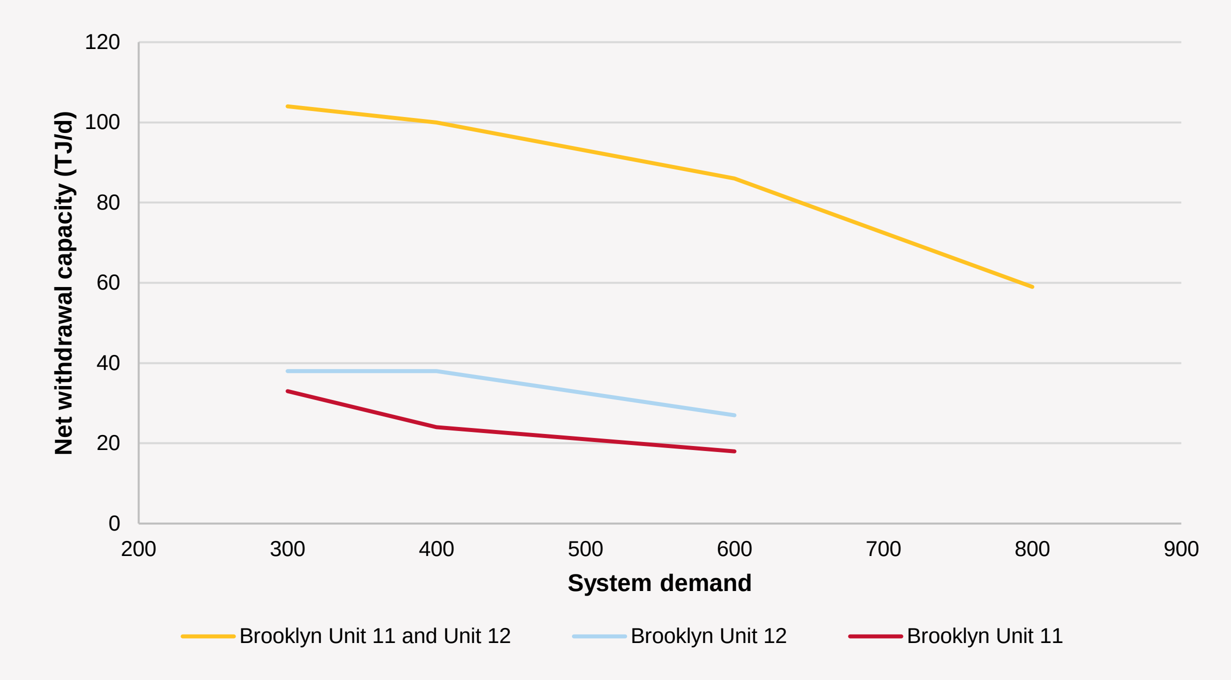
Forecast decline in WTS demand (see Chapter 2) will reduce the total Iona CPP injection capacity, however will not impact the SWP transportation capacity. Laverton North Power Station is the only unit which could increase the pipeline capacity, and only if it generates between the hours of 11:00 pm and 5:00 am. This is considered unlikely, so GPG demand is also not considered to increase SWP capacity. The system pipeline capacity is determined based on a demand profile according to the Gas Planning Approach in Appendix E.

4.2.2 South West Pipeline to Port Campbell

On a 300 TJ/d system demand day, with Brooklyn compressor station (BCS) units 11 and 12 available, the SWP net withdrawal capacity at the Iona CPP is 104 TJ/d. As system demand increases, the SWP withdrawals reduce, due to increased demand in the Geelong SWZ (Chapter 2).

Figure 9 shows SWP net withdrawal capacity with varying BCS unit availabilities.

Figure 9 South West Pipeline net withdrawal capacity at Iona CPP



The net withdrawal capacities have changed since the 2016 VGPR Update:

- There has been an increase for system demands between 300 and 400 TJ/d, due to lower demand on the SWP and WTS. This is predominately due to the closure of several Tariff D sites within the Geelong zone.
- There has been a decrease in the withdrawal capacities for system demands between 600 and 800 TJ/d. A revision of individual BCS unit powers following a review with the DTS service provider demonstrated that the available power was less than the rated power.[23] This became apparent last year, when withdrawals occurred on lower demand days during the winter period, which had previously not occurred.
- For system demand days between 600 and 800 TJ/d, Iona CS may be required to support WTS demand. If demand in the WTS decreases, this will result in an increased net withdrawal capacity, because less gas will be diverted from withdrawals to support WTS demand.

Factors that may affect the net withdrawal capacity are:

- An increase in demand on the SWP, such as proposed pipeline lateral from the SWP to Anglesea discussed in Chapter 5, which could decrease the withdrawal capacity.
- An increase in GPG demand, which will decrease the withdrawal capacity.

Impacts of gas-powered generation

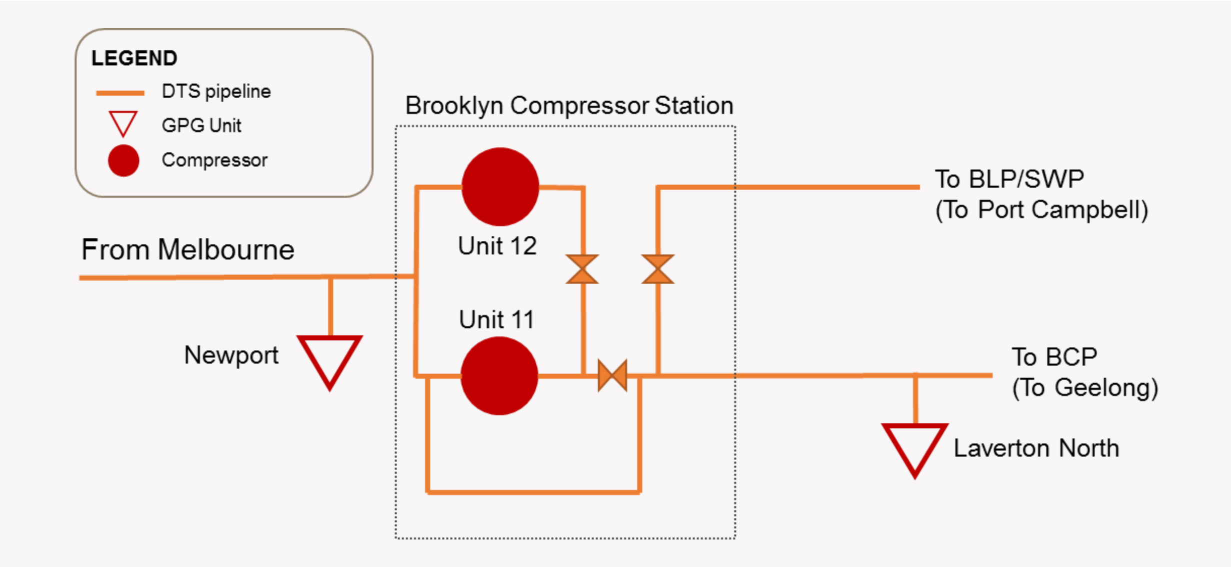
Net Iona withdrawals are impacted by Laverton North and Newport generators, due to the location and high hourly rates of the generators. The GPG offtakes, shown in Figure 10, and the impacts of GPG demand on SWP withdrawal capacity, are:

- 1 TJ of Laverton North Power Station demand reduces SWP withdrawal capacity by 1 TJ.
- 10 TJ of Newport Power Station demand reduces SWP withdrawal capacity by 1 TJ.

[23] Compressor ‘available power’ refers to the maximum power in kilowatts (kW). Compressor ‘rated power’ is the theoretical power of a compressor based on a standard set of conditions from the manufacturer.

The impact of Laverton North is due to the current configuration of BCS, as shown in Figure 10. The compressors are connected to the BCP, which then flows into the BLP once sufficient pressure has built up in the BCP. As Laverton North is connected to the BCP, while it is in operation it draws down the pressure in the BCP, which prevents flows into the BLP to support withdrawals at Port Campbell.

Figure 10 Simplified schematic diagram of current Brooklyn CS configuration



AEMO will schedule the market according to forecast GPG demand, as discussed at the August 2015 Gas Wholesale Consultative Forum.[24]

4.3 Victoria Northern Interconnect

There are two pipelines which make up the VNI:

- The original 300 mm T74 pipeline.
- The new 400 mm T119 pipeline.

Both pipelines run from Wollert to Barnawartha, and the T119 extends into the New South Wales transmission system at Culcairn.

The T74 pipeline supplies two laterals, Echuca and Koonoomoo, and the T119 pipeline supports Culcairn exports to New South Wales.

Possible impacts to VNI export capacity due to load growth are discussed in Chapter 5.

4.3.1 Victorian Northern Interconnect Phase B augmentation

Following the completion of the VNI Expansion (VNIE) Phase A project in November 2016, the DTS service provider is undertaking further Phase B works to further increase the export capacity of the VNI.

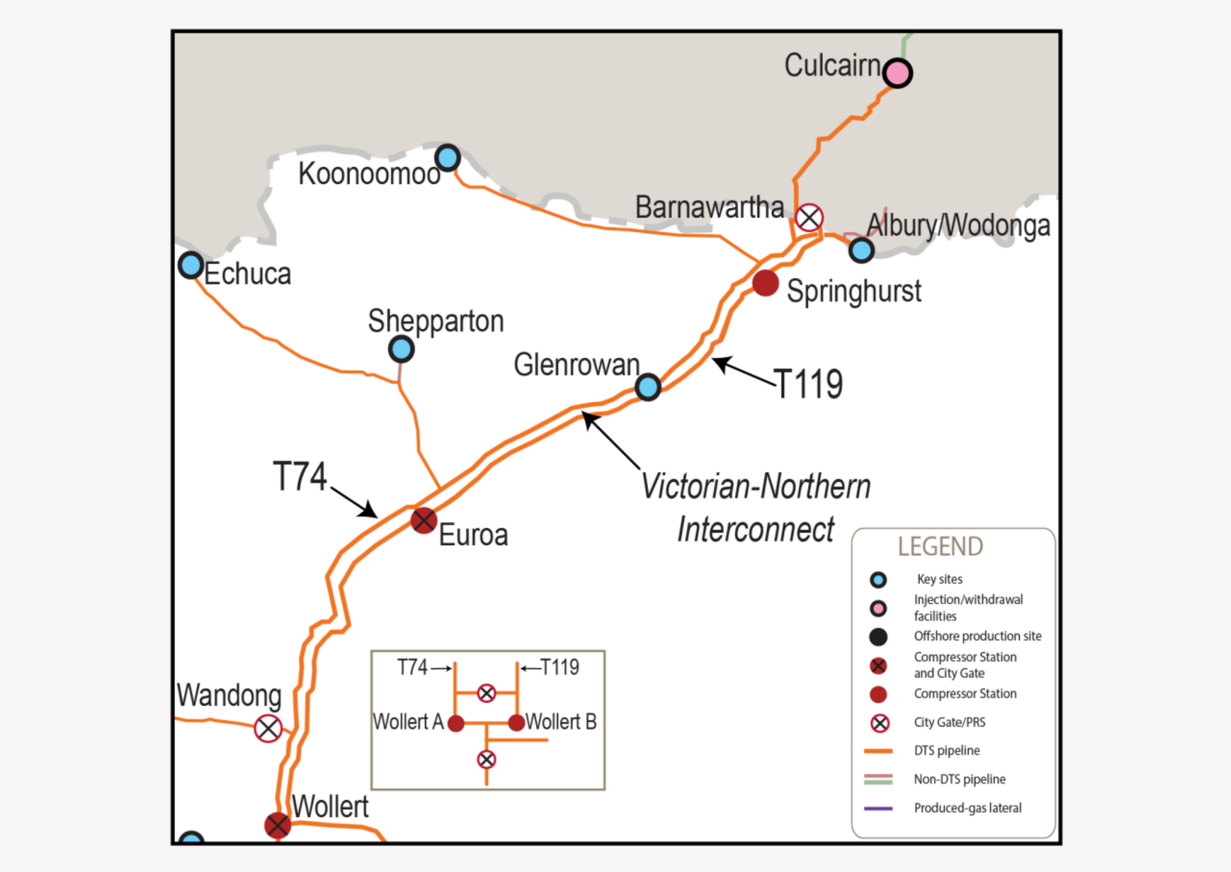
Increased capacity will be achieved by completing the VNI pipeline duplication and moving compression services onto the new pipeline, shown in Figure 11.

[24] South West Pipeline (SWP) Net Withdrawals Scheduling Methodology. August 2015 Gas Wholesale Consultative Forum minutes. Available at: http://aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Wholesale-meetings/Gas-Wholesale-Consultative-Forum.

The VNI Phase B works are expected to be completed by winter 2017, when the 1-in-20 peak system demand day capacity for:

- Exports will increase from 148 TJ/d to 200 TJ/d.
- Imports will increase from 196 TJ/d to 223 TJ/d (however, imports are limited to 125 TJ/d by the New South Wales transmission system).

Figure 11 Map of Northern zone and Victorian Northern Interconnect



The VNIE Phase B augmentation includes these works in the DTS:

- A total of 43.8 km of 400 mm pipeline duplication, completing the new separate T119 pipeline from Wollert to Barnawartha. The final stages consist of:
  - 16.2 km of pipeline between Broadford and Tallarook.
  - 27.6 km of pipeline between Glenrowan and Wangaratta North.
- Modification of the Wollert B, Springhurst, and Euroa compressor stations to operate on the T119 pipeline only.
- Installation of additional pressure reduction equipment at Wollert to allow Northern zone demand to be supported from the T119 pipeline at Wollert if necessary.
- Installation of a water bath heater at the Barnawartha Pressure Reduction Station (PRS), due to the higher pipeline pressure.
- Return of the Wollert A compressors to service, to enable compression into the T74 pipeline.

Additional pipeline expansions outside of the DTS, in the New South Wales transmission system, are also planned to complement the VNIE Phase B project.

4.3.2 Victorian Northern Interconnect to New South Wales via Culcairn

Operating conditions

The facility operator for the New South Wales transmission system north of Culcairn has advised AEMO that the Culcairn compressors[25] can support up to 172 TJ/d of exports. To support higher export capacities, Culcairn supply pressure of 8,600 kPa is required to enable free-flow gas from Culcairn to the Young hub.

The export capacity shown in Figure 12 is taken to be the higher of either:

- The capacity with a supply pressure to Culcairn greater than 8,600 kPa.
- Up to 172 TJ/d with the Culcairn compression.

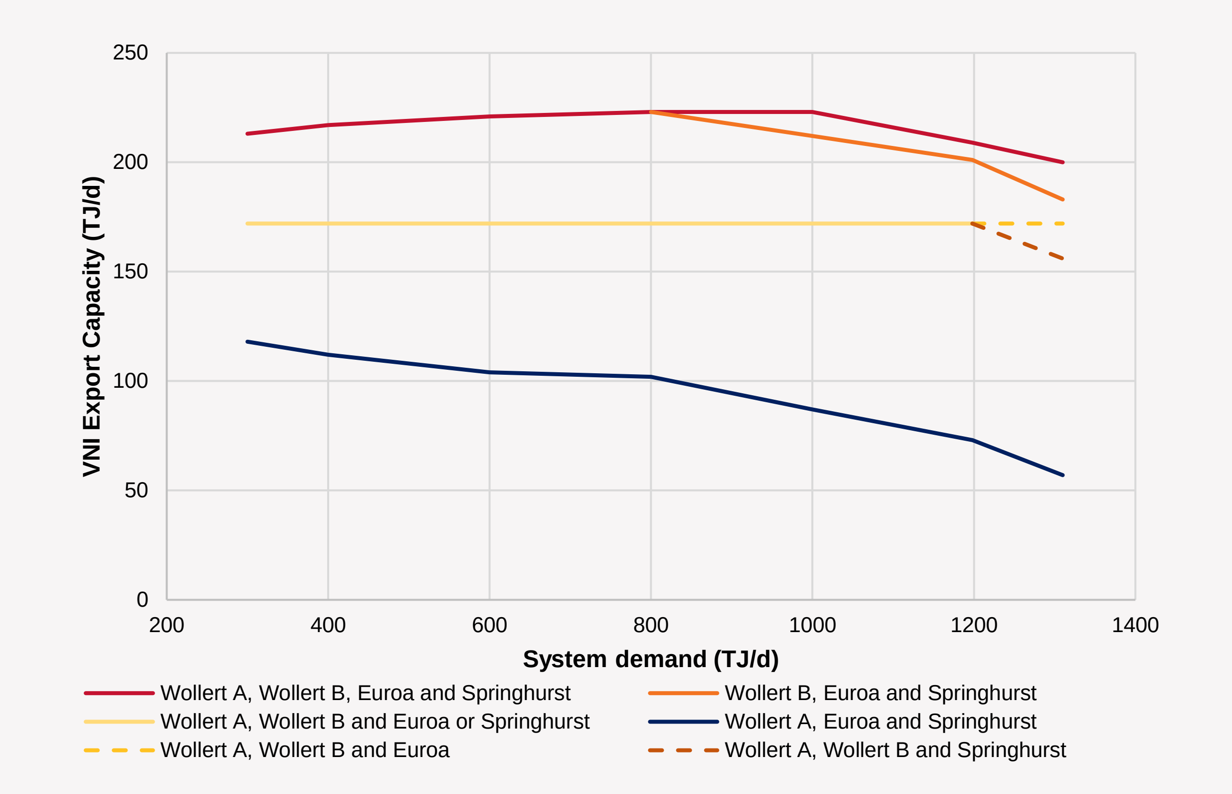
The Northern pipelines also have different operating conditions:

- The T74 pipeline will support Northern demand such as the Echuca and Koonoomoo laterals, and operate up to a maximum operating pressure of 7,400 kPa.
- The T119 pipeline will support exports to New South Wales, and operate at a maximum operating pressure of 10,200 kPa. If required, supply from the T119 to support Northern demand is possible through the Wollert PRS, Euroa PRS, or Barnawartha PRS.

Compressor availability

The VNI export capacity is dependent on the availability of the Northern compressors at Wollert A, Wollert B, Euroa, and Springhurst (more details in Appendix C). The VNI export capacity curves with varying compressors availabilities are shown in Figure 12.

Figure 12 Victorian Northern Interconnect export capacity post VNIE Phase B project



[25] Culcairn compressors are operated by the facility operator of the New South Wales transmission system.

For system demands below 800 TJ/d:

- T119 operates independently of the T74.
- T74 is supplied without Wollert compression from Longford, assuming sufficient injections.

For system demand above 800 TJ/d:

- If Wollert A compression is unavailable, supply from the T119 into the T74 through the Wollert PRS is required to support Northern zone demand, which reduces the export capacity.
- If Wollert B compression is unavailable, the export capacity is reduced by up to 70%, as it is restricted by the available flows from the Gooding CS to the Euroa CS, impacting inlet pressure at Euroa.

The facility operator for the New South Wales transmission system north of Culcairn has advised that exports of above 200 TJ/d may not be achieved, due to pressure requirements upstream of Culcairn.

Peak day supply

The primary purpose of the T119 pipeline is to support exports, and it will generally operate independently of the T74 pipeline and Northern demand, unless demand cannot be supported from the T74 pipeline alone.

On high demand days, the T74 pipeline with Wollert A compression cannot support Northern zone demand alone and additional gas must be supplied from the T119 pipeline to the T74 pipeline. This can be supplied via at the Wollert PRS, Euroa PRS, or Barnawartha PRS.

Maximum exports of 200 TJ, which require all Northern compressors on a 1-in-20 peak day, require:

- 81 TJ of LNG (equivalent to 15 hours at the firm rate of 5.5 TJ/hr).
- To support Northern demand:
  - Wollert A compression into the T74.
  - Supply from the T119 into the T74 through the Euroa PRS and Barnawartha PRS.

If LNG injections above the firm rate were required to support the export quantity, AEMO would limit the exports by reducing Wollert B compression and issuing a notice of threat to system security, consistent with the Wholesale Market System Security Procedures (Victoria). AEMO will follow the Culcairn Operational Transparency procedure[26] for scheduling LNG injections for VNI exports.

The 200 TJ/d export capacity is restricted by the inlet pressure supplied to the Wollert A and B compressors. During the evening peak, high gas demand in Melbourne draws gas quickly away from the inlet to Wollert, which limits the performance of the Wollert A and B compressors.

Load growth in key areas may also impact export capacity in future (Chapter 5 has further discussion).

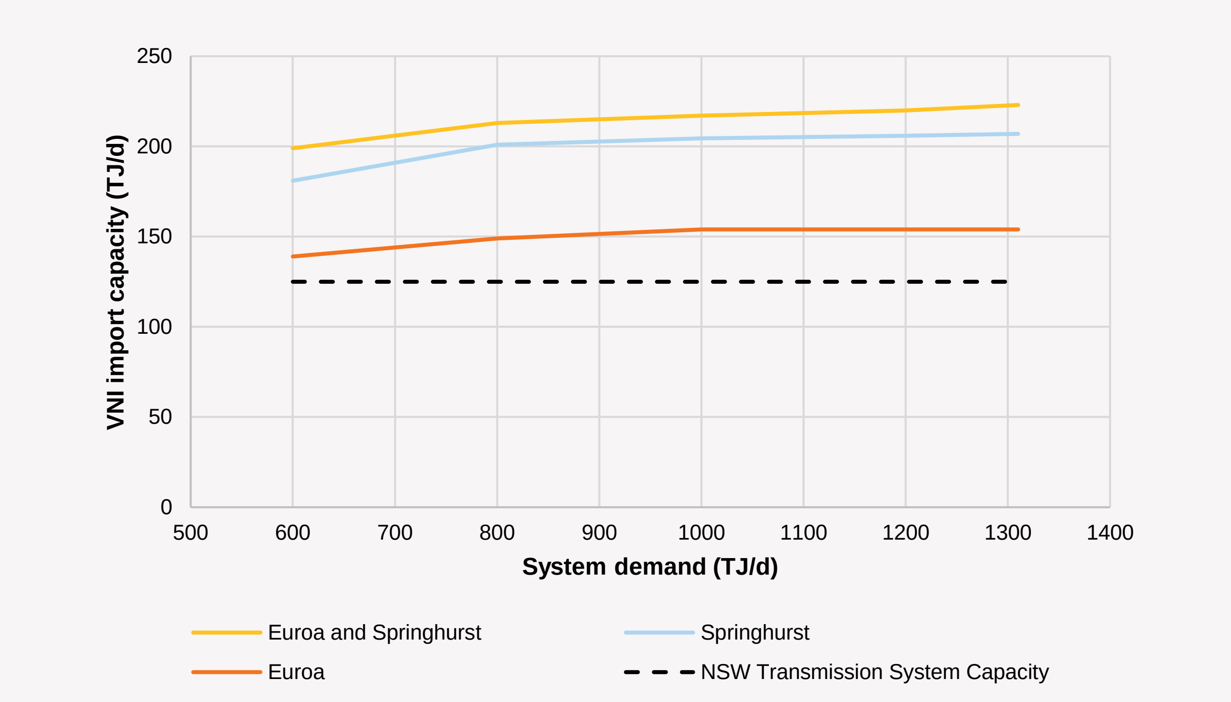
4.3.3 Victorian Northern Interconnect to Melbourne

Figure 13 shows the modelled import capacity of the VNI after the augmentations of the VNIE Phase B project are complete. The capacity curve shows the import capacity with both Euroa and Springhurst available, and also the capacity when either compressor is unavailable.

The VNI import capacities shown here assume the New South Wales transmission system north of Culcairn supplies gas at 6,500 kPa. This would require the Young – Wagga Wagga CS to be available.

[26] AEMO. Culcairn Operational Transparency. April 2011. Available at: https://www.aemo.com.au/media/Files/Other/vicwholesalegas/1000-0075%20pdf.pdf.

Figure 13 Victorian Northern Interconnect import capacity post VNIE Phase B project



The maximum VNI import capacity of 223 TJ/d is achieved on a 1-in-20 peak day demand with both Euroa and Springhurst compressor stations available. The import capacity increases with increasing system demand, because:

- Compressor power increases at lower ambient temperature.[27]
- More of the imported gas is consumed due to higher demand in the Northern zone.

With only the Springhurst compressor station available, the import capacity is reduced by 5–10%. The import capacity is reduced by 30% when only the Euroa CS is available.

As reported in the 2016 VGPR Update, the facility operator for the New South Wales transmission system north of Culcairn has advised that the injection capacity into the DTS at Culcairn through the VNI is limited to 125 TJ/d. The import capacity is further reduced if Uranquinty Power Station is operating on the Young to Culcairn pipeline, or if there is high demand off the Young to Culcairn lateral due to the increased distance from the Young – Wagga Wagga CS.

Neither pipeline looping completed in New South Wales for VNIE Phase A, nor pipeline looping to be completed for VNIE Phase B, will increase the injection capability of the New South Wales transmission system.

4.4 Peak day system capacity

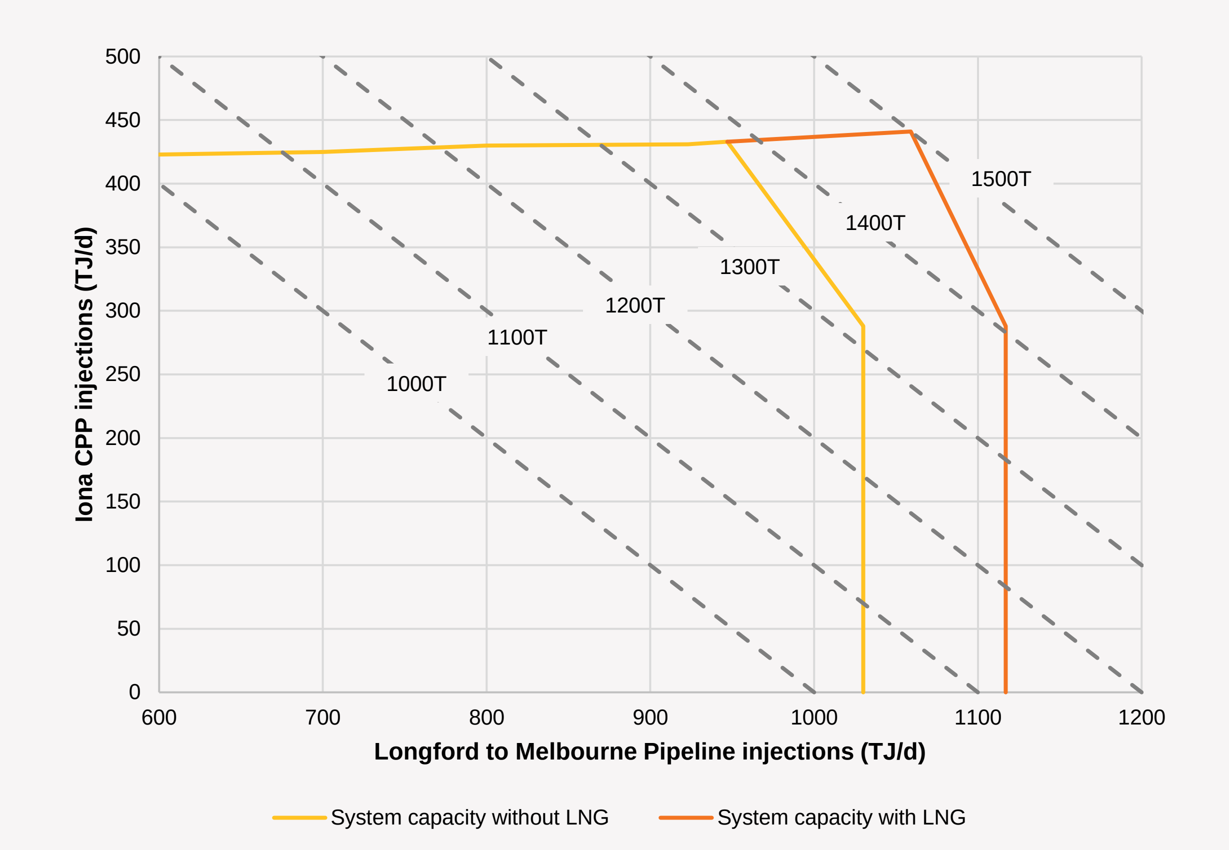
System capacity is defined as the total quantity of gas that can be injected into the DTS on a gas day. The peak day supply scenario used to determine the peak day system capacity, assumes no Culcairn import or export flows, and no GPG demand.

The system capacity shown in Figure 14 is limited by the LMP and SWP capacities. There may also be limitations when both pipelines are near their maximum flow capacity, because the LMP and SWP

[27] Solar Turbines. Gas Turbine Performance, 2005. Available at: http://turbolab.tamu.edu/proc/turboproc/T34/t34-14.pdf.

cannot operate at their maximum capacity at the same time. The area under the curve represents the feasible operating envelope for the DTS, assuming available gas supply.

Figure 14 DTS Peak day system capacity with no Culcairn export flow



For system demands above 1,310 TJ/d (the forecast 1-in-20 peak demand day), shown in Figure 14, demand is assumed to increase across all system withdrawal points. This will result in increases to the SWP demand and a higher SWP transportation capacity.

4.4.1 Without LNG

The maximum system capacity without LNG is 1,380 TJ/d. This occurs when both:

- The Iona CPP is injecting 433 TJ/d (SWP flow of 413 TJ/d, and WTS demand is 20 TJ/d).
- LMP injections are 947 TJ/d.

4.4.2 With LNG

The maximum system capacity at 1,500 TJ occurs with the following supply:

- 87 TJ/d of LNG injections at the maximum firm rate (5.5 TJ/h, as discussed in Chapter 3).
- 441 TJ/d of Iona CPP injections (SWP flow of 418 TJ/d, and WTS demand is 23 TJ/d).
- 972 TJ/d of LMP injections.

The SWP capacity is increased above the 1-in-20 capacity presented in Section 4.2 (from 413 TJ/d to 418 TJ/d), as this assumes increased demand along the SWP, BLP, and in Geelong.

If the trend of industrial closures and residential growth continues, the demand profile will become more 'peaky', as discussed in Chapter 2. A peakier profile will decrease the useable linepack in each individual pipeline, which will:

- Reduce the capacity to deliver gas to Melbourne, as discussed in Chapter 5.
- Impact the ability to support GPG demand, which also tends to be peaky, as discussed in Chapter 5.

