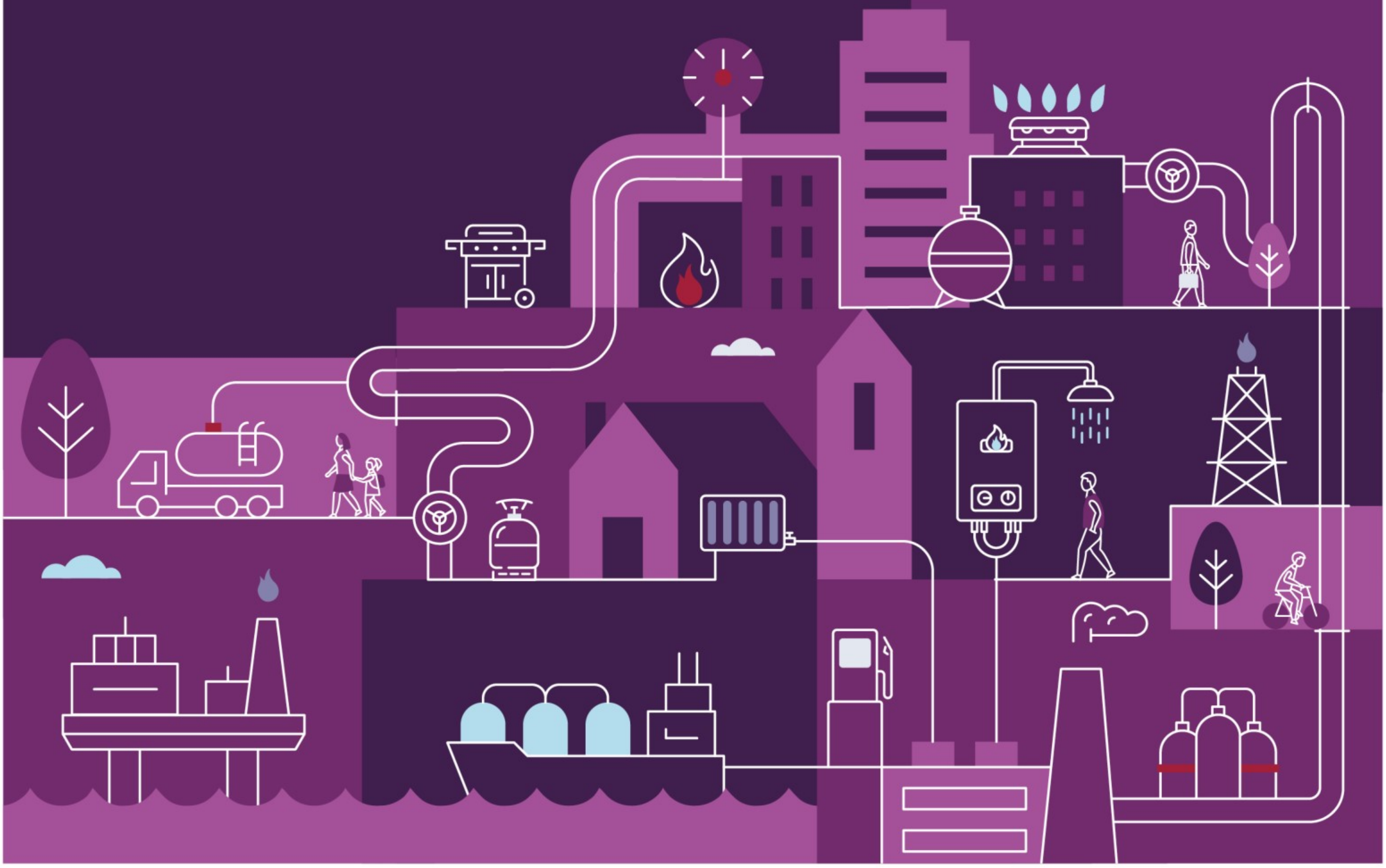
Victorian Gas Planning Report

March 2023

Gas transmission network planning for Victoria



Important notice

Purpose

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Contents

Executive summary

The 2023 *Victorian Gas Planning Report* (VGPR) provides information about the supply demand balance over the next five years (2023-27, called the outlook period) in Victoria and the Victorian Declared Transmission System (DTS). The 2023 VGPR complements AEMO's 2023 *Gas Statement of Opportunities* (GSOO)[1], which assesses wider gas supply adequacy in central and eastern Australia.

Key findings

- The Victorian production outlook has improved since the 2022 VGPR Update, however **Victorian production continues to decline, with large forecast reductions in 2024 and 2027**. Total available Victorian production is forecast to decline from the 374 petajoules (PJ) produced in 2022 to 315 PJ in 2023 (a 16% reduction) and 190 PJ in 2027 (49% lower than 2022).
- **The outlook for peak day supply capacity in winter 2023 has improved since last year's forecast**:
  - Forecast production from the Gippsland region is higher than the forecasts provided for the 2022 VGPR Update. Producers forecast that available[2] Gippsland peak day production in winter 2023 will be 915 terajoules a day (TJ/d), 191 TJ/d higher than the 724 TJ/d forecast last year. This is lower than actual 2022 peak production of 1,126 TJ/d and is forecast to reduce to 771 TJ/d prior to winter 2024.
  - The Winchelsea Compressor 2 project, which was not included in the 2022 VGPR Update, along with the Western Outer Ring Main (WORM) pipeline project, will increase South West Pipeline (SWP) capacity from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023, increasing the peak day supply available from Port Campbell including the Iona underground gas storage (UGS) facility.
  - Dandenong liquefied natural gas (LNG) storage facility inventory will be maximised prior to winter 2023, as AEMO has contracted the remainder of the facility's capacity, in accordance with the Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[1].
- **Expected peak day supply to the DTS is forecast to decline** by 8% from the 1,595 TJ/d available in 2022 to 1,471 TJ/d during winter 2023, which is sufficient to supply the forecast 1-in-20 peak day demand for the DTS. Peak day supply is forecast to decline to 980 TJ/d in 2027 (a 39% decline compared to 2022).
- The 2023 GSOO highlights the risk of peak day shortfalls in the southern states for all years in the VGPR outlook period in the event of high coincident system and gas generation demand across all states. Peak day gas shortfall risks may be lower if reliance on gas use for electricity generation during periods of peak gas demand is reduced, including by the use of liquid fuel or management of electricity demand.
- Victorian supply adequacy is projected to tighten in the later years of the outlook period and **an annual supply and peak day shortfall is forecast in 2027**. This supply adequacy assessment includes a forecast 9.1% reduction in Victorian gas consumption during the outlook period. A tight supply demand balance can cause high gas prices including the triggering of administered market price caps.
- **The forecast shortfall for Victoria in 2027 cannot be supplied by other jurisdictions because there is a projected shortfall of gas across all of Australia's southern states in 2027**, as reported in AEMO's

[1] At https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[2] Expected supply to the DTS is less due to demand on the EGP and in Tasmania as they have no other source of supply. This reduces the Gippsland DTS supply to 854 TJ/d for winter 2023.

2023 GSOO. Unless new Victorian supply is developed, Victoria is forecast to become a net importer of gas from winter 2027, as Victorian annual consumption exceeds Victorian production.

- Forecast high flows out of Victoria, combined with declining Victorian production, **increase southern states' reliance on Victorian gas storage**, both Iona UGS (deep storage) and Dandenong LNG (shallow storage). Southern states' reliance on Victorian storage is offset by the Newcastle Gas Storage Facility (shallow LNG storage) in New South Wales if it continues to be available.
- **The 2023 VGPR contains few committed and anticipated supply projects**, and many of these projects do not have firm timelines, making the analysis of system adequacy difficult. All projects currently underway or proposed in the outlook period face a range of challenges to maintain schedules and reach completion; for example:
  - The Port Kembla Energy Terminal (PKET) project was considered an anticipated project in the 2022 VGPR Update and 2022 GSOO, with supply forecast to become available from 2024. Squadron Energy has advised AEMO there is currently insufficient contracted capacity for the PKET to justify the import and use of the floating storage regasification unit (FSRU). Early 2026 has been advised as a possible date for services to commence. Given the forecast date from which gas will become available remains dependent on capacity being contracted, there is not enough certainty to include PKET or other proposed LNG receiving terminals as anticipated projects in the VGPR supply adequacy assessment.
  - The Golden Beach Gas Project has been further delayed until 2025. Due to several years of delay, the current uncertain investment environment for gas projects, rig availability and investor uncertainty, this project has not been included in the 2023 VGPR supply adequacy assessment as an anticipated project.

Gas consumption forecasts

The 2023 VGPR forecasts focus on the *Orchestrated Step Change (1.8°C)* scenario outlined in the draft 2023 *Inputs Assumptions and Scenarios Report* (IASR), as do the 2023 GSOO forecasts. *Orchestrated Step Change (1.8°C)* is the scenario most similar to the *Step Change* scenario identified in AEMO's 2022 *Integrated System Plan* (ISP) as the most likely pathway for Australia's energy sector[3]. The 2023 *Orchestrated Step Change (1.8°C)* scenario is a refinement of the *Step Change* scenario.

The *Orchestrated Step Change (1.8°C)* scenario represents a future that includes rapid overall transformational investment to decarbonise the economy, leading to a temperature rise below 2°C and targeting 1.8°C. This scenario is driven by consumer-led change, with a focus on energy efficiency, digitalisation and step increases in global emissions policy above what is already committed. Electrification is high, with industry decarbonising manufacturing and other industrial activities and consumers switching from natural gas to electricity to heat their homes. Compared to *Step Change*, electrification forecasts have been updated considering observable consumer change to date and a slower rate of fuel-switching, particularly in the residential and commercial sectors. This has resulted in an initial slower projected decline of gas consumption in the 2023 VGPR, with AEMO forecasting a reduction of 9.1% in annual gas consumption[4] and a reduction of approximately 10% in peak day gas system demand[5] (excluding gas for electricity generation) over the outlook period.

[3] The most likely scenario will be reassessed as part of the preparations for the 2024 ISP.

[4] "Consumption" refers to total gas demand used over longer periods (months and years) whereas "demand" refers to short-term gas use (hours and days).

[5] System demand includes gas use by industry, business and household consumers.

Strong policy incentives and industry investment will be required to realise the level of electrification forecast under this scenario. While in some sectors the electrification of existing loads has already begun, uncertainty remains over how quickly consumers will invest to shift their energy use away from natural gas. To identify the potential influence of slower electrification on gas adequacy risks, AEMO also studied the impact of a conceptual halt on the electrification of gas use in a sensitivity, *Orchestrated Step Change (1.8°C), No Electrification*. If no electrification is assumed, forecast consumption diverges from 2025, with the largest difference in consumption (of 9.7%) occurring in 2027.

Table 1 Victorian annual gas consumption forecast, 2023-27 (PJ/y)

	2022 (Actual)	2023	2024	2025	2026	2027	Change over outlook
System consumption	193.5	195.4	193.0	191.4	187.5	177.6	-9.1%
DTS gas generation consumption	13.8	8.4	5.9	4.5	5.8	8.3	-1.2%
DTS total consumption	207.3	203.7	198.9	195.8	193.3	185.9	-8.7%
Non-DTS system consumption	0.32	0.47	0.46	0.47	0.48	0.49	4.3%
Non-DTS gas generation consumption	6.9	10.0	6.9	5.1	6.3	8.4	-16.0%
Total Victorian consumption	214.5	214.2	206.3	201.4	200.1	194.8	-9.1%
Total Victorian consumption without electrification	-	214.4	208.1	206.0	210.4	212.9	-0.7%

PJ/y: petajoules per year.

Government policy in this area continues to develop, including the Federal Government's 10 January 2023 proposal to require Australia's largest emitters to reduce their emissions by 4.9% each year through to 2030[6]. As progress is made on emissions reductions, including the electrification of gas heating load, AEMO will refine these scenarios and update its supply adequacy assessments in future reports.

Annual supply adequacy

As **Figure 1** shows, there is forecast to be sufficient supply to meet declining annual consumption for most of the outlook period. In 2027 there is forecast to be an annual supply shortfall as forecast annual Victorian consumption exceeds available Victorian production.

The total available[7] supply from the Gippsland region is forecast to reduce 13% from the 326 PJ produced in 2022 to 284 PJ in 2023, and then to 130 PJ in 2027 (54% lower than for winter 2023). This includes production from the committed Kipper compression project with additional supply expected from 2024. The reduced supply is mainly due to the forecast reduction in production associated with the depletion of the Gippsland Basin Joint Venture (GBJV) large legacy fields that supply the Longford Gas Plant.

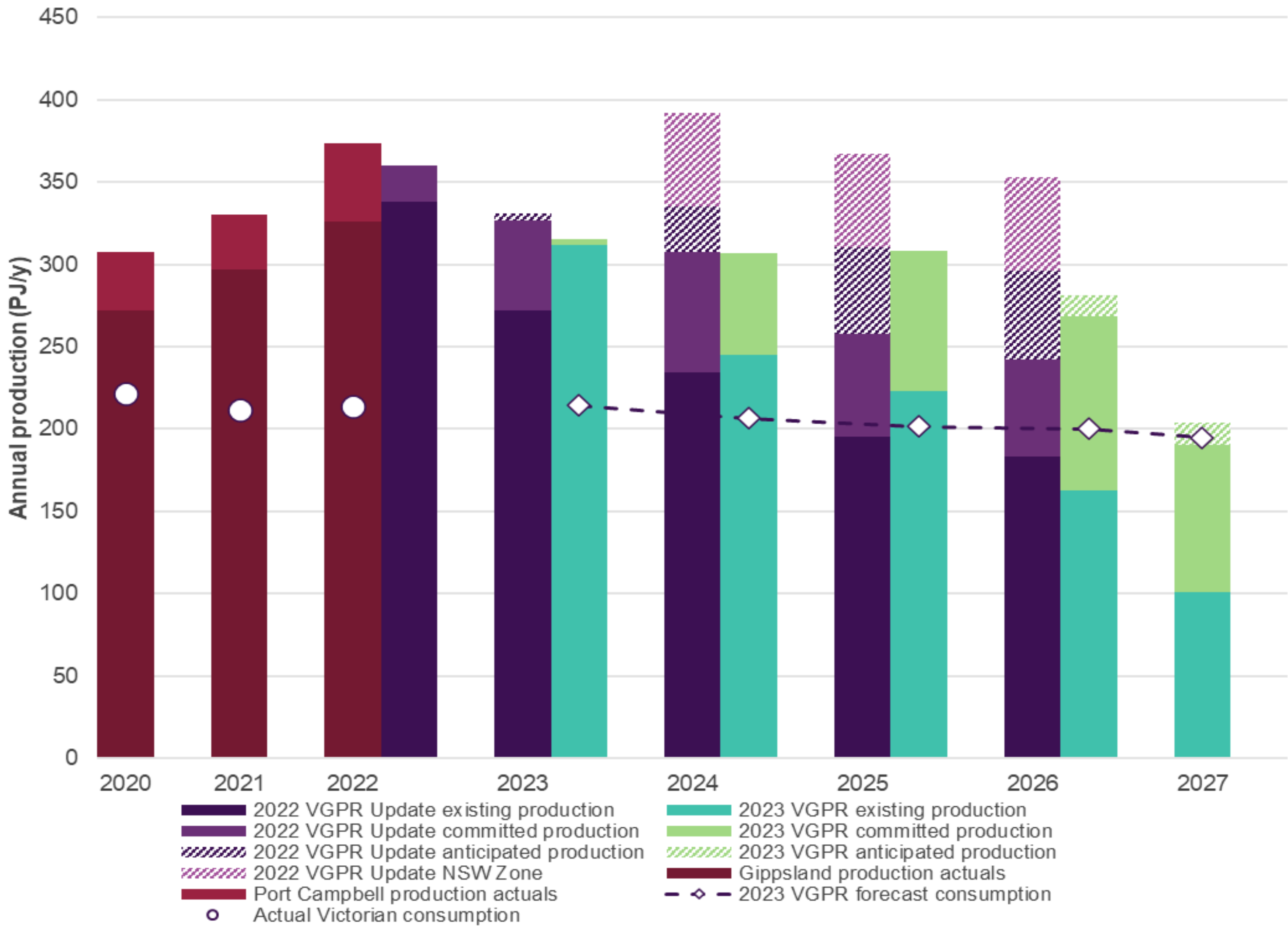
The largest reductions in available Gippsland production are forecast to occur in 2024 and 2027. This is later than the outlook in the 2022 VGPR Update, in which producers advised that the largest drop in production was forecast to occur before winter 2023. The anticipated Kipper Stage 1B infield additional well development project lessens the reduction in Gippsland production from 2026 but does not replace the capacity lost due to the depletion of GBJV's large legacy gas fields.

[6] Australian Government – Department of Climate Change, Energy, the Environment and Water, "Safeguard Mechanism Reforms – Position Paper", January 2023, at https://consult.dcceew.gov.au/safeguard-mechanism-reform-consult-on-design.

[7] Available supply comprises existing gas supplies and committed new gas supply projects.

Total available production from Port Campbell is forecast to decrease 33% from the 48 PJ produced in 2022 to 32 PJ in 2023, then increase by 128% to 73 PJ in 2024 with four new committed[8] Thylacine production wells coming online during winter 2023 and production from the Enterprise gas field from 2024, returning the Otway Gas Plant to nameplate capacity. Production from Port Campbell, which also includes the Athena Gas Plant, is projected to remain relatively stable from 2024 until 2027 when it decreases to 60 PJ.

Figure 1 Historical and forecast annual supply and consumption, and compared to the 2022 VGPR Update, 2023-27 (PJ/y)



Monthly supply adequacy

Monthly Victorian production has historically peaked during winter, as Longford Gas Plant production has been able to increase in line with the seasonal demand profile. Most other production facilities operate with a flatter production rate all year, with production limited by either the processing capacity of the facility or the supply capacity of the connected gas fields.

Figure 2 shows actual Victorian monthly production and consumption in 2022 compared to the available production forecasts for 2023 from both the 2023 VGPR and the 2022 VGPR Update. The graph illustrates how

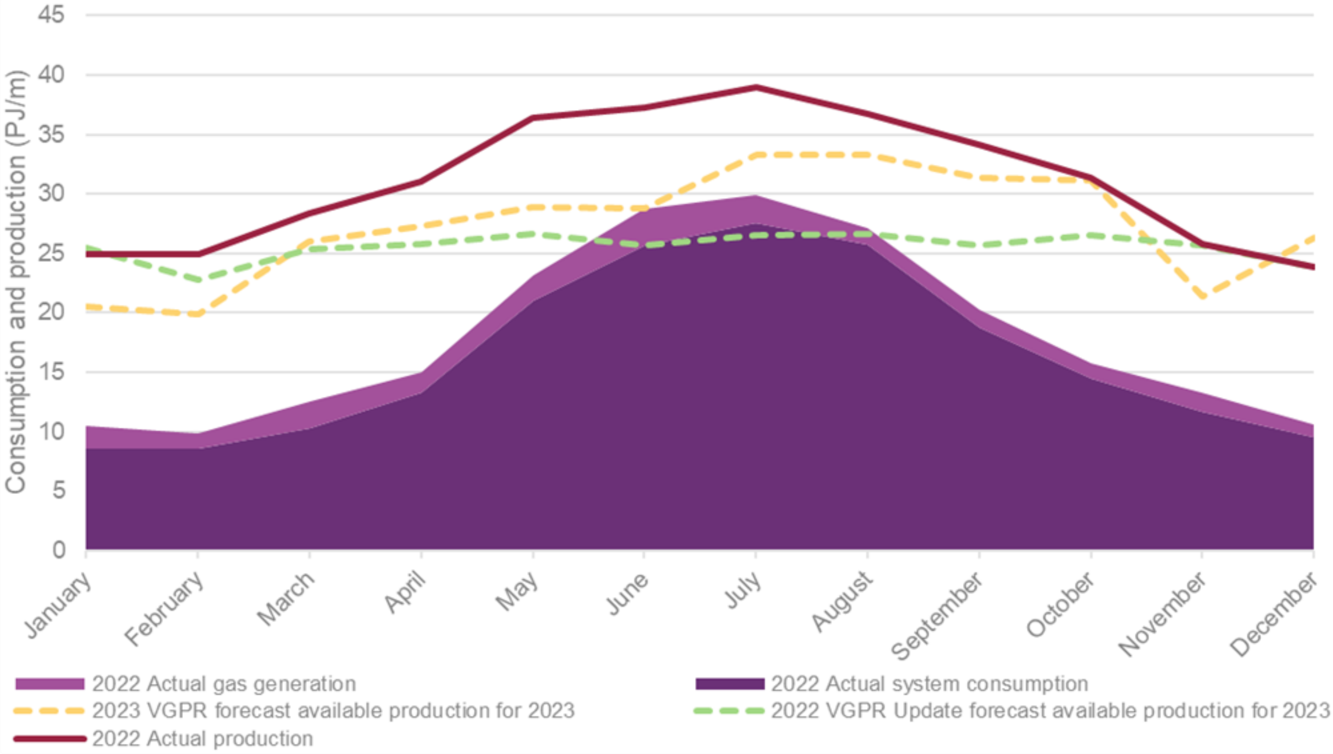
[8] Committed supply considers developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational.

Victorian gas consumption increased substantially during the winter months[9] compared to summer months, and how 2022 gas production remained higher than monthly consumption (with the remaining production supplied to neighbouring states).

Average summer production in 2022 was 27 PJ per month (PJ/m), which increased by 10 PJ/m to an average of 37 PJ/m during the winter months. This was primarily due to Longford's winter production profile and, to a lesser extent, the Otway Gas Plant production profile.

The 2021 VGPR and 2022 VGPR Update reported that, with the forecast reduction in Longford's production capacity and flexibility from 2023, the monthly Victorian production profile was expected to flatten. **Figure 2** shows the 2022 VGPR Update Victorian monthly production forecast for 2023, with the forecast average summer production of 25 PJ/m only increasing by 1 PJ/m to 26 PJ/m for the winter months.

Figure 2 Actual monthly production and consumption in 2022, compared to available production in 2023 from the 2022 VGPR Update and 2023 VGPR (PJ/m)



The 2023 VGPR production forecast includes more of a typical seasonal production profile for winter 2023, due to a higher Longford winter production capacity than reported in the 2022 VGPR Update. The 2023 VGPR forecasts an average 2023 summer production of 25 PJ/m, increasing by 6 PJ/m to average 31 PJ/m in winter. This profile will help mitigate the reliance on Iona UGS to support winter baseload demand, although forecast Victorian monthly production during winter 2023 is approximately 6 PJ/m lower than during winter 2022.

The Victorian production profile is more aligned with the typical Victorian consumption profile for all years in the outlook period than it was in the 2022 VGPR Update forecasts. The forecast Victorian production profile for 2027

[9] The VGPR considers the winter months to be May through to September inclusive.

is flatter, impacting seasonal and peak day supply adequacy, however production profile forecasts are less certain for later years due to the uncertainty introduced by potential[10] production projects.

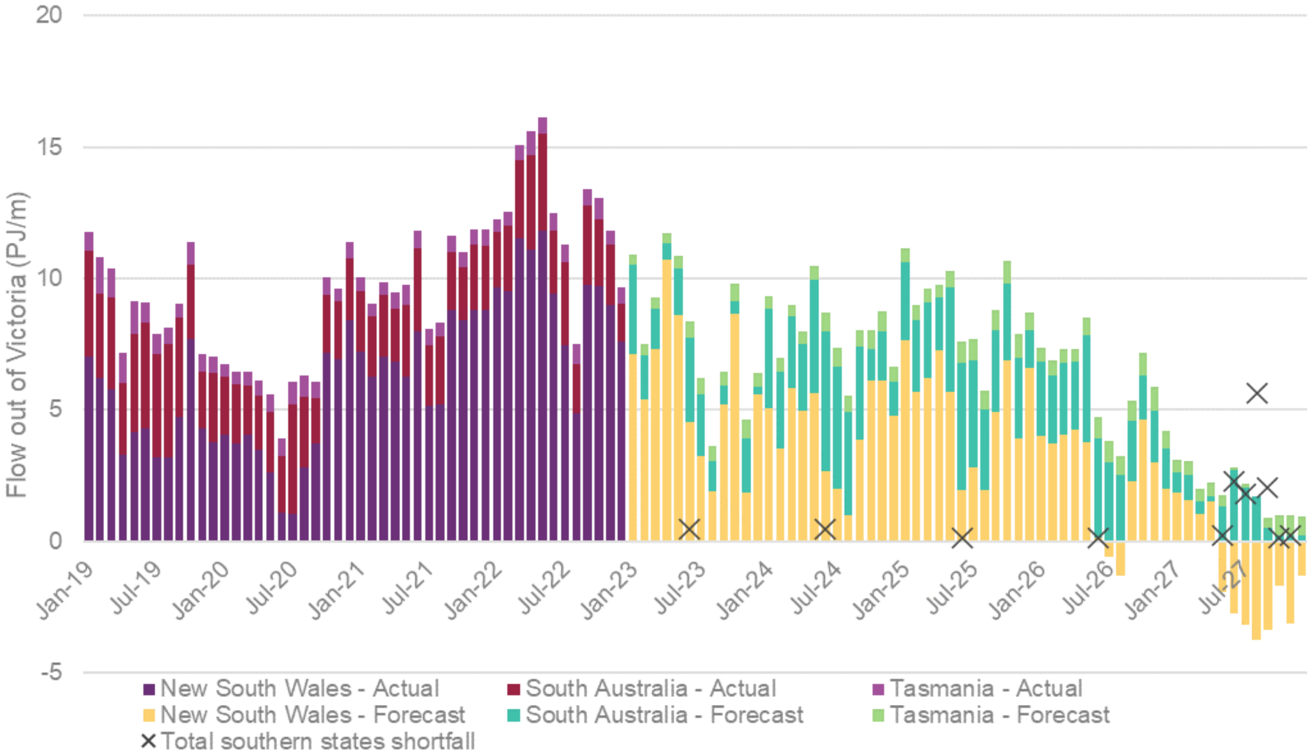
Victorian seasonal adequacy as part of east coast Australia

Victoria is interconnected to neighbouring states by transmission pipelines that form part of a broader east coast gas grid. Victoria can directly supply:

- New South Wales via the Eastern Gas Pipeline (EGP) and the Moomba Sydney Pipeline (MSP) via the Culcairn interconnection.
- South Australia via the SEA Gas Pipeline.
- Tasmania via the Tasmanian Gas Pipeline (TGP).

Victoria can also supply gas to Queensland via the MSP through New South Wales. Alternatively, Victoria can import gas from Queensland via Culcairn, as the MSP is bidirectional. There are also proposed projects to make the EGP and SEA Gas pipelines bidirectional if LNG receiving terminal projects at Port Kembla and Outer Harbor (in Adelaide) respectively are progressed. **Figure 3** shows the actual flow out of Victoria to neighbouring states from 2019 to 2022 and the forecast flow out of Victoria from 2023 to 2027.

Figure 3 Actual and forecast flows out of Victoria 2019-27 (PJ/m)



The forecast flows out of Victoria, using modelling performed for the 2023 GSOO, show that:

[10] Potential projects are uncommitted gas supply projects that have not reached final investment decision (FID), which could potentially proceed during the outlook period.

- The amount of gas exported from Victoria is projected to remain at historical levels for the first years of the outlook period, then decrease through 2026 to 2027, reflecting forecast declining Victorian production.
- The forecast shortfall of annual gas supply for Victoria in 2027 cannot be supplied by other jurisdictions, because there is a projected shortfall of gas across all the southern states[11] in 2027. From winter 2027, Victoria is forecast to become a net importer of gas as Victorian monthly consumption exceeds Victorian production and available storage inventory (unless additional Victorian supply and storage is developed). If potential supply projects progress in other jurisdictions and there is sufficient pipeline capacity from those jurisdictions, Victoria can import gas to overcome the forecast shortfall.
- The total southern states shortfalls forecast for winter months from 2023 to 2026 are driven by high coincident gas generation and system consumption across the southern states during the winter peak demand period.
- The sustained high flows out of Victoria combined with declining Victorian production increases the east coast grid's reliance on Victorian gas storage, even with supply from Queensland maximised. A large portion of the full Iona UGS working inventory[12] of 18-19 PJ is expected to be utilised each winter in the outlook period. The winter 2022 utilisation of Iona UGS inventory was 14.1 PJ. Complete utilisation of Iona UGS would mean there is no longer a supply buffer to cover unplanned outages or increases in demand.
- Modelling in the 2023 GSOO projects that Dandenong LNG storage will be heavily drawn down during each winter, corresponding to complete or near complete inventory utilisation every year during the VGPR outlook period. Using shallow storage to satisfy the supply demand balance increases the risk that this storage would not be available to provide an operational response to alleviate threats to system security or to manage emergencies.
- Historical levels of exports from Victoria to South Australia are forecast to be maintained for longer than exports to New South Wales, as Port Campbell production is forecast to increase then remain stable over the outlook period and supply from Port Campbell to the DTS is limited by the SWP[13] transportation capacity.
- Victoria is forecast to continue to supply all of Tasmania's gas requirements, because Tasmania has no alternate source of supply.

Refer to the 2023 GSOO for further discussion on east coast supply adequacy.

Peak day supply adequacy

Expected peak day supply capacity to the DTS is forecast to decline by 8% from the 1,595 TJ/d available in 2022 to 1,471 TJ/d during winter 2023, and then to 980 TJ/d in 2027 (a 39% decline compared to 2022). The peak day supply capacity includes 87 TJ/d of firm supply from Dandenong LNG[14].

Gippsland producers have advised that maximum available daily production capacity will reduce by 54% from 915 TJ/d in 2023 to 425 TJ/d in 2027. The actual maximum daily Gippsland production in 2022 was 1,126 TJ/d. The reduction in supply capacity is driven by the decline in the large legacy fields that supply the Longford Gas Plant, which was first highlighted in the 2018 VGPR Update.

For Port Campbell:

[11] "Southern states" means New South Wales, South Australia, Victoria, the Australian Capital Territory, and Tasmania.

[12] The full working inventory of Iona UGS assumes the facility is full at 24 PJ (2023) or 24.5 PJ (2024-27) and gas is withdrawn to the minimum modelled inventory of 6 PJ. At some point below 6 PJ, the supply capacity from Iona UGS may be impacted.

[13] The SWP includes the Brooklyn to Lara pipeline (BLP).

[14] Firm Dandenong LNG is up to 5.5 TJ/h, and non-firm LNG is up to 9.9 TJ/h.

- Available peak day supply, including supply from Iona UGS, is forecast to remain relatively stable over the outlook period, increasing from the maximum of 729 TJ/d available in 2022 to 785 TJ/d from mid-2023, then decreasing to 737 TJ/d in 2027.
- Production capacity is projected to increase from the actual maximum production of 188 TJ/d in 2022 to 227 TJ/d in 2023, mainly due to supply from the committed connection of the new Thylacine wells which will return Otway Gas Plant to its nameplate capacity of 205 TJ/d from mid-2023.
- Lochard Energy has increased the Iona UGS capacity from 545 TJ/d in 2022 to 558 TJ/d from January 2023. Lochard Energy will also expand Iona UGS capacity to 570 TJ/d from 2024.
- The Port Campbell peak day maximum daily quantity (MDQ) is expected to continue to be constrained by the SWP transportation capacity limit despite the construction of the WORM and Winchelsea Compressor 2.

Figure 4 shows:

- An improvement to the peak day supply adequacy compared to the 2022 VGPR Update, particularly for winter 2023, because:
  - Gippsland producers' peak day production forecast for winter 2023 has increased by 191 TJ/d from the 724 TJ/d reported in the 2022 VGPR Update to 915 TJ/d. Expected supply to the DTS is less due to demand on the EGP and in Tasmania that have no other source of supply. This reduces the Gippsland DTS supply to 854 TJ/d for winter 2023.
  - The reduced flattening of the Longford supply profile means that higher daily production continues to be available in winter than in summer.
  - The WORM and the Winchelsea Compressor 2 projects increase the SWP capacity from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023, increasing the peak day supply available from Port Campbell.
- Sufficient supply to support peak system demand days for all years in the outlook period except 2027.
- Peak day adequacy tightening from 2024, which limits the amount of Victorian gas available to support gas generation demand and to export to other states. A tight supply demand balance can cause high gas prices including the triggering of administered market price caps. The VGPR only considers physical supply adequacy.

The 2023 GSOO forecasts peak day shortfalls in the southern states for all years in the VGPR outlook period in the event of high coincident system and gas generation demand across all states. AEMO forecasts demand for gas generation to increase during winter, with very high demands for a few days each month. This increases the risk of high coincident system and gas generation demand that would result in insufficient gas supply on these peak days. See the 2023 GSOO for more on east coast supply adequacy.

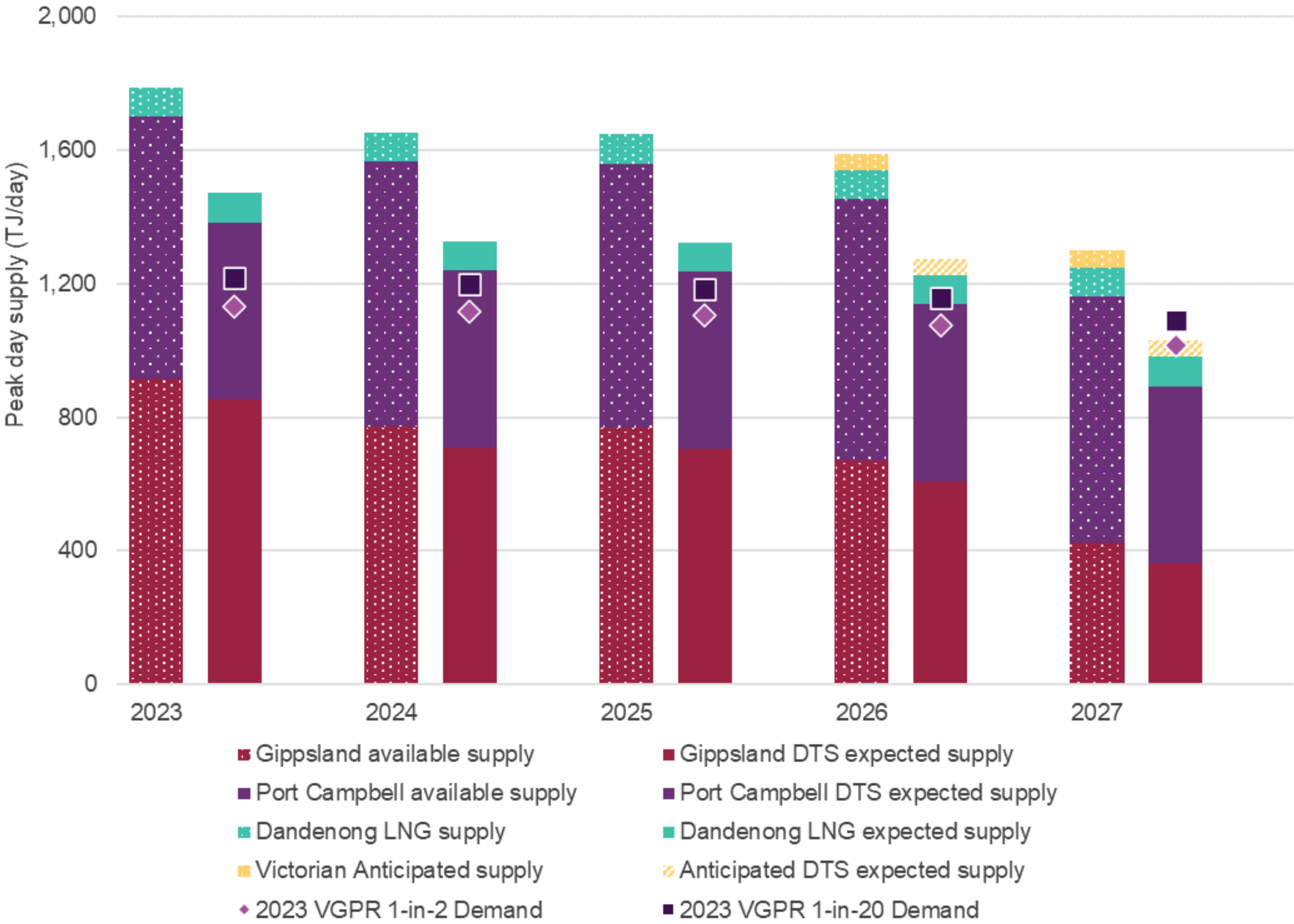
System demand is forecast to exceed available supply on both 1-in-2 and 1-in-20 peak system demand[15] days in 2027. Development of anticipated[16] projects would reduce the projected shortfall in 2027, but forecasts show that development of potential supply projects or an LNG receiving facility would be required to avert a shortfall.

[15] Forecasts with a 1-in-20 probability of exceedance are statistically expected to be met or exceeded one in every 20 years. This represents more extreme weather than the average weather conditions assumed in a 1-in-2 forecast, which is expected to be met or exceeded one in every two years.

