UPDATE
VICTORIAN GAS PLANNING REPORT

GAS TRANSMISSION SYSTEM PLANNING FOR VICTORIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

The purpose of this publication is to provide information about changes in the Victorian Declared Transmission System.

AEMO publishes this Victorian Gas Planning Report Update in accordance with Rule 323 of the National Gas Rules. This publication is based on information available to AEMO at 31 January 2016, although AEMO has endeavoured to incorporate more recent information where practical.

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Version control

Version	Release date	Changes
1	29/2/2016	

EXECUTIVE SUMMARY

The *2016 Victorian Gas Planning Report (VGPR) Update* provides information about changes in the Victorian Declared Transmission System (DTS) since AEMO published the 2015 VGPR in April 2015 as part of the *2015 Gas Statement of Opportunities*.

This VGPR Update is specific to the following material changes since the 2015 VGPR:

- The Victorian Northern Interconnect (VNI) Expansion Project is increasing transportation capacity for gas exports to New South Wales via Culcairn, from 118 terajoules a day (TJ/d) in 2015 to 148 TJ/d in 2016.[1] There is sufficient Victorian gas supply capacity to support the expanded VNI capacity with near maximum firm rates of LNG from the Dandenong LNG facility.
- A transportation capacity limitation has been identified for gas flows from Melbourne to Port Campbell, which is expected to restrict gas flows required for refilling the Iona Underground Gas Storage (UGS) reservoirs. This constraint will also reduce gas supplies for exports to South Australia via the SEA Gas Pipeline, and may reduce the gas available for supply into Victoria during peak demand days from UGS. This constraint will need to be addressed to maximise the full UGS capacity as Port Campbell offshore production declines.
- Expansion plans by Iona UGS may require increased capacity of the South West Pipeline (SWP). This is for gas flows from Port Campbell to Melbourne to unlock the full supply available at Port Campbell to support Victorian and Culcairn export demand.
- Increased local primary production industry and residential demand at the Warragul Custody Transfer Meter means augmentation of the DTS is required to maintain security at this connection point. This augmentation could be deferred by one or two years, subject to the distributor accepting a lower contractual minimum pressure at the Warragul Custody Transfer Meter.

Actual demand and consumption[2]

The 2015 peak gas demand day for Victoria occurred on Tuesday 14 July 2015.

The total demand[3] of 1,177.1 terajoules (TJ) comprised system demand (1,162.1 TJ) and gas-powered generation (GPG) demand (15.0 TJ). This was 34.0 TJ less than the highest demand day the previous year, which was 1,211.1 TJ on 1 August 2014 (also the highest demand day for the last eight years).

On 14 July 2015, the DTS also exported 58.2 TJ through Culcairn to New South Wales.

To support total demand and Culcairn exports, the total gas injected into the DTS was 1,193.1 TJ. Injections were lower than the sum of total demand and Culcairn exports (1,235.3 TJ) because beginning-of-day linepack was above target. All demand was supplied without breaching any pressure requirements throughout the DTS.

Winter[4] 2015 was Victoria's coldest winter since 1989. Total system consumption for winter 2015 was 104.6 petajoules (PJ), 10% higher than winter 2014.

System capacity

System capacity (1,450 TJ/d) is expected to remain materially unchanged for winter 2016 and is sufficient to meet demand for the five-year outlook period. System capacity was increased for winter 2015 following the early 2015 commissioning of the Winchelsea compressor on the SWP.

[1] On a 1-in-20 system demand day. A 1-in-20 forecast means the projection is expected to be exceeded, on average, one out of every 20 years (or 5% of the time).
[2] Demand refers to capacity or gas flow on an hourly or daily basis. Consumption refers to gas usage over a monthly or annual period.
[3] Total demand is equal to the sum of system demand and gas fired generation, but excludes exports.
[4] Winter is defined in the gas industry as 1 June to 30 September.

Supply capacity

The total daily maximum supply expected into the DTS is 1,351 TJ for 2016.

This total consists of Longford and VicHub (850 TJ), BassGas (55 TJ), and the Port Campbell region (446 TJ), noting that:

- Total production capacity at the Longford Gas Plant (1,040 TJ/d) and the Iona UGS (430 TJ/d) is expected to be similar to that available during winter 2015. These production capacities are lower than historical capacities of up to 1,150 TJ/d and 500 TJ/d, respectively. Gas plant capacities are dependent on various factors, including plant maintenance and offshore field production, and are published on the Natural Gas Services Bulletin Board.[5]
- Longford and VicHub injections into the DTS are not modelled above 850 TJ/d due to increased flows expected from Longford to New South Wales along the Eastern Gas Pipeline (EGP). This reduces gas available to be injected into the DTS. The EGP's capacity has increased by 20% to 358 TJ/d following the commissioning of two new compressors on the pipeline in early 2016.

Further supply is also available from the Dandenong liquefied natural gas (LNG) facility (87 TJ firm capacity) and, depending on market conditions, via imports through Culcairn (125 TJ). Neither LNG nor Culcairn imports form part of the 1,351 TJ total daily maximum supply into the DTS, because Culcairn imports are not guaranteed and LNG is a peak shaving facility, and is a limited resource that is utilised as a supply of last resort.

The Tasmanian Gas Pipeline (TGP) connection (120 TJ) into the Longford Melbourne Pipeline (LMP) was expected to be available for winter 2016, but is now not expected to be commissioned until after winter 2016.

After the Basslink electricity interconnector between Victoria and Tasmania became unavailable on 20 December 2015, gas flows from Longford to Tasmania via the TGP increased to supply the Tamar Valley Power Station. AEMO does not expect this to have a material impact on gas supply for Victoria.[6]

Peak gas system demand

The VGPR uses the peak day forecasts for the DTS in AEMO's *2015 National Gas Forecasting Report* (NGFR), published in December 2015.[7] Both the 1-in-2 and 1-in-20 annual peak day system demands are forecast to decrease at an average annual rate of 1.0% over the five-year outlook period:

- The 1-in-2 system demand day is forecast to decrease from 1,194 TJ in 2016 to 1,148 TJ in 2020.
- The 1-in-20 system demand day is forecast to decrease from 1,304 TJ in 2016 to 1,257 TJ in 2020.

The expected maximum daily supply capacity of 1,351 TJ/d is sufficient to satisfy the 1-in-20 peak day system demand during the outlook period.

While there is sufficient supply and system capacity to meet peak day system demand, GPG demand and potential large exports to New South Wales may require increased injections of LNG on high demand days.

Annual gas system consumption

The VGPR uses AEMO's 2015 NGFR annual gas system consumption forecasts. Over the five-year VGPR outlook period, annual gas system consumption (excluding GPG and exports) is forecast to reduce from 204 PJ per year for 2016, to 192 PJ by 2020, an average annual decline of 1.2%.

Average annual consumption for residential, small commercial, and small-to-medium industrial customers (Tariff V) is forecast to decrease by 0.3% per year (revised down from an increase of 1.1% in

[5] The online Gas Bulletin Board (GBB) for eastern and south-eastern Australia is available at http://www.gasbb.com.au/.

[6] Longford has the capacity to supply additional gas to Tasmania without decreasing supply to the DTS, as its supply to Sydney via the EGP can be readily replaced by supply via the Moomba to Sydney Pipeline if required.

[7] AEMO. *2015 National Gas Forecasting Report*. Available: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report.

AEMO's 2014 NGFR[8]). The annual average large commercial and industrial customer (Tariff D) consumption is forecast to decrease by 2.6% per year (revised down from a decline of 1.6% in AEMO's 2014 NGFR).

Victorian gas exports

During winter 2015, Victorian gas exports to New South Wales via Culcairn increased by 116% to 4.8 PJ, compared to winter 2014 (2.2 PJ). In 2015, additional VNI looping was commissioned, which increased export capacity to 118 TJ.

During 2016, additional looped sections of this pipeline are expected to be commissioned, increasing export capacity by a further 25% to 148 TJ/d.

[8] The 2014 NGFR was published in December 2014 and is available at: http://www.aemo.com.au/Gas/Planning/Forecasting/NGFR-Archive/2014-National-Gas-Forecasting-Report.

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CHAPTER 1. INTRODUCTION

1.1 Background

The *Victorian Gas Planning Report* (VGPR) informs market participants and government about gas transmission capacity changes that impact security and reliability in the Victorian Declared Transmission System (DTS). Following a rule change in 2014, Rule 323 of the National Gas Rules requires that AEMO prepare and publish a planning review every second year after 31 March 2015. AEMO published a VGPR in 2015, with the next report due in 2017.

Where AEMO becomes aware of any information that materially alters the most recently published planning review, Rule 323(5) requires AEMO to update that planning review as soon as practicable.

1.2 Overview

This VGPR Update was triggered by the following changes and emerging issues in the DTS.

- **Victorian Northern Interconnect (VNI) Expansion Project:**

  There will be a further increase in the VNI transportation capacity for gas exports from Victoria to New South Wales. The VNI capacity will increase from 118 TJ/d to 148 TJ/d during winter 2016. This VGPR Update provides formal notification of this increased capacity and the impacts on the operation of the DTS. This increase does not present any security or reliability concerns.
- **South West Pipeline (SWP) capacity to Port Campbell:**

  The SWP transport capacity from Melbourne to Port Campbell is forecast to be insufficient to meet future requirements without augmentation of the DTS. SWP withdrawals are used to fill the Iona Underground Gas Storage (UGS) reservoirs and to flow to South Australia via the SEA Gas Pipeline. Declining production from the Otway, Minerva, and Casino gas developments at Port Campbell is contributing to the need for increased SWP withdrawals. Options to address the current capacity limitation are provided in this VGPR Update.
- **Proposed Iona UGS expansion:**

  The Iona UGS facility plays a critical role in supporting Victorian winter peak demand. The capacity of this facility and the SWP have both progressively increased since they were commissioned in 1999. This VGPR Update includes information about the proposed expansion of the Iona UGS facility, which is expected to trigger the need to increase the SWP transportation capacity toward Melbourne. Options for increasing the SWP capacity are provided in this document.
- **Warragul supply:**

  Increased demand from a local primary production industry site and residential customers at the Warragul Custody Transfer Meter (CTM) means augmentation of the transmission system is required to maintain security at this connection point. The minimum contractual pressure at the Warragul CTM was breached on 22 July 2014 due to high demand. Operational mitigations were put in place following this incident however these are temporary measures. Options to address this issue are included in this VGPR Update.

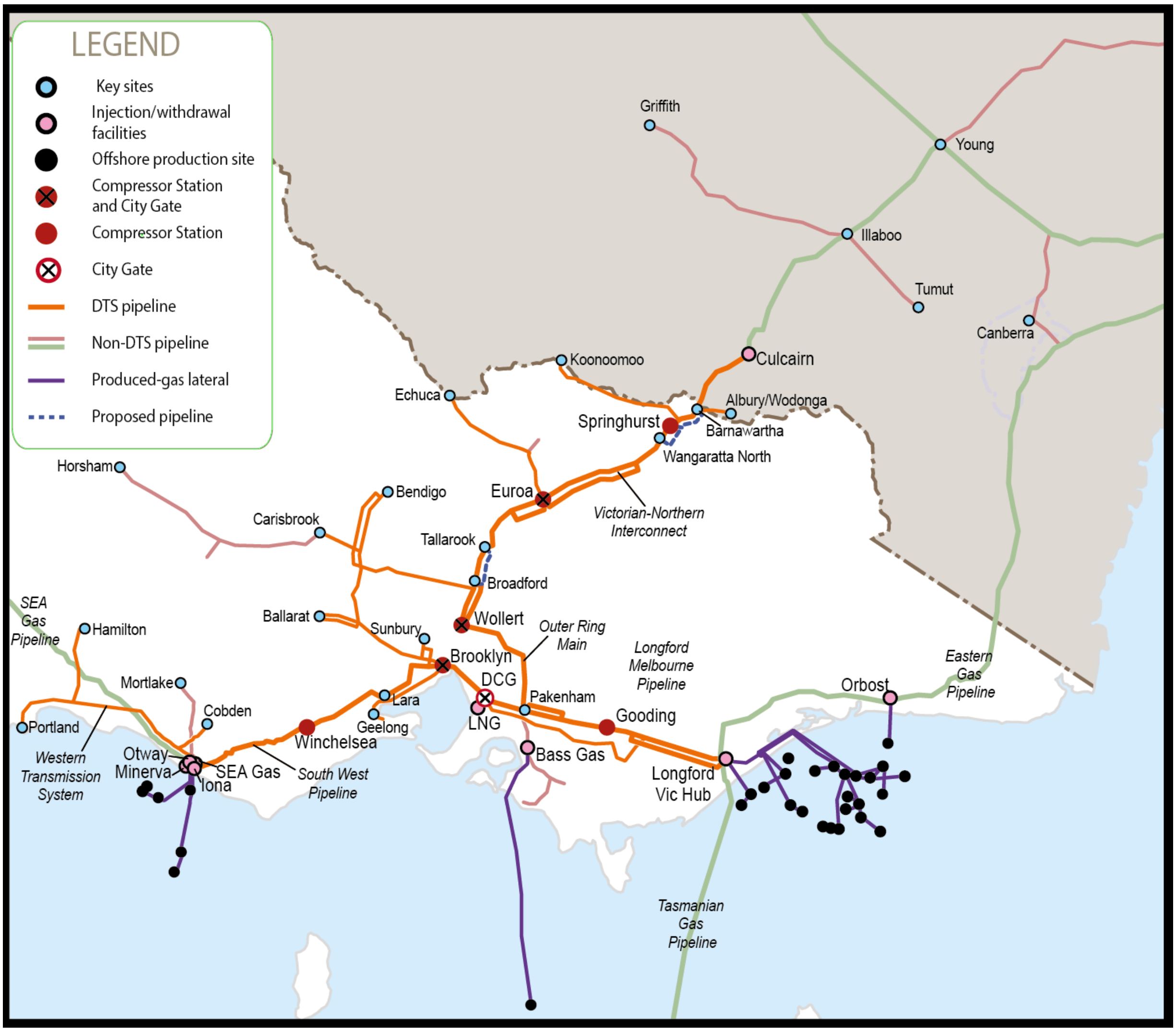
1.3 Gas planning in Victoria

AEMO operates the DTS, and APA GasNet is the DTS Service Provider that owns and maintains the DTS. Third party asset owners maintain and augment the associated infrastructure, including production facilities and interconnected pipelines.

AEMO provides planning information about pipeline constraints, capability, system security and development proposals.

Figure 1 provides a high-level map of the Victorian gas transmission system including the DTS (in orange) and other gas transmission pipelines, as well as the location of gas production and storage facilities, and other key transmission system assets.

Figure 1 Map of Victorian gas transmission system



1.4 Winter 2015 review

During winter 2015, Melbourne experienced its coldest winter in 26 years (since 1989). There were 18 days with a maximum temperature of less than 12°C, which has also not happened since 1989.

This translated into consistent high demand, particularly throughout July, when the DTS recorded:

- Nine consecutive days, and a total of 14 days, when the system demand[9] exceeded 1,000 TJ/d.
- Average system demand of 976.6 TJ/d, which was the highest monthly demand on record.
- The highest average daily injections into the SWP at the Iona UGS facility on record, at 205.7 TJ/d.

[9] System demand is demand from Tariff V customers (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D customers (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 UGS.

- Average daily flow to New South Wales via the VNI of 62.9 TJ/d, which was the highest on record during a winter month.
- The highest total demand day of 1,168 TJ, on 14 July 2015, which was lower than the 2014 peak of 1,213 TJ on 1 August 2014, but higher than the 2011 to 2013 peak days.

