AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Victorian Gas Winter Operations Plan

May 2019

Gas Transmission Winter Operating Strategy

Important notice

PURPOSE

AEMO has prepared this document to provide information about the operation of the Victorian gas transmission system and the market operational strategies for winter 2019. The strategies are designed to support the secure operation of the Victorian Gas Declared Transmission System (DTS) and the Declared Wholesale Gas Market (DWGM).

The annual winter stakeholder information session was held on 8 May 2019 to present the 2019 Victorian Gas Winter Operations Outlook to stakeholders for discussion and comment.

This document supplements the session and provides further technical information on the 2019 Gas Winter Operations Plan.

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VERSION CONTROL

Version	Release date	Changes
1.0	13/5/2019	New Document

Executive summary

AEMO is the operator of the Victorian Gas Declared Transmission System (DTS) and the Declared Wholesale Gas Market (DWGM). As operator, AEMO is responsible for operating the Victorian gas transmission system in a safe and secure manner, and for minimising threats to system security. This document, reviewed and published annually, details AEMO's operational and market strategies for operating the DTS and DWGM during Victoria's 1 May to 30 September peak demand period[1].

The key messages for the 2019 Winter Operations Plan are outlined below.

- Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 peak system demand day of 1,246 terajoules (TJ), and to support forecast DTS-connected gas-powered generation (GPG) demand.
- Peak day Gippsland production capacity is forecast to increase from 1,040 TJ/d in winter 2018 to 1,078 TJ/d in 2019. This capacity will be reduced if the processing of Sole gas through the Orbost Gas Plant is delayed.
- Port Campbell production capacity is forecast to reduce from 218 TJ/d on 2018 to 197 TJ/d, but Iona underground gas storage (UGS) is forecast to increase from 440 TJ/d to 480 TJ/d for winter 2019.
- Commercial operation of the Northern Gas Pipeline (NGP) from 3 January 2019 is expected to increase the available gas supply capacity by an additional 80-90 TJ/d from Queensland to the southern states.
- Forecast GPG consumption during the 2019 peak demand period will reduce to 3.7 petajoules (PJ), less than the 4.6 PJ during the same period in 2018. The likelihood of GPG demand occurring remains greater on high system demand days.
- There will be continued reliance on the Iona UGS facility to balance daily and monthly supply and demand. The Dandenong liquefied natural gas (LNG) storage facility will continue to be used to supply peak shaving gas during periods of very high hourly gas demand or in response to unplanned gas supply disruptions. AEMO will monitor storage inventory throughout winter to identify and manage any supply concerns.
- The DTS service provider is currently constructing a duplication of the Warragul lateral, which is forecast for completion by June 2019. This will remove the threat to Warragul gas supply when the new pipeline is commissioned.
- AEMO expects that current transmission and market operational strategies will be sufficient to manage any potential threats to system security.

Peak day gas demand

AEMO does not expect a peak day supply shortfall for the 2019 winter period, provided storage inventories are not depleted before the end of winter. Winter 2019 DTS peak day gas demand is forecast to be:

- 1,147 TJ for a 1-in-2 year peak system demand day.
- 1,246 TJ for a 1-in-20 year peak system demand day[2].

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[1] The Peak Demand Period is defined in this document as 1 May until 30 September. Winter is 1 June to 31 August.

[2] A 1-in-2 year demand forecast is expected to be exceeded once every two years, while a 1-in-20 year demand forecast is expected to be exceeded once every 20 years.

The 2018 Victorian peak demand day occurred on Thursday 28 June 2018. The total demand[3] on this day was 1,120 TJ, which was comprised of 1,066 TJ of system demand and 54 TJ of GPG.

The highest recent peak demand day occurred on Thursday 3 August 2017. The total demand of 1,279 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[4].

Gas supply adequacy

The total available daily gas supply to the Victorian DTS this winter, allowing for pipeline capacity constraints, is forecast to be 1,551 TJ a day (TJ/d). The total supply consists of the Gippsland region (1,030 TJ/d), the Port Campbell region (434 TJ/d), and the Dandenong LNG facility (87 TJ/d).

Supply is also available from New South Wales via the Young to Culcairn lateral (also known as the Culcairn Interconnection), which is supplied from the Moomba to Sydney Pipeline (MSP). Due to the configuration of the DTS, supply from Culcairn (up to 150 TJ/d) reduces supply from the Gippsland region. Further information is available in the *2019 Victorian Gas Planning Report* (VGPR).

The peak day Gippsland production capacity was forecast in the 2019 VGPR to increase from 1,040 TJ/d in 2018 to 1,078 TJ/d in 2019 due to the commissioning of Sole project via the Orbost Gas Plant. Supply of sales gas from Sole is scheduled to commence in July 2019[5]. A delayed start-up would reduce gas supplies.

Peak day Port Campbell production capacity is forecast to reduce from 218 TJ/d during winter 2018 to 197 TJ/d this winter. This includes production from the Minerva Gas Plant, which is approaching end of life[6].

Supporting gas-powered generation

DTS-connected GPG consumption during the 2019 peak demand period (May to September) is forecast to be 3.7 PJ, which is less than the 4.6 PJ in 2018. Annual consumption is forecast to reduce from 9.6 PJ in 2018 to 7.3 PJ in 2019. This reduction is due to increased renewable generation capacity that is forecast to be commissioned prior to winter 2019.

Consistent with observed behaviour during winter 2018, increased GPG demand is expected on peak winter days. The maximum daily GPG demand during winter 2018 was 137 TJ on 16 May 2018 (system demand was 809 TJ).

Modelling from the 2019 VGPR shows that if GPG demand is accurately forecast in the DWGM, GPG demand is expected to be supportable under all normal operating conditions.

The ability of the DTS to support GPG is reduced if the demand is unforecast, because DTS linepack unlikely to be sufficient to support the higher hourly gas demand. Unforecast GPG may result in a threat to system security that would require AEMO to respond with one, or more, of the following mechanisms:

- Operational response LNG.
- Ad hoc schedule.
- Directions to participants or facility operators.
- Public appeals to reduce gas and electricity demand.
- Gas load curtailment.

To help manage uncertainties around GPG operation, AEMO implements the following strategies to reduce the risk of unforecast GPG operation:

- Monitoring forecast GPG in both the DWGM and National Electricity Market (NEM) pre-dispatch.

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[3] Total demand is system demand, plus GPG.

[4] The record highest total demand was 1,282 TJ on 17 July 2007.

[5] December 2018 Quarterly Report 23 January 2019 - Cooper Energy.

[6] Ibid.

- Communicating with the AEMO NEM control rooms in Sydney and Brisbane, and support teams, regarding NEM reserve levels and generator outages.
- Communicating with market participants to obtain information on possible GPG operations.
- The Gas Supply Guarantee (GSG)[7] will be called upon if required during winter 2019.

Storage inventory management

The Iona UGS facility is an important source of gas supply on high demand days. The capacity of the Iona UGS facility increased from 440 TJ/d to 480 TJ/d from 1 May 2019.

Storage inventory at the start of May 2019 was 19 PJ compared to 23 PJ at the same time last year. AEMO has reviewed the Iona UGS inventory reduction during winter 2018, including draw down from later August. The reduced inventory is expected to be adequate to meet participant forecast flows during winter 2019, provided that gas consumption to support GPG demand is not materially higher than forecast.

Increased supply from Queensland to the southern states is likely to be necessary to conserve storage inventory. An additional 80-90 TJ/d should be able to be supplied from Queensland via the SWQP following the start-up of the NGP from 3 January 2019. This capacity is available as the South West Queensland Pipeline (SWQP) capacity is no longer required to supply the Mount Isa region via the Carpentaria Pipeline (which sources gas from the SWQP).

If Iona UGS inventory is projected to fall to levels that are unlikely to support demand for the remainder of the winter period, AEMO will communicate with industry and the Victorian Government to examine options that will ensure security of supply is maintained. This could include voluntary or mandatory restrictions.

AEMO will also monitor inventory in the Dandenong LNG facility during winter. Supply from this facility is used to support high levels of GPG demand during the morning and evening peak period or following a gas supply disruption.

Warragul supply

As set out in the 2017 VGPR, AEMO issued a *Notice of a Threat to System Security* due to the forecast inability maintain the contractual minimum at the Warragul Custody Transfer Meter (CTM). This was the result of a pressure breach on 22 July 2014 and continuing increases in Warragul peak day demand.

The DTS service provider is currently constructing a duplication of the Warragul lateral, which is forecast for completion by June 2019. This will remove the threat to supply when commissioned.

If project completion is delayed and a peak demand day is forecast, AEMO will work with the retailer of a large commercial load to issue a *Direction to Curtail Load* for that customer in accordance with the *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*. This arrangement was in place during winter 2018.

Peak demand management

A normal operating state, as defined in the *Wholesale Market System Security Procedures (Victoria)*, is where system pressures and flows are maintained, and are forecast to be maintained, within the defined operating limits. A threat to system security may exist if a normal operating state cannot be maintained.

The strategies highlighted in this document are expected to enable AEMO to meet these system security requirements, and minimise threats to system security on peak days, during winter 2019.

On a peak demand day, these strategies include:

- Careful management of usable system linepack and linepack distribution.
- Longford injection profiling to maximise usable linepack before the evening peak.

[7] More information on the Gas Supply Guarantee may be found at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/Gas-Supply-Guarantee.

- Using the demand override methodology if significant demand forecasting differences occur between AEMO's forecast and market participants' aggregate forecast.

If a threat to system security occurs:

- AEMO will assess the threat and notify the market.
- If there is sufficient time, AEMO may request the market to respond to alleviate the threat.
- If there is insufficient time, or the market response is inadequate to alleviate the threat, AEMO will take action in the priority order outlined in the *Wholesale Market System Security Procedures (Victoria)*. This may include injecting gas that is above the market price at a location that can alleviate the threat, which is usually injections from the Dandenong LNG facility.

AEMO will regularly communicate relevant information to participants. If an emergency occurs, AEMO uses the *Emergency Procedures Gas*[8], which are designed to enhance AEMO's and industry's ability to manage the preparation for, response to, and recovery from gas emergencies in Victoria.

[8] Available at http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

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Tables

Figures

1. Winter 2019 outlook

1.1 Supply and demand adequacy

This paper uses the gas system consumption and gas-powered generation (GPG) forecasts published in the *2019 Victorian Gas Planning Report* (VGPR)[9]. The 2019 peak demand period (May to September) gas consumption and peak demand in the Declared Transmission System (DTS) is forecast to be similar to winter 2018 (Table 1).

Table 1 Peak demand period gas consumption and peak day total demand

	2014	2015	2016	2017	2018	2019 (forecast)
Total winter consumption (PJ)	114	126	118	131	126	122
Winter system consumption (PJ)	112	125	116	126	121	118
Winter GPG consumption (PJ)	1.9	1.2	1.9	5.8	4.6	3.7
Actual peak day total demand (TJ/d)	1,209	1,172	1,183	1,275	1,120	N/A

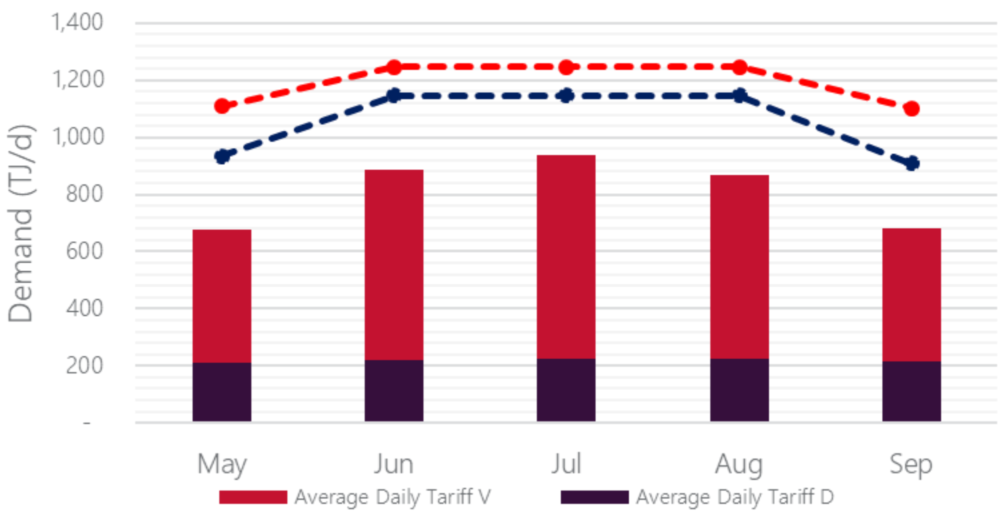
Actual peak total demand in 2018 was 1,120 terajoules (TJ) on 28 June. This included 1,066 TJ of system demand and 54 TJ of GPG. The winter 2019 peak system demand for the DTS is forecast to be:

- 1,147 TJ for a 1-in-2 year system demand day.
- 1,246 TJ for a 1-in-20 year system demand day.