[16] Anticipated supply considers gas supply from undeveloped reserves or contingent resources that producers forecast to be available as part of their best production estimates provided to AEMO.

The VGPR peak day forecast includes an assumption that there is an increasing amount of electrification of gas system demand in the outlook period, mostly residential and small commercial customer demand. Sensitivity modelling forecasts that, if this electrification is delayed beyond the outlook period, the magnitude of forecast shortfalls in 2027 would increase, and the first peak day shortfall would be brought forward a year to 2026.

Figure 4 Forecast peak day supply and DTS adequacy, 2023-27 (TJ/d)



Risks to supply adequacy

Peak day supply adequacy is forecast to tighten beyond 2023, with reduced supply capacity in 2024 and an annual and peak day shortfall projected in 2027 without additional gas supply. Risks to supply adequacy include:

- **Delays to transmission pipeline projects** – the WORM and Winchelsea Compressor 2 are key infrastructure projects that increase supply capacity, reliability and security. There is limited time to complete construction and commissioning prior to winter 2023.
- **Delays to production projects** – increased production from Beach Energy's Otway Gas Plant production from mid-2023 relies on offshore works to connect the new Thylacine wells, while the Enterprise project is subject to regulatory approvals. There is also reduced certainty of the GBJV production forecast, as the timing of their investment cycle is tightening. Cooper Energy has delayed an investment decision for the Otway Phase 3 Development (OP3D) project.

- **Increased gas generation demand** – weather conditions and coal-fired generation outages can result in increased gas generation. Winter 2022 saw high gas generation demand in late May and early June, due to an early winter cold snap coupled with low wind and solar generation, then due to reduced coal generation in Victoria and New South Wales (including due to severe flooding) coinciding with high system demand for electricity.
- **Production facility outages** – Victorian production facilities are aging, so unplanned outages may occur more frequently and there will be limited spare capacity to cover them. As reported in the 2022 VGPR Update, the forecast capacity reduction from Longford's large legacy gas fields and the retirement of the Gas Plant 1 inlet section in 2021 is degrading the resilience[17] of the plant's production system.
- **Unpredictable decline of legacy fields** – accurately forecasting the rate and expected duration of production as reservoirs approach their end of life, can be challenging as deviations can, and occasionally do, occur.
- **Depletion of Iona UGS inventory** – winter 2022 saw rapid depletion of Iona UGS requiring AEMO to issue Threat to System Security notices to ensure storage supply was available for the duration of winter.
- **Reduction in gas made available from Queensland to the southern states –** volumes offered by Queensland LNG producers may be reduced due to lower production or favourable international LNG prices which may attract surplus production. Unplanned outages impacting APA's transmission pipelines from Queensland are also a risk, along with possible delays to the expansions that are forecast to be completed prior to winter 2023 and winter 2024.

Additional supplies during the outlook period

Additional supply is forecast to be required to avoid an annual supply and peak day shortfall in 2027. **Table 2** lists projects currently classified as anticipated and potential.

Table 2 Anticipated and potential projects

Solution	Detail	Description	Analysis
Anticipated production projects	The only supply project that meets the anticipated criteria in the 2023 VGPR is the Kipper Stage 1B project in Gippsland.	The Kipper Stage 1B project is the next stage of development following the committed Kipper compression project that is expected to be commissioned in late 2023. The Kipper Phase 1B project includes the development of an additional subsea well at the Kipper field.	This project will increase the gas available from the Kipper project from 2026 but is not expected to replace the production capacity of the large legacy gas fields.
Victorian LNG receiving terminals	LNG receiving terminals could bring gas from Australian export facilities (acting like a virtual pipeline) or from international supply sources.	There are two publicly proposed LNG receiving terminals in Victoria: • Viva Energy's project in Geelong, to the southwest of Melbourne, which has submitted a completed Environmental Effects Statement (EES) to the Minister for Planning and is waiting for an Assessment decision[A]. • Vopak's project in Avalon, also to the southwest of Melbourne. Vopak has submitted a referral to the Minister for Planning to determine if an EES is required for the project.	• Both terminals would require a new pipeline to connect them to the DTS. • The connection of a new supply source into the SWP near Geelong would increase the SWP transportation capacity to above 700 TJ/d due to its closer proximity to Melbourne, but simultaneous supply capacity from Port Campbell including Iona UGS would be reduced to as low as 150 TJ/d. • Further expansion of the SWP would be required to support simultaneous supply from the Port Campbell facilities at current capacities.

[17] Resilience can be described as the ability of an energy system to limit the extent, severity, and duration of system degradation following an abnormal event.

Solution	Detail	Description	Analysis
Potential production projects	There are potential supply projects in both the Gippsland and Port Campbell zones that, if developed, would increase the available Victorian supply.	• The Golden Beach Gas Project involves the development of the Golden Beach gas field with forecast supply from 2025. • Cooper Energy is proposing to develop the Annie field as part of the OP3D project. Gas produced from the Annie field would be processed at Cooper Energy's Athena Gas Plant. • GBJV are evaluating expansion and optimisation options for the Turrum and North Turrum fields. This project would provide additional gas to be processed at the Longford Gas Plant from 2026. • Other potential projects include Beach Energy's Trefoil and White Ibis projects, Seven Group Holding's Longtom project, Cooper Energy's Manta project and Lakes Blue Energy's Wombat project.	With the exception of the Golden Beach project, these projects are expected to maintain or restore the capacity of existing gas production facilities.
Gas storage development and expansion	There are two proposed projects that would increase Victoria's gas storage capability.	• The Golden Beach Gas Project includes plans to transition the field and facility into a storage facility in 2026. • Lochard Energy's Heytesbury Underground Gas Storage project increases storage reservoir capacity for the Iona UGS facility by utilising the depleted Heytesbury gas fields that were acquired from Origin Energy in 2019[C].	• Golden Beach storage would increase gas supply capacity into the Longford to Melbourne Pipeline, offsetting Longford Gas Plant capacity reductions. • A further increase in Iona UGS capacity would require an SWP expansion to supply this increased capacity into the DTS.
Potential SWP expansion	Port Campbell has additional peak day supply that is currently not available due to the SWP capacity constraint, despite the WORM and Winchelsea Compressor 2 projects.	Additional compression or pipeline looping on the SWP would increase the peak day supply capacity.	This solution would provide additional supply capacity.
Potential increased supply capacity from outside Victoria	Several projects are being developed to improve supply and transmission capacity in south-eastern Australia.	• If gas supply is made available from PKET and the EGP reversal project is complete, this would have the capacity to supply 200 TJ/d into the DTS. There is also a further proposal to install additional compression at Port Kembla to increase the EGP southbound capacity into the DTS from 200 TJ/d to 320 TJ/d. • APA has committed to Stages 1 and 2 of their East Coast Grid Expansion project[D] which will increase the capacity of the MSP and South West Queensland Pipeline (SWQP). A proposed Stage 3 would further increase these capacities. • Venice Energy's proposed Outer Harbor LNG project would increase supply to South Australia. The SEA Gas Pipeline reversal project is required to supply Victoria, however there would be no additional DTS peak day capacity as supply would be constrained by the existing SWP transportation capacity.	While supply projects from outside Victoria may contribute to DTS peak day supply, there would be no net increase as the current and forecast transportation capacities in south-east Australia become a limiting factor.
Distributed gas supply	Hydrogen and biomethane injections into distribution networks could provide a future alternate source of supply.	There are several projects proposed in Victoria to supply either biomethane or hydrogen to end use customers.	Technologies are still in the early stages of trial and adoption. These projects are not expected to produce significant quantities of gas within the outlook period.

A. Victorian Government – Department of Environment, Land, Water and Planning, "Viva Energy Gas Terminal Project", 7 December 2022, at https://www.planning.vic.gov.au/environment-assessment/what-is-the-ees-process-in-victoria.
B. Billy Higgins, Geelong Times, "Vopak hands in gas terminal plan", 6 January 2023, at https://timesnewsgroup.com.au/geelongtimes/news/vopak-hands-in-gas-terminal-plan/.

C. ACCC, "Lochard's acquisition of Heytesbury gas reservoirs not opposed", 21 March 2019, at https://www.accc.gov.au/media-release/lochards-acquisition-of-heytesbury-gas-reservoirs-not-opposed.
D. APA Group, "APA Commences Stage Two of East Coast Gas Grid Expansion", 25 May 2022, at https://www.apa.com.au/globalassets/asx-releases/2022/apa-commences-stage-two-of-east-coast-gas-grid-expansion.pdf.

Project uncertainties

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. Key uncertainties impacting project timelines and likelihood of completion include:

- **Russia-Ukraine conflict** – the Russian invasion of Ukraine in February 2022 has caused shocks in the global energy markets resulting in high international energy prices. The conflict is also driving up demand for electrolysers for hydrogen production and FSRUs for LNG receiving terminals as Europe is driven to seek gas from sources other than Russia.
- **Inflation** – higher inflation in Australia and overseas, combined with rising interest rates to combat inflation, has increased borrowing costs, threatening project economics.
- **Financing** – natural gas is becoming unpalatable for some investors who are screening investments on the basis of environment, social and governance (ESG) issues and want to limit their exposure to fossil fuels.
- **COVID-19** – ongoing impacts of the COVID-19 pandemic has caused prolonged project timelines and delays procuring or the complete unavailability of specialist equipment and skilled resources.
- **Regulatory approvals** – environmental approvals for gas projects are becoming increasingly stringent. Industry has advised that the December 2022 Federal Court decision to set aside NOPSEMA's approval of Santos' Barossa Gas Project Environmental Plan[18] has increased industry uncertainty.
- **Market uncertainty** – from 23 December 2022, the Australian Federal Government imposed a $12/gigajoule (GJ) price cap on new domestic wholesale gas contracts for 12 months[19]. The Government has also introduced a mandatory code of conduct for the gas industry.
- **Competing investment interests for renewable gases** – policy and investment into renewable gases in other jurisdictions has been significant. Examples include the US Department of Energy's US$7 billion hydrogen hubs program[20], US$750 million clean hydrogen technology package[21] and clean hydrogen production tax credits[22], and the European Union's REPowerEU Plan[23].
- **Offshore rig availability** – declining offshore exploration and drilling activity in Australia, combined with a very high rig demand globally, is resulting in few rigs remaining in Australia.

[18] Santos, "Full federal court decision for the Barossa Gas Project", 2 December 2022, at https://www.santos.com/news/full-federal-court-decision-for-the-barossa-gas-project/.

[19] Hon Katy Gallagher (Acting Treasurer), Treasury Portfolio, "Gas price cap to take effect", 22 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/gas-price-cap-take-effect.

[20] Department of Energy, "Biden-Harris Administration Announces Historic $7 Billion Funding Opportunity to Jump-Start America's Clean Hydrogen Economy", 23 September 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-historic-7-billion-funding-opportunity-jump-start.

[21] Department of Energy, "Biden-Harris Administration Announces $750 Million to Accelerate Clean Hydrogen Technologies", 16 December 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-750-million-accelerate-clean-hydrogen-technologies.

[22] Department of Energy - Hydrogen and Fuel Cell Technologies Office, "Financial Incentives for Hydrogen and Fuel Cell Projects", at https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

[23] European Commission, "REPowerEU Plan", 18 May 2022, at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

Dandenong LNG update

The Dandenong LNG storage facility is an essential source of fast response peak shaving gas supply that AEMO uses to quickly respond to incidents that threaten system security.

In the 2021 VGPR and the 2022 VGPR Update, AEMO identified that the retailer-contracted inventory was insufficient to manage operational and market responses during periods of high unforecast demand or a supply disruption, and to safely manage the DTS during an emergency. This necessitated AEMO issuing a Notice of a Threat to System Security[24] in both years and seeking a market response.

In June 2022, Australia's energy ministers[25] noted the importance of gas storage facilities, particularly in light of the challenges facing the east coast gas system, and determined that an urgent rule change should be submitted to the Australian Energy Market Commission (AEMC) to ensure the Dandenong LNG facility's storage inventory is maximised and made available to AEMO to reduce the risk of peak day gas supply shortfalls. After consultation was completed, the AEMC published a final set of rules on 15 December 2022[26] requiring AEMO to contract any uncontracted capacity within the tank and to fill that capacity to reduce the likelihood of curtailment within Victoria.

Consequently, the Threat to System Security relating to insufficient contracted Dandenong LNG inventory has ended.

[24] National Gas Rules (NGR) 341

[25] Energy Ministers, "Energy Ministers Meeting Communique – 8 June 2022", 8 June 2022, at https://www.energy.gov.au/sites/default/files/2022-08/Energy%20Ministers%20Meeting%20Communique%20-%208%20June%202022.docx.

[26] AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

1 Introduction

The *Victorian Gas Planning Report* (VGPR) is published every two years and assesses the adequacy of the Victorian Declared Transmission System (DTS) to supply peak day gas demand and annual consumption over a five-year outlook period. The most recent VGPR was published in March 2021. Due to material changes in the DTS and gas production and consumption forecasts, a VGPR Update was published in March 2022.

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

1.1 Review of 2022

Victorian DTS gas consumption was 207 petajoules (PJ) in 2022, which was a small increase on 2021 consumption.

System consumption (by households and businesses) was 193 PJ:

- Tariff D (industrial and large commercial) consumption was 65 PJ. This was the lowest annual Tariff D consumption since market start in 1999, due in part to the closure of the Mobil Altona refinery[27] in 2021, the mothballing of one plant at Qenos Altona[28] in 2021 and the winding down of Saputo Dairy Australia's facility in Maffra[29].
- Tariff V (small commercial and residential) consumption was 128 PJ. This was the third highest Tariff V consumption since market start (after 2020 and 2017) with higher Tariff V demand driven by cold weather in 2022, particularly in early winter.

Consumption of gas for the generation of electricity was 20.7 PJ in 2022, nearly double the 10.5 PJ used in 2021. This was driven by higher gas generation demand from late May due to an early winter cold snap coupled with low wind and solar generation, then continued high demand due to reduced coal generation in Victoria and New South Wales (including due to severe flooding) coinciding with high system demand for electricity.

Gas consumption for generation could have been even higher, but limitations on gas supply led to some generators running on liquid fuels instead.

Total Victorian production for the year was 374 PJ, up from 331 PJ in 2021. This increase was predominantly due to increased production at the Longford Gas Plant and Otway Gas Plant – the increase at Otway was a result of the successful commissioning of the additional Geographe wells[30].

Key observations for the winter peak period[31] in 2022 include:

[27] ExxonMobil, "Shutting down Altona refinery for the last time", 8 September 2021, at https://www.exxonmobil.com.au/Community-engagement/Local-outreach/Mobil-community-news/2021/Altona-Shut-Down-Teams.

[28] Michaela Meade, Maribyrnong Hobsons Bay Star Weekly "Qenos 'mothballing'; 150 jobs lost", 20 May 2021, at https://maribyrnonghobsonsbay.starweekly.com.au/news/qenos-mothballing-150-jobs-lost/.

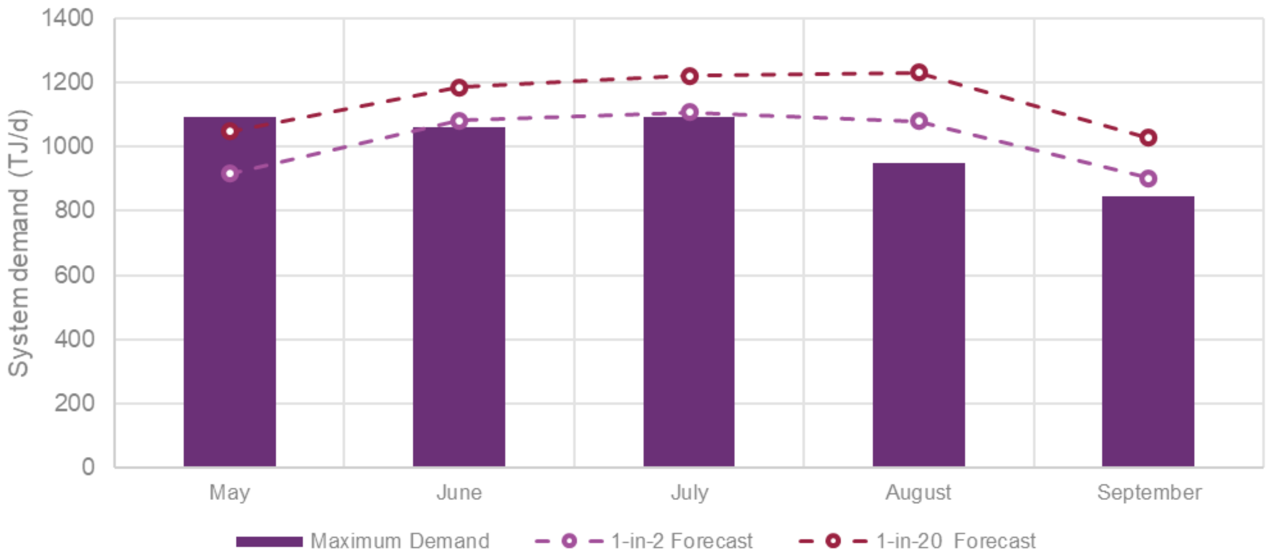
[29] Gippsland Times, "Saputo to permanently close Maffra facility", 9 November 2022, at https://www.gippslandtimes.com.au/news/2022/11/09/saputo-to-permanently-close-maffra-facility/.

[30] Beach Energy, "Otway drilling campaign complete", 12 July 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1099320/BPT_Otway_drilling_campaign_complete.pdf.

[31] The winter peak demand period is defined as the months of May to September inclusive.

- The 2022 Victorian DTS highest demand day occurred on Tuesday 12 July 2022, with a total demand of 1,179 terajoules (TJ). This comprised 984 TJ of system demand and 194 TJ of gas generation. The Effective Degree Day (EDD)[32] on this day was 12.1, which is below the peak EDD recorded for 2022.
- The highest system demand day was observed on 31 May 2022, reaching 1,094 TJ. On this day, an EDD of 14.7 was recorded, which was also the highest observed for the year. This system demand was lower than the highest system demand days for 2021 and 2020, when demand reached 1,129 TJ with an EDD of 13.6 and 1,213 TJ with an EDD of 15.2, respectively.
- **Figure 5** shows that the actual maximum system demand in May exceeded the forecast 1-in-2 and 1-in-20[33] peak system demand for 2022, however for all other months the actual maximum system demand was below the peak system demand forecast.

Figure 5 Actual 2022 monthly maximum system demands compared to the forecast 1-in-2 and 1-in-20 peak demands



- AEMO issued a Notice of a Threat to System Security on seven occasions during winter 2022:
  - On 1 June[34], 14 July, 18 July and 19 July 2022[35], due to insufficient injection offers being made available to meet forecast demand for the DTS. These events occurred due to the Victorian Declared Wholesale Gas Market (DWGM) being in an administered state (with the price capped at $40/gigajoule [GJ]) and market participants in aggregate not offering sufficient supply to meet the high demand on these days. In each event, AEMO observed increased injection offers from market participants after seeking a market response.
  - On 16 June 2022[36], due to an unplanned offshore outage at the Longford Gas Plant. This coincided with the suspension of the National Electricity Market (NEM) the day before, in addition to a relatively low amount of injection offers in the DWGM. These factors resulted in the potential for insufficient supply to be

[32] The EDD is a measure of coldness. The higher the EDD, the more gas is expected to be used for heating.

[33] 1-in-2 peak day forecasts are expected statistically to be met or exceeded one year in two, and are based on average weather conditions. 1-in-20 peak day forecasts are based on more extreme conditions that could be expected only one year in 20.

[34] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-event--intervention--1-june-2022.pdf?la=en.

[35] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-event-14-18-19-jul-2022.pdf?la=en.

[36] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-event-16-jun-2022.pdf?la=en.

available to meet forecast demand. AEMO requested a market response and observed an increased amount of injection offers, allowing the threat to be alleviated.

- On 11 July 2022 and 18 July 2022[37], due to low Iona underground gas storage (UGS) inventory and the corresponding risk of supply shortfalls due to Iona inventory depletion before the end of winter 2022. AEMO intervened in the market on 20 July 2022 by issuing directions for the curtailment of withdrawals for two gas-powered generators in response. These Threat to System Security notices were revised on 2 August 2022 and 10 August 2022, and remained in effect until 30 September 2022.

- While no out-of-merit-order injections from the Dandenong liquefied natural gas (LNG) facility were required, there was a significant increase in merit order LNG injections[38] during winter 2022 in response to insufficient injection offers on multiple days. In 2022, 244 TJ of LNG injections occurred over the winter period, compared to 123 TJ over the same period in 2021.

1.2 Winter 2022 challenges

Winter 2022 presented several challenges in the Australian east coast gas markets, including:

- Tight supply and demand conditions due to high levels of gas generation driven by the reduced availability of coal-fired generation.
- High domestic prices due to the tight supply conditions and high international prices for gas and thermal coal, influenced by the war in Ukraine and sanctions against Russia.

1.2.1 Tight supply-demand

The supply-demand balance was tight due to increased gas generation (noted above), the NEM suspension from 15 June 2022, and the rapid depletion of Iona UGS inventory. This resulted in two Gas Supply Guarantee events being triggered.

Impact of reduced coal fired generation and colder weather

In winter 2022, Victorian gas generation was 13.5 PJ, up by 57% from 8.6 PJ in winter 2021, as shown in **Figure 6.** This was driven by increased demand from nearly all Victorian gas generation units.

Higher winter gas generation was predominantly due to coal-fired unit outages and increased NEM operational demand[39] (in part due to due to wet and cloudy conditions reducing the output of consumers' distributed solar systems). In total, approximately 6.6 gigawatts (GW) of large generation capacity, corresponding to about 20% of winter maximum NEM demand, was offline by 14 June 2022.

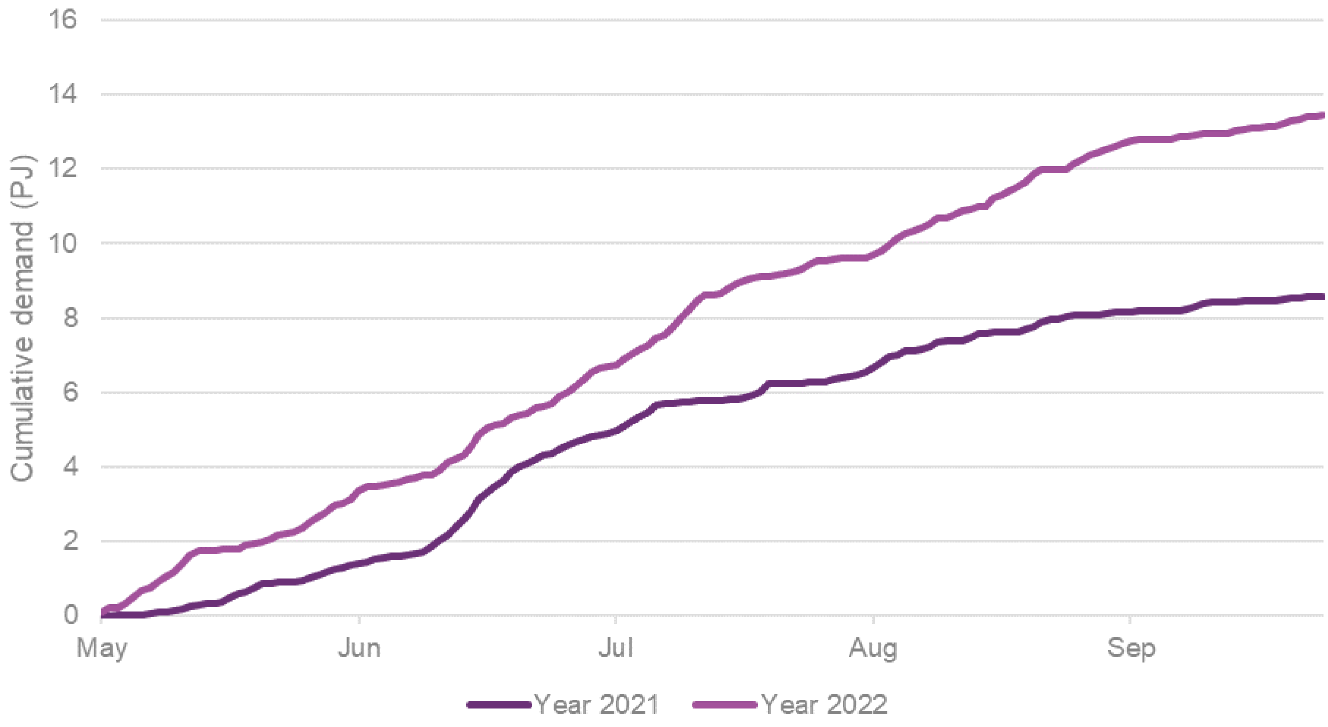
On 1 June 2022, AEMO triggered the Gas Supply Guarantee process for the first time ever due to forecast gas supply shortfalls across Victoria, South Australia, and Tasmania for 2 June 2022. On 19 July, AEMO triggered the Gas Supply Guarantee process for a second time, covering gas days 19 July 2022 to 30 September 2022. The tight supply-demand balance in the east coast gas markets was causing limited supply to gas generation.

[37] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-intervention-report-19-jul-30sep-2022.pdf?la=en.

[38] In merit order LNG injections refers to injection bids at Dandenong LNG below the marginal price and scheduled like any other DWGM injection point. Out of merit order gas is gas scheduled above market price.

[39] See AEMO, *Quarterly Energy Dynamics Q3 2022*, page 23, at https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q3-2022.pdf?la=en.

Figure 6 Victorian gas generation during winter 2021 and 2022



Risk of Iona storage depletion[40]

Iona UGS storage inventory followed a similar pattern to winter 2021, with very fast depletion rates in June and July due to colder weather reflecting higher demand, higher gas generation demand, and a tight supply situation in the first half of the winter. August saw a decrease in gas generation, milder weather, and strong flows from Queensland to the southern markets, which enabled Iona storage levels to recover.

There were significant concerns about Iona UGS inventory depletion during winter 2022. When the storage inventory falls below 6 PJ, the reservoir withdrawal capacity can start to decline, reducing the facility's delivery capacity into the market. This resulted in AEMO taking the following actions:

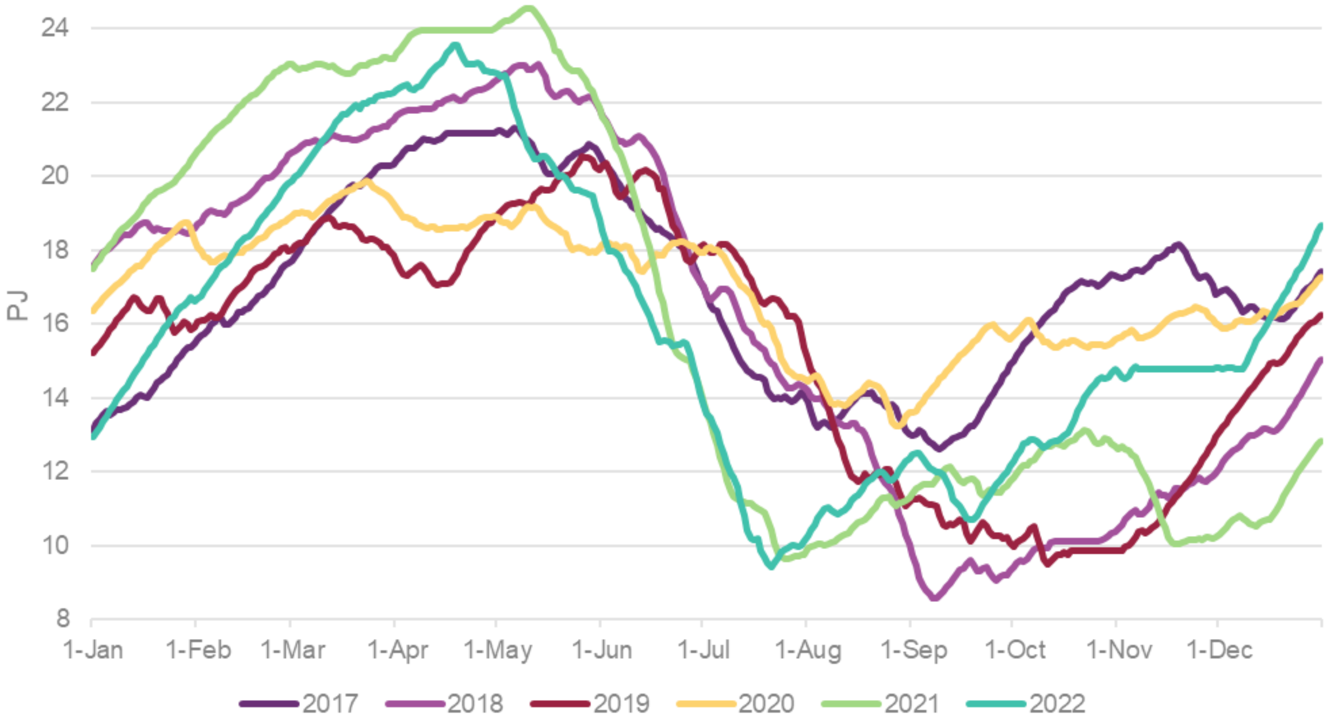
- On 11 July 2022, AEMO issued a notice informing participants of a threat to system security due to low Iona UGS levels and the risk of supply shortfalls due to depletion of Iona inventory during peak winter demand periods. Inventory was forecast to reduce to 6 PJ by 31 July. On 18 July, AEMO published another threat notice advising that it was projected that inventory would reduce to the 6 PJ threshold by 6 August.
  - In these notices, market participants were requested to cease purchasing gas from the DWGM via controllable withdrawals from the DTS to supply gas to customers outside of Victoria and Victorian gas generators connected to the DTS were requested not to generate using gas without supplying a corresponding quantity of gas into the DTS.
- On 20 July 2022, AEMO issued directions for the curtailment of withdrawals for two gas-powered generators as a response to the threat to system security.
- On 2 and 10 August 2022, AEMO issued revisions to the threat to system security notices issued on 11 and 18 July 2022, easing the requests made in July. The 2 August notice no longer requested that controllable

[40] For Intervention Report, see https://aemo.com.au/-/media/files/gas/dwgm/2022/dwgm-intervention-report-19-jul-30sep-2022.pdf?la=en.

withdrawals from the DTS into Iona UGS be supported with corresponding supply and then the 10 August notice allowed limited net withdrawals from the DTS by Victorian gas generators.

- This threat was ended on 30 September 2022.

Figure 7 Iona storage levels from 2017 to 2022



1.2.2 High DWGM prices

Gas prices across the Australian east coast were at record levels for anytime of the year. The DWGM average price in winter 2022 was a record $30.80/GJ, compared to $10.75/GJ in winter 2021, a 187% increase. High international prices were the biggest contributing factor that led to the increase in prices. The high domestic prices resulted in an Administered Price Cap (APC) being applied at the DWGM due to the Cumulative Price Threshold (CPT) being exceeded. The high domestic prices were also the underlying reason for the Retailer of Last Resort (ROLR) events in the Sydney and Brisbane STTM hubs.

Impact of volatile international gas prices

The DWGM is connected to the international LNG export market as Victorian gas can be exported to Queensland via New South Wales or imported from Queensland also via New South Wales. This interconnection between the domestic east coast markets and the international LNG market resulted in international LNG prices influencing the DWGM, particularly during the winter peak demand period.

International energy commodity prices hit record highs, mostly due to the war in Ukraine and sanctions against Russia resulting in an increase in energy export prices (coal, gas and oil)[41].

[41] See AEMO, Quarterly Energy Dynamics Q3 2022, page 40, at https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q3-2022.pdf?la=en.

The sustained high prices resulted in an APC being applied in the Victorian DWGM due to the CPT of $1,400/GJ being exceeded. This resulted in the DWGM price being capped at $40/GJ on 31 May and was removed on 1 August. This was the first time in the DWGM history that the APC has been applied due to the CPT being exceeded.

Invoking of Retailer of Last Resort (RoLR)

On 23 May 2022, AEMO issued a notice of suspension to Weston Energy Pty Ltd under rule 488 of the National Gas Rules (NGR) commencing from gas day 24 May 2022 from all STTM hubs and the DWGM due to a failure to meet financial obligations[42].

This triggered a RoLR event in the Sydney STTM, Brisbane STTM, and the DWGM. While the RoLR event triggered a market administered state in the Sydney STTM, it also added new customers' demand to the host retailers which they would not have anticipated needing to supply, placing further pressure on market prices.

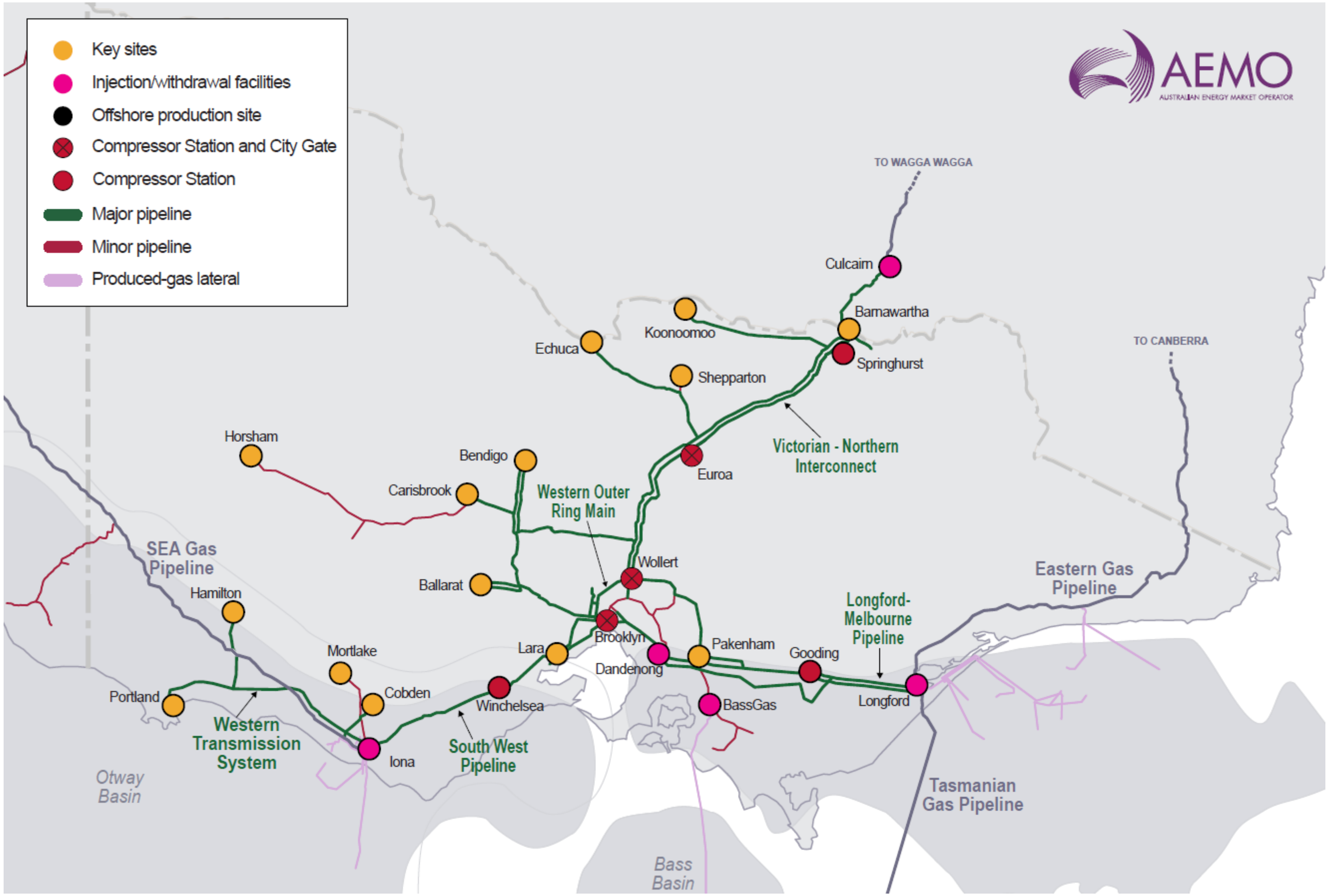
1.3 The Victorian Declared Transmission System

The DTS supplies natural gas to most of the connected households and businesses in Victoria, as well as to communities in New South Wales between Moama and Albury. Gas is transported from the Longford and Lang Lang gas plants 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 the Otway and Athena gas production facilities, the Iona UGS facility, and to South Australia via the SEA Gas Pipeline).

Figure 8 is a high-level map of the Victorian gas transmission network, including the DTS and other gas transmission pipelines.

[42] See AEMO, Quarterly Energy Dynamics Q2 2022, page 42, at https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf?la=en.

