Victorian Gas Planning Report Update

March 2018

GAS TRANSMISSION NETWORK PLANNING FOR VICTORIA

Important notice

PURPOSE

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 2018, although AEMO has endeavoured to incorporate more recent information where practicable.

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VERSION CONTROL

Version	Release date	Changes
1.0	29/3/2018	New document

Executive summary

The *2018 Victorian Gas Planning Report (VGPR) Update* provides information about changes in the supply demand balance over the next five years (2018-22, called the outlook period) and the Victorian Declared Transmission System (DTS) since AEMO published the 2017 VGPR in March 2017[1].

The 2017 VGPR and this VGPR Update complement AEMO's *Gas Statement of Opportunities* (GSOO), which will assess the wider gas supply adequacy in eastern and south-eastern Australia and will be published in mid-2018.

Key findings

This VGPR Update covers the following material changes and new information since the 2017 VGPR:

- Gas supply forecasts provided to AEMO by participants show that gas production, due to the depletion of offshore gas fields, is forecast to reduce further in 2022, following a projected decline to 2021 reported in the 2017 VGPR.
  - Without additional gas supply, there is a potential shortfall in meeting annual Victorian gas consumption from 2022.
  - Without additional gas supply capacity, there is a potential shortfall in meeting Victorian winter peak day demand from 2021.
  - Producers have advised AEMO that, by 2022:
    - Gippsland annual production is forecast to reduce to 38% below the 2018 production forecast (the 2018 forecast reflects a return to the lower production levels seen prior to 2016). Maximum daily production capacity is forecast to reduce by 50% compared to the 2018 forecast.
    - Port Campbell annual production is forecast to reduce by 68% from the 2018 forecast, due to some offshore fields ceasing production. Maximum daily production capacity is forecast to reduce by 76%.
  - Gas supply from Victoria to South Australia and New South Wales is expected to reduce, due to the forecast decline in Victorian gas production. Supply to these states is expected to reduce more during winter, due to inventory limitations on gas stored at the Iona Underground Gas Storage (UGS) facility. The 2018 GSOO will contain information regarding potential shortfalls outside of Victoria.
- Participants are currently investigating additional sources of gas supply including peak day capacity. Options include increased production and storage capacity, additional pipeline import capacity into Victoria, and a liquefied natural gas (LNG) import terminal.
- On 30 November 2017, the Australian Energy Regulator (AER) published its final decision on the APA Victorian Transmission System Access Arrangement that applies from 1 January 2018 until 31 December 2022. The AER approved expenditure to address the two threats to system security that AEMO identified in the 2017 VGPR (the inability to refill Iona UGS prior to winter 2019 and the Warragul supply restriction).

Actual demand and consumption trend

Annual Victorian gas consumption[2] has been relatively consistent at approximately 200 petajoules (PJ) per year since 2013, as shown in Table 1. This stable annual consumption is due to declining industrial gas use being offset by increasing winter residential consumption[3].

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[1] The 2017 VGPR forecast supply and demand, and pipeline capacity adequacy, for the outlook period 2017-21.

[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] Annual variations in system consumption – which comprises residential, commercial, and industrial gas usage – are mainly due to temperature. As the 2017 VGPR noted, lower consumption in 2014 was due to a mild winter, while increased consumption in 2015 corresponded with that year having the coldest winter in 26 years.

Prior to 2017, annual gas consumption for gas-powered generation of electricity (GPG) had been low at 3-4 PJ per year since the end of drought conditions in 2009. Increased GPG gas consumption during 2017 was due to the withdrawal of 1,600 megawatts (MW) of generation capacity when Hazelwood Power Station closed in March 2017.

Table 1 Annual gas consumption and peak gas total demand, 2012-17

	2012	2013	2014	2015	2016	2017
Annual total consumption (PJ)	211	200	195	208	203	218
Annual system consumption (PJ)	208	197	191	205	200	203
Annual GPG consumption (PJ)	3	3	4	3	3	15
Actual peak total demand (terajoules per day [TJ/d])	1,092	1,165	1,214	1,179	1,187	1,279

The 2017 Victorian peak demand day occurred on Thursday 3 August 2017. The total demand[4] on this day of 1,279 terajoules (TJ) was comprised of 1,152 TJ of system demand and 127 TJ of GPG. This was the second highest demand day on record for the Victorian DTS[5].

Forecast consumption

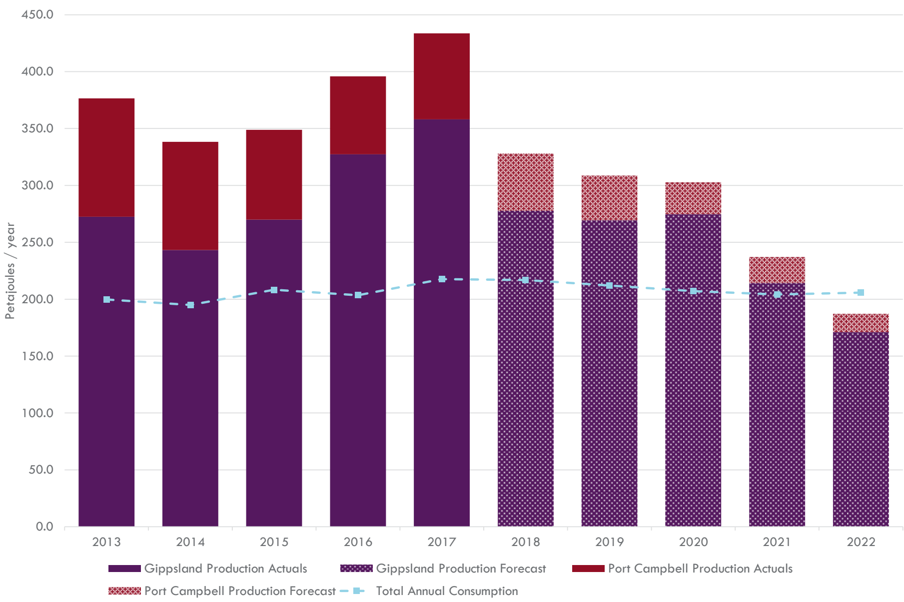
AEMO forecasts that DTS system consumption will decline slightly over the outlook period, as shown in Table 2. The decline is due to forecast ongoing reductions in industrial load, inner city residential users switching from gas to electric appliances, and improvements in energy efficiency. Continuing population growth will not be sufficient to offset these reductions, but it will continue to drive an increase in winter gas consumption.

Annual GPG consumption is forecast to decrease after 2018 through to 2021, as shown in Table 2. This is 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). GPG consumption is forecast to again increase in 2022, due to the planned closure of the Liddell Power Station, which was announced in April 2015. If additional renewable generation does not come online as projected, GPG consumption is expected to be higher than this forecast.

Forecast annual production

The forecast reduction in annual Victorian production is shown in Figure 1.

Figure 1 Annual production (petajoules per year) by location



[4] Total demand is equal to the sum of system demand and GPG, but excludes exports.

[5] Highest total demand (system and gas fired generation) recorded is 1,281.5 TJ, which occurred on 17 July 2007.

The decline to 2021 is generally consistent with forecasts published in the 2017 VGPR, with 2022 projections now added that show a further production decline.

Production reached new heights in 2017, with producers supplying 435 PJ to the east coast gas market[6], however this trend will not be sustained. Gippsland Basin Joint Venture (GBJV) partner Esso has stated that "accelerated extraction inevitably means accelerated decline", and that "the Gippsland basin is not a magic pudding – we are not sitting on a great big endless gas resource, as some seem to think"[7].

These forecast supply reductions are consistent with the Australian Competition and Consumer Commission (ACCC) Gas Inquiry 2017-2020 Interim Report published in December 2017, and the Commonwealth Government-commissioned *Offshore South East Australia Gas Supply Study* published in November 2017 (Commonwealth Study). Figure 2 shows forecasts in the Commonwealth Study and earlier VGPR forecasts, with the forecasts in this VGPR Update.

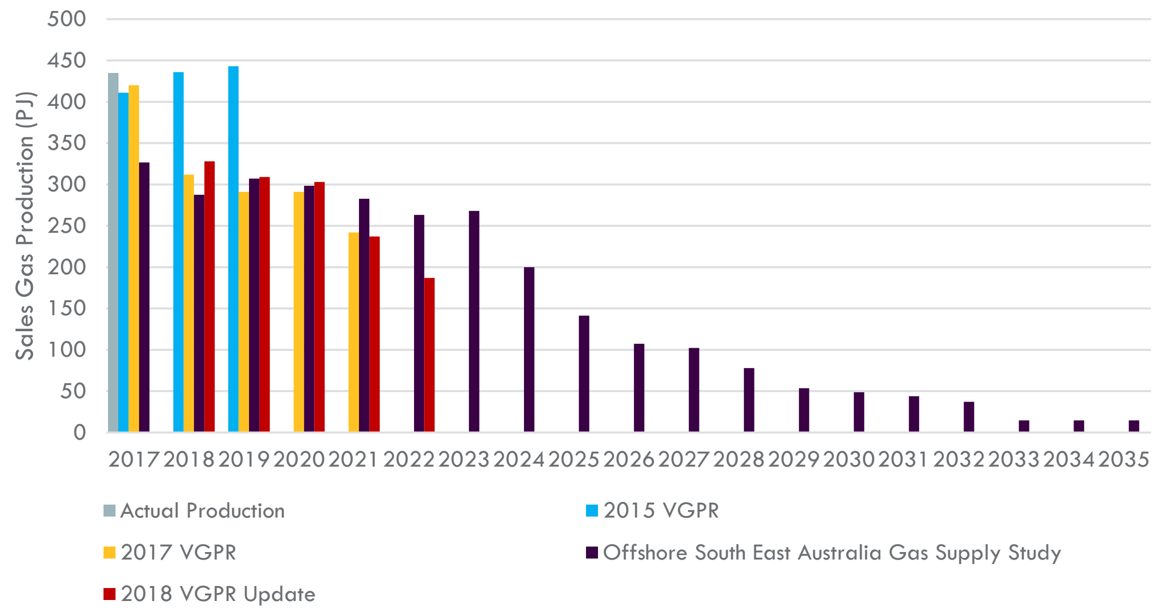
The ACCC report said:

> *"One of the GBJV's large original gas fields has depleted earlier than expected, with another two expected to deplete in the early 2020s. The GBJV has accelerated production from its legacy gas fields over the last two years to meet increasing demand, including the drawdown of gas cycled through reservoirs used to increase system capacity during peak winter demand months. However, Esso stated that the GBJV is unable to sustain these production levels as low impurity resources from its legacy fields decline."*[8]

The Commonwealth Study noted that:

> *"Any forced increases to upstream gas production from producing fields for input into onshore markets will result in a faster erosion of reserves, which, when combined with the mature nature of hydrocarbon exploration and production in the Gippsland Basin and south east Australia in general, will have implications for long-term security of supply."*[9]

Figure 2 Victorian production forecasts by year (PJ/a)



The Longford Gas Plant produced a record 345 PJ in 2017, after what was then a record annual production of 312 PJ in 2016. The 2017 Longford production was 36% higher than the 2012-15 average annual production of 252 PJ per year. The reduced Gippsland production forecast, which is mainly Longford production, is consistent with the findings of the ACCC and Commonwealth studies.

[6] This exceeded the 420 PJ production supply forecast for 2017 in the 2017 VGPR.

[7] ExxonMobil (trading as Esso Australia), "Key gas fields nearing end, but news not all bad", 18 October 2017, available at http://www.exxonmobil.com.au/en-au/community/local-outreach/esso-community-news/key-gas-fields-nearing-the-end-but-new-not-all-bad?parentId=5d196572-0a60-4ffe-ac31-77069061f657.

[8] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 30, available at https://www.accc.gov.au/publications.

[9] Australian Government, Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, 2017, p. 15, available at https://industry.gov.au/resource/Offshore-oil-and-gas/Development/Pages/SEGasSupplyStudy.aspx.

Both the Commonwealth Study and the Victorian Gas Program's first progress report[10] included a total gas resources estimate for offshore south east Australia of 12,450 PJ[11] as at the end of 2016. This resource estimate included 4,009 PJ (3.8 trillion standard cubic feet [Tscf]) proven and probable (2P) reserves[12]. Victorian gas production was 435 PJ in 2017 (all from offshore), which means that Victorian offshore 2P reserves reduced by 11% to 3,574 PJ.

Annual supply adequacy

Without additional gas supply, this VGPR Update forecasts a potential shortfall in meeting annual Victorian gas consumption from 2022. This is due to reduced gas production forecasts from that year, resulting from the depletion of Victoria's offshore gas fields (shown in Table 2). Forecast reductions to 2021 remain generally consistent with those reported in the 2017 VGPR. The projected decline in 2022 supply, and the resulting forecast shortfall, is material new information prompting this VGPR Update.

Table 2 Forecast annual consumption and production supply, 2018-21, with 2017 actuals

	2017 (actuals)	2018	2019	2020	2021	2022
Annual system consumption (PJ)	203	200	200	199	198	197
Annual GPG consumption (PJ)	15	17	12	8	6	8
Total annual consumption (PJ)	218	217	212	207	204	206
Total production supply (PJ)	435	328	309	303	237	187
Surplus/shortfall quantity (PJ)	216	111	97	96	33	-19

Gippsland producers (the Longford and Lang Lang gas plants, and the Sole Project processed via the Orbost gas plant) have advised that annual production will reduce by 38% in the five-year outlook period, from 278 PJ in 2018 to 171 PJ in 2022.

Port Campbell producers (the Otway and Minerva gas plants, and the Casino development, processed via the Iona UGS facility), have advised that annual production will reduce by 68%, from 50 PJ in 2018 to 16 PJ in 2022. Two developments that were previously forecast to cease production will continue, but are unlikely to produce out to 2022.

The production forecasts in this report include only projects that are currently producing or those that have committed timeframes for development. New supplies from currently uncommitted projects can still be brought into production during the next five-year period and change the outlook for supply adequacy. However, if no additional projects proceed and no other alternative supply sources are introduced, shortfalls could occur within the outlook period, as shown in Table 2, Table 3, Figure 1, and Figure 3.

Forecast peak day supply

Gippsland producers have advised that their daily production capacity will reduce by 50% from 1,040 terajoules per day (TJ/d) in 2018 to 515 TJ/d in 2022. The forecast 2021 production capacity advised for the 2017 VGPR was 857 TJ/d. Port Campbell producers have advised that daily production capacity will reduce by 76% from 217 TJ/d in 2018 to 53 TJ/d in 2022. This is similar to the steep decline forecast in the 2017 VGPR, although more production will be available in 2018 than previously advised due to field life extensions.

Iona UGS reservoir withdrawal capacity is forecast to increase by 20% from 435 TJ/d in 2018 to 530 TJ/d by 2022. This capacity can only be used if sufficient gas is available in the Iona storage reservoirs.

Port Campbell supply is limited by the transportation capacity of the South West Pipeline (SWP) toward Melbourne. This capacity is forecast to increase from 413 TJ/d in 2018 to 453 TJ/d in 2021 when the Western Outer Ring Main (WORM) is expected to be commissioned (note that these figures do not include the Western Transmission System).

Figure 3 demonstrates the potential shortfall as the difference between the forecast peak demand day dotted line and the supply capacity stacked bar. The Port Campbell supply capacity forecast assumes that the WORM is constructed within the timeframe provided by APA in its approved Access Arrangement, and that the Iona UGS expansion occurs as planned.

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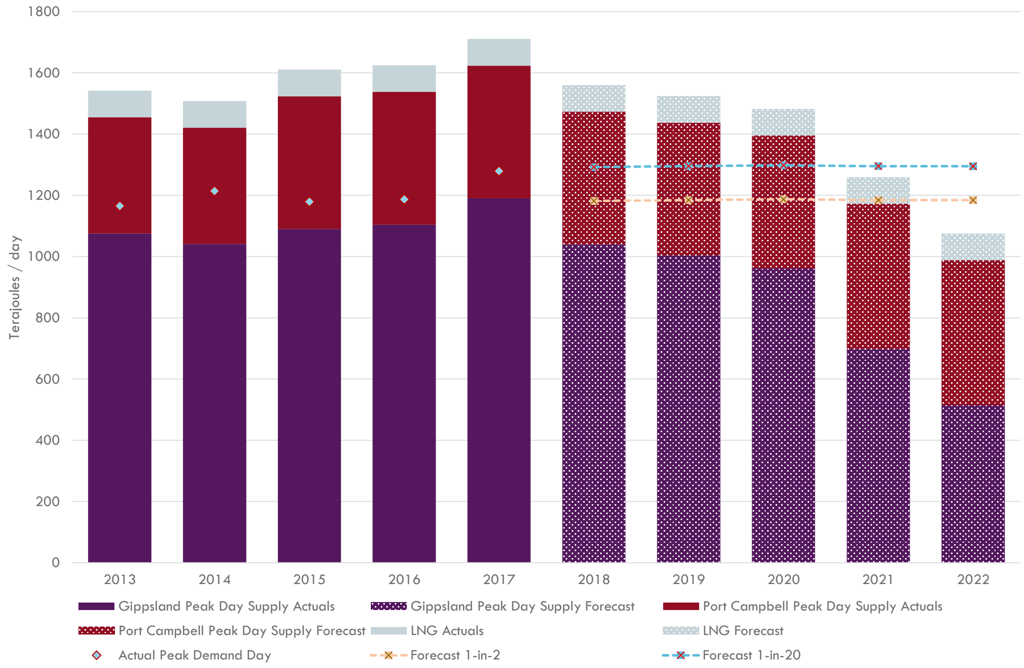
[10] Geological Survey of Victoria, *Victorian Gas Program progress report – report No. 1*, January 2018, available at http://earthresources.vic.gov.au/earth-resources/victorian-gas-program/progress-report.

[11] The value is a summation of 2P, 2C (best estimate of contingent resources, or technically recoverable reserves for discovered but uncommercialised fields), and undiscovered resources outlined in the reports. This report uses a conversion factor of 1,055 PJ/Tscf unless otherwise stated.

[12] 2P is considered the best estimate of commercially recoverable reserves.

Figure 3 Peak day supply capacity by location (terajoules per day)



Without additional gas supply capacity, the shortfall forecast for 2021 would result in reliance on non-firm gas supply on a 1-in-20[13] year peak day, and gas load curtailment if there was high GPG demand. Gas supply restrictions and curtailment would be necessary in 2022.

As production declines, there will be reduced gas supplies available in Victoria for export to New South Wales, Tasmania, and South Australia on a peak demand day. Potential gas supply shortfalls for these states will be explored further in the 2018 GSOO.

Peak day supply adequacy

The forecast reduction in Victorian gas supply capacity will result in a potential shortfall in meeting Victorian winter peak day demand from 2021.

AEMO forecasts that DTS peak system demand will remain relatively flat over the outlook period, as shown in Table 3. Similar to the forecast decline in annual gas consumption, reductions in industrial load, inner city residential users switching from gas to electric appliances, and improvements in energy efficiency are forecast to be offset by population growth driving an increase in peak winter gas consumption. Forecast gas demand on a 1-in-2 year peak system demand day including GPG demand is similar to the system demand on a 1-in-20 year peak day.