4.4.3 Culcairn flows

Culcairn import and export flows have the following impact on system capacity:

- Culcairn exports decrease the system capacity at a ratio of approximately 1:1, shifting the operating boundary in Figure 14 to the left.
- Culcairn imports increase the system capacity, however imports will alter the pipeline interactions causing a back-off effect on the other pipelines. Therefore the system capacity would not be the sum of the three pipeline capacities.[28]

[28] It is not expected that the completion of the VNIE project (see Chapter 4.3) would increase the system capacity, due to a restriction on Culcairn imports in the New South Wales transmission system.

CHAPTER 5. DECLARED TRANSMISSION SYSTEM ADEQUACY

Preface

This chapter outlines AEMO's assessment of the system adequacy of the DTS. If a constraint is identified, AEMO evaluates the system impacts including potential threats to system security, security of supply, and system capacity constraints.

Key findings

- Refilling of Iona UGS for winter 2018 is uncertain and unlikely for each subsequent winter from 2019 onwards. This is due to the existing SWP capacity limitation towards Port Campbell and a decline in gas production.
  - Expansion of the SWP capacity towards Port Campbell is required, to ensure Iona UGS is refilled prior to winter 2019. Failure to refill Iona UGS during summer 2018–19 may result in Victorian gas supply shortfalls during winter 2019. AEMO has identified this as a threat to system security.
  - Increased Laverton North GPG forecast demand over the outlook period will further reduce SWP flows to Port Campbell, impacting the refilling of Iona UGS and flows to South Australia via SEA Gas.
- Expansion work is required to support increased large commercial and residential demand in Warragul. AEMO forecasts show that if investment is not implemented by winter 2019 to support these demand increases, there is a high likelihood of Tariff D curtailment on a peak system demand day. AEMO has identified this as a threat to system security.
- Forecast GPG demand is supportable over the outlook period. Peak shaving LNG injections may be required on 1-in-20 peak demand days to support critical system pressures.
- Changing load profiles due to an increase in Tariff V (residential) demand in the outer Melbourne Metro region may require future investment in pipeline infrastructure.
- System linepack adequacy is critical in supporting GPG demand and the changing load profile of the DTS.

5.1 South West Pipeline

The SWP is a bi-directional pipeline that runs from the Port Campbell production facilities to Lara, then through the BLP to Brooklyn CG. It can also supply the BCP through the Lara CG. Typically:

- In winter, the SWP flows towards Melbourne to support peak system demand days.
- In summer and shoulder seasons, the SWP flows towards Port Campbell to support Iona UGS reservoir refill, and flows to South Australia via the SEA Gas Pipeline.

5.1.1 South West Pipeline to Port Campbell

Historical flows to Port Campbell

In 2016, there was a total 11 PJ of net withdrawals to Port Campbell from Melbourne on the SWP, which led to increased compressor utilisation[29] and fuel usage.

Participants used available capacity to withdraw gas at Port Campbell during winter and shoulder periods shown in Figure 15, either to maintain storage levels or support flows to South Australia via the

[29] See Appendix C for information on compressor utilisation.

SEA Gas Pipeline. This required Iona compression to support demand on the WTS during winter and shoulder periods, discussed in Section 5.1.2.

Figure 15 Historical SWP flows to Port Campbell during June to December 2014–16

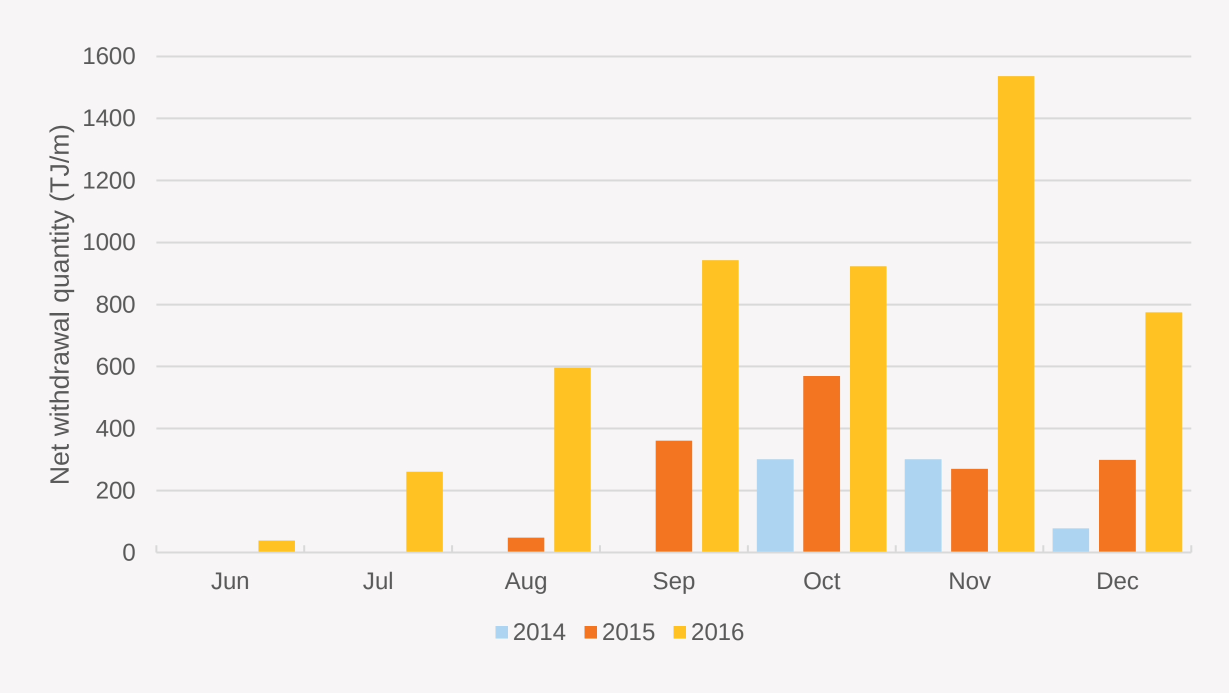


Figure 15 shows, year by year, that market participants are seeking to commence withdrawals earlier, and even during winter. In 2015, the withdrawals were restricted during November and December due to the Brooklyn CS aftercooler failure. In December 2016, withdrawals were reduced due to the SWP pipeline inspection (pigging) project and ongoing Longford maintenance reducing the overall availability of gas.

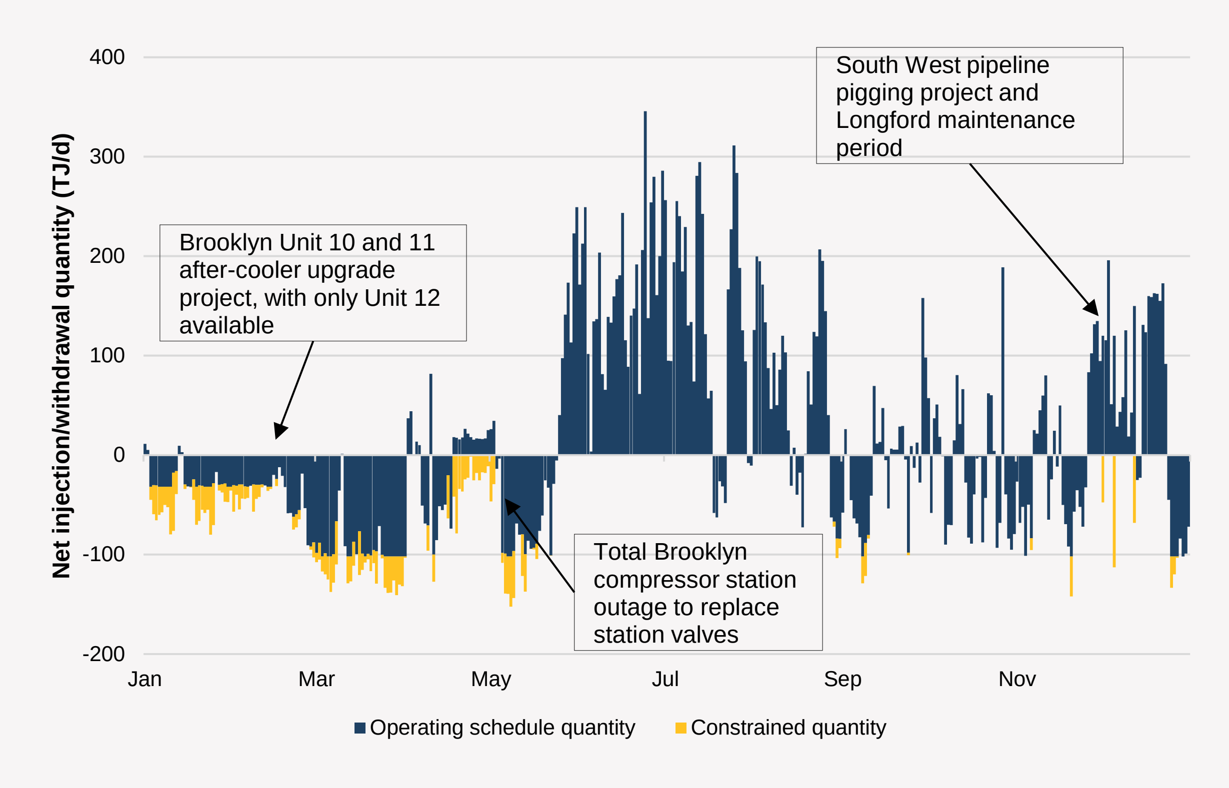
In 2016, there were 114 days with constraints applied at the Iona CPP for SWP net withdrawals to Port Campbell. Figure 16 displays those constraints, and demonstrates the difference between what market participants would have been scheduled to withdraw without a constraint, and what was physically possible.

- The ‘operating schedule quantity’ is the net withdrawals which are physically possible according to the operating schedule (OS) for the DWGM.
- The ‘constrained quantity’ is the difference between the pricing schedule (PS) and the OS at the 6:00 am DWGM schedule.

The constrained values presented in Figure 16 reflect the daily constrained quantities at the 6:00 am DWGM schedule, and do not consider the intraday schedules.

Net flows to Port Campbell in 2016 were impacted by planned project outages by the DTS service provider, unexpected plant trips, and producer maintenance, which limited net withdrawals during those periods.

Figure 16 Net injection and withdrawal quantities in 2016



Projected flows to Port Campbell

Based on forecasts provided to AEMO by market participants in September 2016[30], the projected Port Campbell mass balance between supply and demand is shown in Figure 17. This assumes all gas produced in Port Campbell flows either:

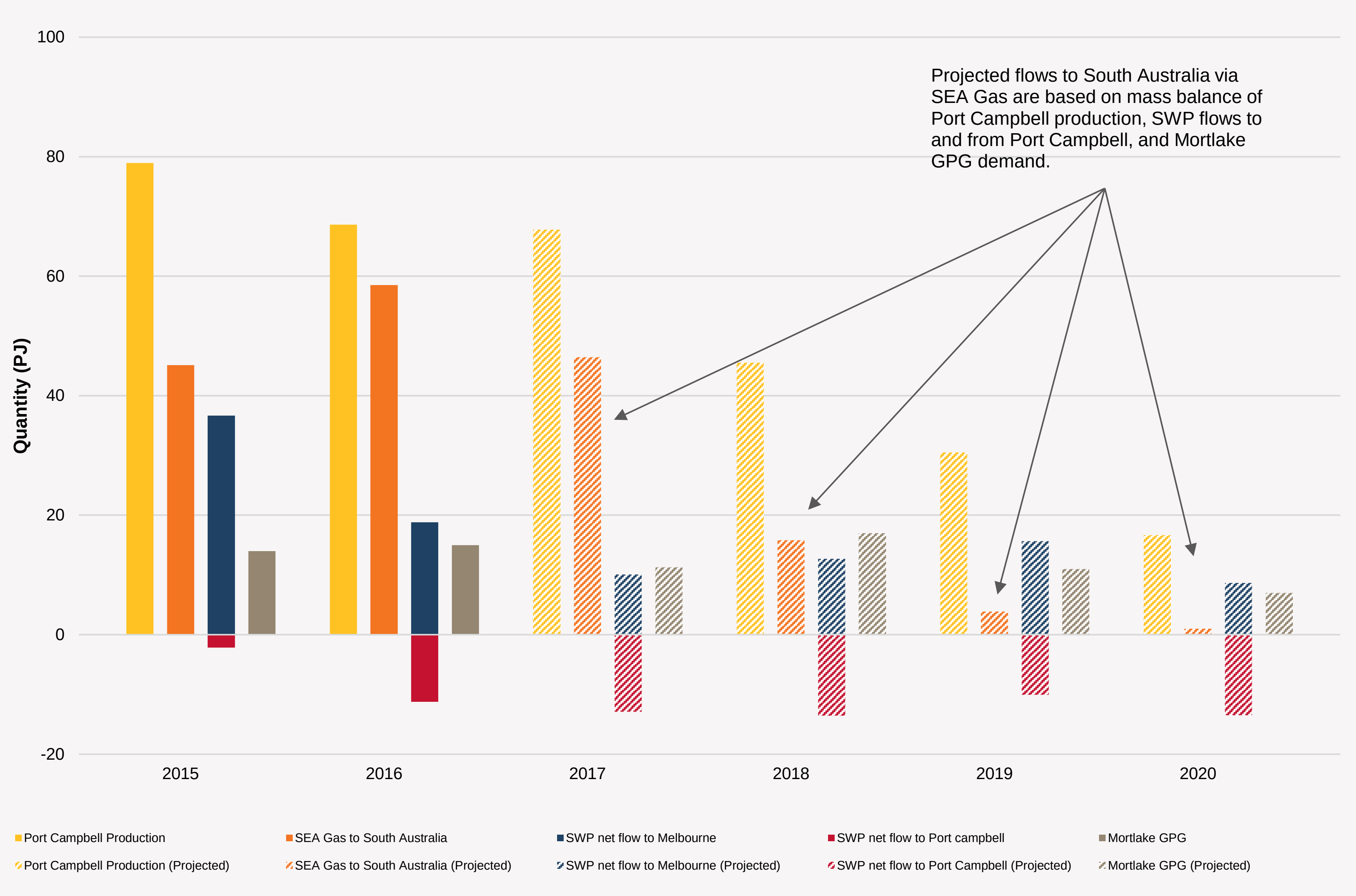
- Directly into the SWP, SEA Gas Pipeline, or to the Mortlake Power Station pipeline.
- Directly into the Iona UGS storage reservoirs. Iona UGS can supply gas into any of the above three pipelines.

The projections in Figure 17 show that:

- Port Campbell production is declining over the outlook period, even with the commencement of Halladale Speculant Project shown as the production increase in 2017.[31]
- Projected flows to SWP net withdrawals to either refill Iona UGS reservoirs, or to support flows to South Australia via SEA Gas.
- Projected flows to South Australia via SEA Gas shown are based on a mass balance of Port Campbell production, SWP transportation capacity, and Mortlake GPG demand. If higher flows to South Australia are required, reduced Mortlake GPG or winter gas supply will be available for Victoria without expansion of the SWP transportation capacity towards Port Campbell.
- The Mortlake GPG demand forecast is based on the updated GPG forecasts utilising the NTNDP[32] forecasting methodology.

[30] Values submitted by market participants exclude possible pipeline constraints.
[31] Origin Energy. "Halladale/Speculant Comes Online", 2016. Available at: https://www.originenergy.com.au/about/investors-media/media-centre/halladale-speculant-comes-online.html.
[32] AEMO. 2016 NTNDP. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

Figure 17 Port Campbell supply – demand balance from 2015–20, based on market participant data submissions



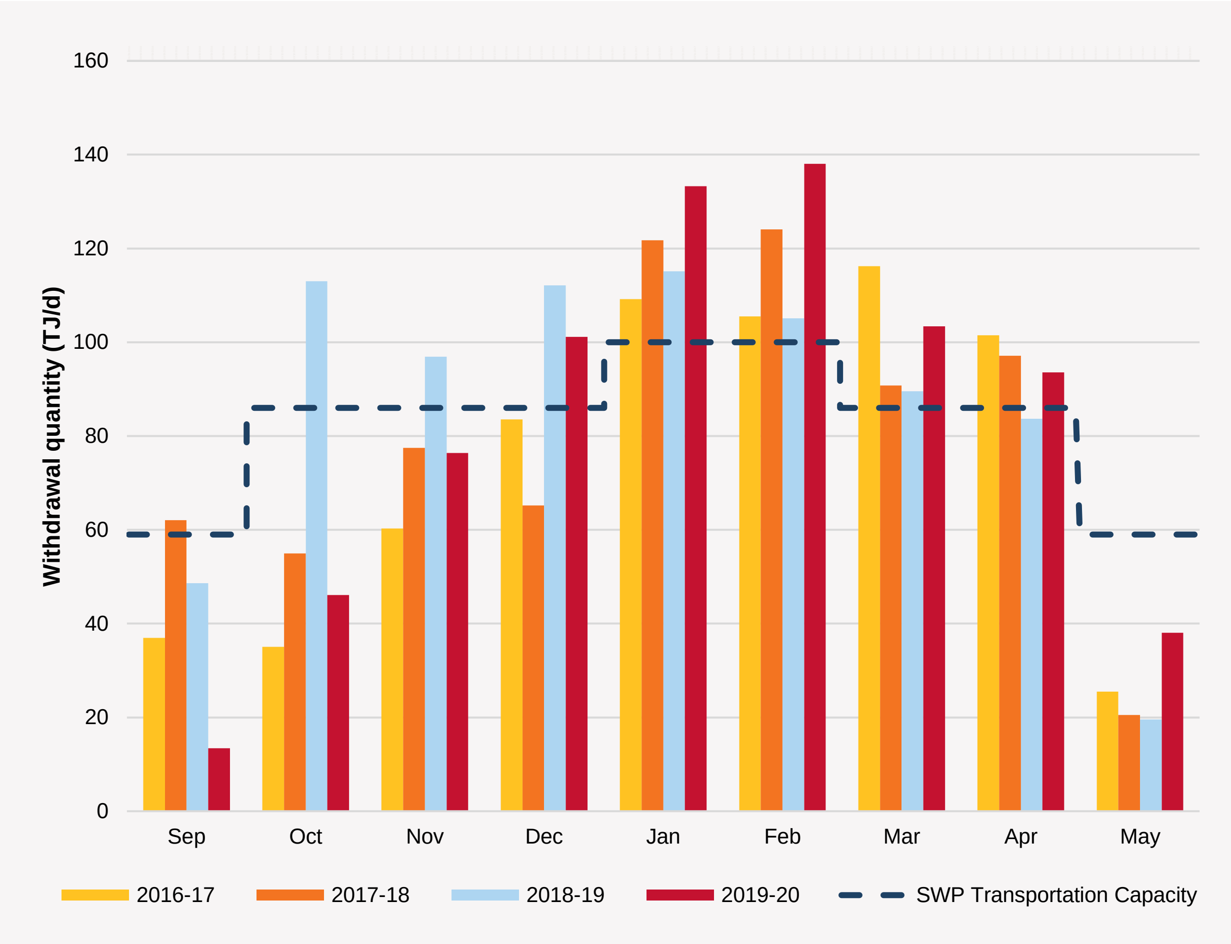
System adequacy

The projected daily SWP withdrawals for the outlook period, shown in Figure 18, are based on forecasts provided to AEMO by market participants in September 2016. The projected daily withdrawal quantity averaged by month accounts for:

- DTS equipment outages, as outlined in Chapter 6, which are assumed to be similar over the outlook period.
- Possible summer GPG demand at Laverton North or Newport impacting SWP withdrawal capacity as discussed above.

It does not include planned facility outages (such as Iona UGS maintenance, or reduced Longford capacity), as this does not impact SWP transportation capacity.

Figure 18 South West Pipeline projected daily withdrawal quantity over the outlook period



These flows represent Iona UGS and SEA Gas flows. Data submissions for 2020–21 were incomplete, so were excluded from analysis. Actual data was used for Sep–Dec 2016, averaged by days of the month.

Figure 18 shows that for the outlook period:

- The current SWP withdrawal capacity (using BCS units 11 and 12) is inadequate to support forecast withdrawals from 2017 onwards during the summer periods of January to March. This is expected to impact the pre-winter Iona UGS inventory and utilisation of storage capacity for winter 2018.

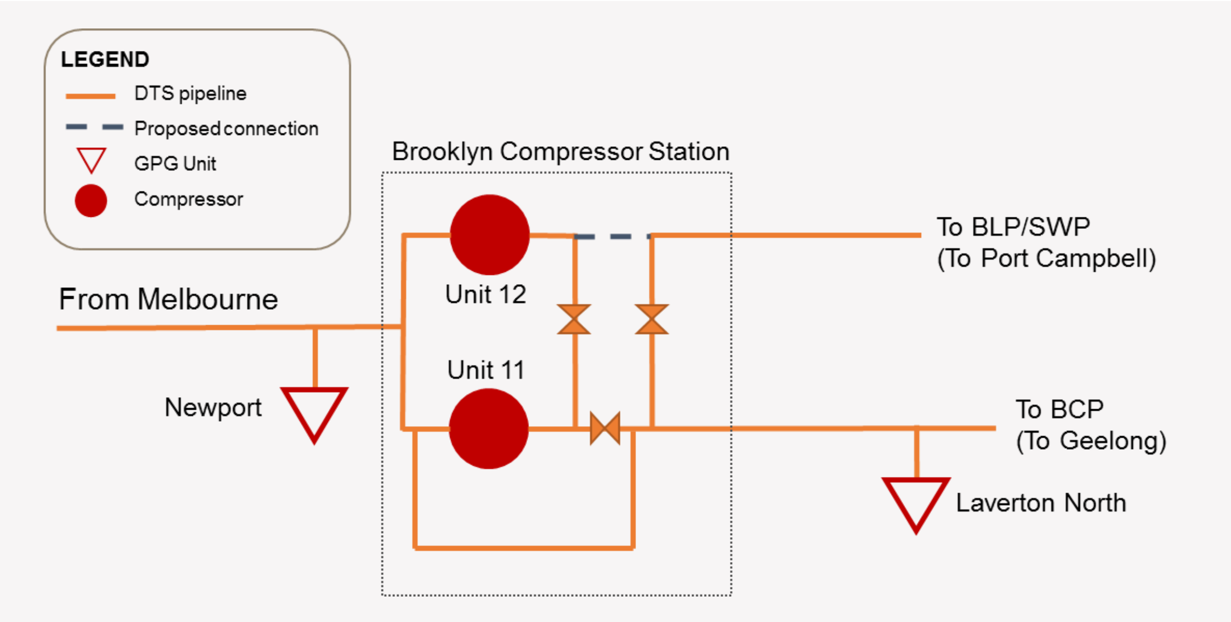
- The inability to refill the Iona UGS reservoirs prior to winter is a threat to system security. If storage is emptied before the end of winter, or lower levels impact supply capacity, this would result in gas supply shortfalls on winter peak days.

Future developments

The DTS service provider has assessed the augmentation options presented in the 2016 VGPR Update and proposed an augmentation in the 2018–22 Access Arrangement, to be completed during 2018. Subject to approval, the proposed augmentation involves:

- Reconfiguration of the BCS, shown in Figure 19, to enable concurrent compression into the BLP and BCP, to support flows to Port Campbell and Laverton North generation separately if required.
- Bi-directional compressibility at Winchelsea CS.

Figure 19 Simplified schematic of the BCS reconfiguration



AEMO has modelled the capacity for the proposed augmentations. Figure 20 shows the proposed augmentations will increase the net withdrawal capacity with BCS Unit 11 and Unit 12 available, from 104 TJ/d to either:

- 139 TJ/d on a 400 TJ system demand day if Winchelsea CS minimum inlet pressure is 4,500 kPa.
- 147 TJ/d on a 400 TJ system demand day if Winchelsea CS minimum inlet pressure is 4,000 kPa.

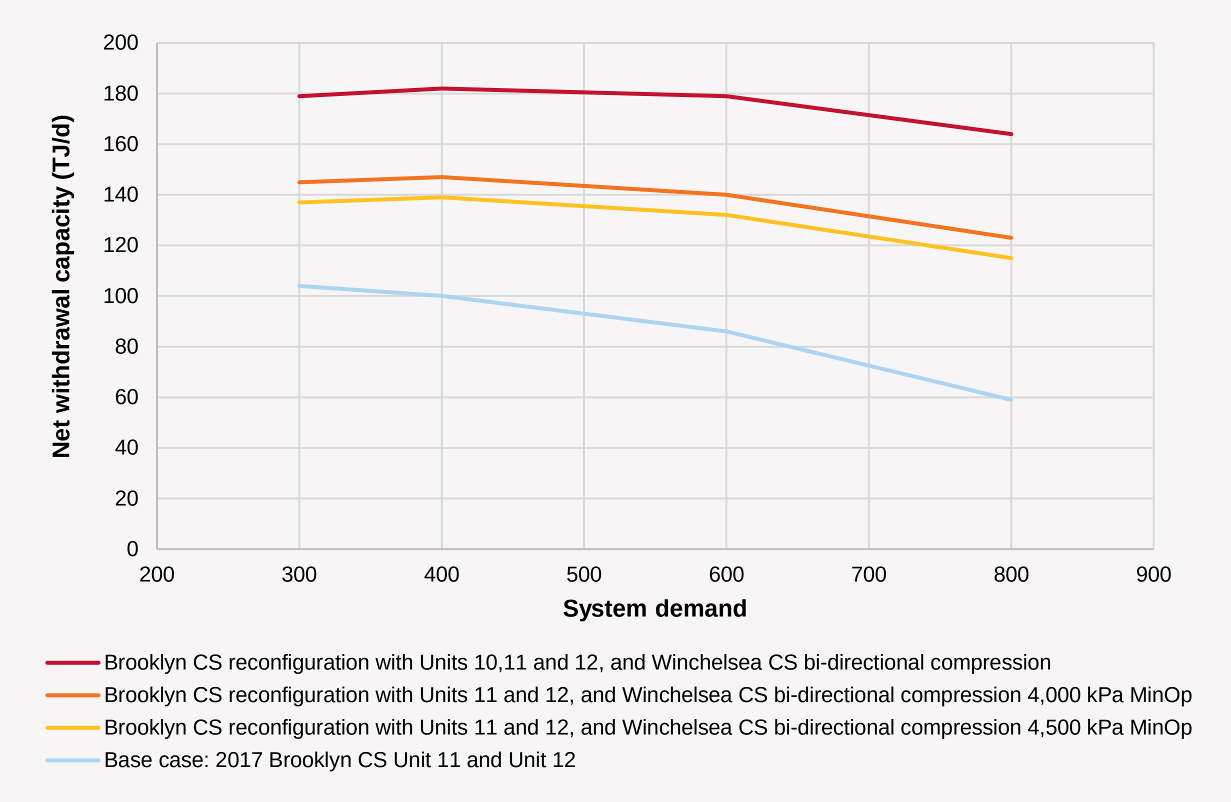
The current minimum inlet pressure in the Service Envelope Agreement[33] for the Winchelsea CS is 4,500 kPa. AEMO and the DTS service provider will work through the engineering requirements to determine an achievable inlet pressure. The lower the Winchelsea CS inlet pressure, the greater increase in SWP to Port Campbell net withdrawal capacity.

The augmentation will also reduce the impacts of GPG demand, discussed in Chapter 4. The augmentation will enable:

- Unit 11 to flow into the BCP to support Laverton North demand.
- Unit 12 to flow into the BLP to support SWP withdrawals at Port Campbell.

[33] APA. APA VTS - SD - APAVTS&AEMO - Service Envelope Agreement Revision - 29130813 - Public.pdf. Available at: https://www.aer.gov.au/system/files/Supporting%20Material%20-%201%20-%20Introduction%20-%20Public.zip.

Figure 20 Net withdrawal capacity with Brooklyn reconfiguration project



Withdrawals at other facilities

Existing Port Campbell facilities could also withdraw gas from the SWP and a new facility could be developed to do this. Having additional facilities withdrawing gas from the SWP at Port Campbell would further exacerbate the pipeline capacity issue that is impacting Iona UGS refilling.

The operator of the Otway Gas Plant[34] has advised AEMO that they intend to trial SWP withdrawals during April 2017. No further details have been provided.

AEMO will continue to monitor and manage SWP withdrawals, including assessing actual and potential impacts on system security.

5.1.2 Western Transmission System

System adequacy

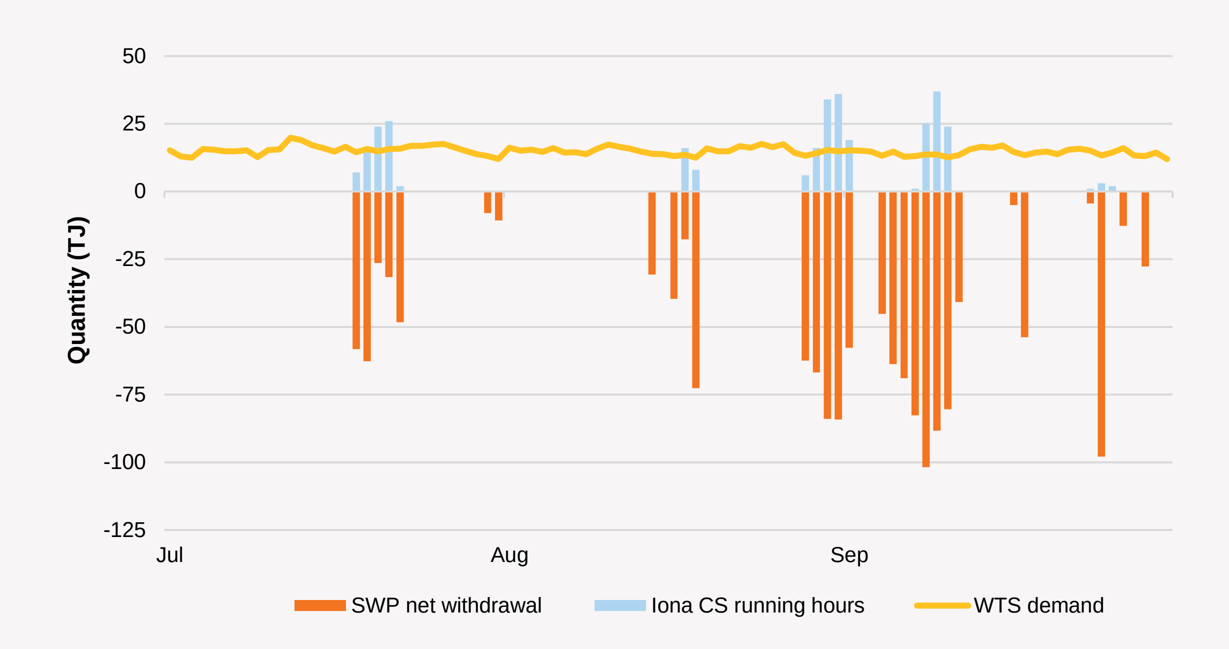
There are no system adequacy issues in the WTS. AEMO has observed an increase in Iona CS usage during shoulder periods when there are net withdrawals at the Iona node, as shown in Figure 21.