Figure 8 The Victorian Declared Transmission System



1.4 Gas planning in Victoria

1.4.1 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 Group must submit an Access Arrangement proposal to the Australian Energy Regulator (AER) every five years, which contains its proposed capital and operating expenditures for the period. The AER assesses the proposal and then provides APA Group with an appropriate cost recovery structure to fund the continued service of the network and any approved projects.

The timing of any capital investment in the DTS is ultimately decided by APA Group. Under the framework set out in the National Gas Law (NGL) and the NGR, APA Group may adjust actual capital expenditure from that assessed by the AER during the Access Arrangement period.

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

1.4.2 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 the 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 except to the extent of the information that AEMO is required to provide in the VGPR.

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

System demand does not include supply for gas generation[43]. Under rule 323(3), AEMO is also required to assess the impact of gas generation demand on 1-in-2 peak system demand days.

AEMO uses the term “demand” to describe hourly and daily usage of gas, and the term “consumption” to refer to monthly and annual usage of gas.

[43] Total demand is the sum of system demand and gas generation demand.

The *Gas Industry Act 2001* (Vic) and the *Gas Safety Act 1997* (Vic) 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. Energy Safe Victoria (ESV) regards an unplanned loss of supply (or interruption) to a customer in any circumstance as a potentially dangerous and undesirable event.

AEMO uses these legislative requirements, along with the planning standard, to assess the adequacy of the DTS to support peak day demand. This assessment is used to recommend augmentations or additional gas supplies that are required to reduce the risk of an unplanned loss of supply and subsequent risks to public safety.

1.4.3 Threat to system security

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

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

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

Under NGR rule 341, AEMO is required to inform registered participants if it believes that a threat to system security is indicated by the VGPR. A threat to system security indicates that, in AEMO's reasonable opinion:

- There is a threat to the supply of gas to customers; and
- There are insufficient assets available within the DTS to provide the capacity to meet forecast gas supply and demand conditions.

2 Gas usage forecast

Key findings

The forecasts in the 2023 VGPR, produced using the *Orchestrated Step Change (1.8°C)* scenario, project system demand decreasing with increasing electrification:

- Annual system consumption is forecast to decrease by 9.1% in the five-year outlook, from 195.4 PJ in 2023 to 177.6 PJ in 2027.
- The forecast peak day system demands are:
  - 1,131 TJ/d for a 1-in-2 year system demand day in 2023, reducing by 10.3% to 1,014 TJ/d in 2027.
  - 1,217 TJ/d for a 1-in-20 year system demand day in 2023, reducing by 10.5% to 1,089 TJ/d in 2027.

In modelling where electrification is delayed beyond the outlook period, only small changes in gas usage are forecast:

- Annual system consumption is forecast to maintain a relatively flat trend, decreasing by less than 1% by 2027.
- The forecast peak day system demands are:
  - 1,129 TJ/d for a 1-in-2 year system demand day in 2023, increasing by 0.8% to 1,138 TJ/d in 2027.
  - 1,219 TJ/d for a 1-in-20 year system demand day in 2023, increasing by 0.6% to 1,226 TJ/d in 2027.

DTS gas generation consumption is forecast to reduce from 8.4 PJ in 2023 to 4.5 PJ in 2025, then increase from 2026 to reach 8.3 PJ in 2027 (0.3% less than the 2023 forecast). Actual DTS gas generation consumption during 2022 was 13.8 PJ.

- The forecast initial reduction in annual gas consumption for power generation is driven by the projection that continued uptake in grid-scale variable renewable energy (VRE) generation and distributed photovoltaics (PV) in the NEM reduces the need for gas generation.
- As additional policy is implemented to incentivise the increased electrification in the *Orchestrated Step Change (1.8°C)* scenario, further increases in NEM winter peak demand are expected. This, combined with the continued planned retirement of coal generation plants, results in increasing annual consumption for gas generation in the latter half of the five-year outlook period.
- Despite the annual consumption forecast remaining similar in 2027 compared to 2023, peak gas generation demand during winter is forecast to increase as gas plays an increasingly critical role during periods of high electricity demand, particularly when there is low VRE generation or coal generation outages. This may coincide with peak system demand conditions, creating very high total demand conditions.

The ongoing popularity of flexible working arrangements including work from home is forecast to continue to impact the system demand profile on high demand days during winter 2023, resulting in greater linepack depletion prior to the evening peak. This can increase the likelihood Dandenong LNG will be required to support system pressures.

Scenario and sensitivity forecasts

The gas usage forecasts in the 2023 VGPR were produced using the GSOO demand forecasting methodology[44].

The 2023 VGPR forecasts focus on the *Orchestrated Step Change (1.8°C)* scenario outlined in the draft 2023 *Inputs Assumptions and Scenarios Report* (IASR), as do the 2023 GSOO forecasts. *Orchestrated Step Change (1.8°C)* is the scenario most similar to the *Step Change* scenario identified in AEMO's 2022 *Integrated System Plan* (ISP) as the most likely pathway for Australia's energy sector[45]. The 2023 *Orchestrated Step Change (1.8°C)* scenario is a refinement of the *Step Change* scenario.

The *Orchestrated Step Change (1.8°C)* scenario represents a future that includes rapid overall transformational investment to decarbonise the economy, leading to a temperature rise below 2°C targeting 1.8°C. This is driven by consumer-led change, with a focus on energy efficiency, digitalisation and step increases in global emissions policy above what is already committed. Electrification is high, with industry decarbonising manufacturing and other industrial activities, and consumers switching from natural gas to electricity to heat their homes. Compared to *Step Change*, electrification forecasts have been updated considering observable consumer change to date and a slower rate of fuel-switching, particularly in the residential and commercial sectors. This has resulted in an initial slower projected decline of gas consumption in the 2023 VGPR.

Strong policy incentives and industry investment will be required to realise the level of electrification forecast under this scenario. While in some sectors the electrification of existing loads has already begun, uncertainty remains over how quickly consumers will invest to shift their energy use away from natural gas. To identify the potential influence of slower electrification on gas adequacy risks, AEMO also studied the impact of a conceptual halt on the electrification of gas use in a sensitivity, *Orchestrated Step Change (1.8°C), No Electrification*.

Definitions

Annual consumption for the DTS includes:

- System consumption (residential, commercial, and industrial customers, compressor and heater fuel gas, and unaccounted for gas [UAFG]), and
- Gas generation consumption.

Unaccounted for gas (UAFG) is the difference between the metered amount of gas entering the DTS and the amount of gas delivered to consumers as well as compressor and heater fuel gas.

System demand refers to daily gas usage by residential, commercial, and industrial gas users. It includes DTS compressor and heater fuel gas usage. Gas generation demand is not included in system demand.

Total demand refers to the sum of system demand and gas generation demand.

System demand and annual consumption are further classified into Tariff V and Tariff D:

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

[44] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[45] The most likely scenario will be reassessed as part of the preparations for the 2024 ISP.

Compressor and heater fuel gas use are proportionally allocated by energy volume to both Tariff V and Tariff D demand.

System demand is primarily driven by Tariff V gas usage for heating, which depends on several variables. To capture the impact of weather on system demand, AEMO uses a measure known as the **Effective Degree Day (EDD)**, which considers the temperature profile, average wind speed, sunshine hours, and the season for the gas day. The higher the EDD, the higher the likely gas use.

Peak day demand forecasts are provided as **probability of exceedance (POE)** forecasts, which means the statistical probability that the forecast will be met or exceeded. The forecasts are provided as:

- **1-in-2** peak day forecasts, meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions.
- **1-in-20** peak day forecasts are based on more extreme conditions that could be expected only one year in 20.

2.1 Annual consumption

Tariff V and Tariff D gas consumption forecasts are discussed in **Section 2.1.1** and **Section 2.1.2** below. **Section 2.4.1** discusses drivers and uncertainties related to forecasts for DTS and non-DTS gas generation consumption.

Under the *Orchestrated Step Change (1.8°C)* scenario, annual DTS total gas consumption is forecast to decrease by 8.7% over the outlook period, from 203.7 PJ in 2023 to 185.9 PJ in 2027, as shown in **Table 3** and **Figure 9**.

The forecast decrease in DTS total gas consumption is driven by decreases in all consumption categories over the outlook period. This forecast falls approximately in the middle of the *Progressive Change* and *Step Change* scenario forecasts in the 2022 VGPR Update[46], which projected total consumption decreasing (including gas generation) to 200.9 PJ and 168.2 PJ in 2026, respectively.

If forecast electrification is delayed beyond the outlook period, the gas consumption forecast is expected to remain near current levels, with minimal change (less than 1%) over the outlook period. **Table 4** shows the difference between the forecasts with and without electrification.

The forecast impact of electrification is larger for Tariff V consumption than Tariff D:

- **Tariff V** consumption without electrification is forecast to increase by approximately 1.8% over the five-year VGPR outlook, from 132.2 PJ in 2023 to 134.6 PJ in 2027, compared to the 11.8% reduction of Tariff V forecast with electrification over the same period.
- **Tariff D** consumption without electrification is predicted to reduce by approximately 3.8%, similar to the forecast with electrification. Forecast gas generation consumption is not impacted.

The ongoing impact of COVID-19 is not included as a long-term variable in the annual and monthly consumption forecasts. AEMO will continue to monitor the situation.

[46] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

Table 3 Total annual gas consumption forecast, 2023-27 (PJ/y)

	2022 (Actual)	2023	2024	2025	2026	2027	Change over outlook
Tariff V	131.7	132.2	130.8	128.5	123.9	116.6	-11.8%
Tariff D	61.8	63.2	62.2	62.9	63.7	61.0	-3.5%
System consumption	193.5	195.4	193.0	191.4	187.5	177.6	-9.1%
DTS gas generation consumption	13.8	8.4	5.9	4.5	5.8	8.3	-1.2%
DTS total consumption	207.3	203.7	199.0	195.9	193.4	185.9	-8.7%
Non-DTS system consumption	0.32	0.44	0.43	0.44	0.45	0.45	4.3%
Non-DTS gas generation consumption	6.9	10.0	6.9	5.1	6.3	8.4	-16.0%
Victorian gas generation consumption	20.7	18.4	12.8	9.6	12.1	16.7	-9.2%
Total Victorian consumption*	214.5	214.2	206.2	201.4	200.1	194.8	-9.1%
Total Victorian consumption without electrification	-	214.4	208.1	206.0	210.4	212.9	-0.7%

Note: totals and change over outlook percentage may not add up due to rounding.
* Total Victorian consumption includes total DTS consumption, non-DTS Tariff V and Tariff D consumption at Bairnsdale, and non-DTS gas generation consumption at Bairnsdale and Mortlake.

Figure 9 Historical and forecast total annual gas consumption, 2018-27 (PJ/y)

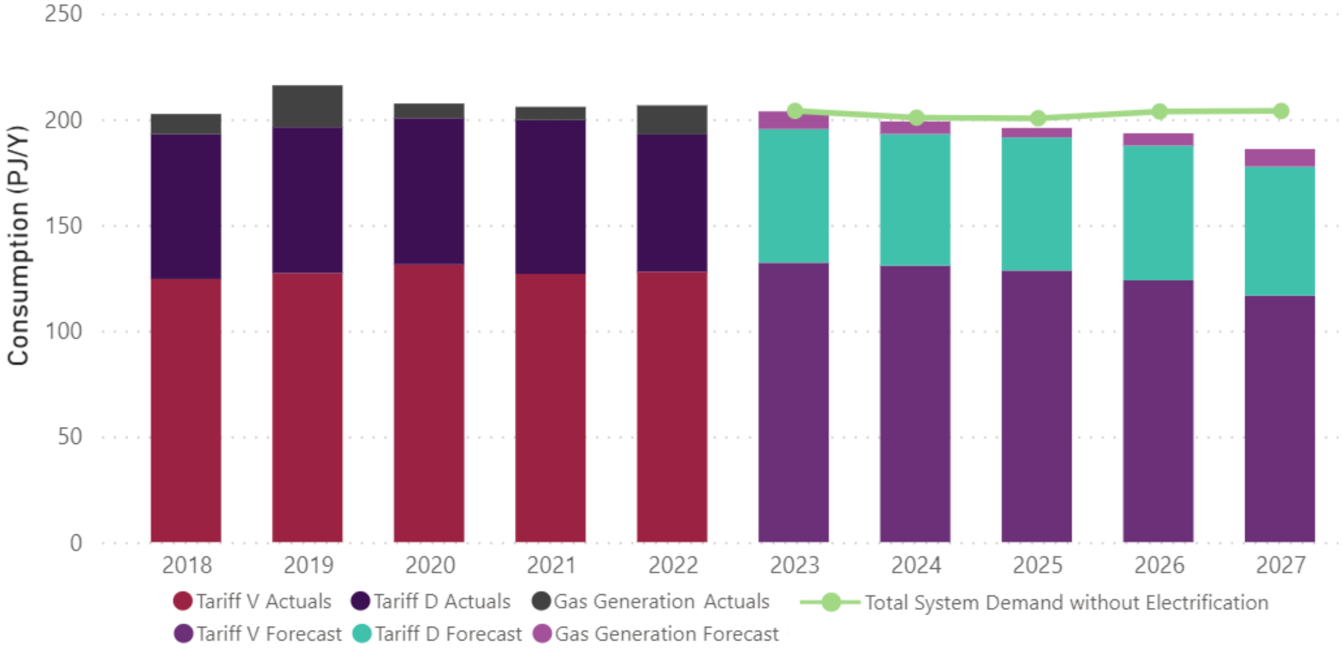


Table 4 DTS total annual gas consumption forecast with and without electrification, 2023-27 (PJ/y)

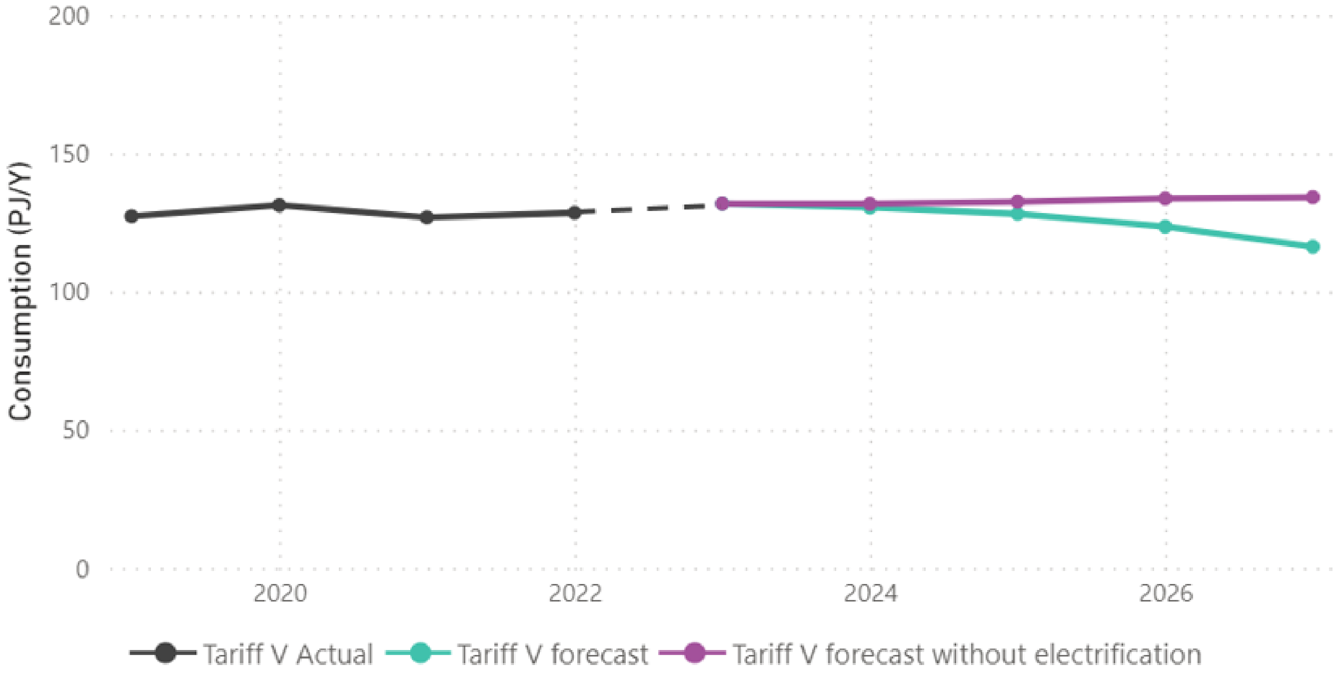
	2023	2024	2025	2026	2027
DTS total consumption	203.7	199.0	195.9	193.4	185.9
DTS total consumption without electrification	203.9	200.7	200.5	203.7	203.9
Percentage difference	0.1%	0.9%	2.3%	5.3%	9.7%

2.1.1 Tariff V consumption

Under the *Orchestrated Step Change (1.8°C)* scenario, Tariff V consumption (residential and small commercial customers) is forecast to decline by 11.8% over the outlook period.

As **Figure 10** shows, however, this rapid decline is only forecast to start in 2026, the second last year of the VGPR outlook period. The forecast during first three years shows relatively flat consumption, declining from 132.2 PJ in 2023 to 128.5 PJ in 2025, then Tariff V consumption is forecast to reduce to 123.8 PJ in 2026 and to 116.6 PJ in 2027.

Figure 10 Historical and forecast DTS Tariff V consumption, 2019-27 (PJ/y)



The forecast initial moderate decline is driven by the gradual uptake of fuel switching via electrification and to a lesser degree energy efficiency savings under the Victorian Energy Upgrades[47] (VEU) scheme, and the Home Heating and Cooling Upgrades Program[48] packages. Both schemes serve to reduce gas consumption per connection for both residential and small commercial customers.

The faster reduction forecast in 2026 and 2027 will require additional strong policy incentives and industry investment to realise the level of electrification assumed under the *Orchestrated Step Change (1.8°C)* scenario.

The Tariff V consumption forecast reflects trends in the Tariff V connections forecast (see **Figure 11**). The trend follows a relatively slow decline in the first three years and then decreases at a sharper rate in the latter two years, primarily due to the assumed increase of consumers switching from gas to electric heating in the *Orchestrated Step Change (1.8°C)* scenario.

The forecast number of connections is illustrative of the number of connections that are required to electrify under the *Orchestrated Step Change (1.8°C)* scenario. In reality, some connections will only partially electrify, especially in the short term.

[47] The VEU program provides Victorian households and businesses with a range of low and no-cost energy saving options such as lighting and draught sealing as well as subsidies for replacing major appliances like energy efficient hot water systems. See https://www.esc.vic.gov.au/victorian-energy-upgrades-program.

[48] The Home Heating and Cooling Upgrades Program is an initiative aimed at improving the comfort, wellbeing and health of low income and vulnerable households via rebates on energy efficient appliances. See https://www.heatingupgrades.vic.gov.au/about-us.

The Tariff V consumption forecast without assumed electrification diverges from the *Orchestrated Step Change (1.8°C)* scenario, remaining near current levels over the VGPR five-year outlook period, with an overall increase of 1.8% as shown above in **Figure 10.**

The significant impact of electrification on Tariff V forecast consumption is also highlighted in **Table 5**, showing the consumption forecast without electrification diverging from the forecast with electrification. The largest difference occurs in 2027, when the no electrification forecast is 15.4% higher than the forecast with electrification.

Figure 11 Historical and forecast DTS Tariff V connections, 2014-27

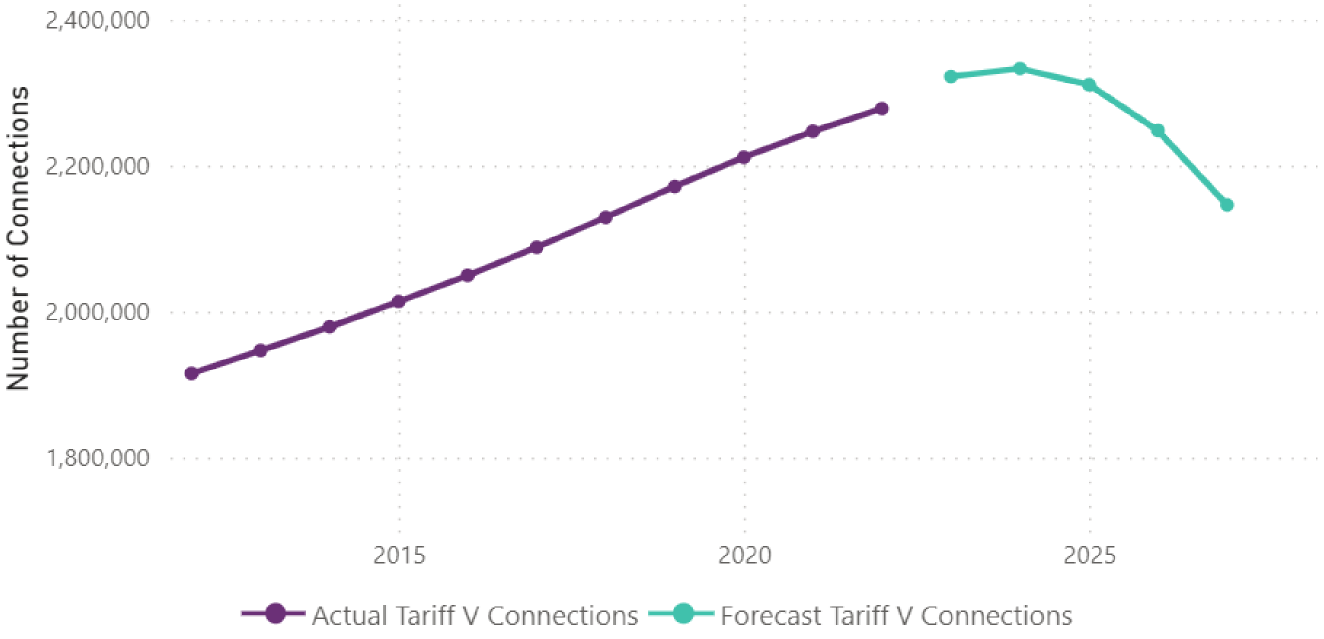


Table 5 DTS Tariff V gas consumption forecast with and without electrification, 2023-27 (PJ/y)

	2023	2024	2025	2026	2027
DTS Tariff V consumption with electrification	132.2	130.8	128.5	123.9	116.6
DTS Tariff V consumption without electrification	132.2	132.1	132.9	134.1	134.6
Percentage difference	0.0%	1.0%	3.4%	8.3%	15.4%

Table 6 shows projected Tariff V consumption by System Withdrawal Zone (SWZ)[49] for the *Orchestrated Step Change (1.8°C)* scenario, with and without electrification.

- There is a strong forecast reduction in Tariff V consumption across all zones except for the Gippsland zone.
- The zones with the greatest Tariff V consumption decreases are the Northern and Melbourne zones, with forecast reductions of 13.8% and 14.6%, respectively. Tariff V consumption in these zones is forecast to decrease as the projected number of new connections is offset by the adoption of electrification and the energy efficiency programs described above.

[49] The DTS is divided into six SWZs: Northern, Geelong, Melbourne, Western (Western Transmission System, or WTS), Ballarat, and Gippsland. The SWZs are used to report demand forecast, and to assess adequacy by zone.

- For Gippsland, Tariff V consumption is forecast to increase by 13.2% over the VGPR outlook. This is due to the number of new connections in low-density population growth corridors in regional towns that are expected to continue to install gas appliances.
- If electrification is delayed beyond the outlook period, Tariff V consumption is forecast to increase or remain near current levels at each zone over the VGPR period.

Table 6 Annual Tariff V consumption by System Withdrawal Zone, 2023-27 (PJ/y)

	2022 (Actual)	2023	2024	2025	2026	2027	Change over outlook
Ballarat	9.6	9.5	9.6	9.5	9.3	8.9	-6.3%
Geelong	11.9	11.8	11.8	11.8	11.5	11.0	-6.8%
Gippsland	6.8	6.9	7.2	7.5	7.7	7.7	13.2%
Melbourne	91.1	91.7	90.1	87.8	83.9	78.3	-14.6%
Western	1.5	1.4	1.4	1.4	1.4	1.3	-7.1%
Northern	10.7	10.9	10.7	10.5	10.0	9.4	-13.8%
DTS Tariff V system consumption	131.7	132.2	130.8	128.5	123.9	116.6	-11.8%
Non-DTS Tariff V system consumption	0.20	0.37	0.37	0.36	0.34	0.32	-13.5%
Total Victorian Tariff V	131.9	132.6	131.2	128.9	124.2	117.0	-11.8%
Total Victorian Tariff V without electrification	-	132.6	132.5	133.3	134.5	135.0	1.8%

Note: totals and change over outlook percentage may not add up due to rounding.

2.1.2 Tariff D consumption

Tariff D (large commercial and industrial) consumption is forecast to remain steady at near current consumption levels during the outlook period across all zones except for Gippsland.

Over the next five years, large commercial and industrial customers are not expected to commence widespread electrification of their processes. Therefore, there is not a large difference forecast between the forecast Victorian Tariff D consumption with or without electrification, as shown in **Table 7**.

Table 7 Annual Tariff D consumption by System Withdrawal Zone, 2023-27 (PJ/y)

	2022 (Actual)	2023	2024	2025	2026	2027	Change over outlook
Ballarat	1.7	1.3	1.3	1.3	1.3	1.3	0.0%
Geelong	10.9	9.9	9.7	9.9	10.1	10.1	2.0%
Gippsland	9.2	9.5	9.4	9.5	9.6	6.5	-31.6%
Melbourne	30.2	31.8	31.4	31.5	31.8	32.1	0.9%
Western	2.3	2.8	2.7	2.8	2.8	2.8	0.0%
Northern	7.7	8.0	7.8	8.0	8.1	8.2	2.5%
DTS Tariff D system consumption	61.8	63.2	62.3	62.9	63.7	60.9	-3.6%
Non-DTS Tariff D system consumption	0.12	0.08	0.08	0.11	0.11	0.11	37.5%
Total Victorian Tariff D	61.9	63.3	62.4	63.0	63.8	61.0	-3.6%
Total Victorian Tariff D without electrification	-	63.4	62.8	63.2	63.8	61.1	-3.6%

Note: totals and change over outlook percentage may not add up due to rounding.

Tariff D consumption is forecast to increase to 63.3 PJ in 2023 in comparison to actual demand in 2022 of 61.8 PJ – with general changes in industrial load consumption – before declining through to 2025. The forecast has a relatively flat trend in all zones except Gippsland, where consumption is predicted to drop significantly by approximately 31.6% over the five-year VGPR outlook. However, this reduction is only expected to occur in the last year of the VGPR outlook in 2027, with the forecast to remain flat, similar to the rest of the zones, to 2026.

The Tariff D consumption forecast does not account for Opal Australian Paper's 15 February 2023 announcement that production of white paper at the Maryvale Mill ceased from 21 January 2023[50] (production of brown paper and cardboard is expected to continue), but does include the impact of the Maryvale Energy from Waste project at the same site[51], which contributes to the forecast drop in consumption in the Gippsland zone from 2027.

2.2 Monthly consumption in 2023

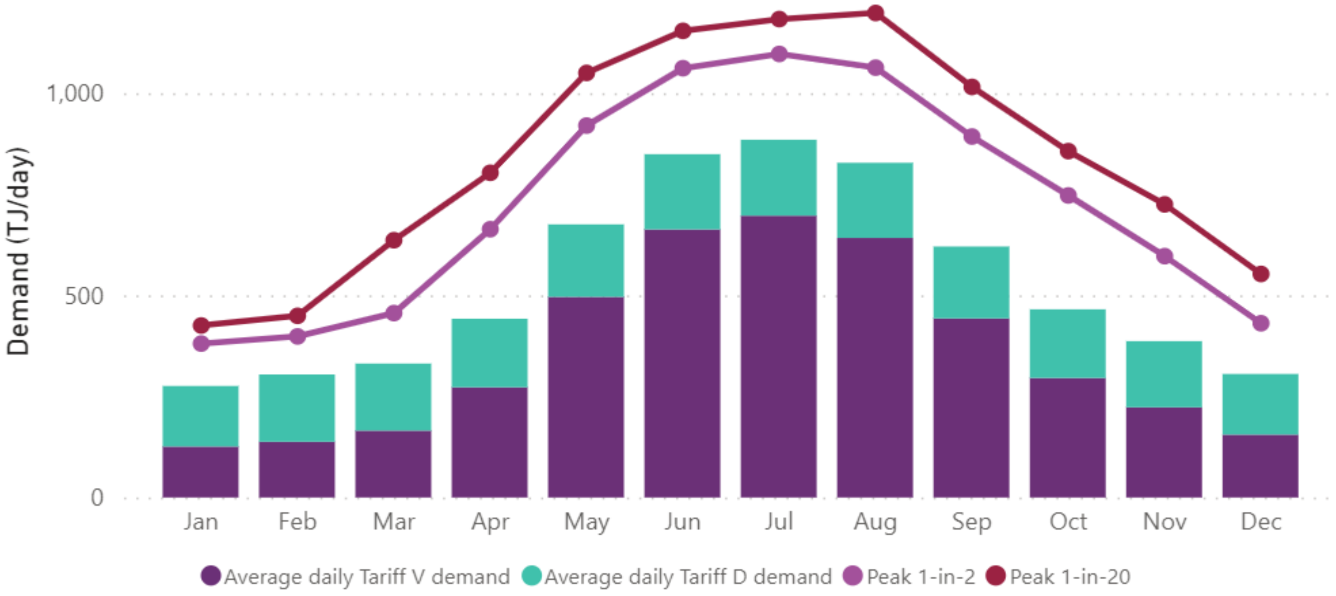
Forecasts in this section use the *Orchestrated Step Change (1.8°C)* scenario. Forecast monthly consumption in 2023 is similar in the *Orchestrated Step Change (1.8°C), No Electrification* sensitivity, because the impacts of electrification this year are expected to be minimal.

Monthly system consumption forecasts for January to December 2023 are shown in **Table 8** and **Figure 12.**

Table 8 Forecast monthly gas consumption for 2023 (PJ/m)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System consumption	8.62	8.59	10.34	13.34	21.05	25.58	27.54	25.77	18.72	14.52	11.69	9.55
Gas generation consumption	0.85	0.50	0.63	0.52	0.87	1.37	0.92	0.71	0.60	0.43	0.64	0.31
Total consumption	9.47	9.09	10.98	13.86	21.92	26.96	28.46	26.49	19.31	14.95	12.32	9.87

Figure 12 Forecast average daily 2023 demand compared to 2023 peak day system demand (TJ/d)



[50] Opal, "Opal Australian Paper Maryvale Mill supply update", 15 February 2023, at https://opalanz.com/news/opal-australian-paper-maryvale-mill-supply-update/.

[51] Opal, "Energy from Waste", accessed 20 February 2023, at https://opalanz.com/future/energy-from-waste/.

The key observations are:

- Consumption is forecast to peak over the winter months. The maximum monthly system consumption forecast is 27.54 PJ per month (PJ/m) during July, with slightly lower amounts during June and August.
- System consumption during summer months is forecast to be less than 10 PJ/m.
- DTS-connected gas generation monthly consumption is forecast to be highest during the winter months due to high coincident NEM demand and reduced VRE output.

2.3 Peak day demand

This section reports annual DTS peak day system demand forecasts over the outlook period, and monthly peak day gas demand forecasts for January 2023 to December 2023.

2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 peak day system demand forecasts, summarised in **Table 9**, show decreasing trends of 10.3% and 10.5%, respectively, for the outlook period. This is due to forecast strong electrification under the *Orchestrated Step Change (1.8°C)* scenario impacting Tariff V peak day demand, which reduces by 12% for both 1-in-2 and 1-in-20 peak in 2027.

Similar to the consumption forecasts, if electrification is delayed beyond the outlook period, then the 1-in-2 and 1-in-20 peak day system demand forecasts remain consistent over the VGPR period, with less than 1% change from 2023 to 2027.

Table 9 Annual peak day system demand forecast with and without electrification, 2023-27 (TJ/d)

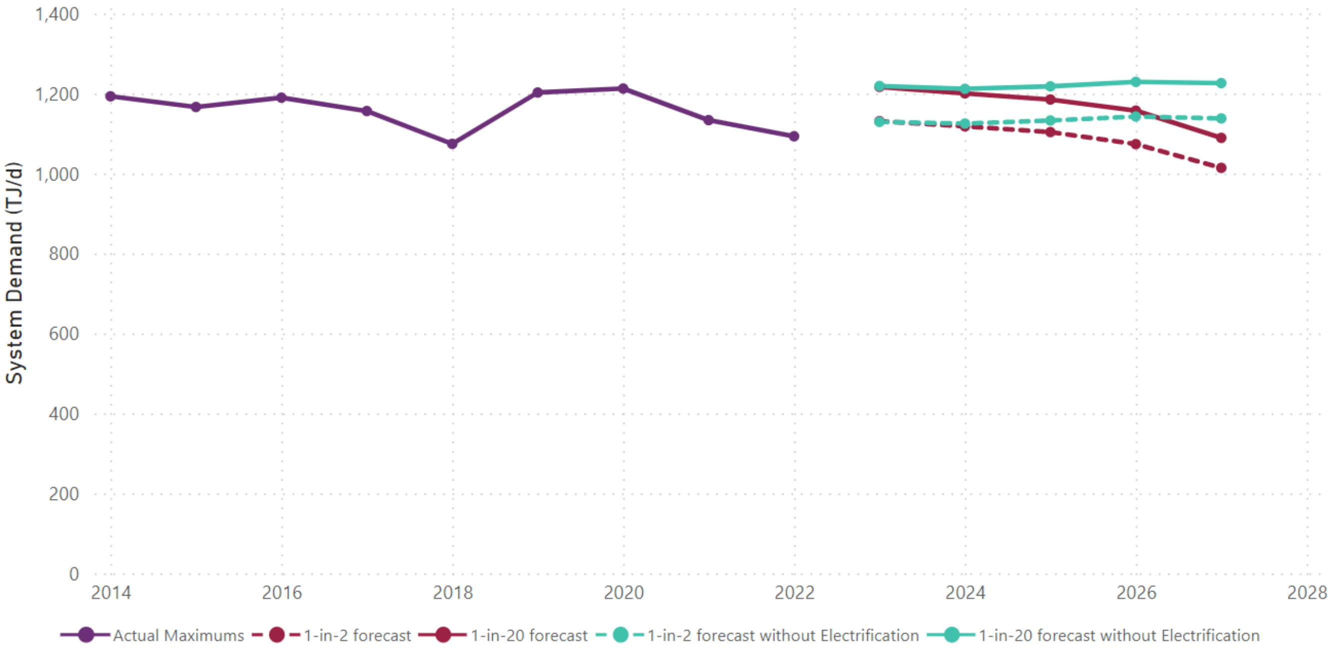
		2023	2024	2025	2026	2027	Change over outlook
1-in-2 peak day	Tariff V	909	900	881	850	799	-12.1%
	Tariff D	223	219	223	224	215	-3.6%
	System demand	**1,131**	**1,118**	**1,104**	**1,074**	**1,014**	-10.3%
	System demand without electrification	**1,129**	**1,125**	**1,133**	**1,143**	**1,138**	0.8%
1-in-20 peak day	Tariff V	990	973	955	924	871	-12.0%
	Tariff D	227	228	230	234	219	-3.5%
	System demand	**1,217**	**1,201**	**1,185**	**1,157**	**1,089**	-10.5%
	System demand without electrification	**1,219**	**1,212**	**1,218**	**1,229**	**1,226**	0.6%

Note: totals and change over outlook percentage may not add up due to rounding.

As shown in **Figure 13**:

- The peak day forecasts represent a reduction in peak day demand, compared to historical levels and an actual peak demand of 1,097 TJ/d in 2022, to a forecast demand of 1,014 TJ/d in 2027 for 1-in-2 peak day, and 1,089 TJ/d in 2027 for 1-in-20 peak day.
- Winter 2022 saw the second lowest winter peak day system demand since 2014, of 1,097 TJ/d. This peak occurred unusually early, on 31 May 2022.

Figure 13 Historical and forecast peak day maximum system demand, 2014-27 (TJ/d)



2.3.2 Monthly peak day demand for 2023

Table 10 shows the forecast peak day system demand for each month during 2023 for the *Orchestrated Step Change (1.8°C)* scenario. Forecast monthly peak day demand in 2023 is similar in the *Orchestrated Step Change (1.8°C), No Electrification* sensitivity, because the impacts of electrification this year are expected to be minimal.

The peak day system demand is forecast to occur during the three coldest winter months: June, July, and August.

Table 10 Forecast monthly peak day demand for 2023, (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day	383	401	458	666	923	1,065	1,100	1,066	896	750	600	434
1-in-20 peak day	428	452	639	806	1,053	1,157	1,187	1,202	1,019	860	728	556

2.3.3 Impact of COVID-19 restrictions on the daily demand profile

During 2020 and 2021, Victorian residents and businesses were subject to various levels of movement restrictions due to the COVID-19 pandemic. Although these restrictions were lifted by the end of 2021, the daily demand profile in winter 2022 did not fully revert to a typical demand profile prior to the COVID-19 pandemic, as shown in **Figure 14**.