AEMO uses Effective Degree Days (EDD) to forecast gas demand in the DTS. This is a factor derived from temperature, wind speed and sunshine hours, and each gas day is assigned an EDD value based on the weather conditions.

The cumulative total EDD for the winter[10] 2015 was 1,113, which is 21% higher than the total EDD of 917 for winter 2014. Total gas consumption, which comprises system demand plus gas-powered generation (GPG), was 104.6 PJ during the winter period, 9.8% higher than the 95.3 PJ consumed during the same period in 2014.

A total of 2,505 tonnes (112.4 TJ) of liquefied natural gas (LNG) was scheduled for injection into the DTS during winter 2015. None of this LNG was scheduled for peak shaving purposes, which is the scheduling of LNG injections to maintain system pressure during periods of very high gas demand.

1.5 Gas forecasting

AEMO published the *2015 National Gas Forecasting Report* (NGFR) in December 2015. This provides forecasts of annual gas consumption and maximum gas demand across eastern and south-eastern Australia, including the Victorian DTS, over a 20-year outlook period. AEMO is required to publish the demand and supply projections in the NGFR and the *Gas Statement of Opportunities* (GSOO) under clause 91D of the National Gas Law.

Under Rule 323(3), AEMO is required to use the NGFR 1-in-2 and 1-in-20 system demand day demand forecasts for the next five years to determine whether there is sufficient gas supply and DTS capacity to match this demand.

A 1-in-20 system demand day is the demand that would be expected under severe weather conditions, which would only be expected to be exceeded, on average, once in 20 years. This demand level has a 5% probability of exceedance (POE). This may also be referred to as the 95% peak day.

[10] Winter period is 1 June to 30 September.

CHAPTER 2. VICTORIAN NORTHERN INTERCONNECT CAPACITY

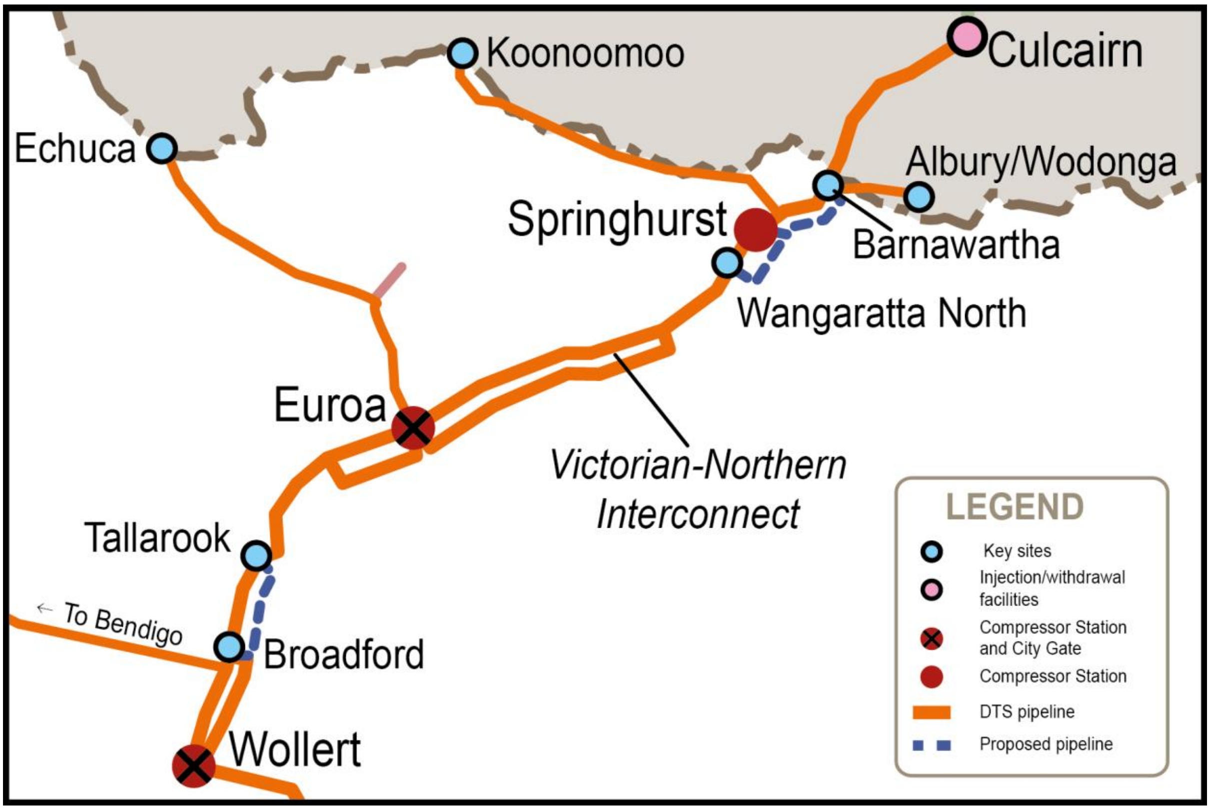
2.1 Key points

- The DTS Service Provider is completing system augmentations to increase the VNI:
  - Export capacity via Culcairn on a 1-in-20 system demand day[11], from 118 TJ/d in 2015 to 148 TJ/d in 2016. AEMO's current operational practice guidelines of profiled LNG injections of 60 TJ/d will be unchanged and will continue to be required to support the new export quantity and to maintain system pressures.
  - Maximum import capacity via Culcairn on a 1-in-20 system demand day, from 125 TJ/d in 2015 to 196 TJ/d in 2016. VNI imports will be limited by the capacity of the New South Wales transmission system to supply gas at Culcairn.
- This capacity change does not present any security or reliability issues for the DTS.

2.2 Background

Following the completion of the previous stages of the VNI Expansion Project in 2015, the DTS Service Provider is undertaking further work to increase the VNI export capacity through the construction of additional sections of duplicated pipeline. A map of the previous and current expansions of the VNI is shown in Figure 2.

Figure 2 Map of proposed northern Victoria DTS augmentation



[11] Export capacity is the gas that can be transported on 1-in-20 system demand day and it is basis for assigning authorised maximum daily quantity (AMDQ).

The current expansion is taking place in both the DTS and the New South Wales gas transmission system, and will increase the VNI export capacity by 25% on a 1-in-20 system demand day, from 118 TJ/d to 148 TJ/d.[12]

The following DTS augmentations are expected to be completed by winter 2016 as part of this project:

- An additional 55.2 km of 400 mm diameter pipeline duplication, comprising:
  - 16.2 km between Broadford and Tallarook.
  - 18.8 km between Wangaratta North and Springhurst.
  - 20.2 km between Springhurst and Barnawartha.
- Modification of the existing Wollert pressure limiter to permit south-bound flow from Culcairn into the Pakenham–Wollert Pipeline (Outer Ring Main).
- Installation of pressure control valves at Euroa to increase the south-bound flow from Culcairn and to assist with managing changes in VNI flow direction.
- Reconfiguration of the Springhurst compressor to support the increased VNI export capacity.

If the VNI from Wollert to Wodonga is fully duplicated in the future, the export capacity is expected to increase to approximately 200 TJ/d, with a Maximum Allowable Operating Pressure (MAOP) of 10,200 kPa. Wollert Compressor Station (WCS) units 1, 2 and 3 (A Station) would need to be returned to service to support demand in northern Victoria on high demand days with high export flows via Culcairn.

The new 400 mm piping being used in the VNI Expansion Project has a pressure rating of 15,300 kPa (Class 900 piping), which would enable future operation at higher pressures and increased flows. Further equipment upgrades would be required to enable these new sections of pipeline to operate at 15,300 kPa. Without these upgrades, the piping will only operate to a pressure of 10,200 kPa.

2.3 Export capacity expansion

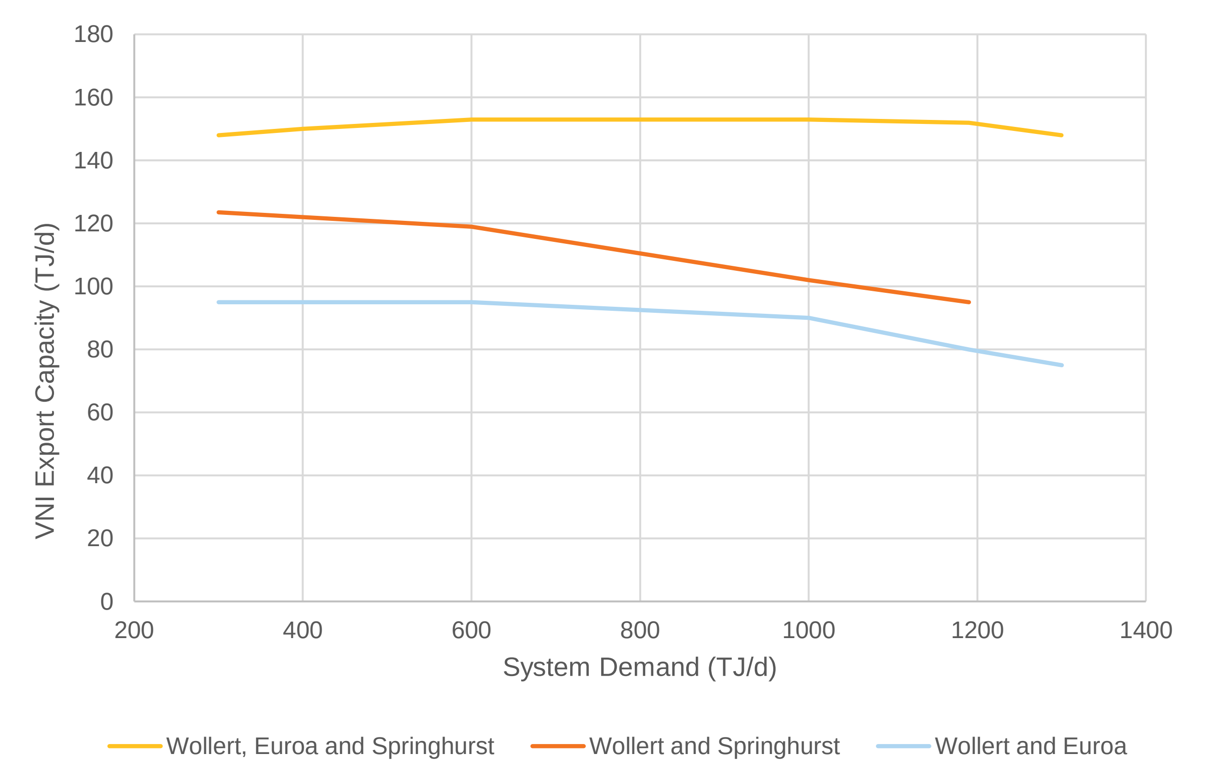
Figure 3 shows the VNI export capacity that will be available after the system augmentations detailed in Section 2.2 are completed for winter 2016 at a MAOP of 10,200 kPa.

These capacity curves include the various combinations of Wollert, Euroa, and Springhurst compressor availabilities.

The current VNI export capacity chart is included in Appendix A.1.4.

[12] See: APA. 24 July 2015. *APA signs new gas transportation agreement to further expand its Victoria – New South Wales Interconnect.* Available: http://www.apa.com.au/investor-centre/news/asxmedia-releases/2015/2015-07-24-apa-signs-new-gta-vnie.aspx

Figure 3 Victorian Northern Interconnect export capacity post winter 2016 expansion



To achieve the maximum VNI export capacity, the Wollert, Euroa, Springhurst, and Culcairn Compressor Stations must be available. The maximum VNI export capacity is:

- 153 TJ/d during system demand days between 600 TJ and 1,000 TJ, constrained by pipeline capacity between Springhurst and Culcairn.
- Reduced to 148 TJ/d on demand days below 600 TJ, as compressor power output reduces at higher ambient temperatures.
- 148 TJ/d on a 1-in-20 system demand day, limited by both the Longford to Melbourne Pipeline (LMP) and the SWP flowing at maximum capacity. Profiled LNG injections are also required.

For winter 2016 after the expansion, 60 TJ of LNG (equivalent to 12 hours of injection at firm rate) is required to maintain critical system pressures and to support VNI exports of 148 TJ/d on a 1-in-20 system demand day. This is unchanged from AEMO’s published operational practice guidelines on LNG injections, which is to inject up to the maximum firm capacity of 100 tonnes/h (5.5 TJ/h) to support exports.[13] If LNG injections above the firm rate were required to support exports, AEMO would reduce the export quantity by stopping the Wollert compressor and issue a Notice of Threat to System Security, consistent with the Wholesale Market System Security Procedures (Victoria).

Without the Euroa and Springhurst Compressor Stations, the projected VNI export capacity reduces by 15% at low system demand and by up to 50% at high system demands. This is due to the reduced compressor capacity also being required to support system demand in northern Victoria.

Due to an increase in the minimum suction pressure of the Springhurst compressor, from 2,300 kPa to 4,500 kPa, no VNI exports via Culcairn can be supported on a 1-in-20 system demand day when the Euroa Compressor Station is unavailable. This is because the Springhurst compressor suction pressure would be less than 4,500 kPa.

[13] AEMO. June 2014. *Increased likelihood of LNG injection requirements in the DWGM.* Available: http://www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum

2.4 Import capacity expansion

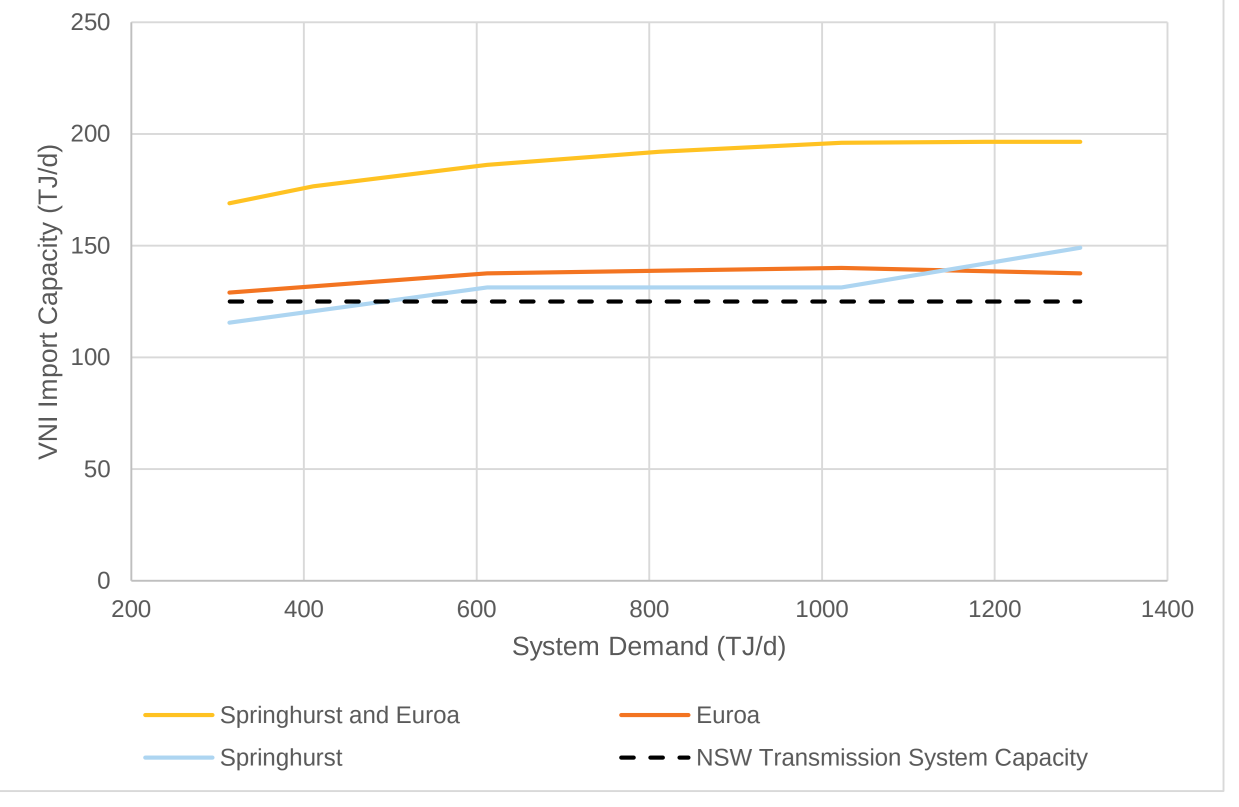
Figure 4 shows the VNI import capacity versus system demand that will be available after the system augmentations detailed in Section 2.2 are completed for winter 2016, with the combinations of Euroa and Springhurst Compressor Stations' availability.