Monthly gas consumption

Figure 1 shows the DTS average monthly winter consumption forecast for 2019.

Figure 1 Monthly average gas demand forecast 2019



[9] AEMO, 2019 VGPR Update, available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

This data and supporting forecasting methodology can be found in the 2019 VGPR Update. This figure does not include GPG, which is analysed in Section 4.

1.2 Gas supply

Peak day supply

The DTS total daily maximum pipeline constrained gas supply for 2019 is expected to be 1,551 TJ[10]. This is sufficient to meet a 1-in-20 system demand day of 1,246 TJ a day (TJ/d). Table 2 summarises supply sources, their available maximum supply to inject into the DTS on a peak demand day, and the total facility capacity at that location for 2019.

Table 2 2019 DTS supply sources and maximum daily supply (TJ/d)

	Total DTS potential supply[A]	Total plant capacity[B]
DTS Supply Sources		
Gippsland	1,030	1,078
Port Campbell	434[C]	677 [D]
Dandenong LNG[E]	87	
Total	1,551	-
Other supply sources	Maximum Supply	
VNI Import	150	

A. Total DTS potential supply is the lesser of the sum of production capacity of plants injecting into that pipeline, and the pipeline capacity on a peak demand day

B. Nameplate capacity expected based on information provided to AEMO's 2019 VGPR Update.

C. The transportation capacity of the SWP is 413 TJ/d plus an additional 21 TJ/d that can be injected at Port Campbell to support demand within the Western Transmission System (WTS), providing a total capacity of 434 TJ/d.

D. The surplus plant capacity can be used to supply Mortlake GPG, and South Australia via the SEA Gas Pipeline

E. Based on 5.5 TJ/h of firm capacity for 16 hours, with an adjustment for ramp up and ramp down rates.

The total daily maximum gas supply of 1,551 TJ/d comprises supply from Longford, VicHub, TasHub, BassGas, Dandenong LNG, and the Port Campbell facilities (see following sections for details of these supply sources).

Victorian Northern Interconnect (VNI) imports are not part of the total daily maximum gas supply, because availability depends on operational and market conditions in New South Wales, which may limit flows into Victoria on peak demand days. AEMO will continue to work with the facility operator for Culcairn to manage flows into the DTS.

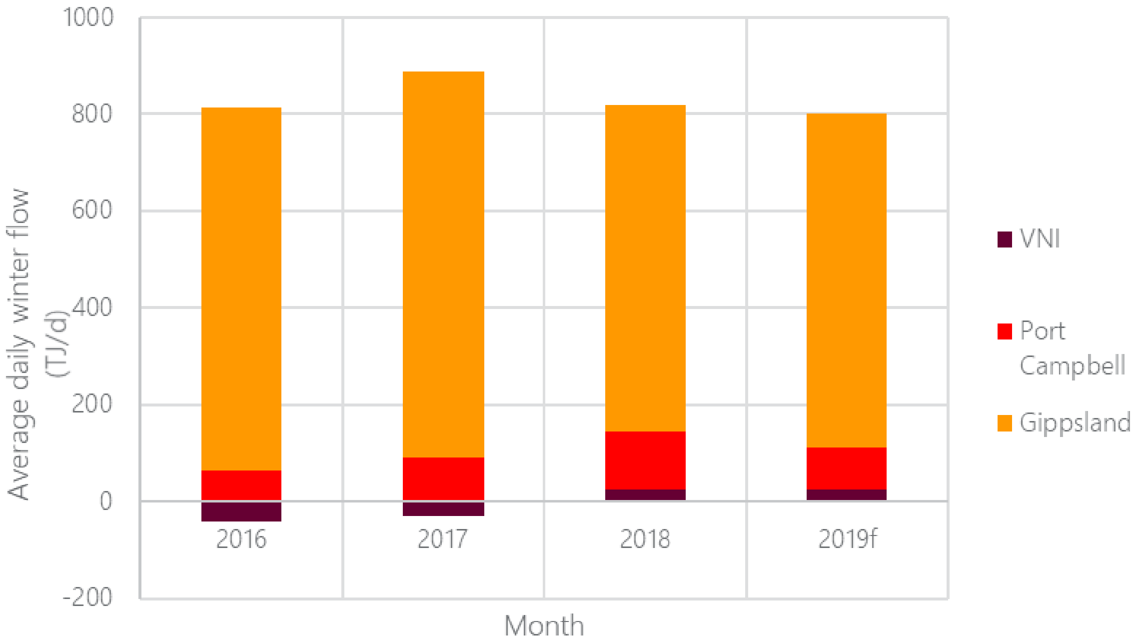
Winter supply

As highlighted in the 2019 VGPR update, Victorian gas supply is adequate to meet forecast annual and peak day demand for 2019[11] provided that Iona underground gas storage (UGS) inventory is not depleted. Figure 2 shows average flows for the last three winter periods, compared to AEMO's forecast for average winter flows in the 2019 winter period. Trends in Figure 2 are explored in the following sections.

[10] This system capacity does not consider reductions in pipeline capacity when the Longford – Melbourne Pipeline and South West Pipeline are operating near their maximum capacities coincidently. More information is in Section 4.4 of the 2017 VGPR, available at https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2017/2017-VICTORIAN-GAS-PLANNING-REPORT.pdf.

[11] AEMO, 2019 VGPR, Figure 1 and 3 p 24 and Table 7 p 12, available at https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2017/2018---Victorian-Gas-Planning-Report-Update.pdf.

Figure 2 Actual and forecast average winter flows into DTS for 2016-19 (forecast)



Gippsland

Gippsland production facilities include the Longford, Lang Lang (BassGas), and Orbost gas plants. The Longford Gas Plant supplies the DTS, Tasmania via the Tasmanian Gas Pipeline (TGP), and New South Wales via the Eastern Gas Pipeline (EGP).

DTS injection points at Longford and the interconnected pipeline points TasHub and VicHub can inject at up to the Longford to Melbourne Pipeline (LMP) capacity of 990 TJ/d. BassGas, which connects into the LMP at Pakenham, increases the pipeline capacity to 1,030 TJ/d.

Peak day Gippsland production capacity is forecast to increase from 1,040 TJ/d in winter 2018 to 1,078 TJ/d in 2019. This includes production from the Sole gas field that will be processed through the Orbost Gas Plant. Average winter flows into the DTS from the Gippsland region are forecast to increase from 673 TJ/d in 2018 to 689 TJ/d in 2019.

Port Campbell

Port Campbell storage and production facilities include Iona UGS, which also processes gas from the offshore Casino development, and the Otway and Minerva gas plants. These facilities supply the DTS, Mortlake GPG, and South Australia via the SEA Gas Pipeline. They are capable of injecting gas into the DTS up to the 434 TJ/d capacity to the South West Pipeline (SWP) and the Western Transmission System (WTS).

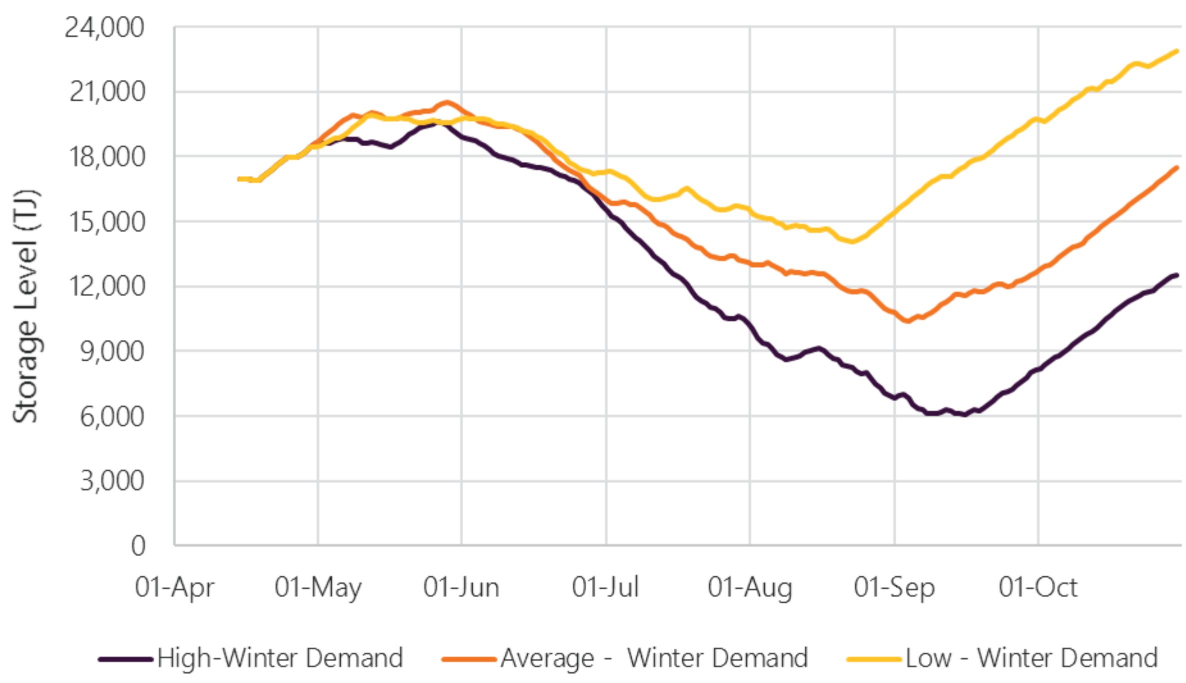
Port Campbell production capacity is forecast to reduce from 218 TJ/d on 2018 to 197 TJ/d. This assumes that the Minerva Gas Plant continues to produce through the winter period. As a result, average Port Campbell injections into the DTS are expected to decrease from 121 TJ/d in winter 2018 to 86 TJ/d winter 2019.

Following the drilling of an additional well in 2018, additional committed plant augmentations will increase the Iona UGS supply capacity from 440 TJ/d to 480 TJ/d in May 2019. This additional capacity can also be used to supply gas to the Mortlake Power Station and to South Australia via the SEA Gas Pipeline.

Iona UGS refilling for winter 2019 has been interrupted by higher than forecast GPG demand during summer and a planned outage of the Longford Gas Plant during March and April 2019. Iona UGS inventory at the start of May 2019 was 19 PJ compared to 23 PJ at the same time last year.

The reduced inventory is expected to be adequate to meet participant forecast flows during winter 2019 based on AEMO's review of the Iona UGS inventory reduction during winter 2018. The range of inventory forecasts for 2019 are shown in Figure 3. If demand is per the forecast ranges shown in Table 1 then there is expected to be sufficient storage inventory. Iona UGS inventory was approximately 13 PJ in mid-August 2018, which is similar to the level at the same time in 2017. The draw down in Iona UGS inventory later in August 2018 was higher than would be expected at that time, suggesting the reduction was a commercial decision by market participant.