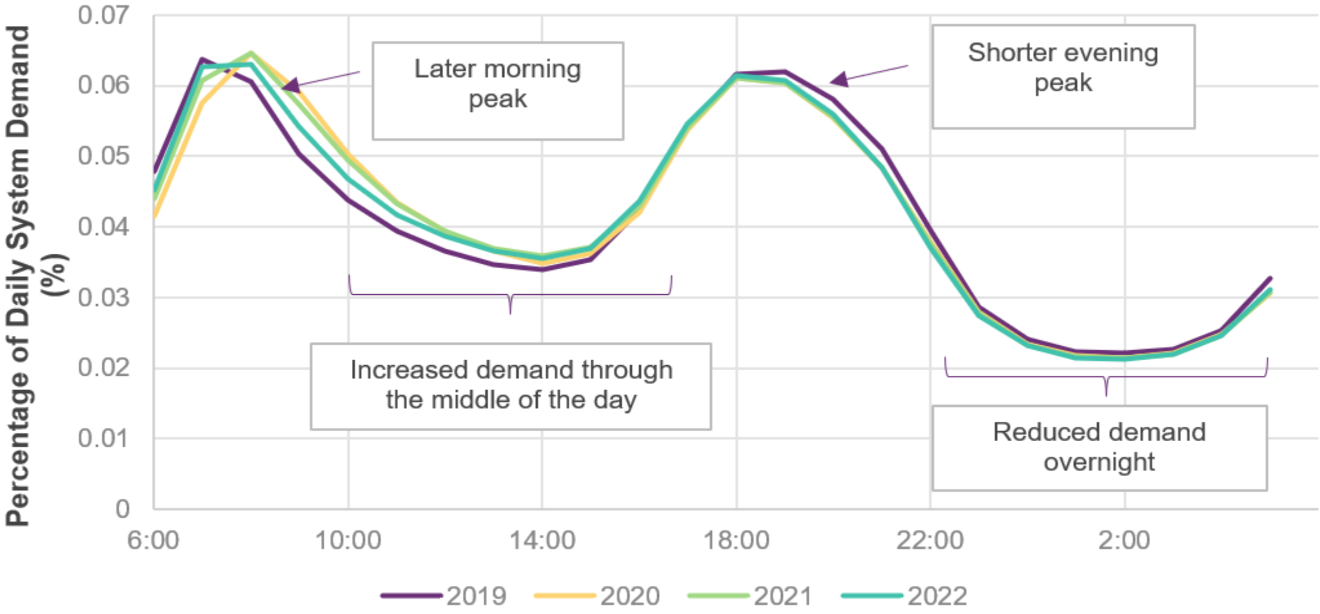
The impact on the demand profile in 2022 remained similar to the profile in years 2020 and 2021, but there was a noticeable trend towards an earlier morning peak (although not back to the 2019 profile). The delayed morning peak and higher demand during the day is driven by the continued popularity of flexible working arrangements such as working from home. Compared to a typical (or historical) demand profile, this means:

- A greater proportion of daily system demand occurs before 10:00 pm, which reduces the usable system linepack at 10:00 pm[52].

[52] This is a critical time operationally, as it corresponds to the time of minimum system linepack, and minimum system pressure.

- There is reduced opportunity to build system linepack during the middle of the day. This reduces system linepack leading into the evening peak, increasing the likelihood of Dandenong LNG being required to manage system pressures.

Figure 14 Average percentage of weekday winter system demand profile in 2019, 2020, 2021 and 2022



AEMO will continue to monitor the demand profile on high demand days, and act in accordance with the Demand Override Methodology[53] to minimise interventions by AEMO.

2.4 Gas generation forecasts

Victorian gas usage for power generation, including for electricity supply on high demand days, is driven by events and conditions in the NEM. Gas generation can be used to replace generation that is unavailable to meet NEM demand, or for individual NEM participants to balance their portfolio positions.

As highlighted in the 2022 ISP, gas generation will play a crucial role as coal generation retires. It will complement battery and pumped hydro generation to support periods of peak demand, particularly during periods when output from VRE is limited, as well as provide critical grid security and stability services when necessary. This critical need for peaking gas generation is forecast to remain through the ISP time horizon to 2050, and older and less efficient gas peaking plants may need to be replaced[54]. AGL has brought forward its expected closure date for the 800 megawatts (MW) gas-fired Torrens Island B Power Station in South Australia from 2035 to 2026[55].

The gas generation forecasting methodology assumes generation and transmission assets are developed in line with the optimal development pathway and the *Orchestrated Step Change (1.8°C)* scenario, detailed in the 2023

[53] At https://aemo.com.au/-/media/files/gas/dwgm/2009-15/demand-override-methodology.pdf.

[54] AEMO, 2022 *Integrated System Plan*, pg. 11, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[55] AGL, "Torrens Island 'B' Power Station to close in 2026", 24 November 2022, at https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/november/torrens-island-b-power-station-to-close-in-2026.

IASR. The forecasts incorporated the most recent assumptions on gas prices, demand forecasts, bidding behaviour, and information on committed generation projects.

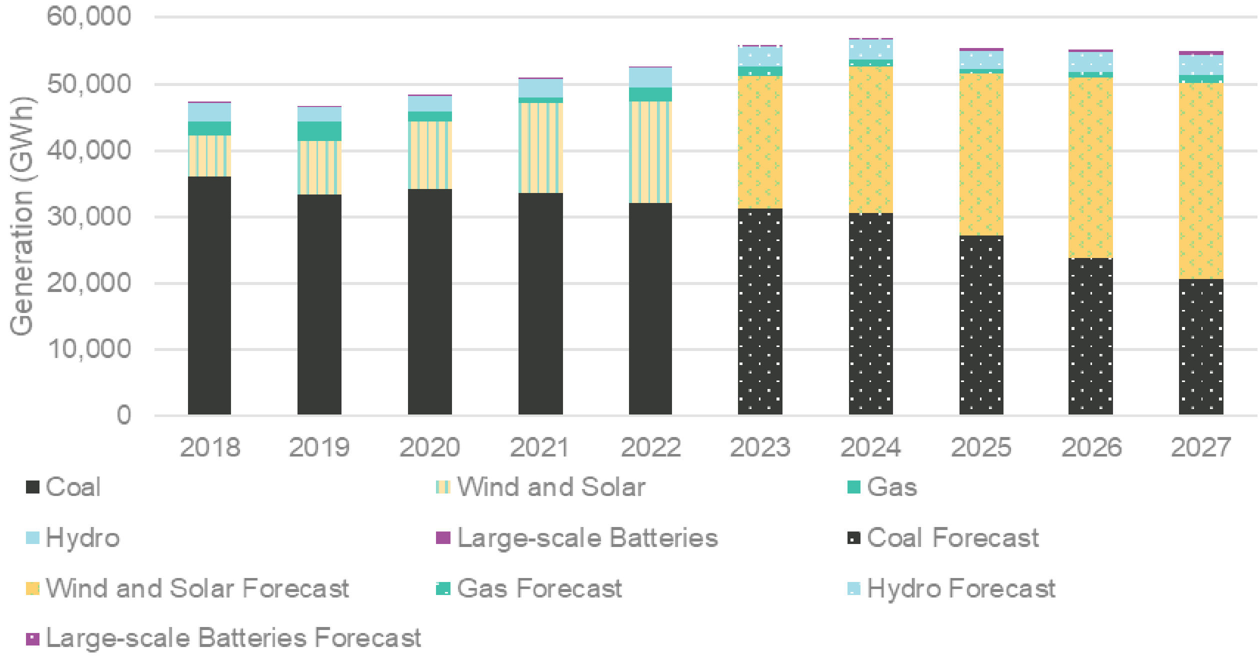
Gas generation forecasts are produced for a variety of scenarios that account for various combinations of weather patterns and generator outages. Therefore, the potential uses for gas generation are varied and depend on actual weather conditions and generator availability.

This section has reported a range of potential gas generation forecast outcomes, rather than an average across all weather conditions.

DTS gas generation consumption forecasts are subject to a wide range of uncertainties, including:

- **Timing of installation of renewable energy projects**, both large-scale and behind-the-meter. A large amount of VRE is forecast to be commissioned in Victoria from 2023, as shown in **Figure 15**[56]. If forecast investments in VRE are delayed or do not proceed, gas generation consumption is likely to be higher than in **Table 11** (in **Section 2.4.1**).

Figure 15 Historical and forecast Victorian electricity generation, 2018-27, GWh/y



- **Weather variability**. Gas generation consumption is highly sensitive to variations in weather conditions. Weather patterns (rainfall, wind, and sun) affect not only consumer demand for electricity, but also the output of renewable (hydro, wind, and solar) generation in the NEM, which subsequently impacts the amount of gas generation. Possible impacts of weather variability on gas generation consumption are presented in this section.
- **Electricity transmission investments**. Several key electricity transmission projects are required to successfully integrate the large amount of forecast VRE generation into the NEM, and to lessen the impact of planned coal-fired power station retirements. The project of particular interest in the outlook period is EnergyConnect, connecting South Australia and New South Wales in 2025. If the completion of this project is delayed, Victorian gas generation consumption is likely to be higher than reported below in **Table 11**.

[56] For large-scale batteries, only generation is shown, not generation net of load (which would be negative due to round-trip losses).

- **Major transmission outages**. Outages of key electricity transmission assets in the NEM can result in increased levels of gas generation.
- **Uncertainty around early closure of coal-fired generators**. These gas generation forecasts consider the early closure of some coal fired generators as modelled in the *Orchestrated Step Change (1.8°C)* scenario. Although this is considered the most likely retirement path in the Draft 2023 IASR, deviations from it could affect gas generation consumption. This is reflected by the announcement that Origin Energy's Eraring coal-fired power station will close in 2025[57], seven years ahead of schedule, and the rejected takeover bid of AGL that sought to retire its coal-fired generators 15 years ahead of schedule[58].
- **Reliability of coal-fired generators**. Unavailability of coal-fired generators can greatly increase gas generation consumption. For example, average Victorian gas generation increased by 195 MW during quarter 2 of 2022, and 159 MW during quarter 3, over the equivalent periods in 2021, driven by a combination of higher spot prices, lower brown coal generation and portfolio dynamics[59]. Very high gas generation was observed throughout winter 2022 due to wet La Niña conditions and flooding across eastern Australia impacting the supply of thermal coal, particularly in New South Wales[60].
- **Operating behaviour of coal-fired generators.** Seasonal mothballing and shutting down at times of low prices are examples of behaviour that may impact the level of gas generation.
- **Gas prices**. Gas prices varying from projected levels may impact the amount of gas generation offered in the NEM.

2.4.1 Annual gas generation consumption forecast

Figure 16 shows historical annual DTS gas generation consumption from 2019 to 2022, and a range of annual gas generation consumption forecasts from 2023 to 2027. The maximum and minimum forecasts in this figure relate to forecast variability due to weather. The average gas generation forecast for all scenarios is presented in **Table 11**.

The following important points are shown in both **Figure 16** and **Table 11**:

- DTS gas generation consumption is forecast to decline in year 2024 and 2025, then increase by a similar amount over the following two years in 2026 and 2027. This results in the DTS gas generation consumption remaining nearly equal over the VGPR outlook period with a slight decrease of 0.3%.
  - This is an increase from the previous forecast reduction of 43% from 2022 to 2026 reported in the 2022 VGPR Update, and gas generation consumption forecasts are now higher – forecast DTS gas generation consumption in the 2022 VGPR Update was 7.1 PJ in 2023 and 4.4 PJ in 2026. The increase in forecast consumption to 8.4 PJ in 2023 and 5.8 PJ in 2026 is largely driven by a reduction in forecast coal generator availability.

[57] Rhiana Whitson and Michael Janda, ABC, "Origin Energy to shut Australia's largest coal-fired power plant, Eraring Power Station, by 2025", 17 February 2022, at: https://www.abc.net.au/news/2022-02-17/origin-to-shut-eraring-power-station-early/100838474#:~:text=Origin%20Energy%20is%20seeking%20approval,to%20close%20by%20August%202025.

[58] Emma Field, ABC, "AGL rejects bid by billionaire Mike Cannon-Brookes to buy energy company", 21 February 2022, at: https://www.abc.net.au/news/2022-02-21/agl-rejects-mike-cannon-brookes-brookfield-bid/100847318.

[59] See https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf and https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q3-2022.pdf.

[60] Reuters 2022, "Key Australian coal line shut due to torrential rain", 6 July 2022, at https://www.reuters.com/business/autos-transportation/key-australian-coal-rail-line-shut-due-torrential-rain-2022-07-06/.

- Weather uncertainty and generator outages create a broad range in forecast annual gas generation consumption, particularly early in the outlook period.
- The reduction in forecast gas generation consumption over the outlook period is influenced by increasing solar and wind generation capacity (shown earlier in **Figure 15**), as well as small amounts of battery storage and distributed energy resources (DER).
- Forecast consumption decreases until 2025 due to the NEM forecast decline in gas generation as renewable energy penetration grows. However, gas generation consumption is expected to increase starting in 2025, as increased electrification in the *Orchestrated Step Change (1.8°C)* scenario raises electricity demand in the NEM, and gas generation is also forecast to provide power system services with security and stability.

Figure 16 Historical and forecast minimum and maximum annual DTS gas generation consumption, 2019-2027, PJ

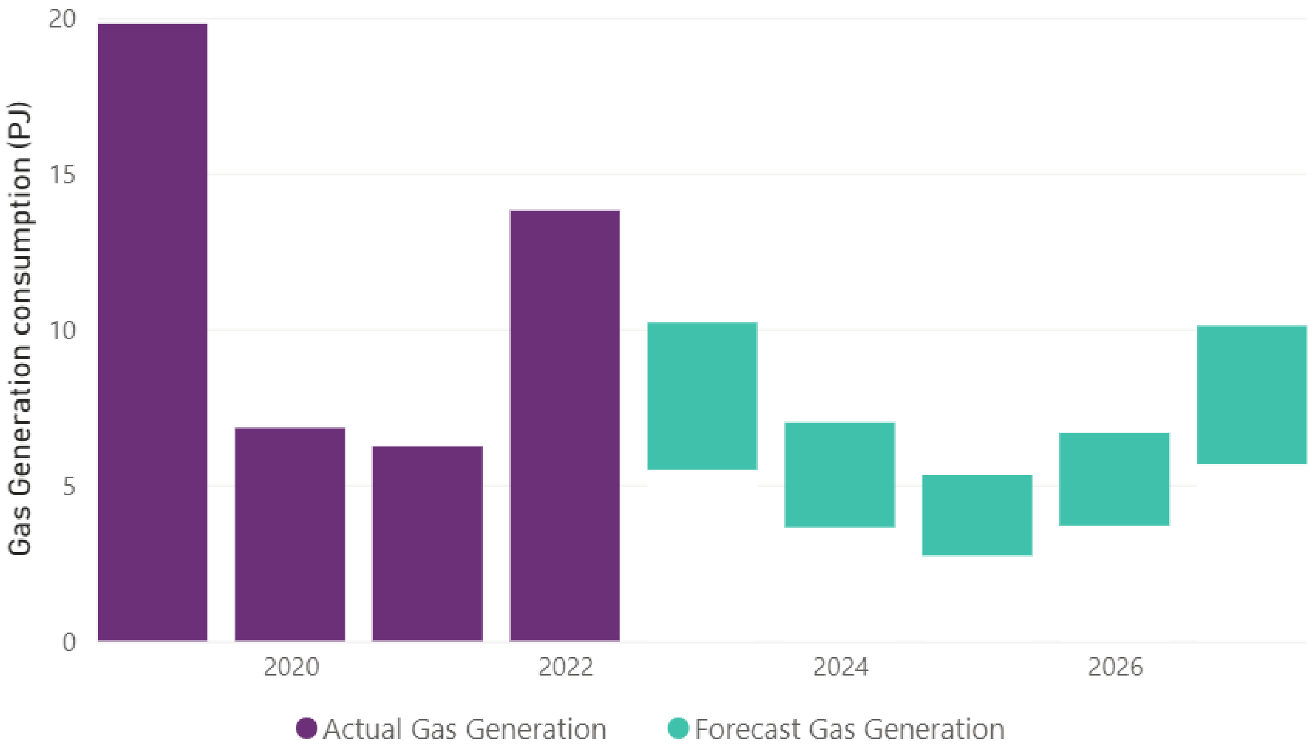


Table 11 Gas generation consumption forecast, 2023-27 (PJ/y)

	2022 (Actual)	2023	2024	2025	2026	2027	Change over outlook
DTS gas generation consumption	13.8	8.4	5.9	4.5	5.8	8.3	-0.3%
Non-DTS gas generation consumption	6.9	10.0	6.9	5.1	6.3	8.4	-16.5%
Victorian gas generation consumption	20.7	18.4	12.8	9.6	12.1	16.7	-9.1%

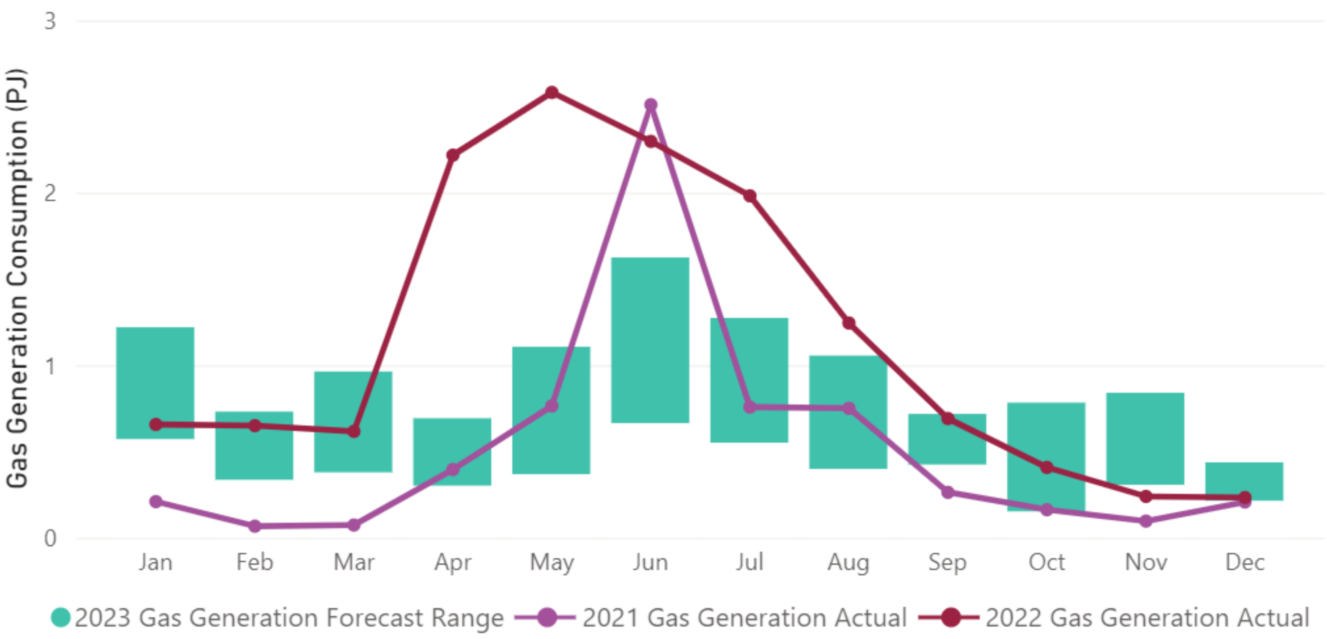
2.4.2 Monthly gas generation forecast for 2023

Figure 17 shows actual monthly DTS-connected gas generation consumption in 2021 and 2022, and the forecast minimum and maximum monthly consumption for 2023.

Monthly gas generation consumption can be significant during the winter and shoulder periods, with the potential to coincide with a 1-in-2 or 1-in-20 peak winter demand day. The forecast shows that monthly gas generation consumption is projected to peak in June 2023, driven by a combination of high NEM demand and limited VRE output. The NEM remains vulnerable to coal generator outages in winter, which could drive gas generation consumption even higher than this forecast.

For actual gas generation consumption, 2022 saw a significant increase starting in April and remained above 2 PJ/m until July, compared to less than 1 PJ/m of consumption during the same period in the previous year for April, May and July 2021. This was driven by the unprecedented increase in wholesale electricity prices in the NEM that was caused by a number of compounding factors including an increase in electricity demand due to colder weather, planned generator outages, coal generator outages and the war in Ukraine. In comparison, the high gas generation consumption in June 2021 was due to extended power station outages that occurred following the Callide Power Station unit C4 incident and flooding at the Yallourn mine which severely impacted Yallourn Power Station operation.

Figure 17 Historical and forecast monthly DTS-connected gas generation consumption, 2021-23 (PJ/m)



2.4.3 Seasonal peak gas generation demand forecast

The seasonal gas generation demand forecast for the summer and winter periods follows a similar trend to annual consumption, with an initial drop and then an increase from 2025. However, peak demand during summer is forecast to decrease by 22% from a maximum forecast of 353 TJ/d in 2023 to 274 TJ/d in 2027.

Peak gas generation demand in winter is predicted to increase by 52%, from a maximum forecast of 213 TJ/d in 2023 to 323 TJ/d in 2027, which – if system demand was above approximately 1,000 TJ – would exceed the current DTS record total demand of 1,308 TJ/d on 9 August 2019. This increase in forecast winter gas generation consumption is due to the expected electrification of winter heating loads as the NEM's winter load increases.

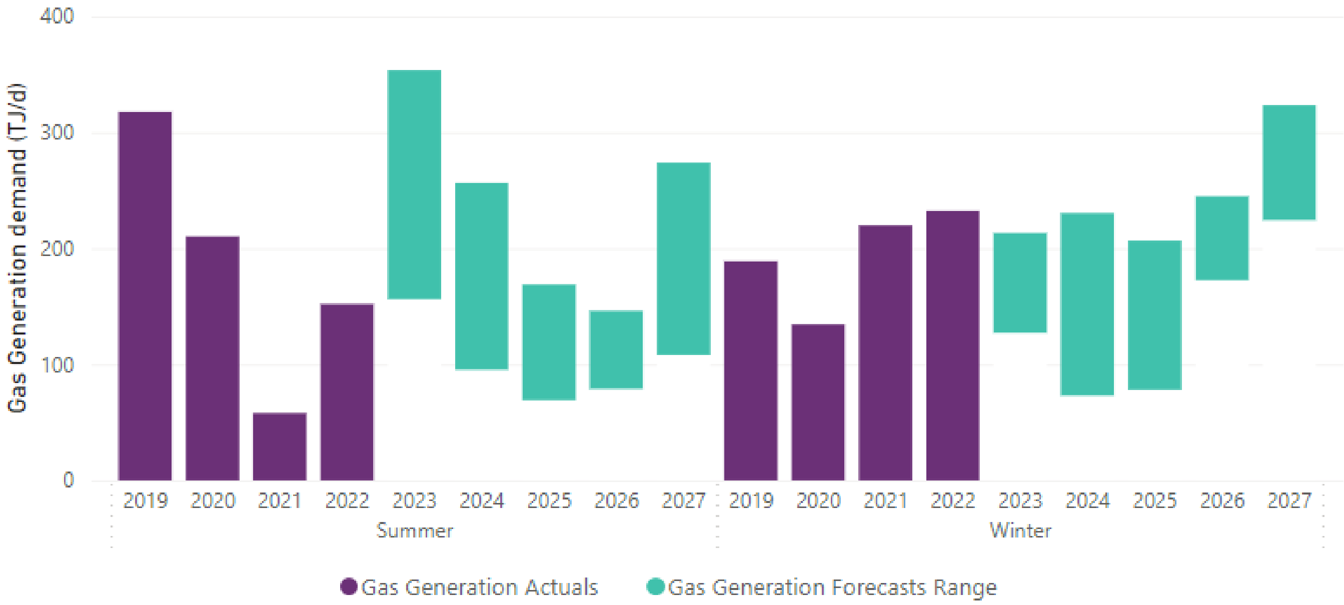
Figure 18 shows that despite the forecast remaining almost equal in annual consumption for gas generation in 2027, maximum gas generation demand during the winter peak period is expected to remain high, and during the outlook period it is forecast to exceed the forecast maximum summer gas generation demand.

The 2023 GSOO reports that gas generation demand is forecast to become increasingly 'peaky' beyond this VGPR outlook period, and in some scenarios, a month's worth of gas generation consumption may be used in a few days. On these days, the value of the capacity provided by gas generation is important for electricity consumers, or the use of alternative resources (such as electricity demand response, alternative secondary generation fuels, and stored energy in electrical storages) will be needed to maintain reliability. Flexible solutions to deliver the gas required under these challenging conditions will become increasingly important, and could include utilisation of the linepack within high-pressure pipelines, local gas storages, and large gas users being on interruptible contracts.

It is important to note that the seasonal peak gas generation shown in **Figure 18** has the potential to coincide with a peak system demand day.

Significant gas generation consumption during the winter period may create operational challenges and has the potential to lead to a threat to system security if gas generation demand is not forecast accurately from the beginning of the gas day, or if it is higher than available gas supply.

Figure 18 Historical (2019-22) and forecast (2023-27) seasonal maximum and minimum DTS gas generation demand in summer and winter, TJ/d



Note: Summer months in this chart are December, January, and February. Winter months are June, July, and August.

3 Gas supply adequacy forecast

Key findings

- Supply adequacy tightens in the later years of the outlook period and there is forecast to be an annual and peak day supply shortfall in 2027. The supply adequacy assessment includes a forecast 9.1% reduction in Victorian gas consumption during the outlook period. A tight supply demand balance can cause market instability and volatile gas prices.
- The 2023 GSOO highlights the risk of peak day shortfalls in the southern states for all years in the VGPR outlook period in the event of high coincident system and gas generation demand across all states. Peak day gas shortfall risks may be lower if reliance on gas use for electricity generation during periods of peak gas demand is reduced, including by the use of liquid fuel or the management of electricity demand.
- Key changes impacting supply adequacy since the 2022 VGPR Update include:
  - There is insufficient certainty to include Port Kembla Energy Terminal (PKET) or other proposed LNG receiving terminals as anticipated projects in the VGPR supply adequacy assessment.
  - Due to several years of delay, the current uncertain investment environment for gas projects, rig availability and investor uncertainty, the Golden Beach Energy Storage Project has not been included in the 2023 VGPR supply adequacy assessment as an anticipated project.
  - APA has committed to the Winchelsea Compressor 2 project which, along with the Western Outer Ring Main (WORM) pipeline project, will increase the capacity of the SWP from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023.
  - Beach Energy has committed to the connection of the Enterprise gas field to the Otway Gas Plant with gas targeted for early 2024. This project, and the connection of additional Thylacine gas field wells to the Otway Gas Plant during winter 2023, will return the plant capacity to its nameplate capacity of 205 TJ/d.
- The forecast shortfall for Victoria in 2027 cannot be supplied by other jurisdictions, as there is a projected shortfall of gas across all of Australia's southern states in 2027, as reported in AEMO's 2023 GSOO. Unless new Victorian supply is developed, Victoria is forecast to be required to become a net importer of gas from winter 2027, as Victorian annual consumption exceeds Victorian production.
- Forecast high gas flows out of Victoria, combined with declining Victorian production, increases the southern states' reliance on Victorian gas storage, both Iona UGS (deep storage) and Dandenong LNG (shallow storage). Reliance on Victorian storage is offset by the Newcastle Gas Storage Facility (shallow LNG storage) in New South Wales if it continues to be available.
- The outlook for peak day supply adequacy in winter 2023 has improved since last year's forecast:
  - Forecast production from the Gippsland region during the outlook period is higher than the forecasts provided for the 2022 VGPR Update. Available Gippsland peak day production is 915 TJ/d, 191 TJ/d higher than the 724 TJ/d reported last year. This is lower than actual 2022 peak production of 1,126 TJ/d and is forecast to reduce to 771 TJ/d prior to winter 2024.
  - The Victorian production profile is more aligned with the typical Victorian consumption profile for all years in the outlook period than it was in the 2022 VGPR Update forecasts.

- Despite improved peak day supply adequacy for winter 2023, expected peak day supply to the DTS is forecast to decline by 8% from the 1,595 TJ/d available in 2022 to 1,471 TJ/d during winter 2023, and then to 980 TJ/d in 2027 (a 39% decline compared to 2022).

Background

AEMO assesses supply adequacy based on its demand forecasts (see **Chapter 2**) and the forecast available Victorian supply from data provided to AEMO by producers, storage providers, pipeline operators, and market participants.

AEMO assesses adequacy over three time periods in the VGPR:

- **Annual consumption** – an annual supply shortfall indicates that annual production within Victoria is projected to be insufficient to meet forecast Victorian annual consumption. Supply from storages and pipeline constraints are not considered.
- **Seasonal (monthly) winter consumption (1 May to 30 September inclusive)** – a seasonal supply demand imbalance indicates that a combination of Victorian production, Iona UGS, and interconnected pipeline flows is projected to be insufficient to meet forecast consumption. Supply from Iona UGS (deep storage) and pipeline constraints are considered.
- **Peak day demand (1-in-2 and 1-in-20)** – a peak day shortfall indicates that supply is projected to be insufficient to meet forecast demand on peak days only. Supply from Iona UGS (deep storage) and Dandenong LNG (shallow storage) and pipeline capacity constraints are considered.

Gas supply classification

Table 12 defines gas supply classifications used in the 2023 VGPR, with notes on the differences to these classifications in the 2023 GSOO and the Petroleum Resources Management System (PRMS)[61].

Table 12 Gas supply classification definitions

VGPR	2023 VGPR description	PRMS	GSOO
Existing supply	Comprises existing gas reserves and projects currently in operation.	Reserves: On Production	Existing supply
Committed supply	Encompasses committed new gas supply projects, including developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement and construction (EPC) phase, but are not currently operational.	Reserves: Approved for Development	Committed supply
Available supply	Incorporates both existing supply and committed supply.	Reserves: On Production, Approved for Development	Existing and committed supply
Anticipated supply	Considers gas supply from undeveloped reserves or contingent resources that producers forecast to be available as part of their best production estimates provided to AEMO. It includes projects or developments which have not reached FID but are considered likely to proceed during the outlook period (often using existing infrastructure).	Reserves: Justified for Development	Anticipated supply

[61] The PRMS for defining reserves and resources was developed by an international group of reserves evaluation experts and endorsed by the World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, and Society of Exploration Geophysicists.

VGPR	2023 VGPR description	PRMS	GSOO
Potential projects	Uncommitted gas supply projects that have not reached FID, which could potentially proceed during the outlook period. These projects have not been included in the anticipated supply forecast. They are considered less likely to proceed than the anticipated supply projects during the outlook period, due to: • The discovered gas fields being classified as contingent resources (not proven reserves) where commercial recovery is dependent on the development of new technology or where evaluation of the gas resource is still at an early stage; or • Insufficient gathering pipeline or appropriate gas processing capacity being available; or • The project requiring new infrastructure that currently does not have approved planning permits or environmental approvals.	Contingent Resources: Development Pending, Development on Hold, Development Unclarified	Uncertain supply
Exploration projects	These projects are associated with undiscovered gas resources that are usually mapped using seismic data. These have not been physically proven with exploration wells, so commercial quantities of hydrocarbons may not actually be present. Neighbouring wells and seismic data are used to estimate the 'gas in place', with the reported prospective resource volumes usually representing the estimated recoverable volume of hydrocarbons. These are not included in any of the supply forecasts but are discussed in the GSOO.	Prospective resources: Prospect/Leads/Plays	

3.1 Changes impacting the supply demand balance

This section highlights updates to key projects that materially impact the supply demand balance since the 2022 VGPR Update.

3.1.1 Updates reducing available supply

Port Kembla Energy Terminal

The PKET project was considered to be an anticipated project in the 2022 VGPR Update and 2022 GSOO, with supply forecast to become available from 2024. Squadron Energy has advised AEMO there is currently insufficient contracted capacity for the PKET to justify the import and use of the floating storage regasification unit (FSRU) [62]. Squadron Energy has informed AEMO that gas supply from PKET may not commence until 2026 based on prospective buyers' and Squadron Energy's own demand. Given the forecast date from which gas will become available remains dependent on capacity being contracted, there is not enough certainty to include PKET or other proposed LNG receiving terminals as anticipated projects in the VGPR supply adequacy assessment.

The 2023 GSOO considers PKET and other LNG import terminal projects as sensitivities for the overall supply adequacy assessment for the southern states [63]. **Section 4.4.2** has more information on the PKET and **Section 4.6** has more information on gas supply project uncertainties.

[62] An FSRU is an LNG storage ship that has an onboard regassification plant capable of vaporising stored LNG for supply into a gas pipeline.

[63] "Southern states" means New South Wales, South Australia, Victoria, the Australian Capital Territory, and Tasmania.

Golden Beach

The Golden Beach Energy Storage Project was reported as an anticipated project in the 2022 VGPR Update with production commencing in 2024 ahead of a conversion to gas storage service in 2026. Production commencement has been further delayed until 2025 with storage services still expected to commence in 2026. A final investment decision (FID) for the project is expected in late June or July 2023[64].

Due to several years of delay, the current uncertain investment environment for gas projects, rig availability and investor uncertainty, this project has not been included in the 2023 VGPR supply adequacy assessment as an anticipated project. The project will be reported as a potential project in the 2023 VGPR and as an uncertain project in the 2023 GSOO. Further details on this project can be found in **Section 4.3**.

Trefoil

The Trefoil development was considered an anticipated project in the 2022 VGPR Update. Beach Energy has chosen to prioritise other projects, leading to the deferment of the FID for Trefoil[65] which has resulted in the reclassification of the Trefoil reserves. AEMO now considers this project as a potential supply. Further details on this project can be found in **Section 4.3**.

3.1.2 Updates increasing available supply

Winchelsea Compressor 2

In April 2022, APA reached FID for the installation of a second compressor on the SWP at the Winchelsea Compressor Station (CS)[66]. This will, with the WORM project, increase the capacity of the SWP from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023, increasing the peak day supply available from Port Campbell including the Iona UGS facility. Further details on this project can be found in **Section 5.2**.

Enterprise

Beach Energy reached FID for the development and connection of the Enterprise gas field to the Otway Gas Plant in March 2022[67] with production targeted for early 2024, subject to regulatory approvals. More details on this project are in **Section 4.1**.

East Coast Grid Expansion

Since the 2022 VGPR Update, APA has committed to Stage 2 of the East Coast Grid Expansion project[68], which will further increase the MSP and SWQP pipeline capacities by winter 2024. Further details on this project can be found in **Section 4.5**.

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[64] Angela Macdonald-Smith, "56 years on, Golden Beach gas nears production", 3 February 2023, at https://www.afr.com/companies/energy/56-years-on-golden-beach-gas-nears-production-20230203-p5chmt.

[65] Beach Energy, "Bass Basin update", 20 May 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1092400/BPT_Bass_Basin_update.pdf.

[66] APA Group, "APA announces additional capacity in Victoria ahead of forecast gas shortfalls", 21 April 2022, at https://www.apa.com.au/news/media-statements/2022/apa-announces-additional-capacity-in-victoria-ahead-of-forecast-gas-shortfalls/.

[67] Beach Energy, "Quarterly report for the period ended 31 March 2022", 26 April 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1087937/BPT_Quarterly_report_for_the_period_ended_31_March_2022.pdf.

[68] APA Group, "APA Commences Stage Two of East Coast Gas Grid Expansion", 25 May 2022, at https://www.apa.com.au/globalassets/asx-releases/2022/apa-commences-stage-two-of-east-coast-gas-grid-expansion.pdf.