The current VNI import capacity chart is included in Appendix A.1.3.

The maximum VNI import capacity of 196 TJ/d is possible when the Euroa and Springhurst Compressor Stations are available and demand will be at or above a 1-in-20 system demand day.

These VNI import capacities assume that the New South Wales transmission system north of Culcairn supplies gas at 6,500 kPa. This would require the Young Compressor Station on the Moomba to Sydney Pipeline to be available.

Figure 4 Victorian Northern Interconnect import capacity post winter 2016 expansion



The VNI import capacity increases with increasing system demand, as compressor power increases at lower ambient temperatures, and greater demand consumes more of the imported gas. When either the Euroa or Springhurst Compressor Stations are unavailable, the VNI import capacity is reduced by 25–30%.

The VNI import capacity in the 2015 VGPR was reported as 130 TJ/d on a 1-in-20 system demand day. This capacity was calculated by modelling the pipeline from Young to Wollert as a single pipeline system.

The updated modelling in this report now only represents the transportation capacity of the DTS from Culcairn to Wollert. This is consistent with changes to the Wholesale Market Gas Scheduling

Procedures (Victoria), introduced in May 2015.[14] This change means that DTS pipeline capacity constraints are no longer applied in the Pricing Schedule.[15]

While the VNI import capacity between Culcairn and Wollert was modelled at 196 TJ/d, the Facility Operator for the New South Wales transmission system north of Culcairn has advised that this pipeline system can only inject 125 TJ/d, which is shown in Figure 4. This capacity is independent of system demand, however, it is reduced if there is GPG on the Young to Culcairn Pipeline.

The Culcairn Interconnect Facility Operator has advised AEMO that the supply capacity from New South Wales via VNI could be increased to 148 TJ/d once the 39 km pipeline loop from Young towards Culcairn is completed in June 2016.

[14] See Paper 7 of the Gas Wholesale Consultative Forum paper for February 2015: http://www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum.

[15] This is an important distinction, as a Facility Operator constraint (like that between Young and Culcairn in the case of Culcairn imports) results in a Directional Flow Point Constraint (DFPC) being applied, rather than an Operating Schedule (OS) only Net Flow Transportation Constraint (NFTC) which may result in ancillary payments and uplift charges.

CHAPTER 3. SOUTH WEST PIPELINE CAPACITY TO PORT CAMPBELL

3.1 Key points

- SWP transportation capacity to Port Campbell is forecast to be insufficient to meet future requirements to fill the Iona UGS reservoirs from 2018 without network augmentation.
- AEMO has identified five options to increase SWP capacity.

3.2 Background

The SWP is a bi-directional pipeline that is used:

- During periods of high gas demand, to supply gas from the gas plants at Port Campbell (including the Iona UGS facility) to Melbourne.
- During low demand periods, to transport gas from Melbourne to Port Campbell, via the Brooklyn Compressor Station (BCS), to refill the Iona UGS reservoirs and to flow to South Australia via the SEA Gas Pipeline.

For further information on transportation capacity from SWP to Melbourne Inner Ring Main, refer to Chapter 4.

AEMO reported the potential for constrained flows on the SWP towards Port Campbell at the Gas Wholesale Consultative Forums[16] in August and October 2015.

The constraint is driven by higher gas flows on the SWP as production declines in the Port Campbell region, and changing gas flows in south-east Australia.

This chapter:

- Informs market participants on the potential for the SWP withdrawal capacity to be constrained.
- Identifies operational risks for 2016 and beyond.
- Presents five options for increasing the SWP capacity for flow towards Port Campbell.

3.3 Supply and demand balance

3.3.1 Port Campbell production trend

Before 2004, refilling of the Iona UGS reservoirs relied on a combination of onshore Port Campbell gas production (now ceased) and withdrawals of Longford-supplied gas from the SWP.

The SEA Gas Pipeline to South Australia was commissioned in late 2003. This was followed by the development and start-up of three projects for processing gas from offshore gas fields at Port Campbell (see Figure 5):

- The 150 TJ/d Minerva Gas Plant (started up January 2005).
- The 120 TJ/d processing of Casino development gas at the Iona UGS facility (started processing in January 2006).
- The 205 TJ/d Otway Gas Plant (started up September 2007).

Annual offshore production peaked at 110 PJ in 2009, an average of 301 TJ/d.

[16] Gas Wholesale Consultative Forum papers can be found on the AEMO website: http://www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum.

Figure 5 Map of Port Campbell gas production facilities

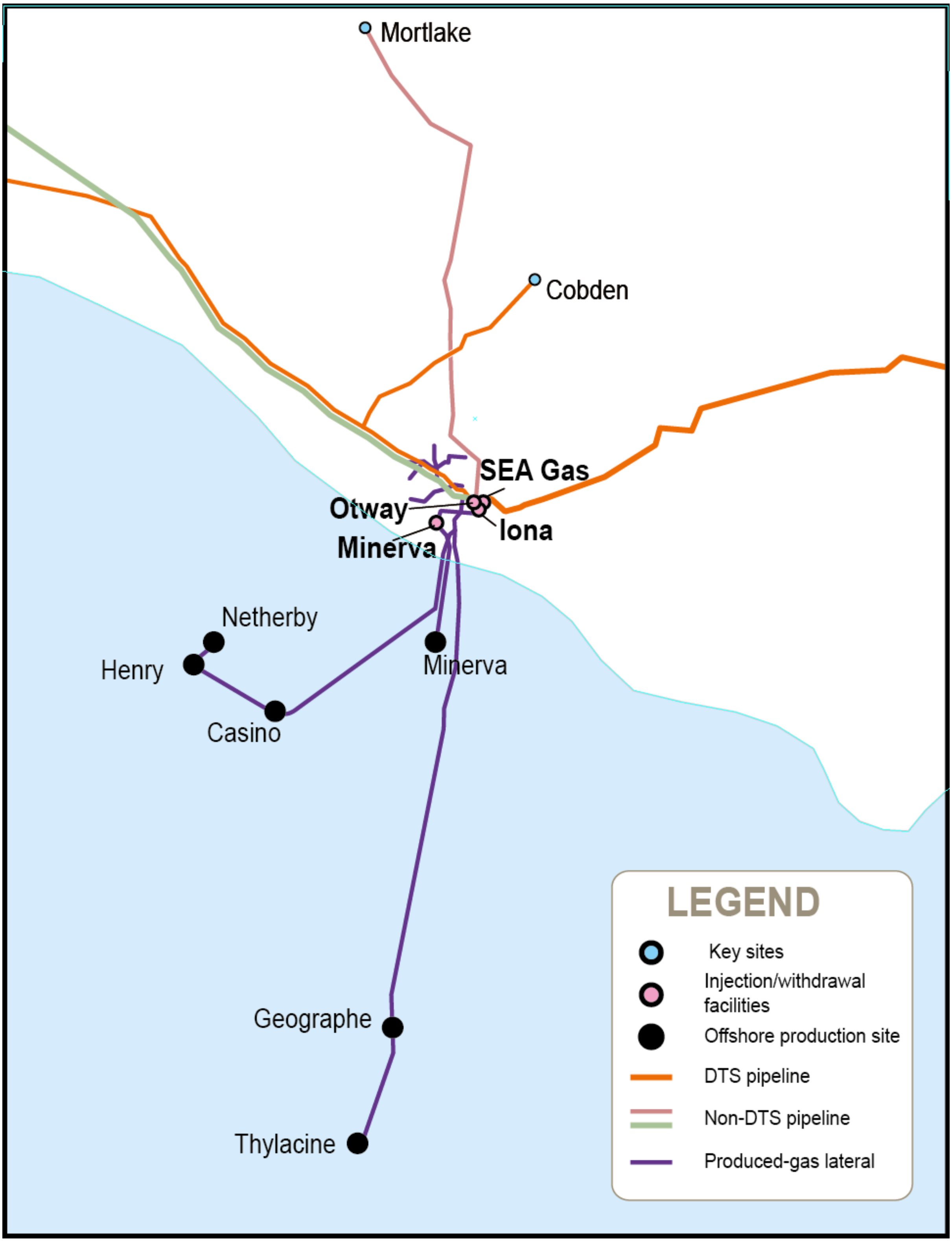
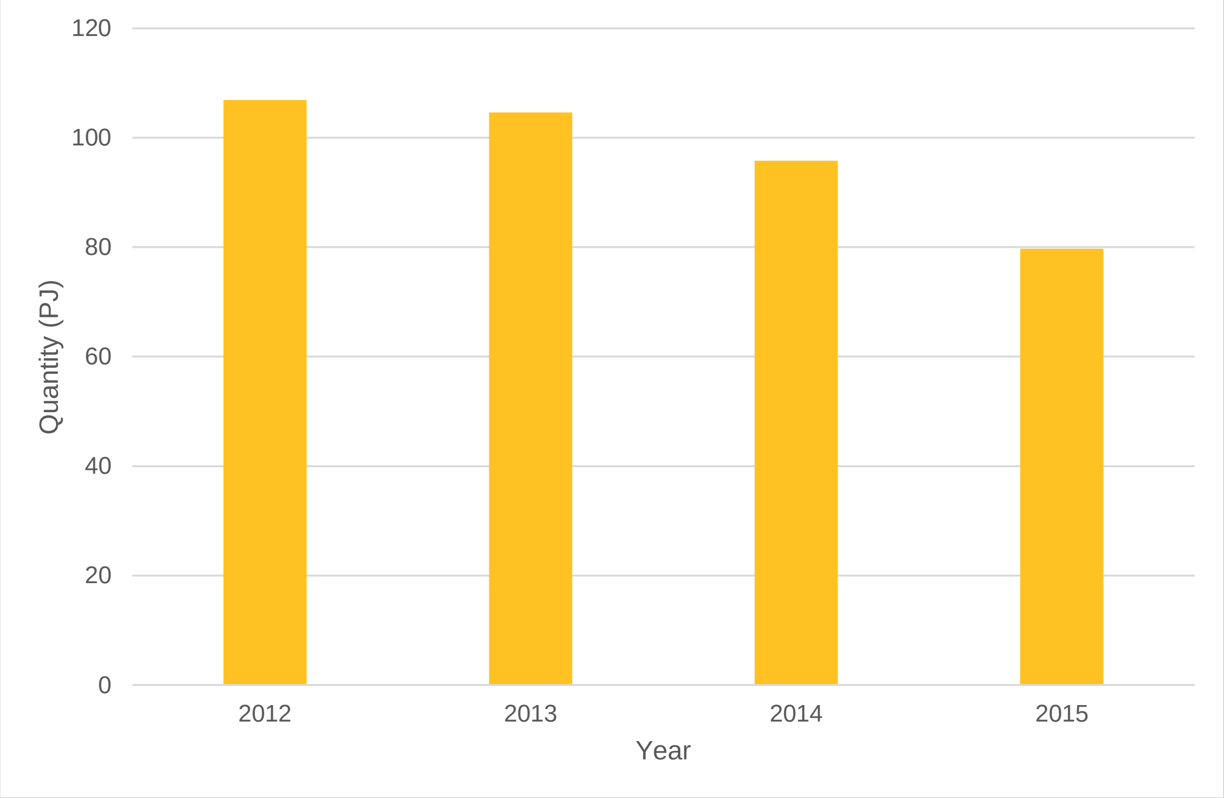


Figure 6 displays gas production in the Port Campbell region[17] since 2012. It shows the decline in annual gas production, to 80 PJ in 2015. The daily capacity of the Port Campbell production facilities has also reduced.

Figure 6 Port Campbell region production quantity, 2012–15



- The Minerva Gas Plant had an expected life of 10 years and contained estimated proven and probable gas reserves of 319 PJ[18], at time of approval. It has been operating for 11 years. From its initial capacity of 150 TJ/d, the plant has current capacity reported on the Natural Gas Services Bulletin Board (GBB) of 79 TJ/d.
- The Casino development was expected to produce up to 420 PJ of gas over 12 years[19], and has operated for ten years. Two additional fields, Henry and Netherby, were commissioned in February 2010 with approximately 180 PJ[20] of estimated recoverable dry gas reserves. Annual production has declined from a plateau of 34 PJ per year (92 TJ/d), to an estimated 23 PJ in 2015 (63 TJ/d). The remaining 1P reserves[21] for the Casino development were reported at 30 June 2015 as 43 PJ, and 2P reserves[22] (which includes 1P reserves) are 62 PJ.[23]
- The Otway Gas Plant was expected to produce 885 PJ of gas over 10 years, and had a nameplate capacity of 205 TJ/d. Planned annual production from the plant was 60 PJ, an average of

[17] Refer to Appendix A.2 for data set and sources.
[18] BHP Billiton release. "BHP Billiton Approves Minerva Gas Development in Victoria", 17 May 2002. Available at: http://www.bhpbilliton.com/investors/news/bhp-billiton-approves-minerva-gas-development-in-victoria. Viewed: 10 February 2016.
[19] Santos release. "Go-ahead announced for new Australian gas project", 12 October 2004. Available at: https://www.santos.com/media/2028/041012_casino-release.pdf. Viewed: 10 February 2016.
[20] "Henry and Netherby Gas Fields, Otway Basin, Australia", Offshore Technology.com. Available at: http://www.offshore-technology.com/projects/henry-netherby-gas-fields-otway-australia/. Viewed: 10 February 2016.
[21] 1P (also called proved) reserves are the most certain estimates.
[22] 2P (proved and probable) reserves are generally used as the best estimate of commercially-recoverable reserves.
[23] AWE. Reserves and Resources with 25% of the Casino development in the Otway Basin. Available at: http://www.awexplore.com/irm/content/reserves-and-resources.aspx?RID=369. Viewed at: 10 February 2016.

164 TJ/d.[24] Current capacity reported on the GBB is 90 TJ/d. Gas was produced from the Thylacine gas field in September 2007, and from the Geographe field in July 2013. Gas from the Speculant and Halladale gas fields is expected to be processed at the Otway Gas Plant. The Otway Gas Plant operator is progressing this project, and design work on the onshore pipeline to transport this gas to the Otway Gas Plant began in the second half of 2015.[25] AEMO has not been advised of a start-up date or expected production rates for this development.