Table 3 Forecast peak day supply adequacy, 2018-22 (terajoules per day)

	2018	2019	2020	2021	2022
Total supply (including Victorian LNG)	1,785	1,712	1,687	1,413	1,184
Total available supply including pipeline constraints	1,551	1,524	1,482	1,259	1,075
1-in-2 peak system demand	1,182	1,185	1,187	1,184	1,184
Surplus/shortfall quantity on 1-in-2 peak day	369	340	295	75	-109
1-in-20 peak system demand	1,292	1,295	1,298	1,295	1,295
Surplus/shortfall quantity on 1-in-20 peak day	258	229	184	-36	-220

[13] A 1-in-2 forecast is defined as a peak day gas demand forecast with a 50% probability of exceedance (POE). 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. It means the forecast is expected, on average, to be exceeded once in 20 years and is used for DTS capacity planning.

Additional supply options

AEMO understands that a number of projects are currently being investigated that could help to resolve both the annual and peak day supply issues. These projects include:

- **Additional gas production.**
  - Esso has submitted plans to the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) to begin geophysical and geotechnical surveys for the proposed GBJV West Barracouta development. GBJV's stated intention is to bring this gas online beginning 2020 to 2021. Development plans have also been submitted to NOPSEMA for a number of small sour gas fields, including Kipper Phase 1B. This gas would be processed through the existing Longford gas conditioning plant. No production forecast or capacity information has been provided to AEMO for these potential projects. However, in March 2018 Esso advised AEMO that if the projects that GBJV are currently investigating proceed and are successful, GBJV believes the current outlook on these could maintain gas production at 2018 levels through to 2022.
  - GBJV has requested a five-year extension on its retention lease for the South East Remora field, due to the requirement to process the gas via the Longford gas conditioning plant (due to impurities in the gas) when capacity becomes available. The field is estimated to hold 280 PJ.
  - In August 2017, Esso announced that it had acquired a 100% interest in the VIC/P70 licence area that includes the previous Dory[14] discovery. Esso is undertaking exploration drilling activities in 2018 as part of its work program obligations, which include testing the extent of the existing discovered Dory resource. If these activities confirm a large gas field with low impurities, it could replace a significant proportion of declining Longford production. Dory is, however, located in deep water and is expected to take approximately seven years to start producing[15].
  - AEMO has been provided with information about proposed projects in the Gippsland, Bass, and Otway basins by other producers, including whether they are committed or if they are awaiting final investment decision (committed projects are included in forecast production). These proposed projects are for the development of small gas fields. If they proceed, production from these fields would reduce or delay the potential gas supply shortfall.
- **Additional gas storage capacity** – Victorian UGS and LNG storage capacity could be expanded.
  - The Victorian Gas Program study includes investigating additional UGS development sites. A new large UGS facility like the Iona facility is unlikely to be available within five years[16].
  - Development of another LNG storage facility within the DTS could increase peak day gas supply capacity, but not annual supply.
- **AGL LNG Import Terminal**[17] – AGL has proposed the development of a floating LNG import terminal at Cribb Point, near Hastings in Victoria.
  - There are currently 23 Floating Storage and Regasification Unit (FSRU) terminals operating worldwide (for example, Boston in the United States). These facilities are used to supply peak gas demand periods.
  - The proposed import terminal does not include onshore storage. Without onshore storage, the FSRU would need to be nearly empty before an LNG ship could complete unloading. If regasification rates are not well managed, there is the potential for gas supply shortfalls if an LNG ship is late.
  - Utilising imported LNG will provide AGL the flexibility to purchase additional gas from contracted suppliers or spot cargoes to meet any increases in demand.
  - The floating nature of the project allows for the potential to swap the facility if long-term technical issues were ever experienced.
  - A similar facility has been proposed for New South Wales[18].

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[14] The Australian, "Exxon Mobil buys huge Bass Strait gasfield", 7 August 2017, available at https://www.theaustralian.com.au/business/mining-energy/exxon-mobil-buys-huge-bass-strait-gasfield/news-story/534634e50c8e646a2b19577a94b43865 (paywall).

[15] Australian Government, Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, 2017, available at https://industry.gov.au/resource/Offshore-oil-and-gas/Development/Pages/SEGasSupplyStudy.aspx.

[16] For more information about the Victorian Gas Program, see http://earthresources.vic.gov.au/earth-resources/victorian-gas-program.

[17] AGL, FSRU fact sheet, October 2017, available at http://www.engageagl.com.au/wp-content/uploads/2017/10/FSRU_Factsheet_A4_FA.pdf.

[18] Australian Financial Review, "Andrew Forrest, Japan Inc team up to ship LNG to NSW", 25 February 2018, available at http://www.afr.com/business/energy/gas/twiggy-japan-inc-team-up-to-ship-lng-to-nsw-20180225-h0wm01.

- **Queensland supply.**
  - Additional gas supply from Queensland cannot address the forecast Victorian gas supply shortfall unless additional pipelines are constructed.
  - Expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline by constructing additional compression facilities could increase southbound capacity.
  - A pipeline from Wallumbilla, near Roma in Queensland, to Newcastle has previously been proposed to increase gas supply to New South Wales.
- **Western Australia supply.**
  - The Federal Government is funding a feasibility study for a West-East gas pipeline to transport gas from Western Australia to the east coast, with a pre-feasibility report due in March 2018. Media reports have estimated the cost at approximately $5 billion[19]. If this project were to proceed it would be unlikely to be completed within the outlook period.

AEMO will continue to seek additional information about these additional gas supply options, to determine whether sufficient gas supply will be available for 2021 and 2022, and beyond.

[19] Australian Financial Review, "West-East Pipeline emerges as threat to LNG import plan", 28 February 2018, available at http://www.afr.com/business/energy/gas/westeast-pipeline-emerges-as-threat-to-lng-import-plan-20180228-h0wrfw.

Contents

Tables

Figures

1. Introduction

The *Victorian Gas Planning Report* (VGPR) outlines the system adequacy of the Victorian declared transmission system (DTS), shown in Figure 4, to supply peak day demand and annual consumption over a five-year outlook period. The most recent VGPR was published in March 2017[20].

Where AEMO becomes aware of any information that materially alters the most recently published VGPR, the National Gas Rules (NGR) require AEMO to update the report as soon as practicable. The material changes that prompted this VGPR Update are:

- Updated gas production forecasts which indicate that, without additional gas supply, there is:
  - A potential shortfall in meeting annual Victorian gas consumption from 2022.
  - A potential shortfall to supply winter peak day demand from 2021.
- Changes to the DTS since the 2017 VGPR was published.

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 gas 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). The DTS has six system withdrawal zones (SWZs), defined in Appendix A2: Ballarat; Geelong; Gippsland; Melbourne; Northern; and Western (Western Transmission System or WTS). Figure 4 provides a high-level map of the Victorian gas transmission network, including the DTS (in blue) and other gas transmission pipelines.

Figure 4 The Victorian Declared Transmission System

[20] Recent VGPR publications are available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

1.2 Gas planning in Victoria

1.2.1 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 capital investment in the DTS through the Access Arrangement process[21] with the Australian Energy Regulator (AER).

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

1.2.2 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 NGR rule 323.

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.

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 DTS supply and system adequacy to meet a forecast 1-in-2 and 1-in-20 peak system demand day over the outlook period:

- A **1-in-2 forecast** is defined as a peak day gas demand forecast with a 50% probability of exceedance (POE). 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. It means the forecast is expected, on average, to be exceeded once in 20 years and is used for DTS capacity planning.

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.

1.3 Winter 2017 review

In 2017, the peak system demand day for Victoria occurred on Thursday 3 August 2017. The total demand of 1,275 terajoules (TJ) was comprised of 1,148 TJ system demand and 127 TJ of demand for gas-powered generation of electricity (GPG). This was the second highest total demand day on record for the DTS. (The highest ever recorded total demand is 1,287 TJ on 17 July 2007.)

The DTS experienced 19 days when system demand exceeded 1,000 terajoules per day (TJ/d) during the winter period (1 June to 30 September 2017), compared to 13 days during the same period in 2016.

The key observations during winter 2017 were:

- Average winter system demand was 853 TJ/d, which is similar to the 855 TJ/d observed in 2016.
- There was 4.6 petajoules (PJ) of DTS-connected GPG demand, compared to 1.4 PJ consumed in winter 2016. This increase was due to the March 2017 closure of the Hazelwood Power Station.
- Participants withdrew 3.2 PJ from the South West Pipeline (SWP) at Port Campbell from June to September, up from 2.0 PJ during the 2016 winter period. The availability of Brooklyn Compressor Station (CS) Unit 10 during September 2017 supported the increased withdrawals.

[21] For more information, see https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2018-22.

- Average daily flow to New South Wales via the Victorian Northern Interconnect (VNI) continued to decline, with an average of 28 TJ/d being exported, compared to 38 TJ/d during the 2016 winter period, and 63 TJ/d in 2015.

The cumulative total EDD[22] for the 2017 winter period was 1,066. This is 7% higher than the total EDD of 999 for winter 2016, but 5% lower than the 1,128 in winter 2015, which was the coldest winter in 26 years.

A total of 590 tonnes (32 TJ) of liquefied natural gas (LNG) was scheduled for injection into the DTS during winter 2017. This includes 18 TJ which was scheduled on the peak demand day of Thursday 3 August 2017 for peak shaving purposes, to maintain system pressures.

[22] EDD, or effective degree days, is a measure of coldness that includes temperature, sunshine hours, chill, and seasonality. The higher the number, the colder it appears to be and the more energy will be used for heating.

2. Gas demand forecast

Key findings

- The forecast peak system demand for 2018 is slightly lower than was forecast in the 2017 VGPR:
  – 1,182 TJ/d for a 1-in-2 peak system demand day.
  – 1,292 TJ/d for a 1-in-20 peak system demand day.
- Over the 2018-22 outlook period, the forecast 1-in-2 and 1-in-20 peak system demand days remain relatively flat (similar to the forecast in the 2017 VGPR), with a slight peak in 2020.
- Annual system consumption is forecast to decrease slightly, from 200 PJ in 2018 to 197 PJ in 2022. This is consistent with (and slightly higher overall than) the 2017 VGPR forecasts.
- Annual DTS-connected GPG consumption increased by 500% in 2017 to 15 petajoules a year (PJ/y), due to the March 2017 closure of Hazelwood Power Station. From 2019, annual DTS-connected GPG consumption is forecast to decrease, due to new renewable generation coming online (the same trend was forecast in the 2017 VGPR). A slight increase in GPG consumption is forecast late in the outlook period, due to the announced withdrawal of the Liddell Power Station in New South Wales.

Background

The gas demand forecasts in this 2018 VGPR Update are produced using the *Gas Statement of Opportunities* (GSOO) gas demand forecasting methodology[23]. The VGPR forecasts are a subset of the forecasts that will be used in the 2018 GSOO for eastern and south-eastern Australia, to be published later in 2018.

There are some material differences between the 2017 and 2018 VGPR forecasts, with updates being made incorporating 2017 actual demand into the forecasting models. The demand forecasts over the outlook period include:

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

Updated monthly peak day GPG demand and peak hourly system demand forecasts have not been included in this VGPR update. Updates to these forecasts will be provided in the 2019 VGPR.

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 2018, and monthly peak day gas forecasts for January 2018 to December 2018. These forecasts are reported by SWZ.

System demand is the forecast daily demand. It includes unaccounted for gas (UAFG) and compressor and heater fuel gas use, but excludes GPG demand.

System demand is split into:

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

[23] The GSOO methodology is available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

Forecast compressor and heater fuel gas use is proportionally allocated by energy volume to both Tariff V and Tariff D demand.

2.1.1 Annual peak system demand

Peak day system demand is primarily driven by Tariff V consumption for space heating, which significantly increases during periods of cold weather.

The 1-in-2 and 1-in-20 peak day system demand forecasts, summarised in Table 4 and Table 5, have a small projected increase until 2020, before gradually declining. The initial incline in peak demand is driven by an increase in Tariff V demand, due to the growth in projected new connections. From 2021, this increase is forecast to be offset by gas to electric appliance switching in high density population areas, and lower heating demand driven by improved energy efficiency. Table 4 and Table 5 also show that peak day Tariff D demand is forecast to remain relatively flat during the outlook period (noting that annual Tariff V and D gas consumption is forecast to decline).

Table 4 Annual 1-in-2 peak day demand forecast (TJ/d)

	2018	2019	2020	2021	2022	Change over outlook (%)
Tariff V	940	943	944	943	943	0.28%
Tariff D	241	242	243	241	241	-0.01%
System demand	1,182	1,185	1,187	1,184	1,184	0.22%

Table 5 Annual 1-in-20 peak day demand forecasts (TJ/d)

	2018	2019	2020	2021	2022	Change over outlook (%)
Tariff V	1,049	1,052	1,053	1,052	1,052	0.04%
Tariff D	243	243	245	243	243	-0.11%
System demand	1,292	1,295	1,298	1,295	1,295	0.01%

In the 2017 VGPR, 1-in-2 and 1-in-20 peak day demand forecasts showed slight decreases each year throughout the outlook period to 2021.

2.1.2 Monthly peak day forecast

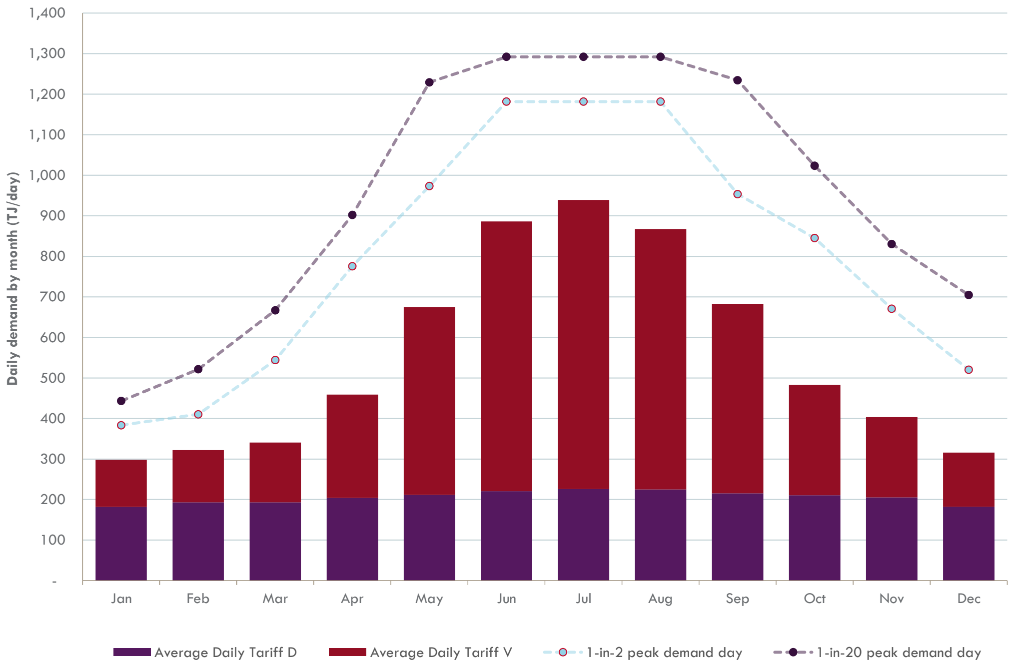
Figure 5 shows forecast average and peak daily system demand by month for 2018. Peak day system demand is assumed to occur during the winter period, which runs from June to September. Monthly peak day system demand, as seen in Table 6, is influenced by weather conditions and seasonal demand variations.

The 1-in-2 and 1-in-20 peak day demands for September have been lowered for 2018. This is the result of a statistical review of historical demands and temperatures. The analysis showed that while September can still be subject to large 1-in-20 peak demands, the magnitude of 1-in-2 peak demand days was much lower, indicating that extreme cold days occurred less frequently compared to June, July, and August.

Table 6 Monthly peak day system demand (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	383	410	544	776	974	1,182	1,182	1,182	954	845	671	521
1-in-20	443	522	667	902	1,229	1,292	1,292	1,292	1,235	1,024	831	705

Figure 5 Average daily demand by month comparison with 1-in-2 and 1-in-20 peak day demand forecasts



2.2 Total consumption

This section presents forecasts of DTS total annual consumption, which includes:

- System consumption (Tariff V, Tariff D, compressor fuel gas, and UAFG).
- DTS-connected GPG consumption.

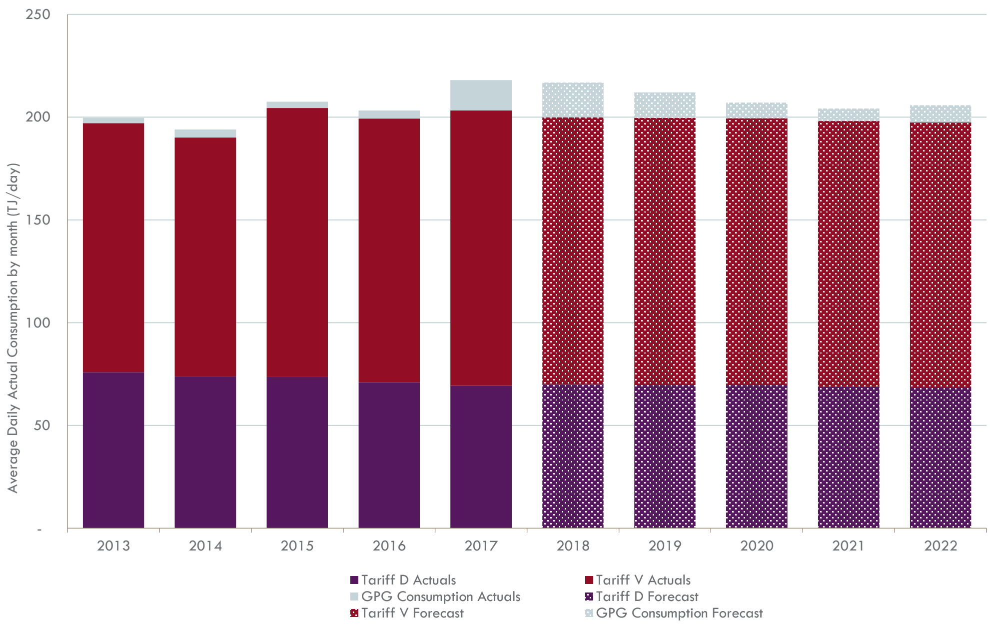
2.2.1 Annual consumption

Annual total gas consumption is forecast to fall from 217 PJ in 2018 to 206 PJ in 2022, as shown in Table 7 and Figure 6. This is attributed primarily to a forecast decline in Tariff D and GPG annual consumption.

Table 7 Total annual gas consumption forecast (PJ/y)

	2018	2019	2020	2021	2022	Change over outlook (%)
Tariff V	130	130	130	129	129	-0.7%
Tariff D	70	70	70	69	68	-2.9%
System consumption	200	200	200	198	197	-1.5%
GPG consumption	17	12	8	6	8	-53.0%
Total consumption	217	212	207	204	206	-5.0%

Figure 6 Historical and forecast total annual gas consumption, 2013 to 2022



This forecast reduction is similar to what was forecast in the 2017 VGPR, which projected total consumption reducing to 197 PJ/y by 2021.

Annual GPG consumption

Table 7 outlines the forecast DTS-connected GPG consumption out to 2022, while Figure 6 provides a graphic comparison between historic and forecast numbers. Since 2012, DTS-connected GPG consumption has averaged 3 petajoules per year (PJ/y). Higher GPG consumption occurred between 2007 and 2011, due to drought conditions in most of southern Australia, which reduced the availability of hydroelectric generation and (due to impacts on cooling water) coal-fired generation.

In 2017, GPG consumption increased by 500% above the 2016 amount to 15 PJ, due to the March 2017 closure of the coal-fired Hazelwood Power Station. The 2018 forecast GPG consumption is 17 PJ, which is similar to the 2017 actual GPG consumption, adding the January to March period without Hazelwood.