AEMO utilises all available linepack in the WTS when it is appropriate to do so, prior to operating Iona CS. The Iona CS is required to ensure adequate pressures at the fringe locations, such as Portland (which includes the Portland aluminium smelter demand), and to support the high Tariff D dairy load in the region during the spring months.

The weather can also be colder in the South West region compared to other regions of the DTS during shoulder and winter periods, therefore Tariff V demand in the area needs to be monitored to prevent interruptions to supply.

[34] The Otway Gas Plant currently only injects into the DTS, but is registered for injection and withdrawals.

Figure 21 Comparison of WTS demand, SWP net withdrawals, and Iona CS running hours for winter 2016



5.1.3 South West Pipeline to Melbourne

Historical flows to Melbourne

The SWP capacity towards Melbourne is typically used during winter to manage peak day supply.

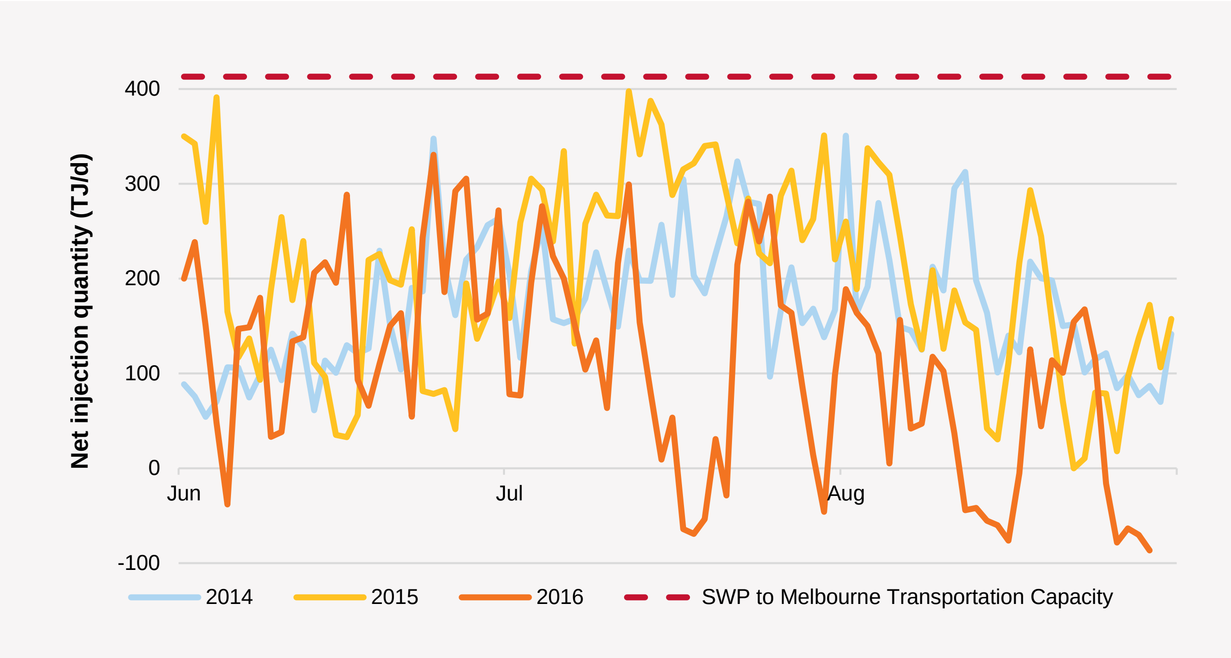
Historical flows to Melbourne, shown in Figure 22, highlight that the flows towards Melbourne decreased in 2015 and 2016. This can be attributed to:

- Tight supply demand balance in the east coast gas markets, with increased flows to South Australia via SEA Gas from the Port Campbell region.
- Market participants managing low Iona UGS storage inventory in winter 2016, by sourcing other gas supplies such as increasing Longford injections and VNI imports into the DTS.
- SWP net withdrawals during winter 2016, discussed in Section 5.1.1, to either supply South Australia or refill storage inventory.

The Winchelsea CS was commissioned in 2015, increasing the SWP capacity from 367 TJ/d to 413 TJ/d.[35] The compressor has been utilised to manage system linepack and supply Melbourne during peak demand periods (morning and evening), and has been scheduled at the maximum hourly capacity for short periods during 2015 and 2016.

[35] SWP transportation capacity has decreased from 429 TJ/d to 413 TJ/d, as discussed in Chapter 4.

Figure 22 Historical Iona CPP injections into the SWP during June to August 2014–16



System adequacy

Based on forecasts provided to AEMO by market participants in September 2016, no system adequacy issues are expected for flows on the SWP to Melbourne.

If there is increased GPG in the Port Campbell region or increased flows to South Australia via the SEA Gas Pipeline, this will reduce the available flows to Melbourne. Participants will need to manage their gas portfolios to ensure there is sufficient gas supply to Melbourne during those periods.

Future developments

As discussed in Chapter 3, to fully utilise the proposed expansion of Iona UGS total injection capacity from 390 TJ/d to 570 TJ/d, an expansion of the SWP capacity towards Melbourne would be required. The projected production decline in the Port Campbell region makes it less likely that pipeline injections will be constrained.

The 2016 VGPR Update reported three possible options to support increased SWP flows to Melbourne:

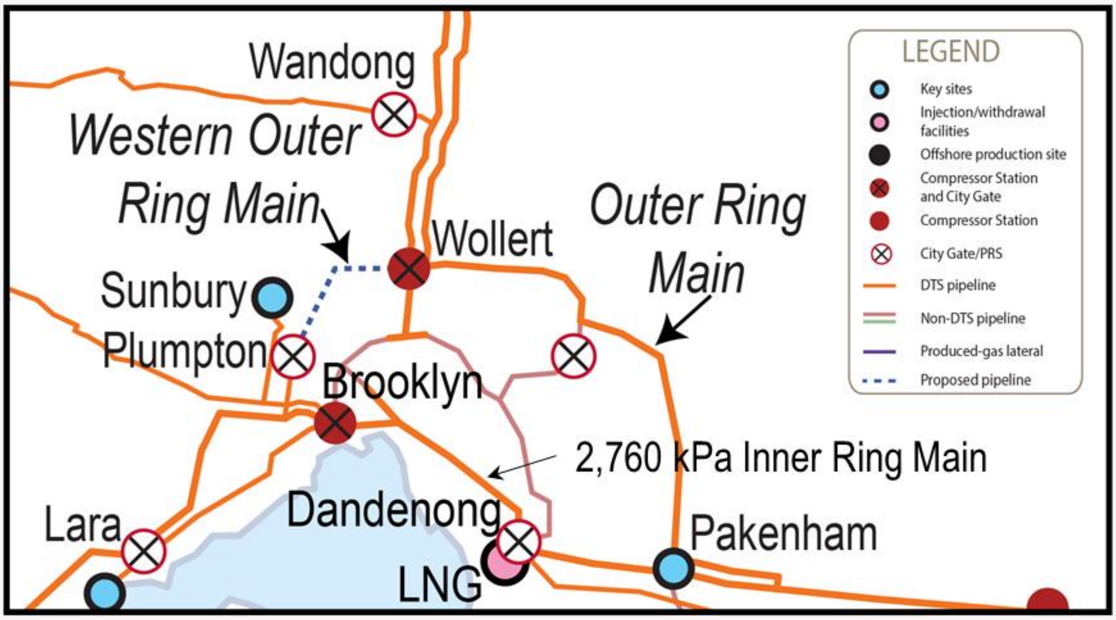
- Operational pressure reduction at Dandenong CG (Option 1). This option:
  - Can only be maintained during summer months, when flows are expected to flow from Melbourne to Port Campbell.
  - Requires agreement from distributors to lower connection pressures during shoulder and winter periods.
- Additional mid-line compression on the SWP (Option 2) with potential locations at:
  - Stonehaven, located upstream of Lara CG.
  - Lara, located downstream of Lara CG.
- Addition of the Western Outer Ring Main (WORM, Option 3), discussed in Section 5.1.4.

5.1.4 Western Outer Ring Main (WORM)

The Western Outer Ring Main (WORM) is a proposed pipeline that extends the SWP and BLP from Plumpton to Wollert, shown in Figure 23.

Currently, gas from the SWP to Melbourne is limited to what flow is achievable into the low pressure (2,760 kPa) inner ring main network at Brooklyn CG. The WORM would provide an alternative route for gas flow from the Iona CPP to flow into the Northern and Gippsland regions. This would support supply into these regions during Longford outages or maintenance periods.

Figure 23 Proposed WORM pipeline



The DTS service provider previously highlighted that the WORM *'reduces exposure to a major supply source trip'* in the 2013–17 Access Arrangement submission[36], and has proposed to secure the pipeline easements in the 2018–22 Access Arrangement[37] submission.

Addition of the WORM to the DTS would allow AEMO to better manage system security, as it:

- Provides additional linepack close to the Melbourne region to support the changing load profile and support increased levels of GPG (Chapter 2 and Section 5.3).
- Reduces the level of curtailment (if any) required during a supply interruption by increasing available linepack.
- Reduces peak shaving LNG requirements during high demand periods by providing increased supply to metropolitan Melbourne through Wollert CG and Dandenong CG.

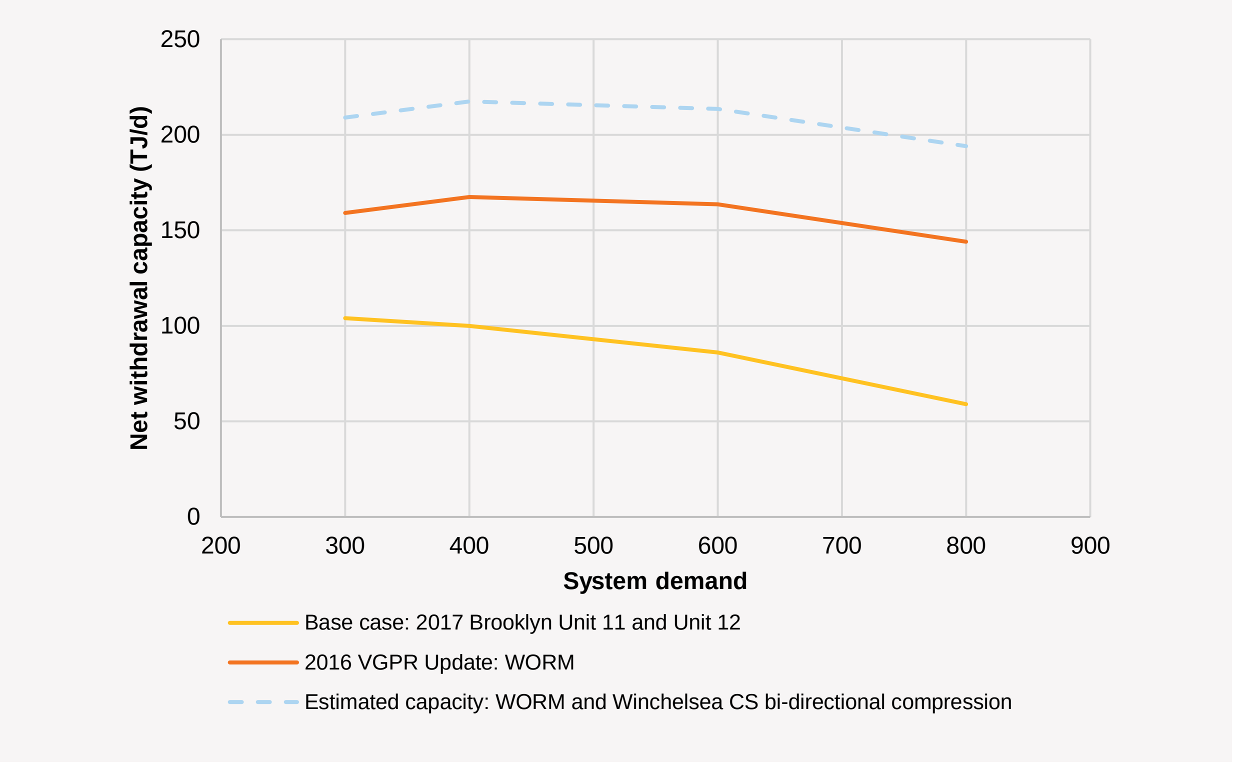
As discussed in the 2016 VGPR Update[38], the WORM would increase the SWP transportation capacity to Port Campbell (shown in Figure 24), and to Melbourne (shown in Figure 25).

[36] APA. *APA GasNet Access Arrangement Submission*. 2012. Available at: https://www.aer.gov.au/system/files/APA%20GasNet%20submission%20- %20public%20-%20March%202012.pdf.
[37] APA. *APA GasNet Access Arrangement Submission*. 2016. Available at: https://www.aer.gov.au/system/files/APA%20VTS%20-%20VTS%20Revision%20Proposal%20submission%20-%2020170103%20-%20Public.pdf.
[38] AEMO. 2016 VGPR Update. Available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Victorian-Gas-Planning-Report-Update.pdf.

Benefits of the WORM from Melbourne towards Port Campbell

Figure 24 shows the current transportation capacity towards Port Campbell, compared to the base case of the WORM with no other augmentations. The proposed Winchelsea CS bi-directional augmentation, discussed in Section 5.1.1, is expected to increase the SWP to Port Campbell transportation capacity with the WORM by an additional 50 TJ/d. Therefore, with the WORM, a compressor at Wollert CS, and the Winchelsea bi-directional augmentation, the transportation towards Port Campbell would be approximately 220 TJ/d.

Figure 24 SWP to Port Campbell capacity with the WORM



The current method of transporting gas from Longford to Port Campbell is very inefficient. Gas flows along the Longford to Melbourne Pipeline to Dandenong CG. During the summer the pipeline pressure is approximately 5,500 kPa. At Dandenong CG, the pressure has to be reduced to 2,760 kPa to flow through the low pressure transmission network from Dandenong to Brooklyn. At Brooklyn, the gas is recompressed to approximately 6,500 kPa (which is limited by the capacity of the Brooklyn compressors) to flow along the BCP, BLP, and SWP towards Port Campbell.

With the WORM, gas would flow from Longford to Wollert via the existing (Eastern) Outer Ring Main. At Wollert, the pressure during summer would be approximately 5,500 kPa (similar to that at Dandenong CG). A compressor at Wollert would boost the gas pressure up to 10,200 kPa to flow around the 500 mm diameter WORM. The WORM would connect into the BLP, which would enable gas to flow to Port Campbell via the SWP.

During the 2015–16 financial year, the Brooklyn compressors consumed approximately 331 TJ of fuel gas. Brooklyn CS had the DTS's highest contribution to AEMO's reporting under the National Greenhouse and Energy Reporting Scheme (NGERS). Assuming a wholesale gas price of $8.50/GJ, 311 TJ of fuel gas translates to a cost of approximately $2.8 million per year for market participants. As the quantity of gas transported from Longford to Port Campbell increases, and if gas prices continue to increase, this fuel gas cost will also continue to increase.

With the installation of the WORM, half the fuel gas will be required, compared to the current quantity used for transportation via Brooklyn CS.

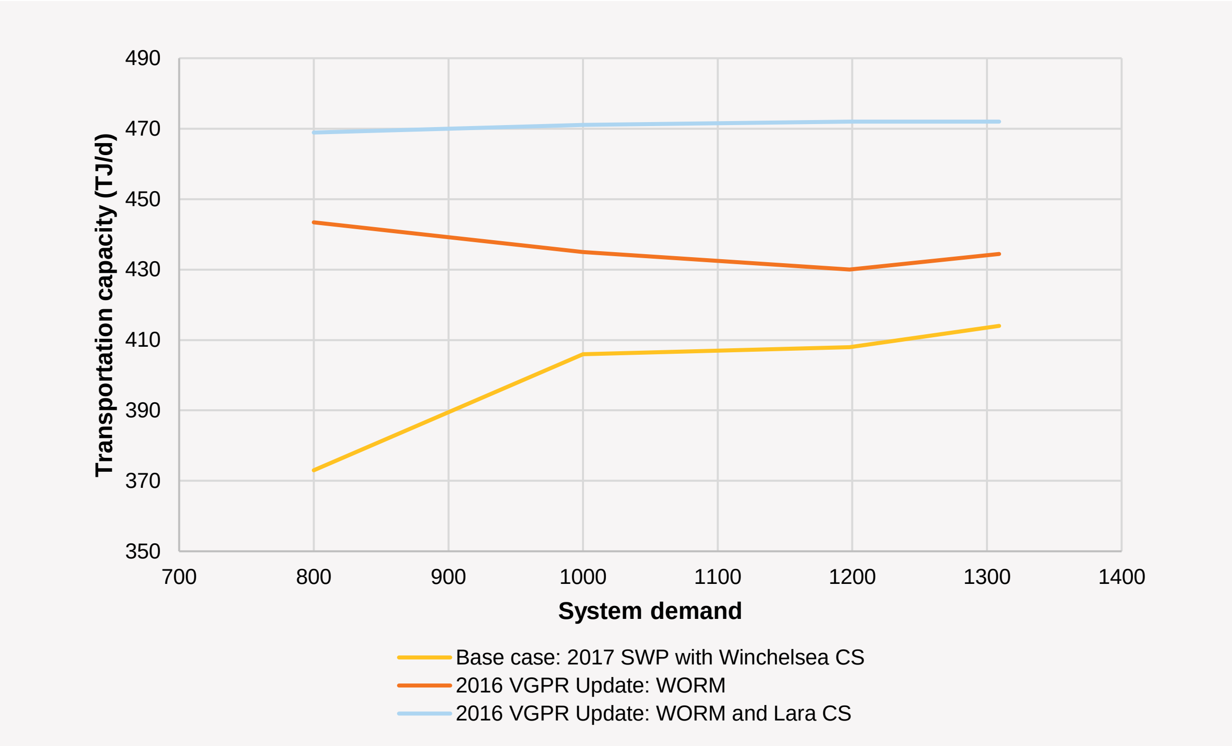
Benefits of the WORM from Port Campbell towards Melbourne

Figure 25 shows the current transportation capacity from Port Campbell to Melbourne, compared to the base case of the WORM with no other augmentations, and then with the addition of another midline compressor at Lara.

The current limitation on the SWP transportation capacity is that it can only deliver gas into Melbourne via the Brooklyn CG. On lower demand days, this is severely reduced as Dandenong CG backs off the Brooklyn CG flows, which can be offset by reducing Dandenong CG pressure during summer periods. The WORM effectively provides additional demand points on the SWP where it can inject the gas into Melbourne via the Wollert CG as well as Brooklyn CG, or also supply the northern Victoria demand. This creates a much flatter capacity curve, providing greater benefits on high system demand days which are not peak demand days.

The WORM addresses the separation of the DTS that currently does not allow gas from Port Campbell to physically supply demand in the Northern zone and the LMP including the (Eastern) Outer Ring Main. The significance of this issue was evident on 1 October 2016, during a six-hour unplanned outage of the Longford Gas Plant requiring AEMO to issue a notice of a threat to system security and intervene in the DWGM. If the outage had persisted, curtailments in northern Victoria, outer-eastern Melbourne, and Gippsland would have been required, despite additional gas supply being available from Port Campbell. During the industrial action at the Longford Gas Plant from early 2015 through to late 2016, the complete loss of gas supply from Longford was considered to be a credible scenario.

Figure 25 SWP to Melbourne capacity with the WORM

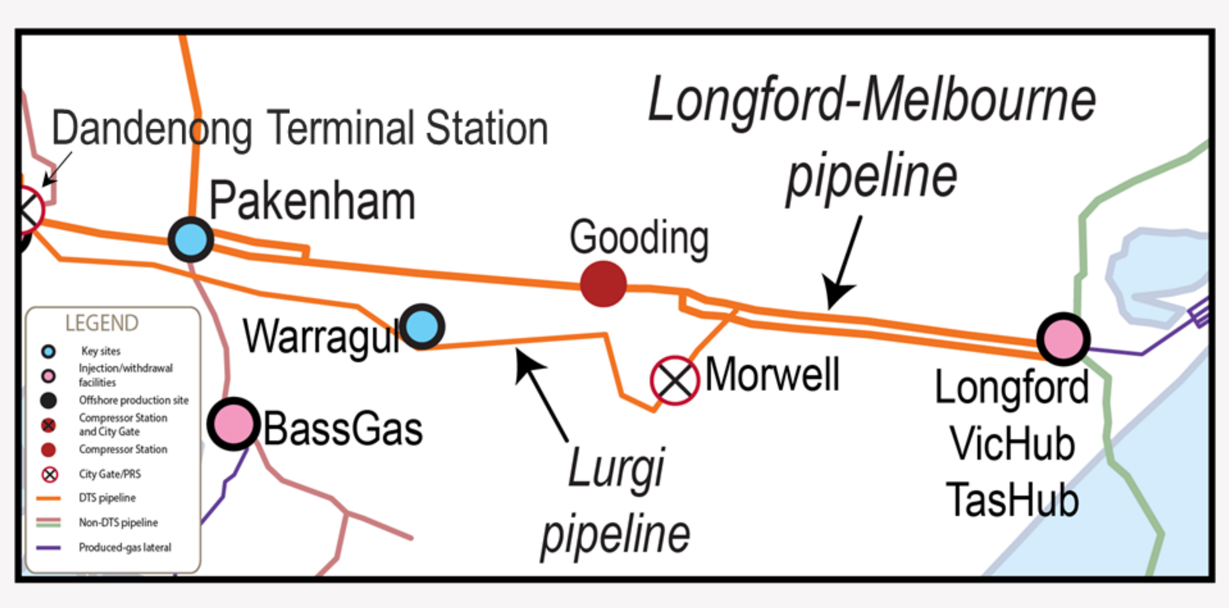


5.2 Warragul

5.2.1 Background

The Warragul CTM is supplied from the Lurgi Pipeline, via a 4.7 km lateral of 100 mm diameter pipe, shown in Figure 26.

Figure 26 Location of Warragul



The DTS service provider stated, in its approved 2013–17 Access Arrangement:

> *"APA Group has identified a need to augment the Warragul lateral by winter 2014 to meet forecast increases in industrial loads in the area. Without augmentation, the Warragul City Gate would breach the required minimum connection pressure of 1400 kPa at the custody transfer meter."*[39]

This augmentation did not proceed, which led to the Warragul CTM breaching minimum contractual pressure of 1,400 kPa at approximately 8:00 am on 22 July 2014. The peak instantaneous flow reached 8.2 kscm/h, which caused the pressure to fall to 1,287 kPa. This issue was raised in the 2016 VGPR Update.[40]

In response to the pressure breach event in 2014, AEMO implemented an operational instruction to manually change the supply pressure of the Lurgi backup regulators[41] located at the Dandenong Terminal Station. During the 22 July 2014 incident, this had to be performed in the field, as AEMO did not have remote control of the regulators' pressure set-point. Following the breach in 2014, the DTS service provider provided AEMO with remote control of the backup regulators.

[39] APA GasNet Australia (Operations) Pty Ltd. Access Arrangement Submission. March 2012. Available at: https://www.aer.gov.au/system/files/APA%20GasNet%20submission%20-%20public%20-%20March%202012.pdf Viewed: 16 February 2017.
[40] AEMO. 2016 VGPR Update. Available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Victorian-Gas-Planning-Report-Update.pdf.
[41] The Lurgi backup regulator at the Dandenong Terminal Station supplies and provides redundancy along the Lurgi Pipeline if the upstream Morwell city gate fails to supply adequate outlet pressure.

Remote control allows AEMO to implement the following operating instruction on peak demand days to:

- Increase the Lurgi backup regulator supply pressure after the evening peak to 2,700 kPa to support the high flows through Warragul CTM during the morning peak.
- Reduce the Lurgi backup regulator supply pressure before the evening peak to maintain linepack in the LMP and the Outer Ring Main.

Although this operational instruction ensures supply to Warragul, it reduces the effective capacity of the LMP and increases the likelihood of peak shaving LNG being required during the evening peak. The effectiveness of this response will be reduced due to:

- Increases in Warragul demand, discussed in Section 5.2.2.
- Increase to Lurgi pipeline demand between Dandenong and Warragul, discussed in Section 5.4.1.

5.2.2 System adequacy

AEMO maintained the Warragul minimum pressure above 1,400 kPa for winter 2016, with the operational instructions discussed above. The maximum instantaneous flow that occurred during winter 2016 was 9.27 kscm/h on 14 June 2016. This corresponded to a minimum Warragul pressure of 1,605 kPa, and an average hourly flow of 8.42 kscm/h.

Figure 27 shows the Warragul pressure versus instantaneous flow, and the increased capacity with the Lurgi backup regulator set-point at 2,700 kPa. Without system augmentation or further operational mitigation measures, AEMO expects that a minimum pressure of 1,400 kPa at Warragul can only be supported up to a peak instantaneous flow of 10 kscm/h.

Figure 27 Warragul pressure versus instantaneous flow

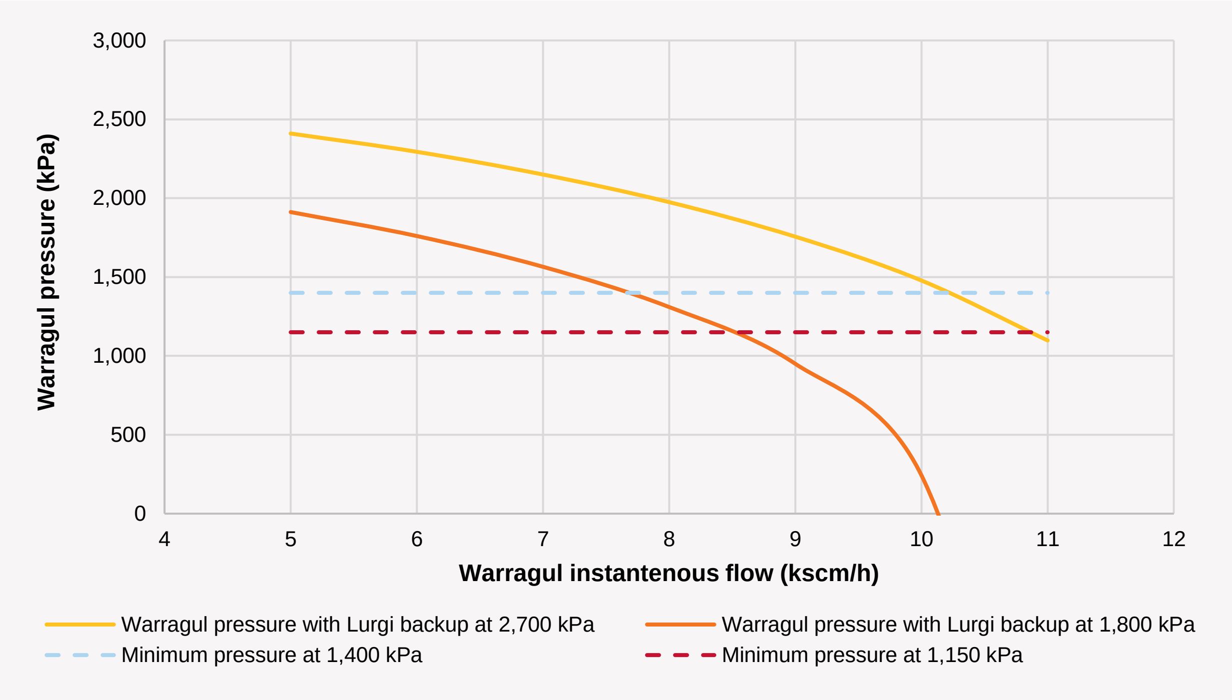
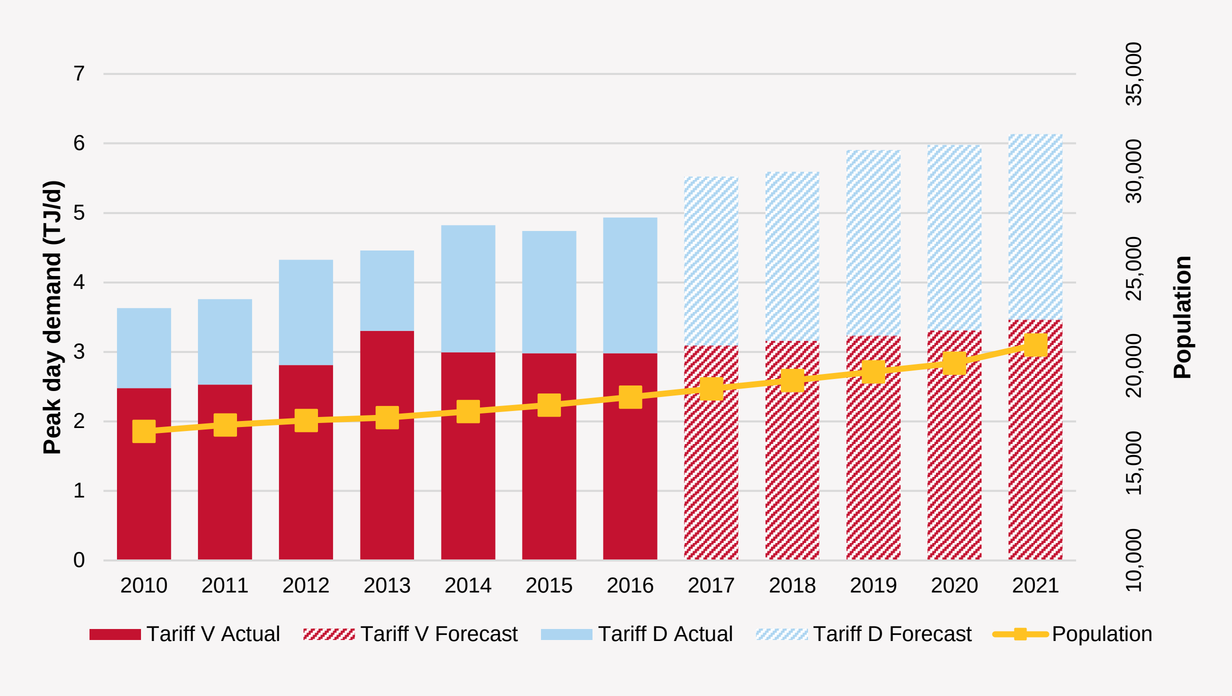


Figure 28 shows the load increase of the large Tariff D site (information provided by distributor), as well as forecast increases in Tariff V demand due to population growth. Due to the demand increase, AEMO expects that the peak instantaneous flow will exceed 10 kscm/h, and that the minimum contractual pressure of 1,400 kPa will not be able to be supported on peak days from winter 2017 onwards.