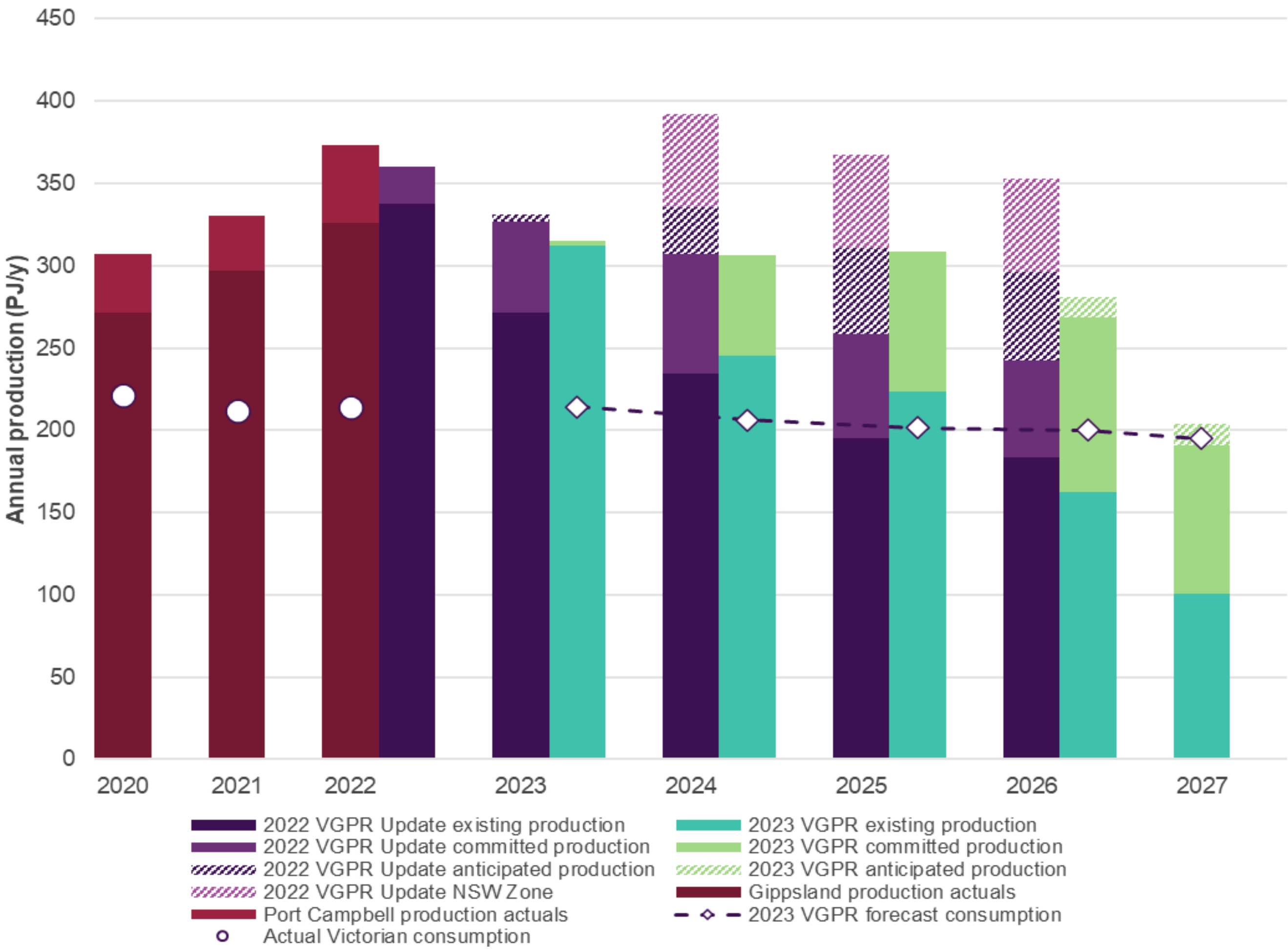
3.2 Annual supply demand balance

This section discusses the reported Victorian annual gas supply and its adequacy during the outlook period. The section does not consider DTS storage facilities, because these facilities provide seasonal balancing for peak demand periods and are not expected to provide annual supplies.

3.2.1 Annual production forecasts

Figure 19 shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2022 VGPR Update. The full data set is available in **Appendix A3**.

Figure 19 Historical and forecast supply and consumption, and compared to the 2022 VGPR Update, 2020-27 (PJ/y)



Gippsland zone[69]

Total Gippsland region production is forecast to reduce from 326 PJ in 2022 to 284 PJ in 2023, which is a 13% reduction. Gippsland region production is forecast to reduce further to 130 PJ in 2027, 54% lower than for winter

[69] Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.

2023. This includes production from the committed Kipper compression project with additional supply expected from 2024.

The reduction is mainly due to the forecast reduction in production associated with the depletion of the Gippsland Basin Joint Venture (GBJV) large legacy fields that supply the Longford Gas Plant. The anticipated Kipper Stage 1B infield additional well development project lessens the reduction in Gippsland production from 2026 but does not replace the capacity lost due to the depletion of GBJV's large legacy gas fields. This project is discussed in **Section 4.2**.

Production from Longford in 2022 was higher than forecast as the plant responded to the market drivers discussed in **Section 1.2**. Total production for 2022 from Longford was 305 PJ, up from 277 PJ in 2021 and the highest production since 2017, with daily supply from the plant reaching over 1,040 TJ/d during winter 2022. Esso achieved this by reconfiguring the offshore pipeline network and working closely with operators of connected transmission pipelines (AEMO as operator of the DTS and Jemena as operator of the EGP) to operate the Longford system at its hydraulic limits.

Accessing higher production earlier than planned can accelerate the depletion of gas fields. Esso has advised AEMO that the increased supply from Longford in 2022 was primarily offset by an increase in legacy field reserves.

The largest reductions in available Gippsland production are forecast to occur in 2024 and 2027. This is later than the outlook provided in the 2022 VGPR Update, which forecast the largest drop in production to occur prior to winter 2023. The delay in the decline is driven by increased quantities of gas from existing fields being available for 2023 as the large GBJV legacy fields have been able to maintain production for longer than previously forecast.

The unpredictable decline in the GBJV legacy fields is characteristic of aquifer-driven reservoirs at the end of their field life. The large size and old age of these fields also creates uncertainty. It is expected than once the fields approach final depletion, the drop in production will be rapid.

Port Campbell[70]

Total available production from Port Campbell is forecast to decrease 33% from 48 PJ in 2022 to 32 PJ in 2023, then increase by 128% to 73 PJ in 2024 with four new Thylacine production wells coming online during winter 2023[71] and production from the Enterprise gas field from the first half of 2024. Completion of these projects will return the Otway Gas Plant to nameplate capacity of 205 TJ/d. Production from Port Campbell, which also includes the Athena Gas Plant, which processes gas from the Casino, Henry, and Netherby gas fields, is projected to remain relatively stable from 2024 until 2027 when it decreases to 60 PJ.

The forecast available production in 2023 from Port Campbell has decreased from the 73 PJ reported in the 2022 VGPR Update to 32 PJ. The large forecast production decrease is due to the connection of the new Thylacine wells being delayed from early 2023 to mid-2023 due to COVID-19 related issues and regulatory approvals. Available Port Campbell production during the outlook period is otherwise similar to what was reported in the 2022 VGPR Update, with the previously anticipated Enterprise development project now classified as a committed project.

[70] Port Campbell zone includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station.

[71] Beach Energy, "Otway Offshore Project – Thylacine Wells Subsea Installation & Commissioning", 17 November 2022, at https://www.beachenergy.com.au/wp-content/uploads/Beach-Energy-Thylacine-Wells-Commissioning-Info-Sheet.pdf.

The increased Port Campbell production is expected to reduce Iona UGS depletion risk, result in higher SWP utilisation for supply to Melbourne, and improve physical supply at Port Campbell for Iona UGS refilling.

New South Wales zone

This zone was introduced in the 2021 VGPR to include net supply from New South Wales into Victoria. The zone captured quantities of gas delivered into Victoria by the PKET via the EGP to VicHub and from the MSP via Culcairn to support future winter demand.

The 2023 VGPR supply adequacy assessment does not include PKET, so no net supply is available from the New South Wales zone during outlook period.

3.2.2 Annual supply adequacy

Table 13 shows the annual supply adequacy forecast over the outlook period.

Table 13 Victorian annual available supply and anticipated supply balance, 2023-27 (PJ/y)

Supply source		2023	2024	2025	2026	2027
Gippsland [A]	Existing	284	229	201	146	90
	Committed	0	5	37	55	40
	Total available	**284**	**234**	**238**	**201**	**130**
	Anticipated	0	0	0	13	14
	Total available plus anticipated	284	234	238	213	144
Port Campbell [B] **(Gippsland)**	Existing	28	16	22	17	11
	Committed	4	57	49	51	50
	Total available	**32**	**73**	**71**	**68**	**60**
	Anticipated	0	0	0	0	0
	Total available plus anticipated	32	73	71	68	60
Total Victorian Production	Existing	312	245	223	163	101
	Committed	4	62	85	106	90
	Total available	**315**	**307**	**308**	**269**	**190**
	Anticipated	0	0	0	13	14
	Total available plus anticipated	315	307	308	281	204
Total Victorian consumption [C]		214	206	201	200	195
Surplus quantity with Victorian available supply		**101**	**100**	**107**	**68**	**-4**

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Port Campbell zone includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station. Iona UGS in not included in annual supply assessments (as it is assumed to fill and empty during the year).
C. Total consumption includes system demand and gas generation demand.

The annual supply adequacy assessment indicates:

- There is forecast to be sufficient annual supply for most of the outlook period, with surplus Victorian production ranging from 101 PJ in 2023 to 68 PJ in 2026 available to supply New South Wales, South Australia and Tasmania.
- In 2027, Victorian consumption is forecast to exceed Victorian production, and there is projected to be an annual shortfall of 4 PJ. Completion of anticipated supply projects, which increases forecast supply by 14 PJ, is

projected to provide sufficient annual supply, although seasonal supply during winter is expected to be insufficient (see **Section 3.3.3**).

- The forecast reduction in Victorian production, even with the anticipated projects, will result in reduced gas being available to supply other jurisdictions from 2026, and negligible supply being available in 2027.

As discussed in **Chapter 2**, the VGPR consumption forecast includes an assumption that there is an increasing amount of electrification of gas demand in the outlook period, mostly of Tariff V demand. If this electrification is delayed beyond the outlook period, this does not change the timing of the annual supply shortfall but does increase the magnitude from 4 PJ to 22 PJ in 2027, which is more than the available and anticipated Victorian production.

The annual adequacy assessment is limited as production and consumption varies throughout the year:

- In summer months, Victorian production is higher than Victorian consumption and the excess gas is used to refill Iona UGS and supply other jurisdictions.
- Victorian consumption exceeds production during the winter months and Iona UGS is used to support increased Victorian demand, with supply also continuing to other jurisdictions during winter.
- Monthly (seasonal) adequacy is discussed in **Section 3.3.2**.

3.3 Monthly supply demand balance

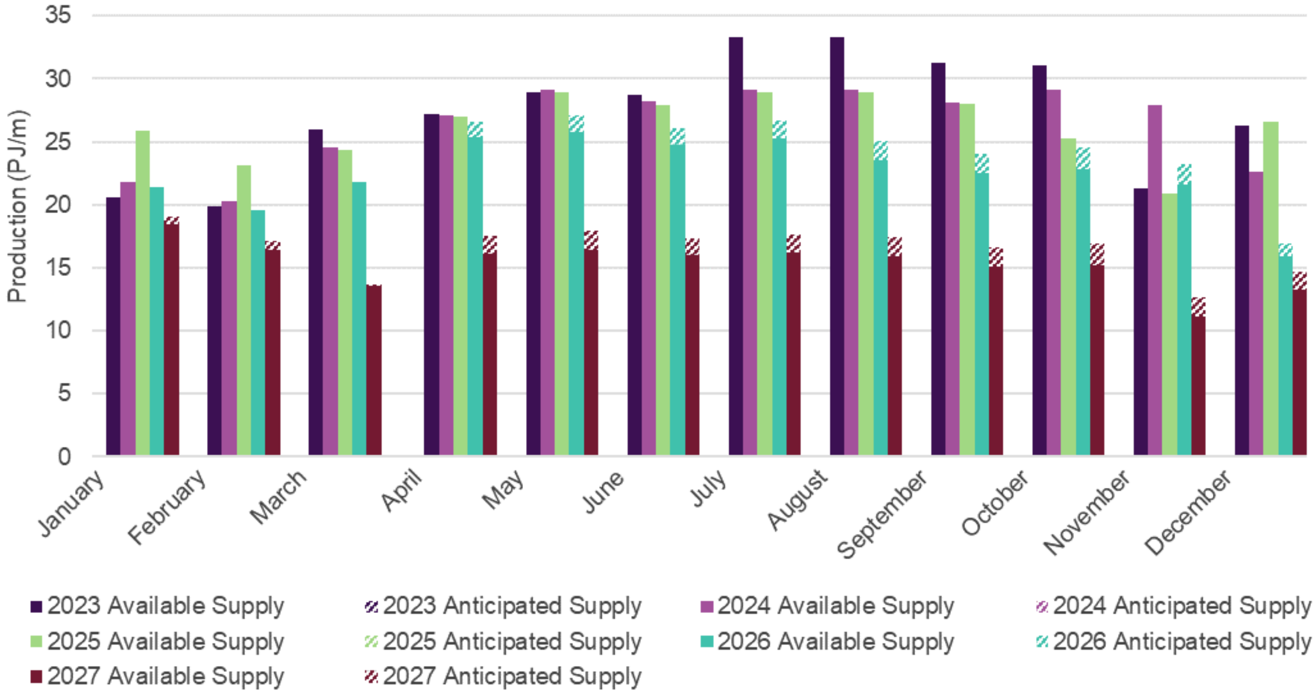
This section discusses the forecast Victorian monthly gas supply for the outlook period, and its adequacy to balance forecast consumption for each month and seasonally over the outlook period. Commentary on DTS storage facilities and interstate supply from DTS-connected gas pipelines is included because they are essential for balancing supply and demand in the southern states during the winter period.

3.3.1 Monthly production forecasts

Figure 20 shows forecast monthly production for the outlook period, highlighting that:

- Forecast monthly gas production is expected to decline over the outlook period. Production for the winter months of 2027 is half of what is forecast to be available for winter 2023 (16 PJ/m compared to 33 PJ/m).
- Available monthly Victorian production during the winter peak demand period is forecast to be similar to monthly winter consumption (19-28 PJ/m) from 2024 to 2025. From 2026, available monthly Victorian production is forecast to be less than winter consumption.

Figure 20 Monthly production forecast, 2023-27 (PJ/m)



3.3.2 Monthly supply adequacy

Monthly Victorian production has historically peaked during winter, as Longford Gas Plant production has been able to increase in line with the seasonal demand profile. Most other production facilities operate with a flatter production rate all year, with production limited by either the processing capacity of the facility or the supply capacity of the connected gas fields.

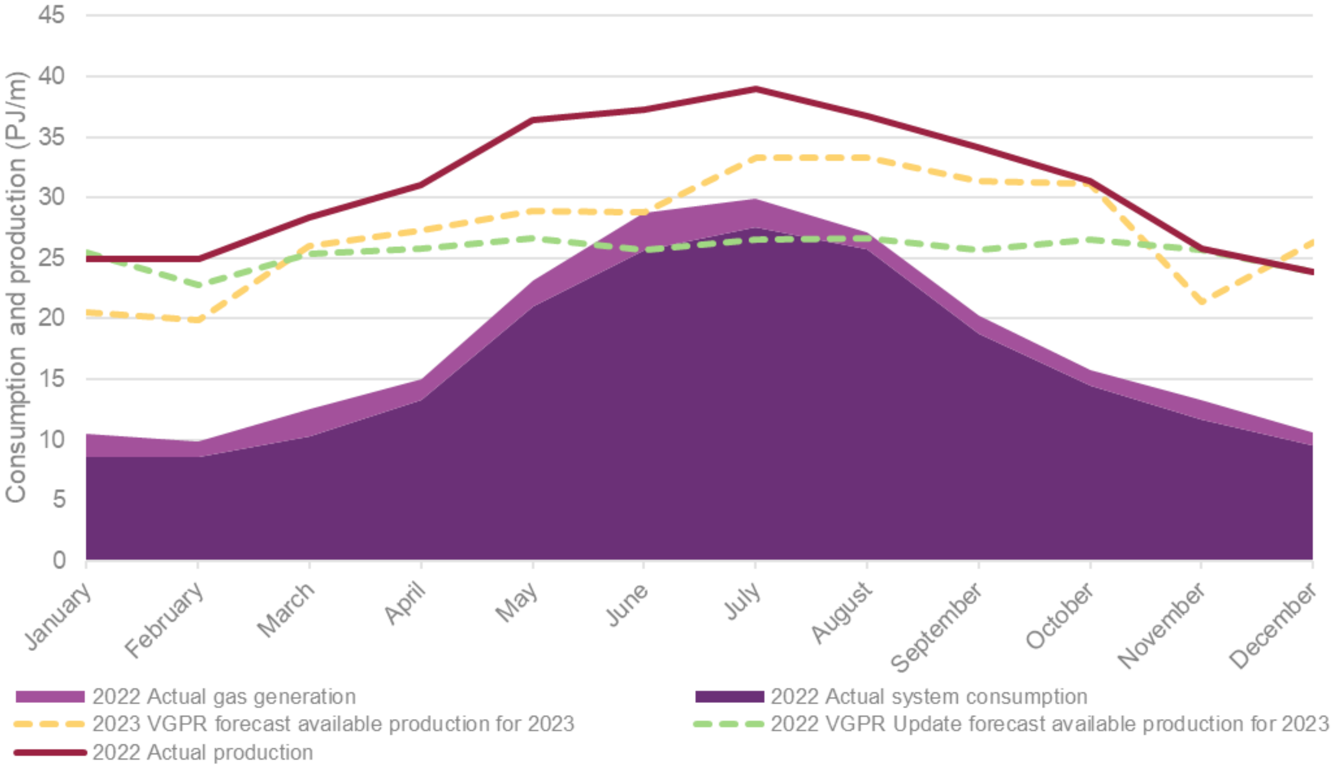
Figure 21 shows actual Victorian monthly production and consumption in 2022 compared to the available production forecasts for 2023 from the 2023 VGPR and the 2022 VGPR Update. The graph illustrates how Victorian gas consumption increases substantially during the winter months compared to summer months, and how 2022 gas production remained higher than monthly consumption (with the remaining production supplied to neighbouring states).

Average summer production in 2022 was 27 PJ/m, which increased by 10 PJ/m to an average of 37 PJ/m during the winter months. This was primarily due to Longford's winter production profile and, to a lesser extent, the Otway Gas Plant production profile.

The 2021 VGPR and 2022 VGPR Update reported that, with the forecast reduction in Longford's production capability and flexibility from 2023, the monthly Victorian production profile was expected to flatten. **Figure 21** shows the 2022 VGPR Update's Victorian monthly production forecast for 2023, with the forecast average summer production of 25 PJ/m only increasing by 1 PJ/m to 26 PJ/m for the winter months.

The 2023 VGPR production forecast includes more of a seasonal production profile for winter 2023, due to a higher Longford winter production capacity than reported in the 2022 VGPR Update. The 2023 VGPR forecasts an average 2023 summer production of 25 PJ/m, increasing by 6 PJ/m to average 31 PJ/m in winter. This profile will help mitigate the reliance on Iona UGS to support winter baseload demand, although forecast Victorian monthly production during winter 2023 is approximately 6 PJ/m lower than during winter 2022.

Figure 21 Actual monthly production and consumption in 2022, compared to available production in 2023 from the 2022 VGPR Update and 2023 VGPR (PJ/m)



The Victorian production profile is more aligned with the typical Victorian consumption profile for all years in the outlook period than it was in the 2022 VGPR Update forecasts. The forecast Victorian production profile for 2027 is flatter, impacting seasonal and peak day supply adequacy, however production profile forecasts are less certain for later years due to the uncertainty introduced by potential production projects.

3.3.3 Victorian seasonal adequacy as part of east coast Australia

The VGPR supply adequacy assessments consider using all available Victorian gas production and storage to support Victorian gas demand. This is a somewhat limited analysis, as it does not account for the export of Victorian production to other states.

Victoria is interconnected to neighbouring jurisdictions by transmission pipelines that form part of a broader east coast gas grid. Victoria can directly supply:

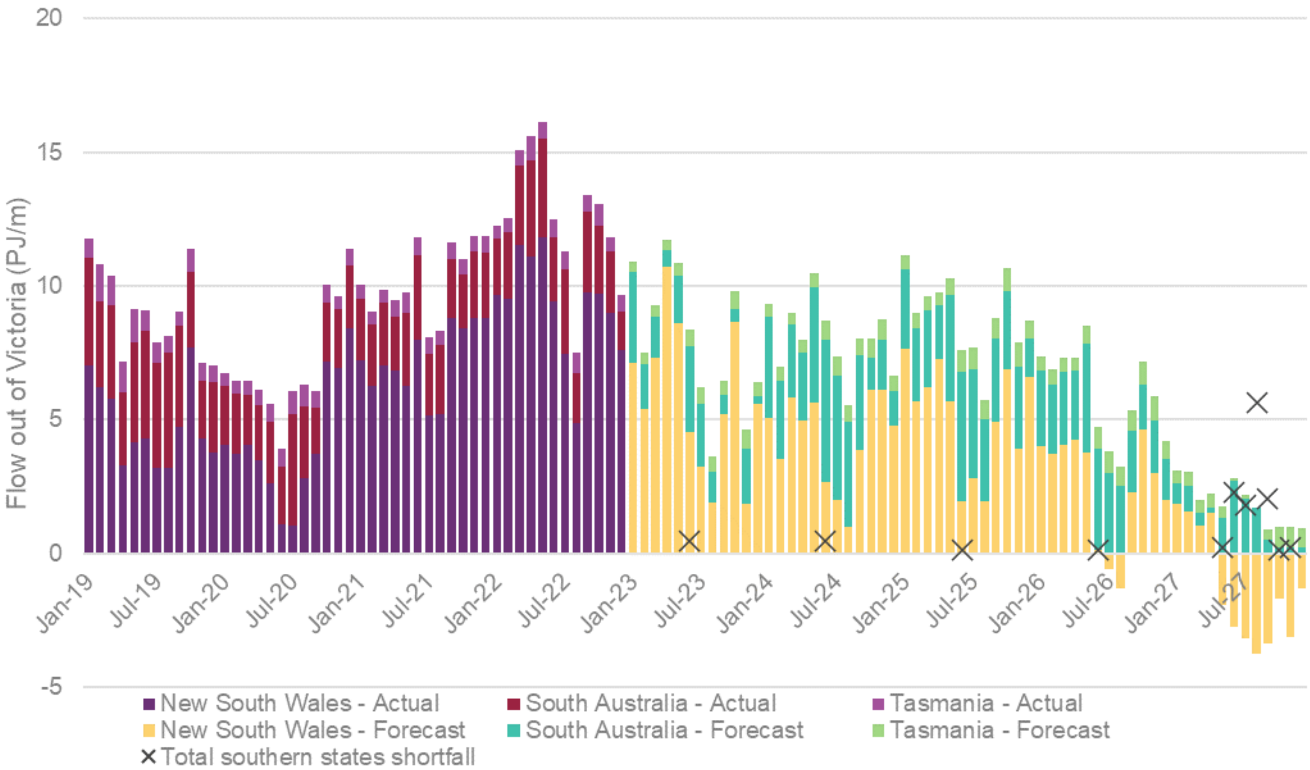
- New South Wales via the Eastern Gas Pipeline (EGP) and the Moomba Sydney Pipeline (MSP) via the Culcairn interconnection,
- South Australia via the SEA Gas Pipeline, and
- Tasmania via the Tasmanian Gas Pipeline (TGP).

Victoria can also supply gas to Queensland via the MSP through New South Wales. Alternatively, Victoria can import gas from Queensland via Culcairn, as the MSP is bidirectional. There are also proposed projects to make the EGP and SEA Gas pipelines bidirectional if LNG receiving terminal projects at Port Kembla and Outer Harbor (in Adelaide) respectively are progressed.

If Victorian demand and exports exceed Victorian production, Iona UGS is used to provide additional supply. During winter 2022, AEMO issued Threat to System Security notices as the heavy draw down of Iona UGS to support uncontracted gas flows from Victoria to other states and gas use by Victorian gas generation without contracted gas supply during the high winter gas demand period risked the emptying of Iona UGS prior to the end of winter (discussed in **Section 1.2.1**).

Figure 22 shows the actual monthly flows out of Victoria to neighbouring states from 2019 to 2022 and the forecast flow out of Victoria from 2023 to 2027. The forecast flows out of Victoria for the outlook period used modelling performed for the 2023 GSOO, which considered demand across the entire east coast and pipeline flows between states. The modelling assumed that all production facilities and transmission assets are available at forecast capacities and included supply from committed projects.

Figure 22 Actual and forecast flows out of Victoria, 2019-27 (PJ/m)



The results show that:

- The amount of gas exported from Victoria is projected to remain at historical levels for the first years of the outlook period, then decrease through 2026 to 2027, reflecting the forecast decline in Victorian production.
- The forecast annual gas supply shortfall for Victoria in 2027 cannot be supplied by other jurisdictions, because there is a projected shortfall of gas across all the southern states in 2027. From winter 2027, Victoria is forecast to become a net importer of gas as Victorian monthly consumption exceeds Victorian production and available storage inventory (unless potential Victorian supply and storage projects are developed). If potential supply projects progress in other jurisdictions and there is sufficient pipeline capacity from that jurisdiction, Victoria could import gas to overcome the forecast shortfall.

- The total southern states shortfalls that are forecast for winter months from 2023 to 2026 are driven by high coincident gas generation and system consumption across the southern states during the winter peak demand period.
- The sustained high flows out of Victoria combined with declining Victorian production increase the east coast grid's reliance on Iona UGS, even with supply from Queensland maximised. A large portion of the full Iona UGS working inventory[72] of 18-19 PJ is expected to be utilised each winter in the outlook period. The winter 2022 utilisation of Iona UGS inventory was 14.1 PJ, noting that milder weather was experienced during August 2022. Complete utilisation of Iona UGS would mean there is no longer a supply buffer to cover unplanned outages or increases in demand, but it is also means that the peak day supply capacity provided by Iona UGS is substantially reduced.
- Modelling in the 2023 GSOO projects that Dandenong LNG storage will be heavily drawn down during each winter, corresponding to complete or near complete inventory utilisation every year during the VGPR outlook period. Relying on shallow storage to satisfy the supply demand balance increases the risk that this supply capacity would not be available to provide an operational response to alleviate threats to system security or to manage emergencies.
- Historical levels of exports from Victoria to South Australia are forecast to be maintained for longer than exports to New South Wales, as Port Campbell production is forecast to increase then remain stable over the outlook period and supply from Port Campbell to the DTS is limited by the SWP[73] transportation capacity.
- Victoria is forecast to continue to supply all of Tasmania's gas requirements, because Tasmania has no alternate source of supply.

Refer to the 2023 GSOO for further discussion on east coast supply adequacy.

3.4 Peak day supply demand balance

This section discusses the forecast Victorian peak demand day gas supply over the outlook period.

3.4.1 Forecast Victorian supply capacity

The forecast maximum daily Victorian supply capacity by System Withdrawal Zone, including capacity from the Iona UGS and Dandenong LNG storage facilities, is shown in **Table 14**. The actual supply available to the DTS from each zone is lower due to DTS capacity constraints and gas flows from Gippsland to other jurisdictions, which is discussed in **Section 3.4.2**.

Based on advice from gas producers and storage providers, the available Victorian peak day supply capacity is forecast to decline by 30% over the outlook period:

- Gippsland producers have advised that maximum daily production capacity will reduce by 54%, from 915 TJ/d in 2023 to 425 TJ/d in 2027. The actual maximum daily Gippsland production in 2022 was 1,126 TJ/d (10% higher than the forecast of 1,018 TJ/d published in the 2022 VGPR Update).

[72] The full working inventory of Iona UGS assumes the facility is full at 24 PJ (2023) or 24.5 PJ (2024-27) and gas is withdrawn to the minimum modelled inventory of 6 PJ. At some point below 6 PJ, the supply capacity from Iona UGS may be impacted.

[73] The SWP includes the Brooklyn to Lara pipeline (BLP).

  - The reduction in production capacity is driven by the decline in the large legacy fields that supply the Longford Gas Plant, which was first highlighted in the 2018 VGPR Update.
  - Available Gippsland production includes supply from the committed Kipper compression project with additional supply expected from 2024.
  - The anticipated Kipper Phase 1B project will partly offset the decline in Gippsland production, but production capacity is still forecast to decline by 48% over the outlook period.
- Port Campbell producers and the storage operator have advised that maximum daily supply capacity will remain relatively stable over the outlook period, decreasing by 6%, from 785 TJ/d in 2023 to 737 TJ/d in 2027.
  - Production capacity is projected to increase from the actual maximum production of 188 TJ/d in 2022 to 227 TJ/d in 2023, mainly due to supply from the committed connection of the new Thylacine wells which will return Otway Gas Plant to its nameplate capacity of 205 TJ/d from mid-2023. This will be sustained by the committed development of the Enterprise field from early 2024.
  - Lochard Energy has increased the Iona UGS supply capacity from 545 TJ/d in 2022 to 558 TJ/d from January 2023. Lochard Energy will also expand Iona UGS capacity to 570 TJ/d from 2024.
- The Port Campbell peak day maximum daily quantity (MDQ) is expected to continue to be constrained by the SWP transportation capacity limit despite the construction of the WORM and Winchelsea Compressor 2.

Table 14 Peak day maximum daily quantity (MDQ) by System Withdrawal Zone, 2023-27 (TJ/d)

Supply source		2023	2024	2025	2026	2027
Gippsland [A]	Available	915	771	767	670	425
	Anticipated	0	0	0	49	51
	Total available plus anticipated	915	771	767	719	476
Port Campbell (Geelong) [B]	Available	785	795	792	783	737
	Anticipated	0	0	0	0	0
	Total available plus anticipated	785	795	792	783	737
Melbourne	Available	87	87	87	87	87
Total Victorian Supply	Total Victorian available	1,787	1,653	1,647	1,541	1,249
	Total Victorian anticipated	0	0	0	49	51
	Total Victorian available plus anticipated	1,787	1,653	1,647	1,590	1,300

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP so all of this capacity cannot be supplied to the DTS because of EGP and TGP demand.
B. Port Campbell zone includes the Otway and Athena production facilities. The combined supply is available to the DTS, South Australia and Mortlake Power Station. All of this supply cannot be supplied into the DTS due to the SWP capacity constraint.

3.4.2 Peak day supply adequacy

AEMO's peak day supply adequacy assessment uses a mass balance analysis combined with hydraulic pipeline modelling to determine what peak day supply capacity is available to the DTS, and whether this is sufficient to ensure continuity of supply to Victorian customers.

The forecasts shown in **Figure 23** and **Table 15** used the following data and assumptions:

- Forecast annual 1-in-2 and 1-in-20 peak day system demands, discussed in **Section 2.3**.

- The full capacity of the Iona UGS and Dandenong LNG storage facilities were assumed to be available, and not restricted due to low storage inventories.
- Demand from gas generation was not considered. Events in the NEM (including unplanned coal generator outages, and low wind and solar generation) could result in higher gas generation demand and total demand higher than a 1-in-20 system demand day level[74].
- The assessment only considers firm sources of gas supply. Imports from Culcairn via the Victorian Northern Interconnect (VNI) have not been included in the peak day supply capacity. 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 the Uranquinty Power Station. Short-term pipeline linepack (for example, in the TGP supplied via TasHub) is also not considered.

Figure 23 and **Table 15** highlight the following key points:

- There is an improvement to peak day supply adequacy compared to the 2022 VGPR Update and 2021 VGPR, particularly for winter 2023.
  - Gippsland producers' peak day production forecast for winter 2023 has increased by 191 TJ/d, from the 724 TJ/d reported in the 2022 VGPR Update to 915 TJ/d. Expected supply to the DTS is less due to demand on the EGP and in Tasmania as they have no other source of supply. This reduces the Gippsland DTS supply to 854 TJ/d for winter 2023.
  - As discussed in **Section 3.3.2**, the delayed flattening of the Longford monthly supply profile means that higher daily production continues to be available in winter than in summer.
  - The WORM and the Winchelsea Compressor 2 projects increase the SWP capacity from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023, increasing the peak day supply available from Port Campbell.
- There is sufficient supply to support peak system demand days for all years in the outlook period except 2027.
- Peak day adequacy tightens from 2024, which limits the amount of Victorian gas available to support gas generation demand and other jurisdictions. A tight supply demand balance can cause high gas prices including the triggering of administered market price caps. The VGPR only considers physical supply adequacy.
- System demand exceeds available supply on 1-in-2 and 1-in-20 peak system demand days in 2027, with forecast shortfalls of 34 TJ/d and 109 TJ/d respectively.
  - The shortfall may be partly offset by anticipated projects, increasing supply by 51 TJ/d, however there is still forecast to be insufficient supply to meet system demand on a 1-in-20 peak system demand day.
  - The shortfall may also be mitigated by non-firm sources such as non-firm Dandenong LNG injections, importing gas from New South Wales via Culcairn (if there is sufficient supply in that state) or utilising pipeline linepack.
  - Development of potential supply projects or an LNG receiving facility is required to avert shortfalls on peak system demand days in 2027. **Chapter 4** includes more information on future supply projects.

The 2023 GSOO forecasts peak day shortfalls in the southern states for all years in the VGPR outlook period in the event of high coincident system and gas generation demand across all states. AEMO forecasts gas

[74] Total demand on 9 August 2019, which was also the highest ever, was 1,308 TJ. This was comprised of 1,194 TJ of system demand and 109 TJ of gas generation demand.

generation demand to increase during winter, with very high demands for a few days each month. This increases the risk of high coincident system and gas generation demand that would result in insufficient gas supply on these peak days. Based on the experience during winter 2022, peak day gas supply shortfalls due to high coincident system and gas generation demands across multiple states are expected to be managed through the use of liquid fuel to supply gas generation (including in Victoria) or the management of electricity demand including response to NEM prices and utilisation of the Reliability and Emergency Reserve Trader (RERT) mechanism. See the 2023 GSOO for more on east coast supply adequacy.

As discussed in **Chapter 2**, the VGPR forecast includes an assumption that there is an increasing amount of electrification of mostly Tariff V demand gas demand in the outlook period. Sensitivity modelling forecasts that, if this electrification is delayed beyond the outlook period, it:

- Increases the magnitude of the shortfalls in 2027 from 34 TJ/d to 157 TJ/d on a 1-in-2 peak system demand day and from 109 TJ/d to 246 TJ/d on a 1-in-20 peak demand day.
- Brings forward the first year with a peak day shortfall from 2027 to 2026. The 69 TJ/d surplus on a 1-in-20 peak day demand day in 2026 becomes a 3 TJ/d shortfall.

Figure 23 Forecast peak day supply and DTS adequacy, 2023-27 (TJ/d)

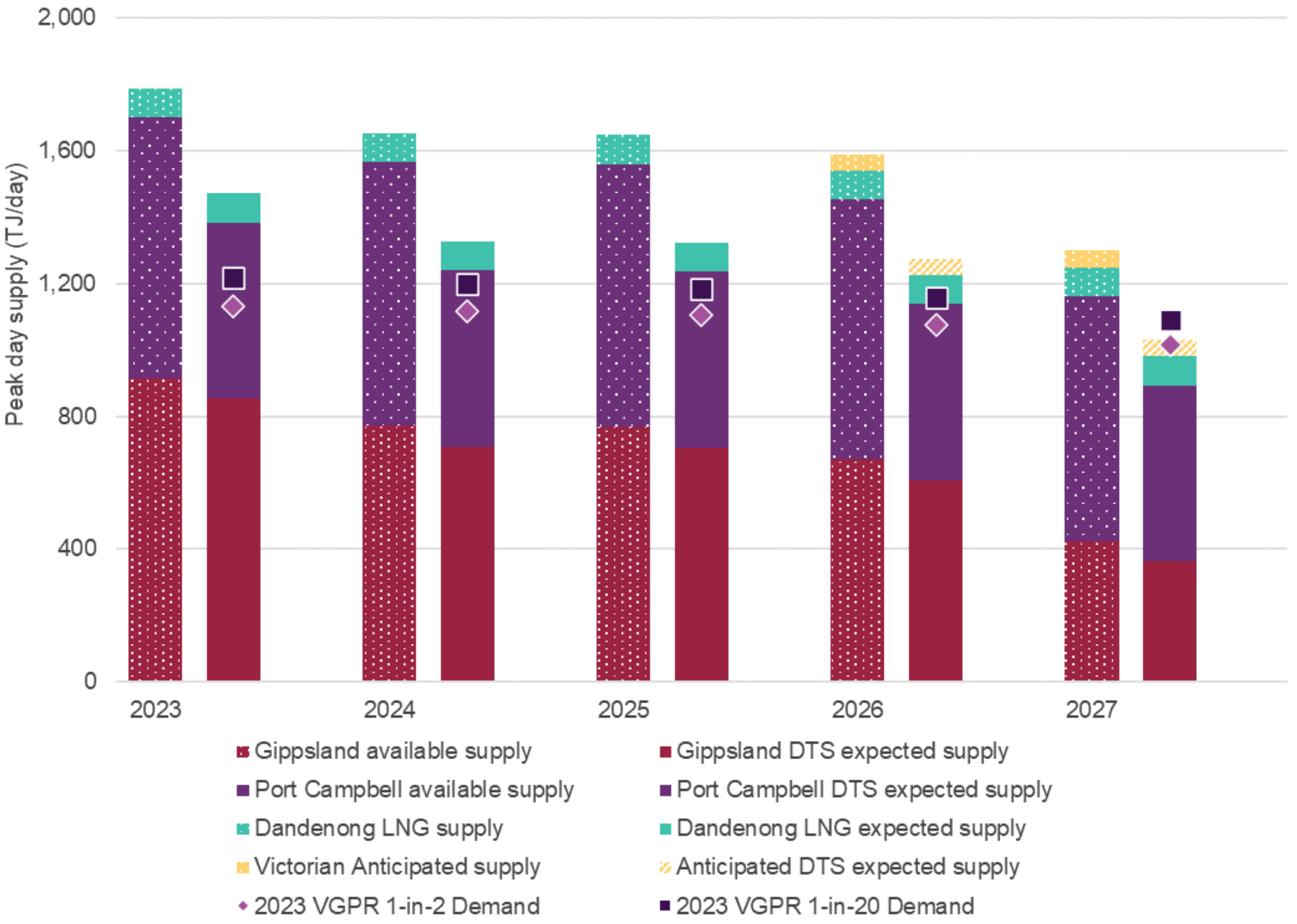


Table 15 Forecast peak day supply adequacy, 2023-27 (TJ/d)

Supply source		2023	2024	2025	2026	2027
Gippsland [A]	Expected [B]	854	709	706	609	363
	Anticipated	0	0	0	49	51
	Total expected plus anticipated	854	709	706	658	414
Port Campbell (Geelong) [C]	Expected [D]	530	530	530	530	530
	Anticipated	0	0	0	0	0
	Total expected plus anticipated	530	530	530	530	530
Melbourne	Expected	87	87	87	87	87
Total Victorian supply	Total Victorian expected	1,471	1,326	1,323	1,226	980
	Total Victorian anticipated	0	0	0	49	51
	Total Victorian expected plus anticipated	1,471	1,326	1,323	1,275	1,031
1-in-2 system demand		1,131	1,118	1,104	1,074	1,014
1-in-20 system demand		1,217	1,201	1,185	1,157	1,089
1-in-2 day surplus quantity with Victorian expected supply		340	208	219	152	-34
1-in-20 day surplus quantity with Victorian expected supply		254	126	137	69	-109

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Expected Gippsland zone supply excludes the portion of available Gippsland supply that is needed to supply Tasmanian demand and demand along the EGP, including in south-east New South Wales, that cannot be supplied from any other source.
C. Port Campbell zone includes the Otway and Athena production facilities and Iona UGS. Combined supply is gas available to the DTS, South Australia and Mortlake Power Station. All of this supply cannot be supplied into the DTS due to the SWP capacity constraint.
D. Expected Port Campbell supply is limited by the capacity of the SWP.