Large amounts of new renewable generation capacity is forecast to come online from 2020 to support the Victorian Renewable Energy Target (VRET) and the Federal Large-scale Renewable Energy Target (LRET). This is forecast to result in reduced GPG consumption.

The slight increase in forecast GPG consumption in 2022 is driven by the announced closure of the Liddell coal-fired power station in New South Wales [24].

Electricity system network constraints in Western Victoria have been identified through the Regulatory Investment Test for Transmission (RIT-T) process and documented in AEMO's *Western Victoria Renewable Integration*[25] consultation report. These constraints may limit the output of this proposed new generation capacity.

The forecasting methodology assumes that these network constraints are built out as new renewable generation comes online. This assumption creates a level of forecast uncertainty. If these electricity network constraints are not resolved as the new renewable energy generation comes online, GPG consumption over the outlook period is likely to exceed the forecast provided in Table 7.

Tariff V Consumption

Tariff V annual consumption represents residential and small commercial demand, which over the outlook period projects a slight decline of 0.70%.

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[24] AGL media release, "AGL announces plans for Liddell Power Station", 9 December 2017, available at https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/december/agl-announces-plans-for-liddell-power-station.

[25] AEMO. Western Victoria Renewable Integration: Project Specification Consultation Report, April 2017, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2017/Western-Victoria-Renewable-Integration---Project-Specification-Consultation-Report_FINAL.pdf.

As Table 8 shows, the behaviour varies in different SWZs:

- In the Melbourne zone, Tariff V consumption is forecast to decrease as the projected number of new connections is offset by reduced consumption per household.
- In the Ballarat, Geelong, Gippsland, and Northern zones, Tariff V consumption is forecast to increase due to the number of new connections in the low density population growth corridors on the fringe of Melbourne.

Table 8 Annual Tariff V consumption (PJ/y) by SWZ

	2018	2019	2020	2021	2022	Change over outlook (%)
Ballarat	8.4	8.5	8.6	8.7	8.8	4.3%
Geelong	10.9	11.0	11.2	11.3	11.5	5.5%
Gippsland	5.7	5.8	5.9	6.0	6.0	6.7%
Melbourne	92.9	92.4	91.8	91.0	90.2	-2.9%
Northern	10.8	10.9	11.0	11.1	11.2	3.3%
Western	1.3	1.3	1.3	1.3	1.3	-0.2%
Tariff V system consumption	130.0	130.0	129.8	129.4	129.0	-0.7%

Tariff D consumption

As seen in Table 9, Tariff D annual consumption is forecast to have a greater relative reduction in annual consumption over the outlook period, of 2.2%.

Table 9 Annual Tariff D consumption (PJ/y) by SWZ

	2018	2019	2020	2021	2022	Change over outlook (%)
Ballarat	1.6	1.6	1.6	1.6	1.6	-1.1%
Geelong	11.4	11.4	11.9	11.2	11.1	-2.4%
Gippsland	9.4	9.3	9.2	9.3	9.3	-1.0%
Melbourne	35.4	35.2	34.9	34.5	34.4	-2.6%
Northern	9.1	9.1	9.0	9.1	9.0	-1.1%
Western	3.1	3.1	3.0	3.0	2.9	-5.4%
Tariff D system consumption	70.0	69.7	69.7	68.7	68.4	-2.2%

3. Gas supply adequacy

Key findings

- Without additional gas supply, there is forecast to be insufficient Victorian production to supply forecast annual Victorian gas consumption from 2022. This is due to the depletion of offshore gas fields, resulting in reduced Victorian gas production forecasts from producers and facility operators.
- Without additional peak day gas supply capacity, a peak demand day shortfall is forecast for 2021 and 2022.
  - In 2021, Victoria is forecast to rely on non-firm gas supply on a 1-in-20 year (severe weather) peak day, and gas supply shortfalls if this peak was to coincide with high GPG demand.
  - For 2022, shortfalls are forecast for both 1-in-20 and 1-in-2 year peak days. Gas supply restrictions and curtailment may be necessary on these days if additional supplies aren't brought to market.

3.1 DTS supply sources

AEMO assesses supply adequacy based upon its demand forecast, provided in Chapter 2, and the forecast 'total supply', using data provided to AEMO by producers and facility operators (see below).

For gas planning purposes, AEMO uses these three classifications of gas supply:

- 'Total supply' is the sum of available and prospective supply, as well as firm capacity LNG. This supply is subject to market participants contracting and offering the gas into the market on the day.
- 'Available supply' is from existing production and storage facilities as firm gas supply contracted by market participants.
- 'Prospective supply' is made up of two components:
  - Production and storage facility capacity from existing facilities that is available to be contracted by market participants but is not currently contracted.
  - Developments or projects which have successfully passed Final Investment Decision (FID) and are progressing through the Engineering, Procurement, and Construction (EPC) phase, but are not currently operational. (Any projects or developments which have not reached FID are not included in this assessment, but are discussed in Chapter 4.)

3.1.1 Production facilities

DTS production capacity by supply source is reported by SWZ (shown in Table 10, with ownership details[26]).

[26] For sources of ownership information, see http://corporate.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/kipper-tuna-turrum, http://www.awexplore.com/irm/PDF/2857_0/AWErecommendstakeoverbidfromMitsuifor095pershare, http://www.cooperenergy.com.au/Upload/4.-Sole-FID.pdf, https://www.originenergy.com.au/content/dam/origin/about/investors-media/170928%20ASX%20release%20Origin%20agrees%20to%20sell%20Lattice%20Energy.pdf, http://www.bhpbilliton.com/our-businesses/petroleum, http://www.cooperenergy.com.au/Upload/2017.01.10-Vic-Gas-Asset-completion.pdf, http://www.qic.com.au/knowledge-centre/gi-media-release-20151008, https://www.mitsui.com/au/en/group/1216674_9223.html.

Table 10 DTS production facilities by SWZ

SWZ	Supply source	Project	Ownership
Gippsland	Longford Gas Plant	Gippsland Basin Joint Venture	• Esso Australia Resources, 50% • BHP Billiton, 50%
		Kipper Unit Joint Venture	• Esso Australia Resources, 32.5% • BHP Billiton, 32.5% • Mitsui E&P Australia, 35%
	Lang Lang Gas Plant	BassGas Project	• Beach Energy, 53.25% • AWE, 35% • Prize Petroleum International, 11.25%
	Orbost Gas Plant	Sole Gas Project	• Cooper Energy, 100%
Port Campbell (Geelong)	Otway Gas Plant	Otway Gas Project	• Beach Energy, 100%
		Halladale/Speculant Project	• Beach Energy, 100%
	Minerva Gas Plant	Minerva Joint Venture	• BHP Billiton, 90% • Cooper Energy, 10%
	Iona Gas Plant	Iona UGS	• QIC, 100%
		Casino Gas Project	• Cooper Energy, 50% • Mitsui E&P Australia, 25% • AWE, 25%

3.1.2 Storage facilities

There are two storage facilities in the DTS:

- Iona UGS, located in Port Campbell (Geelong zone).
- Dandenong LNG facility, located in the Melbourne zone.

Iona UGS

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 150 TJ/d.

A previous VGPR submission provided by the Iona UGS operator flagged a phased expansion, where the reservoir withdrawal capacity would increase to 435 TJ/d, then to 545 TJ/d, and finally to 570 TJ/d[27]. The Iona UGS facility operator has advised AEMO of updated plans, with revised capacities (shown in Table 11). The facility operator has also advised that the proposed expansion to bring the overall capacity of the Iona UGS facility to 570 TJ/d could be dependent on an expansion of the SWP capacity towards Melbourne.

Table 11 Iona UGS proposed capacity expansion plans

Year	Max. reservoir withdrawal capacity (TJ/d)
2018	435
2019	480
2020	530
2021	530
2022	530

[27] 2016 VGPR Update. Available at https://www.aemo.com.au/-/media/Files/PDF/2016-Victorian-Gas-Planning-Report-Update.pdf.

LNG storage

The Dandenong 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.
- The LNG facility is able to vaporise 180 tonnes per hour (t/h) at its maximum (non-firm rate) capacity.
- Vaporisation capacity of up to 100 t/h, equivalent to 5.5 terajoules per hour (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.

3.1.3 Interconnected pipelines

There are four pipelines with connections to 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.
- Young to Culcairn Pipeline off the Moomba to Sydney Pipeline (also known as the Victoria New South Wales Interconnect [VNI]).
- South East Australia Gas (SEA Gas) Pipeline, which supplies gas into the SWP via the SEA Gas and Mortlake connection points.

3.2 Annual supply and demand balance

This section lists the annual available and prospective gas supply for the outlook period. The forecast does not take into account DTS storage facilities, as these facilities provide seasonal balancing for the peak demand periods and are not expected to provide annual supplies.

Updated gas supply forecasts provided to AEMO by gas production facility operators show that gas production is forecast to reduce further in 2022, following a projected decline to 2021 as reported in the 2017 VGPR. The annual available and prospective production by source for the outlook period is shown below in Table 12.

It shows that total Victorian gas production is forecast to decline by 43%, from 328 PJ in 2018 to 187 PJ in 2022:

- Gippsland production is forecast to reduce by 38% from 278 PJ in 2018 to 171 PJ in 2022.
- Port Campbell production is forecast to reduce by 68% from 50 PJ in 2018 to 16 PJ in 2022, due to some offshore formations ceasing production.

As highlighted at the beginning of this chapter, the production forecasts in this report only include projects that are currently producing or have committed timeframes for development. New supplies from currently uncommitted projects could still be brought into production during the next five-year period and would change the outlook for supply adequacy. In March 2018, Esso advised AEMO that GBJV continues to review resource assessments and evaluate development opportunities. If these projects proceed and are successful, GBJV believes the current outlook on these could maintain gas production at 2018 levels through to 2022. AEMO is not able to include these projects in the production forecast until they are committed to for development.

The tight supply-demand balance in 2021 will place a high reliance on storage. The 2022 supply shortfall means Victoria would need to source gas from other states. Victoria can currently only import gas via the Moomba to Sydney Pipeline (MSP) through the Culcairn interconnection.

The 19 PJ shortfall is expected to occur during the four-month winter peak period. The average flow from the MSP to Victoria would need to be 158 TJ/d (19,000 TJ over 120 days). While the Culcairn import capacity has increased from 125 TJ/d to 150 TJ/d, the existing transportation capacity of the MSP could be a limiting factor given that it would also be supporting a higher proportion of New South Wales demand as a result of reduced Victorian supply.

Assuming no material changes in forecast demand, addressing the shortfall forecast for 2022 is most likely to require a combination of new production coming online, storage capacity development, additional imports from other states, and increases in pipeline capacity. Options currently under investigation by industry are discussed in Chapter 4.

Table 12 Total gas production by SWZ (PJ/y), 2018-22

	Supply source	2018	2019	2020	2021	2022
Gippsland[A]	Available	274	240	223	79	78
	Prospective	4	29	52	136	93
	Total available plus prospective	278	269	275	214	171
Port Campbell (Geelong)[B]	Available	44	29	18	15	10
	Prospective	6	10	10	8	6
	Total available plus prospective	50	39	28	23	16
Total available		319	269	241	94	88
Total prospective		10	40	62	144	99
Total supply		**328**	**309**	**303**	**237**	**187**

A) Gippsland zone includes Longford GBJV, Longford Kipper Project, Sole Gas project, and Lang Lang production facilities. The combined Longford number is gas available to the DTS, EGP, and TGP.
B) Port Campbell includes Iona UGS, Otway, and Minerva. These numbers include the total gas available to the DTS, South Australia, and Mortlake Power Station.

3.3 Production decline

In the 2017 VGPR, AEMO outlined that production was forecast to experience a large decline in the outlook to 2021, due to the depletion of offshore gas fields. Updated information from producers, which now includes 2022, shows a continued decline in annual and peak day supply forecasts. A comparison of supply forecasts submitted to AEMO by producers for the 2017 VGPR and the 2018 VGPR Update is shown in Table 13.

Table 13 2017 VGPR and 2018 VGPR Update supply forecast comparison

		2018	2019	2020	2021	2022
Gippsland	2017 VGPR	266	261	274	228	
	2018 VGPR	278	269	275	214	171
	Change (%)	**5%**	**3%**	**0%**	**-6%**	
Port Campbell	2017 VGPR	46	30	17	14	
	2018 VGPR	50	39	28	23	16
	Change (%)	**9%**	**30%**	**65%**	**64%**	
Total	2017 VGPR	311	291	291	242	
	2018 VGPR	328	309	303	237	187
	Change (%)	**5%**	**6%**	**4%**	**-2%**	

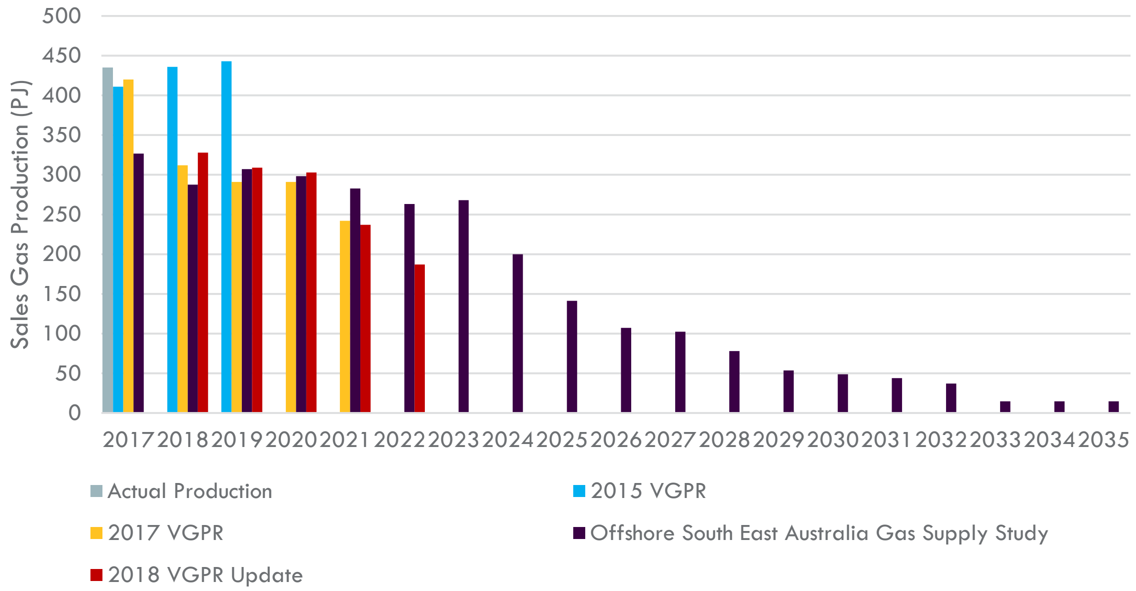
Production forecasts, when used in conjunction with demand forecasts, provide an indication of when new supply projects may need to be brought online to prevent shortfalls. The decline in production observed in last year's forecast has continued. Time is limited to bring new supply online before shortfalls are projected to arise.

Victorian producers are forecasting an aggregate production decline by 2022 of nearly 60% from the 435 PJ record achieved in 2017.

The production decline indicated by producer forecast information was also observed in the *Offshore South East Australia Gas Supply Study* (the 'Commonwealth Study') commissioned by the Commonwealth Government in mid-2017. This study indicated that, without additional development of resources, production could start to decline from 2024.

The forecast in that study was aggregated from information submitted by titleholders to the National Offshore Petroleum Titles Administrator (NOPTA) during the 2016 calendar year. All titleholders in offshore south-east Australia are Victorian producers and submit production forecasts to AEMO for the VGPR's assessment of supply adequacy. A comparison of these production forecasts is shown in Figure 7.

Figure 7 Victorian offshore production forecasts by year (PJ/a)



AEMO has converted volumetric numbers from the Commonwealth Study and calibrated it against actual sales gas production for 2015 and 2016. Forecast volumetric production numbers submitted by titleholders to NOPTA may contain some raw unprocessed gas, ethane, and LPG, as well as sales gas.

The first difference that becomes apparent is that the production forecasts advised to AEMO and published in the 2015 VGPR presented a picture of increasing levels of supply. The forecasts submitted since then have indicated a production decline from 2018.

After the 2015 VGPR, the other production forecasts align fairly closely. Actual production in 2017 was higher than the Commonwealth Study's forecast by approximately 25%[28]. Production from 2017 to 2018 is forecast to reduce by 25%. The 2017 VGPR forecast for 2018 was 13% higher than the numbers presented in the Commonwealth Study, while quantities in 2019 and 2020 are similar.

The production forecasts then diverge from 2021 onwards, with the 2017 VGPR and this 2018 VGPR Update projecting a decline two to three years earlier than the Commonwealth Study.

'The Gippsland Basin is not a magic pudding'

The past two years have seen Victoria hit consecutive production records, mainly due to increased supply from the Gippsland Basin. Victorian production in 2016 was 10% above the 2012-15 average, while 2017 production was 20% above that level. As well as the quote above, Richard Owen, chairman of Esso Australia, said they had been "working hard to meet east coast gas demand by increasing production well above forecast levels" [29]. However, these high levels of production are not sustainable.

Esso (in the same interview with Chairman Richard Marx) and the ACCC (in its gas Inquiry interim report)[30] have recently said that three of the GBJV's largest legacy fields (Barracouta, Marlin, and Snapper) which have been producing for 40-50 years, are reaching their end of life with only limited quantities of recoverable gas left. One field has depleted earlier than expected, and the other two are expected to deplete in the early 2020s.

[28] AEMO has discussed the Commonwealth Study's low forecast for 2017 with the Department of Industry, Innovation and Science as well as the National Offshore Petroleum Titles Administrator. They confirmed that the forecasts in the study were submitted to NOPTA by titleholders during the 2016 calendar year, but were unable to comment further due to confidentiality. However, they were aware of the difference and indicated that factors that influenced the outcome for the 2017 forecast were unlikely to be present in the years that followed.

[29] Fairfax Media opinion piece by Richard Owen, Chairman ExxonMobil Australia, "I talk about energy and I'm no longer the most boring guy at the barbecue", 17 October 2017, available at https://www.smh.com.au/opinion/i-talk-about-energy-and-im-no-longer-the-most-boring-guy-at-the-barbecue-20171013-gz0nsk.html.

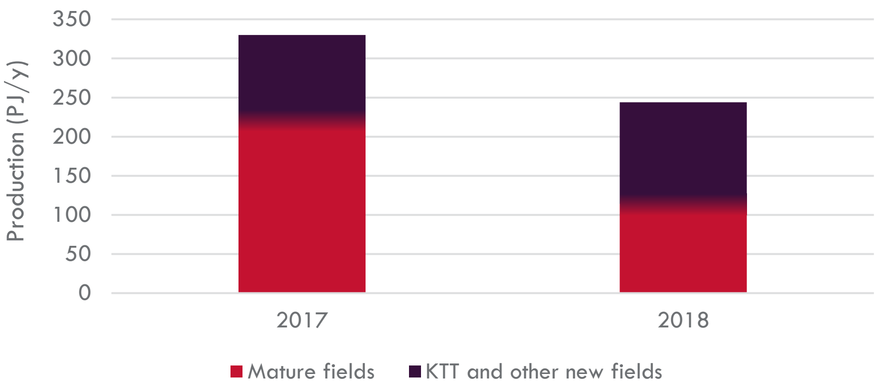
[30] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 30, available at https://www.accc.gov.au/publications.