Figure 28 Warragul CTM 1-in-20 peak day demand and population forecast



To mitigate possible pressure breaches from winter 2017, the network distributor has agreed to the following operating strategy until either system augmentation is completed or until 1 Jan 2021:

- Lurgi backup regulator operating instruction remains, as discussed in Section 5.2.1.
- Manual valve configuration changes at the Dandenong Terminal Station to maximise the supply pressure to the Lurgi line by eliminating the pressure drop across the Lurgi backup regulators on peak demand days.
- Warragul contractual minimum pressure temporarily lowered to 1,150 kPa (augmentation Option 1 in the 2016 VGPR Update[42]).

The above strategies will increase the supportable instantaneous flow to 10.6 kscm/h, based on the observed peak demand profile and forecast increase in Tariff D load (Figure 28).

AEMO has identified a threat to system security, as the above mitigation strategies may not be sufficient to maintain Warragul CTM supply pressure above 1,150 kPa on a peak system demand day from winter 2019 onwards, without system augmentation as discussed in Section 5.2.3.

5.2.3 Future developments

The DTS service provider's 2018–22 Access Arrangement submission to the AER has proposed looping the existing 4.7 km pipeline, with plans to complete the augmentation during 2020.[43] This option was discussed in the 2016 VGPR Update[44], and will allow the minimum contractual Warragul pressure to return to 1,400 kPa.

[42] AEMO. *Victorian Gas Planning Report Update 2016*, p 31. Available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Victorian-Gas-Planning-Report-Update.pdf.
[43] APA. 2012. *APA GasNet Access Arrangement Submission*, p 69. Available at: https://www.aer.gov.au/system/files/APA%20GasNet%20submission%20- %20public%20-%20March%202012.pdf.
[44] AEMO. *Victorian Gas Planning Report Update 2016*, p 32. Available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Victorian-Gas-Planning-Report-Update.pdf.

If a peak system demand day occurs in 2019 and the proposed system augmentation is not completed, AEMO forecasts that supply cannot be maintained to Warragul:

- If the peak demand is forecast, AEMO will issue a notice of a threat to system security and curtail Tariff D load in Warragul to maintain system security.
- If the peak demand is unforecast, Warragul minimum pressure will be breached, creating potential public safety issues due to air ingress into the distribution network. If this occurs, AEMO will issue a notice of a threat to system security and curtail Tariff D loads to prevent further pressure loss in the distribution network.[45]

5.3 Gas-powered generation supportability

5.3.1 DTS-connected GPG

DTS-connected GPG units have historically run as peaking stations during times of high electricity demand, or during baseload generator outages.

The DTS has limited capacity to support GPG demand during winter, because:

- Instantaneous GPG hourly demand can be high, and can reduce linepack levels quickly.
- Some GPG loads (such as the Laverton North GPG station) require Brooklyn compression to be supported.
- GPG can come online at short notice, due to events in the NEM including unplanned outages of baseload generators. Unforecast GPG demand that starts during the gas day reduces the time and gas supply options available to increase DTS injections so the end of day linepack target can still be reached.

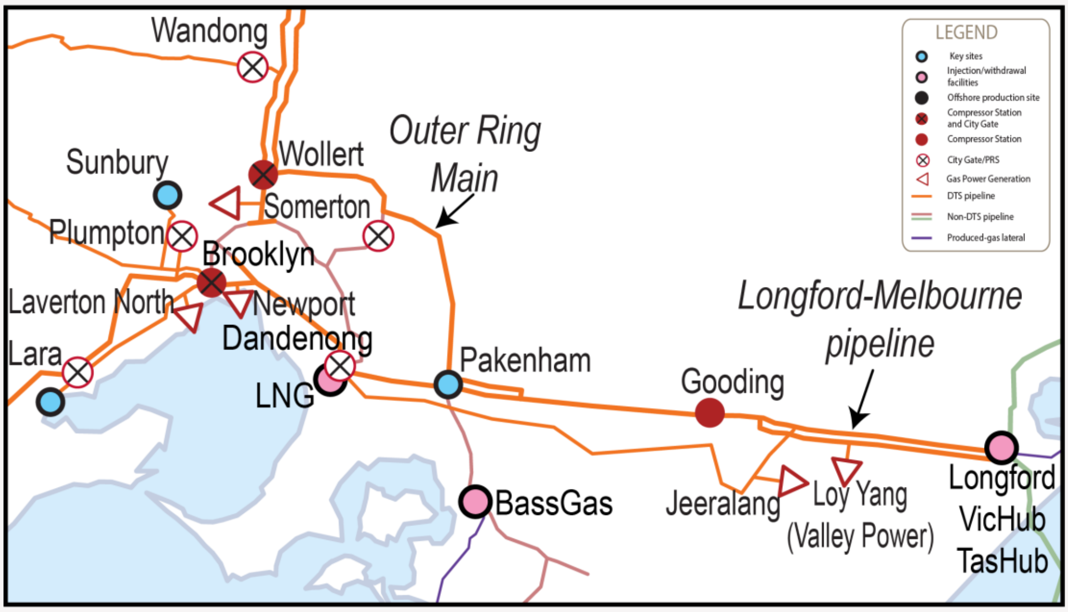
To help manage uncertainties around GPG operation, AEMO:

- Monitors forecast GPG in both the DWGM and NEM pre-dispatch.
- Communicates with AEMO NEM control rooms in Sydney and Brisbane, and support teams, regarding NEM reserve levels, high temperatures, and generator outages.
- Communicates with market participants to obtain information on possible GPG operations.

Figure 29 shows the DTS-connected GPG units. Note that while the Mortlake and Bairnsdale units are situated in Victoria, they are not connected to the DTS.

[45] AEMO. Gas Load Curtailment and Gas Rationing and Recovery Guidelines, May 2010. Available at: https://www.aemo.com.au/Gas/Emergency-management/-/media/6C6D137D3B554DC2ADD3BB2DFD251B85.ashx.

Figure 29 Map of DTS connected GPG sites



A case study was considered to assess the system adequacy of the DTS to support increased GPG forecast demand, discussed in Chapter 2.

This assessment considered a case with the following assumptions for both summer (300 TJ system demand day) and winter (1-in-2 peak system demand day) in 2021:

- Four days of low wind generation in Victoria and New South Wales.
- Hazelwood Power Station retirement at the end of March 2017.
- The construction of a new open cycle gas turbine (OCGT) GPG unit in the Latrobe Valley[46] to support electricity demand and back-up intermittent renewable generation.

Economic modelling was used to determine likely GPG demand profiles in the above scenario. The GPG profiles used for winter and summer 2021 are shown in Figure 30 and Figure 31 respectively. It was assumed that the winter and summer GPG profiles would coincide with a winter 1-in-2 peak system demand day in the DTS (1,198 TJ/d in 2021) and summer system demand day of 300 TJ/d.

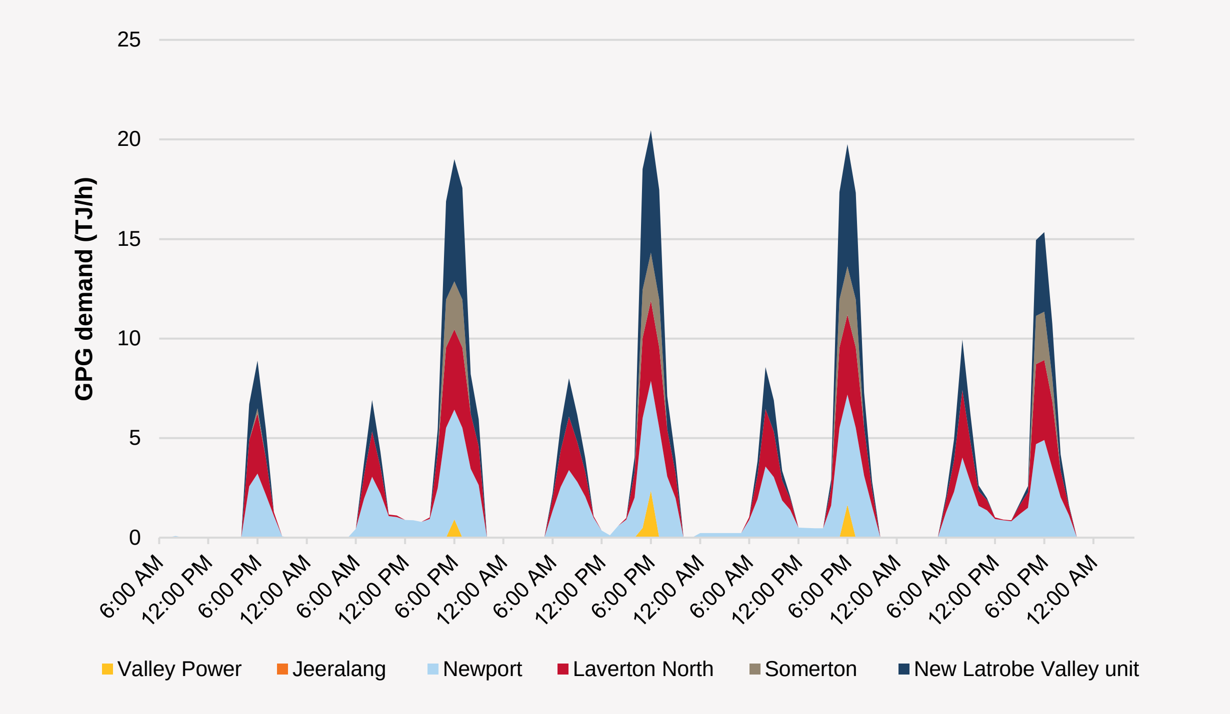
5.3.2 DTS adequacy on a 1-in-2 peak system demand day

The winter GPG profile in Figure 30 shows:

- Large generation from the GPG units from approximately 5:00 pm to 8:00 pm to support the evening peak electricity load.
- Approximately 110 TJ/d of DTS-connected GPG (total demand 1,308 TJ/d).

[46] A Latrobe Valley GPG unit connected directly to the LMP would be expected to have negligible impact on the supportable GPG load and nearby pipeline pressures.

Figure 30 GPG demand forecast on a 1-in-2 peak demand day



This analysis assumes all GPG load is forecast at the start of the gas day, and shows that to support the GPG profile shown on a 1-in-2 system demand day:

- No peak shaving LNG would be required if there were no Culcairn exports.
- 50 TJ of firm peak shaving LNG would be required to support the GPG if there is 150 TJ of coincident Culcairn exports.

Unforecast GPG demand

The ability of the DTS to support this GPG load is drastically reduced if the load is Unforecast, because there is insufficient usable linepack (discussed in Section 5.5). Depending on the location and magnitude of the GPG load that is unforecast, it is possible that either:

- Extra peak shaving LNG, and potentially non-firm LNG[47], would be required.
- Critical supply pressures in metropolitan Melbourne would be breached, threatening supply within the distribution networks. This would lead to AEMO issuing curtailment instructions to GPG sites.

Culcairn exports

It is expected that the Culcairn export capacity would be reduced by the coincident high demand and high GPG load, particularly at Somerton. As in the *Culcairn Operational Transparency Paper*[48], LNG would only be injected up to the firm rate to support Culcairn exports.

[47] Firm capacity LNG refers to injections up to 100 tonnes/hr, and non-firm LNG is injections up to 180 tonnes/hr.
[48] AEMO, 2011. Available at: https://www.aemo.com.au/media/Files/Other/vicwholesalegas/1000-0075%20pdf.pdf.

If the modelled scenario for the 1-in-2 peak day GPG demand profile (Figure 30) was to occur on a 1-in-20 peak system demand day (1,310 TJ/d):

- 65 TJ of firm peak shaving LNG would be required to maintain critical pressures.
- Wollert compression would need to be carefully managed over the evening peak to maintain an appropriate level of linepack near Melbourne.
- No Culcairn exports could be supported, which may impact non-DTS connected GPG demand.[49]

5.3.3 DTS adequacy on a 300 TJ system demand day

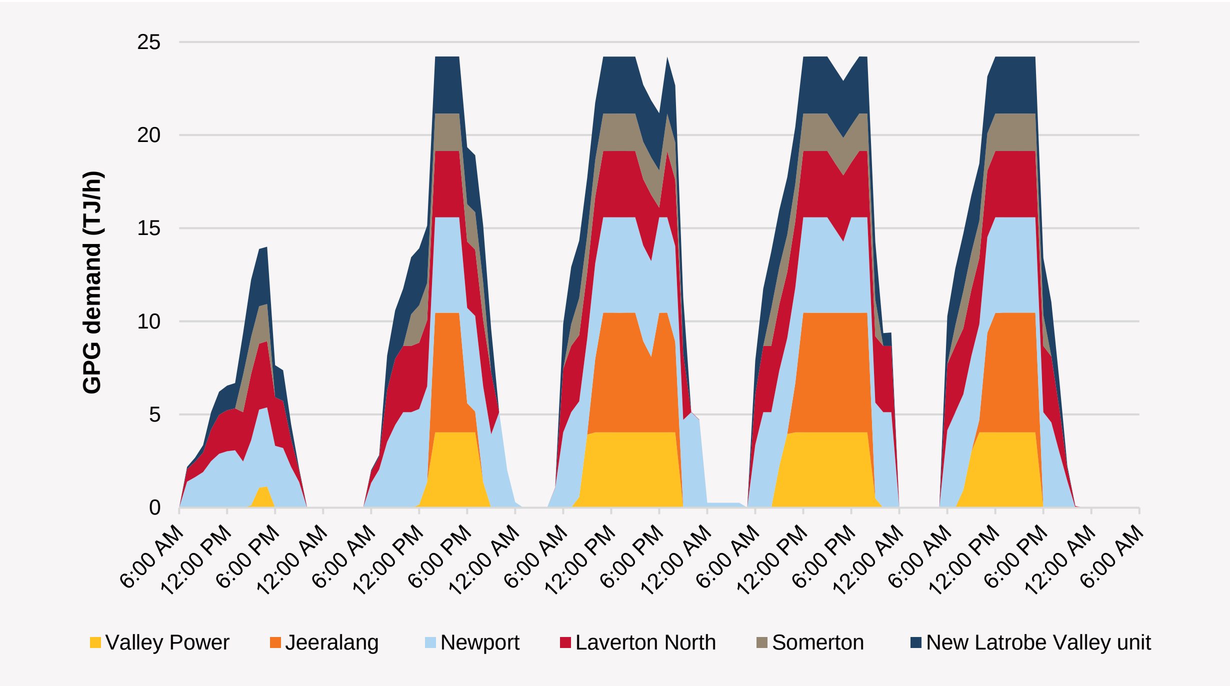
The summer GPG profile shown in Figure 31 shows that:

- Most generators are at their maximum load between approximately 10:30 am and 10:30 pm each day.
- There is approximately 330 TJ/d of DTS-connected GPG load (total demand 630 TJ/d).

If all GPG load is forecast, the entire GPG load, as well as 200 TJ/d of Culcairn exports can be supported without the need for peak shaving LNG.

As discussed above, the ability to support GPG load is greatly reduced if it is unforecast, and may result in the requirement for peak shaving LNG, or curtailment of GPG to prevent critical pressure breaches.

Figure 31 GPG demand forecast on a summer 300 TJ demand day



5.3.4 Future developments

The 2016 NGFR highlighted that both annual GPG consumption and peak demand in the medium to long term are projected to increase, *"necessitated by the assumed achievement of the 2030 emissions reduction target, which can only be met by reducing output of coal-fired generation".*

[49] This could have impacts for GPG across the NEM, as discussed in the *2017 Gas Statement of Opportunities*. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

The timing and magnitude of this increase depends on:

- Federal and State energy policy, including renewable energy targets (such as LRET and VRET).
- Timing of retirements of coal generators.
- Development and uptake of existing and emerging renewable energy technology.

To support the forecast increase in renewable generation in Victoria, new DTS-connected GPG units will be needed to support the intermittent generation (as assumed in the above analysis).

Although modelling has shown that forecast peak GPG loads in 2021 can be supported with current DTS infrastructure, it is possible that DTS augmentations will be required to support peak GPG load beyond 2021. This may include pipeline duplications or new pipelines to increase the amount of usable linepack, or extra compression services.

5.4 Changing load profiles

Background

AEMO is required to assess the DTS adequacy by SWZ shown in Appendix E. For discussion purposes, the zones have been merged into regions of Victoria, as shown in Table 20.

Table 20 DTS regions and SWZ

Region	SWZ
Melbourne	Melbourne
Gippsland	Gippsland Lurgi
Northern Victoria	Northern (excluding Wandong offtake to Bendigo)
Western Victoria	Ballarat Northern (from Wandong offtake to Bendigo)
South West Victoria	Geelong Western (WTS)

5.4.1 Melbourne

The Melbourne region is the main demand centre for the DTS, shown in Figure 32, comprising up to 70% of DTS system demand. The majority of supply into the Melbourne region is through three city gates: Dandenong, Brooklyn, and Wollert. During peak periods it may also include supply through the Yarra Glen PRS and from the Dandenong LNG storage facility.

The Melbourne region has the highest Tariff V loads in the DTS (making up 83% of the demand in the region on a 1-in-2 day in 2017). Key findings for Melbourne are:

- There are no capacity limitations in the Melbourne region for the outlook period.
- There is no peak day demand growth in the inner city.
- There is locational growth, due to urban expansion, in the western, northern and south-east corridors. This correlates with the Australian Bureau of Statistics (ABS) Regional Population Growth report.[50]
- The peak day Melbourne SWZ demand profile is one of the peakiest in the DTS compared to other zones, due to the large Tariff V component, which is more sensitive to weather variability.

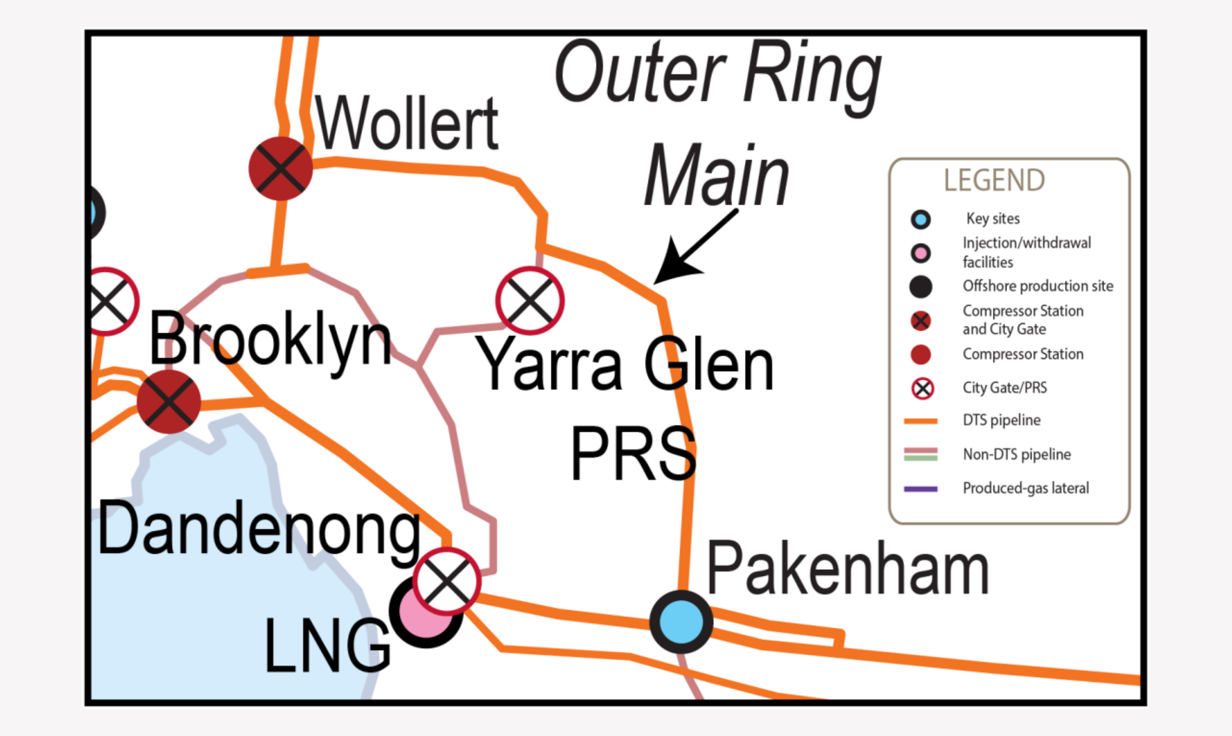
[50] Australian Bureau of Statistics, "3218.0 - Regional Population Growth, Australia, 2014-15", 30 March 2016. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3218.0Main%20Features252014-15?opendocument&tabname=Summary&prodno=3218.0&issue=2014-15&num=&view=.

While the peak system demand is forecast to reduce during the outlook period, a number of the outer suburbs of Melbourne are showing peak day demand increases. This includes the northern and south-eastern corridors, which are growing due to new gas connections in suburbs such as South Morang, Epping, Croydon Hills, Lilydale, Ringwood, and the Cranbourne area.

Strategic assets operated by distributors, such as the Yarra Glen PRS, have had pressure set-point increases to accommodate for localised load growth and load profile changes.

Other load growth areas which affect the Melbourne demand profile are Sunbury and Melton. These are discussed in Section 5.4.4.

Figure 32 Map of Melbourne region

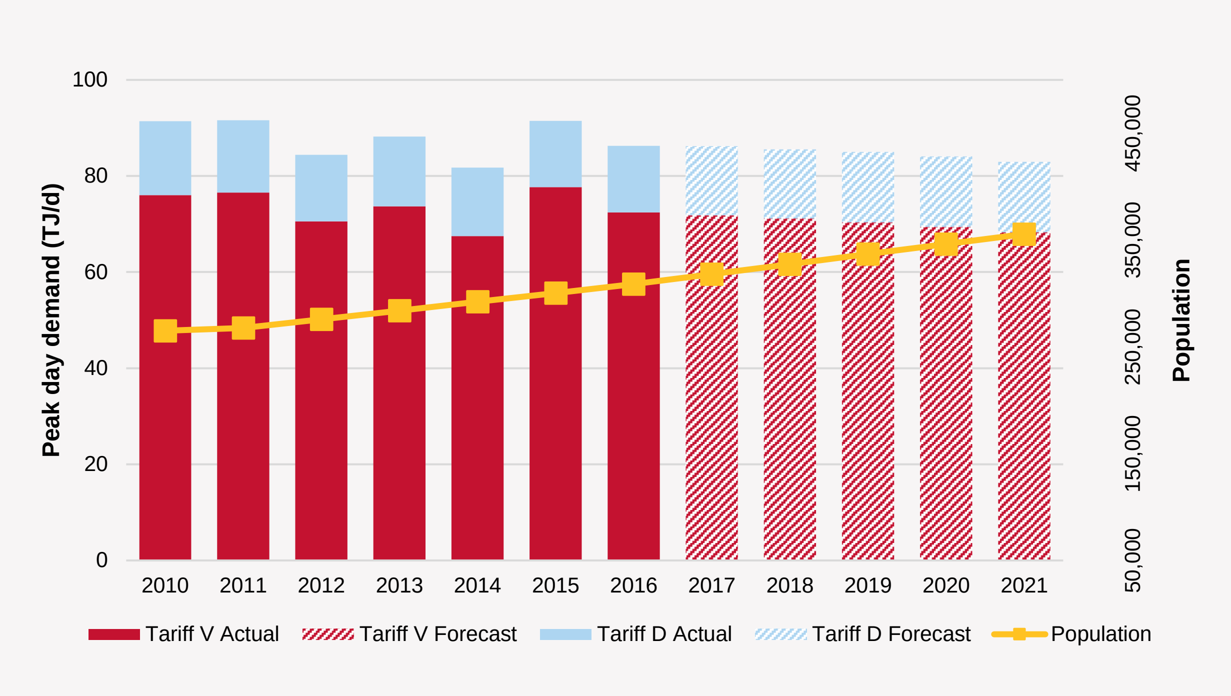


Melbourne Inner City

Figure 33 shows that, while the Melbourne inner city area has seen steady population growth, Tariff V and Tariff D peak day demand has flattened due to an increasing *"ratio of high-rise apartments which require less energy to heat than larger detached homes; [and] consumers are purchasing more energy-efficient heaters and hot water systems*".[51]

[51] AEMO. 2016 NGFR. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Figure 33 Melbourne Inner City demand, forecast load, and population growth



Yarra Glen Pressure Reduction Station

The Yarra Glen PRS was commissioned in 2012 to increase supply on high demand days from the Outer Ring Main into the outer eastern suburbs.

Natural gas connections off the Yarra Glen PRS are forecast to grow at an average rate of 2.5% per annum in areas such as Croydon Hills, Lilydale, and Ringwood.[52] The forecast growth has increased the demand supplied through the PRS into the distribution network. To supply current and new connections in the forecast period, the distribution network operator has increased the outlet pressure at Yarra Glen PRS.

A Yarra Glen pressure increase facilitates:

- Increased supply to support forecast load growth due to new connections without any distribution network restrictions.
- Increased linepack in the distribution network to support a peakier load profile.
- Reduced risk to customer supply.

New connections for natural gas due to new residences create load growth, however appliance selection also impacts the load profile.

Epping

The Epping CTM is forecast to grow at an average rate of 8.9% per annum, due to growth in areas such as Epping and South Morang. The forecast growth is predominantly residential, which is occurring in new estates with new gas connections.

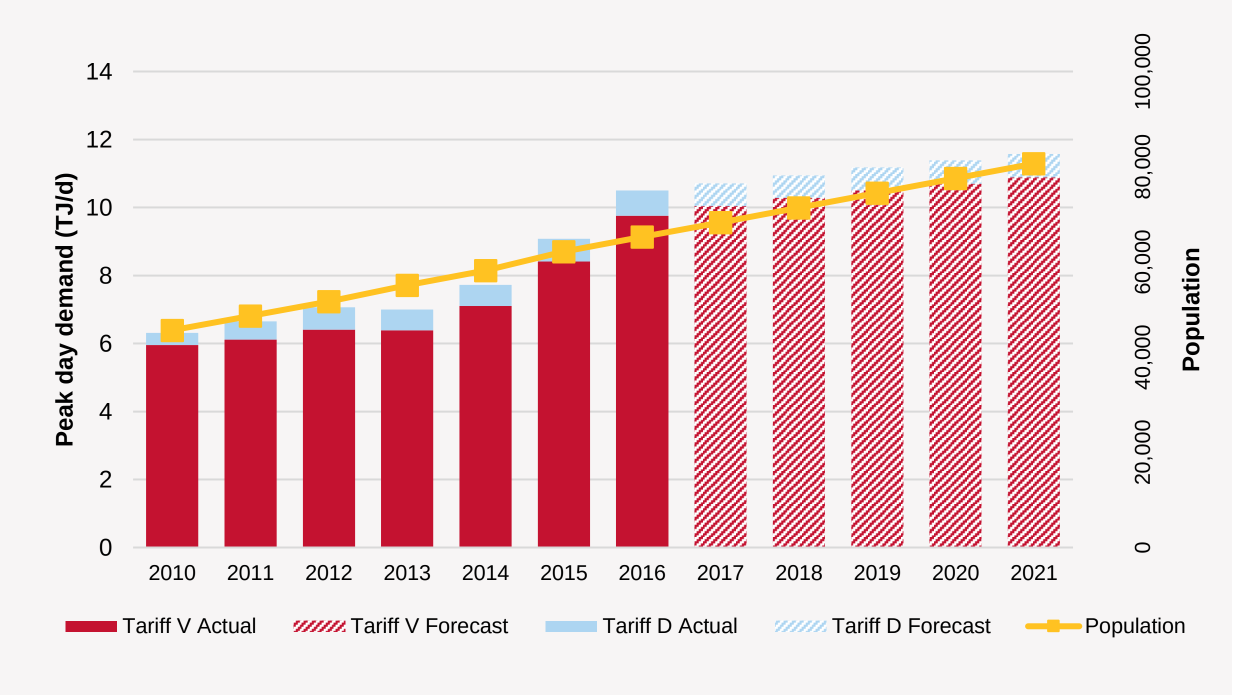
The existing and new connections supplied from the Epping CTM are mainly new residences using new appliances, which are typically more efficient than older appliances. The characteristics of the load growth and load shape are similar to other new estate areas.

[52] As calculated from information compiled from the distributors' mandatory data submissions.

In 2015, Epping and South Morang experienced 9.3% and 7.6% population growth respectively, which correlates to the forecast peak day load growth shown in Figure 34.[53] The forecast increase in demand is able to be supported by the DTS without any capacity limitations.

The demand growth from 2015 to 2016 was due to the pipeline duplication by the distributor from the Epping CTM to the downstream network regulator. This augmentation was only detected by AEMO when pressure issues occurred at this connection point, as the duplication allowed greater flows through the Epping CTM and reduced load off the Keon Park East CTM.