3.5 System resilience and supply risks

Peak day supply adequacy is forecast to tighten beyond 2023, with reduced supply capacity in 2024 and an annual and peak day shortfall projected in 2027 without additional gas supply. **Table 16** summarises risks to supply adequacy.

Table 16 Risks to the supply demand balance

Risk	Description	Risk type	Impact
Transmission pipeline and/or compression project delay	WORM project delay. There is limited time to complete construction and commissioning prior to winter 2023.	Peak day and seasonal adequacy risk	Reduces SWP transportation capacity by 83 TJ/d on a 1-in-20 system demand day and reduces available DTS pipeline linepack. Also reduces the SWP withdrawal capacity by 198 TJ/d, impacting the capability to refill storage.
	Winchelsea Compressor 2 project delay. There is limited time to complete construction and commissioning prior to winter 2023.	Peak day risk	Reduces SWP transportation capacity by 54 TJ/d on a 1-in-20 system demand day.
Production project delay and uncertainty	Regulatory approval delay of Beach Energy's committed Enterprise project. Cooper Energy has also delayed an investment decision on the Otway Phase 3 Development.	Seasonal adequacy risk	Reduced Port Campbell production also impacting the refilling of storage.
	GBJV advised AEMO that the production forecast provided in December 2022 is at risk due to regulatory uncertainty.	Peak day and annual adequacy risk	Reduced Gippsland production and / or winter peak day supply capacity

Risk	Description	Risk type	Impact
	GBJV also advised that it has only approved expenditures for the first six months of 2023 which reduces forecast confidence for 2023 and beyond.		
Unpredictable decline of legacy fields	Accurately forecasting the production capacity and remaining reserves as gas fields approach depletion can be challenging. Deviations can, and occasionally do, occur. The Blacktip field in Northern Territory depleted unexpectedly rapidly in 2022[A], which impacts supply capacity from Queensland to the southern states.	Peak day, seasonal and annual adequacy risk	Reduced supply capacity to meet demand, potentially also impacting the refilling of storage.
Gas generation	As discussed in **Section 2.4.3**, winter gas generation is forecast to increase and may coincide with high system demand. Winter 2022 saw high gas generation demand in late May and early June, due to an early winter cold snap coupled with low wind and solar generation, then due to reduced coal generation in Victoria and New South Wales (including due to severe flooding) coinciding with high system demand for electricity.	Peak day and seasonal adequacy risk	Increased gas demand on winter days by over 200 TJ/d, potentially also impacting the rate at which storages are depleted.
	Gas generation consumption at the Uranquinty Power Station in New South Wales can significantly reduce gas supply into Victoria via Culcairn.	Peak day risk	Injections into Victoria via Culcairn may reduce to a lower rate than scheduled, reducing DTS linepack and increasing the utilisation of storages to recover from the shortfall.
	Prolonged outages at coal-fired generators can lead to increased gas generation. Extended coal generation outages occurred during 2019, 2021 and 2022.	Seasonal adequacy risk	Increased gas generation, leading to increased gas supply requirement that may not be available. Potential to also impact the rate at which storage is depleted.
Production facility outages	Production facilities are aging and unplanned facility outages may occur more frequently. Unplanned outages can threaten peak day supply even if they are short-term.	Peak day and seasonal adequacy risk	Depletion of Longford large legacy fields also reduces capability to recover from within day outages. Depending on the scale of the outage, supply could be reduced by up to 400 TJ/d.
Demand under-forecast	Peak demand days are difficult to forecast and are typically under-forecast.	Peak day risk	Under-forecasting demand may reduce the amount of supply available on peak demand days while also increasing Dandenong LNG depletion.
	Significantly colder weather than expected will increase seasonal system consumption above forecast levels, particularly a period of sustained cold weather.	Seasonal adequacy risk	Increased production, gas made available from Queensland LNG producers (subject to available pipeline capacity from Queensland to the southern states) and/or utilisation of storage required.
Depletion of Iona UGS inventory	As highlighted in **Section 1.2.1**, winter 2022 saw rapid depletion of Iona UGS requiring AEMO to issue threat to system security notices to ensure storage supply was available for the duration of winter.	Seasonal adequacy risk	The depletion of storage reservoirs reduces Iona UGS supply capacity by up to 50%.
Reduction in gas made available from Queensland to the southern states	The Queensland LNG producers have made gas available to the domestic market during previous winters. Volumes may be reduced due to lower production, favourable international LNG prices which may attract surplus production or higher demand (particularly Mt Isa demand as a result of reduced Northern Territory supply due to low Blacktip field production).	Seasonal adequacy risk, peak day risk	Less imports from Queensland into New South Wales and Victoria, resulting in a storage depletion risk and possible shortfalls.

A. Daniel Fitzgerald, ABC Rural, "NT's Blacktip gas field production drops, forcing shutdown of Northern Gas Pipeline", 22 October 2022, at https://www.abc.net.au/news/2022-10-22/blacktip-gas-field-production-problems-power-and-water/101555526.

Table 17 outlines improvements or other changes to the system resilience outlook since the 2022 VGPR Update.

Table 17 Improvements to the system resilience outlook

Risk	Description	Notes
Winchelsea outage	Winchelsea CS on the SWP has no spare unit. An outage of this compressor reduces the SWP transportation capacity and the ability to move linepack towards Melbourne to support evening peak demands.	The Winchelsea Compressor 2 project provides redundancy if one unit is offline (but lower capacity than with both compressors available).
Unavailability of Dandenong LNG	Retailer contracted volumes at the Dandenong LNG facility were insufficient to respond to operational and emergency response scenarios.	The AEMC published a final set of rules on 15 December 2022[A] requiring AEMO to contract any uncontracted capacity within the tank and to fill that capacity to reduce the likelihood of curtailment within Victoria.
Longford full plant outages	As part of the Longford production decline and reduced redundancy, full plant outages are being planned to enable the completion of major onshore and offshore maintenance activities.	Esso has advised AEMO that the updated maintenance plan for Longford has delayed the requirement for the full plant outages reported in the 2022 VGPR Update until 2025 or 2026. Lower production capacities are expected during some outages due field decline and reduced redundancy.
Ethane constraint	The Longford production system produces an ethane by-product stream that is used by a downstream customer. Periods of reduced customer ethane offtake constrained Longford production during winter 2022.	Operational changes at Longford during 2022 have minimised the impact of reduced ethane customer offtake on Longford production capacity. This does not apply for periods of no ethane customer offtake which requires the flaring of ethane at the Esso Long Island Point fractionation plant near Hastings for Longford production to continue. In September 2021[B], Esso proposed the development of a small 40 MW ethane-fuelled power station at the Long Island Point plant to prevent ethane being flared during periods of no customer ethane offtake[C]. Development of this facility remains subject to planning approvals.

A. AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.
B. ExxonMobil, "Long Island Point Plant Update", 16 September 2021, at https://www.exxonmobil.com.au/community-engagement/local-outreach/esso-community-news/2021/long-island-point-plant-update.
C. ExxonMobil, "Hastings Generation Project", 25 January 2023, at https://www.exxonmobil.com.au/energy-and-environment/energy-resources/upstream-operations/hastings-generation-project.

4 Future supply sources

Key findings

- **Several committed, anticipated and potential projects may provide additional DTS supply during the outlook period**. These include:
  - Committed, anticipated and potential production projects in the Gippsland and Otway basins.
  - LNG import terminal projects in Victoria and in other jurisdictions.
  - Pipeline expansion projects in Victoria and from other jurisdictions which increase supply into Victoria.
- The **transition to biomethane and hydrogen** is expected to play an important role in the decarbonisation of Australia's energy sector. These distributed supply sources are not expected to produce significant volumes in the outlook period or sufficient gas to replace the current declining Victorian production.
- AEMO recognises that **the current investment environment for projects is challenging and uncertain**. The 2023 VGPR contains few committed and anticipated supply projects. Many projects do not have firm timelines, making the analysis of system adequacy in **Chapter 3** difficult. All projects currently underway or proposed in the VGPR outlook period face a range of challenges to maintain schedules and reach completion.

4.1 Committed supply projects

Kipper field compression

As reported in the 2022 VGPR Update, the Kipper Unit Joint Venture (KUJV) is progressing with the development of additional committed supply from the Kipper compression project. This supply, which is processed through the Longford Gas Plant, is expected to commence in early 2024[75]. The project is expected to maintain Kipper field production rates, but it does not replace the Longford production capacity reduction due to the decline of GBJV's large legacy gas fields.

Iona UGS expansion

Lochard Energy's expansion of the Iona UGS capacity is underway with the successful connection of the Seamer field in late 2022. The supply capacity expansion will occur in two steps; the first step from 545 TJ/d to 558 TJ/d occurred in January 2023 and the second step from 558 TJ/d to 570 TJ/d will occur from January 2024. The project has also increased the Iona UGS storage capacity from 23.5 PJ to 24 PJ from January 2023 and this capacity will further increase to 24.5 PJ in 2024.

[75] ExxonMobil, "Esso Australia to Expand Gas Development in the Gippsland Basin", 17 March 2022, at https://www.exxonmobil.com.au/news/newsroom/news-releases-and-alerts/2022/esso-australia-to-expand-gas-development-in-the-gippsland-basin.

Thylacine and Enterprise

Beach Energy's connection of the four new offshore Thylacine wells to the Otway Gas Plant is in progress, with gas from these wells targeted for production from mid-2023[76]. The Thylacine drilling was delayed for six months from the date reported in the 2022 VGPR Update due to COVID-19 related delays. Connection of these four Thylacine wells will return the Otway Gas Plant to its nameplate capacity of 205 TJ/d.

Beach Energy also reached FID for the connection of the nearshore Enterprise-1 well to the Otway Gas Plant in March 2022[77]. Work on the connection is progressing and gas from the Enterprise field is targeted to come online prior to 2024, subject to regulatory approvals.

4.2 Anticipated supply projects

Kipper Stage 1B

In addition to the committed Kipper compression project, there is ongoing planning for the development of a further subsea well at the Kipper facility as part of the Kipper Phase 1B project. This project will increase the gas available from the Kipper project from 2026.

As noted in **Section 4.6**, GBJV has advised AEMO that there is an elevated risk of this project not being approved for development (that is, committed) and therefore the commissioning date being delayed.

4.3 Potential supply projects

Golden Beach

The Golden Beach Energy Storage Project involves the production and development of the Golden Beach gas field in the Gippsland Basin, with a forecast supply of 68.5 PJ over two years from 2025 (delayed from 2024), and an initial delivery capacity of up to 125 TJ/d for winter 2025. GB Energy is scheduled to drill an appraisal well between April and June 2023 ahead of making FID in late June or July[78].

The field operator, GB Energy, plans to transition the field and facility into an underground gas storage facility in 2026 to initially provide approximately 12.5 PJ of storage which can be withdrawn at rates up to 250 TJ/d. GB Energy has also advised that the facility could then be further expanded to store 40 PJ, and it has interest to increase the storage withdrawal capacity and is investigating options of between 500 TJ/d and 750 TJ/d.

The Golden Beach Energy Storage Project was reported as an anticipated project in the 2022 VGPR Update. Due to several years of delay, the current uncertain investment environment for gas projects, rig availability, and investor uncertainty, this project has been considered a potential project in the 2023 VGPR.

[76] Beach Energy, "Annual General Meeting Addresses and Presentation", 16 November 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1413977/BPT_Annual_General_Meeting_Addresses_and_Presentation.pdf.

[77] Beach Energy, "Quarterly report for the period ended 31 March 2022", 26 April 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1087937/BPT_Quarterly_report_for_the_period_ended_31_March_2022.pdf.

[78] Angela Macdonald-Smith, "56 years on, Golden Beach gas nears production", 3 February 2023, at https://www.afr.com/companies/energy/56-years-on-golden-beach-gas-nears-production-20230203-p5chmt.

Annie

Cooper Energy is developing Annie as part of the Otway Phase 3 Development Project. Gas produced from the Annie field would be processed at the Athena Gas Plant. The project is progressing to enter detailed front end engineering design (FEED) and procurement of long-lead time items[79]. Cooper Energy has signed a conditional gas sales agreement (GSA) with AGL for supply from Annie[80] but has delayed the FID for the project[81].

Trefoil and White Ibis

Beach Energy, the operator of the Lang Lang Gas Plant (BassGas) and offshore assets including the Yolla gas field, has chosen to prioritise the ongoing development of Yolla West in the near term and defer the FID for Trefoil[82]. This decision resulted in the reclassification of the Trefoil reserves to contingent resources. As such AEMO now considers this project as a potential supply.

Beach Energy is progressing with a seismic survey covering the Trefoil and White Ibis fields with completion of the interpretation of the survey results expected in 2023[83].

Turrum and North Turrum

GBJV is evaluating expansion and optimisation options for the Turrum and North Turrum fields. This project would provide additional gas to be processed at the Longford Gas Plant from 2026, noting that GBJV has advised AEMO that it is reviewing the timing and risks for future development projects.

Neither this project nor the Kipper Stage 1B project are expected to increase future Longford winter capacity to the levels provided by the current GBJV legacy field production. If both projects are complete and available within 2026, this is forecast to maintain the winter 2026 Longford capacity at similar rates to 2024 and 2025, however even with these projects there is a reduction in capacity for winter 2027.

Artisan

Beach Energy discovered Artisan 1 as part of the recent Otway drilling campaign[84]. The field is currently in the pre-FEED stage of planning with gas produced to be processed at the Otway Gas Plant.

Manta

Cooper Energy is progressing planning work for the Manta gas project, which requires the drilling of an appraisal well prior to a development decision. Gas from Manta would be processed at the Orbost Gas Plant as a backfill for gas from the Sole field. Cooper Energy is also considering the development of a Manta Hub that encompasses

[79] Cooper Energy, "Annual Report 2022", 10 October 2022, at https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2450934-2022-AR.pdf.

[80] Cooper Energy, "Gas Sales Agreement with AGL for the next phase of Otway Basin development and exploration", 10 November 2022, at https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2022.11.10-OP3D-GSA-announcement.pdf.

[81] Elouise Fowler, Financial Review, "Cooper Energy puts go-slow on new gas project", 28 February 2022, at https://www.afr.com/companies/energy/cooper-energy-puts-go-slow-on-new-gas-project-20230228-p5co5t.

[82] Beach Energy, "Bass Basin update", 20 May 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1092400/BPT_Bass_Basin_update.pdf.

[83] Beach Energy, "FY23 Second Quarter Activities Report", 31 January 2023, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1427801/BPT_FY23_Second_Quarter_Activities_Report.pdf.

[84] Beach Energy, "Otway drilling campaign complete", 12 July 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1099320/BPT_Otway_drilling_campaign_complete.pdf.

the prospects Wobbegong, Manta Deep and Chimaera Deep[85]. Cooper Energy has also signed a memorandum of understanding (MOU) with Emperor Energy for processing of the Judith prospect at the Orbost Gas Plant[86].

Longtom

The Longtom field is wholly owned by Seven Group Holdings, which is seeking to resume production from the field. Gas from the Longtom field was previously processed at the Orbost Gas Plant.

Wombat

The Wombat field is wholly owned by Lakes Blue Energy. Work has commenced to secure approvals for drilling of Wombat-5[87], which has an estimated capacity of 10 TJ/d. Gas processing and compression facilities would need to be constructed to treat and transport any gas produced at Wombat.

Lakes Blue Energy is currently prioritising the evaluation of its prospect Enterprise North in the Otway Basin[88].

Iona UGS Expansion

Lochard Energy has completed the pre-FEED stages of the Heytesbury Underground Storage (HUGS) project. The HUGS development aims to increase the storage capacity of the Iona UGS facility to up to 28 PJ and may increase supply capacity. The SWP would need to be expanded to utilise any increased Iona UGS capacity to supply the DTS.

4.4 LNG receiving terminal projects

4.4.1 Victorian projects

Viva Energy Gas Terminal Project

Viva Energy's proposed LNG receiving terminal, located adjacent to its Geelong refinery, would connect to the SWP at Lara. The terminal is forecast to supply up to 140 PJ/y, have a capacity of 600-750 TJ/d, and potentially be operational and available to the market as early as 2025.

Viva Energy has submitted a completed Environmental Effects Statement (EES) to the Minister for Planning[89] and the Minister has since requested for a supplementary information statement to assist in their decision[90]. Viva Energy has deferred an FID for this project until 2023[91], after the EES decision has been made. Viva Energy

[85] Cooper Energy, Annual Report 2022, 10 October 2022, at https://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2450934-2022-AR.pdf.

[86] Emperor Energy, Memorandum of Understanding with Cooper Energy, 7 October 2022, at https://emperorenergy.com.au/wp-content/uploads/2022/10/7-Oct-22.pdf.

[87] Lakes Blue Energy, "Annual Report for the Year Ended 30 June 2022", 30 September 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02575223-3A603477?access_token=83ff96335c2d45a094df02a206a39ff4.

[88] Research as a Service on behalf of Lakes Blue Energy, "Enterprise North upgraded and reset", 1 November 2022, at https://static1.squarespace.com/static/6287c98799a0cf2147462016/t/637d51684f48201371a7d418/1669157228271/LKO+Lakes+Blue+Energy+RaaS+Update+Report+2022+11+01.pdf.

[89] Victorian Government – Department of Environment, Land, Water and Planning, "Viva Energy Gas Terminal Project", 7 December 2022, at https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/viva-energy-gas-terminal-project.

[90] Viva Energy, "Viva Energy Gas Terminal Project update", 8 March 2023, at https://events.miraqle.com/DownloadFile.axd?file=/Report/ComNews/20230308/02641357.pdf.

[91] Sonali Paul, Reuters via Nasdaq, "Australia's Viva Energy defers decision on LNG import terminal to 2023", 25 August 2022, at https://www.nasdaq.com/articles/australias-viva-energy-defers-decision-on-lng-import-terminal-to-2023.

entered a commercial agreement with Geelong Port for the construction of the pier and berthing infrastructure[92] and is also working to secure a FSRU for the project after losing the FSRU allotment it made in 2021[93].

The impacts of injections from the Viva LNG receiving terminal on SWP capacity are discussed in **Section 5.4.1**.

Vopak Victoria LNG

Vopak is progressing a project to develop an FSRU off the shoreline of Avalon in Port Phillip Bay. The offshore FSRU would be connected to the SWP near Lara or Avalon via a subsea pipeline. Vopak has submitted a referral to the Minister for Planning to determine if an EES is required for the project. Vopak is intending to reach FID during 2024 with the terminal planned to be operational in late 2026[94].

This project would also impact SWP capacity, which is discussed in **Section 5.4.1**.

4.4.2 Projects in other jurisdictions

Port Kembla Energy Terminal

Squadron Energy's PKET project involves the construction of an LNG receiving terminal at Port Kembla and connecting facilities to the EGP at Kembla Grange.

Squadron Energy is progressing with the construction of the wharf and Jemena with the pipeline connection to the EGP. The pipeline in on track to be completed by the end of 2023; the terminal is expected to be commissioned in time to meet anticipated buyers' demand. Squadron Energy has informed AEMO that gas supply from PKET may not commence until 2026 based on prospective buyers' and Squadron Energy's own demand.

Outer Harbor LNG Project

Venice Energy has a proposal to develop an LNG receiving terminal at Outer Harbor, near Adelaide in South Australia. Venice Energy is targeting FID in late 2023 with first gas targeted for pre-winter 2026.

Injections at the Venice LNG terminal would offset supply from Moomba via the Moomba to Adelaide Pipeline System (MAPS) and from Port Campbell via the SEA Gas Pipeline.

The project will not increase Victorian peak day gas supply capacity, as gas from the SEA Gas pipeline into the DTS at Port Campbell will be restricted by the capacity of the SWP, which already limits supply from Port Campbell including from Iona UGS. The Venice Energy facility could be used to refill Iona UGS.

Newcastle GasDock LNG terminal

EPIK (Energy Projects & Infrastructure Korea) is no longer proceeding with the Newcastle GasDock project due to the negative impacts of COVID-19, volatility in the global LNG market, and increasingly difficult economic conditions worldwide.

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[92] Viva Energy Australia, "Viva Energy Gas Terminal Project update", 27 July 2022, at https://events.miraqle.com/DownloadFile.axd?file=/Report/ComNews/20220727/02545750.pdf.

[93] Sonali Paul and Florence Tan, MarketScreener, "Europe's dash for gas puts Australia's LNG import plans at risk", 30 May 2022, at https://www.marketscreener.com/quote/stock/VIVA-ENERGY-GROUP-LIMITED-44388561/news/Europe-s-dash-for-gas-puts-Australia-s-LNG-import-plans-at-risk-40589187/.

[94] Ella Keskin, TankTerminals.com, "Vopak's Victoria Energy Terminal Plans Due By Christmas", 12 October 2022, at https://tankterminals.com/news/terminal-plans-due-by-christmas/.

4.5 Other supply sources

APA East Coast Grid Expansion project

On 5 May 2021, APA announced a 25% expansion of the MSP and the SWQP in two stages, along with an additional expansion stage:

- **Stage 1** – APA is on track to complete Stage 1 of the project prior to winter 2023. This consists of an additional compressor between Moomba and Young, and an additional compressor on the SWQP. Stage 1 will increase the nominal capacity of the SWQP by 49 TJ/d from 404 TJ/d to 453 TJ/d and the MSP by 29 TJ/d from 446 TJ/d to 475 TJ/d.
- **Stage 2** – on 25 May 2022[95], APA committed to Stage 2 of the project, which will further increase capacity by winter 2024. Stage 2 consists of a second additional compressor on both the SWQP and MSP. Stage 2 will increase the nominal capacity of the SWQP by another 59 TJ/d to 512 TJ/d and the MSP by another 90 TJ/d to 565 TJ/d.
- **Stage 3** – Stage 3 is currently in initial design phases and subject to customer demand and project approval. It is planned to provide a further 92 TJ/d expansion to southern transportation capacity with increases on both the SWQP and MSP.

Constrained Port Campbell supply

As discussed in **Section 3.4.2**, the forecast increase in peak day supply at Port Campbell would not be available to the DTS, due to the SWP transportation capacity constraint. The SWP will be constrained to 530 TJ/d upon completion of the WORM and Winchelsea Compressor 2 projects, which are expected to be available from mid-2023.

Further future SWP expansion options include pipeline duplication ("looping") upstream and downstream of the Winchelsea CS or the installation of additional compressor station(s).

Eastern Gas Pipeline bi-directional flows

The EGP is a unidirectional pipeline that transports gas from Longford to Sydney. Jemena plans to modify the EGP to enable bidirectional flow with the capacity to initially inject 200 TJ/d of southern flow from PKET into the DTS. The timing for this project is dependent on commencement of LNG import terminal operations at PKET.

A potential future expansion includes the installation of a compressor station at Kembla Grange, which would increase southbound capacity on the EGP towards Victoria to 323 TJ/d.

SEA Gas Pipeline bi-directional flows

The SEA Gas Pipeline is currently unidirectional and can only transport gas from Port Campbell to Adelaide. Venice Energy is finalising a joint feasibility study with SEA Gas to make the SEA Gas Pipeline bi-directional to allow gas to be transported to Victoria[96]. The timing for this project is dependent on commencement of LNG import terminal operations at the Outer Harbor LNG Project.

[95] APA Group, "APA Commences Stage Two of East Coast Gas Grid Expansion", 25 May 2022, at https://www.apa.com.au/globalassets/asx-releases/2022/apa-commences-stage-two-of-east-coast-gas-grid-expansion.pdf.

[96] Sanja Pekic, Offshore Energy, "Venice Energy speeds up Outer Harbor LNG construction", 3 March 2022, at https://www.offshore-energy.biz/venice-energy-speeds-up-outer-harbor-lng-construction/.

Supply into the DTS from the SEA Gas Pipeline (at Port Campbell) would be limited by the capacity of the SWP.

Distributed renewable gas supply

Several projects are proposed in Victoria to supply either biomethane or hydrogen blended with natural gas to end use gas customers.

One is the Hydrogen Park Murray Valley (HyP Murray Valley) project by Australian Gas Infrastructure Group (AGIG). The project would construct a 10 MW electrolyser to produce hydrogen and blend with natural gas into the Albury-Wodonga gas distribution network. This project is expected to commence production in 2025[97].

Other hydrogen projects in Victoria include:

- Geelong Hydrogen Hub – a suite of hydrogen facilities to be located in Geelong proposed by GeelongPort, including infrastructure to produce and distribute hydrogen[98]. GeelongPort has signed an MOU with Fortescue Future Industries to undertake a joint feasibility study. This feasibility is aimed to be completed by end of 2023 and targeting FID at the end of 2024.
- Melbourne Hydrogen Hub – a proposed project in Melbourne's northern suburbs by Countrywide Hydrogen to supply buses with renewable hydrogen that has been expanded to also consider hydrogen blending[99].
- Hydrogen Portland – a renewable hydrogen project proposed by Countrywide Hydrogen located in Portland that would initially consist of a 10 MW electrolyser with a second stage expanding the project to at least 500 MW[100].
- Hydro-Gen 1 – a pilot program by Yarra Valley Water at Wollert to test the feasibility of an electrolyser producing renewable hydrogen via a water-to-energy process[101]. It is currently intended primarily for the use of transport, but other options are being considered.

AEMO is aware of increasing interest in biomethane from large industrial and commercial users of natural gas as an alternative method of decarbonisation. Several small-scale biomethane projects have been proposed across Victoria, primarily using agricultural or municipal waste to produce biomethane. Some projects are being developed to inject biomethane into distribution networks while others would reduce on-site natural gas consumption by substituting biomethane and any excess biomethane could be injected into networks. The Future Fuels Cooperative Research Centre has identified a number of potential biomethane hubs in Australia, including Echuca, Shepparton and Wodonga in Victoria[102].

The transition to biomethane and hydrogen is expected to play an important role in the decarbonisation of Australia's energy sector. These distributed supply projects are not expected to be able to produce significant volumes during the outlook period or sufficient gas to replace the current declining Victorian production. Chapter 2 of the 2023 GSOO discusses the expected reduction in natural gas consumption due to hydrogen and biomethane uptake across a range of possible futures.

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[97] Australian Gas Infrastructure Group, "Hydrogen Park Murray Valley", at https://www.agig.com.au/hydrogen-park-murray-valley.

[98] GeelongPort, "The Geelong Hydrogen Hub", at https://engage.geelongport.com.au/geelonghydrogenhub.

[99] Countrywide Hydrogen, "Our Projects - Melbourne Hydrogen Hub", at https://countrywidehydrogen.com/.

[100] Countrywide Hydrogen, "Our Projects - Hydrogen Portland", at https://countrywidehydrogen.com/.

[101] Yarra Valley Water, "Yarra Valley Water launches green hydrogen pilot", 27 September 2022, at https://www.yvw.com.au/news-room/yarra-valley-water-launches-green-hydrogen-pilot.

[102] Future Fuels CRC, "Where are the most viable locations for bioenergy hubs across Australia?", 1 June 2022, at https://www.futurefuelscrc.com/wp-content/uploads/RP1.2-04-BiomethaneViability_summary.pdf.

The Australian Energy Market Commission (AEMC) is considering the market impacts of distributed connected facilities and renewable gases including:

- The "DWGM distribution connected facilities" rule change made on 8 September 2022, with the new rule to come into effect on 1 May 2024[103].
- The "Review into extending the regulatory frameworks to hydrogen and renewable gases", with the final report published on 24 November 2022[104].

4.6 Project risks and uncertainties

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. The 2023 VGPR contains few committed and anticipated supply projects. Many of these projects do not have firm timelines, making the analysis of system adequacy in **Chapter 3** difficult. All projects currently underway or proposed in the VGPR outlook period – including gas supply projects, LNG receiving terminal projects, pipeline projects and distributed supply projects – face a range of challenges to maintain schedules and reach completion..

Table 18 summarises the key uncertainties impacting gas projects.

Table 18 Gas project uncertainties

Factor	Description	Impacts	Projects impacted
Russia-Ukraine conflict	The Russian invasion of Ukraine in February 2022 has caused shocks in the global energy markets as Russia is a major oil and gas producer. The interruption of the Nord Stream gas pipeline decreased possible supplies of Russian gas to Europe.	• High demand for electrolysers (for hydrogen production) and FSRUs as Europe is driven to seek gas from sources other than Russia. • Increased international energy prices including oil and spot market LNG prices.	• LNG import terminal projects. • Gas production projects. • Hydrogen projects.
Inflation	Higher inflation in Australia and overseas combined with rising rates to combat inflation.	• Higher borrowing costs. • Increasing projects costs not keeping pace with some long-term projections of gas contract prices.	• All.
Financing	Natural gas is becoming unpalatable for some investors who are screening investments on the basis of environment, social and governance (ESG) issues and want to limit exposure to fossil fuels.	• Higher borrowing costs. • Limited financing options.	• Natural gas projects undertaken by small companies. • High-profile natural gas projects.
COVID-19	Ongoing impacts of the COVID-19 pandemic include global supply chain disruptions, limited resources and a backlog of projects.	• Prolonged project timelines due to COVID-19 management. • Delays procuring or the complete unavailability of specialist equipment and resourcing. • Very tight availability windows.	• All.

[103] AEMC, "DWGM distribution connected facilities", 8 September 2022, at https://www.aemc.gov.au/rule-changes/dwgm-distribution-connected-facilities.

[104] AEMC, "Review into extending the regulatory frameworks to hydrogen and renewable gases", 24 November 2022, at https://www.aemc.gov.au/market-reviews-advice/review-extending-regulatory-frameworks-hydrogen-and-renewable-gases.

Factor	Description	Impacts	Projects impacted
Regulatory approvals	Environmental approvals for gas projects are becoming increasingly stringent. Approval requirements are dependent on which jurisdiction the project falls within. Industry has raised that the December 2022 Federal Court decision to set aside NOPSEMA's approval of Santos' Barossa Gas Project Environmental Plan[A] has increased industry uncertainty.	• Project delays or cancellation of projects entirely. • Increased project costs.	• Gas production projects. • LNG import terminal projects. • Transmission pipeline projects.
Market uncertainty	From 23 December 2022, the Australian Federal Government imposed a $12/GJ price cap to new domestic wholesale gas contracts for 12 months[B]. The government has also introduced a mandatory code of conduct for the gas industry.	• Industry has raised possible reduction in the economic viability of projects potentially causing project delays or deferral. • Industry has raised possible depressed investment interest in Australian projects due to the risk of government intervention.	• Gas production projects. • LNG import terminal projects.
Competing investment interests for renewable gases	Policy and investment into renewable gases in other jurisdictions has been significant. Examples include: • The US Department of Energy's US$7 billion hydrogen hubs program[C], US$750 million clean hydrogen technology package[D] and clean hydrogen production tax credits[E]. • The European Union's REPowerEU Plan with accelerated targets for 10 million tonnes of domestic renewable hydrogen production and 10 million tonnes of renewable hydrogen imports by 2030[F].	• Reduced investment in Australia as companies prioritise investment in other locations. • Limited talent in the developing industry exiting Australia to follow growth opportunities elsewhere.	• Renewable gas projects.
Offshore rig availability	Declining offshore exploration and drilling activity in Australia combined with very high rig demand globally is resulting in few rigs remaining in Australia. Regulatory approval delay and uncertainty (combined with high demand for rigs) is making it challenging for producers to commit to bringing development rigs to Victoria.	• Project delays due to difficulties scheduling rig time. • Increased long-term project costs as rigs must be imported and local workforce numbers will decline.	• Offshore gas production projects.

A. Santos, "Full federal court decision for the Barossa Gas Project", 2 December 2022, at https://www.santos.com/news/full-federal-court-decision-for-the-barossa-gas-project/.
B. Hon Katy Gallagher (Acting Treasurer), Treasury Portfolio, "Gas price cap to take effect", 22 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/gas-price-cap-take-effect.
C. Department of Energy, "Biden-Harris Administration Announces Historic $7 Billion Funding Opportunity to Jump-Start America's Clean Hydrogen Economy", 23 September 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-historic-7-billion-funding-opportunity-jump-start.
D. Department of Energy, "Biden-Harris Administration Announces $750 Million to Accelerate Clean Hydrogen Technologies", 16 December 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-750-million-accelerate-clean-hydrogen-technologies.
E. Department of Energy - Hydrogen and Fuel Cell Technologies Office, "Financial Incentives for Hydrogen and Fuel Cell Projects", at https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.
F. European Commission, "REPowerEU Plan", 18 May 2022, at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

5 Declared Transmission System adequacy

Key findings

- AEMO has included the two APA capital projects currently under construction in assessing the adequacy of the DTS: the Western Outer Ring Main (WORM) and the installation of a second compressor at the Winchelsea CS. Both projects are due to be commissioned by mid-2023.
- Although full day outages of the Longford Gas Plant have been delayed until later in the outlook period, when they do occur AEMO will need to operate the DTS in an unprecedented manner by moving gas from Port Campbell to the eastern edge of the DTS. Lowering the Sale city gate (CG) minimum operating pressure to 4,500 kilopascals (kPa) and adding remote control to the bypass valve at Gooding CS are important projects to further increase the resilience of the DTS.
- The DTS peak day system capacity is 1,533 TJ/d. The DTS capacity, assuming there is sufficient gas supply, is expected to support forecast peak system demand days during the outlook period.
- The DTS is projected to have sufficient capacity to be able to support forecast gas generation on low and peak system demand days. Peak shaving gas from the Dandenong LNG facility may be required to maintain critical system pressures when high gas generation coincides with periods of high system demand or if gas generation is unforecast.

5.1 Western Outer Ring Main Project

The new 51 km WORM pipeline (which will become part of the DTS) will connect the Brooklyn to Lara Pipeline (BLP) at Plumpton to the VNI and the Pakenham to Wollert Pipeline at the Wollert CS to the east. The WORM increases South West Pipeline (SWP) capacity by providing a means to bypass Brooklyn CG and the Melbourne Inner Ring Main constraints, and also increases useable DTS linepack.

The WORM project also includes additional compression via a third unit to be installed at the Wollert B CS, providing a new, more efficient flow path to compress gas from Wollert towards Port Campbell via the WORM (instead of via the Brooklyn CS), as well as additional compression capacity towards Culcairn via the VNI.

APA began construction of the project in 2022 and it is expected to be completed by mid-2023. AEMO has included the WORM as a completed project in the capacity modelling for this VGPR. Modelling results are presented and discussed in **Chapter 6**.