3.3.2 Port Campbell gas consumption

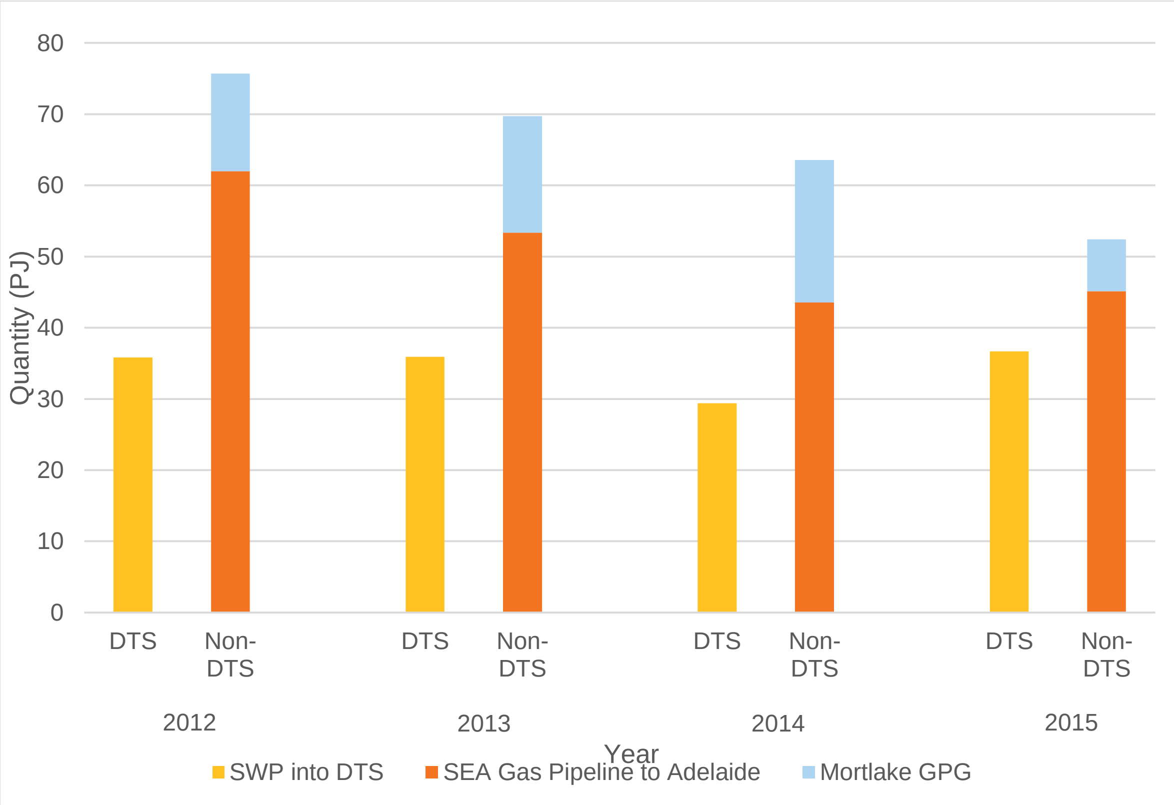
All gas that is produced in Port Campbell flows either:

- Directly into the SWP, the SEA Gas Pipeline, or the Mortlake Power Station pipeline (see Figure 7), or
- Into the Iona UGS storage reservoirs, from which the gas will flow into one of these three pipelines.

The graph shows that:

- The flow from Port Campbell into the SWP has been consistent each year, except 2014. The reduction in 2014 was due to high DTS import flows from Culcairn, which resulted in lower utilisation of the Iona UGS facility. This was due to the ramp-up of Queensland coal seam gas (CSG) production ahead of the first Gladstone LNG production facility start-up.
- As Port Campbell production has declined, there has been an overall reduction in flows to the non-DTS pipelines (SEA Gas and Mortlake).

Figure 7 Port Campbell pipeline flows, 2012–15



[24] “Otway project pumping at last”, Gas Today, November 2007. Available at: http://gastoday.com.au/news/otway_project_pumping_at_last/4532. Viewed: 10 February 2016.
[25] Wood Group release. “Wood Group wins onshore pipeline work for Origin Energy”, 1 July 2015. Available at: http://www.woodgroup.com/news-events/news-releases/Pages/2063625.aspx. Viewed: 12 February 2016.

3.3.3 Projected SWP withdrawals

Figure 8 shows that, as production from the Port Campbell gas plants has reduced, withdrawals from the SWP by the Iona UGS facility have increased. Gas withdrawn from the SWP is used for refilling the Iona UGS reservoirs, however some gas may also be transported to South Australia via the SEA Gas Pipeline.

This graph includes projected withdrawals in 2016, based on forecasts provided to AEMO by market participants in December 2015. Forecast SWP withdrawals at Iona UGS for 2016 are over 12 PJ, which is approximately half of the Iona UGS reservoir capacity.

Figure 8 Iona Underground Gas Storage net South West Pipeline withdrawal quantity, 2012–16

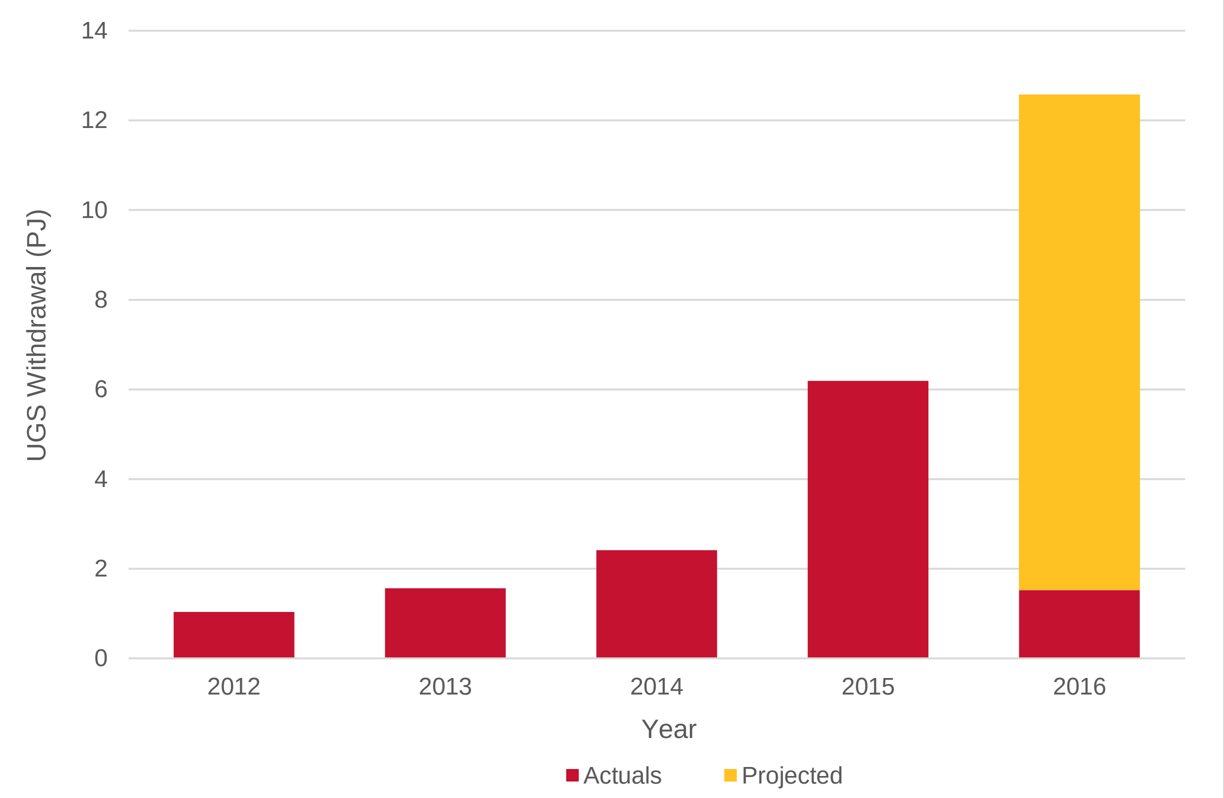


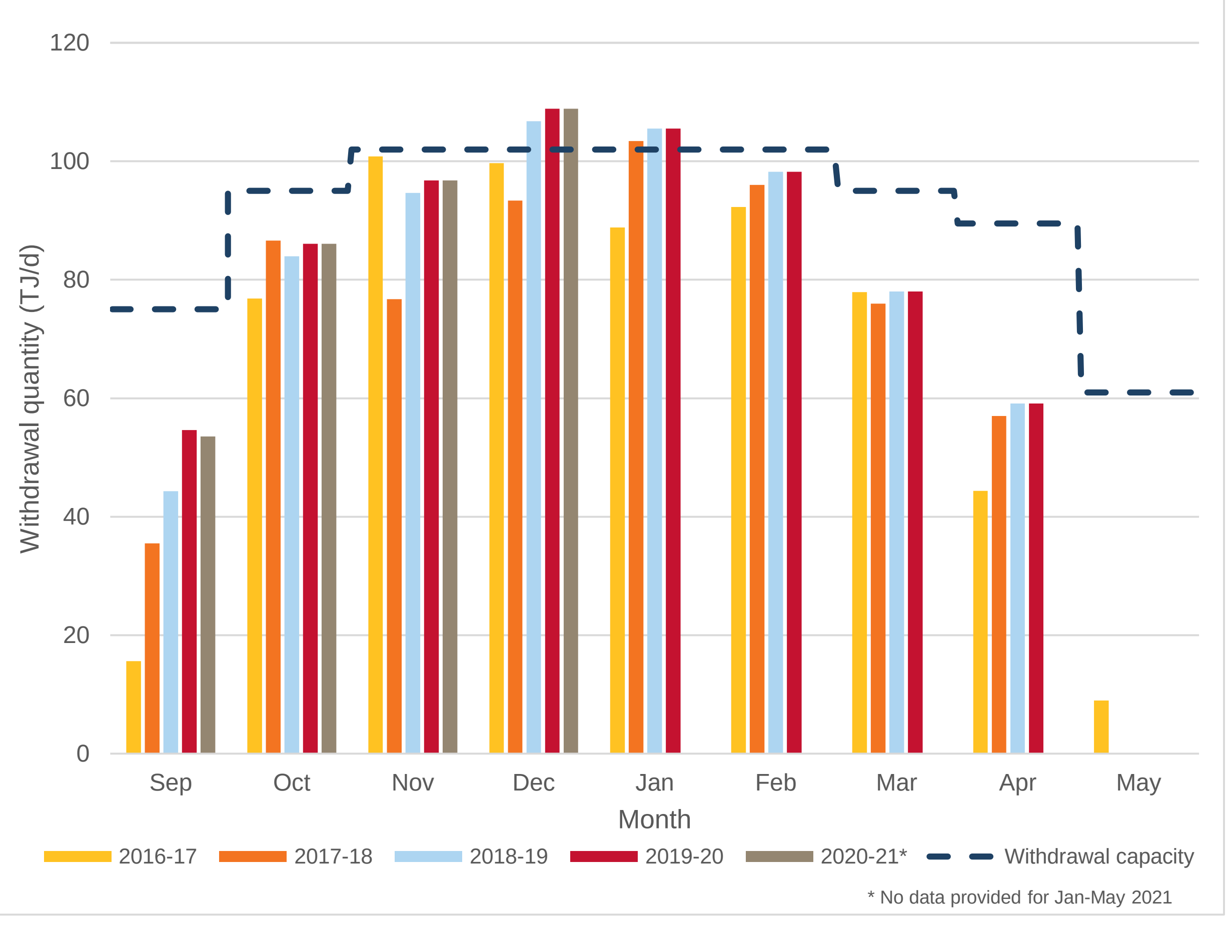
Figure 9 shows the average projected daily withdrawal quantity on the SWP from 2016–17 to 2020–21, which is also based on forecasts provided to AEMO by market participants in December 2015.

It shows that:

- The current SWP withdrawal capacity (using BCS units 11 and 12) is expected to be sufficient to support forecast withdrawals during 2016 and 2017.
- From 2018, SWP withdrawals are expected to be above pipeline capacity during December and January. Increasing amounts of gas are expected to be withdrawn from the SWP during the shoulder months, particularly September and April.

These projected higher SWP withdrawals assume that sufficient gas is supplied into the DTS. Plant outages (including planned Longford Gas Plant and Iona UGS outages), summer GPG demand, and other equipment outages (including BCS compressors) could result in insufficient supply being available for transport to Port Campbell to meet the requirements of market participants, including the refilling of the Iona UGS reservoirs.

Figure 9 South West Pipeline projected daily withdrawal quantity[26], September – May



[26] These flows represent Iona UGS and SEA Gas flows.

3.3.4 System adequacy

The reduced Port Campbell supply, and changes in gas flows in south-east Australia, could result in any one, or a combination, of the following:

- Increased dependence on Longford supply, implying one or more of:
  - Reduced flows to New South Wales through the Eastern Gas Pipeline (EGP).
  - Reduced flows to New South Wales through Culcairn.
  - Increased reliance on LNG injections during winter periods.
- Reduced capability to maintain storage levels via summer withdrawals in Iona UGS, which subsequently reduces the quantity of gas available for injection to the DTS throughout winter.
- Reduced supply to South Australia through the SEA Gas Pipeline.

The actual impact on the DTS depends on the actual levels of supply, system demand, and equipment availability.

3.4 South West Pipeline capacity to Port Campbell

On a 300 TJ system demand day[27], and with BCS units 11 and 12 available, the SWP capacity for net withdrawals at the Iona Close Proximity Points (CPP)[28] near Port Campbell is 102 TJ/d. The increase from 92 TJ/d in the 2015 VGPR is due to reduced non-winter demand on the SWP and updated modelling assumptions.

Figure 10 shows this current withdrawal capacity and also AEMO's assessment of potential operational changes and system augmentations that would further increase the net withdrawal capacity at the Iona CPP, and might alleviate the system adequacy concerns.

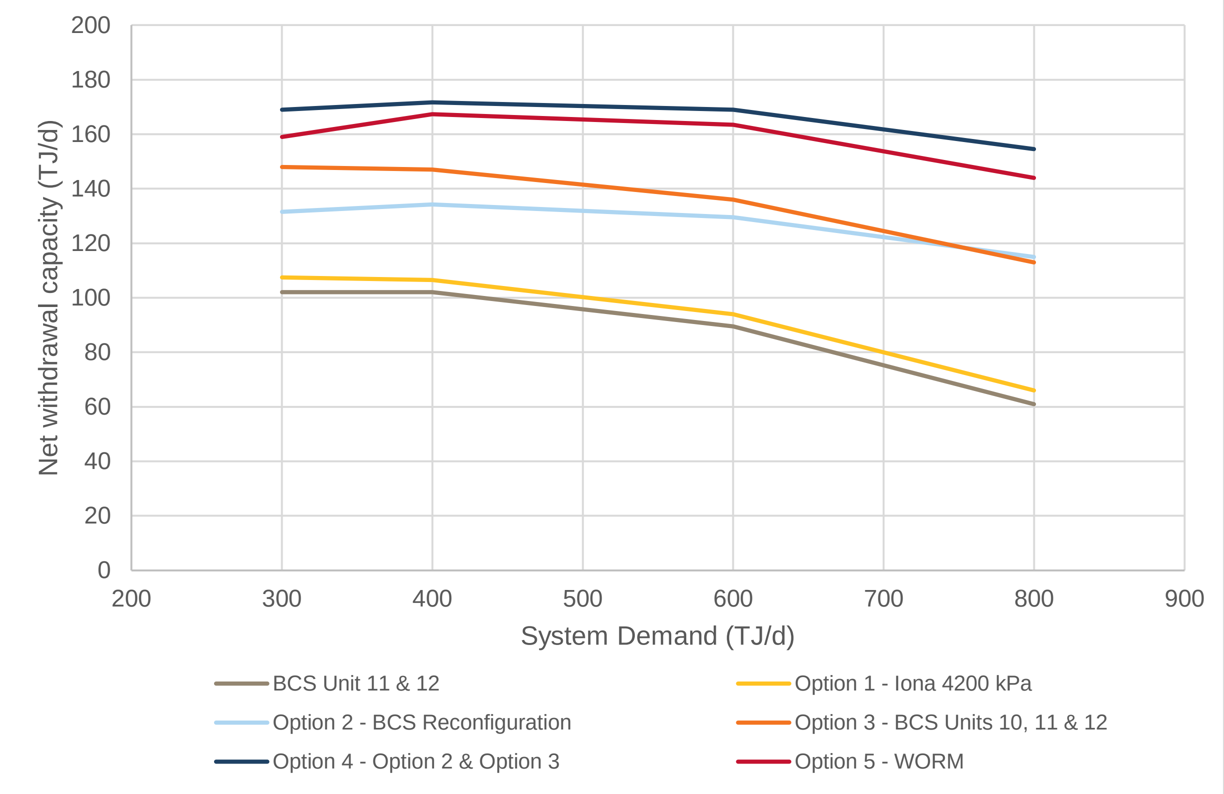
The potential operational changes and system augmentation options addressed here are:

- Option 1 – Reduction of Iona minimum withdrawal pressure from 4,500 kPa to 4,200 kPa.
- Option 2 – Reconfiguration of BCS to allow direct compression of units 11 and 12 into the Brooklyn–Lara Pipeline (BLP).
- Option 3 – Operation with BCS Units 10, 11 and 12.
- Option 4 – Combination of Options 2 and 3.
- Option 5 – Construction of the Western Outer Ring Main (WORM).