Figure 34 Epping CTM 1-in-20 peak day demand, forecast load and population growth



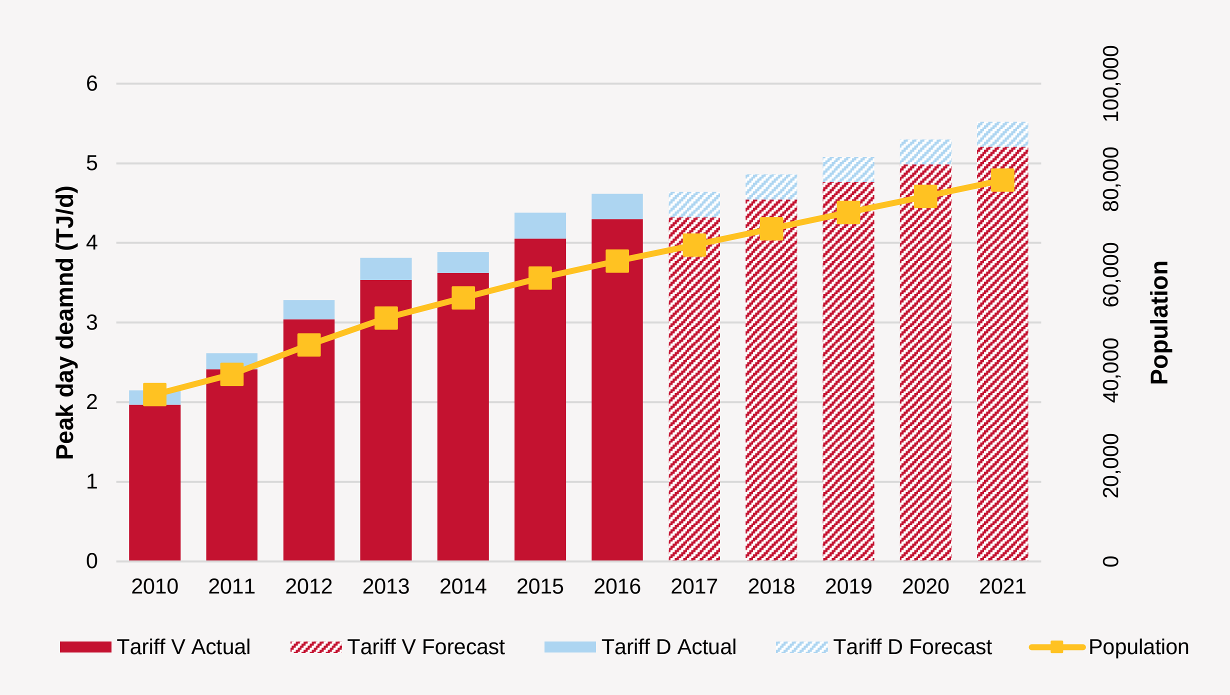
Mernda

The Mernda CTM is forecast to grow at an average rate of 4.9% per annum. There is continuing forecast load growth due to new gas connection and population growth in Mernda over the outlook period, shown in Figure 35.

There are no capacity limitations on this connection. The increased demand is on the inlet of the Wollert CS, which will reduce the VNI export capacity. As the demand on the inlet to the Wollert CS grows, increased LNG and further augmentation may be required to meet the 1-in-20 peak demand day VNI export capacity.

[53] Australian Bureau of Statistics, "3218.0 - Regional Population Growth, Australia, 2014-15", 30 March 2016. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3218.0Main%20Features252014-15?opendocument&tabname=Summary&prodno=3218.0&issue=2014-15&num=&view=.

Figure 35 Mernda CTM 1-in-20 peak day demand, forecast load and population growth



Cranbourne

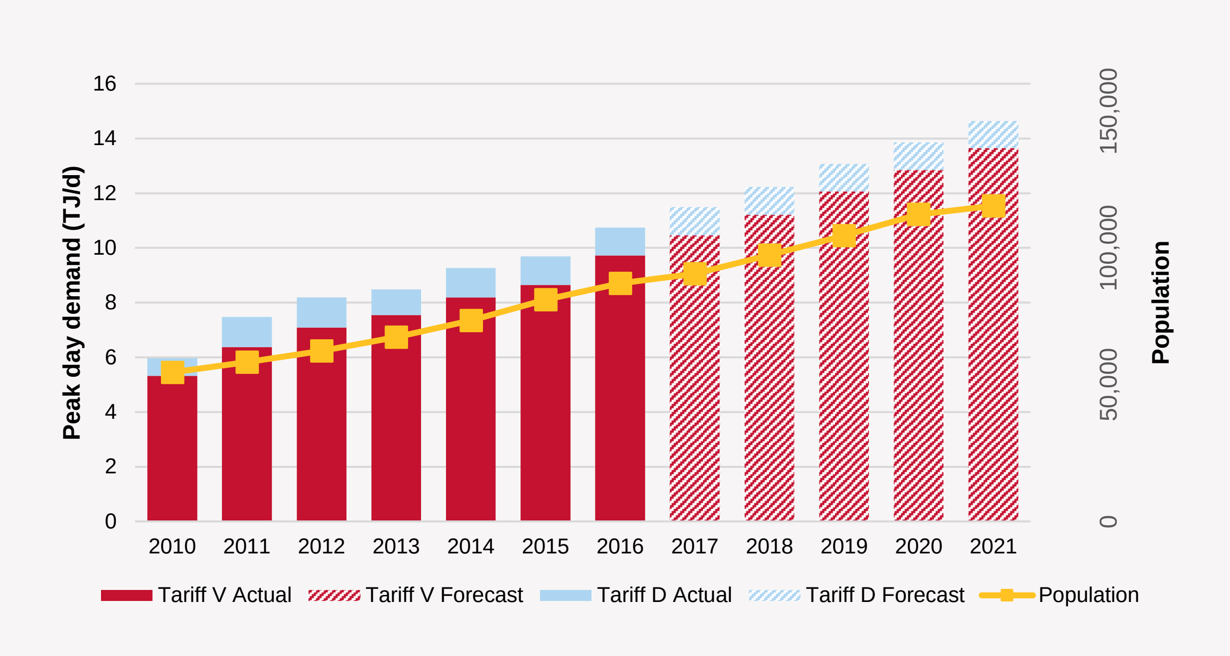
The Cranbourne area is supplied by two CTMs from the Lurgi Pipeline. Cranbourne experienced the *"largest growth of any area in Australia, [and] Cranbourne East also had the fastest growth in the state (and the second-fastest nationally), increasing by 32 per cent in 2014-15"*[54], with a further forecast average demand growth of 6.9% per annum.

While there are no capacity limitations on the connection, as discussed in Section 5.2, the Lurgi back-up regulators are required to support flows to Warragul. The Cranbourne load is located on the Lurgi Pipeline between the Dandenong Lurgi back-up regulators and Warragul. The forecast growth will limit the effectiveness of the Lurgi back-up regulator to support Warragul pressure on peak demand days.

AEMO will monitor the effectiveness of the current operating practice to manage Warragul peak day demand and the growth in Cranbourne demand.

[54] ABS. "Melbourne our fastest-growing capital", March 2016. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3218.0Media%20Release12014-15?opendocument&tabname=Summary&prodno=3218.0&issue=2014-15&num=&view=#Victoria.

Figure 36 Cranbourne CTMs 1-in-20 peak day demand, forecast load, and population growth



Emerging trends in gas usage

In two separate studies conducted into gas consumption[55] and water temperature[56], it was demonstrated that water heating and residential heating plays a large role in gas consumption, and that new technologies are impacting how this occurs. Solar-boosted gas instantaneous hot water units are adjusting the load profile shape and impacting annual gas consumption.

Traditional storage gas hot water units consume a larger quantity of gas annually, but consume this as a flat rate over the year. Solar-boosted gas instantaneous hot water consumes very little gas during the summer months but, during winter use, consumes natural gas at a much higher hourly rate than the older, less efficient storage hot water units.

The higher hourly natural gas flow results in a much peakier demand, which typically occurs during the morning and evening peak. A peakier load profile impacts the required supply pressures and the rate of pressure decline, leading to a higher linepack requirement.

The peak day gas demand is being maintained, as the solar component of these units is less effective during winter, but the overall annual consumption is much lower as the solar component provides most of the heating during the summer months.

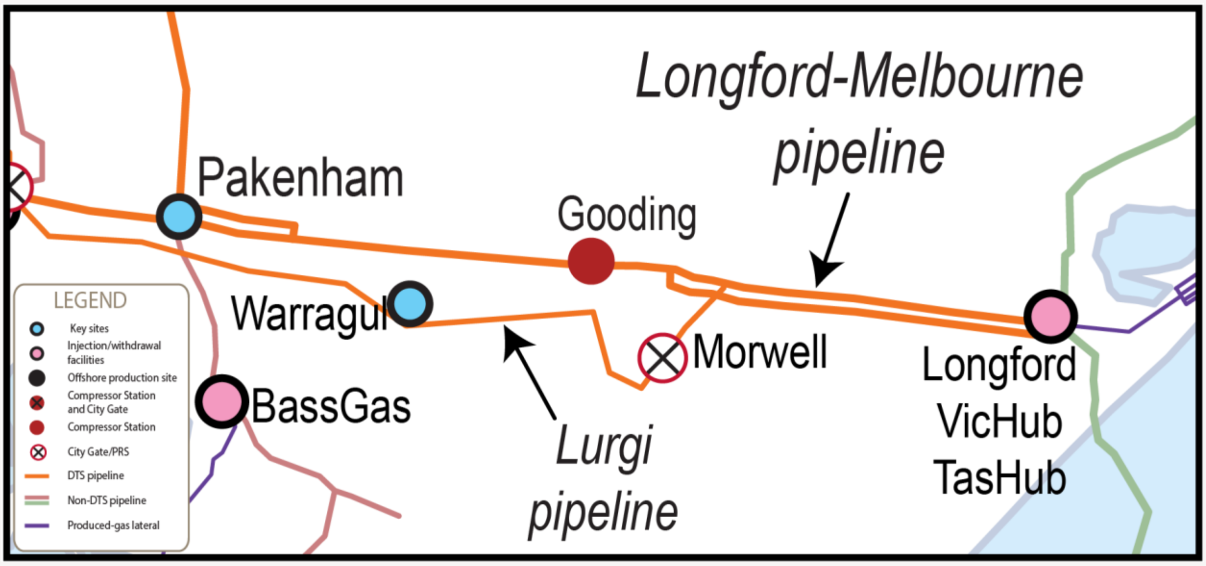
5.4.2 Gippsland

The Gippsland region includes all demand on the LMP and Lurgi Pipeline, shown in Figure 37. South Gippsland is not part of the DTS, and is either supplied directly by the BassGas injection point (supplied by the Lang Lang Gas Plant), or from the DTS via Pakenham if the Lang Lang Plant is offline.

[55] Core Energy Group. ENA | Gas Network Sector Study, August 2014. Available at: http://www.energynetworks.com.au/sites/default/files/ENAs-Gas-Network-Sector-Study_August2014.pdf.

[56] The University of Queensland. Cold Water Temperature in Melbourne 2004-2013, preliminary statistical analysis. Available at: https://www.clearwater.asn.au/user-data/research-projects/swf-files/9tr1---001-grace-2014-cold-water-temperature-in-melbourne-1994-2013-final.pdf.

Figure 37 Map of Gippsland region



Gippsland region supply during abnormal system conditions

The Gippsland region is supplied by the Longford Gas Plant during normal operation. In the event of an unexpected Longford Gas Plant outage or trip, there is limited supply to the region. The DTS configuration does not allow gas to flow from the Iona CPP to the Gippsland region through Dandenong CG, or the Northern region through Wollert CG or Wandong PRS.

This means that, under this scenario, all demand in the Northern and Gippsland regions can only be supplied by Northern zone pipeline linepack, VNI imports and BassGas injections. Full capacity from these injection sources of 170 TJ/d could supply the system demand in these regions during summer. There is no sufficient capacity to prevent curtailment in these regions outside the summer period, or to support GPG demand supplied from the LMP.

An example of such an event occurred on 1 October 2016, where the Longford Gas Plant ceased injections into the DTS at 4:26 am[57] for approximately seven hours. Although there was no interruption to customers' supply on this gas day:

- Contractual pressures to Sale, Edithvale, and Peninsula CTMs[58] were breached, in consultation with the affected distributors.
- LNG was scheduled at the maximum firm rate of 100 t/h from 9:03 am (AEMO intervention via an ad hoc schedule).
- Culcairn was unable to inject gas into the DTS due to a New South Wales transmission outage.

The Longford Gas Plant resumed injections into the DTS at 10:45 am. If the Longford outage had continued, curtailment in the Northern and Gippsland regions, and outer eastern Melbourne, would have been required.

[57] AEMO. *DWGM Event – Intervention – 1 October 2016*, October 2016. Available at: http://www.aemo.com.au/-/media/Files/Gas/DWGM/DWGM-IR-16-002-14th-October-2016.pdf.
[58] Edithvale and Peninsula CTMs are located at Dandenong.

Sale contractual pressure

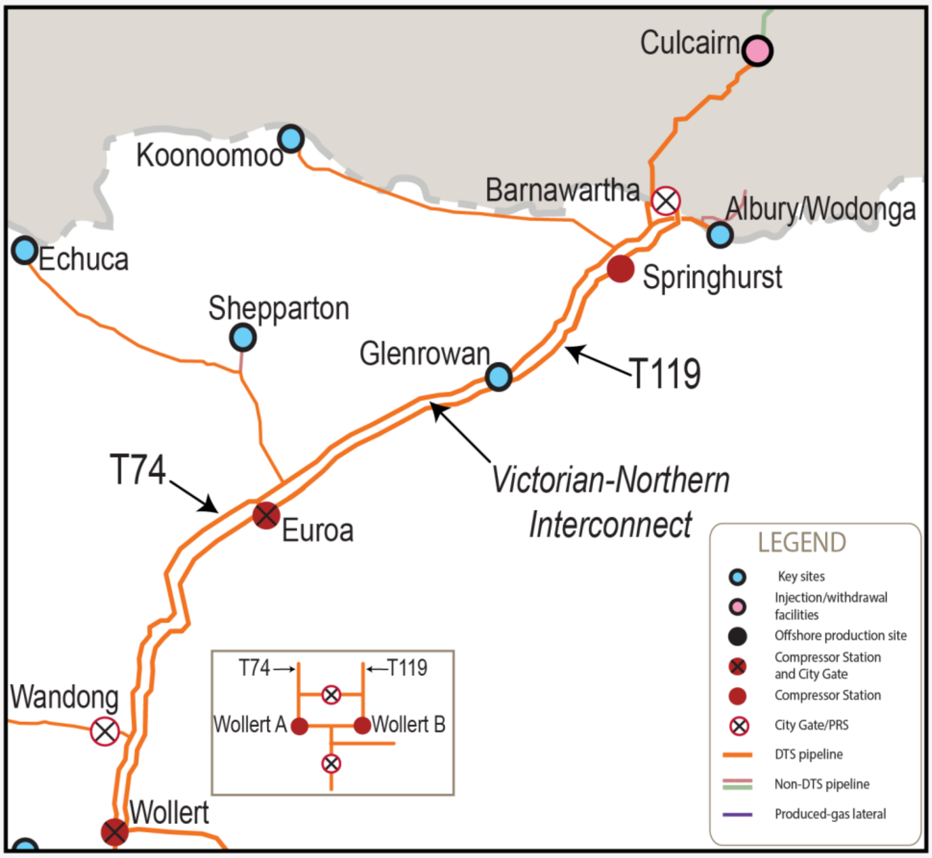
The survival time[59] of the Gippsland region is currently driven by the minimum contractual pressure at Sale. AEMO has initiated discussions with the distributor for that connection to identify ways to reduce this pressure and extend the survival time in such scenarios.

The distribution network operator has acknowledged this in its 2018–22 Access Arrangement submission to the AER.[60]

5.4.3 Northern Victoria

Northern Victoria includes the VNI and the lateral pipelines supplying Echuca, Koonoomoo, and Wodonga. Northern demand is supplied through Wollert or through imports from New South Wales via Culcairn.

Figure 38 Map of the Northern Victoria region



With the completion of the VNIE Phase B project, as discussed in Chapter 4, Northern demand will be primarily supported by the T74 pipeline without Wollert A compression on low demand days.

On high demand days, Wollert A compression into the T74 is required to support Northern demand. Additional gas will be supplied from the T119 pipeline through the Wollert PRS, Euroa PRS, or

[59] The time for which contractual minimum pressures can be maintained during emergency events.
[60] Australian Gas Networks. *AGN Access Arrangement Submission*, 2016, pg 93. Available at: https://www.aer.gov.au/system/files/AGN%20-%20Final%20Plan%20-%20Access%20Arrangement%20Information%20for%20our%20Victorian%20and%20Albury%20natural%20gas%20distribution%20networks%202018-2022%20-%2020161222%20-%20Public.pdf.

Barnawartha PRS, because, above a 1-in-2 peak demand day, Northern demand cannot be supported with compression from Wollert A into the T74 pipeline alone.

Historical peak day supply

Northern region demand is currently supplied by both the T74 and T119 pipelines. Wollert B compresses into both pipelines to support Northern demand and VNI exports via Culcairn. The region has a high portion of Tariff D demand and a reasonably flat demand profile. Current supply using Wollert B compressors is sufficient to meet Northern demand.

Reconfiguration at Wollert performed as part of VNIE Phase A enables gas to be transported from the VNI into Melbourne and around the Outer Ring Main into the Gippsland region. This capability was utilised during the 1 October 2016 Longford outage.

System adequacy

Following the completion of the VNIE Phase B project, Northern demand on a 1-in-20 peak demand day cannot be supported with compression from Wollert A into the T74 pipeline alone. Additional flow from the T119 pipeline through the Euroa PRS and the Barnawartha PRS is required to ensure demand is met.

With the increased export capacity of the VNI, it is expected that compressor utilisation in the Northern region will increase. Wollert B, Euroa, and Springhurst compressor stations will be required more often to support exports, and on higher demand days, Wollert A is required to support Northern demand.

To support system demand via VNI imports or utilising Northern pipeline linepack, Euroa or Springhurst compression is necessary to transport high quantities of gas from north to south. Melbourne and Gippsland region demand can be supplied through Wollert if required.

Import supply via Culcairn is limited by the New South Wales transmission system capacity, discussed in Chapter 4.

Impact of load growth on Victorian Northern Interconnect capacity

Without a sufficiently high inlet pressure at the Wollert CS, the export capacity through the VNI is restricted. As demand increases in Melbourne, along the LMP or Lurgi Pipeline, there will be reduced supply to the inlet of Wollert CS. The VNI may have capacity, but insufficient gas from the LMP can be transported to the VNI. As discussed in Section 5.1.4, the WORM would increase supply at Wollert from SWP to supply the VNI.

On high demand days, the Melbourne zone demand draws down the Wollert inlet pressure. The changing load profile in the DTS will also impact the Wollert inlet pressure, as ‘peakier’ evening demand causes the pressure to drop faster.

Load growth along the pipelines that supply the Wollert CS will increase the likelihood that the Wollert inlet pressure cannot be maintained. Key areas of load growth, which may impact the Wollert inlet pressure, include Epping, Mernda, and Yarra Glen/Lilydale, discussed in Section 5.4.1.

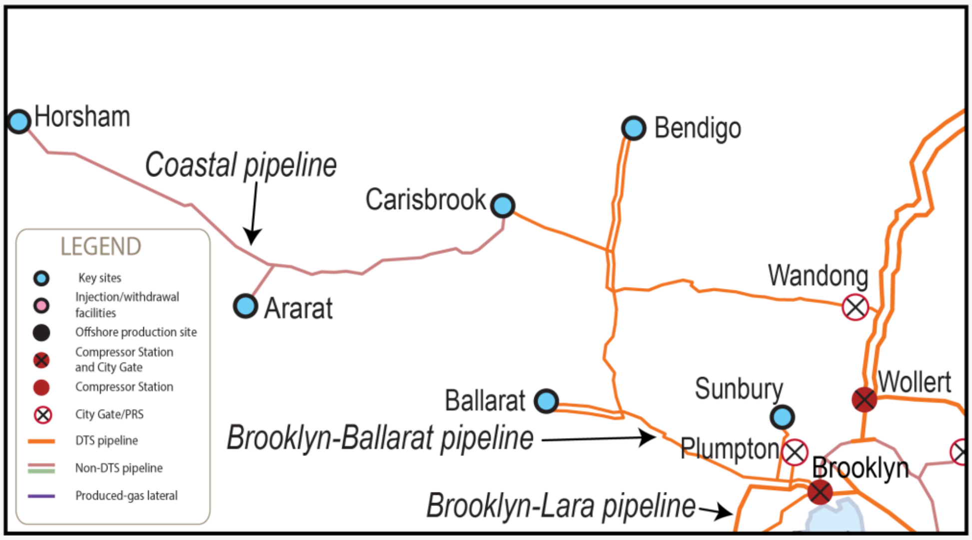
5.4.4 Western Victoria

Western Victoria, shown in Figure 39, includes the Brooklyn to Ballarat Pipeline (BBP), the Wandong to Bendigo and Carisbrook pipelines, and the Sunbury lateral. These areas can receive supply through the Wandong PRS, from Brooklyn or through the Plumpton PRS.

The growing trends in this region for the outlook period are:

- There are no capacity limitations in the Western region for the outlook period.
- Forecast load growth in the western corridor, primarily in Sunbury and Melton South. The distribution network operator at Melton South has requested an increase to 3,000 kPa for winter operations.
- Update to the Plumpton PRS operating requirements for remote set-point control.

Figure 39 Map of Western region



Peak day supply and demand

The Western region capacity is adequate to meet peak demand on a 1-in-20 peak demand day for the outlook period. To meet demand in this region:

- Ballarat requires supply from Brooklyn compression.
- Bendigo requires supply from the Wandong PRS.

An alternative, to reduce the utilisation and reliance on Brooklyn compression, thereby reducing fuel gas consumption, is to:

- Install a new PRS from the BLP into the BBP, in an area such as Rockbank.
- Construct a lateral off the existing BLP at Mt Cottrell (where BLP meets the easement of the BBP), out to the Ballan–Ballarat junction. This could negate the requirement for Brooklyn compression altogether if the WORM is constructed.

Plumpton PRS

The Plumpton PRS connects from the Plumpton Lateral into the Deer Park–Sunbury Pipeline. The Plumpton PRS experiences operational issues when the supply pressure cannot be maintained above the discharge set point.

On several occasions, the Plumpton PRS has failed to control to its pressure set-point and has breached the pipeline's Maximum Allowable Operating Pressure (MAOP). This high pressure risks activating the pressure protection slam-shut valves and isolating supply from the BLP.

AEMO does not have set-point control over the Plumpton PRS and cannot remotely open the slam-shuts if they are triggered. If this occurred during a peak demand day there is a risk of a pressure breach or supply disruption in the Western region.

AEMO proposes that the DTS service provider complete an upgrade of the Plumpton PRS to enable remote control of the site. Increased functionality will allow AEMO to:

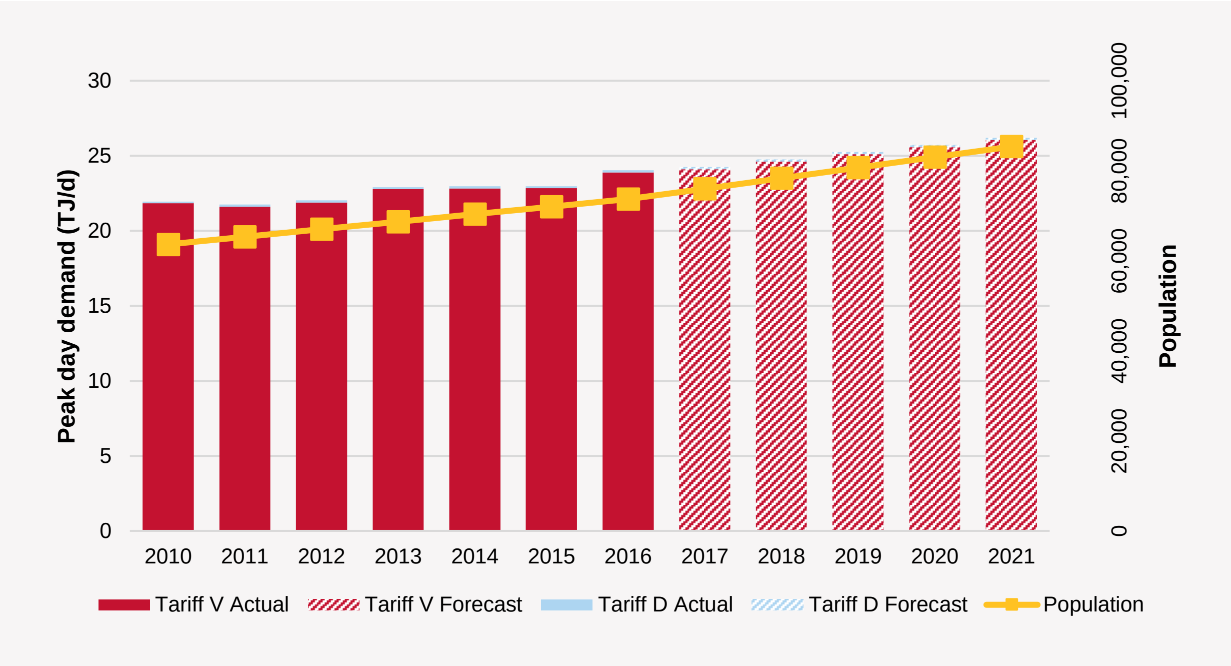
- Remotely re-open the slam-shut valves and secure supply.
- Optimise the Sunbury lateral supply, which can be supplied from either the BLP or the BBP.
- Provide the capability to support increased withdrawals to Iona UGS in the winter and shoulder periods. Currently, with a fixed set-point, Plumpton PRS withdraws gas from the BLP to supply Sunbury year-round, whereas it is not needed during the summer and shoulder months.

Sunbury region

Sydenham, Diggers Rest, Plumpton, and Sunbury offtakes, supplied off the Sunbury lateral, are forecast to grow at an average rate of 1.6% per annum, shown in Figure 40. The Sunbury lateral is supplied from the BLP via Plumpton PRS during the winter and shoulder periods, and the BBP during the summer. Planned residential development in Sunbury is forecast to continue load growth at this withdrawal point over the outlook period.

The load growth is not expected to impact DTS operations, and the Sunbury lateral supply pressure is adequate to meet 1-in-20 peak demand day for all withdrawal points along the lateral.

Figure 40 Sunbury lateral 1-in-20 peak day demand, forecast load, and population growth



Melton South

The City of Melton is a major growth area, with a number of new suburbs planned.[61] As shown in Figure 41, demand is forecast to increase at an average rate of 3% per annum. To ensure supply into the

[61] City of Melton. New Suburbs: map of the new suburb boundaries. Available at: http://www.melton.vic.gov.au/Council/About-the-City/New-suburbs Viewed: 13 February 2017.

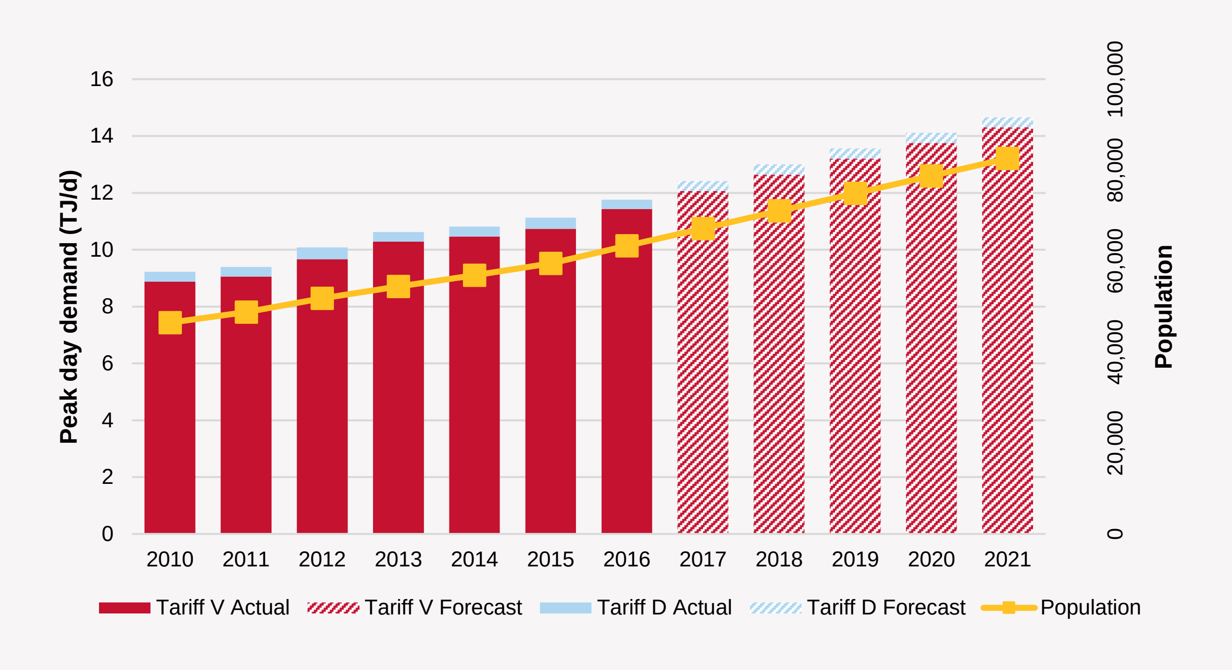
distribution network to support this load growth, the distributor has requested a seasonal minimum operating pressure at the Melton South CTM of:

- 3,000 kPa for winter periods.
- 2,500 kPa remains for summer and shoulder periods.

This load growth area is located on the BBP between Brooklyn and Ballarat. As this demand increases over time, it will reduce the delivery pressure to Ballarat, therefore increasing the Brooklyn to Ballarat compression requirements.

Over the outlook period, the compression available is forecast to be sufficient, but there will be an increase in the utilisation of winter Brooklyn compression.

Figure 41 Melton South CTM 1-in-20 peak day demand, forecast load, and population growth

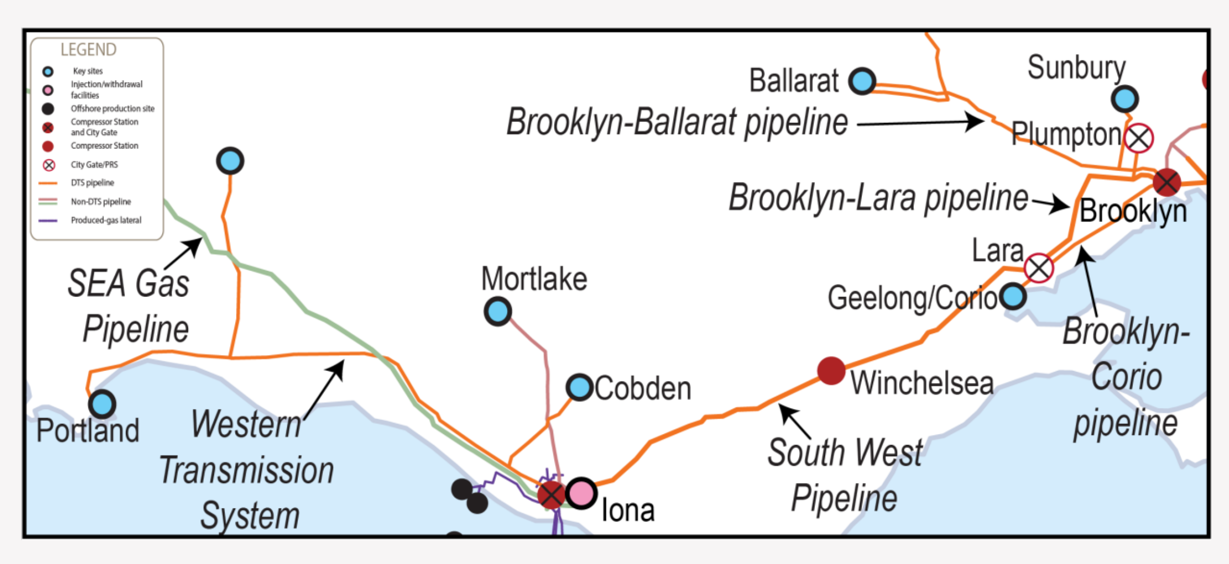


5.4.5 South West Victoria

South West Victoria includes the SWP, BLP, BCP, and WTS, as shown in Figure 42, and is supplied from the Port Campbell region (Iona) and/or Brooklyn CS.