Esso has also explained that the action of accelerating production from the legacy fields had accelerated their decline[31]. This appears consistent with production forecasts submitted to the VGPR, and is supported by the Commonwealth Study, which said that "any forced increases to upstream gas production from producing fields for input into onshore markets will result in a faster erosion of reserves, which, when combined with the mature nature of hydrocarbon exploration and production in the Gippsland Basin and south east Australia in general, will have implications for long-term security of supply".

Longford Gas Plant produced a record 345 PJ[32] in 2017. The 2017 ACCC Gas Inquiry Interim Report[33] stated that the GBJV share of 2017 production was expected to be 330 PJ and that their forecast production for 2018 would decline to 244 PJ. In contrast with this overall decline, the ACCC report noted that GBJV production is increasing from the $5.5 billion Kipper Tuna Turrum (KTT) Project (which contains production from their share of the Kipper Unit Joint Venture as well as the Tuna and Turrum fields) and other recent investments. KTT and other recent projects were expected to provide one third of Longford production in 2017, increasing to one half in 2018 (Figure 8 illustrates these factors applied to the GBJV share of production). While this information is only approximate, it illustrates the rate at which production from the older fields have reduced, and how much the KTT project is already being relied upon.

As previously stated by the Commonwealth Study and by the ACCC, the amount of gas that can be produced from higher impurity fields, such as Kipper and Turrum, is currently limited. While the Longford Gas Plant has an annual processing capacity of ~429 PJ[34], it is only capable of this rate if processing gas from low impurity fields. The new gas conditioning plant, which was constructed to process gas from the Kipper and Turrum fields, is only capable of processing ~156 PJ annually.

Figure 8 Estimated breakdown of GBJV production for 2017 and 2018



Reserves

As of 2016, there were approximately 4,009 PJ (3.8 trillion standard cubic feet [Tscf]) of proved and probably (2P) gas reserves, 3,904 PJ (3.7 Tscf) of 2C contingent resources, and 4,537 PJ (4.3 Tscf) of undiscovered resources in the offshore basins adjacent to Victoria[35]. Victorian gas production was 435 PJ in 2017 (all from offshore), which means that Victorian offshore 2P reserves reduced by 11% to 3,574 PJ.

2P reserves are often seen as the best indicator of recoverable resource quantities. Reserves classified in the 2P category are either producing or approved for development with a development timeframe of five years or less (unless a delay is justifiable). Contingent resources are potentially recoverable but face technological or financial hurdles which prevent commercial development, and may be reclassified as reserves sometime in the future when these hurdles are overcome. 2C is considered the best estimate of contingent resources. The 4,537 PJ of undiscovered resources is estimated from seismic survey data and is subject to large uncertainty[36].

Further information on potential options to increase future supply are discussed in Chapter 4.

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31 Fairfax Media opinion piece by Richard Owen, Chairman ExxonMobil Australia, "I talk about energy and I'm no longer the most boring guy at the barbecue", 17 October 2017, available at https://www.smh.com.au/opinion/i-talk-about-energy-and-im-no-longer-the-most-boring-guy-at-the-barbecue-20171013-gz0nsk.html.

32 Gas Bulletin Board, www.gasbb.com.au.

33 ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 30, available at https://www.accc.gov.au/publications.

34 These figures may not take into account low production periods associated with plant and offshore infrastructure maintenance.

35 Australian Government, Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, 2017, p. 6, available at https://industry.gov.au/resource/Offshore-oil-and-gas/Development/Pages/SEGasSupplyStudy.aspx.

36 Commonwealth Study, p. 15.

3.4 Peak day supply and demand balance

As discussed in Section 3.3, the production decline is driving down, not just annual production, but also peak day production capacities. This is placing a greater reliance on storage to meet peak day demands.

Table 14 shows the total peak day gas supply capacity is forecast to decrease by 34% over the outlook period. These supply capacities do not include gas supplied from interconnected pipelines' linepack[37].

Table 14 Available peak day MDQ capacity by supply source (TJ/d), 2018-22

Supply source		2018	2019	2020	2021	2022
Gippsland	Available	950	850	779	217	215
	Prospective	90	154	182	482	300
	Total available plus prospective	**1,040**	**1,004**	**962**	**699**	**515**
Port Campbell (Geelong)	Available	573	527	404	446	415
	Prospective	85	95	234	172	167
	Total available plus prospective	**658**	**622**	**638**	**618**	**582**
Melbourne	LNG	87	87	87	87	87
Total available		1,523	1,377	1,183	663	630
Total prospective		175	249	416	654	467
Total supply		**1,785**	**1,712**	**1,687**	**1,404**	**1,184**
Total supply available to the DTS including pipeline constraints		1,551	1,524	1,482	1,259	1,075
1-in-2 peak system demand		1,182	1,185	1,187	1,184	1,184
DTS surplus/shortfall quantity on 1-in-2 peak day		**369**	**340**	**295**	**75**	**-109**
1-in-20 peak system demand		1,292	1,295	1,298	1,295	1,295
DTS surplus/shortfall quantity on 1-in-20 peak day		**258**	**229**	**184**	**-36**	**-220**

The gas supply maximum daily quantity (MDQ)[38] capacity reductions are:

- Gippsland MDQ capacity is forecast to decrease from 1,040 TJ/d in 2018 to 515 TJ/d by 2022.
- Port Campbell MDQ capacity is forecast to decrease from 658 TJ/d in 2018 to 582 TJ/d in 2022.

The large production declines are somewhat offset by:

- The Sole gas field coming online in 2019.
- The phased Iona UGS expansion (see Table 11).
- The Western Outer Ring Main project (see Chapter 6).

These three projects are included in Table 14. AEMO has not been provided with any further information on committed new gas supplies during the outlook period.

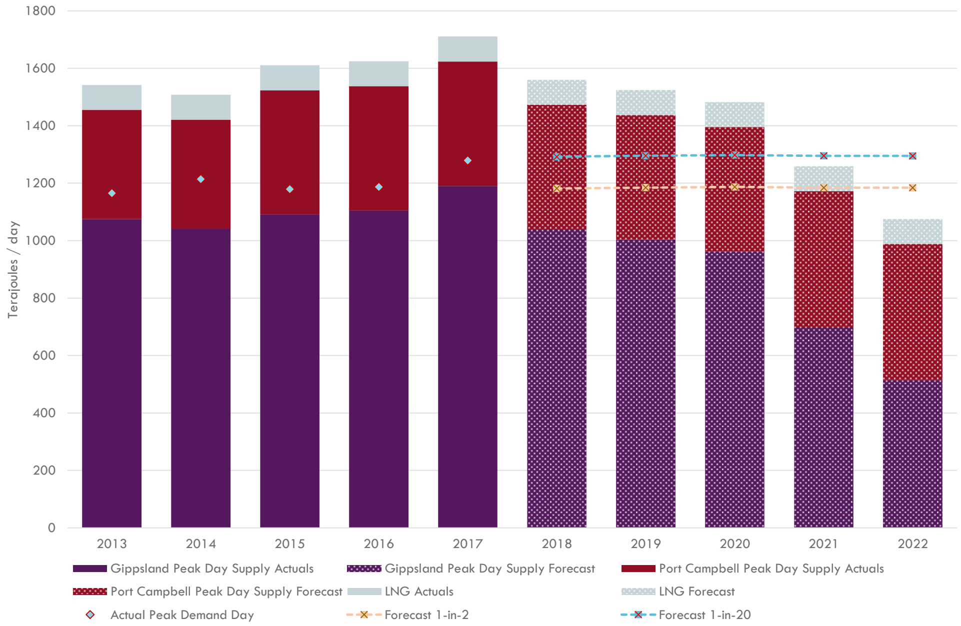
[37] Linepack is gas in pipelines – it is important to store gas and to maintain gas pressure.

[38] 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.

3.4.1 Peak day supply outlook

The peak system demand day supply outlook for 2018 through to 2022 is shown in Table 14 and Figure 9.

Figure 9 Peak day supply capacity by location (TJ/d)



The outlook uses a mass balance analysis which includes:

- Contract information available to AEMO.
- Plant peak supply capacity, from the total supply (shown in Table 14).
- DTS pipeline capacities and approved expansions (discussed in chapters 5 and 6).

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.

Non-firm peak day supply

This peak day supply adequacy assessment only considered firm sources of gas supply. VNI imports via Culcairn have not been included in the peak day supply capacity, because the Culcairn compressors are unable to compress gas south into Victoria. As a result, Culcairn supply depends 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 also not included in the available peak day supply, because it would rely on sufficient pipeline linepack being maintained at all times.

2018 peak day outlook

The available supply to the DTS on a 1-in-20 year peak system demand day during winter 2018 is forecast to be similar to the gas supply available during winter 2017. Table 15 shows that there is forecast to be 493 TJ/d of spare capacity available to supply DTS GPG demand and to flow to other states.

Table 15 DTS capacities and expected supply on a 1-in-20 peak demand day, 2018 (TJ/d)

		Total plant capacity	Pipeline capacity	DTS potential supply	Expected supply	Remaining supply capacity
Gippsland		1,040	1,030	1,030	900	140
Port Campbell	**To Melbourne**	658	413	434	371	266
	To WTS		28		21	
Melbourne	**LNG Storage**	87	-	87	0	87
Total Supply		**1,785**	**1,471**	**1,551**	**1,292**	
1-in-20 system demand		1,292	1,292	1,292	1,292	
DTS surplus/shortfall quantity (TJ/d)		**493**	**179**	**259**	**-**	**493**

2022 peak day outlook

The analysis in Table 16 shows there is a large supply shortfall for a 1-in-20 year peak system demand day during winter 2022. The remaining 138 TJ/d of spare supply capacity is unable to supply DTS demand due to pipeline capacity constraints on the SWP.

Table 16 DTS capacities and expected supply on a 1-in-20 peak demand day, 2022 (TJ/d)

		Total plant capacity	Pipeline capacity	DTS potential supply	Expected supply	Remaining supply capacity
Gippsland		515	1,030	515	485	30
Port Campbell	**To Melbourne**	582	453	474	453	108
	To WTS		28		21	
Melbourne	**LNG Storage**	87		87	87	0
Total supply		**1,184**	**1,511**	**1,076**	**1,045**	
1-in-20 system demand		1,295	1,295	1,295	1,295	
DTS surplus/shortfall quantity (TJ/d)		**-111**	**216**	**-219**	**-249**	**138**

In this forecast, the maximum firm LNG and SWP injection rates as well as the majority of the Gippsland daily production (Longford, Lang Lang and Orbost gas plants) are scheduled to supply the DTS. A small quantity of Gippsland gas is required to support demand in Eastern Victoria, Southern New South Wales, and Tasmania, and so cannot be used to support the DTS.

This forecast has also assumed that the WORM is constructed, which enables increased supply from the Port Campbell region. Without the construction of the WORM, the potential shortfall could worsen by 40 TJ/d.

This forecast identifies a shortfall of 249 TJ/d for a 1-in-20 year peak demand day in 2022. Even if the non-firm LNG capacity of 237 TJ/d was used to support demand, a supply shortfall of 100 TJ/d would still occur, which would result in a number of localised pressure breaches and curtailments.

4. Potential future gas supply sources

Key findings

There are several projects currently under investigation by participants and others that could provide additional gas supply to Victoria, including:

- Further exploration and development of gas reserves in south eastern Australia.
- Increasing gas storage volumes and injection capacity.
- Augmenting or building new pipelines, further interconnecting the east coast gas network and providing additional avenues of supply.
- Building an LNG import terminal as an additional source of supply.

4.1 Exploration and development

There are several offshore brownfield and greenfield projects in the Gippsland and Otway basins currently being considered for exploration and development by producers over the next five years.

It is, however, expected that none of these projects will be a like-for-like replacement of the legacy fields that have been supplying gas to Victoria for nearly 50 years, and which are now nearing depletion[39]. Newer fields are smaller than their predecessors, with higher quantities of impurities that require additional processing. This has been evidenced by the GBJV's $1 billion investment in a new gas conditioning plant at Longford to process gas from the Kipper and Turrum fields that was brought online in 2017.

Development of resources from these smaller fields may improve the supply outlook out to 2022. Esso has advised AEMO that if potential projects proceed and are successful, GBJV believes the current outlook on these could maintain gas production at 2018 levels through to 2022.

Exploration and development is costly and time-consuming, with some projects taking a decade or more to complete. The development of offshore resources can be particularly difficult given the increased technical complexity, logistical challenges, and the size of the infrastructure involved. Having a pipeline of projects available to develop is essential to maintain production into the future.

This is especially relevant in offshore south-east Australia, where producers have told the ACCC there are limited offshore prospects that have been identified for development. Those that have been identified are smaller and are of poorer quality (requiring additional investment in plant processing equipment) than the fields currently in production[40].

In the December 2017 interim report on its 2017-2020 Gas Inquiry, the ACCC stated:

> *"It is important to note that there can be significant lead times between exploration and development activities – from when gas is first discovered to when it is developed for commercial use. This means more exploration needs to occur now, to ensure there is enough gas for production to meet demand in later years."*[41]

Given the production decline in mature fields and the fact that new prospects are smaller, an increase in drilling activity might be expected. Figure 10 demonstrates, however, that offshore drilling has been subdued in recent years compared to historical trends.

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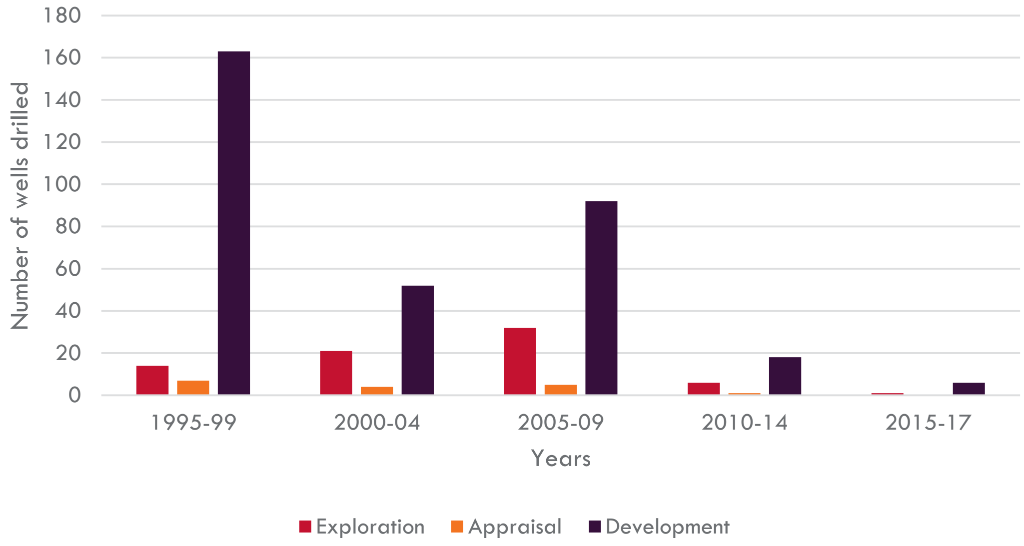
[39] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 30, available at https://www.accc.gov.au/publications.

[40] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 80, available at https://www.accc.gov.au/publications.

[41] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 79, available at https://www.accc.gov.au/publications.

The recent period of reduced activity may be due to low global oil prices affecting business' investment decisions. Low global oil prices generally reduce exploration and development activity, as the incentive to increase production is reduced and lower revenues from existing production restricts the availability of funds for such activities. In addition, the quality and potential size of remaining prospects and leads also make exploration and eventual development potentially more marginal.

Figure 10 Offshore wells drilled in offshore south east Australia 1995-2017



Geoscience Australia, Petroleum Wells Database, available at http://dbforms.ga.gov.au/www/npm.well.search.

Onshore exploration and development is currently not permitted in Victoria. A moratorium on conventional onshore activities is in place until 30 June 2020, and unconventional resource development (which utilises hydraulic fracturing) is permanently prohibited by legislation.

The Victorian Government has contributed $42.5 million to deliver a Victorian Gas Program to further evaluate the feasibility of onshore conventional resource development and help inform future decision-making[42]. Some components of this program include estimating the quantities of prospective onshore resources, as well as assessing the risks involved with exploration and production.

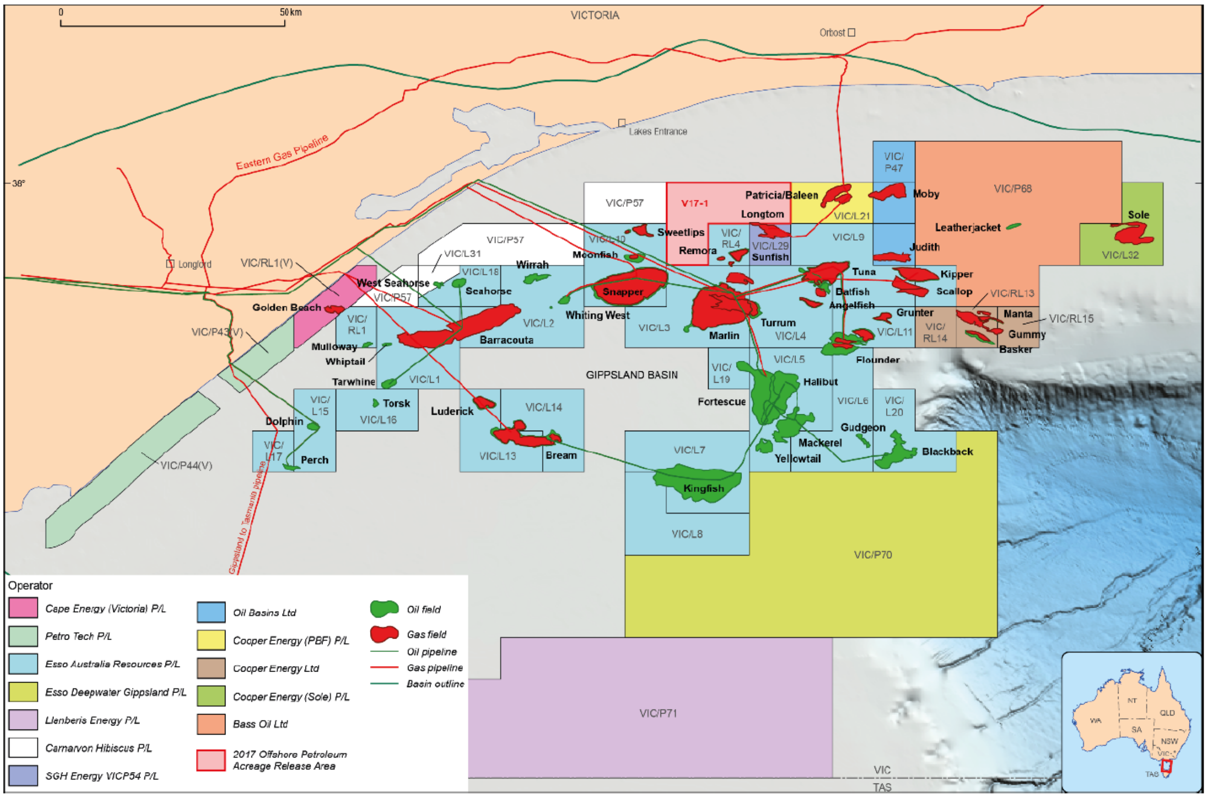
It should be noted that even if the development of resources post-2020 is permitted and prospects are identified by the Victorian Gas Program, there is likely to be some time lag before any gas can be brought to market.