Options considered here are subject to engineering and financial assessments by the DTS Service Provider and shippers' requests to the DTS Service Provider for increased capacity.

[27] 300 TJ is a reference as this is the typical weekday system demand during summer when the Iona UGS reservoirs are being refilled.
[28] Iona CPP includes the following injection and withdrawal meters: Iona, SEA Gas, Mortlake and Otway.

Figure 10 South West Pipeline net withdrawal capacity at Iona Close Proximity Points, with Options 1–5



The current SWP withdrawal capacity chart, that includes varying BCS unit availability, is included in Appendix A.1.2.

3.4.1 Option 1 – Reduction of Iona minimum operational pressure from 4,500 kPa to 4,200 kPa

This option could increase SWP withdrawals by approximately 5%, from 102 TJ/d to 107 TJ/d on all system demand cases.

AEMO is currently investigating this operational change, with the DTS Service Provider, and Facility Operators at the Iona CPP. AEMO intends to provide an update in 2016.

3.4.2 Option 2 – Reconfiguration of Brooklyn Compressor Station

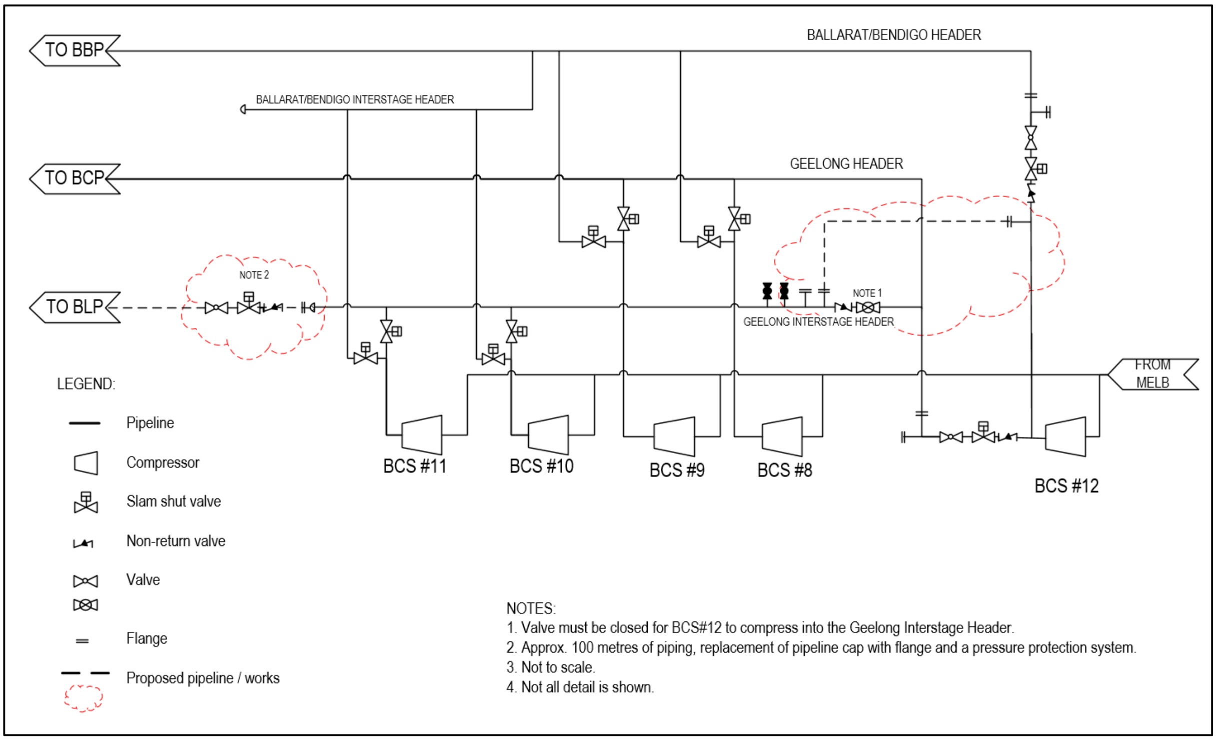
Option 2 would increase SWP withdrawal capacity by 29%, from 102 TJ/d to 132 TJ/d on a 300 TJ/d system demand day.

The BCS consists of two solar turbine ‘Saturn’ machines (units 8 and 9) and three solar turbine “Centaur” machines (units 10, 11, and 12). The operation of unit 10 is restricted (discussed in Option 3).

The current configuration of the BCS has the outlet of units 11 and 12 supplying both the Brooklyn–Corio Pipeline (BCP) and the BLP. This is inefficient, as Geelong demand supplied via the BCP does not require compression outside of winter.

The proposed reconfiguration of the BCS, shown in Figure 11, would involve connecting units 11 and 12 directly into the BLP, enabling flows into BCP and BLP to be separated. Removing compression to Geelong demand would increase the amount of gas that units 11 and 12 can transport to the Iona CPP at Port Campbell, while reducing fuel gas consumption and maintenance costs at the BCS.

Figure 11 Proposed reconfiguration of Brooklyn Compressor Station



As shown in Figure 11, the proposed augmentation would be expected to include the following construction and system changes:

- A pressure protection system on the new connection into the BLP.
- Approximately 100 metres of pipework to connect the Geelong inter-stage header to the BLP.
- Changes to Supervisory Control and Data Acquisition (SCADA) and system control logic.

Ballarat is another demand region which usually does not require compression outside of winter. The proposed reconfiguration would enable demand to be supported using the units 8 and 9 Saturn compressors as required, while retaining the flexibility to utilise units 11 and 12 to support Ballarat demand on very high demand days.

The DTS Service Provider would need to complete a detailed engineering design review and determine whether other options exist to achieve a similar outcome.

3.4.3 Option 3 – Operation of Brooklyn Compressor Station units 10, 11 and 12

Operation of all three Centaur compressor units (10, 11 and 12) at BCS would increase the SWP withdrawal capacity by 45%, from 102 TJ/d to 148 TJ/d, on a 300 TJ system demand day.

The DTS Service Provider, with the support of AEMO, is investigating this option. As discussed in Option 2, there is some inefficiency with operating units 10, 11 and 12 together, as supply to Geelong is compressed unnecessarily.

Unit 10 is a wet-seal compressor unit, which means that small amounts of oil are present in the compressor discharge gas, which could limit the frequency of this operating option due to gas quality issues. The installation of additional equipment on unit 10 might be required to mitigate compressor oil leakage into the DTS.

Noise concerns may limit when all three units can be operated, or the DTS Service Provider could be required to take other steps to mitigate noise. It is unlikely that the Saturn units will be operating when the three Centaur units are running, which would be expected to reduce the overall noise at the site.

The use of unit 10 in this option, given the noise and gas quality issues, would require the approval of Energy Safe Victoria (ESV) and the Environmental Protection Authority (EPA) Victoria.

BCS unit 10 is currently maintained as a back-up for when unit 11 or 12 is unavailable and is not part of the DTS equipment. When unit 10 is temporarily utilised, AEMO and the DTS Service Provider undertake additional gas quality monitoring.

3.4.4 Option 4 – Combination of Options 2 and 3

The combination of Option 2 and Option 3 could result in a 66% increase in SWP withdrawal capacity, from 102 TJ/d to 169 TJ/d, on a 300 TJ/d system demand day.

As noted above, the combination of Options 2 and 3 would require BCS augmentation works, and approval from ESV and the EPA to operate all three Centaur compressor units at BCS.

3.4.5 Option 5 – Construction of Western Outer Ring Main

Construction of the proposed Western Outer Ring Main (WORM – see Section 4.5.3 for more information) would provide a more efficient gas transmission route from the Longford Gas Plant and Culcairn.

The chart in Figure 10 shows that the SWP withdrawal capacity is similar for Option 4 and Option 5. The SWP withdrawal capacity at the Iona CPP with the WORM, shown in Figure 10, could be increased by using any of:

- A larger or additional compressor unit at Wollert.
- An additional in-line compressor on the SWP or BLP.
- Bi-directional flow capability at the Winchelsea Compressor Station (Winchelsea CS).

The WORM would also increase the SWP flow capacity towards Melbourne.

CHAPTER 4. PROPOSED IONA UNDERGROUND GAS STORAGE EXPANSION

4.1 Key points

- The Iona Underground Gas Storage Facility Operator has advised AEMO of expansion plans for 2016 and 2017, which may trigger the need for further expansion of the SWP.
- The SWP transportation capacity on a 1-in-20 system demand day is 429 TJ/d with the Winchelsea CS operating. This is unchanged from 2015.
- AEMO has identified three options for increasing the SWP transportation capacity to Melbourne.

4.2 Background on Iona Underground Storage

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. Iona UGS also supports summer GPG demand in South Australia via the SEA Gas Pipeline and, to a lesser extent, in Victoria if the capacity at other production facilities is reduced due to maintenance.

The construction of the Iona UGS facility and the SWP was fast-tracked following the 1998 Longford Gas Plant outage, and it was commissioned in 1999. In 2003, the capacity of the Iona UGS facility was increased from 240 TJ/d to 320 TJ/d, and the reservoir capacity increased from 10 PJ to 12 PJ. It was the first facility to supply South Australia via the SEA Gas Pipeline in 2004. In 2006, the Iona UGS facility started processing offshore Casino development gas in 2006 and the reservoir capacity was increased to 15 PJ.

A major expansion of the Iona UGS facility was commissioned in March 2010. This included a second processing train to increase the nameplate capacity of the facility to 500 TJ/d, with the potential to increase capacity further to 570 TJ/d. Two additional storage fields were also developed, which increased the reservoir capacity to 22 PJ.

4.3 Iona Underground Gas Storage expansion

The current Iona UGS capacity reported on the GBB is 430 TJ/d, which indicates that the facility is limited by supply. The Facility Operator of the Iona UGS has advised AEMO that it is planning to expand the reservoir withdrawal and injection capacity at Iona UGS by:

- Increasing reservoir withdrawal capacity from 390 TJ/d to 440 TJ/d by the end of 2016, and to 545 TJ/d by the end of 2017.
- Increasing reservoir injection capacity from 170 TJ/d to 190 TJ/d by end of 2016, and to 230 TJ/d by the end of 2017.

This expansion would bring the overall capacity of the Iona UGS facility close to 570 TJ/d by the end of 2017.

The Facility Operator has also advised that this expansion could be contingent on whether there is a further expansion of the SWP.

Options for expansion of the SWP are discussed in Section 4.5, and shown in Figure 14 and Figure 15.

4.4 Existing South West Pipeline capacity to Melbourne

The SWP was commissioned in 1999 and the first expansion was commissioned in 2008 when the BLP was completed.

The SWP was expanded again during 2014 through the construction of the Winchelsea CS, which was commissioned in early 2015 and increased the SWP capacity from 367 TJ/d to 429 TJ/d.

The Winchelsea CS was used 25 times during winter 2015. It increases the available linepack closer to Melbourne to help support morning and evening peaks on high system demand days. The SWP was scheduled at its capacity (that is, a scheduling constraint was applied) for the 6.00 pm and 10.00 pm schedule on Sunday 12 July 2015.

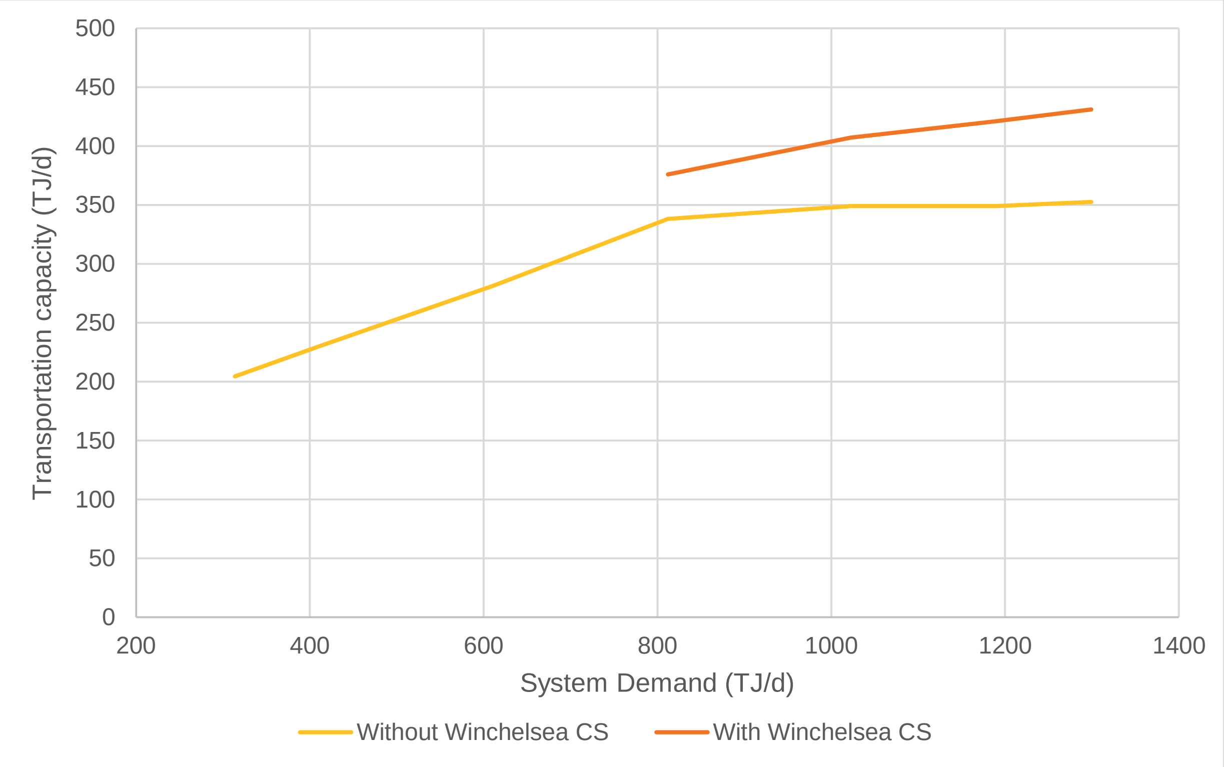
The SWP capacity is determined by total net injections at the Iona CPP, less Western Transmission System (WTS)[29] demand. Figure 12 shows that the current SWP capacity increases when the Winchelsea CS is used and when system demand increases. This higher SWP capacity is the result of increased gas demand on the SWP during winter, which increases overall pipeline throughput.