As discussed in Chapter 3, the supply to this region over the outlook period is decreasing due to closure of industrial gas users. This has enabled a slight increase in the SWP to Port Campbell transportation capacity discussed in Chapter 4 and Section 5.1.

Figure 42 Map of South West Victoria region

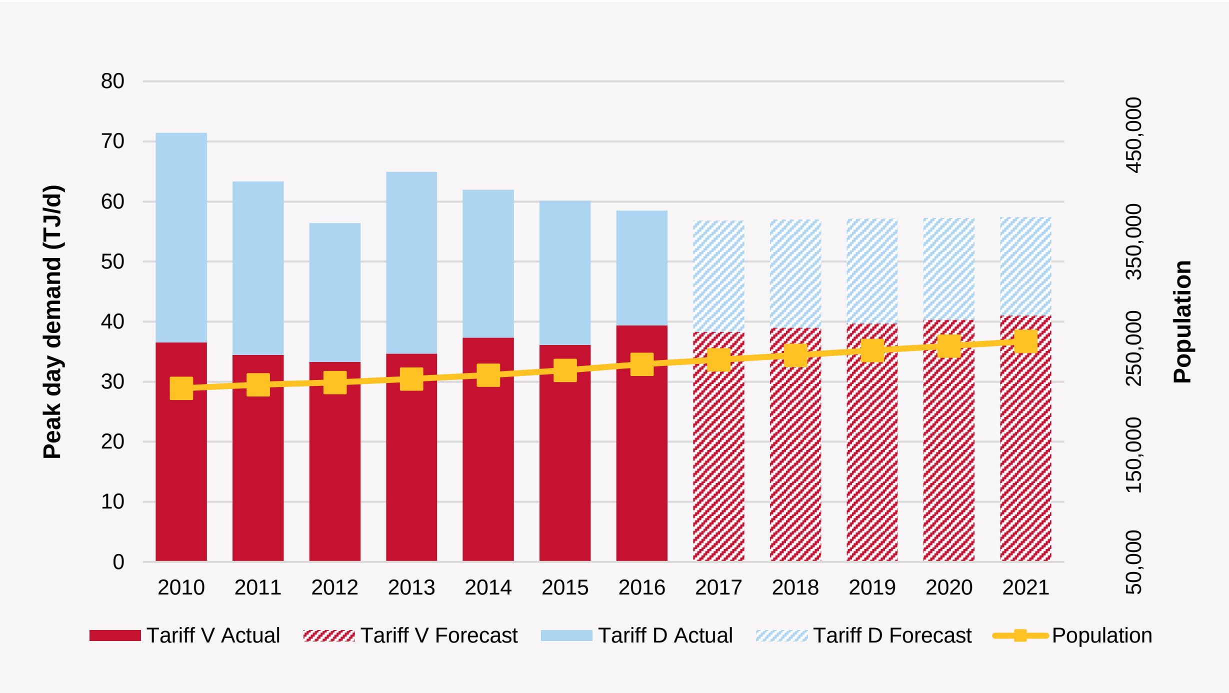


Geelong and Surf Coast region

The Geelong and entire surf coast is currently supplied by the Corio CTM through the Geelong distribution network. The Corio CTM is the network distributor's *"most critical gas asset in terms of the number of customers it supplies and is the single supplier of natural gas to Geelong and the Bellarine Peninsula in Victoria. The large region includes the townships of Port Arlington, Queenscliff, Torquay, Barwon Heads and Point Lonsdale".*[62]

Figure 43 shows the forecast Tariff V growth and decline in Tariff D demand over the outlook period, which combine to create a 'peakier' demand profile.

Figure 43 Corio CTM 1-in-20 peak day demand, forecast load, and population growth



[62] Zinfra. Gas: Corio City Gate. Available at: http://www.zinfra.com.au/Projects/Gas/Corio%20City%20Gate.aspx.

To alleviate the effect of forecast hourly demand increases on the Corio CTM, the distribution network operator and DTS service provider have proposed an augmentation to provide a secondary source of supply to the Geelong region as part of their respective 2018–22 Access Arrangements.

The proposed augmentation includes:

- 20.2 km of 250 mm pipeline Class 600 from the SWP to Anglesea.
- New city gate at Anglesea into the distribution network.

This lateral from the SWP may impact SWP flows to Port Campbell in summer and shoulder periods. AEMO will work with the distribution network operator to reduce the impacts on the SWP's net withdrawal capacity.

A possible option to reduce the impact on the SWP withdrawal capacity is to implement seasonal set-point control at the proposed Anglesea connection. This will minimise flows on the lateral during the summer and shoulder periods, and maximise flows in winter to support the load growth in the region.

5.5 System linepack

Background

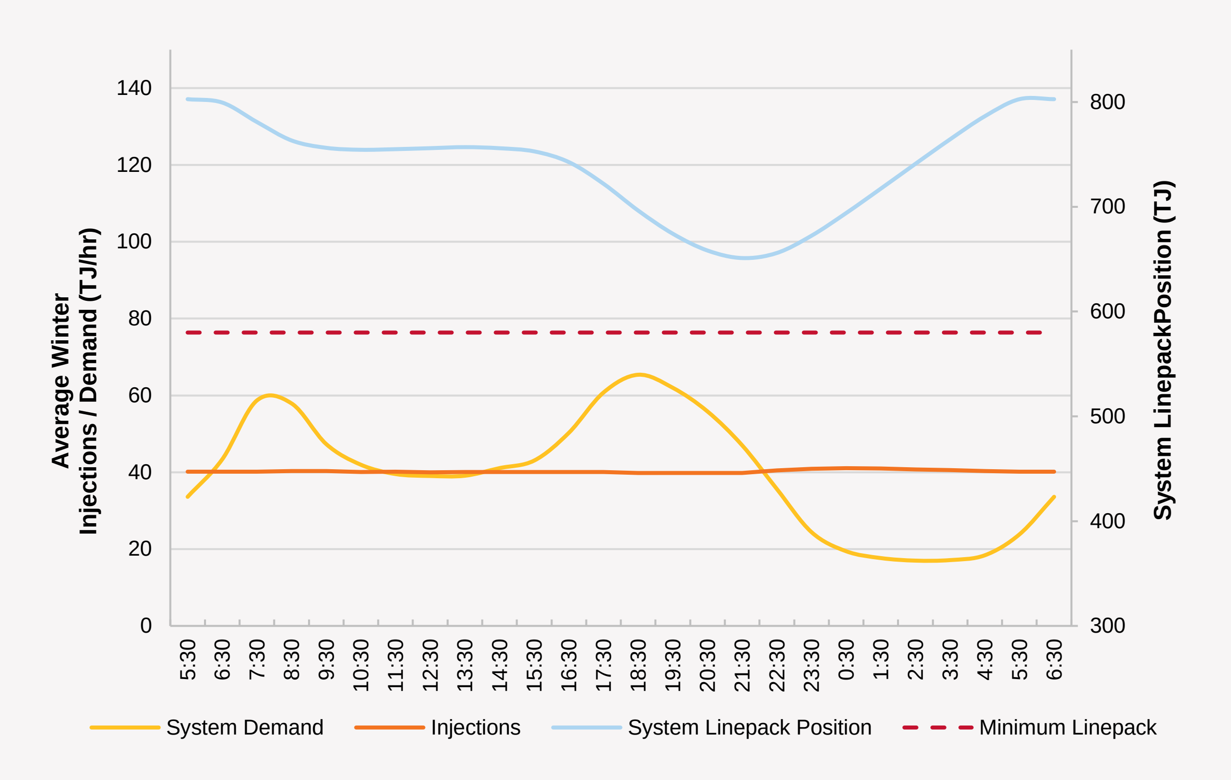
Demand in the DTS varies throughout an average winter day, with variations between 17 TJ/h and 65 TJ/h, shown in Figure 44. The highest demand occurs during the morning and evening peaks, reaching up to 80 TJ/h in recent years. The lowest demand occurs overnight, when the system linepack recovers to support the following gas day.

Gas injections into the DTS are scheduled at a constant rate throughout the day (with some variation for re-scheduling and ramping), because many production facilities have limitations on their ability to quickly change production rate. System linepack is utilised to balance the constant rate of injections with the variable demand.

Figure 44 demonstrates that on an average winter day (approximately 950 TJ) which is perfectly forecast, with no GPG and where all facilities inject as scheduled, the DTS is left with 71 TJ of usable linepack.

Another observation from Figure 44 is that, for the average winter system demand profile, approximately 80% of the system demand for a gas day occurs before 10:00 pm. This is when only 67% of the gas day is over, and hence only 67% of the gas has been injected. This is when system linepack is at its lowest.

Figure 44 Average winter demand, injection, and linepack profile



5.5.1 Linepack adequacy of the Victorian DTS

Useable linepack

Not all the gas in the DTS is useable. A minimum quantity of gas is required to maintain the minimum allowable operating pressures (MinOp) at each of the custody transfer meters in the DTS. A portion of the area under the blue curve (in Figure 44) must remain in the system for the DTS to be in a secure state. Furthermore, the minimum linepack required to keep the system in a secure state varies with demand. The higher the demand, the more linepack is required to maintain minimum operating pressures throughout the system. This results in a lower useable linepack.

To understand why the useable linepack decreases with demand, consider how the pressure of gas drops as it flows along a pipeline.

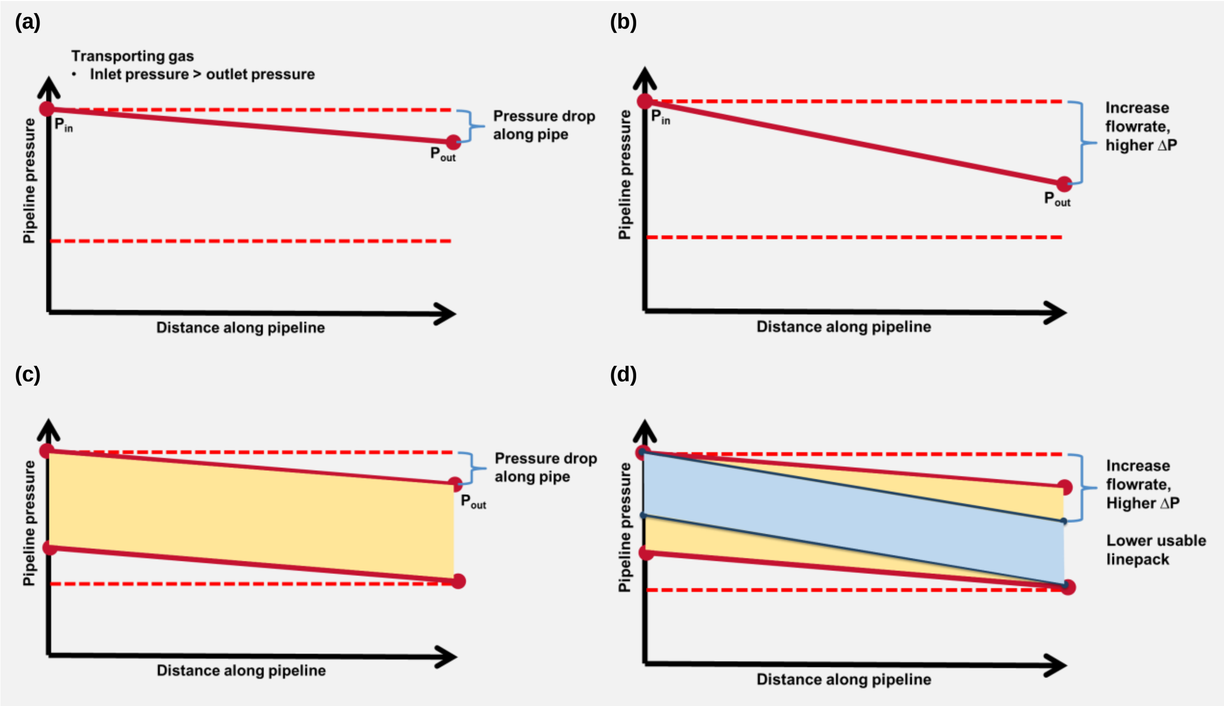
When flow increases, the pressure drop also increases, as shown in Figure 45 (a) and (b).

For a given flowrate, the useable linepack can be represented by the yellow area between the two curves in Figure 45 (c). Each curve has the same pressure drop, which is proportional to the gradient of the curve. One curve has the inlet to the pipeline at the maximum pressure (this would typically be the MAOP of the pipeline, or the maximum pressure at which a facility can inject), and the second curve, has the outlet at the MinOp pressure.

This useable linepack is what allows the quantity of gas in the system to reduce during peak times without breaching MinOp.

As a result, the gradient of the two flow vs pressure curves increases. The shaded area between the two curves reduces in this case, as in Figure 45 (d). As a result, during higher demand periods, when the flow along each of the pipelines is high, the useable linepack in the system is lower.

Figure 45 Useable linepack reduces as the flowrate along the pipeline increases, due to the higher pressure drop



The Victorian DTS is made up of many interconnected, bi-directional pipelines, and the system flows vary considerably. The variability of demand results in variability of flow along the pipelines, therefore the useable linepack changes throughout the day.

The flowrate and direction of flow along the VNI and SWP changes from day to day, and often during a gas day.

The linepack available in each zone in the system, and in the system as a whole, therefore depends on many variables, including:

- Injection pressure and injection rate.
- Flow direction.
- Demand along the line.

All these variables change throughout the gas day, and balancing linepack to ensure sufficient gas is available at every point in the system is critical for maintaining system security, even on days where supply is more than adequate to meet demand.

Operating conditions

Under normal operating conditions, the linepack adequacy of the Victorian DTS is sufficient to support 1-in-2 and 1-in-20 peak demand days. The modelling conducted to assess this assumes:

- All demand has been forecast accurately.
- Facilities inject and withdraw according to the Operating Schedule.
- The system is configured optimally, with no configuration changes required to support changing scheduled quantities.

In real-time operations, a number of unknown variables may impact security of the system. These variables include:

- Supply side variation.
  - Long-term or short-term interruption to supply.
  - Production facilities deviating from scheduled quantities.
  - Low beginning of day (BoD) linepack.
- Demand side variation.
  - Incorrect weather forecasting, or sudden deterioration of weather conditions.
  - Incorrect demand forecasting.
  - Unforecast GPG.
- Schedule variation.
  - Changes in market participant bids can change the system configuration requirements, such as a sudden increase in Culcairn withdrawals requiring additional compression.

For this reason, AEMO:

- Monitors market participants' bids.
- Tracks the system demand in real time to determine whether the forecast is over or under actual demand.
- Maintains the system in a balanced state to respond to any change in market bids.
- Monitors the NEM to determine any potential GPG requirements.

5.5.2 Demand profile and linepack adequacy

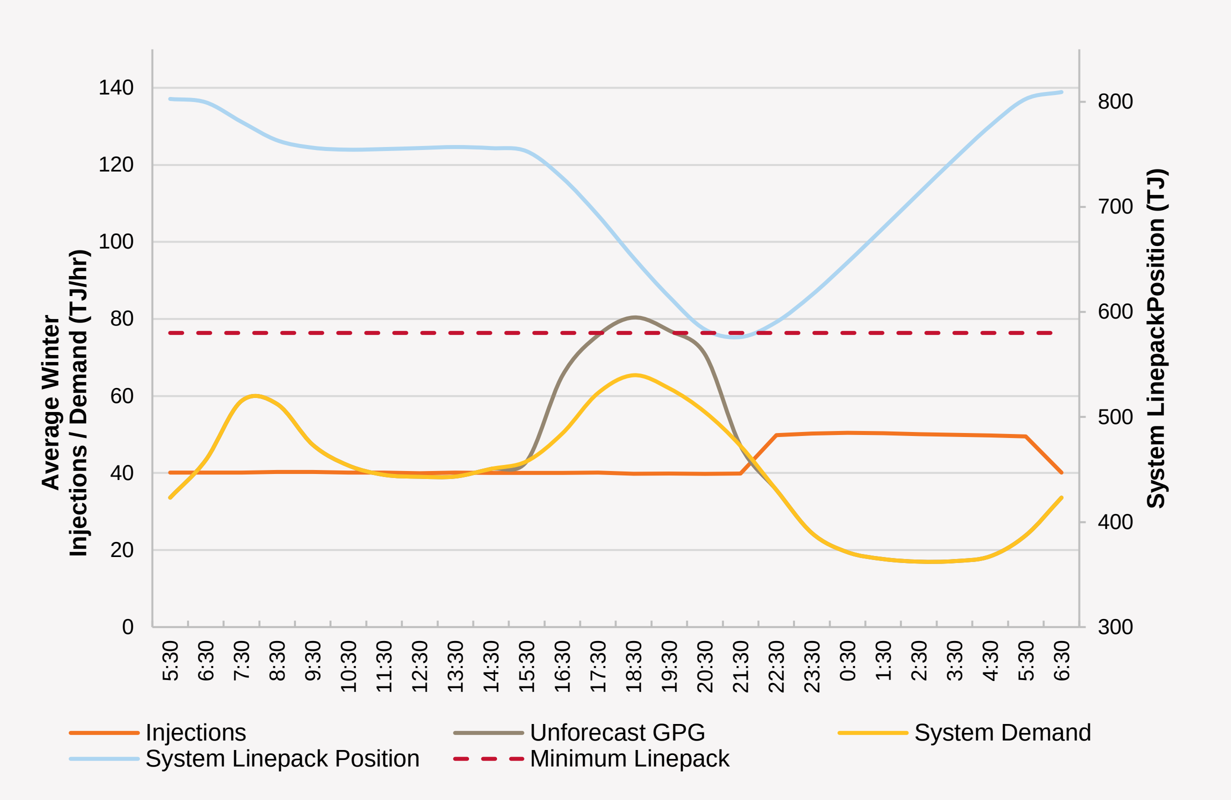
The changing shape of a typical winter demand profile is discussed in Section 5.4.1. This section highlighted that in winter the instantaneous gas demand during the morning and evening peak is increasing, while the gas demand overnight is decreasing.

As the demand profile continues to change and the peak hourly flows continue to increase, the system linepack will be further depleted from its current 10:00 pm minimum. Over time, this will consume the 71 TJ of usable linepack remaining on an average winter's day.

There are two other variables impacting the usable linepack:

- Culcairn exports:
  - For no exports, the Northern zone has usable linepack which can be utilised to support the system demand. From a mass balance basis, there is approximately 25 TJ of usable linepack remaining.
  - For any level of exports above a 1-in-2 peak demand day, there is no usable linepack, and peak shaving LNG is required to be injected.
- GPG demand:
  - Forecast GPG demand, discussed in Section 5.3, is supportable on a 1-in-2 peak demand day with no Culcairn exports and no LNG injections.
  - Figure 46 shows what the current DTS can support in terms of unforecast GPG on an average winter's day. The unforecast GPG in Figure 46 is 15 TJ/h for five hours, which is 65% of the installed GPG maximum withdrawal capacity. GPG has an installed withdrawal capacity of 23 TJ/h, which equates to the remaining usable linepack for a peak system demand day of 25 TJ.

Figure 46 Average winter demand, injection, and linepack profile with unforecast GPG



5.5.3 Options to increase system linepack

Linepack can be increased by:

- Increasing the MAOP of the pipeline.
- Adding compression along the pipeline.
- Installing additional pipelines or looping existing pipelines.

The following options for increasing useable linepack in the DTS are discussed throughout this VGPR:

- Looping the LMP (discussed in Chapter 4).
- Addition of the WORM (discussed in Section 5.1.4).
- Additional mid-line compression on the SWP (discussed in Section 5.1.3). Potential locations are Stonehaven, upstream of Lara CG, and Lara, downstream of Lara CG.

CHAPTER 6. SYSTEM MAINTENANCE AND AUGMENTATIONS

DTS maintenance planning

AEMO facilitates the Victorian Gas Wholesale Maintenance Workshop in February, August, and November each year. Workshops are held with the DTS service provider and the facility operators of gas production facilities, storage providers, and interconnected pipelines, to identify any potential supply adequacy issues, and threats to system security.

6.1 DTS service provider maintenance plan

AEMO coordinates maintenance planning of the DTS with the DTS service provider on a weekly basis, under rule 326 of the NGR.

The DTS service provider's maintenance schedule for 2017, and the capacity impact, is shown in Table 21.

The maintenance is scheduled to minimise impacts to DTS capacity. The import and export transmission capacities shown in the table are based on monthly 1-in-2 peak demand day (see Appendix B), and assume that VNIE Phase B will be commissioned by winter 2017.

AEMO will work with the DTS service provider to update any major maintenance work which impacts the DTS transmission capacity, such as Brooklyn CS outages.

Changes to the maintenance schedule are published to the Natural Gas Services Bulletin Board[63], in the:

- Capacity Outlook Report (INT 922)[64] for short-term maintenance.
- Medium Term Capacity Outlook Report (INT 928)[65] for medium-term to long-term maintenance.

[63] AEMO. Available at: http://www.gasbb.com.au/.
[64] AEMO. Available at: http://www.gasbb.com.au/Reports/Capacity%20Outlook.aspx.
[65] AEMO. Available at: http://www.gasbb.com.au/Reports/Medium%20Term%20Capacity%20Outlook.aspx.

Table 21 Proposed DTS service provider maintenance schedule for 2017[A] (subject to change)

SWZ	Asset unavailable		Maintenance window	Import capacity (TJ/d)[A]	Export capacity (TJ/d)	Comments
Melbourne	Brooklyn Compressor Station	Unit 11	3 Apr – 14 Apr 2017	–	27	Up to 5 days unit outage, with 8 hour recall.
		Unit 12	17 Apr – 28 Apr 2017	–	18	Up to 5 days unit outage, with 8 hour recall.
		Full station	1 May – 12 May 2017	–	0	Total facility outage for 5 days within the period. Recall time of 4 hours. The full station outage period(s) may be revised to coincide during expected periods of net injections at Iona UGS.
			4 Sep – 15 Sep 2017	–	0	
	Wollert Compressor Station	Station A	10 Apr – 14 Apr 2017	–	–	
			6 Nov – 10 Nov 2017	–	223	
		Station B	17 Apr – 28 Apr 2017	–	0	No export capacity is available, unless Wollert A is made available to AEMO during the maintenance period.
			23 Oct – 3 Nov 2017	–	104	
	Dandenong LNG facility		1 May – 29 May 2017	0	–	Total LNG facility outage for 10 days within time period. The site may be recalled within 4 hrs, if there is a threat to system security.
			6 Nov – 1 Dec 2017	0	–	
Geelong (Port Campbell)	Winchelsea Compressor Station		3 Apr – 14 Apr 2017	271	–	
			2 Oct – 13 Oct 2017	332	–	
			16 Oct – 27 Oct 2017	332	–	
Gippsland	Gooding Compressor Station		6 Mar -17 Mar 2017	700	–	
			9 Oct – 20 Oct 2017	700	–	
Northern	Euroa Compressor Station		20 Feb – 3 Mar 2017	118	125	
			31 July – 11 Aug 2017	125	102	Maximum Victorian imports are achievable without Euroa CS.
			14 Aug – 25 Aug 2017	125	102	
	Springhurst Compressor Station		3 Apr – 14 Apr 2017	125	93	
			6 Nov – 17 Nov 2017	125	172	
			20 Nov – 1 Dec 2017	125	172	

A) A dash line (–) indicates no impact to import or export capacity.

6.2 DTS service provider augmentations

This section covers the DTS service provider's planned augmentations for the next five years (shown in Table 22), and are related to capacity augmentation for growth and/or security of DTS supply.

The following categories have been used to define the proposed augmentation status:

- Committed – includes projects that have been budgeted by the DTS service provider. AEMO takes these projects into account for DTS capacity modelling.
- Proposed in the 2018–22 Access Arrangement – includes projects subject to AER approval as part of the DTS service provider's 2018–22 Access Arrangement submission. AEMO has not included these projects in DTS capacity modelling.

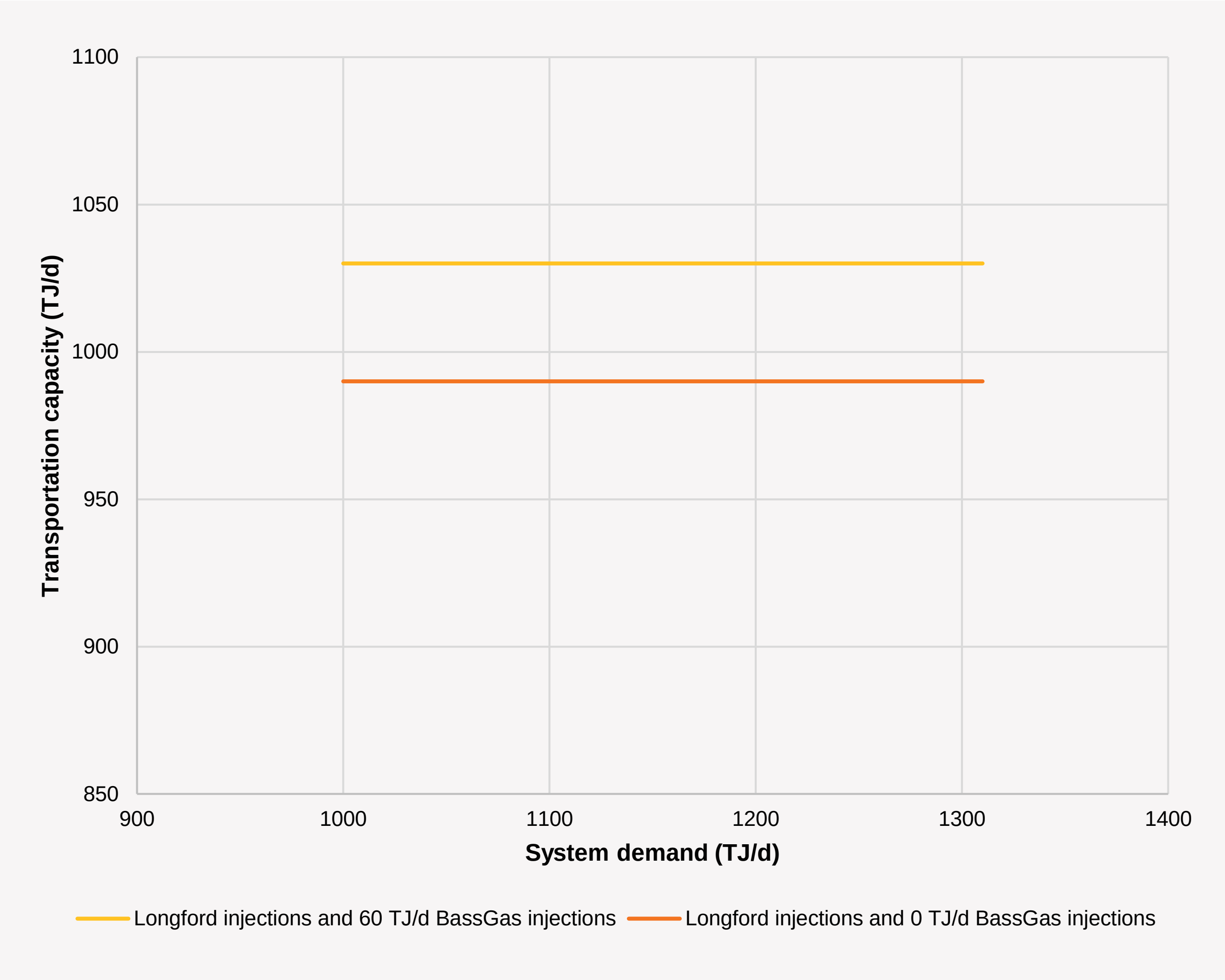
Table 22 Proposed DTS service provider augmentations

Status	Augmentation	Details	Date effective (winter of)	Comments
Committed	Victorian Northern Interconnect	Broadford to Tallarook (13.9 km, 400 mm) and Glenrowan to Wangaratta North (25.5 km,400 mm)	2017	
Proposed in the 2018–22 Access Arrangement	Iona Compressor Station	Facility upgrade to address WTS constraints	2018	Ensure reliability of the Iona CS to maintain critical fringe pressures in the WTS.
	Anglesea Pipeline Extension	Lateral from the SWP to Anglesea with city gate	2019	AEMO supports this proposal, which may maintain SWP to Melbourne transportation capacity during winter periods.
	SWP Expansion	Reconfiguration of Brooklyn site and Winchelsea bi-directional compression	2019	AEMO supports this proposal to increase SWP to Port Campbell capacity to alleviate system adequacy issues.
	Lurgi Pipeline to Warragul Looping	Pipeline looping to alleviate possible pressure breach at Warragul	2020	AEMO supports this proposal, however potential capacity restrictions may occur from winter 2019 leading to possible curtailment of load in Warragul.
	Rockbank to Wollert pipeline easement	Easements to accommodate a 500 mm Plumpton to Wollert (10,200 kPa) pipeline, 1 Centaur 50 at Wollert and Rockbank PRS	2020	AEMO supports this proposal as prudent planning in the DTS to ensure system linepack adequacy and supply to Gippsland during Longford outages.