Figure 3 Iona inventory forecast for winter 2019



AEMO will continue to monitor Iona UGS levels to ensure gas will be available through the May to September winter period. If storage is projected to empty before the end of winter, AEMO will communicate with industry and the Victorian Government to examine alternate supply options or gas usage restrictions. If storage was to empty before the end of winter and a peak system demand day then occurred, it could result in a gas supply shortfall.

Culcairn Interconnection

The Victorian Northern Interconnect (VNI) runs from Wollert, north of Melbourne, to Culcairn in southern New South Wales. It is connected to the Moomba to Sydney Pipeline (MSP) via the Young to Culcairn Lateral (also known as the Culcairn Interconnection).

The VNI can import gas from Queensland via New South Wales and export gas from Victoria. Its flow direction usually depends on market conditions in the DWGM, the Short Term Trading Market (STTM) Sydney Hub, and shipper/retailer portfolio balancing to supply GPG units that are bid in the National Electricity Market (NEM).

The Culcairn Interconnection supply capacity is dependent on transmission system conditions in New South Wales. These conditions include gas demand by the Uranquinty Power Station, located near Wagga Wagga (which is north of the Culcairn facility), MSP linepack levels, and regional demand in southern New South Wales.

The Culcairn supply capacity of 150 TJ/d is less than the VNI import capacity of 223 TJ/d, so imports from Culcairn are not expected to be materially constrained by the capacity of the VNI (which is part of the DTS) unless both the Springhurst or Euroa compressors are unavailable.

Average winter VNI flows when from net exports to New South Wales during winter 2017, to net imports from during winter 2018 due to reduced Gippsland production. Gippsland production flow up the Eastern Gas Pipeline during the same period was higher, meaning that overall there was a net Gippsland flow to New South Wales.

Imports into Victoria via the VNI are expected again during winter 2019. These may be higher than during winter 2018 due to the lower Iona UGS inventory (Figure 2).

Dandenong LNG

Gas from the Dandenong LNG facility can be injected in the DTS for two main purposes:

- Operational response, otherwise known as peak shaving gas, where AEMO schedules out of merit order gas (gas that is above the market price) in response to a threat to system security.
- Market response, where market participants can use LNG, as they would any other injection facility, to manage their gas supply portfolio.

The Dandenong LNG facility can inject gas into the DTS at either a:

- Firm rate of up to 5.5 TJ/hr (100 tonne per hour), or
- Non-firm rate of up to 9.9 TJ/hr (180 tonne per hour).

When used for operational response, LNG is not usually scheduled from the beginning-of-day, but is included in an intraday schedule for linepack management purposes. LNG only effectively supports system pressures when injected before 22:00, which is when DTS linepack is at its lowest point.

If operational response LNG was injected from the beginning of the gas day until 22:00, the maximum supply quantity during this 16 hour period is 87 TJ.

Operational response LNG was not required to support demand at any point during 2018.

1.3 Peak day supply and demand sensitivity analysis

AEMO has considered three scenarios to demonstrate a potential supply and demand balance within the DTS for a 1-in-20 system demand day:

- Scenario 1 – base scenario.
- Scenario 2 – reduced Longford injections.
- Scenario 3 – reduced Longford injections with GPG.

DTS peak demand can be satisfied in all scenarios, by scheduling gas from sources such as LNG and VNI imports as required.

The scenarios do not take into account pipeline dynamics, which are explained in Section 6.1-6.2 of the *2019 VGPR* and assumes an accurate beginning-of-day demand forecast, no facility deviations, and perfect linepack distribution. The supply-demand balance does not account for intraday DTS congestion and does not consider the supply-demand balance in other states.

Scenario 1 – Base scenario

Base scenario considers that all peak day supplies are available and represents the expected supply on a 1-in-20 system demand day in winter 2018, as shown in 0. Under this scenario, the DTS has enough supply to meet the 1-in-20 system demand day. A range of flows from the Longford and Port Campbell supply hubs are possible, and these are expected to be influenced by gas demand in New South Wales (including the Uranquinty Power Station), Port Campbell (including the Mortlake Power Station), and South Australia.

Table 3 Scenario 1 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford, VicHub and TasHub	747-800	1-in-20 system demand	1,246
BassGas	36	GPG	0
Port Campbell	434-381		
VNI	29		
Dandenong LNG	0		
Total supply	**1,246**	**Total demand**	**1,246**

Scenario 2 – reduced Longford injection

Scenario 2 considers Longford supply into the DTS being reduced to 650 TJ on a 1-in-20 system demand day, assuming Longford supplies into Sydney increase along the EGP when compared with Scenario 1. The scenario assumes other supply sources are fully available.

As Table 4 shows, this scenario indicates that maximum Port Campbell supply (434 TJ) and 126 TJ of VNI imports are required to maintain a supply-demand balance. Alternatively, some LNG may be injected.

Table 4 Scenario 2 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford, VicHub and TasHub	650	1-in-20 system demand	1,246
BassGas	36	GPG	0
Port Campbell	434		
VNI	56-126		
Dandenong LNG	0-70		
Total supply	**1,246**	**Total demand**	**1,246**

Scenario 3 – reduced Longford injection with GPG

Scenario 3 builds on Scenario 2, where Longford injections are reduced to 650 TJ and GPG demand is 100 TJ/d, on a 1-in-20 system demand day. The total demand for this day would be 1,346 TJ[12].

As Table 5 shows, this scenario indicates that maximum VNI imports of 150 TJ and 76 TJ of firm LNG flows would be required to maintain a supply-demand balance. Alternatively, non-firm LNG flows would be scheduled if maximum VNI imports could not be achieved, or liquid fuel may be used to support some GPG demand.

[12] The largest total demand ever recorded in the DTS was 1,286 TJ, during July 2007.

Table 5 Scenario 3 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford, VicHub and TasHub	650	1-in-20 system demand	1,246
BassGas	36	GPG	100
Port Campbell	434		
VNI	100-150		
Dandenong LNG	76-126		
Total supply	**1,346**	**Total demand**	**1,346**

2. Operations plan

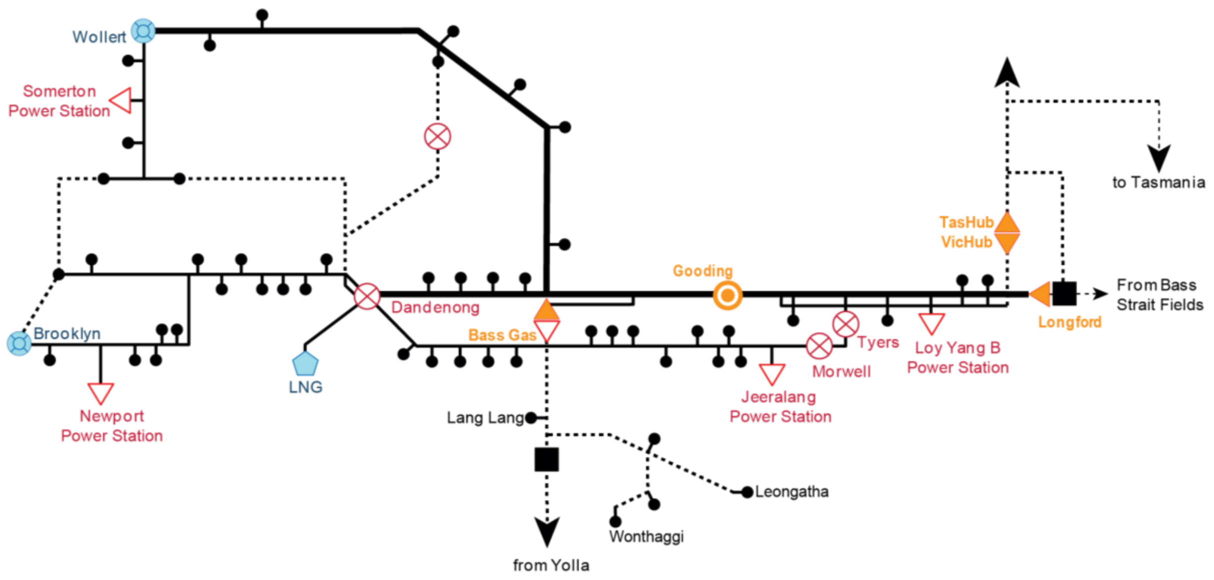
2.1 Transmission operations

2.1.1 Longford to Melbourne Pipeline system

The Longford to Melbourne Pipeline system (Figure 4) includes:

- The Longford to Melbourne Pipeline (LMP), which runs from Longford to Dandenong City Gate (DCG).
- The Pakenham to Wollert Pipeline (also known as the Outer Ring Main), which runs north from Pakenham to the Wollert City Gate and Wollert Compressor Station.
- The Lurgi Pipeline, which runs parallel to the LMP, from the Tyers Pressure Limiter to the Dandenong Terminal Station, which is where DCG is located.

Figure 4 Longford to Melbourne Pipeline



Pipeline pressure

Pressures along the LMP are dependent on the Longford supply pressure, the quantity of gas being transported, Melbourne and Gippsland demand, operation of the Gooding and Wollert compressors, and the amount stored at any point in time. AEMO can manage these pressures so that they remain within operating parameters by distributing, or "balancing", the linepack through the DTS.

Where an imminent high pressure event is identified, AEMO will notify the Longford Gas Plant. The notification is to allow time for the Longford facility operator to take appropriate action and minimise the ramp down rate required. The Gooding and Wollert compressors can be used to help move linepack from Longford to Melbourne and into the Northern Zone if system conditions allow compressors to be run effectively. Generally, two Gooding compressors will be run on days where Longford CPP injections are higher than 750 TJ/d. Up to three Gooding compressors can be run simultaneously if required.

Average winter Longford CPP supply during 2018 were only 629 TJ/d, compared to 735 TJ/d in 2017. This resulted in the Gooding compressors only being run on three days in winter 2018 to manage LMP pressures. In 2017 at least two Gooding compressors were required to for almost all the peak demand period to support the high Longford CPP supply.

As the average daily Longford CPP supply is forecast to increase to 689 TJ/d (see Figure 2), Gooding compressor operations are expected to be required more frequently during winter 2019 compared to 2018.

Dandenong City Gate

On high system demand days, the DCG inlet pressure can approach its minimum operational target pressure of 3,300 kilopascals (kPa) as linepack is depleted along the LMP[13]. Maintaining this minimum operational pressure target is critical for ensuring Melbourne metropolitan demand is safely met.

Operational strategies to maintain the DCG inlet pressure above 3,300 kPa include:

- Maximising SWP supply and usable linepack.
- Operating Gooding compressors.
- Injecting operational response Dandenong LNG.

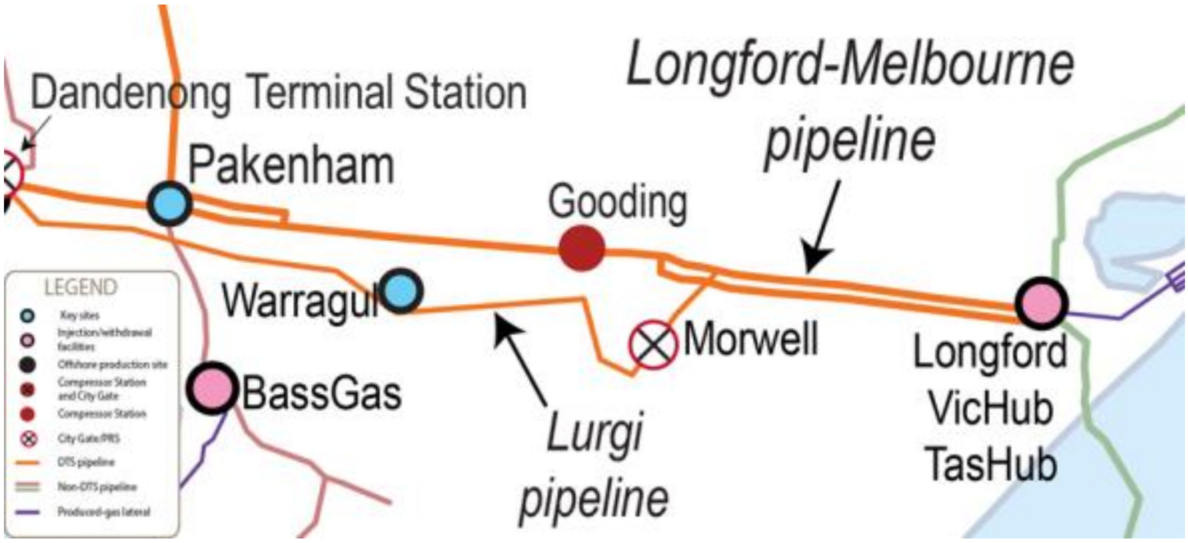
[13] While the operational target is 3,300 kPa, the minimal operations pressure of the Dandenong City Gate is 3,200 kPa, as detailed in AEMO's Wholesale Market Critical Location Pressures, available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures.