The following sections provide an overview of the fields that are being, or have the potential to be, looked at for exploration and development. Where information has not been provided or confirmed to AEMO directly by the relevant operator, information about these potential projects is drawn from publicly available sources.

[42] Information about the Victorian Gas Program is available at http://earthresources.vic.gov.au/earth-resources/victorian-gas-program.

Gippsland Basin

Figure 11 Gippsland Basin titles map



West Barracouta

Ownership Gippsland Basin Joint Venture

Permit/Lease VIC/L1 (Production License)

Discovered 1969

Estimated resource Not available

GBJV is evaluating options to recover some “unswept” gas from the western part of the Barracouta field, likely via the drilling of a number of subsea wells tied-back to existing infrastructure. Gas from this field is relatively low in impurities and would be processed by the Longford Gas Plant. Esso has advised AEMO that they are targeting production from 2020 to 2021.

Forecast production numbers for West Barracouta were not submitted to AEMO and have not been included in this report’s supply forecast.

Kipper Phase 1B

Ownership Kipper Unit Joint Venture

Permit/Lease VIC/L09 & VIC/L25 (Production Licenses)

Discovered 1986

Estimated resource Not available (estimated to be 622 PJ at end of 2016[43])

Part of the continuing development plan for the Kipper gas field, this activity involves drilling additional subsea wells which will come online when pre-conditioning plant processing capacity becomes available. The operator confirmed to AEMO in March 2018 that this project could be developed by 2021.

Forecast production numbers for Kipper Phase 1B were not submitted to AEMO and have not been included in this report’s supply forecast.

[43] EnergyQuest, *EnergyQuarterly* November 2016, available at http://www.energyquest.com.au/insightsandanalysis.php?id=264.

Dory

Ownership	Esso Deepwater
Permit/Lease	VIC/P70 (Exploration Permit)
Discovered	2008
Estimated resource	Not available

Discovered and then discarded by Apache as an uncommercial discovery, Liberty Petroleum subsequently reassessed the field and identified the potential for a large accumulation. Since acquired by Esso, and recent media reports indicate that it could contain up to 2,300 PJ[44]. In addition to its potential size, the gas may be low in impurities. In samples captured and analysed during the drilling of the Dory-1 by Apache in 2008, CO_2 content was less than 3%[45]. If representative of the field, this would mean gas could be processed without going through a gas-conditioning plant. Publicly available information indicates the operator is planning to drill two exploration wells within the permit area in mid-2018[46] and, if the resource can be proven and is commercial, production could potentially commence from 2024[47].

No information has been received by AEMO concerning this field.

South East Remora

Ownership	Gippsland Basin Joint Venture
Permit/Lease	VIC/RL4 (Retention Lease)
Discovered	2010
Estimated resource	280 PJ[48]

GBJV has applied to renew its retention lease. Gas from this field has a high CO_2 content. GBJV has indicated that the Longford gas conditioning plant does not currently have capacity and is proposing to hold off developing the field for at least another five years[49].

No information has been received by AEMO concerning this field.

Sole

Ownership	Cooper Energy
Permit/Lease	VIC/L32 (Production License)
Discovered	1973
Estimated resource	249 PJ (2P)[50]

FID was reached in August 2017 approving development. Production is expected to commence in 2019 and it is expected to supply 24 PJ/y[50]. Drilling of the Sole-3 and Sole-4 production wells are expected to commence towards the end of March 2018[51]. APA agreed to acquire and undertake upgrades on the Orbost Gas Plant, which will be processing Sole gas, in June 2017[52]. However, the producer has previously outlined that there will be limited capacity for Sole to provide seasonal swing[53].

Forecast production numbers for Sole were submitted to AEMO and have been included in this report's supply forecast.

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44 The Australian, "Exxon's Bass Strait prospect could ese east coast gas shortage", 8 August 2017, available at https://www.theaustralian.com.au/business/mining-energy/exxons-bass-strait-prospect-could-ease-east-coast-gas-shortage/news-story/840e24a74776de594a617b098d326246 (paywall).

45 Apache Energy, Dory-1 Well Completion Report, May 2009.

46 ExxonMobil, "Offshore projects" webpage, at http://www.exxonmobil.com.au/en-au/energy/natural-gas/natural-gas-operations/offshore-projects?parentId=d4feec55-2e4f-4e6b-b261-9c8aaf4f8735.

47 ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 96, available at https://www.accc.gov.au/publications.

48 The Australian, "Oil giants ExxonMobil and BHP bid for delay on new Bass Strait gas", 30 May 2017, available at https://www.theaustralian.com.au/business/mining-energy/oil-giants-exxonmobil-and-bhp-bid-for-delay-on-new-bass-strait-gas/news-story/a2fcf1fdce5e889b38344be5678b0d9c (paywall).

49 The Australian, "Bass gas in Exxon's frame due to onshore constraint", 3 October 2017, available at https://www.theaustralian.com.au/business/mining-energy/bass-gas-in-exxons-frame-due-to-onshore-constraint/news-story/d9e889a0d41f01d336e4f27a75452fc4 (paywall).

50 Cooper Energy, "Sole gas project final investment decision", 29 August 2017, available at http://www.cooperenergy.com.au/Upload/4.-Sole-FID.pdf.

51 Oil & Gas Journal, "Cooper Energy moves semi to Victorian waters for Sole field drilling", 20 February 2018, available at https://www.ogj.com/articles/2018/02/cooper-energy-moves-semi-to-victorian-waters-for-sole-field-drilling.html.

52 Cooper Energy, ASX announcement, "APA & Cooper Energy execute Orbost Gas Plant agreement", 1 June 2017, available at http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2017.06.01-ASX-release-OGP-APA-agreement-FINAL.pdf.

53 Cooper Energy Response to ACCC East Coast Gas Inquiry Issues Paper, 2015, p. 7. Available at https://www.accc.gov.au/system/files/ECGI%20-%20Submission%20to%20Issues%20Paper%20-%20PUBLIC%20-%20Cooper%20Energy.PDF.

Manta

Ownership	Cooper Energy
Permit/Lease	VIC/RL13 (Retention Lease)
Discovered	1984 (Manta), 1983 (Basker), 1990 (Gummy)
Estimated resource	106 PJ (2C)[54]

This field is expected to be produced following production from Sole[55]. The operator intends to drill an appraisal well, Manta-3, in 2019, with FID in 2019 and production starting in 2021[56].

Information about this project was provided to AEMO. As FID has yet to be reached, forecast production has not been included in this report's supply forecast.

Longtom

Ownership	SGH Energy
Permit/Lease	VIC/L29 (Production License)
Discovered	1995
Estimated resource	80 PJ

Longtom gas field was in production from 2009 until 2015, when operations were indefinitely suspended due to a major electrical fault. This issue was rectified in January 2017 after new underwater cables were laid. While both wells (Longtom-3 and Longtom-4) are ready to resume production, agreement needs to be reached with the owners of the Patricia-Baleen pipeline (Cooper Energy) and the Orbost Gas Plant (APA) before gas production can resume[57].

There is an estimated 20 PJ of gas that could currently be made available from the field. The operator has flagged that drilling Longtom-5 well and working over Longtom-4 could increase the recoverable gas quantity by another 60 PJ[58].

No information about this field has been received by AEMO. Forecast production has not been included in this report's supply forecast as it is subject to ongoing negotiation between parties.

Judith

Ownership	Emperor Energy
Permit/Lease	VIC/P47 (Exploration Permit)
Discovered	1989
Estimated resource	Not available

Emperor Energy was granted a five-year renewal on its exploration permit in February 2018. The work plan specified in the exploration permit includes drilling an exploration well in the north block of the Judith Field in 2021. Recently reprocessed 3D seismic survey data indicates that there may be a larger quantity of gas-in-place (up to 1.8 Tscf or 1,899 PJ) than was originally thought[59].

No information has been received by AEMO concerning this field.

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[54] Cooper Energy, *Quarterly Report* September 2017, p. 8, available at http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2017.10.26-Quarterly-report-Q1-18.pdf.

[55] Cooper Energy, ASX announcement, "APA & Cooper Energy execute Orbost Gas Plant agreement", 1 June 2017, available at http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2017.06.01-ASX-release-OGP-APA-agreement-FINAL.pdf.

[56] Cooper Energy, *Quarterly Report* December 2017, p. 11, available at http://www.cooperenergy.com.au/Upload/Documents/ReportsItem/2018.01.23-Quarterly-report-Q2-.pdf.

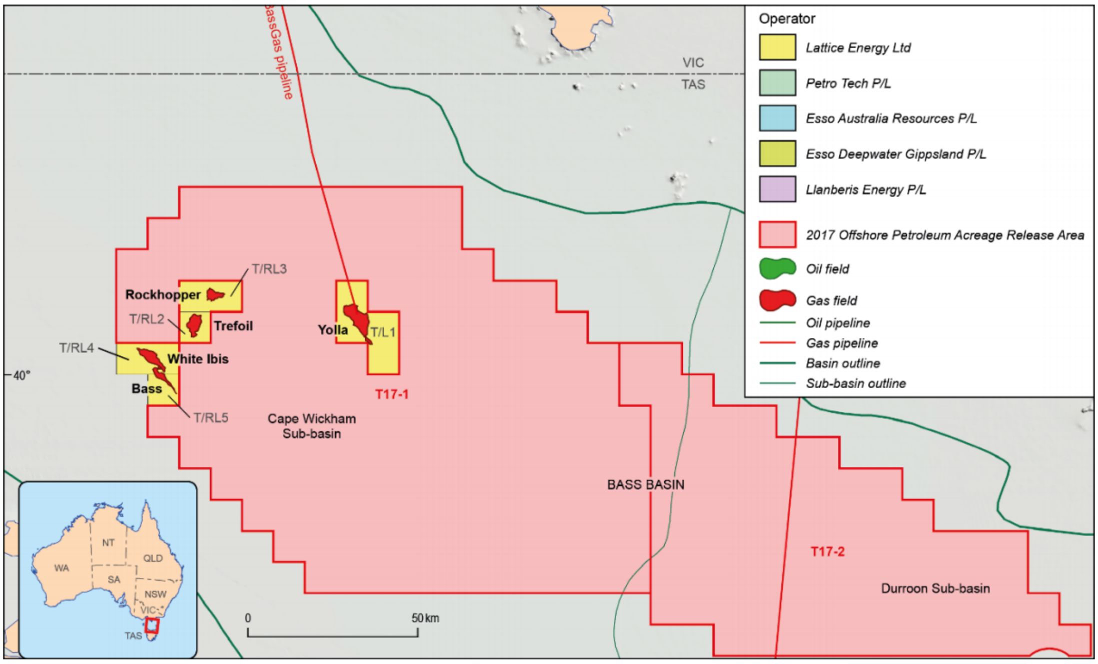
[57] Australian Financial Review, "SGH Energy CEO Margaret Hall sees Longtom gas as part of solution for east coast", 12 March 2017, available at http://www.afr.com/business/energy/gas/sgh-energy-ceo-margaret-hall-sees-longtom-gas-as-part-of-solution-for-east-coast-20170310-guvogs.

[58] Australian Financial Review, "SGH Energy mulls $150m boost to east coast gas push", 18 December 2017, available at http://www.afr.com/business/energy/gas/sgh-energy-mulls-150m-boost-to-east-coast-gas-push-20171218-h06k6v.

[59] Emperor Energy, 'Emperor Energy London Presentation', November 2017. Available at https://emperorenergy.com.au/wp-content/uploads/2017/12/London-Presentation-29-Nov-17-1.pdf.

Bass Basin

Figure 12 Bass Basin titles map



Trefoil

Ownership BassGas Project

Permit/Lease T/RL2

Discovered 2004

Estimated resource 263 PJ or 43 million barrels of oil equivalent (mmboe) (2C)[60]

This field is currently being evaluated and, subject to FID, could be developed in 2020-21[61]. Gas from Trefoil would likely backfill production from the Yolla field as it depletes[62].

No information has been received by AEMO concerning this field.

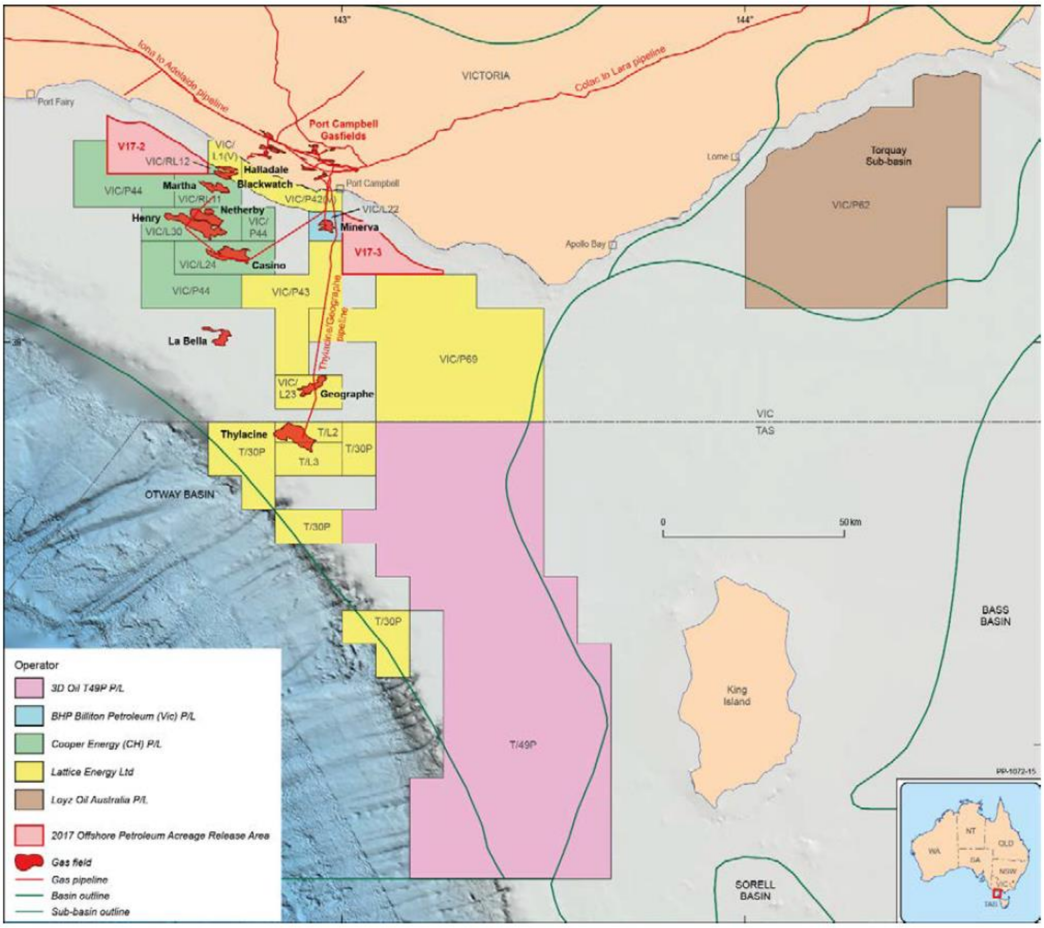
[60] AWE, "BassGas Project" webpage, available at http://www.awexplore.com/irm/content/bassgas-project.

[61] AWE, Asia Roadshow Presentation, May 2017, available at http://www.awexplore.com/irm/PDF/2631_0/AWE39sAsiaRoadshowPresentation.

[62] AWE, ASX announcement, "AWE Target's Statement – Mitsui Offer", 21 February 2018, p. 33, available at http://www.awexplore.com/irm/PDF/2937_0/AWETarget39sStatementMitsuiOffer.

Otway Basin

Figure 13 Otway Basin titles map



Black Watch

Ownership	Beach Energy, Cooper Energy, AWE and Mitsui EP
Permit/Lease	VIC/L1(v) (Victorian Production License - Beach Energy)
	VIC/RL11 (Retention Lease – Cooper Energy, AWE, Mitsui EP)
Discovered	2005
Estimated resource	Not available

This field straddles a permit boundary, with Beach Energy on one side and Cooper Energy, AWE, and Mitsui E&P Australia on the other. The operator is progressing plans to drill the Black Watch development well in late 2019[63].

Information on this field was provided to AEMO, but has not been included in this paper's supply forecast as development is subject to ongoing negotiation between parties.

Martha

Ownership	Cooper Energy, AWE and Mitsui EP
Permit/Lease	VIC/RL11 (Retention Lease)
Discovered	2004
Estimated resource	Not available

[63] Beach Energy Half Yearly Presentation, 19 February 2018, available at http://www.beachenergy.com.au/irm/archive/presentations.aspx?RID=345.

The Commonwealth Study states that the field is relatively small and has been perceived as unfavourable for development[64].

No information has been received by AEMO concerning this field.

La Bella

Ownership	Not currently held under permit
Permit/Lease	Cancelled March 2017
Discovered	1993
Estimated resource	114 PJ (Contingent)[65]

The Commonwealth Study states that the field is 50 km from land and has high CO_2 content and has been perceived as unfavourable for development[66].

No information has been received by AEMO concerning this field.

4.2 Gas storage

Gas storage is an increasingly important service, which allows retailers and traders to manage seasonal variation in demand. Increasing storage volumes and deliverability would help address the forecast reduction in peak day supply from 2021.

Several options to increase Victorian gas storage capacity have been canvassed in recent years.

Iona Underground Gas Storage expansion

The supply adequacy assessment for this 2018 VGPR Update includes the proposed Iona UGS reservoir injection and withdrawal capacity increases outlined in the 2017 VGPR.

Iona UGS injections are limited by SWP transportation capacity towards Melbourne. This will continue to be the case even after the proposed construction of the Western Outer Ring Main (WORM). The 2017 VGPR noted that additional transmission system capacity would be required to maximise injections into the DTS.

New underground gas storage facility in Otway Basin

An investigation into additional gas storage sites in the Otway Basin is being undertaken as part of the Victorian Gas Program. It will incorporate geological assessments, detailed technical assessments, and an economic and regulatory feasibility study. A report is expected to be submitted to government for consideration in November 2018[67]. It is not clear whether this report will consider the additional transmission system capacity that would be required to facilitate injections from any new facility.

New underground gas storage facility in Gippsland Basin

Another field identified as a potential UGS location is Golden Beach in the Gippsland Basin. It is located close to shore and could be tied into the DTS or the EGP. No recent public announcements have been made about this potential project, but information published by the ACCC indicates that it is a proposal that is being actively considered for investment, and that, once the existing gas has been produced, the storage capacity would be comparable to that of Iona UGS [68]. The potential reservoir injection and withdrawal capacities, which are highly dependent on the characteristics of the formation, were not discussed.

Golden Beach was not included in the section on exploration and development prospects, because it is relatively small and unlikely to be commercial unless subsequent transformation into a UGS facility is feasible.

New LNG storage facility

Another potential option is the construction of a second LNG liquefaction and storage facility connected to the DTS, close to the Melbourne metropolitan demand centre. The most suitable location for such a facility would likely be Wollert. Following the proposed construction of the WORM in 2020, Wollert will become the central intersection point

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[64] Australian Government, Department of Industry, Innovation and Science, *Offshore South East Australia Future Gas Supply Study*, 2017, p. 32, available at https://industry.gov.au/resource/Offshore-oil-and-gas/Development/Pages/SEGasSupplyStudy.aspx.

[65] WHL Energy, 'WHL Energy progressing "La Bella" development "window of opportunity"', 26 June 2013, available at https://www.asx.com.au/asxpdf/20130626/pdf/42gpjcbn9b7yxh.pdf.

[66] Commonwealth Study, p. 32.