APPENDIX A. DTS PIPELINE CAPACITY CHARTS

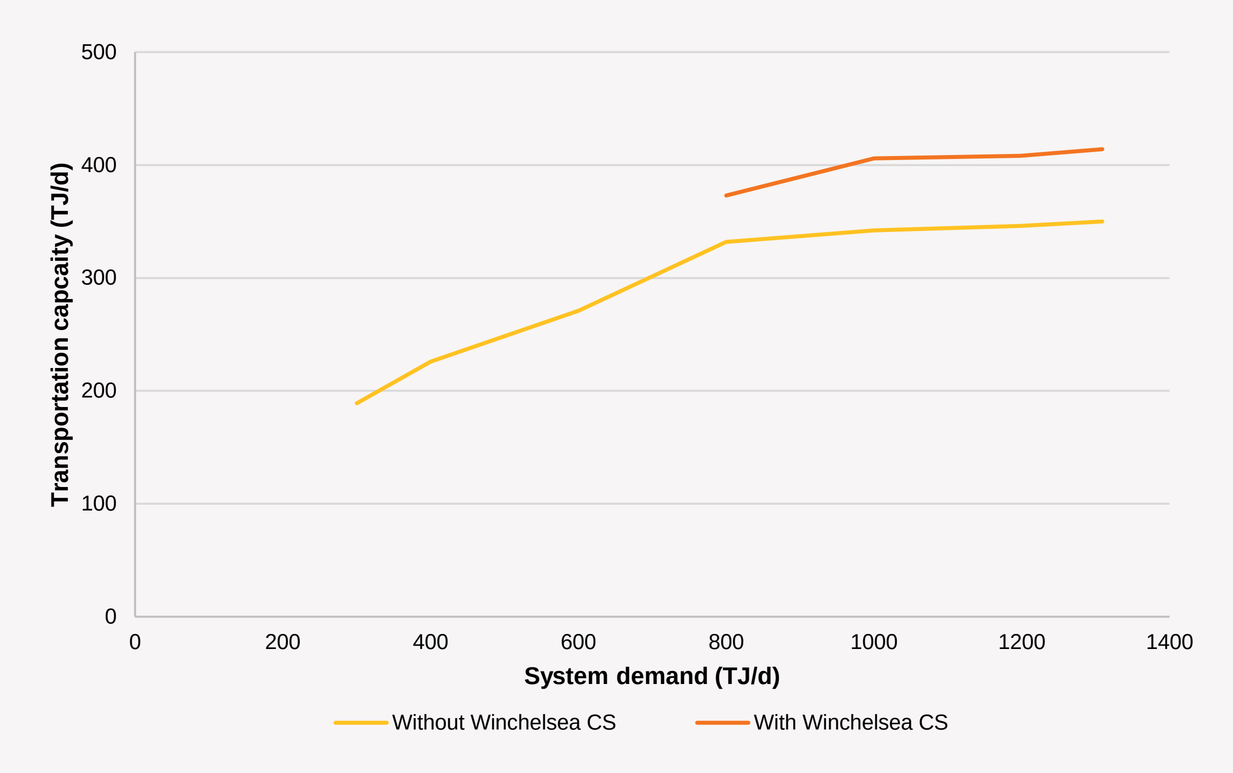
This appendix brings together pipeline capacity charts produced in the body of the report.

A.1 Longford to Melbourne pipeline

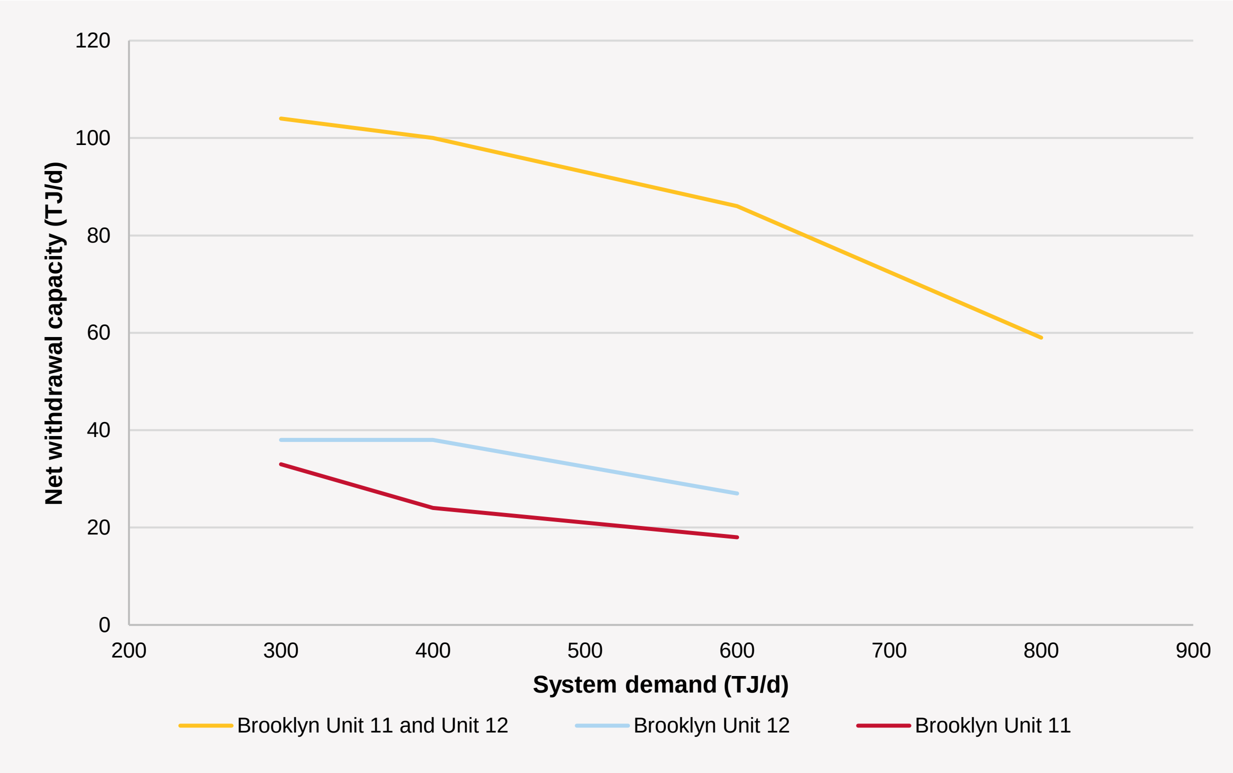


A.2 South West Pipeline

A.2.1 South West Pipeline to Melbourne

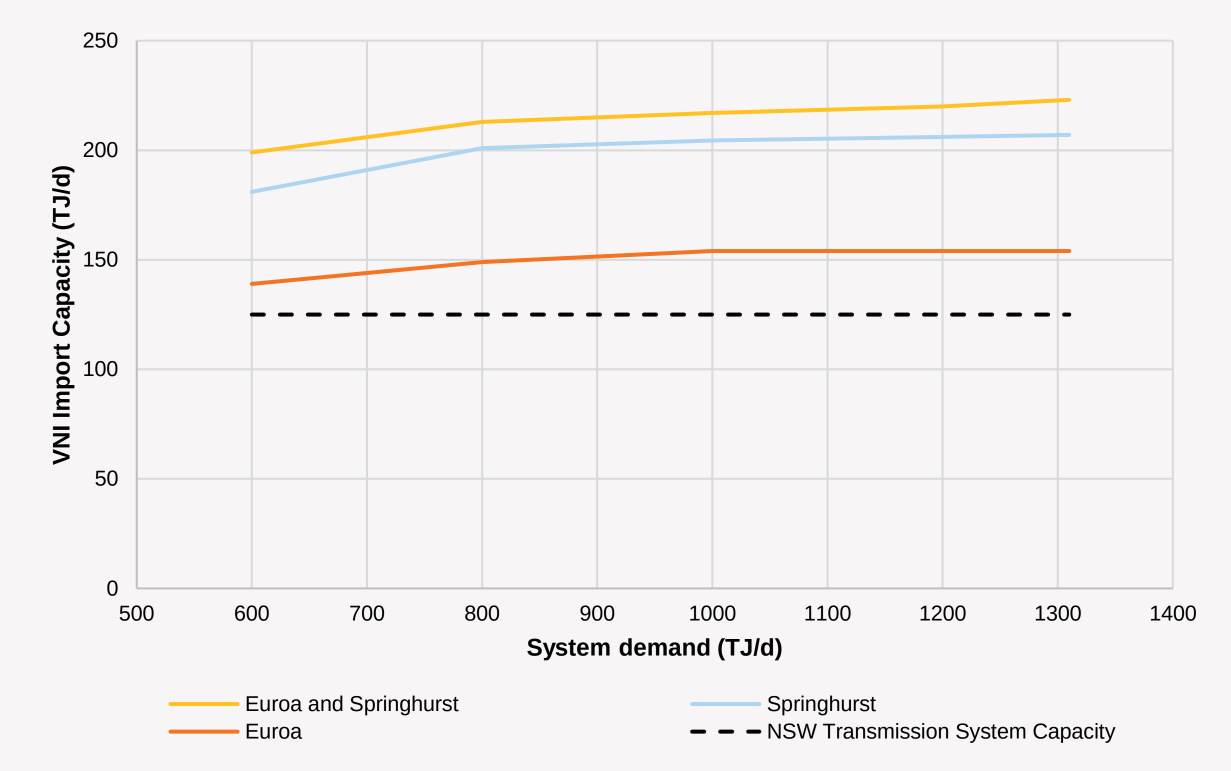


A.2.2 South West Pipeline to Port Campbell

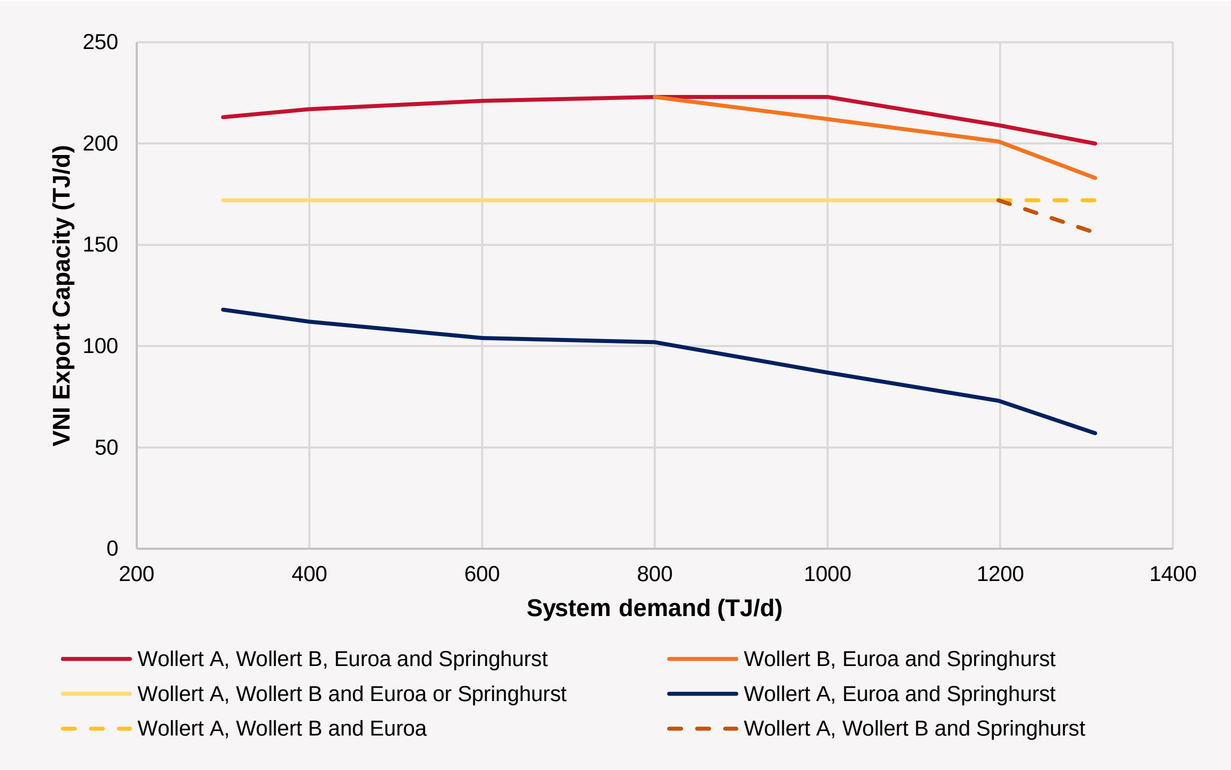


A.3 Victorian Northern Interconnect

A.3.1 Victorian Northern Interconnect to Melbourne



A.3.2 Victorian Northern Interconnect to NSW



APPENDIX B. GAS DEMAND FORECAST DATA BY SYSTEM WITHDRAWAL ZONE

The DTS system withdrawal zones are defined in Appendix E.

B.1 2017 – 2021 Annual demand

Table 23 and Table 24 show annual peak day demand broken down by SWZ for 1-in-2 and 1-in 20 peak days respectively. The difference in declining demand between the six SWZs results from differences in the SWZs' different relative composition of demand between Tariff D and Tariff V.

Table 23 Annual 1-in-2 peak daily demand (TJ/d) by SWZ

SWZ		2017	2018	2019	2020	2021	Annual average change (%)
Ballarat	Tariff V	60.4	60.1	60	59.7	59.3	-0.46%
	Tariff D	6.70	6.70	6.60	6.50	6.50	-0.75%
	SWZ demand	**67.1**	**66.8**	**66.6**	**66.2**	**65.8**	**-0.49%**
Geelong	Tariff V	76.8	76.8	77.2	77.5	77.3	-0.16%
	Tariff D	34.9	34.8	33.4	32.8	33.1	-1.30%
	SWZ demand	**112**	**112**	**111**	**110**	**110**	**-0.29%**
Gippsland	Tariff V	40.2	40.2	40.3	40.3	40.2	0.00%
	Tariff D	28.9	27.9	26.4	24.9	24.2	-4.33%
	SWZ demand	**69.1**	**68.1**	**66.7**	**65.2**	**64.4**	**-1.74%**
Melbourne	Tariff V	678	674	671	665	658	-0.77%
	Tariff D	143	143	141	139	140	-0.51%
	SWZ demand	**821**	**817**	**812**	**804**	**798**	**-0.73%**
Northern	Tariff V	79.1	78.7	78.3	77.6	76.7	-0.77%
	Tariff D	31.2	31.1	30.5	30.0	30.2	-0.81%
	SWZ demand	**110**	**110**	**109**	**108**	**107**	**-0.78%**
Western	Tariff V	8.80	8.70	8.70	8.60	8.40	-1.15%
	Tariff D	10.1	8.40	8.30	8.10	8.20	-4.80%
	SWZ demand	**18.9**	**17.1**	**17.0**	**16.7**	**16.6**	**-3.12%**

Table 24 Annual 1-in-20 peak daily demand (TJ/d) by SWZ

SWZ		2017	2018	2019	2020	2021	Annual average change (%)
Ballarat	Tariff V	67.4	67.1	67.0	66.7	66.2	-0.44%
	Tariff D	6.79	6.82	6.72	6.63	6.68	-0.42%
	SWZ demand	**74.2**	**73.9**	**73.7**	**73.3**	**72.9**	**-0.44%**
Geelong	Tariff V	85.8	85.7	86.2	86.5	86.3	0.16%
	Tariff D	35.2	35.1	33.8	33.2	33.4	-1.30%
	SWZ demand	**121**	**121**	**120**	**120**	**120**	**-0.26%**
Gippsland	Tariff V	44.9	44.9	45.0	45.0	44.9	-0.00%
	Tariff D	29.4	28.4	26.9	25.5	24.7	-4.26%
	SWZ demand	**74.3**	**73.3**	**71.9**	**70.4**	**69.6**	**-1.62%**
Melbourne	Tariff V	758	752	749	743	735	-0.76%
	Tariff D	144	144	142	140	141	-0.49%
	SWZ demand	**901**	**896**	**891**	**882**	**876**	**-0.72%**
Northern	Tariff V	88.0	87.5	87.1	86.4	85.4	-0.75%
	Tariff D	31.0	30.9	30.3	29.8	30.0	-0.81%
	SWZ demand	**119**	**118**	**117**	**116**	**115**	**-0.77%**
Western	Tariff V	9.76	9.67	9.61	9.50	9.37	-1.03%
	Tariff D	10.2	8.6	8.4	8.3	8.3	-4.77%
	SWZ demand	**20.0**	**18.2**	**18.0**	**17.8**	**17.7**	**-2.95%**

Table 25 Annual peak hourly demand (TJ/hr) by SWZ

	SWZ	2017	2018	2019	2020	2021
1–in-2 peak day demand	Ballarat	4.44	4.44	4.43	4.41	4.39
	Geelong	6.91	6.91	6.85	6.83	6.83
	Gippsland	4.13	4.10	4.04	3.98	3.95
	Melbourne	52.3	52.0	51.7	51.2	50.9
	Northern	6.21	5.96	6.12	6.06	6.01
	Western	1.05	0.95	0.94	0.93	0.93
1-in-20 peak day demand	Ballarat	4.92	4.92	4.91	4.89	4.96
	Geelong	7.49	7.49	7.44	7.42	7.43
	Gippsland	4.47	4.31	4.38	4.32	4.29
	Melbourne	57.5	57.2	56.8	56.3	55.9
	Northern	6.71	6.68	6.62	6.55	6.51
	Western	1.11	1.01	1.00	0.99	0.99

Table 26 Annual system demand (PJ/y) by SWZ (Tariff V and D split)

SWZ	Tariff type	2017	2018	2019	2020	2021
Ballarat	Tariff V	7.95	7.91	7.88	7.83	7.75
	Tariff D	1.62	1.62	1.59	1.57	1.58
Geelong	Tariff V	10.5	10.5	10.6	10.6	10.5
	Tariff D	10.7	10.7	10.3	10.1	10.2
Gippsland	Tariff V	5.35	5.35	5.36	5.34	5.31
	Tariff D	8.84	8.53	8.08	7.66	7.42
Melbourne	Tariff V	92.1	91.5	90.9	89.9	88.7
	Tariff D	34.9	34.8	34.1	33.6	33.9
Northern	Tariff V	10.1	10.0	10.0	9.90	9.77
	Tariff D	9.56	9.56	9.39	9.24	9.31
Western	Tariff V	1.28	1.27	1.27	1.25	1.24
	Tariff D	3.01	2.50	2.46	2.42	2.44

B.2 Monthly demand for 2017

Table 27 Monthly peak daily demand (TJ/d) in 2017 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day demand	Ballarat	13.4	13.1	24.9	34.4	49.4	67	67	67	67	41.3	28.7	23.9
	Geelong	42.2	44.3	56.2	64.8	91.3	112	112	112	112	78.8	63.2	59.5
	Gippsland	31.0	28.7	37.9	45.0	43.9	69.1	69.1	69.1	69.1	48.6	42.3	39.6
	Melbourne	217	212	333	448	616	821	821	821	821	514	385	320
	Northern	37.5	43	53.7	65.6	87.1	110.3	110.3	110.3	110.3	70.9	52.8	50.2
	Western	10.2	10	11.2	12.2	14.7	18.9	18.9	18.9	18.9	14.7	13.5	12.8
	System demand	**351**	**351**	**517**	**670**	**902**	**1,198**	**1,198**	**1,198**	**1,198**	**768**	**586**	**506**
1-in-20 peak day demand	Ballarat	18.3	20.1	32.4	46.8	61.8	74.2	74.2	74.2	74.2	47.2	37.7	34.9
	Geelong	48.8	53.5	66.2	81.0	108	121	121	121	121	86.5	75.2	74.3
	Gippsland	34.4	33.4	43.0	53.4	52.3	74.3	74.3	74.3	74.3	52.6	48.4	47.0
	Melbourne	273	293	420	589	759	901	901	901	901	581	487	445
	Northern	44.5	52.9	64.3	82.9	104.7	119	119	119	119	79.1	65.6	65.9
	Western	10.9	11.1	12.4	14.0	16.5	20.0	20.0	20.0	20.0	15.5	14.8	14.5
	System demand	**430**	**464**	**638**	**867**	**1,102**	**1,310**	**1,310**	**1,310**	**1,310**	**862**	**728**	**682**

Table 28 Monthly peak hourly demand (TJ/hr) in 2017 by SWZ

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak hourly demand	Ballarat	0.88	0.88	1.81	2.35	3.23	4.44	4.44	4.44	4.44	2.75	2.05	1.78
	Geelong	1.61	1.61	2.17	2.81	3.52	6.91	6.91	6.91	6.91	3.03	2.46	2.13
	Gippsland	2.23	2.23	3.06	3.96	5.40	4.13	4.13	4.13	4.13	4.56	3.46	2.99
	Melbourne	13.8	13.8	22.0	28.5	38.0	52.3	52.3	52.3	52.3	33.0	24.9	21.6
	Northern	1.99	2.00	2.93	3.79	4.68	6.21	6.21	6.21	6.21	4.69	3.48	3.01
	Western	0.51	0.51	0.56	0.72	0.84	1.05	1.05	1.05	1.05	0.83	0.63	0.55
1-in-20 peak hourly demand	Ballarat	1.08	1.16	2.24	3.11	3.94	4.92	4.92	4.92	4.92	3.09	2.61	2.39
	Geelong	1.98	2.13	2.68	3.42	4.30	7.49	7.49	7.49	7.49	3.40	2.87	2.86
	Gippsland	2.73	2.94	3.77	5.15	6.60	4.47	4.47	4.47	4.47	5.12	4.33	4.03
	Melbourne	16.9	18.2	27.2	37.3	46.4	57.5	57.5	57.5	57.5	37.0	31.3	29.0
	Northern	2.54	2.74	3.79	5.29	6.04	6.71	6.71	6.71	6.71	5.26	4.44	4.05
	Western	0.62	0.67	0.69	0.94	1.03	1.11	1.11	1.11	1.11	0.94	0.79	0.73

Table 29 Monthly GPG consumption by SWZ (TJ/m) for 2018

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	969	991	563	551	844	1228	694	574	187	265	334	524
Gippsland	344	118	0	0	12	3	29	1	0	0	0	52
Melbourne	1,585	1,379	942	878	1,314	1,626	1,060	898	549	599	530	844
Northern	-	-	-	-	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-	-	-	-	-
Total GPG consumption	**2,898**	**2,488**	**1,505**	**1,429**	**2,170**	**2,857**	**1,783**	**1,473**	**736**	**864**	**864**	**1,420**

Table 30 Monthly gas consumption by SWZ (PJ/m) for 2017

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SWZ consumption	Ballarat	0.35	0.30	0.45	0.61	1.17	1.37	1.51	1.38	0.95	0.68	0.45	0.36
	Geelong	1.21	1.10	1.34	1.40	2.34	2.55	2.82	2.62	1.70	1.58	1.31	1.24
	Gippsland	0.86	0.75	0.95	1.03	1.41	1.52	1.67	1.63	1.31	1.11	1.03	0.92
	Melbourne	5.42	5.07	6.68	8.46	14.4	17.0	19.0	17.0	11.9	9.44	6.86	5.73
	Northern	0.97	1.01	1.23	1.30	2.15	2.54	2.67	2.43	1.84	1.48	1.06	0.99
	Western	0.27	0.23	0.28	0.30	0.41	0.43	0.48	0.45	0.41	0.39	0.34	0.30
	Total	**9.08**	**8.46**	**10.9**	**13.1**	**21.9**	**25.4**	**28.2**	**25.5**	**18.1**	**14.7**	**11.0**	**9.5**
GPG consumption	Ballart	-	-	-	-	-	-	-	-	-	-	-	-
	Geelong	0.65	0.83	0.50	0.67	0.54	0.12	1.14	0.94	0.54	0.53	0.61	0.80
	Gippsland	0.28	0.04	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.05
	Melbourne	0.87	0.80	0.33	0.66	0.51	0.32	1.64	1.37	0.89	0.86	0.93	1.31
	Northern	-	-	-	-	-	-	-	-	-	-	-	-
	Western	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**1.80**	**1.67**	**0.84**	**1.33**	**1.04**	**0.44**	**2.79**	**2.31**	**1.43**	**1.39**	**1.54**	**2.17**
Total consumption	Ballart	0.35	0.30	0.45	0.61	1.17	1.37	1.51	1.38	0.95	0.68	0.45	0.36
	Geelong	1.86	1.93	1.84	2.06	2.87	2.67	3.96	3.56	2.25	2.11	1.92	2.04
	Gippsland	1.14	0.79	0.95	1.04	1.42	1.52	1.68	1.63	1.31	1.11	1.03	0.98
	Melbourne	6.29	5.87	7.01	9.11	15.0	17.4	20.6	18.4	12.8	10.3	7.79	7.04
	Northern	0.97	1.01	1.23	1.30	2.15	2.54	2.67	2.43	1.84	1.48	1.06	0.99
	Western	0.27	0.23	0.28	0.30	0.41	0.43	0.48	0.45	0.41	0.39	0.34	0.30
	Total Consumption	**10.9**	**10.1**	**11.8**	**14.4**	**23.0**	**25.9**	**30.9**	**27.9**	**19.6**	**16.1**	**12.6**	**11.7**

APPENDIX C. SYSTEM OPERATING PARAMETERS

C.1 Critical system pressures

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 31).

Table 31 lists key critical locations and associated pressure obligations (MAOP and MinOP).

This table is required to be published under Rule 323(3)(g) and can also be found in AEMO's Wholesale Market Critical Location Pressures.[66]

Table 31 Critical Location Pressure in the Declared Transmission System

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of Data and Comments
Longford to Melbourne	6,890	Longford	4,500	Connection Agreement. Operational maximum pressure of 6,750 kPa applies due to operating limits at the plant.
		Sale	4,800	AEMO-Distributor Connection Deed
		Gooding CS Inlet	4,200	APA design parameter
		Loy Yang B GPG	4,000	
		VicHub	4,200	Connection Agreement
		TasHub	4,200	Connection Agreement
		BassGas	3,500	Connection Agreement
		Dandenong CG Inlet	3,200	APA Design Parameter
		Wollert CS Inlet	3,000	APA Design Parameter
Lurgi	2,760	Morwell Porters Rd	2,650	
		Warragul	1,400	AEMO-Distributor Connection Deed
		Pakenham South	1,400	AEMO-Distributor Connection Deed
		Jeeralang GPG	2,500	
Metropolitan Ring Main	2,760	Dandenong Terminal Station	2,650	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Dandenong North	2,500	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Nth pressure obligation

[66] AEMO. 2015. Available at: http://aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-Critical-Location-Pressures-NGR-10.pdf.

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of Data and Comments
		Brooklyn (Melbourne side)	1,700 1,800	AEMO-Distributor Connection Deed Brooklyn compressor suction min pressure requirement
		Keon Park	2,200	AEMO-Distributor Connection Deed
		Newport GPG	1,800	
		Somerton GPG	2,000	
Wollert to Euroa	8,800	Wandong PRS inlet	3,700	APA design parameter
		Euroa CS Inlet	3,200	APA design parameter
Euroa to Wodonga	7,400	Wodonga	2,400	AEMO-Distributor Connection Deed
		Shepparton	2,400	AEMO-Distributor Connection Deed
		Echuca	1,200	AEMO-Distributor Connection Deed
		Rutherglen	2,400	AEMO-Distributor Connection Deed
		Koonoomoo	1,200	AEMO-Distributor Connection Deed
		Springhurst CS Inlet	3,000	APA design parameter
		Culcairn	2,700	Connection Agreement
Victorian Northern Interconnect Expansion	10,200	Euroa CS Inlet	3,200	APA design parameter
		Springhurst CS Inlet	3,000	APA design parameter
Brooklyn Corio Pipeline	7,390	Corio (Avalon, Lara and Werribee)	2,300 w 1,900 s	7,390 kPa Pipeline licence pressure 2,300 kPa during high flow (winter), 1,900 kPa during low flow (summer), Distributor Connection Deed
		Coogee Methanol	1,800	
		Laverton North GPG	1,700	
Brooklyn Lara Pipeline	10,200	Qenos	3,800	3,800 kPa approved AEMO-Distributor Connection Deed (Wyndham Vale & Qenos) Usually controlled >4,500 kPa by BLP CG
Brooklyn Ballan Pipeline	7,400	Sunbury	2,000	AEMO-Distributor Connection Deed
		Ballarat	2,100	AEMO-Distributor Connection Deed
		Plumpton PRS	4,500	APA design minimum pressure
South West Pipeline	10,200	Iona	3,800	Connection Agreement Operational maximum pressure of 9,500 kPa applies due to operating limits at the plant
		SEAGas	3,800	Connection Agreement
		Winchelsea Inlet	4,500	APA Design Parameter
		Colac	3,800	APA Group-Distributor Connection Deed
Western Transmission System	7,400	Iluka	2,500	APA Group-Distributor Connection Deed
		Portland	2,800	AEMO-Distributor Connection Deed
Wandong to Bendigo	7,390	Bendigo	3,000	AEMO-Distributor Connection Deed
		Maryborough	3,000	AEMO-Distributor Connection Deed
		Carisbrook	3,000	AEMO-Distributor Connection Deed

C.2 Storage operating parameters

C.2.1 Dandenong LNG facility

The LNG storage provider requires one hour pre-notification (by AEMO) ahead of commencing injections into the DTS. This is to enable preparation and plant cool down due to the low temperatures of the LNG process. Injections of LNG in the first and last hour need to be equal or less than 5.5 TJ/h. This is to assist with the cool-down and warm-up of the re-liquidation process. The LNG is generally scheduled at the firm rate of 5.5 TJ/h for 16 hours, which equates to the firm contracted rate of 87 TJ/d.

Table 32 LNG operating parameters

Year	Min. hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure Range (kPa) [67]
2017– 21	2.2	10	5.50	5.52	2,750 – 2,760

C.2.2 Iona Underground Storage

Iona UGS requires two hours notification to switch between withdrawals to storage and injection into the DTS.

The storage operating parameters shown in Table 33, including injection and withdrawal rate and pressures, have been historically and are foreseeably sustainable. These may, however, be impacted by a combination of maintenance, peak demand conditions and a low total storage inventory.

Table 33 Iona operating parameters

Year	Min. hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure Range (kPa)
2017	1	18.13	4.531	3.188	4,500 – 9,600
2018	1	18.33	4.583	3.604	4,500 – 9,600
2019	1	23.75	5.938	4.792	4,500 – 9,600
2020	1	23.75	5.938	4.792	4,500 – 9,600
2021	1	23.75	5.938	4.792	4,500 – 9,600

C.3 Compressor utilisation in 2016

Table 34 lists the hours of usage for each DTS compressor station by month for the year 2016.

The most utilised compressors in the DTS are the Brooklyn compressors, which have been heavily used to support Iona UGS refill and also Ballarat and Geelong demand during winter. Brooklyn compressors have been operated twice as much as all VNI compressors[68] combined, indicating the priority of participants to refill Iona UGS levels before winter 2017.