- Restricting or shutting down the Wollert Compressor Station (see Section 2.1.3 for 'Prioritisation of Operational Response LNG' if this is required to support Culcairn exports).

Warragul

The Warragul CTM is supplied from the Lurgi Pipeline via a 4.7 km, 100 mm diameter lateral, as shown in Figure 5.

Figure 5 Location of Warragul



A pressure breach occurred at the Warragul CTM on 22 July 2014 when the pressure dropped below its contractual minimum of 1,400 kPa.

To reduce the risk of future pressure breaches, the gas distributor entered into an agreement to temporarily reduce the contractual minimum pressure from 1,400 kPa to 1,150 kPa[14]. Additionally, AEMO implemented the following operational strategies to maximise supply pressure to the Warragul CTM:

- Increase the Lurgi backup regulator setpoint after the evening peak to 2,700 kPa to support the high flows through the Warragul CTM during the morning peak.
- Manual valve configuration changes at the Dandenong Terminal Station to maximise the supply pressure to the Lurgi Pipeline by reducing the pressure drop across the Lurgi backup regulators on peak demand days.

These strategies support a flow of up to 10.6 kscm/h through the Warragul CTM. If this flowrate is exceeded there is still a risk of curtailment to end users.

AEMO will continue to work with the distributor and retailer for a large commercial site in Warragul to monitor and respond if necessary to peak demands. If AEMO forecasts a pressure breach at the Warragul meter in winter 2019, a *Direction to Curtail Load* will be issued to customers via their retailer in accordance with the *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*[15].

These risk mitigation measures will be in place until the DTS service provider completes the duplication of the Warragul lateral, which is forecast for completion by June 2019. This will enable the minimum contractual Warragul pressure to return to 1,400 kPa. In the event that there are delays to the completion of the project, the current risk mitigation plan will remain in place until completion.

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[14] This agreement will remain in place until either the Warragul lateral looping project is completed, or 1 January 2021.

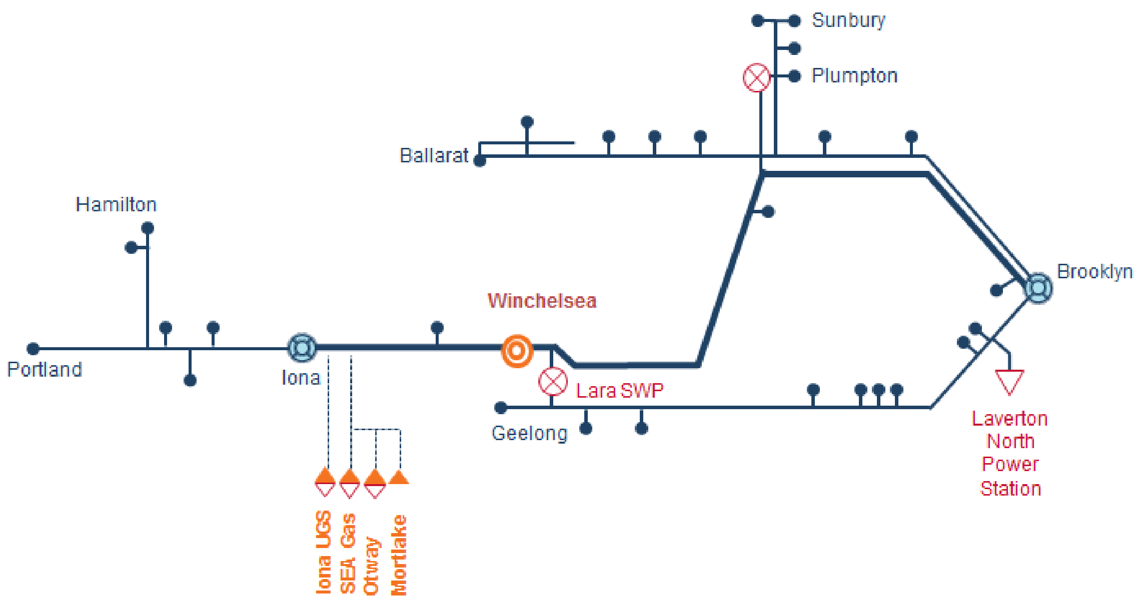
[15] Available at http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

2.1.2 South West Pipeline

Figure 6 includes:

- The SWP, which runs from the Iona UGS facility in Port Campbell to the Lara City Gate.
- The Brooklyn to Lara Pipeline (BLP), which is a continuation of the SWP and extends from Lara to the Brooklyn City Gate.
- The Brooklyn to Corio Pipeline (BCP), which runs south of the BLP from Brooklyn City Gate to Corio, near Geelong, with supply from the SWP into the BCP at Lara.
- The Brooklyn to Ballan Pipeline, which runs from Brooklyn City Gate to Ballarat.
- The Western Transmission System (WTS), which runs from Iona UGS to Portland.

Figure 6 South West Pipeline



On peak demand days, flows on the SWP may approach its transportation capacity for 2019 of 434 TJ/d.

Strategies to maximise Port Campbell supply to Melbourne include:

- Using SWP linepack prior to the end of the evening peak where possible, due to the reduced ability to flow gas at capacity through the Brooklyn City Gate overnight[16].
- Running Winchelsea Compressor Station (CS) to increase pipeline capacity and to shift linepack towards Melbourne to support evening peak demand and prevent the Brooklyn City Gate inlet pressure from reducing below its minimum setting.

Failure to effectively implement these strategies may result in high SWP pressure and low LMP pressure. This can affect the ability of the gas facilities to inject gas into the pipeline. If not managed, this can reduce supply, affect the system linepack balance, limited the capacity to support GPG demand, and potentially necessitate injections from other sources.

When the net SWP injections are less than the SWP, WTS, and BCP demand on high demand days, careful management of SWP linepack and Brooklyn CS operation is required to maintain pressures along the SWP, WTS, and BCP, as well as at Ballarat.

[16] Flow from Brooklyn City Gate into Melbourne gets backed out by high inner ring main pressures from Dandenong City Gate after the evening peak

When there are withdrawals during winter, Iona CS may be run to support pressures in the WTS. If there are consecutive days of withdrawals during the shoulder season, the end-of-day linepack target may be reduced to accommodate the lower-than-normal linepack levels in the SWP.

Brooklyn to Ballan Pipeline

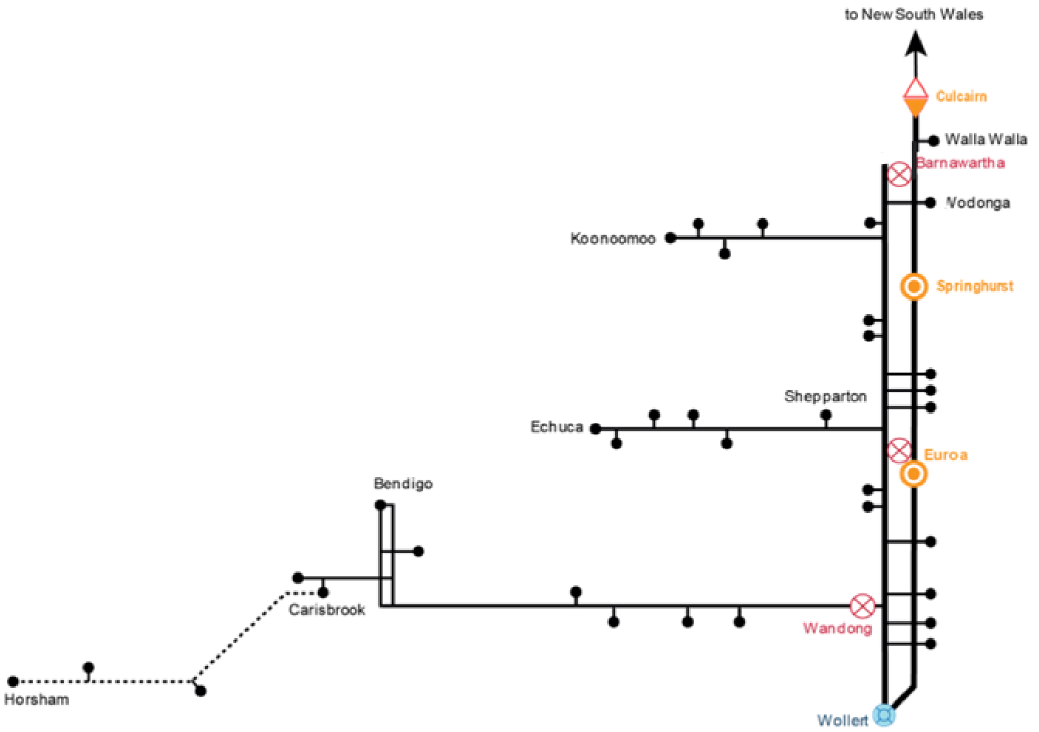
The Brooklyn to Ballan Pipeline runs from the Brooklyn City Gate to Ballarat, which is the highest demand point along the pipeline. During winter on peak demand days, a Brooklyn compressor is required to maintain minimum operational pressures at Ballarat.

2.1.3 Victorian Northern Interconnect

The Victorian Northern Interconnect (VNI, shown in Figure 7) includes:

- The major pipelines for transportation of gas to and from New South Wales via Culcairn.
- Wollert, Euroa, and Springhurst Compressor Stations, which increase the transportation capacity along the VNI.
- Lateral pipelines to Bendigo, Echuca, Koonoomoo, and Wodonga.

Figure 7 Victorian Northern Interconnect



VNI flows

For winter 2019, Culcairn supply is expected to be similar or exceed the flows that occurred during winter 2018 (see section 1.2). Culcairn imports are supported by operation of the Euroa and Springhurst compressors in a north-to-south configuration as required.

When Culcairn imports are scheduled on high system demand days, the linepack in the VNI must be lower than the level required to support exports. This is because the minimum contractual pressures along the VNI are typically much lower than the receipt pressure required to support Culcairn exports. Culcairn imports therefore increase usable system linepack and assist in maintaining system security.

If Culcairn exports are scheduled during winter, they are supported through operation of Wollert B, Euroa, and Springhurst compression as required. If maximum Culcairn exports are scheduled on a peak demand day, Wollert A compression is required to maintain critical pressures at Shepparton and Wodonga.

Prioritisation of operational response LNG

On peak demand days, maintaining a high VNI linepack to support high exports can decrease the linepack available to support Melbourne demand. If this occurs, LNG may be required to maintain the DCG inlet pressure above 3,300 kPa.

In the event that DCG inlet pressure is forecast to fall below the minimum operating pressure, AEMO will take the following steps in order of priority to maintain system security:

1. Use Gooding compressors to shift linepack toward Melbourne.
2. Ensure all available system linepack from other pipelines has been used to support pressures at DCG.
3. Schedule peak-shaving Dandenong LNG at up to the firm rate of 100 tonnes/hr (5.5 TJ/hr).
4. Reduce compression at Wollert CS to prioritise the supply of gas to Melbourne.
5. Schedule peak-shaving Dandenong LNG at up to the non-firm capacity of 180 tonnes/hr (9.9 TJ/hr).

If these steps are insufficient, AEMO may reduce demand by calling for voluntary restrictions or curtail load by using the *Gas Load Curtailment and Rationing and Recovery Guidelines*[17].