[67] Department of Economic Development, Jobs, Transport and Resources, *Victorian Gas Program progress report*, January 2018, p. 26, available at http://earthresources.vic.gov.au/earth-resources/victorian-gas-program/progress-report.

[68] ACCC, *2017-2020 Gas Inquiry: Interim report*, pp. 72-73, available at https://www.accc.gov.au/publications.

for Victoria's main transmission pipelines, and an LNG storage facility at that location would permit gas to be dispatched to any point in the DTS. It should also be noted that gas demand at Wollert may increase substantially in the future. APA has proposed the construction of a 1,000 MW gas-powered generator[69].

LNG at Wollert is not an entirely new concept. In a related vein, LNG processing was discussed as a possibility in a Utilities Infrastructure Servicing Assessment as part of shaping the Wollert Precinct Plan in 2012. The report about this Plan stated that APA was investigating a potential site at Wollert for a natural gas liquefaction facility to produce LNG for use as a transport fuel[70].

4.3 Pipeline augmentation

It is expected that there will be insufficient production in south-eastern Australia to meet forecast demand in 2018, and that gas will need to be sourced from Queensland to avoid a shortfall[71]. With the forecast Victorian production decline to 2022, it is expected that the southern states will become more reliant on imports from Queensland unless sufficient additional southern supply is brought online or an LNG import terminal is developed.

If there are no other additional developments to increase gas supply in Victoria, there is a possibility that the two pipelines that transport gas south from Queensland – the South West Queensland Pipeline (SWQP) and the MSP – may not have sufficient transportation capacity to support Victorian demand in winter 2022.

As highlighted in Section 3.2, Victoria is projected to require 19 PJ of additional supply during the four-month winter peak demand period in 2022. This would equate to an average flow from the MSP to Victoria of 158 TJ/d. Given that the MSP would also be supporting most of New South Wales' demand as a result of reduced Victorian supply, the existing transportation capacity of the pipeline could be a limiting factor.

There are a number of potential projects to augment existing pipelines, or construct new ones, that would increase the capacity for additional gas to flow south from Queensland.

MSP expansion (New South Wales)

APA discussed options to expand the southbound MSP capacity with AEMO in March 2018. APA has stated that capacity could be increased following the installation of additional compression stations.

VNI expansion (New South Wales)

As discussed in Chapter 3, APA has increased the southbound non-firm[72] flow capacity of the VNI to 150 TJ/d by reconfiguring their New South Wales transmission assets. An additional 73 TJ/d of capacity could be unlocked through further expansion of the New South Wales transmission system before the Victorian DTS becomes the limiting factor (southbound DTS import capacity has recently been expanded to 223 TJ/d).

Western Slopes Pipeline (New South Wales)

In 2017, APA entered into a memorandum of understanding with Santos to investigate developing the Western Slopes Pipeline, which would connect the Narrabri Gas Project to the MSP. A planning application has been submitted to the New South Wales Government, but has not yet been approved. In addition to the Western Slopes Pipeline, an expansion of the MSP and VNI (on the New South Wales side) may be required for this project to increase supply to Victoria.

Queensland Hunter Gas Pipeline (Queensland – New South Wales)

Another option to increase southward gas transportation capacity is the construction of the Queensland Hunter Gas Pipeline (QHGP). The QHGP would connect Wallumbilla to Newcastle via an 830 km pipeline and would provide a transportation capacity in the range of 230-450 TJ/d[73].

The project could be constructed in two stages:

- Stage 1 – Narrabri to Newcastle.
- Stage 2 – Wallumbilla to Narrabri.

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[69] AEMO Generation Information page, Victoria information (new developments tab), 29 December 2017, available from http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[70] CPG Australia, Wollert Precinct Structure Plan, August 2012, available at https://vpa-web.s3.amazonaws.com/wp-content/uploads/2017/05/Wollert-Utilities-report.pdf.

[71] ACCC, *2017-2020 Gas Inquiry: Interim report*, p. 11, available at https://www.accc.gov.au/publications.

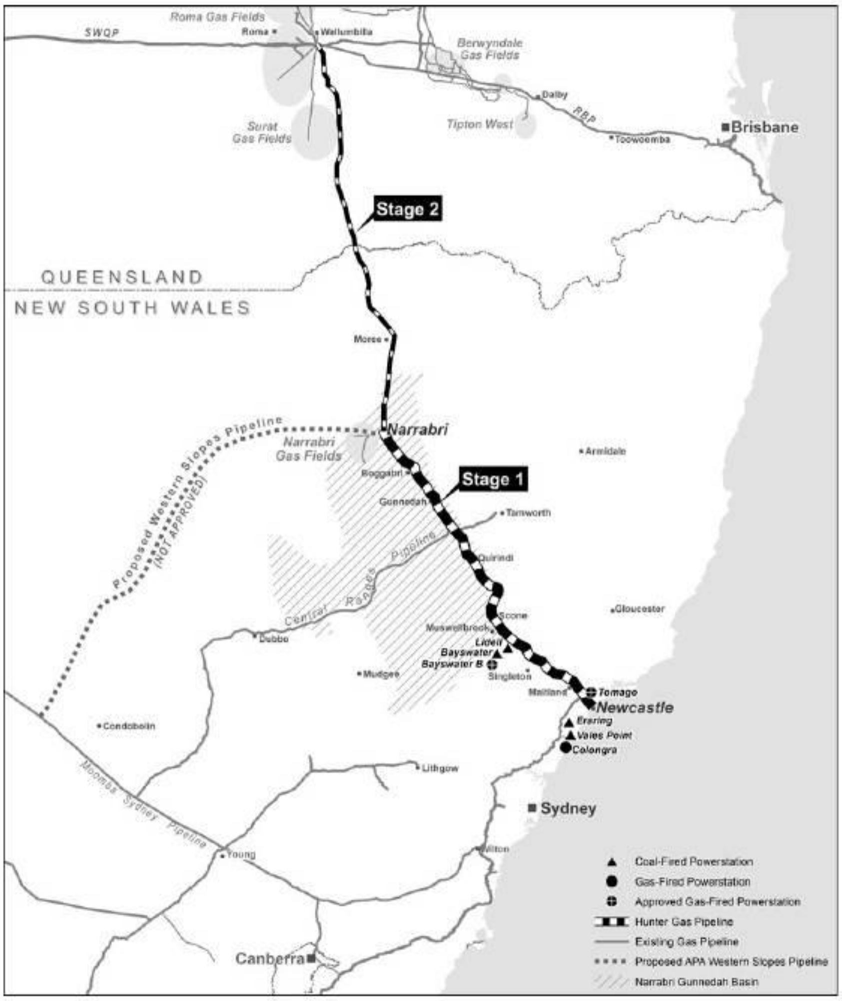
[72] Capacity is dependent on demand on the Young-Culcairn lateral of the MSP.

[73] AEMO, 2017 *Gas Statement of Opportunities* input data file. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

New South Wales Government planning approval to develop the project has been granted, and Hunter Gas Pipeline has entered into a memorandum of understanding with Jemena to construct the pipeline, which is shown in Figure 14[74]. The timing of construction remains uncertain.

This project has not been proposed as a means to increase supply to Victoria. Additional piping is likely to be required to connect the QHGP to the EGP to do so.

Figure 14 Queensland Hunter Pipeline



West-East Gas Pipeline (Western Australia – east coast gas markets)

The Commonwealth Government has commissioned a pre-feasibility study for the construction of a West-East Gas Pipeline. This study is due to be completed in March 2018. The impact of any proposed pipeline from Western Australia on the supply and demand balance would be dependent on where it connected into the east coast grid.

Media reports have estimated the cost of building the pipeline to be approximately $5 billion[75].

4.4 Floating Storage Regasification Unit

In August 2017, AGL announced that Crib Point in Western Port Bay was its preferred location for its proposed $250 million LNG import terminal (Figure 15). AGL has opted to investigate procuring a Floating Storage and Regasification Unit (FSRU) which would receive LNG via shipments from interstate or overseas, store it, and then convert it to its gaseous form for distribution.

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[74] Queensland Hunter Gas Pipeline, "Push to block Narrabri gas heading interstate", available at http://www.huntergaspipeline.com.au/news-room/Push-to-block-Narrabri-gas-heading-interstate.

[75] Australian Financial Review, "West-East Pipeline emerges as threat to LNG import plan", 28 February 2018, available at http://www.afr.com/business/energy/gas/westeast-pipeline-emerges-as-threat-to-lng-import-plan-20180228-h0wrfw.

Figure 15 Proposed LNG import terminal site including piers and former BP refinery

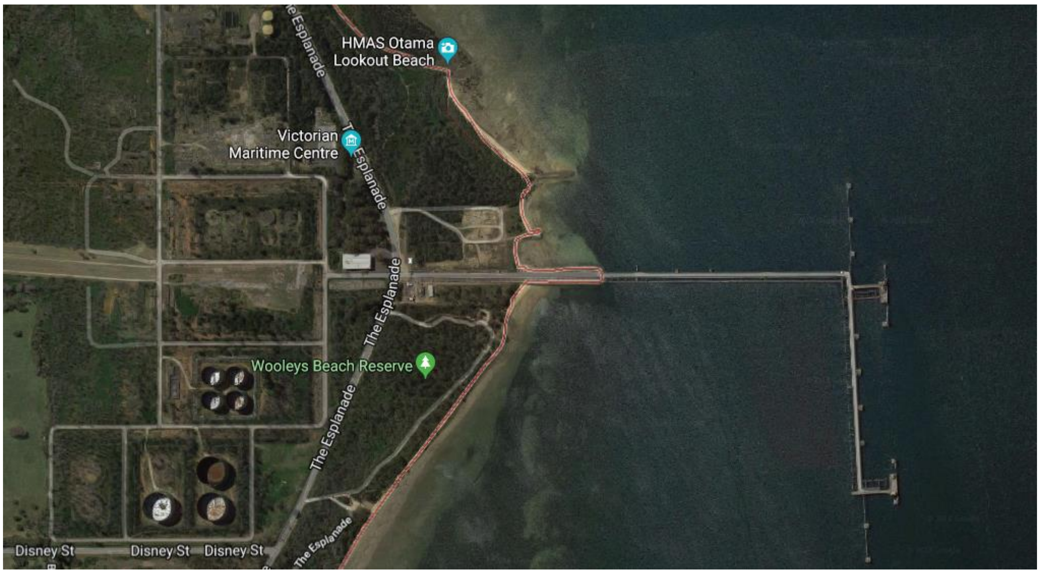
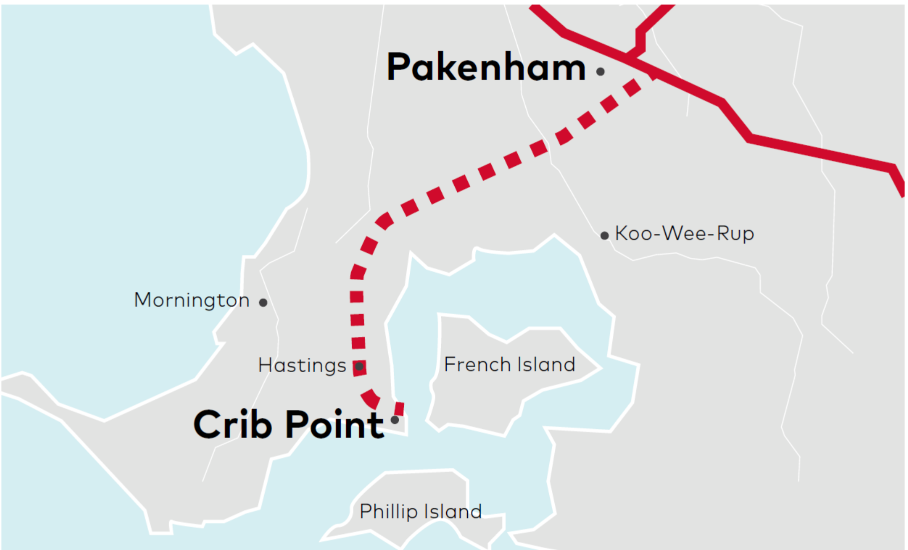


Image from Google Maps.

AGL has engaged APA to undertake investigations into the construction of a ~60 km high pressure gas pipeline that would connect the FSRU at Crib Point to the DTS (Figure 16).

Figure 16 Proposed pipeline route



From https://www.apa.com.au/about-apa/our-projects/crib-point-to-pakenham-pipeline/.

AGL is currently investigating procuring quantities of LNG supply for the project. Late last year it was reported that AGL had issued a request for proposal (RFP) asking interested parties to submit offers for an annual supply of 50 PJ of LNG for the project[76]. AGL has also stated that up to 40 LNG tankers could supply the FSRU annually. The most common LNG tanker volumes are 140,000 and 170,000 m^3 (approximately 3,250 to 4,000 TJ), which would mean the project could supply up to 130-160 PJ/y. This equates to 60-80% of Victoria's total annual gas consumption. The actual total volume supplied would depend on the commercial requirements of the facility owner as well as market dynamics.

AGL has issued a RFP for a 10-year charter of a FSRU starting in 2020[77]. There are several FSRU storage and vaporisation capacity combinations that could be selected for the project.

[76] Australian Financial Review, "AGL Energy invites LNG bids for $250m Vic import terminal", 19 November 2017. Available at http://www.afr.com/business/energy/gas/agl-energy-invites-lng-bids-for-250m-vic-import-terminal-20171118-gzo380

[77] Poten & Partners, "AGL Seeks FSRU Proposals", December 2017. Available at http://www.poten.com/agl-seeks-fsru-proposals

Looking at FSRUs that have been recently built[78], storage capacities vary between 3,250 and 4,000 TJ, with maximum vaporisation rates from 450 to 950 thousand standard cubic meters per hour (kscm/h, or 415 to 830 TJ/d). Using these numbers, if the FSRU was called upon to vaporise at maximum rate indefinitely, it would be able to do so for 3.5 to 10 days before needing to be refilled.

It should be noted that the actual firm vaporisation rate may be lower after taking into account operational considerations such as unit redundancy, maintenance and capacity of the pipeline. The floating nature of the project also allows for the potential to swap the facility if long-term technical issues were ever experienced.

Figure 17 LNG ship transferring cargo to an FSRU

Photo courtesy of Excelerate Energy.

Maintaining supply to the FSRU (example shown in Figure 17) would require careful procurement planning to ensure that the supply of gas to Victoria was maintained without interruption. If the forecast decline in Victorian production capacity was not addressed by other projects, this LNG import terminal would be relied on to provide peak day gas supply capacity.

The proposed FSRU storage capacity is similar to the indicated delivery volumes, so it may have to be at or near empty to transfer LNG. If an LNG ship arrived early and could not unload in a timely manner, the FSRU owner may incur demurrage. If the ship arrived late, it would mean regasification rates, and supply to the DTS, would need to be reduced. This risk is managed in some countries by either building onshore storage or having additional LNG import facilities.

[78] More information about recent FSRUs is available from http://excelerateenergy.com/fleet/ and http://www.hoeghlng.com/Pages/Fleet.aspx.

5. Declared Transmission System adequacy

Key findings

- The DTS capacity is expected to be sufficient to support forecast peak day demand during the outlook period, with the exception of Warragul.
  - Warragul supply will require augmentation before winter 2019 to support forecast peak day demand. This threat to system security was identified in the 2017 VGPR, and an update on this augmentation is provided in Chapter 6.
- A project to increase the SWP capacity towards Port Campbell from 104 TJ/d to 147 TJ/d was completed in March 2018. This augmentation is forecast to provide sufficient transportation capacity to enable Iona UGS refilling prior to winter 2019 and 2020 and reduce the possibility of gas supply shortfalls. The threat to system security that was identified in the 2017 VGPR has been averted.
- The forecast decline in Port Campbell production, and a corresponding increase in Iona UGS utilisation, indicate that the SWP transportation capacity towards Port Campbell will again become a system capacity constraint. This is likely to impact system security again unless the Western Outer Ring Main (WORM) is constructed prior to spring 2021, to support Iona UGS refilling prior to winter 2022. The increased SWP capacity provided by the WORM is also forecast to be required to support peak day demand during winter 2022.
- The operator for the New South Wales transmission system north of Culcairn has advised that the injection capacity into the DTS at Culcairn (for transportation to Melbourne via the VNI) has increased from 125 TJ/d to 150 TJ/d. This Culcairn supply capacity is less than the VNI transportation capacity (which remains 223 TJ/d), so imports are not expected to be limited by the capacity of the DTS.
- Dandenong City Gate (DCG) has operated close to its capacity limit at times during winter 2017 due to increased GPG and low injections from Port Campbell. It may be necessary to restrict Iona UGS withdrawals during the morning peak, or schedule out of merit order injections at Port Campbell, to manage this constraint.

5.1 South West Pipeline augmentation

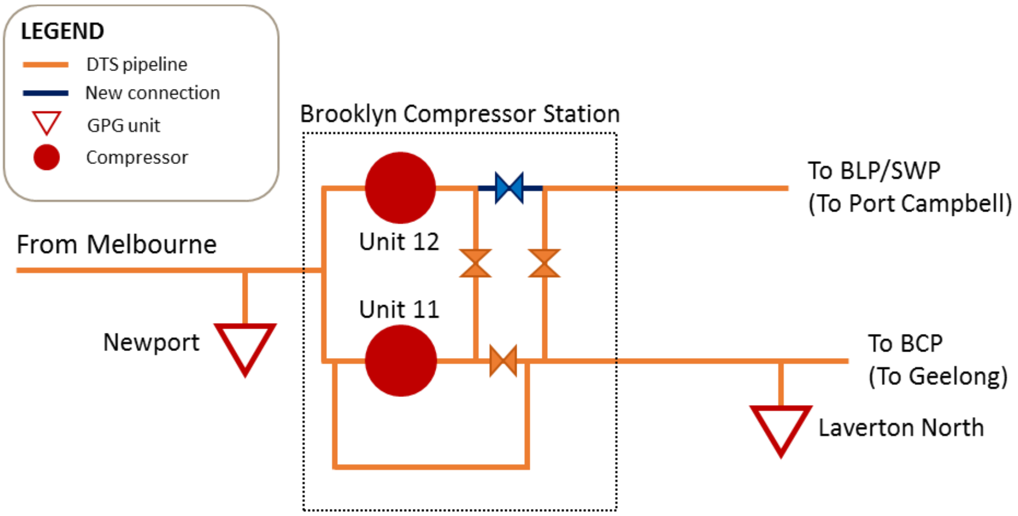
The SWP is a bi-directional pipeline that runs between Port Campbell and Lara, where is connects to the Brooklyn to Lara Pipeline (BLP) that runs from Lara to the Brooklyn CG. The SWP can also supply the Brooklyn to Corio Pipeline (BCP) through the Lara CG.

The SWP is typically used to:

- Transport gas from the Port Campbell production facilities and Iona UGS towards Melbourne during periods of high gas demand.
- Support Iona UGS reservoir refilling, and flows to the Mortlake PS and to South Australia via the SEA Gas Pipeline, during periods of lower gas demand in the summer and shoulder seasons.

The DTS service provider completed a reconfiguration of Brooklyn CS in March 2018, shown in Figure 18. The reconfiguration allows gas to be compressed directly into the BLP. Previously gas could only be compressed from Brooklyn CS into the BLP via the BCP. The augmentation increases the SWP withdrawal capacity, because Brooklyn CS can now be configured to more efficiently to deliver gas to Port Campbell.