Two key maintenance activities at Brooklyn impacted compressor availability during 2016 and hence Iona UGS refill efforts:

- Jan–Feb 2016 – Brooklyn Unit 10 and Unit 11 outage due to fin fan after cooler upgrade.
- April 2016 – BCS outage due to station valve upgrade.

[67] The minimum and maximum pressure is based on injection in the 2800kPa system.
[68] The VNI compressors are Wollert, Euroa, and Springhurst.

Table 34 Total operating hours by compressor station in 2016

Compressor station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn	699	848	1482	474	980	192	409	663	1,071	814	721	383
Winchelsea	93	148	196	198	406	476	357	302	331	306	406	192
Iona	0	1	1	0	0	66	52	1	1	21	0	0
Gooding	0	0	0	0	3	60	178	78	26	5	0	0
Wollert (A+B)	25	13	15	116	64	133	113	25	43	163	183	0
Euroa	130	122	128	247	108	142	32	25	66	91	103	18
Springhurst	0	4	0	0	39	2	45	57	94	22	4	0

APPENDIX D. DTS SERVICE PROVIDER ASSETS AND OTHER MAINTENANCE

D.1 Critial DTS assets

Critical assets in the DTS are considered assets required to maintain system security on peak demand days. Table 35 outlines these assets by SWZ and operational purpose.

Table 35 Critical DTS assets

SWZ	Asset	Description	Purpose/role
Melbourne	Brooklyn Compressor Station	• Two Saturn compressors: Unit 8 rated at 850 kW and Unit 9 rated at 950 kW. • Two Centaur compressors: Unit 11 rated at 2,850 kW and Unit 12 rated at 3,500 kW. • Unit 10 (Centaur compressor) is not available to AEMO to operate under the Service Envelope Agreement (SEA).	• Provides compression to the Brooklyn Corio pipeline, SWP and the Brooklyn Ballarat pipeline. • The Centaur machines are used to supply Laverton GPG and Iona UGS withdrawals. • The Saturn machines are used only to supply system demand.
	Wollert Compressor Station	• Station B: Two Centaur compressors; Unit 4 and Unit 5 rated at 4,550 kW. • Station A: Three Saturn compressors; Unit 1 and Unit 2 rated at 950 kW and Unit 3 rated at 850 kW. – Currently not available to AEMO to operate, however will be reintroduced into the SEA as part of the VNI Phase B project.	• Provides compression to the Wollert to Wodonga pipeline and assists supply to NSW via the NSW-Vic Interconnect at Culcairn. Exports to NSW are generally not possible without Wollert Centaur compression.
	Dandenong LNG Facility	• The LNG facility has a maximum capacity of 180 t/h, requiring the availability of three vaporisers, three pumps and one boil off compressor. The LNG contracted rate is 100 t/h for 16 hrs, which provides up to 87 TJ/d.	• The LNG facility is used mainly to supplement supply on days of high peak gas demand. LNG can be used also by participants throughout the year to balance their portfolio (market scheduled LNG).
	Brooklyn CG	• Five Regulator runs • Two water bath heaters • Station inlet and outlet isolation valves	• Is one of the three main supply sources to the Melbourne Metropolitan Region along with Wollert CG and Dandenong CG. • It supplies gas from Port Campbell gas fields. The station provides pressure reduction of gas flowing from the Brooklyn to Corio pipeline and/or from the Brooklyn to Lara CG.
	Dandenong CG	• Eight Regulator runs; which are categorised into Station A (3 regulator runs) and Station B (5 regulator runs) • Station inlet and outlet isolation valves	• Is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Dandenong CG • The station provides pressure regulation of gas being supplied into Dandenong to Princess Hwy and Dandenong to West Melbourne pipelines. The station is supplied from Longford gas facility via the Longford to Melbourne pipeline.
	Wollert CG	• Four Regulator runs • One water bath heater • Station inlet and outlet isolation valves	• Is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Wollert CG • It provides pressure regulation of gas being supplied into the Keon Park to Wollert transmission pipeline. The facility provides two sources of gas supply, one from Longford gas facility via Pakenham to Wollert pipeline and the other from Moomba gas facility via the Wollert to Wodonga pipeline.

SWZ	Asset	Description	Purpose/role
Geelong (Port Campbell)	Winchelsea Compressor Station	• One Taurus Compressor rated at 5,740 kW.	• Provides compression to increase SWP network transportation capacity to Brooklyn.
Gippsland	Gooding Compressor Station	• Four Centaur Compressors each rated at 2,850 kW. – Up to three compressor units can be operated simultaneously, with one redundant unit.	• Provides compression within LMP when total Longford injections exceed approx. 700 TJ/d. • Compression is utilised to increase transportation capacity of LMP, maintain DCG inlet pressure above its min operating pressure during peak period and to move gas away from Longford injection point to prevent backing off the Longford plant before the peak demand when linepack is low.
Northern	Euroa Compressor Station	• One Centaur Compressor rated at 4,550 kW.	• Provides compression to the Euroa to Wodonga pipeline mainly for increasing export capacity to NSW when higher pressure is required at Culcairn. The compressor may be also used to increase import capacity into Victoria from NSW.
	Springhurst Compressor Station	• One Centaur Compressor rated at 4,550 kW.	• Provides compression for imports or exports via NSW – VIC interconnect at Culcairn.
Western	Iona Compressor Station	• Two reciprocating compressors rated at 300 kW each.	• Provides compression to Western Transmission Network from the SWP.

D.2 Other proposed maintenance

The DTS Service provider will be performing a series of pipeline inspections (pigging) works during 2017, which are listed below:

- Dandenong to Henty Street pigging proposed for March 2017.
- Euroa to Kyabram pigging proposed for April/May 2017.
- Ballarat to Bendigo pigging proposed for April/May 2017.

Pipeline inspections are carried out on live pipelines, but do not affect pipeline capacity. The timing of these works will depend on resource availability, suitable flows, and pressure conditions.

APPENDIX E. VICTORIAN GAS PLANNING APPROACH

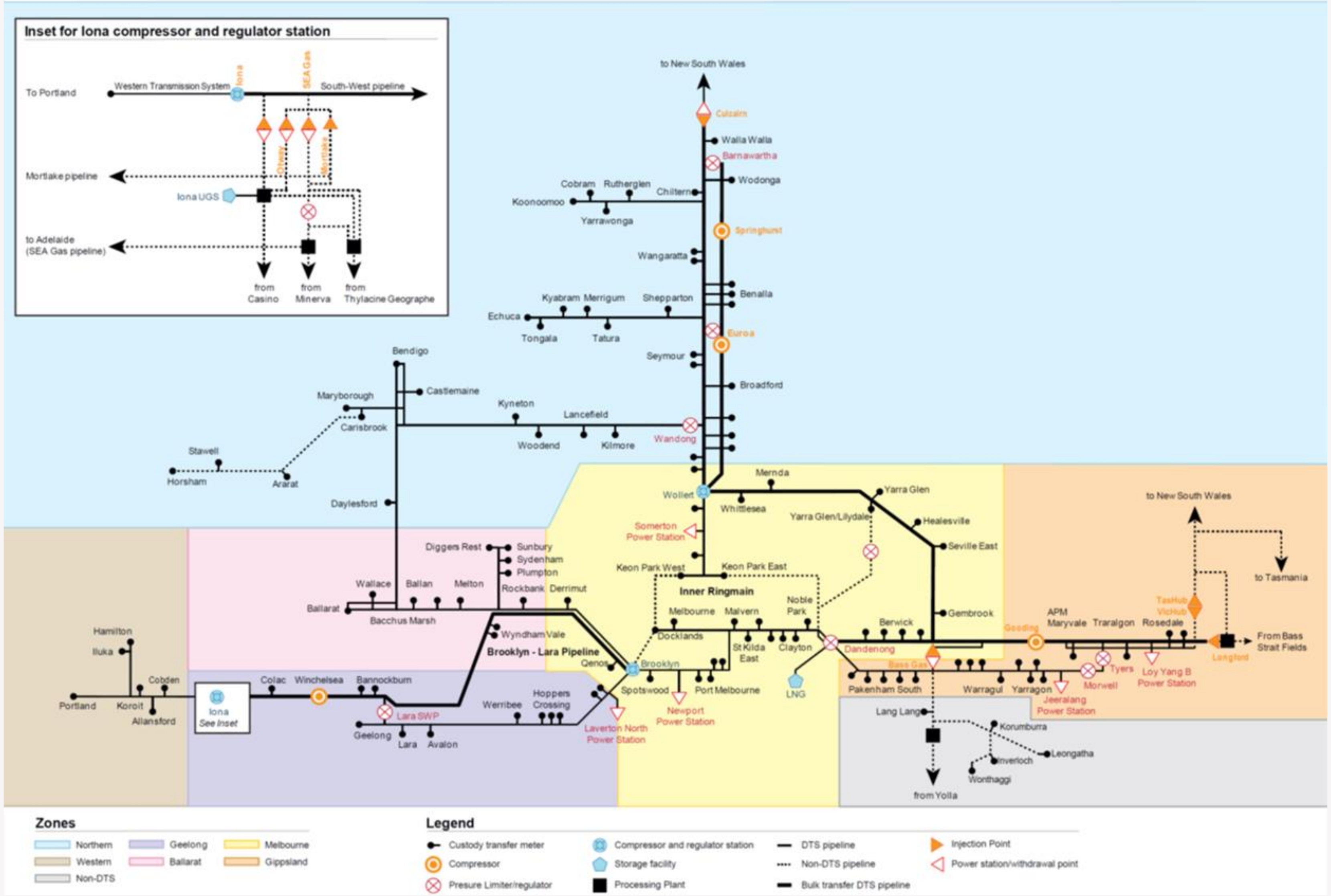
E.1 DTS System withdrawal zones

The DTS is divided into six zones, shown in Figure 47:

- Northern.
- Geelong.
- Melbourne.
- Western (Western Transmission System).
- Ballarat.
- Gippsland.

The SWZs are used to report demand forecast, and to assess system adequacy by zone.

Figure 47 System Withdrawal Zones in the DTS



E.2 Victorian gas planning criteria

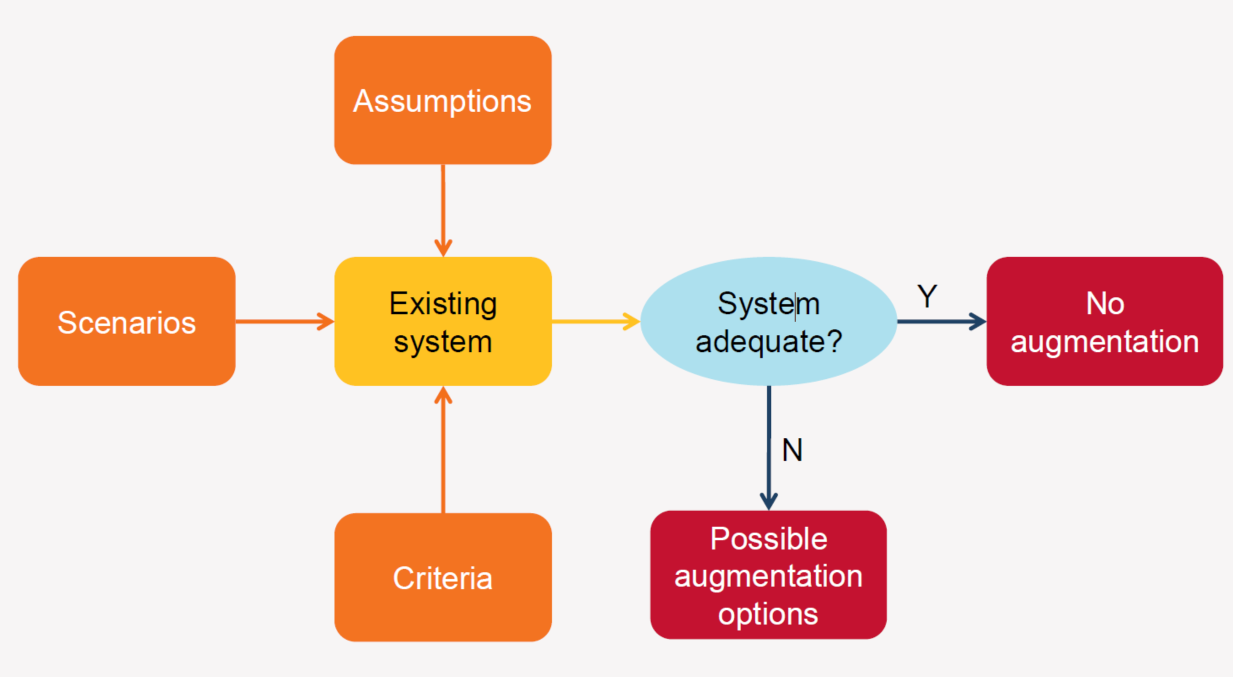
E.2.1 Gas planning

Under Rule 323(1), AEMO must publish a planning review, *"by no later than 31 March 2015 and by 31 March in every second year thereafter"*.

AEMO's planning objective is to identify 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 assess and report on the adequacy of the gas supply and transmission capacity to meet forecast demand. AEMO carries out detailed computer simulations of the DTS to analyse system adequacy.

Figure 48 Victorian gas planning process



When a DTS augmentation requirement is identified, AEMO publishes the information in the VGPR or a detailed planning report specific to that augmentation.

E.3 Planning methodology

AEMO's planning methodology involves a series of assessments of gas supply and demand, system capacity, and system adequacy, to ensure a safe and reliable supply over the outlook period.

Figure 49 shows an overview of the gas planning methodology, and Table 39 provides more detail.

Figure 49 Gas planning methodology overview

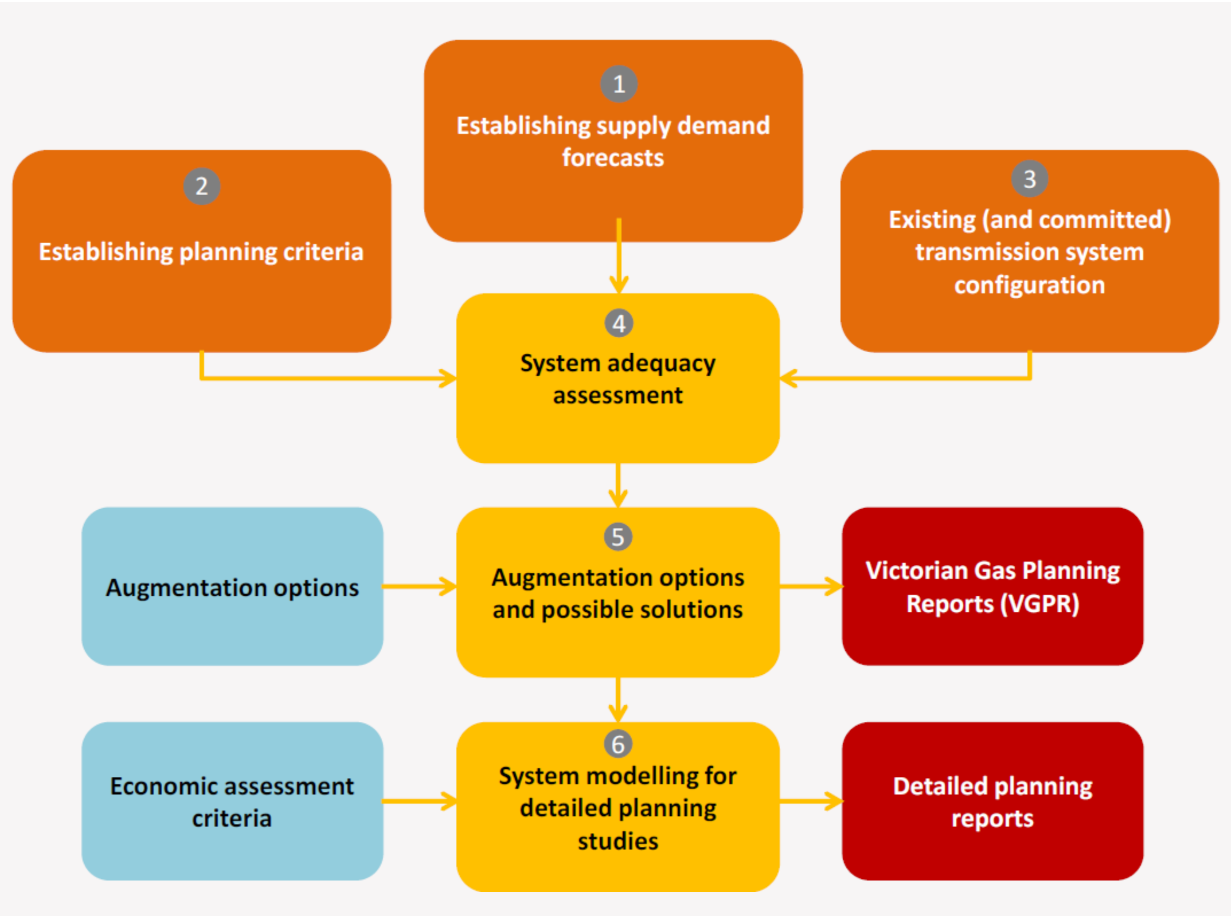


Table 36 Gas planning methodology summary

Process	Detail
Establishing supply demand forecast	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	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)[A], and a range of other operating criteria that need to be satisfied, such as linepack targets.
Existing and committed transmission system configuration	In conjunction with the DTS service provider, 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 DTS service provider.
System adequacy assessment	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).
Augmentation options and possible solutions	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. 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

A) AEMO. 2015. Available at: http://aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-System-Security-Procedures-NGR-11.pdf.

E.4 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 37 to Table 40 list the standard modelling assumptions used by AEMO.

AEMO uses a set list of assumptions used for capacity modelling for SWP (Table 41) and Northern zone export (Table 42).

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[69] (lower than the linepack target) and surprise cold weather.[70]

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

[69] The BoD target is 780 TJ, being the total DTS linepack which includes both passive and active linepack.
[70] 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.

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.

E.4.1 Supply assumptions

Table 37 and 0 list the assumptions relating to the supply of gas to the DTS.

Table 37 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
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.

Table 38 Gas DTS modelling heating values

Location	Heating value (MJ/m^3)
Longford	38.67
BassGas	38.63
Iona (winter)	37.95
Iona (summer)	37.60
LNG	39.11

E.4.2 Demand assumptions

Table 39 lists the assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table 39 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 (AusNet design requirement).
Transmission 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 GPG demand (OCGT)	A 25 TJ/d GPG demand profile.[A]

A) The GPG demand profile is from 12:00 pm until 9:00 pm.

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[71] 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 the NTNDP and with 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.

E.4.3 Impact of operational factors modelling assumptions

Table 40 lists the assumptions relating to operation of the DTS, and assist with the management of linepack and constraints specified in various agreements.

Table 40 Impact of operational factor modelling assumptions

	Impact of operation factor modelling assumptions and conditions	
Location	**Operational assumptions**	**Notes**
Longford	Maximum pressure is 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.
	Minimum pressure is 4,500 kPa	
Iona	Maximum pressure is 9,500 kPa	As per pipeline licences, operating agreements and practice.
	Minimum pressure is 4,500 kPa	
Culcairn	Minimum pressure is 8,600 kPa for exports, 6,500 kPa for imports.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
Brooklyn-Lara Pipeline	Minimum pressure is 4,500 kPa	Pipeline design requirement for the BLP.
Brooklyn City Gate	Minimum pressure is 3,200 kPa	Normal operating condition.
Wollert City Gate	Minimum pressure is 3,000 kPa	Normal operating condition.
Dandenong City Gate	Minimum pressure is 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).
Other factors	BoD and end-of-day (EoD) linepack are equal	For capacity modelling, mining of linepack not allowed.
	BoD linepack 20 TJ below target[A]	Used for lateral constraint modelling.
	DTS service provider's 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.
	Gas delivery temperature above 2 °C	Gas Quality Regulations requirement.

A) The normal BoD linepack target is 780 TJ which includes both passive and active linepack. In this case the BoD linepack is 760 TJ.

[71] Tariff D customers use more than 10 TJ/y or 10 GJ/h. Tariff V customers are the small industrial and commercial users and residential customers.

E.4.4 Capacity modelling assumptions

Modelling assumptions are listed in Table 41 for SWP capacity, and Table 42 for Northern capacity. Under different operating conditions on the day, the capacity results will differ.

Table 41 SWP capacity modelling assumptions

SWP capacity modelling assumptions and conditions		
SWP capacity assumptions		**Notes**
Injections		For SWP to Melbourne: • Maximum injection from Iona and the rest will be supplied from Longford and/or BassGas for all cases. For SWP to Port Campbell: • Maximum injection from Longford and/or BassGas for all cases.
GPG demand		No GPG demand for all cases.
Culcairn export demand		Export demand of 100 TJ/d 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		For SWP to Melbourne: • For the case with Winchelsea compressor in place, the target compressor outlet was set to 10,200 kPa; compressor would control on maximum power during model runs. For SWP to Port Campbell: • Capacity for varying compressor configurations at Brooklyn was determined to manage outages.
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. Minimum pressure is 4,500 kPa.
	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 [A]	Minimum pressure is 3,500 kPa

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

Table 42 Northern capacity modelling assumptions

Northern capacity modelling assumptions and conditions		
Northern capacity assumptions		**Notes**
Injections		Maximum injection from Longford does not exceed 970 TJ/d. 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		Capacity for varying compressor configurations was determined, to manage outages.
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 8,600 kPa for Northern export capacity modelling cases. Modelled minimum pressure is 4,500 kPa for Northern import capacity modelling cases.
	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[A]	Minimum pressure is 3,500 kPa

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

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 LNG, can assist overall system capacity.

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.

E.4.5 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 43 lists the planning assumptions for deterministic mass-balance modelling.

Table 43 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[A]
Supply reschedules	Effective 10:00 am, 2:00 pm, 6:00 pm, 10:00 pm

A) The normal BoD linepack target is 780 TJ which includes both passive and active linepack.

E.4.6 Seasonal variations in the DTS capacity

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.

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

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
EDD	Effective degree days
kPa	Kilopascals
kscm/h	Thousand standard cubic meters per hour
PJ	Petajoules
PJ/m	Petajoules per month
PJ/y	Petajoules per year
t/h	Tonnes per hour
TJ	Terajoules
TJ/d	Terajoules per day
TJ/h	Terajoules per hour
TJ/m	Terajoules per month
TJ/y	Terajoules per year

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulators
AEST	Australian Eastern Standard Time
BBP	Brooklyn to Ballarat Pipeline
BCP	Brooklyn to Corio Pipeline
BCS	Brooklyn Compressor Station
BLP	Brooklyn to Lara Pipeline
BoD	Beginning of day
CG	City Gate
CPP	Close Proximity Point
CS	Compression Station
CTM	Custody Transfer Meter
DCG	Dandenong City Gate
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
ESV	Energy Safe Victoria
GPG	Gas-powered Generation
GSOO	Gas Statement of Opportunities
LMP	Longford to Melbourne Pipeline
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MAOP	Maximum Allowable Operating Pressure

Abbreviation	Expanded name
MDQ	Maximum Daily Quantity
MinOp	Minimum Allowable Operating Pressure
NEM	National Electricity Market
NGERS	National Greenhouse and Energy Reporting Scheme
NGFR	National Gas Forecasting Report
NGR	National Gas Rules
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine
OS	Operating Schedule
POE	Probability of Exceedance
PRS	Pressure Reduction Station
PS	Pricing Schedule
PV	Photovoltaic
SEA Gas	South East Australian Gas
SWP	South West Pipeline
SWZ	System Withdrawal Zones
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for Gas
UGS	Iona Underground Storage
VGPR	Victorian Gas Planning Report
VNI	Victorian Northern Interconnect
VNIE	Victorian Northern Interconnect Expansion
VRET	Victorian Renewable Energy Target
WORM	Western Outer Ring Main
WTS	Western Transmission System

GLOSSARY

Term	Definition
1-in-2 peak day	The 1-in-2 peak day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). 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.
back-off	A forced reduction in gas injections.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS), and injected at Pakenham.
beginning-of-day linepack	Beginning-of-day linepack (BoD LP) is equal to the end-of-day linepack (EoD LP) from the previous gas day.
bid stack	Incremental gas quantities by injection point offered by market participants and stacked in price order.
BOC Gases Australia Limited	The BOC plant, situated next to APA Group in Dandenong, liquefies natural gas for storage in APA Group's liquefied natural gas (LNG) tank.
connection point	A gas delivery point, transfer point, or receipt point.
Culcairn	The gas transmission network interconnection point between Victoria and New South Wales.
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
custody transfer meter	A meter installed at a connection point to measure gas withdrawn from or injected into a transmission system.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the DWGM) or may be registered as market participants in their own right.
Dandenong Terminal Station	The Dandenong Terminal Station is located adjacent to the LNG storage facility. The Dandenong Terminal Station receives gas from the Dandenong City Gate, the Lurgi line (Morwell-Dandenong TP), and the BOC liquefaction plant. The terminal station facilitates the metering and regulating of gas before it flows into the Distribution networks or back into the Declared Transmission System.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the *National Gas (Victoria) Act*, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Transmission System constraint	A constraint on the gas Declared Transmission System.
Declared Wholesale Gas Market (DWGM or market)	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
Degree Day	A commonly used temperature model for predicting gas demand for area/space heating. See also Effective Degree Day.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.
distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.
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 that will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
end-of-day linepack	End-of-day linepack (EoD LP) is measured at the end of a gas day at 6:00 AM. EoD LP is equal to the beginning-of-day linepack (BoD LP) for the next gas day.

Term	Definition
facility operator	Operator of a gas production facility, storage facility, or pipeline.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas quality excursion	A breach of a gas quality limit (as determined by the Gas Quality Guidelines).
Gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
injection	The physical injection of gas into the transmission system.
Iona node	The injection node for the South West Pipeline (SWP), Western Transmission System (WTS) and SEA Gas pipelines, the Underground Gas Storage (UGS), and the on-shore and offshore Otway Basin supplies.
lateral	A pipeline branch.
let-down gas	Gas released from the BOC plant (during the liquefaction processes) into the high pressure distribution system.
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 liquefied natural gas (LNG) storage facility is located at Dandenong.
Longford node	Injection node for the Eastern Gas Pipeline, gas Declared Transmission System, Tasmanian Gas Pipeline, and Gippsland gas supplies.
maximum allowable operating pressure	The maximum pressure at which a pipeline is licensed to operate.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand.
maximum hourly quantity	Maximum hourly quantity (MHQ) of gas supply or demand.
meter	A device that measures and records volumes and/or quantities of electricity or gas.
meter ID number	The number attaching to a daily metered site with annual gas consumption greater than 10,000 GJ or an maximum hourly quantity (MHQ) greater than 10 GJ, which are assigned as Tariff D in the AEMO meter installation register. See also Tariff D.
metering	The act of recording electricity and gas data (such as volume, peak, and quality parameters) for the purpose of billing or monitoring quality of supply.
metering data	The data obtained from a metering installation, including energy data.
metering identification registration number	The unique gas supply withdrawal point identifier (applying to daily metered sites and Customer Transfer Meters (CTM)). See meter ID number.
metropolitan ring main	The 450 mm, distributor-owned pipeline from Dandenong to Keon Park to West Melbourne.
minimum operating pressure	The minimum pressure at which a pipeline can operate.
natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
participant	A person registered with AEMO in accordance with the Victorian gas industry Market and System Operation Rules (MSOR).
peak day profile	The hourly profile of injection or demand occurring on a peak day.
peak flow rate	The highest hourly flow rate of gas or maximum hourly quantity (MHQ) passing a particular point in the system under normal conditions (as determined by AEMO) in the immediately preceding 12-month period or, if gas has passed a particular point in the system for a period of less than 12 months, the highest hourly flow rate that in AEMO's reasonable opinion is likely to occur in respect of that system point under normal conditions for the following 12-month period.
peak loads	A short duration peak in gas demand.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
petajoule (PJ)	An International System of Units (SI) unit, 1 PJ equals 1,015 Joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
pipeline throughput	The amount of gas that is transported through a pipeline.

Term	Definition
retailer	A seller of bundled energy service products to a customer.
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the Market and System Operation Rules (MSOR), for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
SEA Gas Interconnect	The interconnection between the SEA Gas pipeline and the gas Declared Transmission System (DTS) at Iona.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
shoulder season	The period between low (summer) and high (winter) gas demand, it includes the calendar months of April, May, October, and November.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
Statement of Opportunities	The Statement of Opportunities published annually by AEMO.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).
summer	In terms of the gas industry, December to February of a given fiscal year.
surprise event	An event that can occur within the day for which, in order to operationally balance the system, AEMO may need to change the schedule of gas injections and/or withdrawals issued at the start of the gas day (due to a change in forecast weather, for example).
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 the following: • 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. • Compressor station power and efficiency.
system coincident peak day	The day of highest system demand (gas). See also system demand.
system constraint	See Declared Transmission System constraint.
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 gas powered generation (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 (gas DTS) 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	Part of the gas Declared Transmission System (gas DTS) that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
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 VicHub (Longford) to Tasmania.
terajoule	Terajoule (TJ). An International System of Units (SI) unit, 1 TJ equals 1,012 Joules.
transmission customer	A customer that withdraws gas from a transmission delivery point.

Term	Definition
transmission delivery point	A point on the gas Declared Transmission System (DTS) at which gas is withdrawn from the transmission system and delivered to a transmission customer or injected into a storage facility.
unaccounted for gas	The difference between metered injected gas supply and metered and allocated gas at delivery points. Unaccounted for gas (UAFG) comprises gas losses, metering errors, timing, heating value error, allocation error, and other factors.
Underground Gas Storage	The Underground Gas Storage (UGS) facility at Iona.
uplift charges	When higher than market price gas needs to be injected for operational reasons, market participants are paid to cover the difference between the market price and their bid price (ancillary payments). The uplift charges fund the ancillary payments. Congestion uplift charges are a sub-set of uplift charges.
value of customer reliability	The value consumers place on having a reliable supply of energy, which is equivalent to the cost to the consumer of having that supply interrupted.
Value of Lost Load	Value of Lost Load (VoLL) is a price cap applied to gas prices. The value of VoLL, , is currently $800 per GJ
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas Declared Transmission System (DTS) at Longford, facilitating gas trading at the Longford hub.
Western Transmission System (WTS)	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 (DTS).
winter	In terms of the gas industry, 1 June to 30 September of a given calendar year.
within-day balancing	The balancing of supply and demand during the gas day by use of scheduled injections and depletion of system linepack. Liquefied natural gas (LNG) is used as an additional supply if linepack is predicted to fall below the minimum level required for system security.