The SWP capacity on a 1-in-20 system demand day with the Winchelsea CS available is 429 TJ/d when the pressure at the Iona CPP is 9,500 kPa. When the Winchelsea CS is not available, the SWP capacity is reduced to 352 TJ/d on a 1-in-20 system demand day.

This capacity with the Winchelsea CS unavailable is reduced from the 2015 capacity of 367 TJ/d, due to reduced demand in Geelong following industrial closures. The capacity with Winchelsea CS available is unchanged because the compressor moves linepack closer to Melbourne, which supports the morning and evening peaks, and offsets decreased demand on the SWP.

Using the Winchelsea CS increases the SWP capacity when system demand is 800 TJ/d or more. When system demand is below 800 TJ/d, using the Winchelsea CS has little impact on SWP capacity. This is due to the SWP flow being backed out of the Melbourne Inner Ring Main due to the interaction with Longford injections via the Dandenong City Gate (DCG).

Figure 12 Current South West Pipeline capacity to Melbourne



[29] The WTS is part of the DTS and supplies gas from the Iona CPP to southwest Victoria including Portland, Hamilton and Cobden.

4.5 Options to increase SWP capacity to Melbourne

4.5.1 Option 1 – Dandenong City Gate pressure reduction

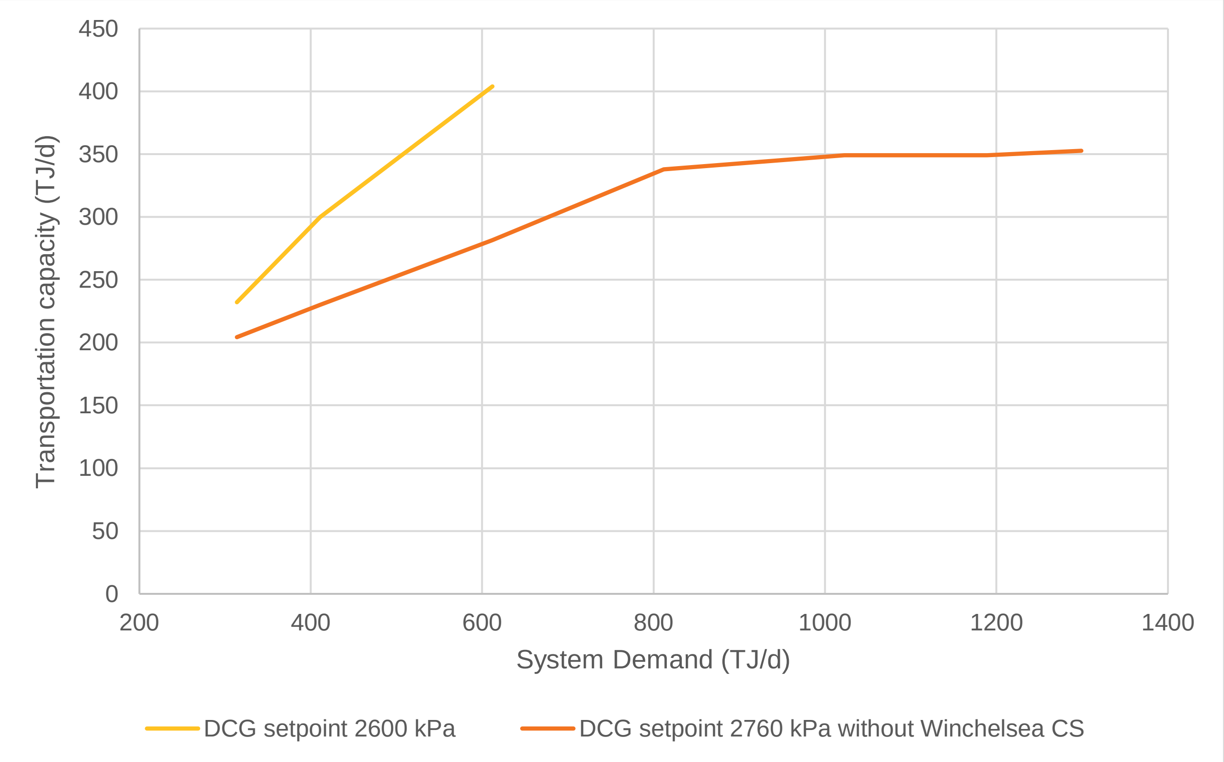
Figure 13 shows that the SWP capacity can be increased during summer months by reducing the DCG control pressure from 2,760 kPa to 2,600 kPa (a 160 kPa reduction). DCG control pressure of 2,600 kPa reduces gas flow through DCG and increases the gas flow from the SWP to supply Melbourne Inner Ring Main's demand.

This operational strategy is typically only used outside of winter during periods of very low supply from the Longford Gas Plant. It was used between 14 February 2015 and 23 April 2015, and between 17 December 2015 and 3 January 2016, during Longford Gas Plant maintenance.

Large reductions in the DCG pressure are not possible during winter because the minimum contractual pressures for the Mornington Peninsula, Edithvale and Dandenong North[30] connection points would not be met. These minimum contractual pressures ensure sufficient pressure is maintained in the distribution system on peak system demand days.

AEMO expects a reduction of approximately 20 kPa in the DCG pressure to be possible during winter.

Figure 13 Current South West Pipeline capacity to Melbourne at reduced Dandenong City Gate pressure



4.5.2 Option 2 – Additional South West Pipeline compression

During the hours of high demand on peak system demand days, the control system on the BLP City Gate (CG) reduces flow from the BLP (and therefore the SWP) to stop the BLP CG upstream pressure reducing below 4,500 kPa. This is a DTS Service Provider design requirement to extend the life of the pipeline.

[30] For more information please see: AEMO, *2016. Wholesale Market System Security Procedures.* Available: http://www.aemo.com.au/Gas/Policies-and-Procedures/~/media/Files/Gas/Policies%20and%20procedures/DWGM%20rules/AEMO%20Wholesale%20Market%20System%20Security%20Procedures%20NGR%201.1.ashx.

The SWP transportation capacity could be increased by installing another compressor on the SWP between the Winchelsea CS and the BLP CG. This would increase the pressure upstream of the BLP CG, increasing the SWP flow by reducing the duration and extent of the BLP CG flow restriction through which the control system maintains the pressure above 4,500 kPa.

Potential locations for an additional compressor station include Stonehaven and Lara. Stonehaven is upstream of Lara City Gate (Lara CG), and Lara is downstream of the Lara CG.

Lara CG is used to supply Geelong and other demand on the BCP during winter. Installing a compressor at Lara would remove the need to inefficiently compress the gas that supplies Geelong and the BCP.

The Lara CG pressure would also be lower, so the existing pre-heater would not require upgrading, where there would be higher pipeline pressure if there was compression at Stonehaven.

On a 1-in-20 system demand day, the addition of a Lara Compressor Station (CS)[31] would increase the SWP capacity by 3% from 429 TJ/d to 444 TJ/d over the case with only the Winchelsea CS operating (see Figure 15). The Lara CS would also provide additional SWP capacity compared to the SWP capacity without the Winchelsea CS, if the Winchelsea CS was not available.

When the system demand is 1,000 TJ or less, the addition of the Lara CS would provide little benefit over the Winchelsea CS, since the SWP capacity is constrained by the interaction with Longford injections via the DCG (discussed in Section 4.4 and 4.5.1).

Lowering DCG pressure in combination with additional compression along the SWP could further increase capacity (see Figure 15). On a 1-in-20 system demand day, reducing the DCG pressure by 20 kPa increases the capacity by a further 2%, from 444 TJ/d to 454 TJ/d. This is an increase of 25 TJ/d over the current 429 TJ/d SWP capacity.

Modelling has shown that the pressure reduction would not cause the minimum contractual pressures in the Melbourne Inner Ring Main to be breached.

4.5.3 Option 3 – Western Outer Ring Main

The Western Outer Ring Main (WORM) is a proposed pipeline that extends the SWP and BLP from Plumpton to Wollert (see Figure 14). This pipeline would provide a route for gas from the Iona CPP to flow into the VNI and the LMP. This flow path would enable increased SWP capacity at lower system demands, because the capacity would not be not limited by demand on the SWP and BLP and the amount of gas that can be supplied into the Melbourne Inner Ring Main. The WORM also has the potential to increase system security, as it increases the amount of linepack closer to Melbourne.

Construction of the WORM was proposed in the DTS Service Provider's 2013–17 Access Arrangement submission to the Australian Energy Regulator (AER).

The submission stated the primary benefits of the WORM to the DTS were to:

- Reduce exposure to a major supply source outage (such as the Longford Gas Plant), and
- Facilitate increased SWP and VNI capacity.[32]

The AER rejected the proposal to construct the WORM. The DTS Service Provider has advised AEMO that it is unlikely to submit any proposal to the AER for an increase in the current SWP capacity, unless it receives additional requests from market participants for Authorised Maximum Daily Quantity (AMDQ) credits.[33]

[31] Assumed to be a Solar Taurus 60 machine, with the same power as the Winchelsea CS and a minimum inlet pressure of 3800 kPa.
[32] APA. *2012. APA GasNet Access Arrangement Submission.* Available: https://www.aer.gov.au/system/files/APA%20GasNet%20submission%20-%20public%20-%20March%202012.pdf.
[33] AMDQ credits are transportation rights in the DTS.

Figure 14 Map of proposed Western Outer Ring Main pipeline

AEMO has modelled the WORM using the following assumptions, consistent with the details provided in the DTS Service Provider's Access Arrangement submission:

- A 50 km length pipeline with a 500 mm diameter, and a 10,200 kPa MAOP, connecting Plumpton to Wollert.
- A new pressure reduction station installation at Wollert that regulates flow from the WORM into the Outer Ring Main and the VNI.
- The installation of an additional compressor at the WCS with the same capacity as WCS units 4 and 5, with the capability to:
  - Take suction from the WORM and discharge into the VNI, which supports increased SWP injections at the Iona CPP, or
  - Take suction from the Outer Ring Main and discharge into the WORM to support increased SWP withdrawals. This option is discussed in Section 3.4.5.
- If the MAOP of the VNI is increased to 15,300 kPa, as discussed in Section 2.2, additional compression would be required at the WCS.

Figure 15 displays the projected SWP injection capacities that could be achieved through the construction of the WORM.

The WORM produces a larger increase in the SWP capacity on days when the system demand is 500 TJ/d to 800 TJ/d, when the SWP capacity is otherwise limited by demand on the SWP and the Melbourne Inner Ring Main. For example, on a 600 TJ system demand day, the WORM would increase the SWP capacity by 54%, from 281 TJ/d to 434 TJ/d.

On low system demand days, it is possible for most of the DTS system demand to be supplied from the Iona CPP. It is expected that the WORM would offer increased SWP capacity on low system demand days over other SWP expansion options.

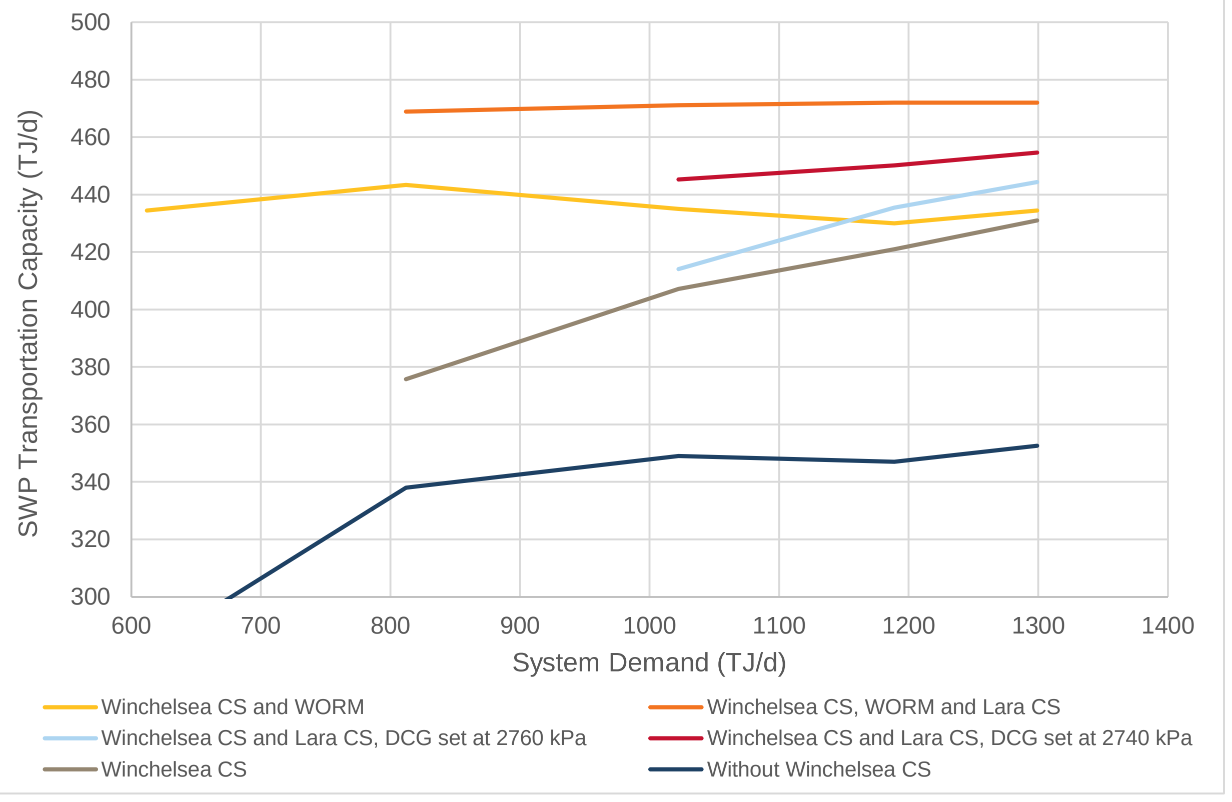
For system demands above 800 TJ/d, modelling indicates that:

- The SWP capacity with the WORM would decrease with increasing demand, due to the interaction with Longford injections at Wollert.
- The WORM would also reduce the amount of LNG injections required to support exports via the VNI on very high demand days. This would increase the LNG injection capacity available for responding to threats to system security.

The SWP capacity with the WORM built could be further increased through the installation of another compressor station along the SWP at Stonehaven or Lara (see Figure 15):

- With the addition of a compressor station at Lara, the SWP capacity is projected to increase to 472 TJ/d on a 1-in-20 system demand day. The system security benefit of the WORM would greatly increase on high demand days, compared to the projections with no additional compressors.
- The installation of a compressor station at Stonehaven would be expected to have a similar impact in increasing the SWP capacity.

Figure 15 South West Pipeline capacity to Melbourne with Western Outer Ring Main and Lara Compressor Station



CHAPTER 5. WARRAGUL SUPPLY CAPACITY

5.1 Key points

- Increased peak demand means augmentation is required to maintain supply pressure within contractual limits at the Warragul Custody Transfer Meter (CTM).
- The supply to Warragul could be increased by duplicating the existing supply lateral from the Lurgi Pipeline or by constructing a new supply lateral from the LMP.
- The augmentations could be deferred in the short term by increasing the Morwell Backup regulator set point during winter and lowering the minimum pressure requirements at the Warragul CTM (subject to local distributor confirmation).