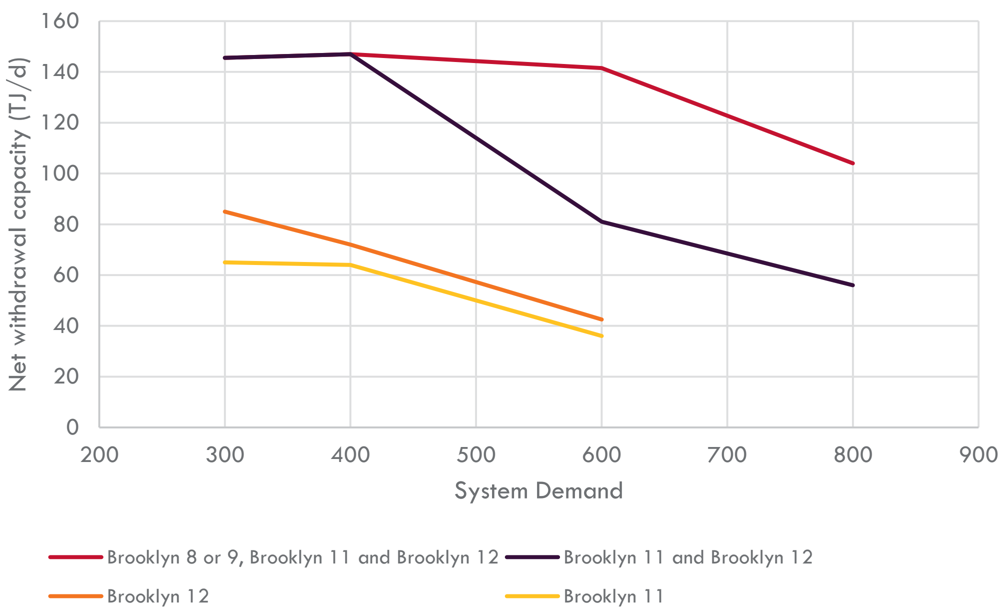
Figure 18 Simplified schematic of the Brooklyn CS reconfiguration



The DTS service provider has also augmented the Winchelsea CS to allow bi-directional compression. This new capability to compress gas towards Port Campbell provides additional SWP capacity to support Iona UGS refilling. The Winchelsea CS minimum inlet pressure has also been reduced, which further increases the SWP capacity in both directions.

Figure 19 shows the modelled SWP withdrawal capacity following the completion of these augmentations. The capacity curve shows the withdrawal capacity with a range of compressor units available.

Figure 19 Net withdrawal capacity with Brooklyn CS reconfiguration and Winchelsea CS bi-directional



The maximum SWP withdrawal capacity of 147 TJ/d is achieved on a 400 TJ system demand day with Unit 11 and Unit 12 available. Before the augmentations were completed, the maximum SWP withdrawal capacity was 104 TJ/d.

To enable higher SWP withdrawals in the shoulder season and on mild winter days, Brooklyn CS Unit 8 or Unit 9 will be required to support Geelong morning and evening peak demand. As a result, these compressors are likely to be operated more often. Figure 19 shows the significant reduction in SWP transportation capacity towards Port Campbell on a 600 TJ system demand day if both Unit 8 and Unit 9 are unavailable.

Impact of GPG

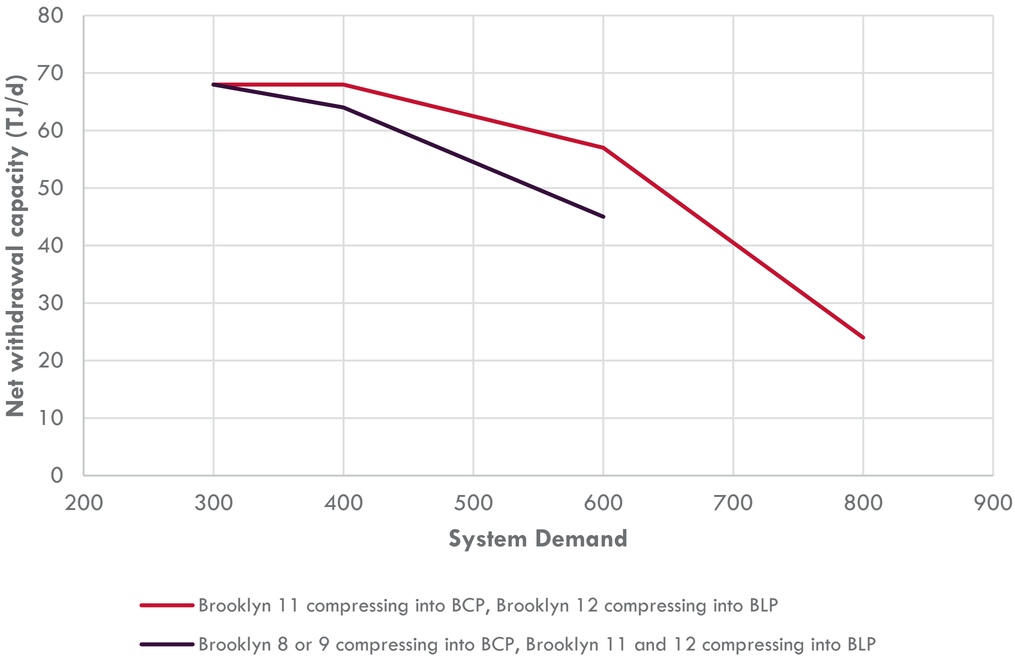
Due to the location of Laverton North PS and Newport PS, and their high offtake rate, SWP transportation capacity towards Port Campbell is impacted by the operation of these generators. The completion of the Brooklyn and Winchelsea augmentations has reduced the impact of these power stations on SWP withdrawal capacity.

Figure 20 shows the modelled SWP withdrawal capacity with Laverton North PS running at full rate, 4 TJ/h, and Newport PS not running. The capacity depends on the configuration of Brooklyn CS, with either:

- Brooklyn CS Unit 8 or Unit 9 compressing into the BCP supporting Laverton North PS demand and Unit 11 (series mode) and Unit 12 compressing into the BLP supporting SWP withdrawals.
- Brooklyn CS Unit 11 (parallel mode) compressing into the BCP supporting Laverton North PS demand and Unit 12 compressing into the BLP supporting SWP withdrawals.

The configuration that maximises withdrawal capacity when Laverton North PS is not running is with Brooklyn CS Unit 8 or Unit 9 compressing into the BCP and Unit 11 and Unit 12 compressing into the BLP, as shown as the top line in Figure 20.

Figure 20 Net withdrawal capacity with Laverton North PS running at full rate



The impact of Laverton North PS operation on the SWP withdrawal capacity will vary between no impact when the generator is off, as shown in Figure 19, through to the generator operating at full rate, shown in Figure 20, depending on the rate of operation and operating hours.

The impact of Newport PS operation on SWP withdrawal capacity has also been revised following recent analysis of transmission operations and modelling of the new configuration. The SWP withdrawal capacity reduces by 1 TJ/d for every 13 TJ/d of Newport PS demand. This was previously 1 TJ/d reduction for every 10 TJ/d of Newport PS demand.

Impact of Winchelsea CS availability

Modelling has indicated that the Winchelsea CS, which is a high flow capacity compressor, can only operate efficiently when SWP withdrawals are greater than 85 TJ/d. The SWP withdrawal capacity is reduced when Winchelsea CS is unavailable to compress towards Port Campbell. The impact depends on the configuration of the Brooklyn CS at the time and will only impact withdrawal capacities over 85 TJ/d.

The reduction in capacity is:

- 20 TJ/d when Brooklyn CS Unit 11 and Unit 12 are compressing into the BLP.
- 13 TJ/d when Brooklyn CS Unit 12 is compressing into the BLP alone.

Withdrawal of 2017 notice of a threat to system security due to SWP to Port Campbell constraint

AEMO reported in the 2017 VGPR[79] that the SWP withdrawal capacity would not be sufficient to support the forecast withdrawals necessary to refill the Iona UGS reservoirs. This inability to refill the Iona UGS reservoirs was identified as a threat to system security[80]. AEMO issued a notice of a threat to system security following the publication of the VGPR in March 2017.

To increase the SWP capacity towards Port Campbell, the DTS service provider proceeded with the Brooklyn CS and Winchelsea CS augmentation projects. The DTS service provider also made Brooklyn CS Unit 10 available until these projects were completed. These projects have increased the SWP withdrawal capacity, averting the threat to system security. As such, AEMO is able to withdraw this notice of a threat to system security issued in 2017.

The forecast decline in Port Campbell production during the outlook period, increased Mortlake GPG consumption, and the proposed Iona UGS expansion, along with its increased utilisation to support DTS demand including increasing levels of GPG, is likely to contribute to a future transportation capacity constraint on SWP withdrawals. This was outlined in AEMO's submission to the AER in support of the construction of the WORM[81] to prevent this threat to system security returning. The WORM is discussed further in Section 6.3.

Reduction in BCP maximum operating pressure

As part of the DTS service provider's access arrangement proposal for the 2018-22 period[82], the DTS service provider highlighted that the BCP runs through areas of high consequence risk from pipeline rupture due to urban encroachment. The SWP capacity augmentations completed in early 2018 enable the maximum operating pressure of the BCP to be lowered to 5,150 kilopascals (kPa) to reduce the rupture possibility without impacting system security. This lower operating pressure reduces the likelihood of pipeline rupture.

AEMO has agreed to amend the Service Envelope Agreement to implement the BCP pressure reduction. This change will have minimal impact on transmission capacity.

5.2 Dandenong CG capacity

Flows through DCG during winter 2017 were higher than in previous years, particularly on days with moderate system demand. This was due to a combination of factors, including:

- Lower SWP injections compared to similar demand days in previous years.
- Higher Longford to Melbourne Pipeline (LMP) injections from Longford, BassGas, VicHub, and TasHub.
- Increased GPG, particularly at Newport and Laverton North, due to the closure of the Hazelwood Power Station.
- Increased flow via DCG into the Lurgi back-up regulators to maintain supply to Warragul.
- The continuing trend towards higher instantaneous demand, as noted in the 2017 VGPR.

These factors often lead to gas flowing from the LMP (via DCG) being shipped across Melbourne through the inner ring main and the Brooklyn CS to support demand supplied from the SWP, BCP, and BLP.

On 27 July 2017, the DCG outlet pressure dropped to 2,685 kPa (compared to the usual tightly controlled pressure of 2,760 kPa) when flow through the station reached its capacity of 1,062 kscm/h. Total demand at the time was high, at 2,000 kscm/h, due to high GPG demand at Laverton North and Newport power stations. Injections into the SWP at Port Campbell were low, resulting in Brooklyn CS operating to support Laverton North and other demand on the SWP, BCP, and BLP. Operational steps were taken to reverse this pressure decline and there was no interruption to gas supply.

DCG flows have been observed near capacity on a number of occasions. Operational processes have been put in place to manage this issue. It may be necessary to restrict Iona UGS withdrawals during the morning peak, or schedule out of merit order injections at Port Campbell, to manage this constraint.

AEMO is working with the DTS Service Provider and distribution network operators on other possible solutions. Addressing the Warragul supply constraint and construction of the WORM is expected to reduce DCG load.

This issue highlights the impact of increased instantaneous demand including GPG.

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79 AEMO. *2017 VGPR*. Available at: http://aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2017/2017-VICTORIAN-GAS-PLANNING-REPORT.pdf.

80 AEMO. *Threat to System Security – Seeking a Market Response*. Available at: http://aemo.com.au/-/media/Files/Gas/DWGM/2017/Threat-to-System-Security-Notice---SWP-to-Port-Campbell-constraint.pdf.

81 AEMO. *APA VTS Access Arrangement 2018-2022 AEMO WORM submission* - 16 May 2017. Available at: https://www.aer.gov.au/system/files/Australian%20Energy%20Market%20Operator%20-%20APA%20VTS%20Access%20Arrangement%202018-2022%20-%20Western%20Outer%20Ring%20Main%20-%2016%20May%202017%20-%20PUBLIC.pdf.

82 APA. *Victorian Transmission System Access Arrangement Submission*. Available at: https://www.aer.gov.au/system/files/APA%20VTS%20-%20VTS%20Revision%20Proposal%20submission%20-%2020170103%20-%20Public.pdf.

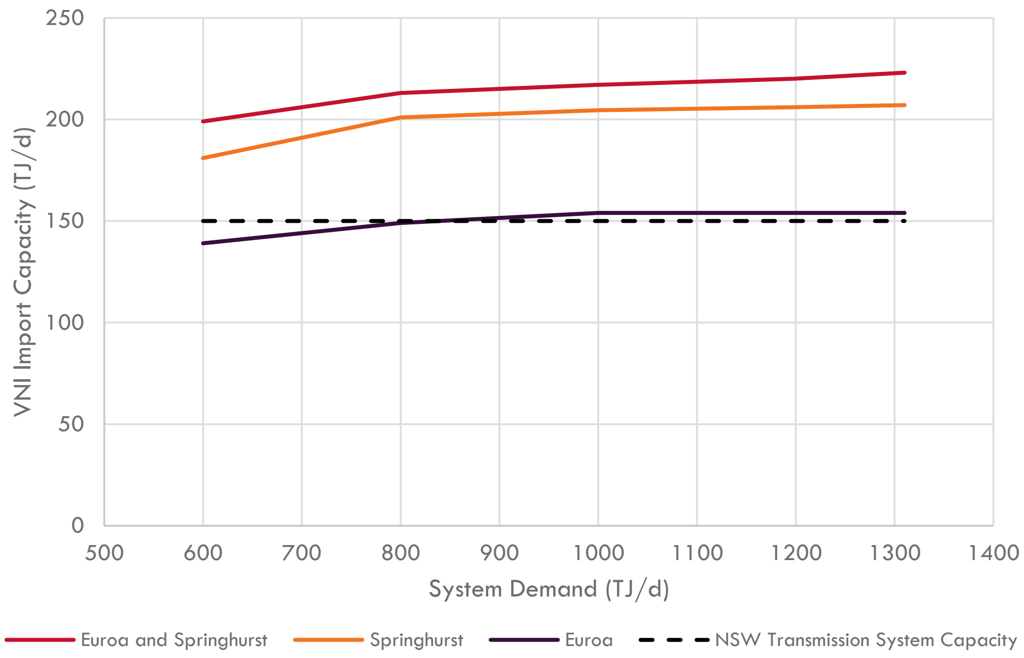
5.3 Victorian Northern Interconnect capacity towards Melbourne

The Facility Operator for the New South Wales transmission system north of Culcairn has advised that its injection capacity into the DTS (via the VNI) has increased from 125 TJ/d to 150 TJ/d. This increased import capacity is due to the completion of pipeline looping in the Young to Wagga Wagga section of the New South Wales transmission system.

This increased supply capacity via Culcairn is within the existing DTS import capacity through the VNI, which is unchanged from 223 TJ/d (so the DTS is capable of transporting this increased injection capacity).

Figure 21 shows the modelled import capacity of the VNI, as reported in the 2017 VGPR, with the New South Wales Transmission System Capacity increased to 150 TJ/d. The capacity curve shows the import capacity with both Euroa and Springhurst available, and also the capacity when either compressor is unavailable.

Figure 21 Victorian Northern Interconnect import capacity post VNI Expansion (VNIE) Phase B project



The Culcairn CS (which is part of the New South Wales transmission system) cannot currently compress gas in a southerly direction towards Victoria – it can only withdraw from the DTS. AEMO has observed that the Culcairn supply capacity into the DTS is reduced if the Uranquinty Power Station (which is supplied from the Young to Culcairn Pipeline) is operating, or during cold weather resulting in higher system demand on this pipeline.

6. System augmentations

Key findings

In November 2017, the AER reached a final decision on the 2018-22 DTS Access Arrangement. The DTS Service Provider is being funded by the market to make a number of augmentations, the following being the most relevant to pipeline transportation capacity:

- Warragul looping – constructing a duplicated section of pipe between the Lurgi Pipeline and the Custody Transfer Meter (CTM) will support increasing demand at this network offtake. A threat to system security notice was issued in 2017 for Warragul, flagging potential supply interruptions on high demand days.
- WORM – this augmentation, which is expected to be completed by 2021, will boost injection and withdrawal capacities from Port Campbell into the DTS as well as provide additional system linepack.
- Anglesea pipeline extension – a new connection between the SWP and Waurn Ponds will provide a second source of supply to Geelong and support growing demand on the Surf Coast and Bellarine Peninsula.

6.1 APA DTS access arrangement 2018-22 approved projects

Table 17 summarises the AER-approved DTS projects from the DTS service provider's access arrangement for the 2018-22 period.

Table 17 AER-approved 2018-22 access arrangement projects for the DTS

Status	Project	Details	Date effective (winter of)	Comments
Approved 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.
	SWP Expansion	Reconfiguration of Brooklyn CS and Winchelsea CS bi-directional compression.	2018	Increases SWP transportation capacity towards Port Campbell as discussed in Section 5.1.
	Anglesea Pipeline Extension	Lateral from the SWP with a new city gate to increase supply to Anglesea.	2019	May increase SWP injection capacity during winter periods.
	Lurgi Pipeline to Warragul Looping	Pipeline looping to alleviate potential pressure breach at Warragul.	2019	Potential capacity restrictions may occur from winter 2019 leading to possible curtailment of load in Warragul[A].
	Western Outer Ring Main (WORM)	Pipeline from Plumpton to Wollert (500 mm, 10,200 kPa), a Centaur 50 at Wollert and a Pressure Reduction Station (PRS) at Wollert to regulate gas flow from the WORM.	2021	Discussed in Section 6.3.
	Brooklyn Compressor Station	Upgrade of safety, control, ventilation and fuel gas systems.	2022	

Status	Project	Details	Date effective (winter of)	Comments
	Turbine overhauls	Replacement of compressor engines for Gooding CS Unit 3 and Wollert CS Unit 4 and Unit 5.	2022	
	Safety management program	Reduction of BCP MOP to from 7,390 kPa to 5,150 kPa. Slabbing of sections of the Wollert to Wodonga Pipeline and BLP.	2018-2022	Discussed in Section 5.1.

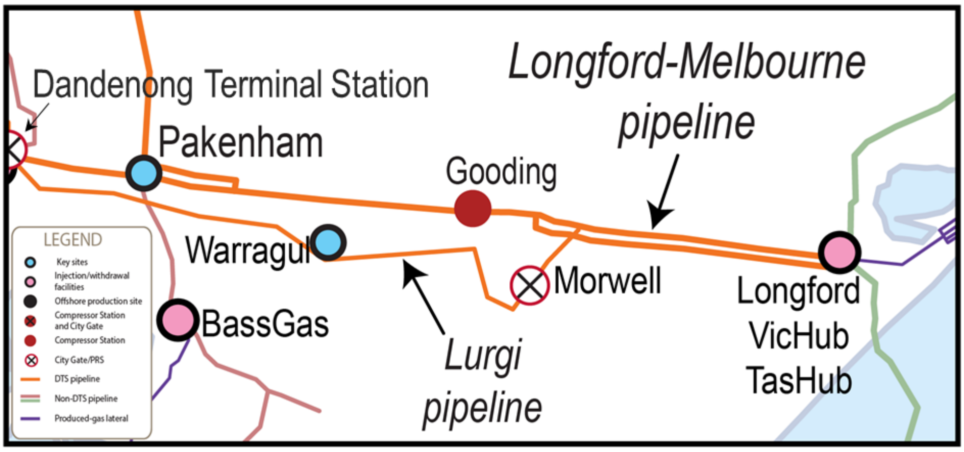
A. AEMO. *Notice of a Threat to System Security*, available at: http://aemo.com.au/-/media/Files/Gas/DWGM/2017/Threat-to-System-Security-Notice---Warragul.pdf.