AEMO does not expect high VNI exports on high system demand days during winter 2019.

2.2 Scheduling constraints

Constraints can be initiated by AEMO or a facility operator, and are applied to either:

- The Operating Schedule (OS) only, or
- Both the Pricing Schedule (PS) and OS.

If the application of a constraint is necessary, the constraint can be applied to:

- Injections, where the highest priced injection bid at the constrained point is removed first, and then the second highest bid, until the injections are reduced down to the constraint quantity.
- Controllable withdrawals, where the lowest priced withdrawal bid at the constrained point is removed first, and then the second lowest bid, until the withdrawals are reduced down to the constrained quantity.

If multiple bids set the market price, participants with Authorised Maximum Daily Quantity (MDQ) are given priority. If multiple participants have Authorised MDQ, then they are prorated.

Each type of scheduling constraint is detailed below.

Supply and Demand Point Constraint (SDPC)

An SDPC is applied to restrict or specify gas flows at an injection or a withdrawal point. For example, if a facility operator advises AEMO that there will be planned or unexpected maintenance at an injection or a withdrawal point, an SDPC is applied to both the PS and OS at an injection point to the facility operator's specified quantity.

Directional Flow Point Constraint (DFPC)

A DFPC is used to limit net flows at a bi-directional supply point. Historically DFPCs have primarily been used to prevent net withdrawals at bi-directional meters where financial flows are allowed but physical net withdrawals are not possible. A DFPC is applied in both the PS and the OS

[17] AEMO, *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*, available at http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

DFPCs have been applied permanently on the VicHub, TasHub, and SEA Gas bi-directional meters to prevent net withdrawals, because these facilities currently cannot physically withdraw from the DTS.

A DFPC is also used to limit a facility to a particular net rate during maintenance or other physical limitation occurring outside the DTS. For example, if one of the three compressors at the Culcairn facility is undergoing maintenance, a DFPC can limit exports at the Culcairn injection and withdrawal meters to achieve a specific withdrawal rate.

Net Flow Transportation Constraint (NFTC)

An NFTC is applied to a collection of meters on a pipeline to prevent the transportation capacity being exceeded. For example, an NFTC may be applied to the SWP meters, which will limit the total net scheduled quantity on the SWP to its transportation capacity.

NFTCs are applied to the OS only, according to the *Wholesale Market Gas Scheduling Procedures*[18].

Supply Source Constraint (SSC)

An SSC can be applied on a production facility located outside the DTS that supplies an injection meter. This may be useful where multiple facilities supply one injection meter. If one plant trips, an SSC can be applied to that plant, so that injection bids from participants obtaining gas from the affected facility can be constrained. As an SSC is a facility constraint, it would be applied in both the PS and the OS.

To date, no participants have registered to use an SSC, so it is not anticipated that an SSC will be applied during winter 2019.

2.3 Demand forecast management

Demand forecast accuracy is critical when scheduling gas during winter.

If gas demand is under-forecast:

- Scheduled supply may be insufficient to meet the actual demand.
- A system withdrawal point could breach its minimum operating pressure, resulting in a possible loss of gas supply in the distribution network.
- Operational response Dandenong LNG may be scheduled to support system pressures, which comes at a cost to the market.

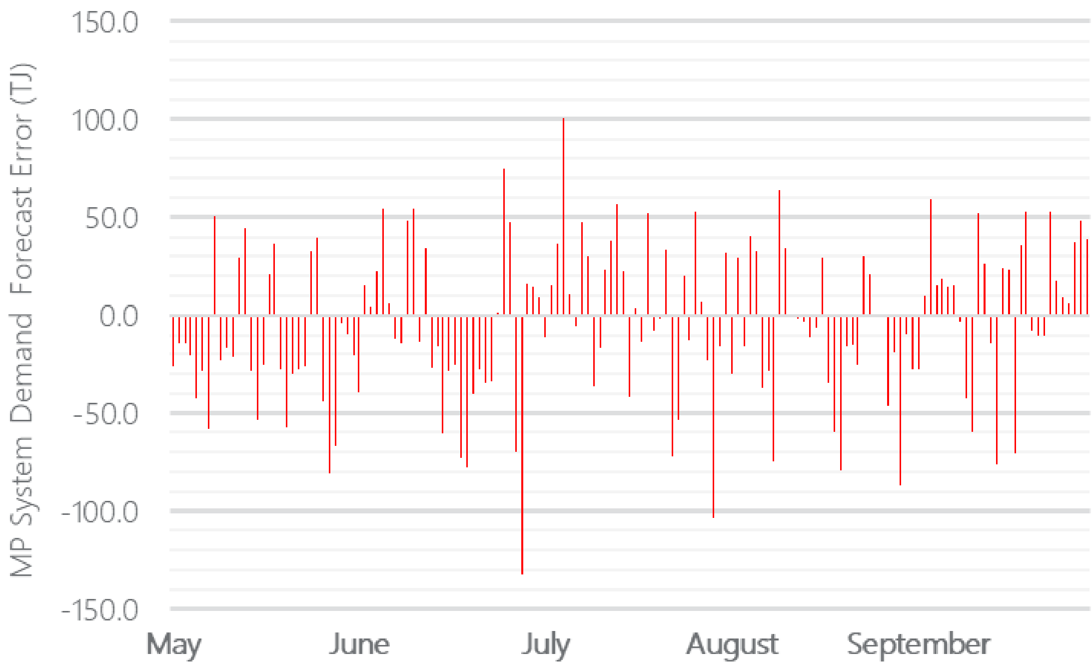
If gas demand is over-forecast:

- Oversupply can cause gas injections to be "backed-out", where the gas pressure at the injection point exceeds the facility's supply pressure. This may cause injection plants to trip, threatening supply availability.
- Facility operators may not meet their injection schedules resulting in deviations.
- The market price can decrease later in the gas day.

Figure 8 shows the difference between market participants' aggregated forecast system demand and actual system demand during winter 2018. A negative MP forecast error is an under-forecast, and a positive MP forecast error is an over-forecast.

[18] AEMO, *Wholesale Market Gas Scheduling Procedures (Victoria)*, 4 May 2016, available at http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures.

Figure 8 Difference between market participants' system demand forecast and actual system demand, winter 2018

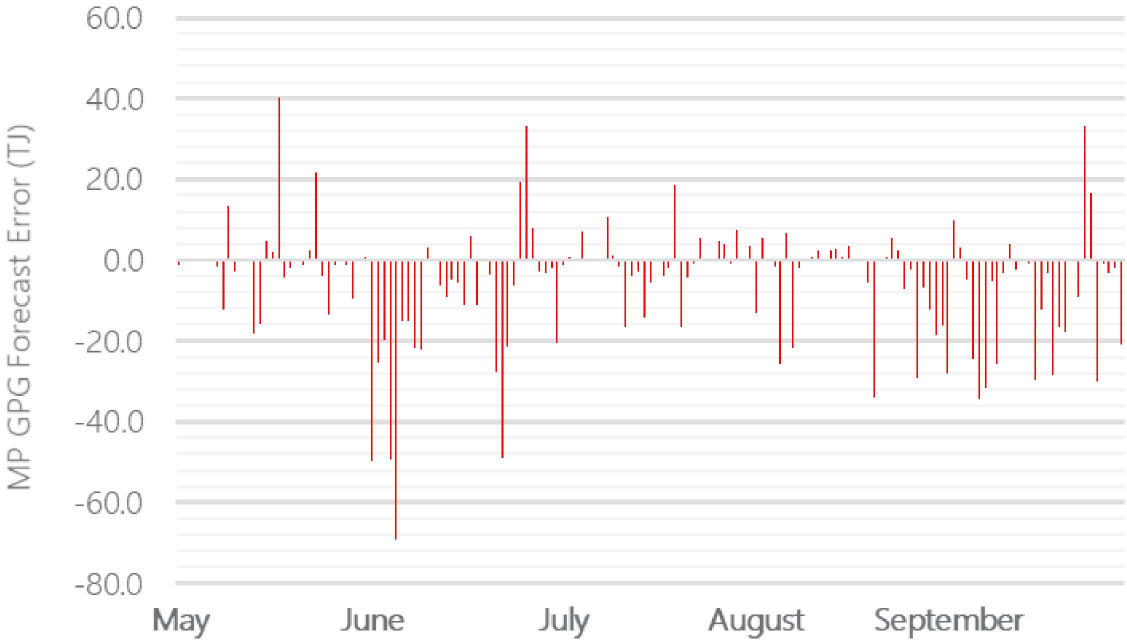


Actual demand compared to participants demand forecast at the 6am schedule interval.

This suggests that market participants tended to under-forecast system demand during winter 2018, particularly around the beginning of the winter period.

Participants also tended to under-forecast GPG demand at the 6am schedule as shown in Figure 8 below, noting that GPG demand forecasts were generally updated in later schedules to more accurately reflect NEM dispatch and the actual GPG demand.

Figure 9 Difference between market participants' GPG demand forecast and actual GPG demand, winter 2018



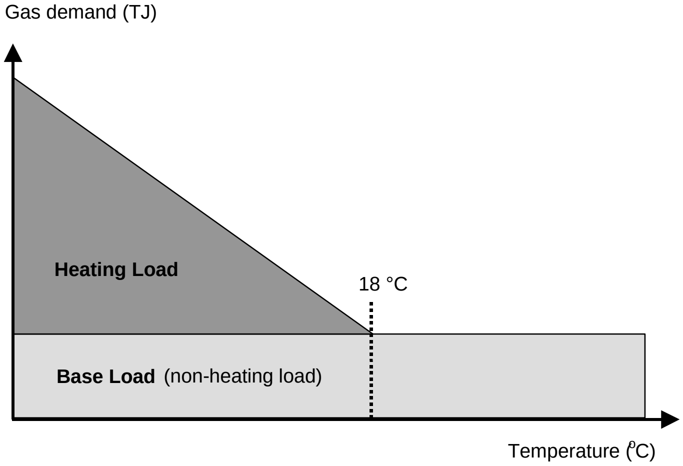
Actual GPG demand compared to participants GPG demand forecast at the 6am schedule interval

Demand forecasts

Market participants forecast both system and site-specific demands, which are aggregated to produce a total demand forecast quantity.

System demand includes base load and heating load. Base load typically does not change throughout the year, but heating load is dependent on temperature. In winter, there is greater demand variance due to heating load and its relationship to temperature changes (see Figure 10).

Figure 10 Gas demand and temperature relationship



Site-specific demand includes GPG and large industrial sites[19].

Heating load can be seen as an increasing proportion of system demand when the temperature reduces below 18° Celsius.

Forecast uncertainties

The accuracy of demand forecasts in winter can be impacted by weather variables such as temperature, wind, sunshine, the previous day's actual temperature, weather forecast error, and changes in GPG demand.

There are market mechanisms to ensure the supply and demand balance is met throughout the gas day:

- Intraday scheduling process to take into account the current DTS pressures, actual supply and demand for past hours in the day, and updated market participants' aggregated total demand forecast.
- AEMO may override market participants' aggregated total demand forecast for future hours of the gas day, in accordance with the *Victorian Wholesale Gas Demand Override Methodology*[20].

Intraday schedules

System demand varies and deviates more from forecast during winter compared to summer. This can be due to unforecast weather changes, resulting in inaccurate demand forecasts. Schedule deviations may also occur any time of the year due to unplanned facility outages, unplanned DTS asset maintenance, or unforecast changes in site-specific demands.

These variations result in intraday schedule deviations and can cause the DTS to experience higher than expected linepack variations. To maintain system security, the Market Clearing Engine (MCE) takes into account current system pressures, updated demand forecasts, and facility injections at each intraday

[19] An industrial site forecast may be required if variations in the site's demand could have a material impact on the operation of the DTS.

[20] AEMO, *Victorian Wholesale Gas Demand Forecast Methodology*, available at http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures.

schedule. The MCE then adjusts the supply and demand balance to ensure the end-of-day linepack target can be met so that sufficient gas is available for the next gas day.