5.2 Background

The Warragul CTM is supplied from the Lurgi Pipeline via a 4.7 km section of 100 mm pipeline.

In 2006, AEMO first reported that an upgrade of the Warragul supply would be required before winter 2009. In 2008 the load growth projections reduced so the augmentation was pushed back, subject to demand increasing.

Until July 2014, AEMO's system adequacy models had assumed a Maximum Hourly Quantity (MHQ) of 7.4 kscm/h at the Warragul CTM.

On the morning of 22 July 2014, the actual hourly flow rate through the Warragul CTM reached 7.8 kscm/h, and the instantaneous peak flow reached 8.2 kscm/h. These high flows were due to low overnight temperatures and a Tariff D site exceeding its MHQ.[34]

At approximately 8:00 am, the gas pressure at Warragul CTM fell to 1,287 kPa, breaching the minimum contractual pressure of 1,400 kPa. This was due to the pressure drop along the supply lateral from the Lurgi Pipeline increasing from approximately 300 kPa to over 900 kPa. Nevertheless, this pressure breach did not result in an interruption in supply.

AEMO has modelled the impact at the time of the breach of demand from Jeeralang Power Station, which is supplied from the Lurgi Pipeline upstream from the Warragul CTM. During the morning of the pressure breach, Jeeralang was operating with a demand of up to 100 kscm/h. Modelling showed that Jeeralang demand only impacted minimum pressure at the Warragul CTM by approximately 10 kPa.

Under similar conditions, and without any system augmentation and or operational mitigation, the pressure at the Warragul CTM would again fall below the minimum contractual pressure. The current operational mitigation outlined in Section 5.3 has prevented a repeat of the pressure breach.

5.3 Current operational mitigation

Until the system is augmented to reduce the likelihood of further breaches, AEMO manually changes the settings at the Morwell Backup Regulator.[35] This occurs after the evening peak, to maintain the highest possible pressure along the Lurgi Pipeline for the following gas day's morning peak, when the flow through the Warragul CTM is at its highest. On high demand days, AEMO reduces the Morwell Backup Regulator setting before the evening peak, to preserve linepack in the LMP and the Outer Ring Main.

On 4 August 2014, instantaneous peak flow through the Warragul CTM reached 8.8 kscm/h (higher than when the breach occurred on 22 July 2014). The increased set pressure at the Morwell Backup

[34] The region's distributor informed AEMO that the Tariff D site is expected to operate at their MHQ much of the time, and may want to increase their MHQ.
[35] The Morwell Backup Regulator at the Dandenong Terminal Station supplies and provides redundancy along the Lurgi Pipeline if the Morwell Regulator Station failed to supply adequate outlet pressure.

Regulator kept the pressure at the Warragul CTM above the 1,400 kPa contractual obligation, with the pressure falling to 1,462 kPa.

While this strategy has mitigated the risk of pressure breaches at Warragul CTM:

- AEMO is running the Morwell Backup Regulator at or near the maximum pressure, so as instantaneous peak flows continue to increase[36] in the Warragul and outer south-eastern Melbourne corridor, this strategy will no longer be effective.
- This strategy increases load through the DCG and reduces linepack in the LMP and therefore reduces security of supply to the Melbourne Inner Ring Main.

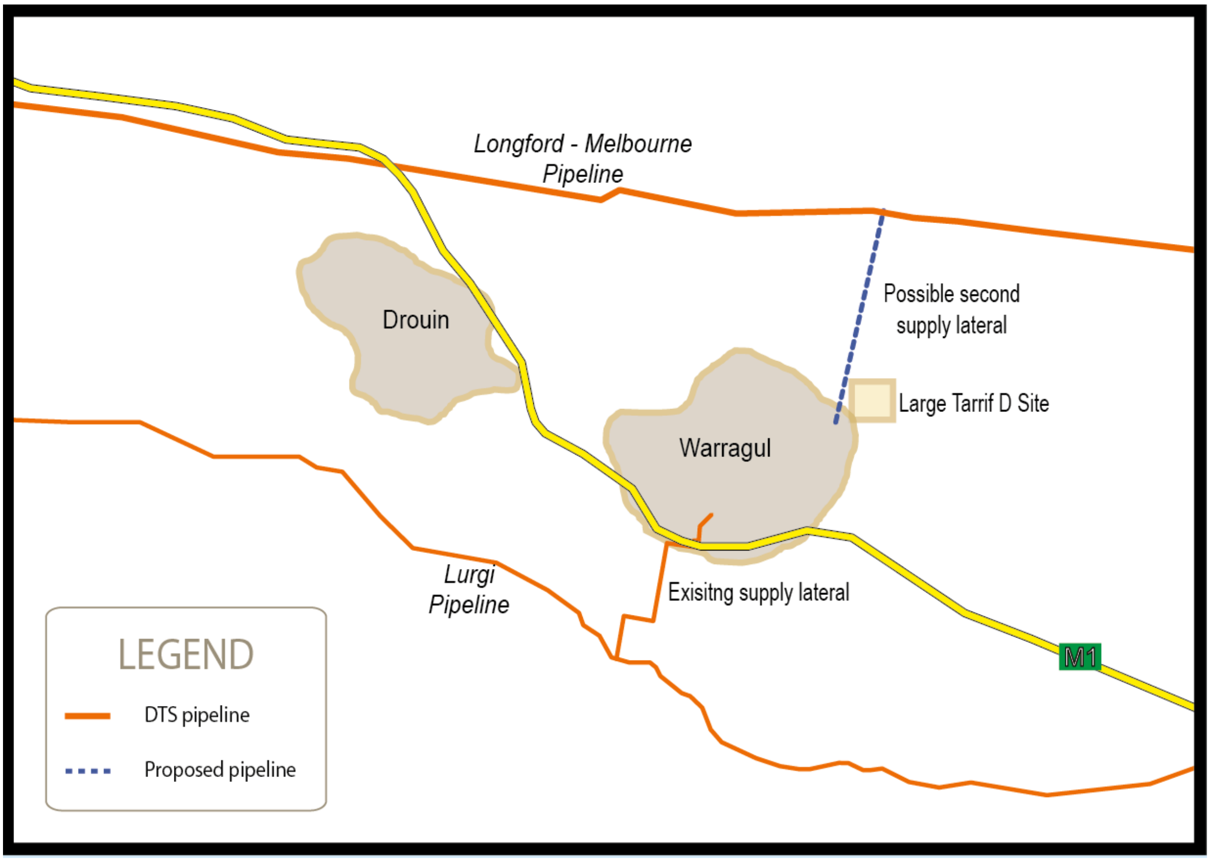
5.4 Augmentation options

To mitigate this risk, three options have been identified:

- Option 1 – Reducing the Warragul CTM minimum delivery pressure and increasing utilisation of the Morwell Backup Regulator.
- Option 2 – Looping of the existing 4.7 km branch pipeline.
- Option 3 – Construction of a new branch pipeline from the LMP to support Warragul load.

Figure 16 shows the location of Warragul between the Lurgi Pipeline and the LMP, along with the two augmentation options.

Figure 16 Map of Warragul supply augmentation options



[36] AEMO's 2015 NGFR forecasts demand to decrease across Victoria, however the region's distributor has informed AEMO that Tariff V demand through Warragul may not align with the average Victorian Tariff V growth rate, and may increase. In addition, AEMO has observed increases to the instantaneous peak flow through Warragul CTM via AEMO's SCADA system.

5.4.1 Option 1 – Reducing the Warragul CTM minimum delivery pressure

The DTS Service Provider is in the process of negotiating a lower minimum pressure with the local distributor, which might be able to lower the pressure requirements at the CTM based on the projected demand forecast from 1,400 kPa to 1,150 kPa.

In combination with increasing the Morwell Backup Regulator set point during the winter period (the current operational mitigation described in Section 5.3), this could defer the augmentations referred to in Options 2 or 3 for one to two years, depending on actual demand growth.

5.4.2 Option 2 – Looping of the existing 4.7 km branch pipeline

To demonstrate the potential benefit of looping the existing 4.7 km branch pipeline that supplies the Warragul CTM, AEMO has modelled the following three scenarios, using the events of 4 August 2014 (see Section 5.3) as the base scenario (Scenario 1).

Table 1 Comparison of Warragul supply options from the Lurgi Pipeline

Scenario	Scenario Detail	Minimum pressure at Warragul CTM[a]
1	Base Scenario.	1,462 kPa
2	Scenario 1, but without using the Morwell Backup Regulator to supply demand along the Lurgi Pipeline.	1,120 kPa
3	Looping the 4.7 km lateral using 150 mm diameter pipe, but without using the Morwell Backup Regulator.	2,150 kPa

[a] The minimum pressure obligation at Warragul CTM is 1,400 kPa.

The scenario modelling shows that a pressure breach at the Warragul CTM on 4 August 2014 without using the Morwell Backup Regulator would have been worse than the event on 22 July 2014. The modelling also demonstrates that duplicating the Warragul lateral increases the pressure at the CTM by approximately 700 kPa, which makes a pressure breach unlikely.

5.4.3 Option 3 – Construction of a new supply from Longford to Melbourne Pipeline

Constructing a new supply lateral off the LMP would enable gas to be back-fed into the distribution currently supplied by the Warragul CTM. The pressure reduction required from the new supply lateral could either be part of the DTS, or part of the distribution system downstream of the new CTM.

This option provides an additional supply source to Warragul and therefore increases its security of supply. Depending on the configuration of the distribution system, this option would be expected to reduce the load on the Lurgi Pipeline, and therefore support demand growth on the Lurgi Pipeline in the longer term.

5.5 Comparison of the augmentation options

An initial estimate by the DTS Service Provider suggests that the projected costs of Option 2 and 3 are similar, while Option 1 has no additional cost. Some additional points to consider are below.

Option 1:

- Reducing the CTM minimum pressure, in combination with increased Morwell Backup Regulator set point during winter, will defer Options 2 or 3 for between one and two years, depending on the actual demand growth.
- This short-term solution will help defer augmentation by using the capacity available on both the DTS and local distribution system as far as possible.

Option 2:

- This maintains the status quo – it continues supporting current loads while ensuring pressure obligations are met, although it offers no additional security of supply.
- The duplicated lateral would run through built-up areas.

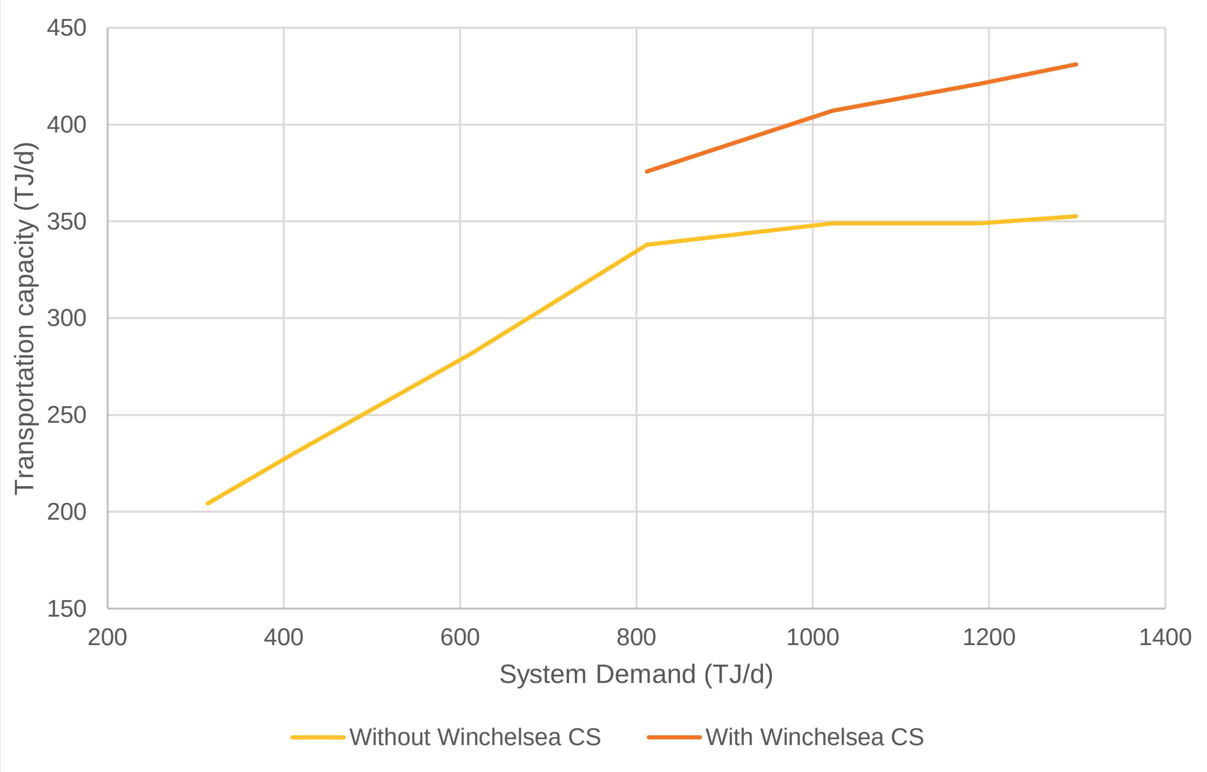
Option 3:

- Supports current loads while ensuring pressure obligations are met, but it also increases security of supply by providing a secondary supply source.
- It would cater better than Option 2 for long-term load growth in Warragul, particularly if demand on the Lurgi Pipeline increases.
- The pipeline route is mostly through farmland rather than built-up areas.
- This option requires the installation of a new CTM.