5.2 Winchelsea Compressor 2 Project

On 21 April 2022, APA announced that it had reached FID[105] on a further expansion of the SWP by installing an additional compressor at the existing Winchelsea CS.

[105] APA Group, "APA announces additional capacity in Victoria ahead of forecast gas shortfalls", 21 April 2022, at https://www.apa.com.au/news/media-statements/2022/apa-announces-additional-capacity-in-victoria-ahead-of-forecast-gas-shortfalls/.

The AER approved APA's request for funding this project as part of the 2023-2027 Access Arrangement Review, announced on 9 December 2022[106].

The project is currently in progress with the new Taurus 60 (5.6 MW) compressor arriving on site in early 2023. The unit will be installed to operate in series (as opposed to a parallel configuration) with the existing Taurus 60 Winchelsea compressor. Series operation will only be available to compress from Port Campbell towards Melbourne.

Upon completion, the second Winchelsea compressor, along with the WORM pipeline which includes a third Wollert B compressor, is expected to increase the SWP injection capacity at Port Campbell from 447 TJ/d during winter 2022 to 530 TJ/d for winter 2023. AEMO has included the second Winchelsea compressor as a completed project in the capacity modelling for this VGPR. Modelling results are presented and discussed in **Chapter 6**.

5.3 APA 2023-2027 Access Arrangement Review

As a regulated business, APA's transportation tariffs for the DTS undergo five-yearly reviews by the AER. APA's proposal for the period 1 January 2023 to 31 December 2027 was submitted in December 2021. After undergoing the standard revision process, the AER's final decision was published on 9 December 2022.

Capital expenditure of $105 million for two expansion projects was approved, which was comprised of additional expenditure for the WORM and Winchelsea Compressor 2.

5.4 Longford full plant outage

The 2022 VGPR Update noted that there was a planned Longford Gas Plant full day outage in late 2023 and a longer full plant outage of up to one month in late 2025. Esso has advised AEMO that the full plant outage is no longer likely to occur in 2023 and may occur from 2024 onwards. The exact timing and duration of any future full Longford Gas Plant outage is currently uncertain and will be confirmed by Esso at a later date.

Completion of the WORM creates a flow path for gas from the west of the DTS to the east, increasing the operability and resilience of the DTS if the Longford Gas Plant is to experience a full plant outage in the future.

Sale City Gate minimum operating pressure

Sale CG is part of the Australian Gas Networks (AGN) distribution network and supplies gas to the townships of Sale and Maffra. The Sale CG minimum operating delivery pressure is 4,800 kPa and, due to its geographical proximity to the Longford Gas Plant, is the connection point most susceptible to a minimum supply pressure breach when the Longford close proximity point (CPP) is at low injection quantities.

AEMO issued Threat to System Security notices during winter 2021 that identified the need to maintain the Sale CG minimum operating pressure following Longford Gas Plant production interruptions. Prior to winter 2022, AEMO and AGN implemented a temporary process for AGN to consider reducing the minimum operating pressure at Sale CG on days where AEMO has forecast potential of a pressure breach. The temporary process is likely to continue into winter 2023.

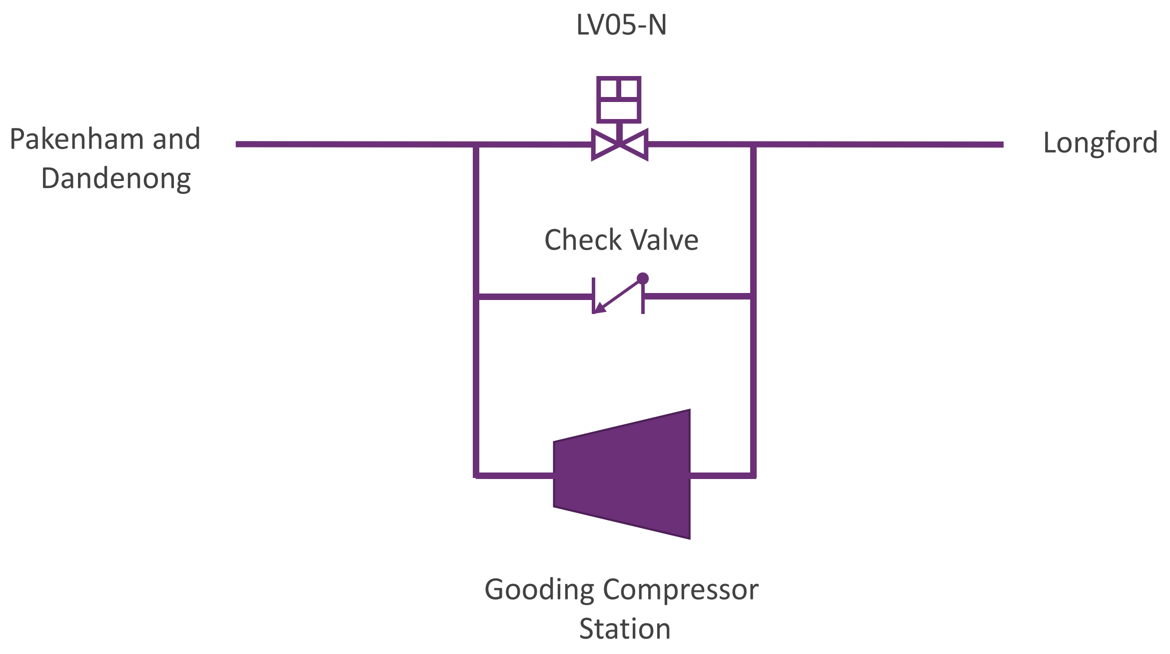
[106] Australian Energy Regulator, "APA Victorian Transmission System – Access arrangement 2023-27", 9 December 2022, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/apa-victorian-transmission-system-access-arrangement-2023%E2%80%9327/final-decision.

AGN's 2023-2028 Access Arrangement Review proposal to the AER[107] included proposed augmentation expenditure at Sale CG. Completion of AGN's proposed augmentation would allow the Sale CG minimum operational pressure to be permanently reduced to 4,500 kPa. The AER approved this capital expenditure in its draft decision published on 9 December 2022.

Gooding Compressor Station bypass valve automation

The Gooding CS is located near the mid-point of the LMP and provides compression towards Dandenong from Longford. As well as four high-flow compressor units, it has a single direction bypass valve that enables gas to free flow from Longford towards Dandenong when the compressors are not operating. In this bypass there is a check valve that prevents gas from flowing in the reverse direction towards Longford. Gas can also bypass the entire Gooding CS via line valve LV05-N which is normally in the closed position and has no remote operability, meaning that it can only be operated by APA manually on site.

Figure 24 Gooding compressor station valving arrangement

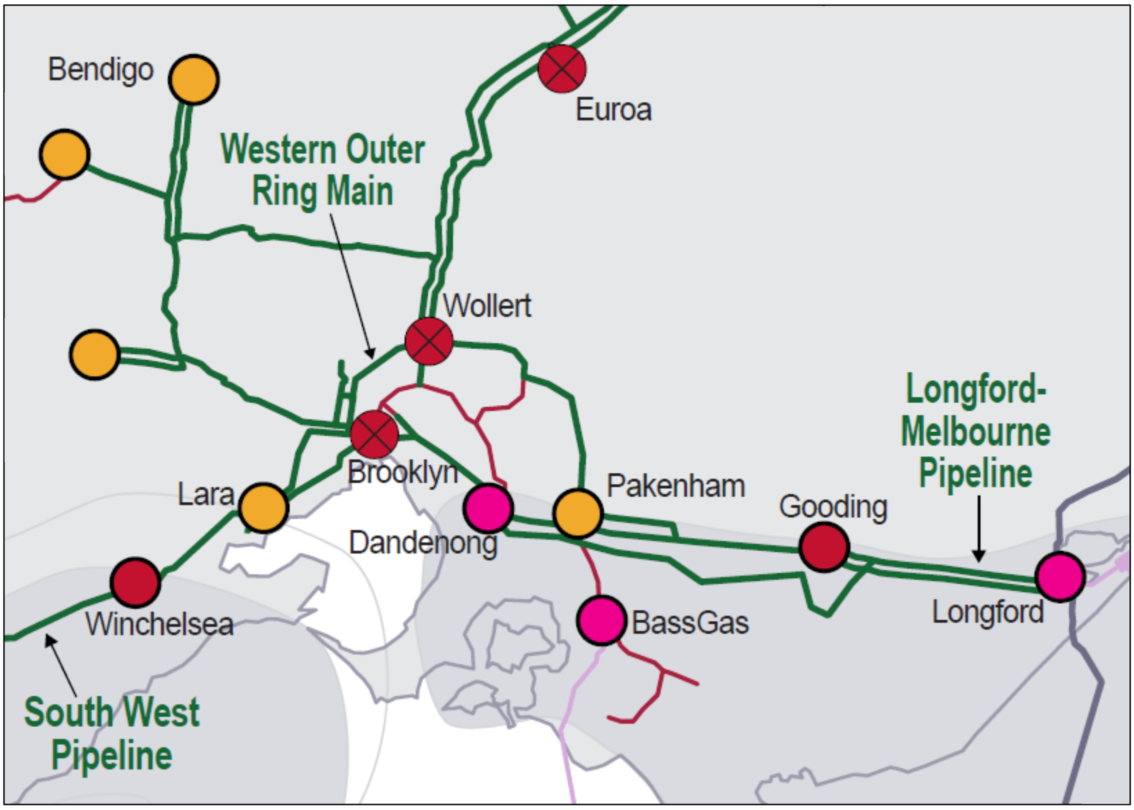


Flows in the DTS have typically been from the Longford Gas Plant towards Dandenong via Pakenham. As discussed above, however, there is an increasing likelihood that in the event of insufficient Longford CPP injections in future, gas will need to flow east towards Longford. This would require LV05-N to be opened to allow gas to flow from the Wollert to Pakenham Pipeline into the LMP, then east past the Gooding CS and towards Longford. The valve would need to be manually closed again to enable Gooding compression.

To remove the requirement for APA to attend site every time easterly flow is required (which could be due to an unplanned full Longford Gas Plant outage), modification of LV05-N would need to occur to allow AEMO and APA to remotely open and close this valve.

[107] AER, "Australian Gas Networks (Victoria and Albury) – Access arrangement 2023-2028", 1 July 2022, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-victoria-and-albury-access-arrangement-2023%E2%80%9328/proposal.

Figure 25 Schematic of the DTS indicating relative location of Longford, Gooding and Pakenham



5.4.1 Victorian LNG receiving terminals

As discussed in **Section 4.4.1**, there are two proposed Victorian LNG terminals that could increase supply to the DTS. Viva is proposing an LNG receiving terminal at its Geelong oil refinery and Vopak is proposing an offshore LNG receiving terminal at Avalon. Both projects are proposing to connect to the DTS at the SWP (which includes the BLP). Neither of the projects have reached FID.

As presented in the 2021 VGPR, modelling completed by AEMO indicated that an LNG receiving terminal connected to the SWP would increase the SWP injection capacity significantly once the WORM is completed.

However, modelling also indicates that maximising LNG injections on the SWP causes supply from the Iona CPP to be backed out and unable to inject at the current SWP capacity, due to the higher supply pressure of the LNG receiving terminal that is closer to Melbourne.

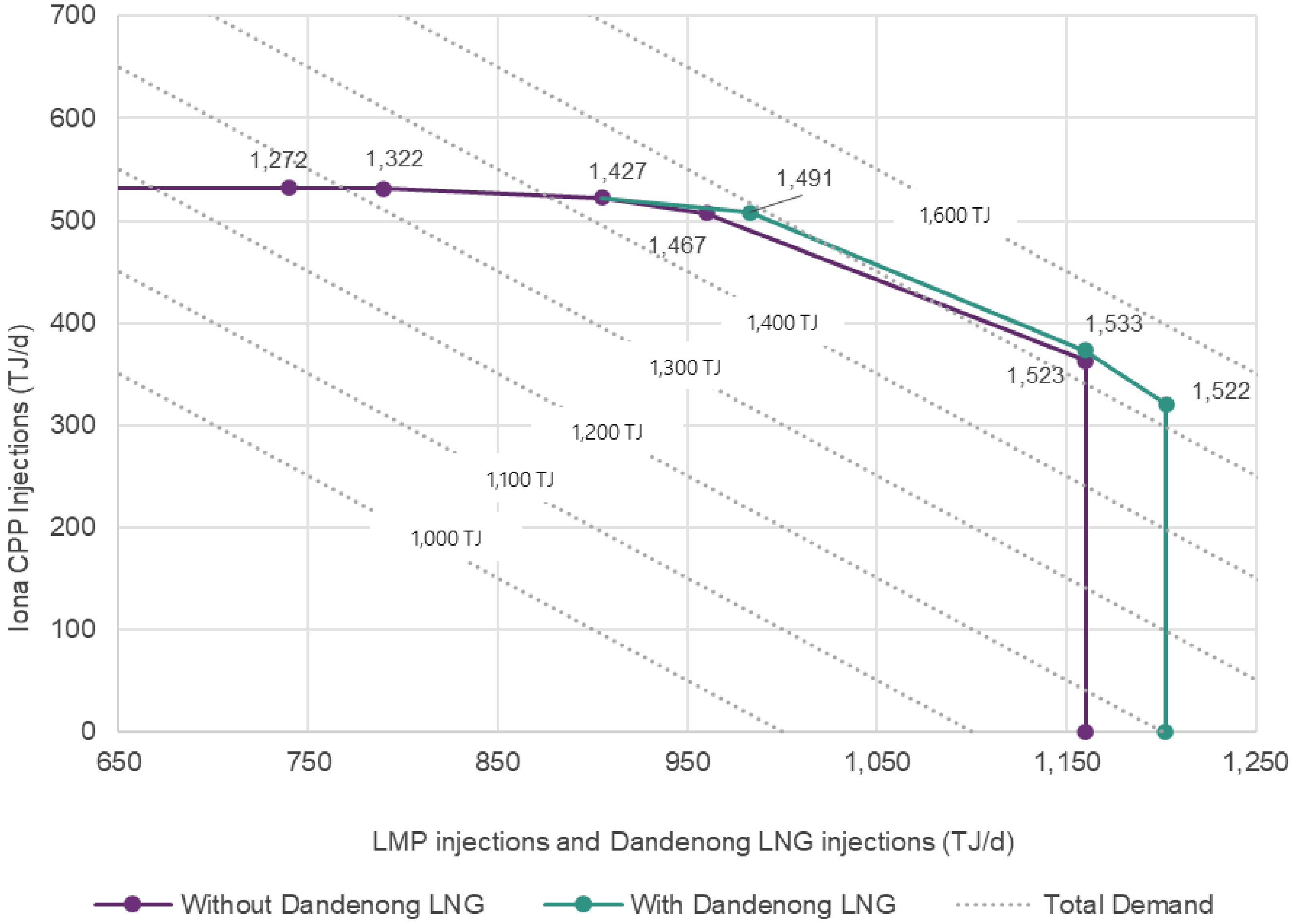
AEMO will conduct further capacity modelling if FID is reached.

5.5 Peak day system adequacy

Peak day system adequacy, shown in **Figure 26**, quantifies the main sources of DTS injections – the LMP, Iona CPP and Dandenong LNG injections – required to meet total DTS demand (including gas generation).

The area under the curve represents the feasible operating envelope of the DTS, assuming sufficient gas supply is available.

Figure 26 DTS peak day system capacity (TJ/d)



Key observations are:

- The maximum capacity of 1,533 TJ/d is achieved with Dandenong LNG injecting at its maximum firm rate of 87 TJ/d, and 1,523 TJ/d without Dandenong LNG injections.
- The introduction of the WORM for 2023 has resulted in increased flow interactions between Iona CPP and LMP injections. It also allowed significantly more LMP injections compared to the 2021 VGPR.
- Culcairn injections or withdrawals are not included in system capacity modelling.

5.6 Gas generation supportability

DTS-connected gas generation units typically operate during times of high electricity demand or when supply from other generation sources is limited.

As outlined in **Section 2.4.3**, gas generation peak demand during winter is forecast to increase, while the summer gas generation trend declines over the outlook period. This increase in forecast winter peak gas generation demand is due to the expected electrification of winter heating loads and periods of low VRE production, increasing the potential for peak gas generation to coincide with a peak system demand day. Assessing the ability of the DTS to support DTS-connected gas generation demand is therefore critical.

Operational challenges arise when high gas generation demand is not accurately forecast at the start of the gas day during winter because:

- The DTS has limited useable linepack to absorb unforecast gas generation demand.
- Instantaneous gas generation demand can be high and reduce linepack levels quickly, especially during the morning and evening peak periods when hourly gas demand is already high.

To ensure the uncertainties associated with gas generation demand are managed, the AEMO gas control room:

- Monitors the forecast gas generation in both the DWGM demand forecasts and the NEM pre-dispatch (forecast) data.
- Seeks confirmation and updates from market participants who operate DTS-connected gas generation units.
- Communicates regularly with AEMO's NEM control room and support teams regarding forecast electricity demand, NEM reserve levels and generator outages.

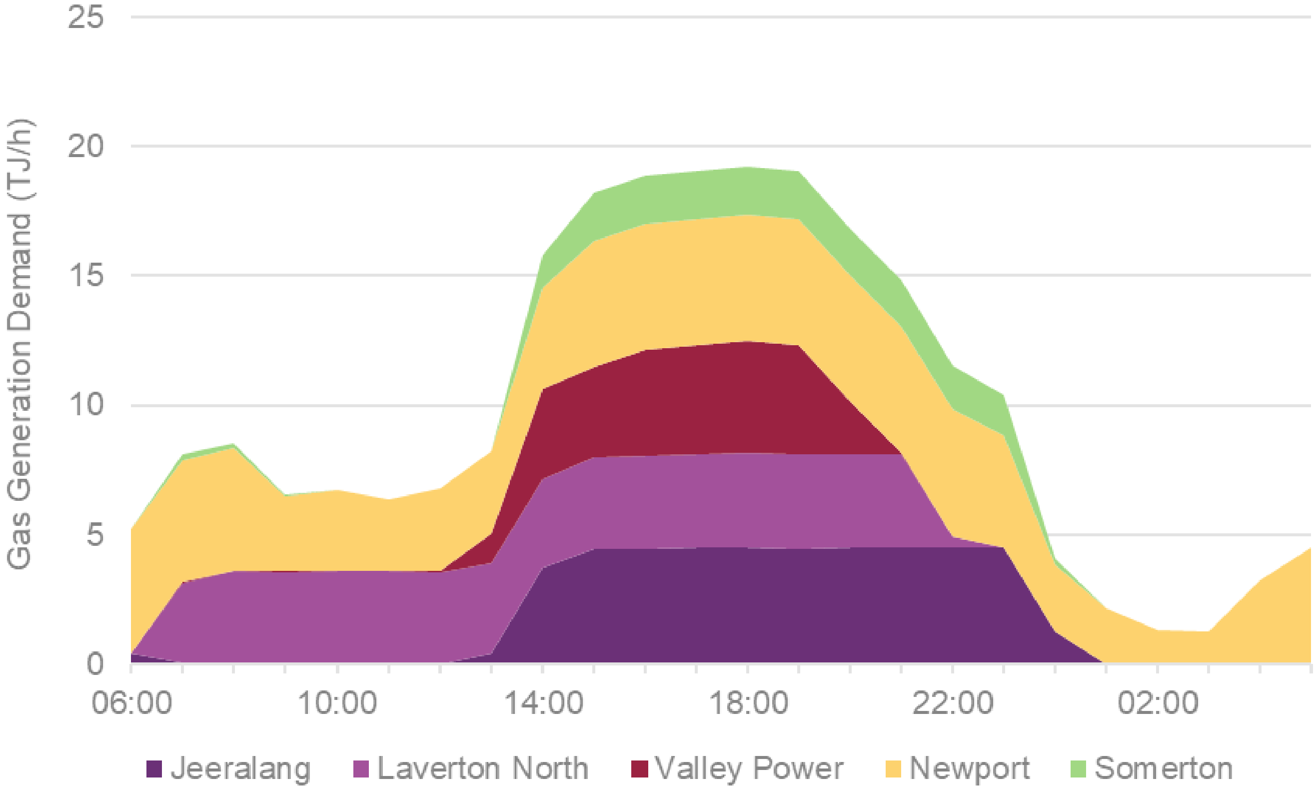
AEMO has assessed the ability of the DTS (including the WORM) to support forecast demand for DTS-connected gas generation of 237 TJ for a summer day and 297 TJ for a peak winter day. These summer and winter gas generation quantities illustrate scenarios of daily high gas generation based on historical demand.

Peak gas generation in summer

This scenario modelled coincident peak gas generation of 237 TJ in total for all DTS-connected units on a 400 TJ system demand day with the WORM operational.

The DTS can support the modelled gas generation profile with withdrawals at Iona CPP and Culcairn.

Figure 27 Modelled peak gas generation profile – summer



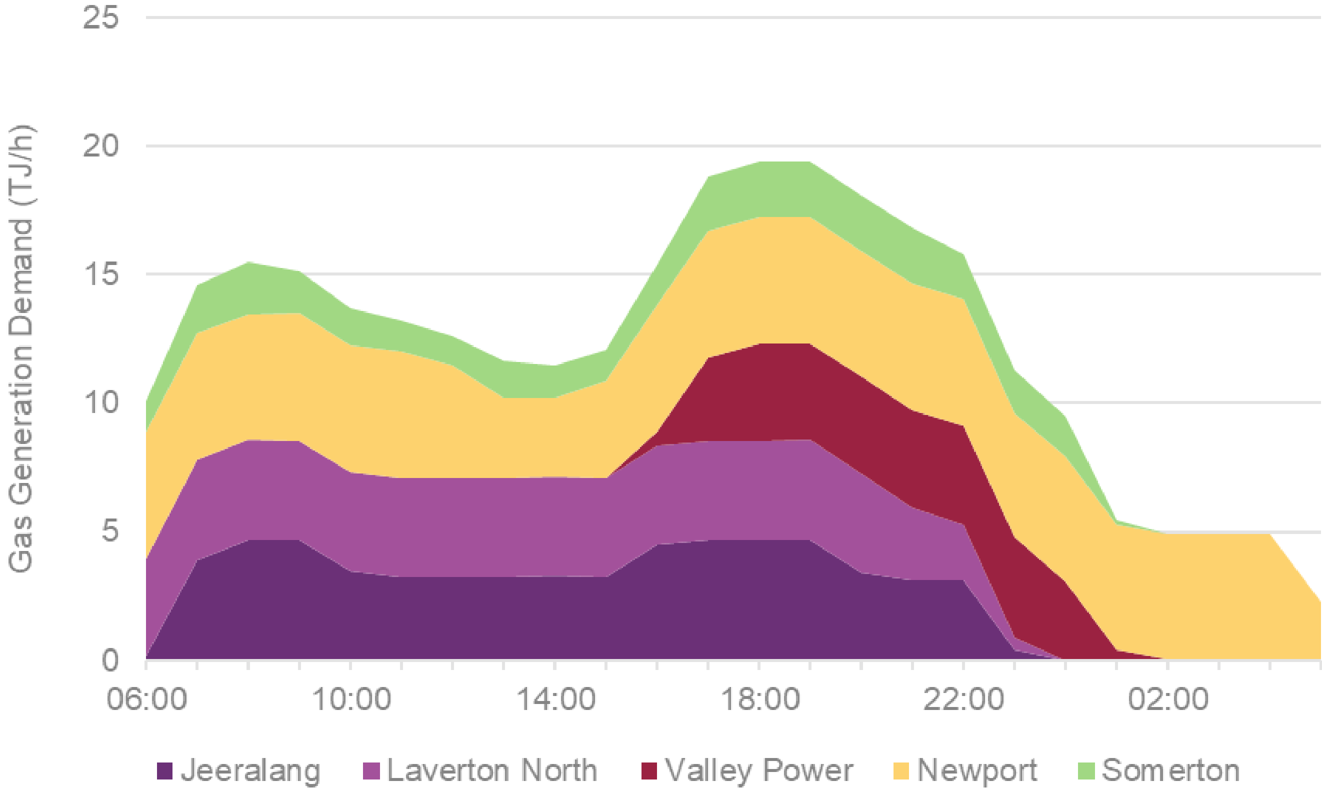
Peak gas generation in winter

This scenario modelled coincident peak gas generation of 297 TJ in total for all DTS-connected units on a 1,128 TJ (1-in-2) peak system demand day with the WORM operational. Modelling for this scenario indicated that:

- 20 TJ of LNG injections at Dandenong were required during the evening peak to maintain Dandenong CG inlet pressure.
- Injections were required at Iona CPP.

The DTS can support the modelled gas generation profile, however if gas generation or system demand is not accurately forecast at the beginning of the day, additional LNG injections are likely to be required and the supportable gas generation demand may be lower.

Figure 28 Modelled peak gas generation profile – winter



6 Declared Transmission System pipeline capacities

Key findings

- The WORM (construction of a new pipeline and installation of a third compressor at Wollert B CS) and the second compressor at the Winchelsea Compressor Station are expected to be operational by winter 2023. AEMO has assumed that both projects are in operation for the purposes of all 2023 capacity modelling.
  - Capacity modelling for 2023 indicates that the addition of the WORM and second Winchelsea compressor increases the SWP injection capacity for supply towards Melbourne from 447 TJ/d, as reported in the 2022 VGPR Update, to 530 TJ/d.
- Other pipeline capacities for this VGPR remain comparable to previous results.
- The pipeline capacities in this chapter will be used:
  - For the application of scheduling constraints in the DWGM,
  - To inform the assessment of any proposed DTS service provider and facility operator maintenance plans, and
  - For the auctioning of entry and exit capacity certificates.

This section outlines the DTS pipeline capacities as at the publication date of this VGPR. All 2023 capacity modelling assumes that the WORM and the second Winchelsea compressor are operational. See **Appendix A6** for more detail on AEMO's change in modelling approach for this VGPR and all 2023 capacity modelling assumptions.

Table 19 Summary of DTS pipeline capacities

Pipeline		Maximum capacity (TJ/d)	Comment
Longford to Melbourne	To Melbourne	1,160	-
	To Longford	0	-
South West Pipeline	To Melbourne	530	Includes 17 TJ of Western Transmission System (WTS) demand. Material capacity increase compared to the 2022 VGPR Update due to inclusion of the WORM and second Winchelsea compressor.
	To Port Campbell	328	Material change to capacity compared to 2022 VGPR Update is due to inclusion of the WORM which includes Wollert compression toward Port Campbell.
Victorian Northern Interconnect	To Melbourne	218	Limited to 180 TJ/d due to capacity constraints in the New South Wales transmission network.
	To New South Wales via Culcairn	224	-

6.1 DWGM Improvement to AMDQ Regime

Entry and exit capacity certificates replaced transportation rights previously represented by the authorised maximum daily quantity (AMDQ) regime on 1 January 2023 in accordance with the AEMC's final rule change determination on 12 March 2020[108].

The new regime allocates system injection points and system withdrawal points to capacity certificate zones[109]. The system capability modelling for determining the types and quantity of capacity certificates available at each auction are outlined in **Appendix A1**.

The main method of acquiring capacity certificates is via the capacity certificates auction. Auctions will be held twice a year, with AEMO required to publish the date no later than 20 business days before the auction commences. In 2023, auctions are expected to be held in May and November, with exact dates to be advised closer to the month of the auction.

6.2 Longford to Melbourne Pipeline

The Longford to Melbourne Pipeline (LMP) transports gas from Longford to Dandenong CG, which is the main supply point for the Melbourne inner ring main, as well as from Pakenham to Wollert. The LMP is supplied by the Longford CPP[110] and the BassGas injection point at Pakenham.

6.2.1 Longford to Melbourne import capacity

Figure 29 shows the LMP injection capacity to Melbourne. The LMP transportation capacity varies with system demand and asset availability.

The LMP capacity is constrained by the capability of the DTS compressors to move gas from the LMP to other parts of the system, particularly the Gooding CS which is closest to the Longford CPP injection point. Gooding compression increases the LMP transportation capacity by up to 188 TJ/d on peak demand days, although it is less effective during lower system demand days.

On system demand days above 800 TJ/d, the capacity also becomes constrained by the requirement to maintain minimum pressure requirements at the inlet to Dandenong CG during the evening peak (to maintain the required pressure for distribution network connection points downstream of the outlet of Dandenong CG).

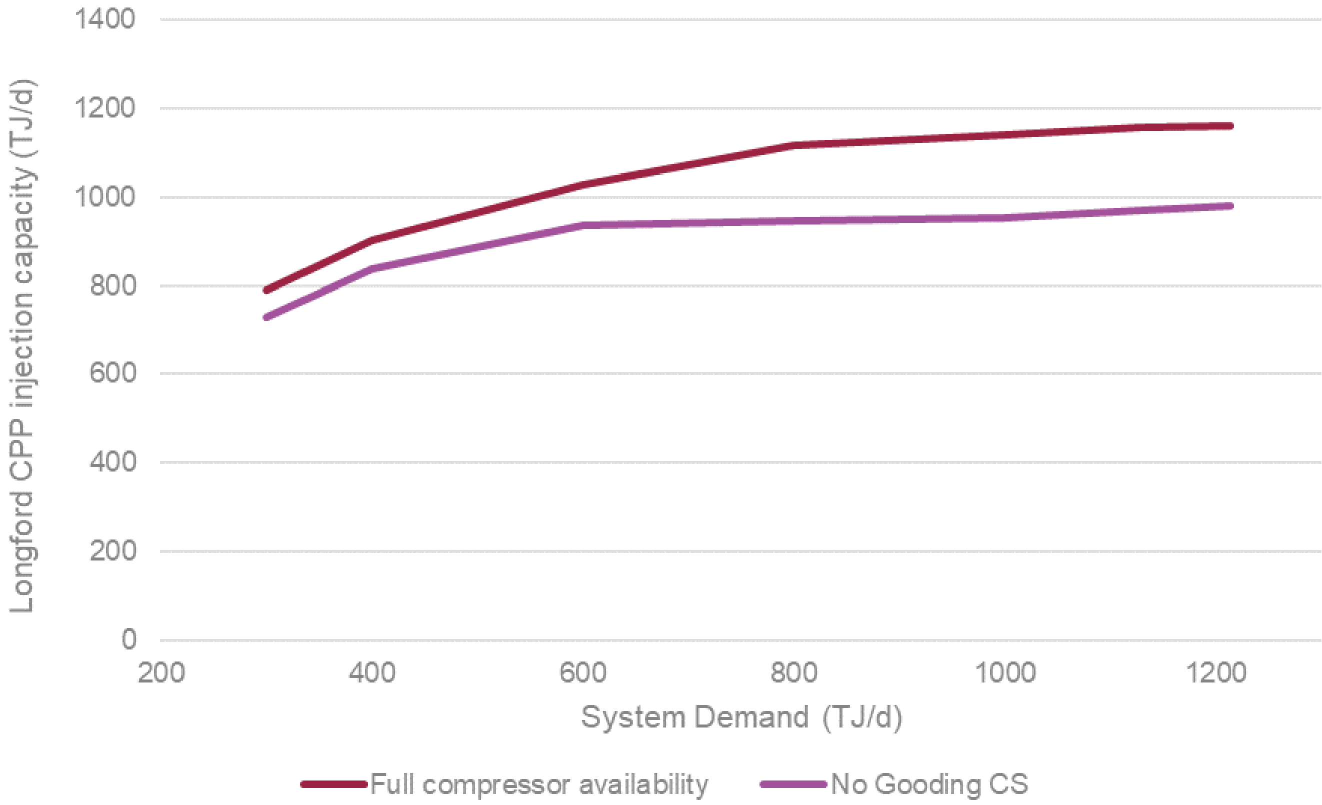
The LMP capacity is comparable to the 2022 VGPR Update, with a decrease in the 1-in-20 system demand day capacity from 1,177 TJ/d to 1,160 TJ/d. This can be attributed to an updated modelling assumption at the BassGas connection point for 2023 (see **Appendix A6**).

108 AEMC, "DWGM improvement to AMDQ regime", 12 March 2020, at https://www.aemc.gov.au/rule-changes/dwgm-improvement-amdq-regime.

109 AEMO, "Entry and Exit Capacity Certificates", November 2022, at https://aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/market-operations/entry-and-exit-capacity-certificates.

110 The Longford CPP consists of the Longford, VicHub and TasHub injection points.

Figure 29 LMP injection capacity (TJ/d) with varying Gooding CS availability



6.3 South West Pipeline

The SWP is a bi-directional pipeline that runs between Port Campbell and Lara, where it connects to the BLP that runs from Lara to Brooklyn CG (both pipelines combined can also be referred to as the SWP). The SWP can also supply the Brooklyn to Corio Pipeline (BCP) through the Lara PRS and will be connected to Wollert via the WORM which will run from Plumpton to Wollert.

The SWP is typically used to:

- Transport gas from the Port Campbell production and storage facilities at Iona CPP[111] towards Melbourne to support DTS demand, including supplying gas to northern and eastern Victoria (once the WORM is commissioned).
- Transport gas from Melbourne for withdrawal at the Iona CPP during shoulder and low system demand periods for:
  - Iona Underground Gas Storage (UGS) reservoir refilling,
  - Supply to the Mortlake Power Station, and
  - Transportation to South Australia via the SEA Gas Pipeline.
- Physical withdrawals from the SWP at the Iona CPP requires compression at the facility withdrawing the gas. Iona UGS is currently the only Port Campbell facility that physically withdraws gas from the SWP.

[111] Iona CPP consists of the Iona UGS, Mortlake, Otway and SEA Gas injection and withdrawal points.

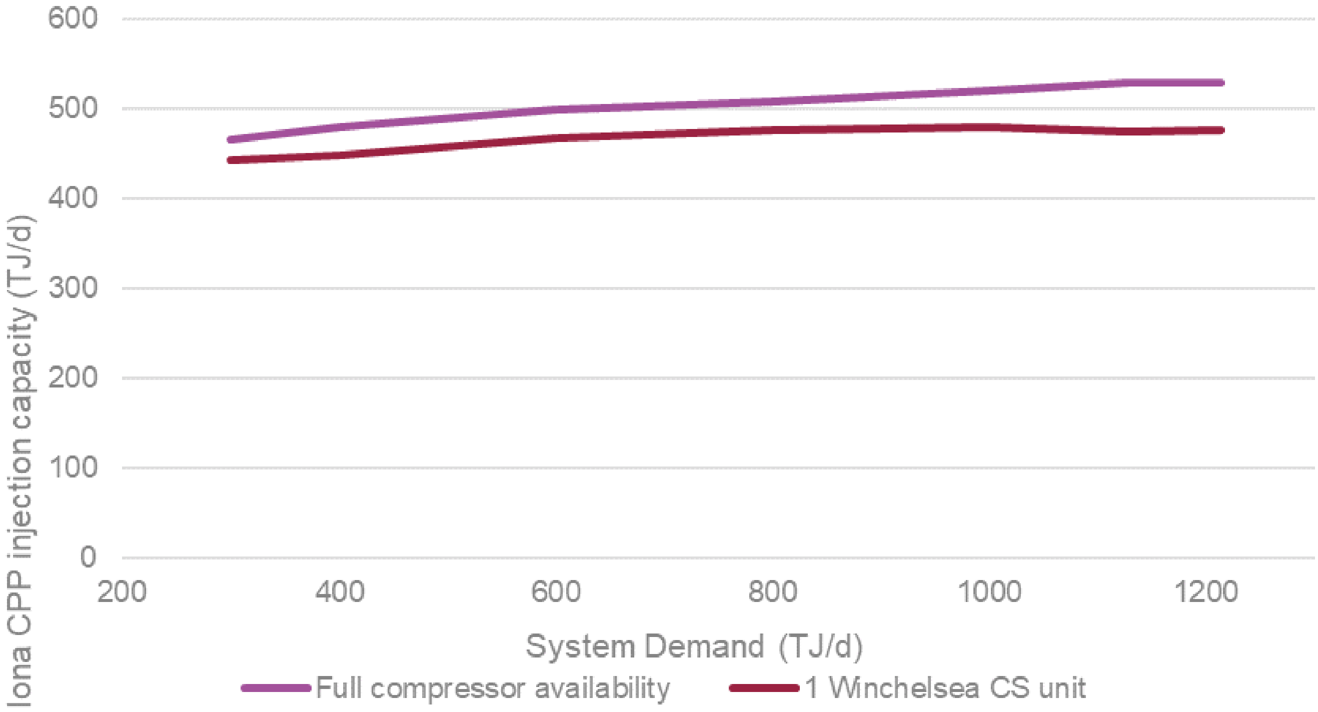
- Supply gas into the Western Transmission System (WTS) at Port Campbell for supply to towns and cities in south-west Victoria including Warrnambool, Portland, Hamilton, and Cobden.

As detailed in **Section 5.2**, APA has begun construction on a second compressor at Winchelsea Compressor Station.