These rebalancing actions are required to account for under-forecasting and over-forecasting in previous horizons, and can affect the market outcome as follows:

- When demand has been over-forecast in previous scheduling intervals, injections are reduced and/or withdrawals are increased for the following scheduling interval, usually resulting in a lower market price.
- If demand has been under-forecast in previous scheduling intervals, injections are increased and/or withdrawals are reduced for the following scheduling interval, potentially increasing the market price.

Improved accuracy of market participants' intraday demand forecasts (for each four hour scheduling interval) can reduce the likelihood of system congestion and market price volatility.

Demand forecast override

If the market participants' demand forecasts are too low (or too high) relative to AEMO's demand forecast, an override quantity may be added to (or subtracted from) the market participants' aggregate demand forecast. This ensures that an appropriate amount of gas is scheduled to maintain a safe level of linepack reserve, and to maintain system security.

The override quantity is calculated based on the *Victorian Wholesale Gas Demand Override Methodology*. It considers variables such as:

- Beginning-of-day linepack level (high, on target or low).
- Profile type (light, average or heavy).
- Demand override adjustment factors.

These variables are then used to calculate upper or lower threshold limits for each scheduling interval. The difference between AEMO's and the market participants' total demand forecasts is compared to this calculated threshold limit. If necessary, an adjustment is then made to the market participants' aggregate demand forecast so it is within the upper or lower threshold limit.

2.4 Gas market interaction

AEMO anticipates that Victorian gas production will continue to supply other markets during winter 2019. This results in market interactions between the DWGM and the STTMs, as well as the NEM. These interactions are not expected to result in a threat to system security if there are no large changes into DTS flows during the gas day.

2.4.1 Short Term Trading Market

Victoria supplies gas to the following STTMs:

- Adelaide hub via the SEA Gas Pipeline. The SEA Gas Pipeline and Moomba to Adelaide Pipeline (MAP) are interconnected, which means flows on SEA Gas can support some demand on the MAP.
- Sydney hub via the EGP and the VNI (which connects to the MSP). The EGP is also interconnected with the MSP at Wilton.

Contingency gas

The contingency gas mechanism will continue to apply for 2019 with no changes from previous years.

As well as facilitating STTM conferences during Contingency Gas events, AEMO participates in the conferences for the Sydney hub as the DTS pipeline operator, providing information on DWGM scheduling outcomes and the availability of gas to support export flows from the DTS via the VNI.

2.4.2 Gas Supply Hub

The Wallumbilla Gas Supply Hub is being used as a market to source additional gas supplies for the interconnected eastern Australian gas markets. In winter 2018 there was evidence that participants:

- Purchased gas at the Wallumbilla Gas Supply Hub
- Transported gas to Victoria via the MSP through Culcairn and the VNI.
- Transported gas to Sydney via the MSP, which allowed more Longford gas to be used to supply Victorian demand.
- Transported gas to Adelaide via the MAP, which allowed more Port Campbell gas to be used to supply Victorian demand.

Winter 2019 is likely to see gas supplied from the Wallumbilla Gas Supply Hub, supported by an effective increase in the SWQP capacity following the commissioning of the NGP. This would offset supply of Victorian gas into the Adelaide and Sydney STTM hubs. VNI import flows via Culcairn of up to 150 TJ/d could also occur.

These flows will largely depend on the portfolio position of participants and therefore cannot be forecast with certainty.

3. Peak day management

AEMO aims to operate the DTS in a normal operating state, as defined in the *Wholesale Market System Security Procedures*[21]. A normal operating state includes maintaining system pressures and flows within defined operating limits.

3.1 Injection profiling

On peak demand days, conserving or increasing system-usable linepack before the evening peak is an effective way to reduce the likelihood of a threat to system security. When a peak demand day is forecast, AEMO can improve system security margins by scheduling more Longford gas injections into the DTS early in the gas day and balancing this with less gas later in the day (referred to as injection profiling).

The total quantity injected for the day is the same, so the market is not impacted by this process[22]. This plan may be used when the total Day+1 demand forecast exceeds 1,150 TJ. AEMO consults Longford and VicHub facility operators before scheduling profiled injections[23].

Accurate forecasting of GPG demand for the Day+1 and the Day+2 schedules assists AEMO in determining whether or not to initiate injection profiling. There were no days during winter 2018 when demand was greater than 1,150 TJ/d, hence injection profiling was not utilised.

[21] AEMO. *Wholesale Market System Security Procedures*, available at https://www.aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-System-Security-Procedures-NGR-11.pdf.

[22] Profiling injections does not impact either imbalance or deviation payments.

[23] Injection profiling is available at the Longford injection point.

3.2 Threat to system security

AEMO must monitor operational conditions to identify any material schedule deviation or forecast that may cause a threat to system security. This includes:

- Rapidly increasing demand due to deteriorating weather conditions.
- Unforecast increases in GPG demand.
- Unscheduled DTS asset outage.
- A transmission pipeline incident and/or a gas supply incident.

If AEMO identifies a threat to system security, the following actions will be taken as described in full in the *Wholesale Market System Security Procedure*[15]:

- Notify market participants of the threat. AEMO may also request for a market response to the threat to system security.
- Take appropriate action to resolve the threat to system security which includes, but is not limited to, publishing an ad hoc schedule, injecting out of merit order gas at the next operating schedule, directing participants to inject or withdraw gas, and curtailment.
- Notify market participants that the threat to system security has ended.

4. Supporting gas-powered generation

There are five GPG power stations directly connected to the DTS, as shown (with triangles) in Figure 11:

- Jeeralang.
- Laverton North.
- Newport.
- Somerton.
- Valley Power.

Each of these GPG units has an impact on the operation of the DTS, due to their location and the large quantity of gas (up to approximately 23 TJ/h) the simultaneous operation of all DTS units can withdraw.

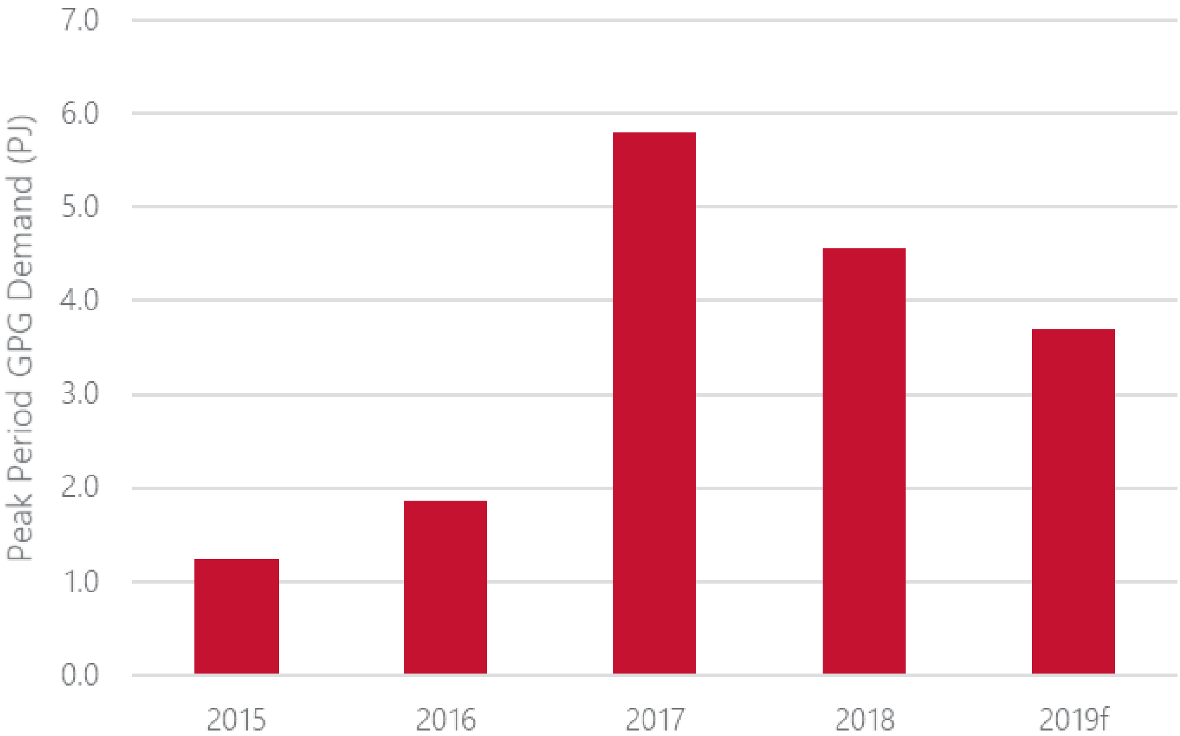
The Mortlake Power Station is not connected to the DTS. It is supplied directly by gas facilities at Port Campbell via a dedicated pipeline.

Figure 11 Map of DTS-connected GPG sites

4.1 GPG demand

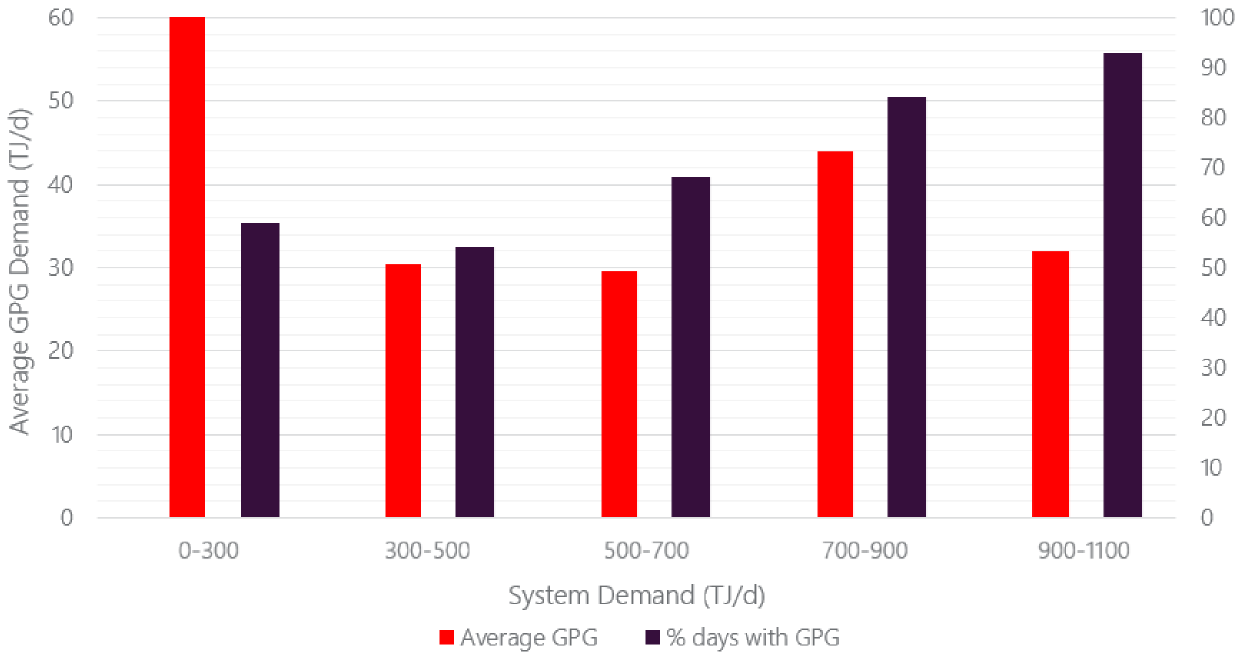
As presented in Section 2.2 of the 2019 VGPR, the 2019 forecast peak demand period (May to September) GPG consumption is 3.7 PJ (7.3 PJ annual) which is less than the 4.6 PJ (9.6 PJ annual) in 2018 due to the increase in the amount of renewable generation that is forecast to be commissioned prior to winter 2019.