APPENDIX A. SUPPORTING MATERIAL

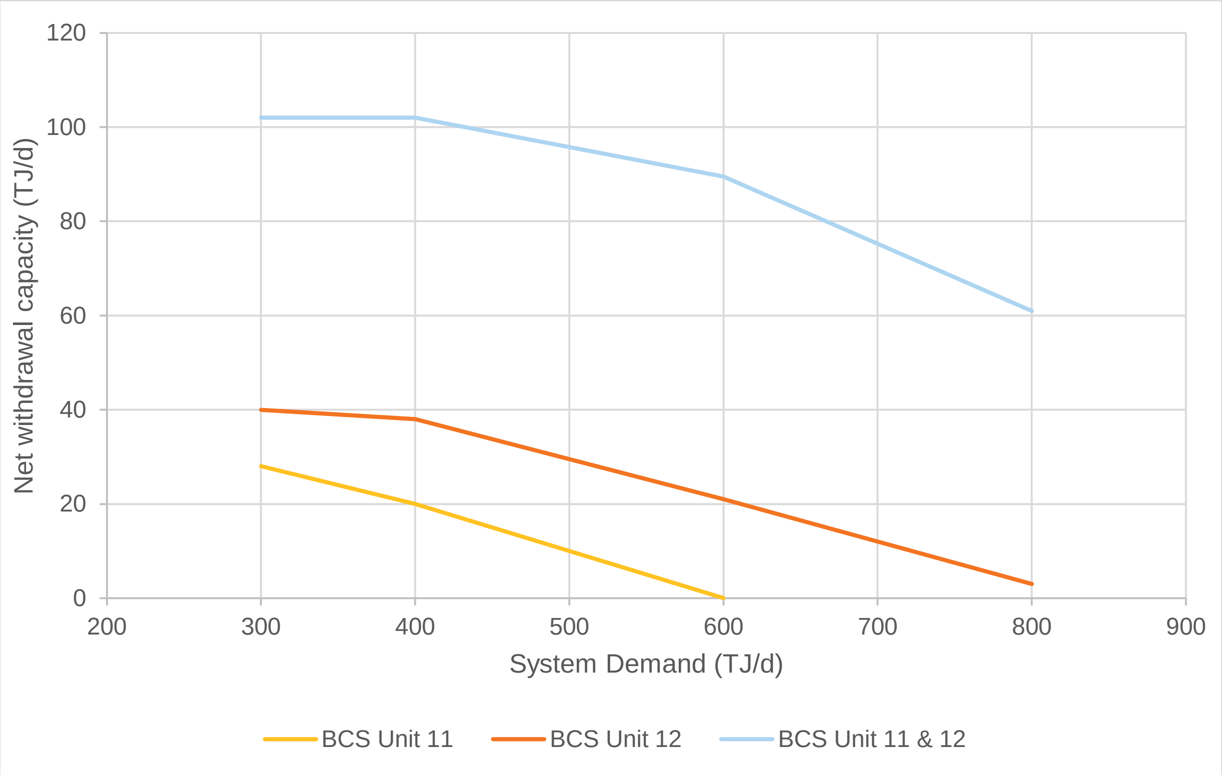
A.1 Current pipeline capacity charts

A.1.1 South West Pipeline to Melbourne with Winchelsea compressor availability[a]



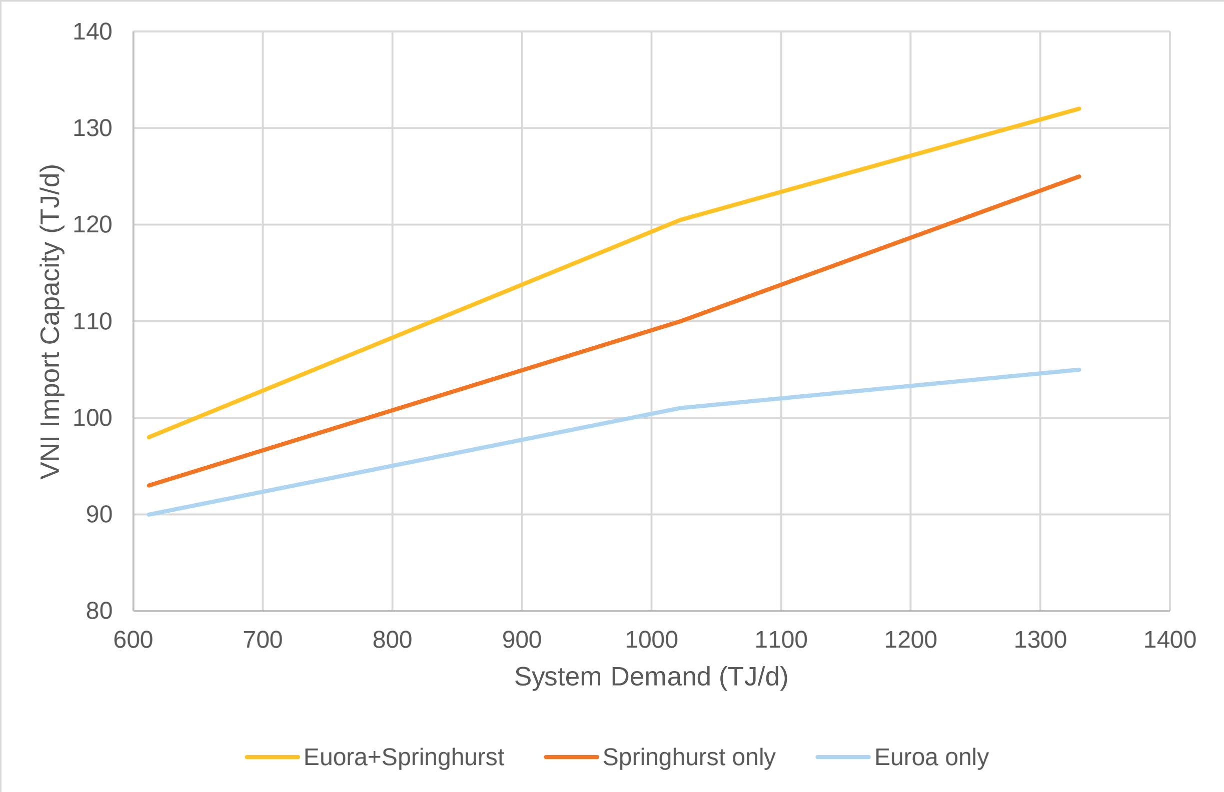
[a] The capacity chart was revised since the 2015 VGPR was published in April 2015.

A.1.2 South West Pipeline to Port Campbell with Brooklyn compressor unit availability[a]

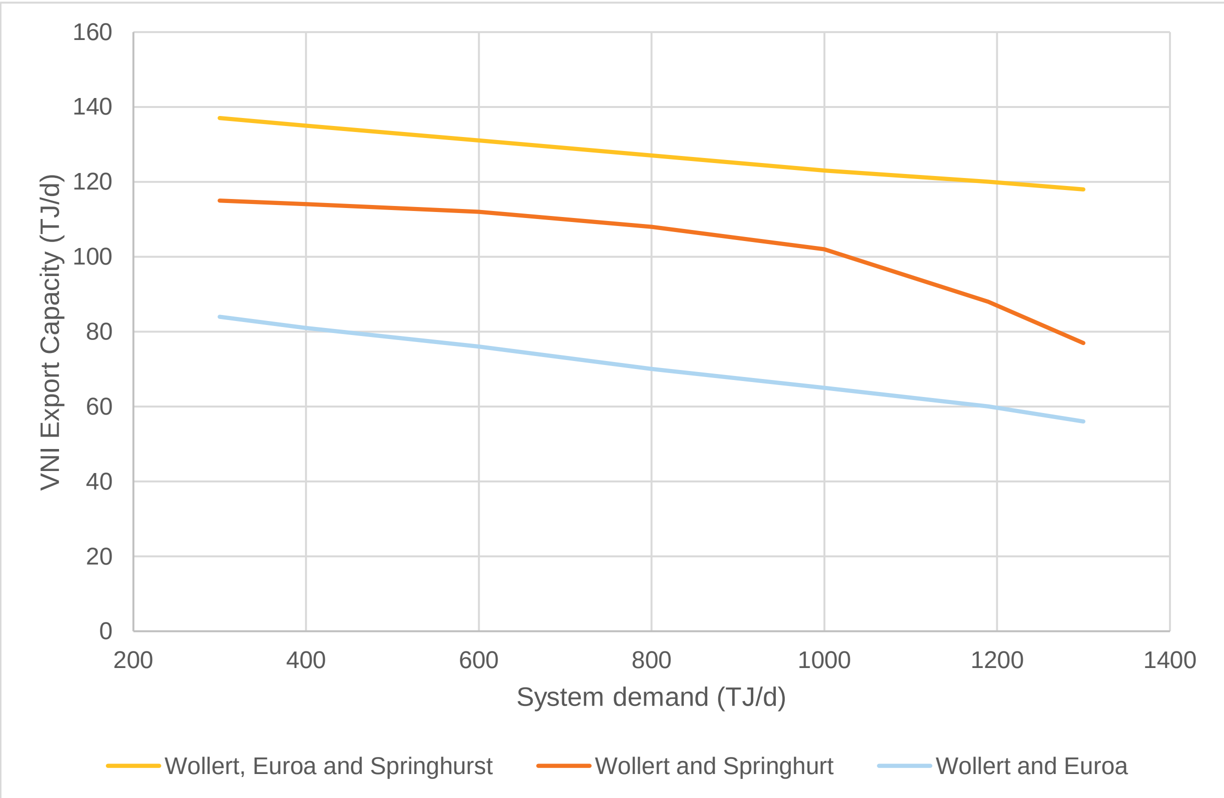


[a] The capacity chart was revised since the 2015 VGPR was published in April 2015.

A.1.3 Victorian Northern Interconnect import capacity



A.1.4 Victorian Northern Interconnect export capacity



A.2 Supporting data

Table 2 Data for Port Campbell supply demand balance

Variable	2012	2013	2014	2015	Data Source
DTS to SWP	1.0	1.6	2.4	6.2	GBB: http://www.gasbb.com.au/
Port Campbell production	106.4	104.0	95.1	79.7	GBB: http://www.gasbb.com.au/
SEA Gas Pipeline to South Australia	62.0	53.4	43.6	45.1	GBB: http://www.gasbb.com.au/
SWP to DTS	35.8	35.9	29.4	36.7	GBB: http://www.gasbb.com.au/
Mortlake GPG	13.7	16.4	20.0	7.3	Core Energy Group, Victorian GPG Asset Profile 2015

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
$	Australian dollars
km	Kilometres
kPa	Kilopascals
kscm/h	thousand standard cubic metres per hour
mm	Millimetre
PJ	Petajoule (1 PJ = 1,000 TJ)
TJ	Terajoule (1 TJ = 1,000 GJ)
TJ/d	Terajoules per day
tonnes/h	Tonnes per hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BCP	Brooklyn–Corio Pipeline
BCS	Brooklyn Compressor Station
BLP	Brooklyn–Lara Pipeline
CG	City Gate
CPP	Close Proximity Points
CS	Compressor Station
CTM	Custody Transfer Meter
DCG	Dandenong City Gate
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
EPA	Environmental Protection Authority
ESV	Energy Safe Victoria
GBB	Natural Gas Services Bulletin Board
GPG	Gas-powered generation
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
MAOP	Maximum Allowable Operating Pressure
MAP	Melbourne to Adelaide Pipeline
SCADA	Supervisory Control and Data Acquisition
SWP	South West Pipeline
UGS	Underground Gas Storage
VNI	Victorian Northern Interconnect
WCS	Wollert Compressor Station
WORM	Western Outer Ring Main (proposed)
WTS	Western Transmission System

GLOSSARY

Term	Definition
1-in-2 system demand day	The 1-in-2 system demand 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 system demand day	The 1-in-20 system demand 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.
Annual planning report	An annual report providing forecasts of gas supply, capacity and demand, and other planning information.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Authorised Maximum Daily Quantity (AMDQ)	Authorised Maximum Daily Quantity (Authorised MDQ) and Authorised Maximum Daily Quantity Credit Certificate (AMDQ CC) are transportation rights in the DTS, collectively known as AMDQ. Authorised MDQ is a withdrawal right for customers and/or market participants on the DTS for transported gas injected at Longford. Subsequent capacity increases to the DTS such as South West Pipeline, the Western Transmission System and the Bass Gas project have been allocated as AMDQ CC. AMDQ is an input to • Determining congestion uplift charges payable by a market participant for each scheduling interval of a gas day as part of the funding of ancillary payments. • Tie-breaking rights when scheduling equal priced injections or withdrawals bids, and in determining the order of curtailment in the event of an emergency.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS), and injected at Pakenham.
Capacity	Pipeline transportation capacity.
Culcairn	The gas transmission system interconnection point between Victoria and New South Wales.
constraint	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
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 or may choose to become market participants in their own right, and take on the retailing functions themselves.
Declared Transmission System	The declared gas transmission system in Victoria, in accordance with the National Gas Law. Owned by APA GasNet 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 DTS. See also Constraint (gas).
distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.
distribution system	Pipelines for the conveyance of gas with one or other of the following characteristics: • A maximum allowable operating pressure of 515 kPa or less. • Uniquely identified as a distribution pipeline in a distributor’s access arrangement, where the maximum operating pressure is greater than 515 kPa.
distributor	The service provider of the distribution pipelines that transport gas from transmission pipelines to customers.
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 more energy will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
Facility Operator	Producers, Storage Providers and interconnected transmission pipeline service providers in the DTS.
firm capacity	Guaranteed or contracted capacity to supply gas.

Term	Definition
gas	See natural gas.
gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
Gas Statement of Opportunities (GSOO)	The GSOO is published annually by AEMO, under the National Gas Law and Part 15D of the National Gas rules, to report on the projected adequacy of eastern and south-eastern Australian gas markets to supply forecast maximum demand and annual consumption.
Gigajoule (GJ)	An International System of Units (SI) unit, 1 gigajoule equals 1,000 J.
injection	The physical injection of gas into the transmission system.
Inner Ring Main	Melbourne Inner Ring Main is a pipeline loop from Dandenong to Brooklyn and Keon Park.
Interconnect (The)	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
lateral	A pipeline branch off a larger pipeline.
limiter	A regulator installed in a pipeline to reduce pressure and remove the need for heaters at downstream off-takes.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline system throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas (LNG)	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.
maintenance	Work carried out by service providers, Producers and Storage Providers that, in AEMO's opinion, may affect any of: • AEMO's ability to supply gas through the declared transmission system. • AEMO's ability to operate the declared transmission system. • DTS capacity. • System security. The efficient operation of the DTS generally. It includes work carried out on pipeline equipment, but does not include maintenance required to avert or reduce the impact of an emergency.
market participant	A party who is eligible to participate in an energy market operated by AEMO in one or more of the following roles: • A market generator, market customer, or a market network service provider (electricity). • Storage provider. • Transmission customer. • Distribution customer. • Retailer. • Trader (gas).
maximum allowable operating pressure (MAOP)	The maximum pressure at which a pipeline is licensed to operate.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand. See also Authorised Maximum Daily Quantity.
maximum hourly quantity	Maximum hourly quantity (MHQ) of gas supply or demand. MHQ is a withdrawal right for customers and/or market participants on the DTS.
meter	A device that measures and records volumes and/or quantities of gas.
National Gas Forecasting Report (NGFR)	The NGFR is published annually by AEMO, under clause 91D of the National Gas Law, to report on forecast maximum demand and annual consumption in eastern and south-eastern Australia.
Natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
Natural Gas Services Bulletin Board (GBB)	The GBB (http://www.gasbb.com.au/) is an online gas market and system information website covering all major gas production fields, major demand centres and natural gas transmission pipeline systems of South Australia, Victoria, Tasmania, NSW, the ACT, and Queensland. It was established in 2008 and is operated by AEMO.

Term	Definition
Outer Ring Main	Pakenham to Wollert Pipeline.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
Petajoule (PJ)	An International System of Units (SI) unit, 1 petajoule equals 1,000 TJ (or 10^{15} joules). Also PJ/yr or petajoules per year.
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.
planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours' notice.
probability of exceedance	Refers to the probability that a forecast peak demand figure will be exceeded. For example, a forecast 1-in-20 peak demand will, on average, be exceeded only 1 year in every 20.
scheduling	The process of scheduling bids that AEMO is required to carry out in accordance with Part 19 of the National Gas Rules for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
Shoulder	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 Port Campbell.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).
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 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 UGS.
system injection point	A gas transmission system 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.
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 (TJ)	An International System of Units (SI) unit, 1 terajoule equals 1,000 GJ (or 10^{12} joules). Also TJ/d or terajoule per day.
transmission pipeline	A pipeline for the conveyance of gas that is licensed under the Pipelines Act and has a maximum design pressure exceeding 1,050 kPa.
transmission system	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.

Term	Definition
Underground Gas Storage (UGS)	The Iona Underground Gas Storage (UGS) facility at Port Campbell which supplies gas to Victoria to meet winter peak demand, and in summer supports South Australian GPG demand via the SEA Gas Pipeline and, as needed, Victorian demand if capacity is reduced at other facilities.
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.
winter	1 June to 30 September.