6.2 Warragul looping

6.2.1 Background

The Warragul CTM is supplied from the Lurgi Pipeline, via a 4.7 km 100 mm diameter pipeline lateral, as shown in Figure 22.

Figure 22 Location of Warragul



As set out in the 2017 VGPR, a pressure breach occurred at the Warragul CTM on 22 July 2014 when pressure dropped below the 1,400 kPa contractual minimum. Additional supply via the Lurgi backup regulators[83] located at the Dandenong Terminal Station has been used to maintain the Warragul supply pressure. This change was sufficient to support a peak instantaneous Warragul CTM flow of 10 kscm/h.

To mitigate against possible future pressure breaches due to increased demand, from winter 2017 onwards, the gas distributor agreed to a temporary reduction of Warragul contractual minimum pressure to 1,150 kPa until 1 January 2021 (or earlier if the Warragul looping is completed). Manual valve configuration changes at the Dandenong Terminal Station were also made to maximise the supply pressure on peak demand days. This was expected to increase the supportable instantaneous flow to 10.6 kscm/h.

While these operational strategies help to maintain supply to Warragul, it increases the flow through DCG, 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 operating mode will be reduced due to:

- Increases in Warragul demand.
- Increases to Lurgi pipeline demand between Dandenong and Warragul.

6.2.2 System adequacy

In the 2017 VGPR, AEMO identified that 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. AEMO identified this as a threat to system security.

[83] 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.

AEMO will work with the distributor and the retailer for a large Tariff D demand site in Warragul to monitor peak day demand during winter 2018.

6.2.3 Future developments

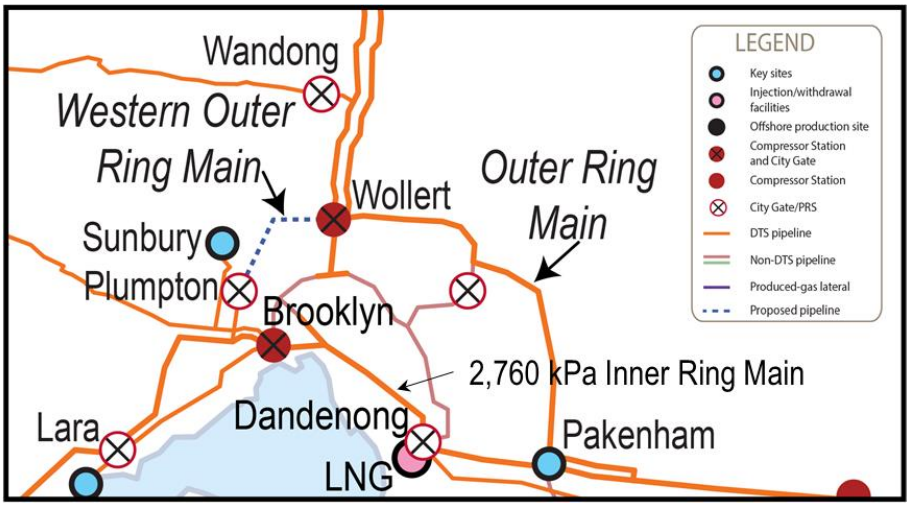
The AER approved funding in the DTS service provider's 2018-22 Access Arrangement to loop the existing 4.7 km Warragul supply pipeline. The plan for augmentation has been brought forward from 2020 to 2019 based on forecast increased demand at Warragul[84]. When completed, this pipeline looping will allow the minimum contractual Warragul pressure to return to 1,400 kPa.

6.3 Western Outer Ring Main (WORM)

As outlined in the 2017 VGPR, the Western Outer Ring Main (WORM) is a proposed pipeline that extends the SWP and BLP from Plumpton to Wollert, as shown in Figure 23. The pipeline will increase the SWP transportation capacity towards Port Campbell (to support Iona UGS refilling) and towards Melbourne to support peak day demand.

The WORM will also provide a route to supply gas from Port Campbell to the Northern and Gippsland regions. This would provide additional supply to these regions during Longford outages or maintenance periods.

Figure 23 Proposed WORM pipeline



The WORM would also enable AEMO to better manage system security, as it:

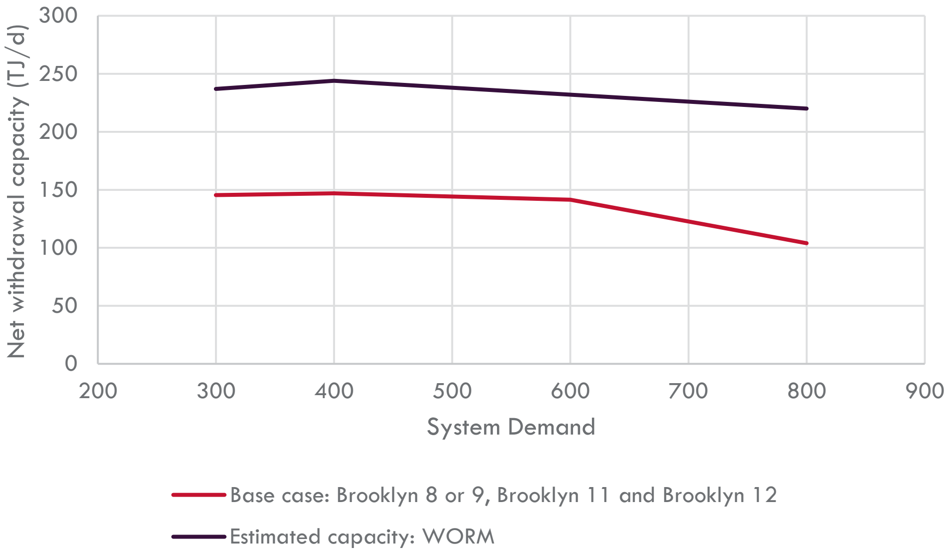
- Provides additional linepack close to the Melbourne demand centre to support the changing load profile and increased levels of GPG.
- Reduces peak shaving LNG requirements during high demand periods by providing increased supply to metropolitan Melbourne through Wollert CG and Dandenong CG.
- Reduces the likelihood of curtailment required during a supply interruption due to increased linepack availability and increased supply flexibility.

Benefits of the WORM from Melbourne towards Port Campbell

With the WORM and a compressor at Wollert CS the transportation capacity towards Port Campbell would be approximately 244 TJ/d. Figure 24 compares this to the current transportation capacity towards Port Campbell. This capacity estimate is dependent on the configuration at Wollert, and may change when the detailed design is complete.

[84] *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.

Figure 24 SWP to Port Campbell capacity with the WORM



The 2017 VGPR noted the inefficiency of the current method of transporting gas from Longford to Port Campbell, given pipeline pressure must be reduced at Dandenong CG, then recompressed at Brooklyn to flow along the BLP and SWP towards Port Campbell. Brooklyn CS used some 414 TJ of fuel gas in 2016-17, at an estimated cost of $3.5 million[85].

With the WORM connecting into the BLP, which would enable gas to flow to Port Campbell via the SWP, half the fuel gas would be required to transport the same quantity, compared to the current fuel gas usage via Brooklyn CS.

Benefits of the WORM from Port Campbell towards Melbourne

As outlined in the 2017 VGPR, SWP transportation capacity towards Melbourne is currently limited by the amount of gas that can flow into the Melbourne inner ring main via the Brooklyn CG, plus the demand that is supplied from the SWP and the BLP.

On lower demand days, the Brooklyn CG throughput is reduced due to supply from Dandenong CG backing off the Brooklyn CG flows, which can be offset by reducing Dandenong CG pressure during summer periods. This results in the SWP capacity increasing as system demand increases. The WORM provides additional demand points on the SWP by extending it to flow around outer north-west Melbourne, to inject the gas into the Melbourne inner ringmain via Wollert CG and also supply northern Victorian demand.

AEMO has modelled the Port Campbell injection capacity with a variety of compressor and regulator configurations at Wollert, with each producing varying results. The injection capacity, and therefore the SWP transportation capacity once the WORM is constructed, will depend on the Wollert configuration and whether Culcairn is injecting into the DTS or withdrawing from the DTS.

Dependant on these factors, the Port Campbell injection capacity can range from 433 TJ/day up to 492 TJ/day. A SWP transportation capacity of 473 TJ/d on a 1-in-20 peak system demand day has been used for assessing peak day supply adequacy in winter 2021 and 2022. AEMO will continue to work with the DTS service provider on the Wollert configuration to provide more accurate capacity modelling.

6.4 Anglesea pipeline extension

The Anglesea pipeline extension will provide a second source of supply to the Geelong region, particularly to meet increasing peak demand the Surf Coast and Bellarine Peninsula.

The project includes a new 20.2 km, 10,200 kPa, 250 mm diameter pipeline lateral that connects to the SWP west of Geelong and runs to Waurn Ponds. At Waurn Ponds there will be a city gate that includes custody metering and pressure regulation for connection to the AusNet distribution system.

While still tentatively scheduled for completion by winter 2019, construction had been delayed while the distributor negotiated with landowners to acquire a site for the city gate.

85 Assuming a wholesale gas price of $8.50/GJ.

A1. Gas demand forecast data by System Withdrawal Zone

Table 18 Annual 1-in-2 peak daily demand (TJ/d) by SWZ

SWZ		2018	2019	2020	2021	2022	Change over outlook (%)
Ballarat	Tariff V	60	61	62	62	63	4%
	Tariff D	6	6	6	6	6	-1%
	SWZ Demand	**66**	**67**	**68**	**68**	**69**	**4%**
Geelong	Tariff V	78	81	84	86	89	13%
	Tariff D	41	41	44	42	43	5%
	SWZ Demand	**119**	**123**	**128**	**129**	**132**	**11%**
Gippsland	Tariff V	42	44	45	47	48	14%
	Tariff D	28	29	29	29	30	5%
	SWZ Demand	**71**	**73**	**74**	**76**	**78**	**10%**
Melbourne	Tariff V	676	672	668	662	656	-3%
	Tariff D	126	126	125	124	123	-3%
	SWZ Demand	**802**	**798**	**792**	**785**	**779**	**-3%**
Northern	Tariff V	74	75	75	76	76	3%
	Tariff D	30	30	30	30	30	-1%
	SWZ Demand	**104**	**105**	**105**	**106**	**106**	**2%**
Western	Tariff V	9	9	9	10	10	7%
	Tariff D	10	10	11	11	10	1%
	SWZ Demand	**19**	**20**	**20**	**20**	**20**	**4%**

Table 19 Annual 1-in-20 peak daily demand (TJ/d) by SWZ

SWZ		2018	2019	2020	2021	2022	Change over outlook (%)
Ballarat	Tariff V	67	68	69	70	70	4%
	Tariff D	6	6	6	6	6	-1%
	SWZ Demand	**73**	**74**	**75**	**76**	**76**	**4%**
Geelong	Tariff V	87	90	93	96	99	13%
	Tariff D	41	42	44	43	43	5%
	SWZ Demand	**129**	**132**	**138**	**139**	**142**	**11%**
Gippsland	Tariff V	47	49	51	52	54	14%
	Tariff D	29	29	29	30	30	5%
	SWZ Demand	**76**	**78**	**80**	**82**	**84**	**11%**
Melbourne	Tariff V	710	706	701	695	689	-3%
	Tariff D	127	126	125	124	124	-3%
	SWZ Demand	**836**	**832**	**826**	**819**	**813**	**-3%**
Northern	Tariff V	82	83	84	84	85	3%
	Tariff D	30	30	30	30	30	-1%
	SWZ Demand	**112**	**113**	**113**	**114**	**115**	**2%**
Western	Tariff V	10	10	10	11	11	7%
	Tariff D	11	11	11	11	11	1%
	SWZ Demand	**21**	**21**	**21**	**22**	**21**	**4%**

Table 20 Annual system demand (PJ/y) by SWZ (Tariff V and D split)

SWZ		2018	2019	2020	2021	2022	Change over outlook (%)
Ballarat	Tariff V	8	9	9	9	9	13%
	Tariff D	2	2	2	2	2	0%
	SWZ Demand	**10**	**11**	**11**	**11**	**11**	**10%**
Geelong	Tariff V	11	11	11	11	11	0%
	Tariff D	11	11	12	11	11	0%
	SWZ Demand	**22**	**22**	**23**	**22**	**22**	**0%**
Gippsland	Tariff V	6	6	6	6	6	0%
	Tariff D	9	9	9	9	9	0%
	SWZ Demand	**15**	**15**	**15**	**15**	**15**	**0%**
Melbourne	Tariff V	93	92	92	91	90	-3%
	Tariff D	35	35	35	35	34	-3%
	SWZ Demand	**128**	**127**	**127**	**126**	**124**	**-3%**
Northern	Tariff V	11	11	11	11	11	0%
	Tariff D	9	9	9	9	9	0%
	SWZ Demand	**20**	**20**	**20**	**20**	**20**	**0%**
Western	Tariff V	1	1	1	1	1	0%
	Tariff D	3	3	3	3	3	0%
	SWZ Demand	**4**	**4**	**4**	**4**	**4**	**0%**

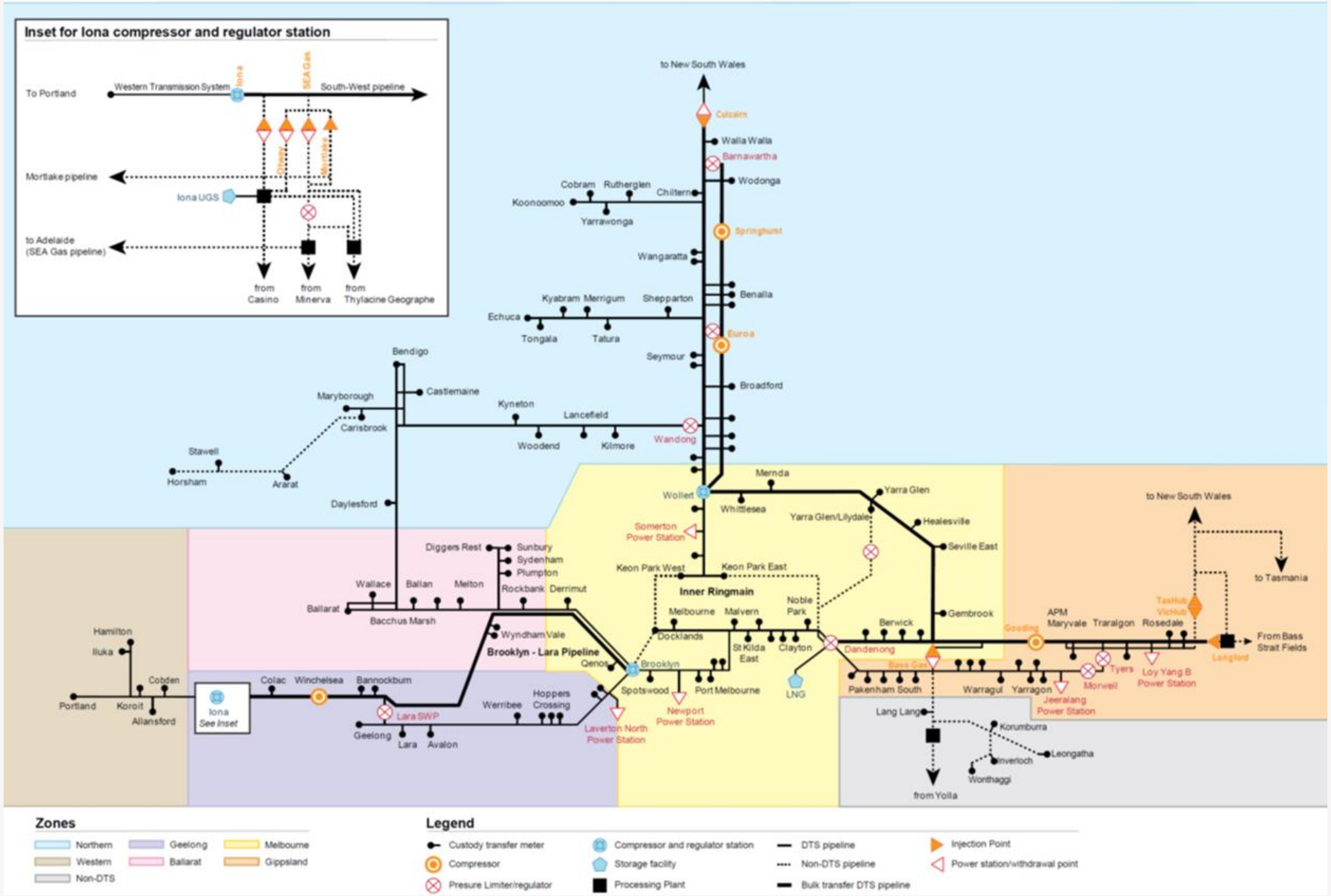
A2. DTS system withdrawal zones

The DTS is divided into six zones, shown in Figure 25:

- 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 25 System Withdrawal Zones in the DTS



Measures, abbreviations, and glossary

Units of measure

Abbreviation	Unit of measure
EDD	Effective degree days
kPa	Kilopascals
kscm/h	Thousand standard cubic meters per hour
mmboe	Million barrels of oil equivalent
MW	megawatts
PJ	Petajoules
PJ/y	Petajoules per year
t/h	Tonnes per hour
TJ	Terajoules
TJ/d	Terajoules per day
TJ/h	Terajoules per hour
TJ/y	Terajoules per year
Tscf	trillion standard cubic feet

Abbreviations

Abbreviation	Expanded name
AER	Australian Energy Regulators
AEST	Australian Eastern Standard Time
BCP	Brooklyn to Corio Pipeline
BCS	Brooklyn Compressor Station
BLP	Brooklyn to Lara Pipeline
CG	City Gate
CS	Compression Station
CTM	Custody Transfer Meter

Abbreviation	Expanded name
DCG	Dandenong City Gate
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ACCC	Australian Competition and Consumer Commission
EGP	Eastern Gas Pipeline
EPC	Engineering, Procurement, and Construction
ESV	Energy Safe Victoria
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
GBJV	Gippsland Basin Joint Venture
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
KTT	Kipper Tuna Turrum
LMP	Longford to Melbourne Pipeline
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MDQ	Maximum Daily Quantity
MSP	Moomba to Sydney Pipeline
NGR	National Gas Rules
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
OCGT	Open cycle gas turbine
OS	Operating Schedule
POE	Probability of Exceedance
PRS	Pressure Reduction Station
QHGP	Queensland Hunter Gas Pipeline
RFP	Request for proposal
RIT-T	Regulatory Investment Test - Transmission
SEA Gas	South East Australian Gas
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zones
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for Gas
UGS	Underground Storage

Abbreviation	Expanded name
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.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS), and injected at Pakenham.
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.
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.

Term	Definition
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.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
gas supply	The total volume of gas a facility is able to supply on an annual basis
gas supply capacity	The maximum volume of gas a facility is able to supply in a single day
injection	The physical injection of gas into the transmission system.
lateral	A pipeline branch.
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.
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.
metropolitan ring main	The 450 mm, distributor-owned pipeline from Dandenong to Keon Park to West Melbourne.
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.
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.

Term	Definition
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.
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.
unaccounted for gas (UAFG)	The difference between metered injected gas supply and metered and allocated gas at delivery points. UAFG comprises gas losses, metering errors, timing, heating value error, allocation error, and other factors.
Underground Gas Storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date. The only UGS currently in the DTS, is the Iona UGS located in the Port Campbell region.
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.