Figure 12 Peak demand period GPG demand trend



Both the average GPG consumption and percentage of days with GPG consumption increased as DTS system demand increased during winter 2018 (see Figure 13). Since the March 2017 closure of the Hazelwood Power Station, there has been an increased reliance on GPG to support electricity demand. As electric heating load increases with decreasing temperature, the trend of increasing GPG demand with increasing system demand is expected to continue during winter 2019.

Figure 13 Average GPG demand for various demand ranges in 2018



High levels of wind contribute to increased system demand (that is, wind increases the EDD[24]), but this would also be expected to support wind generation. One of the highest GPG demand days (130 TJ) during winter 2018 was 3 September 2018, which was a cold day with low wind.

4.2 Peak day GPG demand

Forecasting analysis completed for the 2019 VGPR modelled two different peak day GPG demand scenarios shown below. These models take into account system dynamics.

1. Peak GPG demand in winter

This scenario modelled a peak winter GPG demand of 178 TJ on a system demand day of 1,180 TJ with two different generator demand profiles to represent two system demand days with the same level of GPG demand. The modelling scenario projected that:

- The system can support the GPG profiles without LNG injections by maximising supply from the Longford CPP and Iona CPP.

Culcairn withdrawals were not included in the model, however some withdrawals could be supported without Dandenong LNG as Dandenong City Gate was above the required minimum inlet pressure.

2. Event-driven severe GPG demand in winter

This scenario modelled a severe event occurring on a 1-in-2 peak system demand day of 1,180 TJ. The event creates a peak GPG demand day of 182 TJ/d followed by an exceptionally high GPG demand day of 265 TJ/d. There is significantly less usable linepack in this event-driven GPG demand scenario. Modelling for this case study projected that:

[24] Effective Degree Day (EDD) is a measure of coldness that includes temperature, sunshine hours, chill, and seasonality. The higher the number, the more energy will be used for area heating purposes.

- While the system can support GPG demand of 265 TJ/d, Dandenong City Gate inlet reaches its minimum operational pressure, even with the GPG demand being forecast, due to the higher hourly demand values.
- If GPG or system demand increases, or if any of the demand is unforecast, peak shaving Dandenong LNG injections would be required to support critical system pressures.

Culcairn withdrawals were not included in the model, and could not be supported without firm rate Dandenong LNG injections.

4.3 Unforecast GPG demand

The ability of the DTS to support GPG load is significantly reduced if the load is not forecast, because the DTS does not have sufficient usable linepack. Depending on the location and magnitude of the GPG load that is unforecast, it is possible that either:

- Extra operational response LNG injections, and potentially non-firm LNG, would be required.
- Minimum supply pressures in metropolitan Melbourne could be breached, threatening supply within the distribution networks. This would lead to AEMO issuing curtailment instructions to GPG sites according to the *Gas Load Curtailment and Rationing and Recovery Guidelines*[25].

It is critical to the normal operation of the DTS and the DWGM that participants accurately forecast GPG demand. If not, there is an increased likelihood of a threat to system security and AEMO using abnormal market processes such as operational response LNG, ad hoc schedules, or the issuing of directions to balance gas supply and demand.

4.4 Managing GPG demand

4.4.1 Longford to Melbourne Pipeline

The Valley Power, Jeeralang, Somerton, and Newport power stations all consume gas directly from the LMP. The Laverton North Power Station also consumes linepack from the LMP, if there are not sufficient injections into the SWP at Port Campbell, but Brooklyn compression must be operated to support its load. Compression is not required if there is sufficient SWP injections, which can also support the operation of the Newport Power Station on peak days.

Given the challenges and uncertainty around accurately forecasting GPG demand, AEMO aims to maintain sufficient usable linepack in the LMP to support unforecast GPG demand. Operational strategies to support forecast or unforecast GPG are the same as those employed to maintain DCG minimum inlet pressures, as set out in Section 2.1.1.

4.4.2 South West Pipeline

On lower demand days when Iona UGS withdrawals from the SWP may be scheduled, the net withdrawal capacity is reduced when the Laverton North and Newport power stations are online, due to their location and the high hourly gas demand of these GPG units.

When injections into the SWP allows, AEMO aims to maintain sufficient usable linepack in the Brooklyn to Lara Pipeline when the Laverton North and Newport power stations are anticipated to come online. The Winchelsea compressor can also be used to support high GPG demand during the morning and evening peaks.

4.4.3 Monitoring DTS-connected GPG

Gas consumption by DTS-connected GPG units is monitored in real time through the AEMO Gas System Control and Data Acquisition (SCADA) system. GPG forecasts are obtained from site-specific forecasts

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[25] AEMO, *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*, available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

submitted by market participants as well via the NEM Pre-Dispatch. AEMO monitors these forecasts to ensure they are consistent and that any known increase in GPG forecast can be supported by the DTS.

The NEM operates on five-minute dispatch intervals, whilst the DWGM operates using schedules at 06:00, 10:00, 14:00, 18:00, and 22:00 for the current gas day. It is therefore possible for a generator's dispatch instructions to change within a DWGM scheduling interval, with additional gas not scheduled for up to four hours (unless AEMO intervenes in the DWGM by publishing an ad hoc schedule).

Monitoring

AEMO maintains awareness of intended GPG operation by:

- Monitoring of NEM Pre-Dispatch and current GPG demand through its Gas SCADA.
- Modelling pipeline pressures to determine whether sufficient gas is available to maintain DTS pressures.
- Having the AEMO NEM Control Room inform the AEMO Gas Control Room of likely unforecast increases in GPG demand. The Gas Control Room will also notify the NEM Control Room of any issues within the gas system that may lead to DTS-connected GPG units having insufficient gas supply.
- Contacting participants to clarify the intended operation of their GPG units.

Response

AEMO may implement the following operational responses to manage unforecast GPG demand:

- Update the total demand forecast in accordance with the demand override methodology to account for the forecast increase in GPG demand. Total demand includes system demand and GPG demand.
- Issue a notice of a threat to system security if modelling indicates that an unforecast increase in GPG demand will cause a threat to system security. AEMO's range of responses to a threat to system security includes publishing an ad hoc schedule, which is a market intervention (detailed in Section 3.2).
- Issue a direction to facility operators to inject additional gas into the DTS including non-firm gas, or issue DTS-connected GPG units with a *Direction to Curtail Load*.

The four largest DTS-connected GPG power station are able to switch to liquid fuel in the event of insufficient gas supply. If AEMO needs to curtail gas supply to these units, they would have the option of continuing to operate using liquid fuel.

The AEMO Gas Control Room will consult with the NEM Control Room prior to curtailing DTS-connected GPG units. The NEM Control Room may direct GPG units with alternative fuel supply to generate to maintain power system security.

4.4.4 Monitoring non-DTS connected GPG

AEMO does not have real-time monitoring of non-DTS gas pipeline flows and linepack conditions (that is, the AEMO Gas SCADA only monitors and controls the DTS). AEMO monitors non-DTS connected GPG demand via the NEM Pre-Dispatch and non-DTS pipeline flows via the Natural Gas Services Bulletin Board.

By monitoring these flows along with the DWGM bid stacks, AEMO has some indication of whether DTS injections or withdrawals are more or less likely to occur. Examples include:

- Exports from Victoria via Culcairn to support Uranquinty Power Station operation.
- Imports into Victoria via Culcairn being impacted by the operation of the Uranquinty Power Station.
- Supply into the SWP at Port Campbell when the Mortlake Power Station is or is not operating, as well as SEA Gas Pipeline flows and South Australian GPG demand.
- VicHub and TasHub supply into the LMP when the Tallawarra (as well as Bairnsdale) and Tamar Valley power stations (respectively) are operating.

Monitoring demand at these GPG units enables AEMO to anticipate gas flows into and out of the DTS.

4.4.5 Gas Supply Guarantee

The Gas Supply Guarantee[26] was instituted in response to commitments by production facility operators and pipeline operators to the Commonwealth Government to make gas available for GPG during peak demand periods in the NEM.

The Gas Supply Guarantee mechanism is a process to identify, assess, and confirm a potential supply shortfall. AEMO will then communicate with industry and call for a response to the shortfall. The Gas Supply Guarantee process will be available for use if required during winter 2019.

5. Communications

AEMO has procedures in place to ensure consistent communications with market participants regarding events that may affect operational and scheduling decisions.

5.1 Market Information Bulletin Board

The Market Information Bulletin Board (MIBB), in accordance with the *Wholesale Market Electronic Communication Procedure*[27], is the primary source of all information about the DWGM including all System Wide Notices (SWNs) and reports.

5.2 System Wide Notices

AEMO provides SWNs to communicate operational issues to the market. SWNs are posted on the MIBB and also sent via SMS and/or email to each participants' registered contacts.

Common events that AEMO will communicate to the market include, but are not limited to:

- Gas Quality SWN – notification of gas quality excursions.
  - The market is notified within 30 minutes after a gas quality parameter excursion initially occurs.
- Scheduling SWN – application of constraints that reflect the physical limitations of facilities or pipelines (such as for maintenance or a pipeline that is constrained).
  - Facility constraint – The market is notified shortly after a capacity constraint application is received by AEMO, allowing participants to make adjustments to bids as required.
  - DTS constraint – The market is notified that a transmission system capacity constraint has been reached, and that AEMO will be applying a constraint based on the transportation limits published in the most recent VGPR.
- Scheduling SWN – changes to system conditions, such as the end-of-day linepack target.
  - The market is usually notified three days before the gas day on which a change in linepack target will occur, unless a shorter notice period is required for operational reasons.
- Scheduling SWN – facility nomination confirmation.

[26] More information available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/Gas-Supply-Guarantee.

[27] AEMO, *Wholesale Market Electronic Communication Procedure*, available at: https://www.aemo.com.au/-/media/Files/PDF/10910070pdf.pdf.

- The market is notified when AEMO has a facility confirmation that is materially different to AEMO's scheduled quantity. AEMO contacts participants to determine whether their nominations are the same as the scheduled quantity to reduce the threat to system security.

AEMO will also communicate the following information via a Scheduling SWN when an abnormal market state exists:

- Longford pipeline pressure issue.
- Large increase of Effective Degree Day (EDD).
- Low linepack reserve.
- Threat to system security.
- Ad hoc schedules.

Participants should review their INT134 Company Contact Detail report to ensure their contacts for Scheduling and Gas Quality SWNs are up to date.

5.3 Natural Gas Services Bulletin Board

AEMO publishes data to the Natural Gas Services Bulletin Board[28] at each scheduling interval including:

- Scheduled flows for each scheduling interval.
- Linepack capacity adequacy for each pipeline (status is indicated by green, amber or red flags).
- Capacity information for production facilities and pipelines.

Participants may find it useful to monitor this information, because AEMO will change the linepack flag in the event of low linepack or a threat to system security.

5.4 Email reports

AEMO provides participants with a variety of reports via email. A participant can ask to be added to the 'SupplyDemand' email distribution list by contacting AEMO's Support Hub[29].

5.4.1 Peak Day

On peak demand days, additional communications are sent to the market. One important notification is the intraday supply and demand shortfall likelihood chart, as shown in Figure 14.

Communication is triggered when the total demand forecast exceeds 1,150 TJ/d. AEMO will send an email notification at the 06:00, 10:00, 14:00, and 18:00 scheduling intervals. This communication indicates the likelihood of an intraday demand/supply linepack shortfall at each scheduling interval.

[28] More information on the Natural Gas Services Bulletin Board (http://www.gasbb.com.au/) can be found in the Natural Gas Bulletin Board Procedures, available at http://www.gasbb.com.au/Bulletin%20Board%20Information/Procedures%20and%20Guides.aspx.

[29] Email Support.Hub@aemo.com.au or phone 02 8884 5335 to contact the AEMO Support Hub.

Figure 14 Weather and AEMO gas demand forecast – example

Current Gas Day Weather and AEMO Gas Demand Forecast

Gas Day: Wednesday 13/07/2016

Weather Forecast				Total Demand Forecast (System + GPG)
Maximum	Minimum	Sunshine Hr	EDD	
10.0	7.0	3	13.2	1196.3 TJ

Intra Day Demand / Supply Linepack Shortfall Likelihood Chart

Last Update: 13/07/2016 01:31PM

5.4.2 Daily reports

Every day AEMO emails the participants subscribed to the 'SupplyDemand' distribution list the:

- AEMO Gas Demand Forecast Report – emailed after 16:00 with a summary of system constraints. Provides an overview of the gas flows expected in the Current Day, Day+1 schedule, and Day+2 schedule, and an indication of current gas day linepack condition.
- Operational Data Report – emailed before 08:00. Summarises the previous gas day's schedule outcomes, actual flows recorded by the AEMO Gas SCADA, and price/flow information for the first schedule of the current gas day.

5.5 Industry conferences

If there is an abnormal event that is not an emergency, but it may impact the operation of the DTS and/or DWGM outcomes, AEMO may (if time permits) hold an industry conference to inform participants of the issue or event. This may include information about the issue, what operational or market responses AEMO may implement, and the outcomes that could be expected.

If the event is an emergency, emergency communication processes will be implemented.

6. Emergency management

6.1 Legislation and rules

The *National Gas (Victoria) Act 2008* is the legislation for the application of the National Gas Law (NGL) and rules in Victoria. The NGL defines an emergency as it applies in Victoria. It specifies what is required to prepare for gas emergencies, the requirements for the Gas Emergency Protocol, and that participants must comply with the Gas Emergency Protocol.

6.2 Emergencies

Emergencies are defined under the Section 333 of the National Gas Rules (NGR) as follows:

> *(1) An emergency occurs when:*
>
> *(a) AEMO reasonably believes there to be a situation which may threaten:*
>
> *(i) reliability of gas supply; or*
>
> *(ii) system security or the security of a declared distribution system; or*
>
> *(iii) public safety,*
>
> *and AEMO in its absolute discretion considers that the situation is an emergency and declares there to be an emergency; or*
>
> *(b) AEMO declares there to be an emergency at the direction of a government authority authorised to give such directions.*

AEMO will declare an emergency if it reasonably believes that an operational response cannot address the issue. It will implement the declaration by issuing an Emergency Declaration Notice to the Emergency Manager, Duty Manager, or General Manager of each participant.

AEMO is also responsible for maintaining the Gas Emergency Protocol[30]. This protocol consists of the:

- *Gas Load Curtailment and Gas Rationing and Recovery Guidelines* – define classes of gas customers within prioritised curtailment tables, from which curtailment lists are derived. These guidelines are based on system security criteria and can be modified by government direction.
- *Wholesale Market System Security Procedures* – set the thresholds for operation of the DTS, so threats to system security are averted or minimised.
- *Emergency Procedures (Gas)* – guide the management, preparation, response and recovery for gas emergencies in Victoria. The procedures are underpinned by the principles of maintaining gas supply reliability, maintaining DTS system security, and minimising risks to public safety.

The NGR outlines four key requirements for participants. Each participant must:

- Notify AEMO as soon as practicable of any emergency or situation that may threaten system security.
- Use best endeavours to ensure that its safety plan (if any) permits it to comply with emergency directions.
- Provide AEMO with emergency contacts (including an email address, telephone and fax number, name, and title) of an appropriate representative who has the authority and responsibility to act in the event of an emergency.
- Ensure all relevant officers, staff, and customers are familiar with the emergency protocol and the participant's safety plan or procedures.

AEMO's powers during an emergency

AEMO may use section 91BC of the NGL to issue directions for managing:

- The operation or use of any equipment or installation.
- The control of natural gas flow.
- Any other matter that may affect the safety, security, or reliability of the declared transmission or declared distribution systems.

[30] Gas Emergency Protocol documents can be found at http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

While AEMO's powers under NGL 91BC can be used without declaring an emergency or issuing a notice of a threat to system security, it is unlikely AEMO would invoke these powers without initiating one or both of these mechanisms.

Energy Safe Victoria power to issue directions

During a gas emergency, the Director of Energy Safe Victoria (ESV) may also issue a direction that ESV believes is needed to avoid a situation occurring that is likely to impact public safety. The intent is to regulate the available gas supply (having regard to community needs), and facilitate the reliability of gas supply or the security of systems for transmitting or distributing gas.

The Governor and the Minister for Energy

The Governor may also declare a proclamation under Part 9 of the *Gas Industry Act*, if it appears that the available supply of gas is (or is likely to become) insufficient for the community's essential needs. The proclamation remains in effect until the Governor revokes it. While the proclamation is in force, the Minister for Energy may give any direction necessary to ensure the safe and secure supply of gas.

6.3 Threats to system security

A threat to system security[31] can be indicated by any one of the following:

- The annual planning reviews prepared by AEMO.
- An operating schedule.
- Any other fact or circumstance that AEMO becomes aware of.

A threat to system security may impact the DTS partially or as a whole. AEMO has the power to issue a notice of a threat to system security if it reasonably believes some level of operational response can address the issue, otherwise an "emergency" will be declared.

Market response and Intervention

AEMO may take the following measures to manage a threat to system security (under s.91BC of the NGL):

- Directing the injection of LNG.
- Increasing withdrawals.
- Using reasonable endeavours to inject gas which is available, including non-firm gas.
- Injecting off-specification gas.
- Curtailment[32] (in accordance with curtailment tables).
- Doing anything AEMO believes necessary in the circumstances.

6.4 Emergency communications

Participants must have registered with AEMO at least one emergency contact, that is, a person having appropriate authority and responsibility within their organisation to act as the primary contact for AEMO in the event of an emergency.

Participants must provide AEMO with a telephone number and facsimile number at which a representative(s) is contactable by AEMO, 24 hours a day, seven days a week. This person will be contacted in the event of an emergency under the *Emergency Procedures Gas* and the *Victorian Energy Emergency Communications Protocol*.

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[31] A threat to system security is defined in rule 341 of the NGR.

[32] In the event of a threat to system security attributable to a transmission constraint, AEMO will curtail customers in accordance with sections 3 and 4 of the *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*, available at http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

Measures and abbreviations

Units of measure

Abbreviation	Unit of measure
$	Australian dollars
EDD	Effective degree days
kPa	Kilopascals
PJ	Petajoule (1 PJ = 1,000 TJ)
TJ	Terajoule (1 TJ = 1,000 GJ)
TJ/d	Terajoules per day
TJ/h	Terajoules per hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
CS	Compressor Station
DCG	Dandenong City Gate
DFPC	Directional Flow Point Constraint
DTS	Declared Transmission System
EDD	Effective Degree Day
EGP	Eastern Gas Pipeline
EMF	Emergency Management Framework
ESV	Energy Safe Victoria
GBB	Natural Gas Services Bulletin Board
GPG	Gas-powered generation
ICT	Incident Coordination Team
IMP	Incident Management Plan
MIBB	Market Information Bulletin Board
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas

Abbreviation	Expanded name
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
NFTC	Net Flow Transportation Constraint
OS	Operating Schedule
PS	Pricing Schedule
SDPC	Supply and Demand Point Constraint
SSC	Supply Source Constraint
STTM	Short Term Trading Market
SWN	System-wide notice
SWP	South West Pipeline
TGP	Tasmanian Gas Pipeline
UGS	Underground Gas Storage
VNI	Victorian Northern Interconnect
WTS	Western Transmission System

Glossary

Term	Definition
1-in-2 system demand day	The 1-in-2 system demand day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 system demand day	The 1-in-20 system demand day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Authorised Maximum Daily Quantity	Authorised Maximum Daily Quantity (Authorised MDQ) and Authorised MDQ Credit Certificate are transportation rights in the DTS, collectively known as AMDQ. Authorised MDQ is a withdrawal right for customers and/or market participants on the DTS for transported gas injected at Longford. Subsequent capacity increases to the DTS such as South West Pipeline, the Western Transmission System and the Bass Gas project have been allocated as AMDQ Credit Certificates. AMDQ is an input to: • Determining congestion uplift charges payable by a market participant for each scheduling interval of a gas day as part of the funding of ancillary payments. • Tie-breaking rights when scheduling equal priced injections or withdrawals bids, and in determining the order of curtailment in the event of an emergency.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS) and injected at Pakenham.
Capacity	Pipeline transportation capacity.
Culcairn	The gas transmission system interconnection point between Victoria and New South Wales.
constraint	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
Declared Transmission System	The declared gas transmission system in Victoria, in accordance with the National Gas Law. Owned by APA VTS 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.
distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.
distribution system	Pipelines for the conveyance of gas with one or other of the following characteristics: A maximum allowable operating pressure of 515 kPa or less. Uniquely identified as a distribution pipeline in a distributor's access arrangement, where the maximum operating pressure is greater than 515 kPa.
distributor	The service provider of the distribution pipelines that transport gas from transmission pipelines to customers.

Term	Definition
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
Facility operator	Producers, Storage Providers, and interconnected transmission pipeline service providers in the DTS.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
injection	The physical injection of gas into the transmission system.
Victorian Northern Interconnect	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
Lateral pipeline	A pipeline branch off a larger pipeline.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline system throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne liquefied natural gas (LNG) storage facility is located at Dandenong.
maintenance	Work carried out by service providers, Producers and Storage Providers that, in AEMO's opinion, may affect any of: • AEMO's ability to supply gas through the declared transmission system. • AEMO's ability to operate the declared transmission system. • DTS capacity. • System security. • The efficient operation of the DTS generally. It includes work carried out on pipeline equipment, but does not include maintenance required to avert or reduce the impact of an emergency.
market participant (participant)	A party who is eligible to participate in an energy market operated by AEMO in one or more of the following roles: • A market generator, market customer, or a market network service provider (electricity). • Storage provider. • Transmission customer. • Distribution customer. • Retailer. • Trader (gas).

Term	Definition
maximum allowable operating pressure (MAOP)	The maximum pressure at which a pipeline is licensed to operate.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand. See also Authorised Maximum Daily Quantity.
Natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
Natural Gas Services Bulletin Board (GBB)	The GBB (http://www.gasbb.com.au/) is an online gas market and system information website covering all major gas production fields, major demand centres and natural gas transmission pipeline systems of South Australia, Victoria, Tasmania, NSW, the ACT, and Queensland. It was established in 2008 and is operated by AEMO.
Operational response LNG	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
peak shaving	See operational response LNG
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours' notice.
probability of exceedance	Refers to the probability that a forecast peak demand figure will be exceeded. For example, a forecast 1-in-20 peak demand will, on average, be exceeded only one year in every 20.
scheduling	The process of scheduling bids that AEMO is required to carry out in accordance with Part 19 of the National Gas Rules for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Port Campbell.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include the following: • Load distribution across the system. • Hourly load profiles throughout the day at each delivery point. • Heating values and the specific gravity of injected gas at each injection point. • Initial linepack and final linepack and its distribution throughout the system. • Ground and ambient air temperatures. • Minimum and maximum operating pressure limits at critical points throughout the system. • Compressor station power and efficiency.
system constraint	See Declared Transmission System constraint.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large

Term	Definition
	commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas-powered generation (GPG) demand, exports, and gas withdrawn at Iona UGS.
system injection point	A gas transmission system connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas Declared Transmission System (gas DTS) connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
Tariff D	The gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Tasmanian gas pipeline	The pipeline from VicHub (Longford) to Tasmania.
transmission pipeline	A pipeline for the conveyance of gas that is licensed under the Pipelines Act and has a maximum design pressure exceeding 1,050 kPa.
transmission system	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
Underground Gas Storage (UGS)	The Iona Underground Gas Storage (UGS) facility at Port Campbell which supplies gas to Victoria to meet winter peak demand, and in summer supports South Australian GPG demand via the SEA Gas Pipeline and, as needed, Victorian demand if capacity is reduced at other facilities.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas Declared Transmission System (DTS) at Longford, facilitating gas trading at the Longford hub.
Western Transmission System (WTS)	The transmission pipelines serving the area from Port Campbell to Portland.
Winter	1 May to 30 September as per the *Wholesale Market System Security Procedure*