6.3.1 South West Pipeline to Melbourne

The SWP injection capacity (including WTS demand), shown in **Figure 30**, is dependent on system demand so it is maximised on peak demand days. The Winchelsea CS is typically operated to increase the transportation capacity and shift linepack closer to Melbourne to support high hourly demand, particularly during winter evening peaks.

Figure 30 SWP injection capacity (TJ/d) (including WTS demand) toward Melbourne with varying Winchelsea CS availability



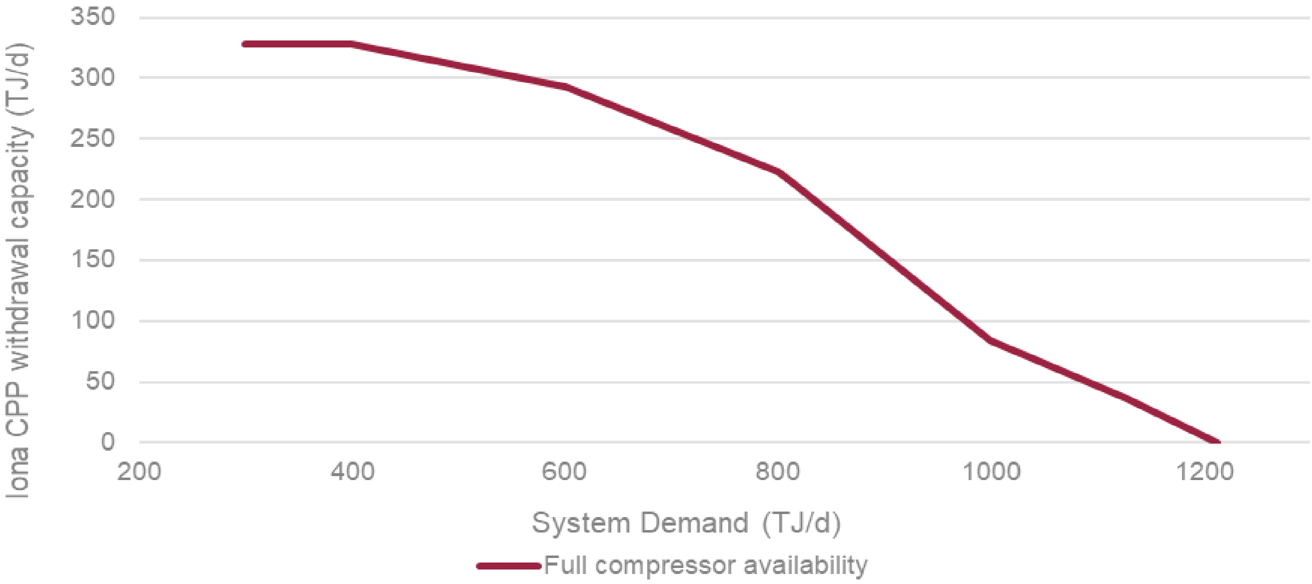
Due to the addition of the WORM and a second Winchelsea compressor, the maximum SWP injection capacity has increased from 447 TJ/d in 2022 to 530 TJ/d in 2023 on a 1-in-20 peak system demand day. This injection capacity is higher than the 517 TJ/d reported by APA during its 2023-27 Access Arrangement consultation in May 2022[112]; AEMO and APA finalised the SWP modelling assumptions since that time (see **Appendix A6**).

[112] APA Group via AER, "Victorian Transmission System Stakeholder Engagement Group 2023-27 access arrangement (AA6). Roundtable 14 – Updates on Winchelsea. Demand and Supply. Discussion about stakeholder submissions.", 25 May 2022, at https://www.aer.gov.au/system/files/APA%20VTS%20AA%20Roundtable%2014%20%20-%20Update%20on%20Winchelsea%2C%20Forecasts%2C%20Submissions%20-%2025%20May%202022.pdf.

6.3.2 South West Pipeline to Port Campbell

The SWP capacity to support Iona UGS withdrawals is shown in **Figure 31**. The withdrawal capacity is maximised on low system demand days when Winchelsea CS and all three Wollert CS B units are available.

Figure 31 SWP withdrawal capacity (TJ/d) to Port Campbell



The maximum SWP withdrawal capacity is 328 TJ/d on a 400 TJ/d system demand day. The maximum capacity has increased from the 320 TJ/d reported in the 2021 VGPR due to a change in the assumptions at Culcairn, as discussed in **Appendix A6**. With lower Culcairn exports assumed, flow from Wollert to the VNI is minimised, maximising flow through the WORM towards the SWP.

The unavailability of one of the three Wollert CS B units and compression at Winchelsea CS reduces the SWP export capacity by approximately 80 TJ/d during shoulder and low system demand days. On higher demand days, the reduction in capacity is less pronounced as compression at Brooklyn CS can be used to offset the reduction in compression at Wollert.

6.4 Victorian Northern Interconnect

The VNI runs between Wollert and Culcairn, connecting Victoria with New South Wales via the Culcairn interconnection. Culcairn is a bi-directional site and can be used to either import gas to Victoria from New South Wales, or export gas from Victoria to New South Wales and beyond to Queensland.

The VNI encompasses three pipelines:

- T74 (300 mm) Wollert to Wodonga Pipeline supports Northern Zone demand, including Bendigo via the Wandong Pressure Reduction Station (PRS), and the Echuca and Koonoomoo laterals. The pipeline has a section with an 8,800 kPa maximum allowable operating pressure (MAOP) (Wollert to Euroa) and a 7,400 kPa MAOP (Euroa to Wodonga).

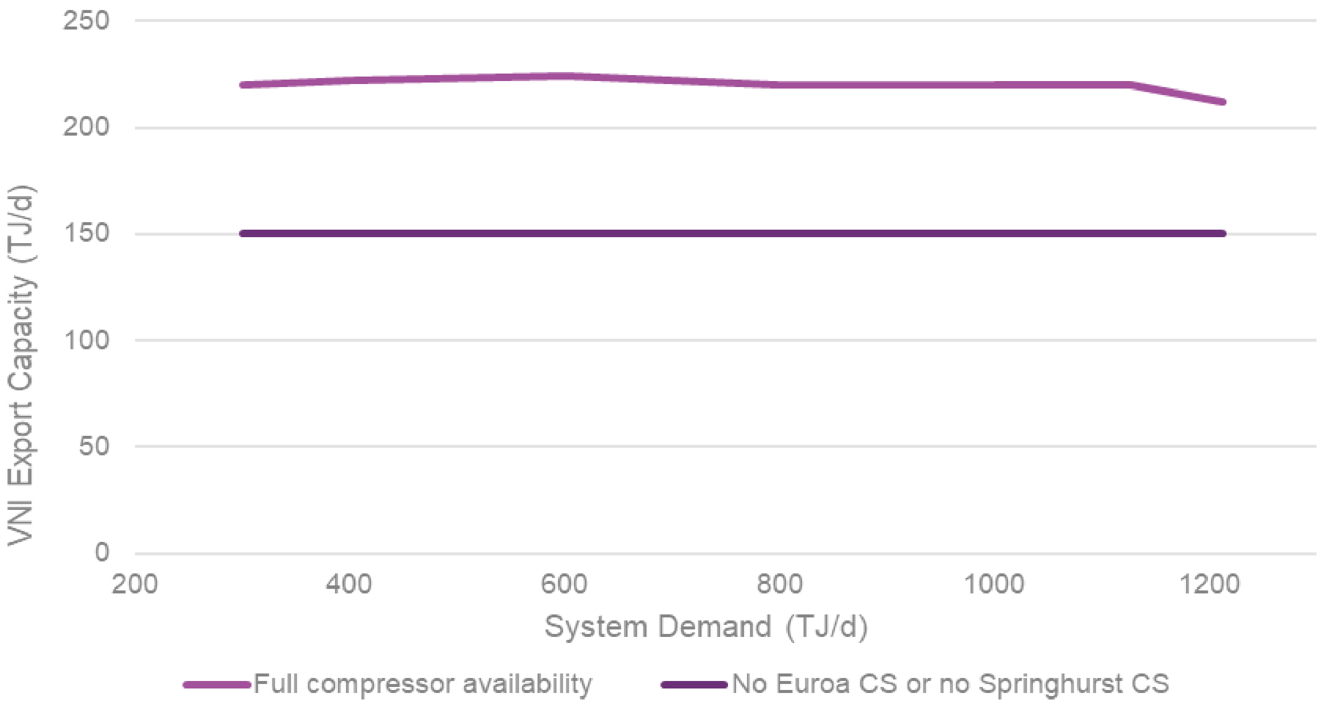
- T119 (400 mm) Wollert to Barnawartha Pipeline, with a 10,200 kPa MAOP, that supports exports to and imports from New South Wales; and supports Northern Zone demand through connections into the T74 at the Wollert, Euroa and Barnawartha PRSs.
- T99 (450 mm) Barnawartha to Culcairn 10,200 kPa MAOP pipeline supporting exports to and imports from New South Wales, and supplying the town of Walla Walla.

The planning assumptions for VNI capacity are outlined in **Appendix A6**.

6.4.1 Victorian Northern Interconnect export capacity (to New South Wales)

The VNI export capacity is dependent on the availability of the Wollert, Euroa and Springhurst compressor stations, and varies with different compressor configurations. The export capacity is represented in **Figure 32** as the DTS maximum capacity when the DTS supply pressure to Culcairn is greater than the 8,600 kPa required by the Culcairn facility to free-flow gas into the New South Wales transmission system. If the DTS is unable to supply a pressure of at least 8,600 kPa, Culcairn facility flow is limited to a maximum of 150 TJ (assuming all three Culcairn compressors are available[113]).

Figure 32 Victorian Northern Interconnect export capacity (TJ/d)



The export capacity on system demand days below 1,000 TJ is limited by maximum allowable flow through the VNI Discharge Flow Controller (DFC) located at the outlet of the Wollert B compressor station. On peak system demand days, the export capacity is limited by the minimum free-flow pressure of 8,600 kPa at Culcairn.

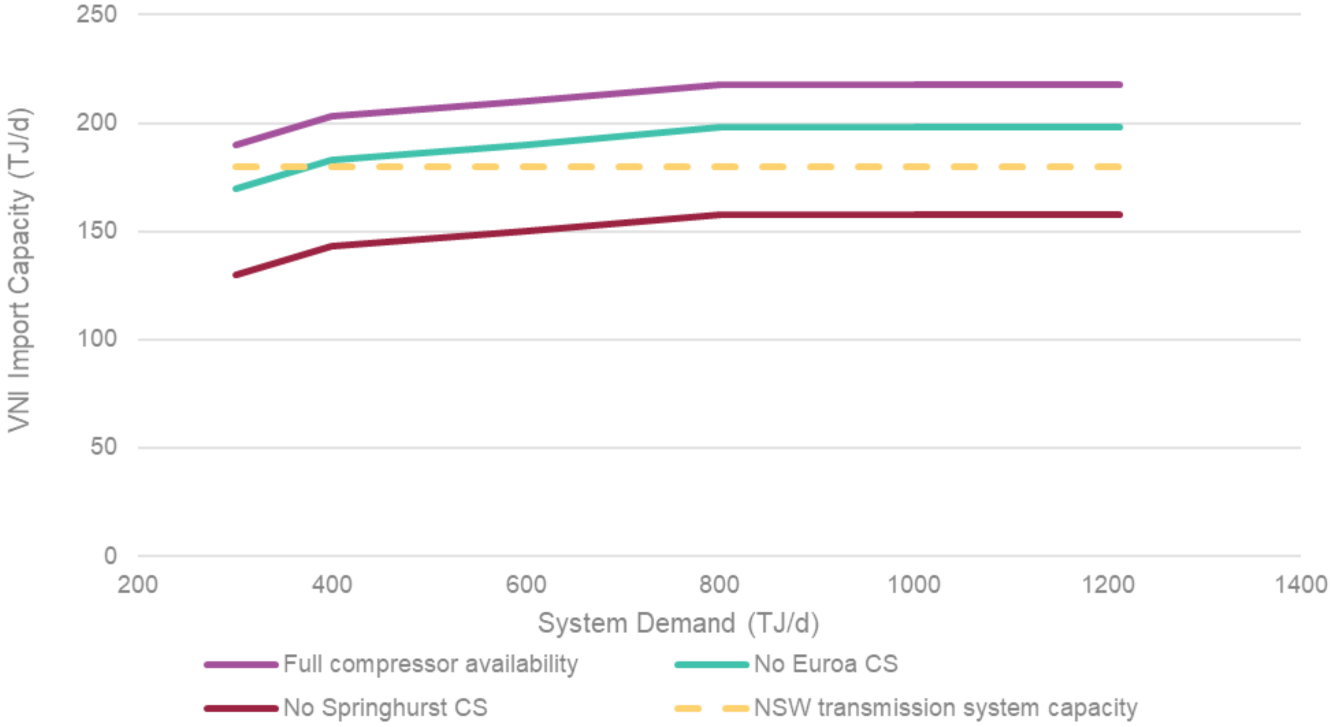
[113] Culcairn compressors are located outside of the DTS and are operated by the facility operator of the New South Wales transmission system.

APA has notified AEMO that, when operational, the Culcairn compressors are limited to a maximum flow of 150 TJ/d. This export quantity can be supported across all system demand days when Wollert CS B and only one of Euroa CS or Springhurst CS are available.

6.4.2 Victorian Northern Interconnect import capacity (to Victoria)

The VNI import capacity is shown in **Figure 33**, with the maximum capacity of 218 TJ/d achievable on all system demand days above 600 TJ/d. The import capacity is reduced if either the Euroa CS or Springhurst CS is unavailable, but more so when the Springhurst CS is offline, due to the longer distance from Culcairn to the Euroa CS.

Figure 33 Victorian Northern Interconnect import capacity (TJ/d)



For most DTS compressor configurations, the VNI import capacity is higher than the Culcairn supply capacity.

APA, as the operator of the New South Wales transmission system north of Culcairn, has advised AEMO that Culcairn can supply up to 180 TJ/d of firm injections into the DTS. This is unchanged from the 2021 VGPR Update.

Actual Culcairn supply is often limited by the supply pressure that APA can provide at Culcairn. Culcairn supply is dependent on the Young CS pressure (as there is no southern flow compression capability at Culcairn), which varies due to Moomba to Sydney Pipeline flows.

Culcairn injection capacity into the DTS can also be reduced if the Uranquinty Power Station is operating, or if there is high system demand off the Young to Culcairn lateral.

A1. System capability modelling

A1.1 Monthly peak demand for 2023-2026

Table 20 shows forecast peak day system demand for each month from 2023 to 2026. The forecast peak day system demand will be used to inform the amount of capacity certificates for any month and capacity certificate type[114].

Table 20 Forecast monthly 1-in-20 peak day demand from 2023 to 2026 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	428	452	639	806	1,053	1,157	1,187	1,202	1,019	860	728	556
2024	423	449	631	793	1,048	1,142	1,170	1,190	1,008	848	721	550
2025	417	446	623	787	1,032	1,129	1,156	1,172	998	838	710	547
2026	414	440	610	761	1,004	1,098	1,128	1,141	972	816	699	535

A1.2 Capacity certificates zones

There is no change to the capacity certificate zones that AEMO determined and published in the 2022 VGPR Update. **Table 21** shows the capacity certificates zone and the system points allocated to the capacity certificates zone.

Table 21 Capacity certificate zones and equivalent VGPR pipeline capacity

Capacity certificate zone	System points	VGPR pipeline capacity
Gippsland entry zone	Longford injection point VicHub injection point TasHub injection point BassGas injection point	Longford Melbourne Pipeline to Melbourne (**Figure 34**)
Gippsland exit zone	VicHub withdrawal point TasHub withdrawal point	Longford Melbourne Pipeline to Longford (**Table 22**)
Melbourne entry zone	Dandenong LNG injection point	(**Table 23**)
South west entry zone	Iona injection point SEA Gas injection point Otway injection point Mortlake injection point	South West Pipeline to Melbourne (including WTS demand) (**Figure 35**)
South west exit zone	Iona withdrawal point SEA Gas withdrawal point Otway withdrawal point	South West Pipeline to Port Campbell (**Figure 36**)
Northern entry zone	Culcairn injection point	Victorian Northern Interconnect to Melbourne (**Figure 37**)
Northern exit zone	Culcairn withdrawal point	Victorian Northern Interconnect to New South Wales via Culcairn (**Figure 38**)

[114] Capacity certificate type means each combination of exit capacity certificate or entry capacity certificate and capacity certificates zone.

A1.3 DTS pipeline and system points capacity charts

The capacity modelling assumptions used for the system capability modelling are the same as the assumptions used in the 2023 VGPR (see **Appendix A6**).

Unless otherwise stated, the system point capacities are obtained from the Nameplate Rating reports published on the Gas Bulletin Board. System point capacities refers to the aggregated capacities for either system injection points or system withdrawal points (as the case may be) in a capacity certificates zone.

A1.3.1 Longford to Melbourne Pipeline

Figure 34 LMP injection capacity to Melbourne (TJ/d)

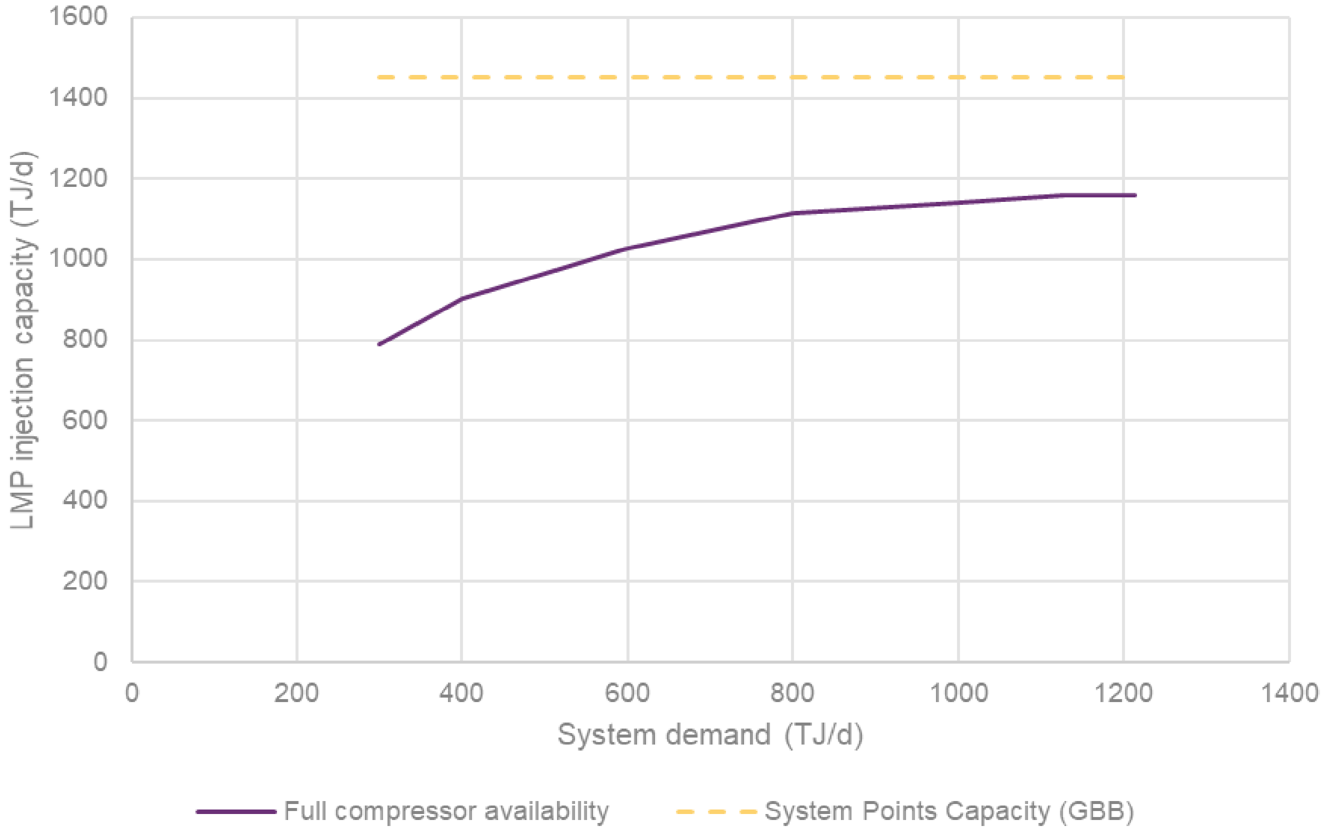


Table 22 Longford to Melbourne Pipeline to Longford capacity

Pipeline	System capability modelling (TJ/d)	System points capacity (TJ/d)	Notes
Longford to Melbourne Pipeline (LMP) to Longford	0	270	Modelling indicates that withdrawals at the Longford CPP are not currently possible, therefore the pipeline capacity for the LMP towards Longford is 0 TJ/d.

A1.3.2 Melbourne entry zone

For the purposes of the DWGM entry certificate auctions, AEMO declared the pipeline capacity for the Melbourne entry zone equal to the nameplate capacity of the Dandenong LNG facility. This simplified approach is allowed as the quantity of capacity certificates to be auctioned is the lower of the maximum pipeline capacity or the maximum facility capacity.

Table 23 Melbourne entry zone capacity

Capacity certificate zone	System capability modelling (TJ/d)	System points capacity (TJ/d)	Notes
Melbourne entry zone	237	237	This assumption will be reviewed if another system point connects to the Melbourne zone.

A1.3.3 South West Pipeline

Figure 35 SWP injection capacity to Melbourne (TJ/d)

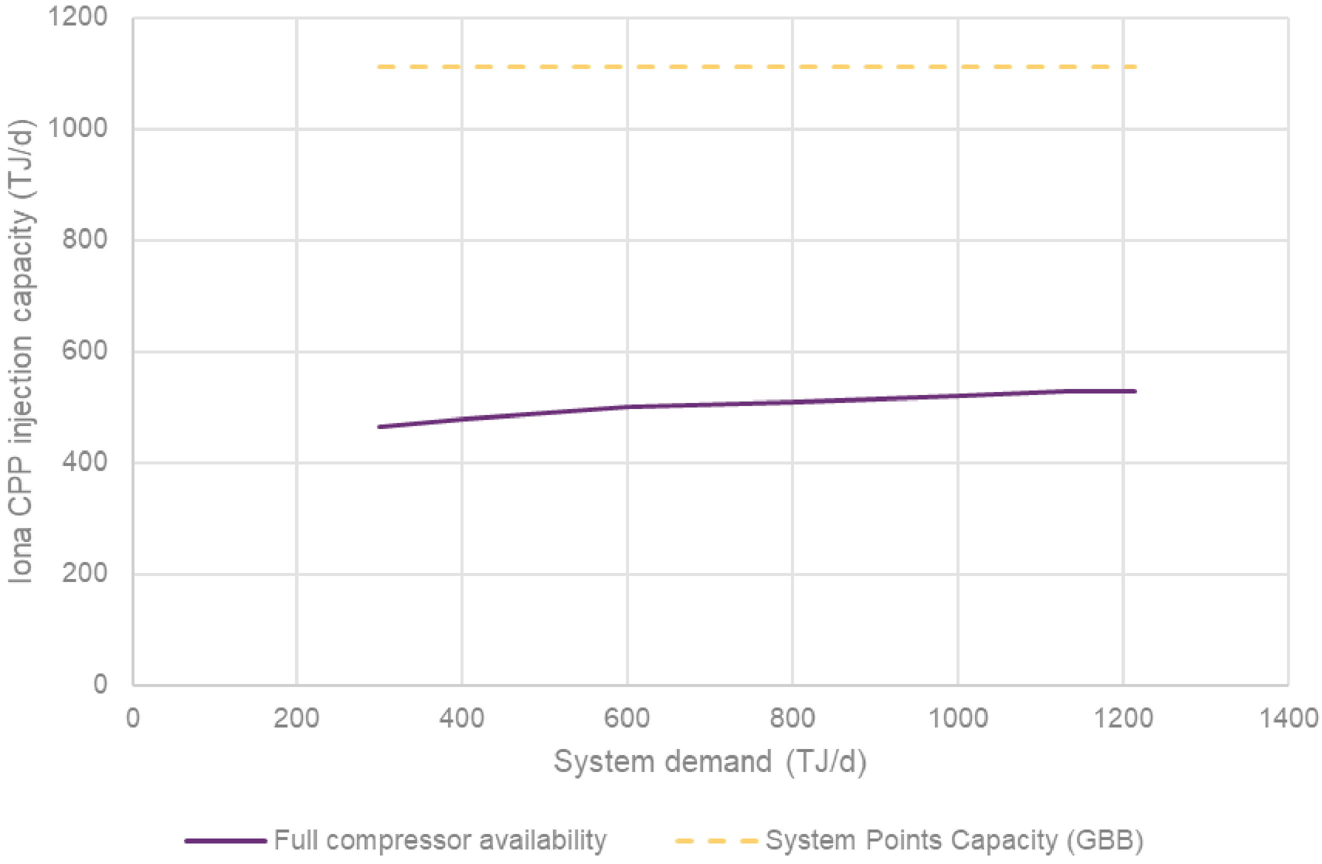
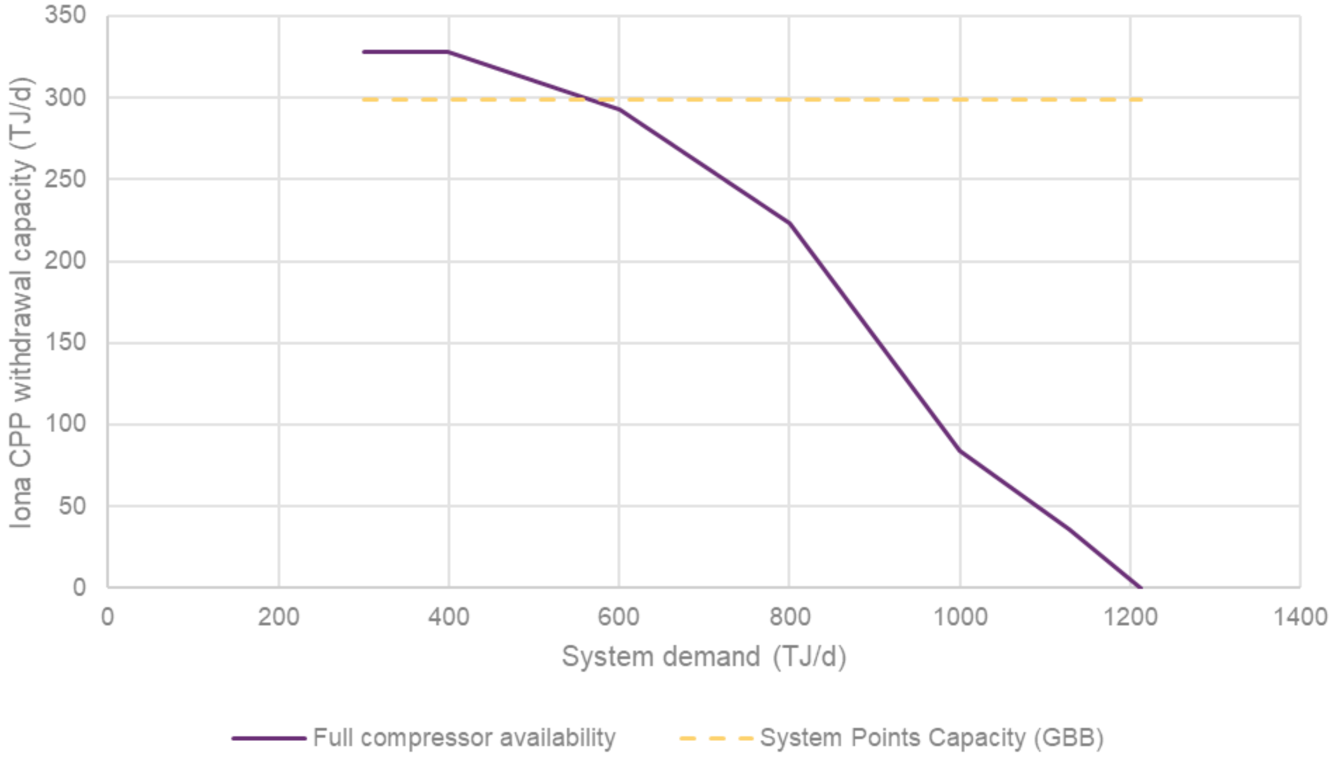


Figure 36 SWP withdrawal capacity to Port Campbell (TJ/d)



A1.3.4 Victorian Northern Interconnect

Figure 37 Victorian Northern Interconnect import capacity (TJ/d)

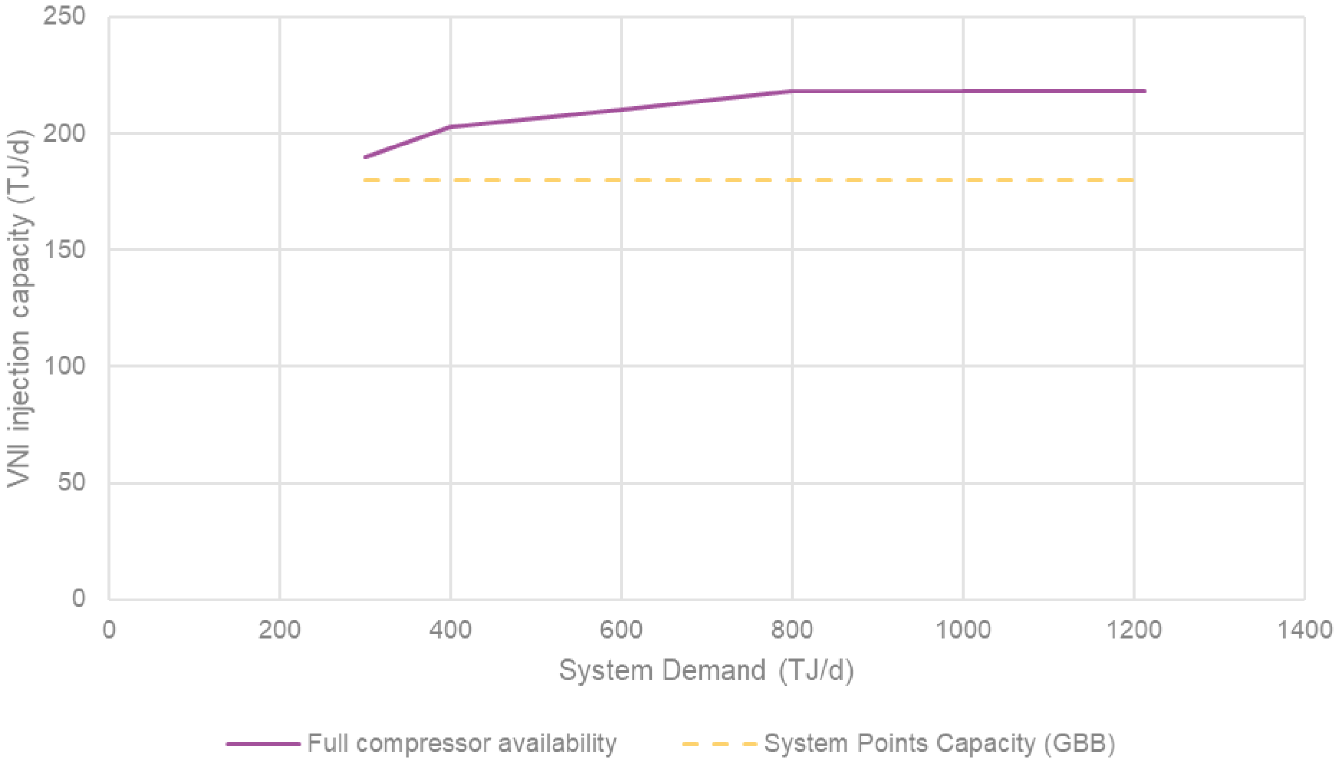
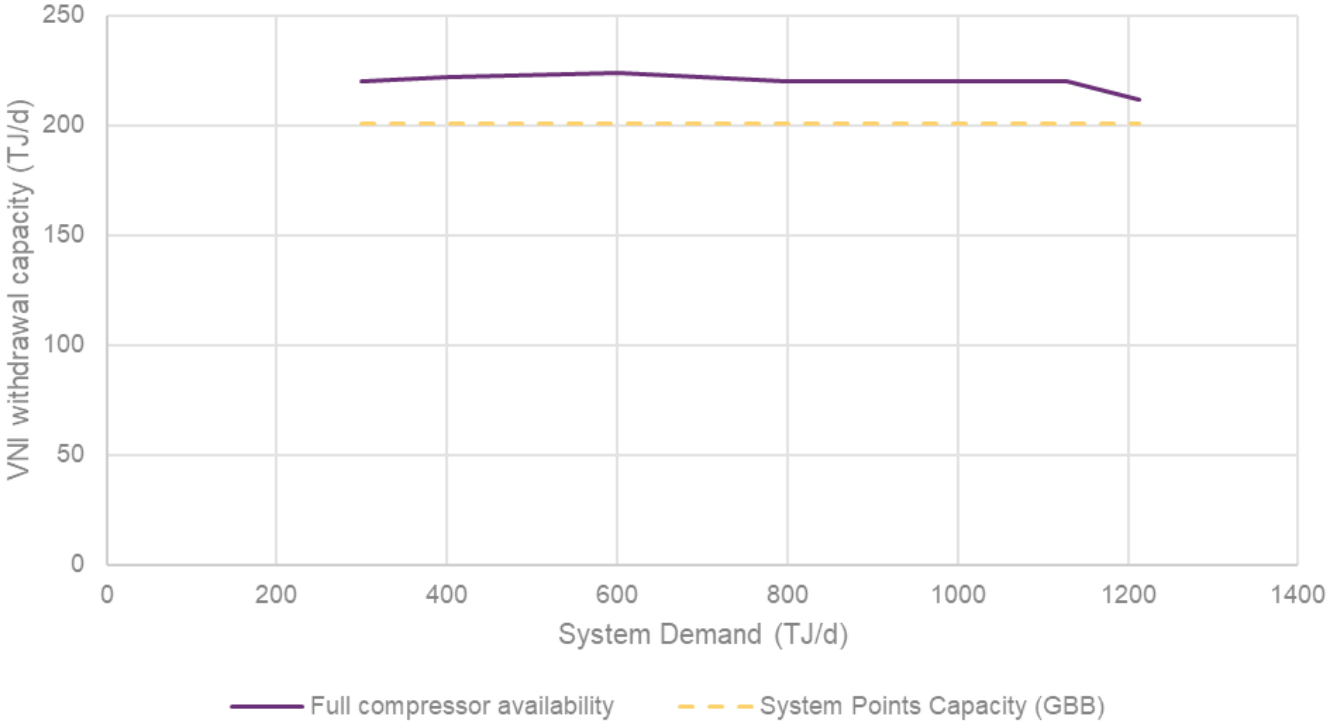


Figure 38 Victorian Northern Interconnect export capacity (TJ/d)



A2. Gas demand forecast data by System Withdrawal Zone

A2.1 Annual consumption and demand

Totals and change over outlook percentages may not add up due to rounding.

Table 24 Annual system consumption by System Withdrawal Zone (Tariff V and Tariff D split) (PJ/y)

SWZ		2023	2024	2025	2026	2027	Change over outlook
Ballarat	Tariff V	9.5	9.6	9.5	9.3	8.9	-6.3%
	Tariff D	1.3	1.3	1.3	1.3	1.3	0.0%
	SWZ total	**10.8**	**10.8**	**10.8**	**10.6**	**10.2**	-5.6%
Geelong	Tariff V	11.8	11.8	11.8	11.5	11.0	-6.8%
	Tariff D	9.9	9.7	9.9	10.1	10.1	2.0%
	SWZ total	**21.7**	**21.5**	**21.7**	**21.6**	**21.1**	**-2.8%**
Gippsland	Tariff V	6.9	7.2	7.5	7.7	7.7	13.2%
	Tariff D	9.5	9.4	9.5	9.6	6.5	-31.0%
	SWZ total	**16.3**	**16.5**	**16.9**	**17.2**	**14.1**	**-13.1%**
Melbourne	Tariff V	91.7	90.1	87.8	83.9	78.3	-14.6%
	Tariff D	31.8	31.4	31.5	31.8	32.1	0.9%
	SWZ total	**123.5**	**121.4**	**119.3**	**115.7**	**110.4**	**-10.6%**
Northern	Tariff V	10.9	10.7	10.5	10.0	9.4	-13.8%
	Tariff D	8.0	7.8	8.0	8.1	8.2	2.5%
	SWZ total	**18.8**	**18.6**	**18.4**	**18.2**	**17.6**	**-6.4%**
Western	Tariff V	1.4	1.4	1.4	1.4	1.3	-7.1%
	Tariff D	2.8	2.7	2.8	2.8	2.8	0.0%
	SWZ total	**4.1**	**4.1**	**4.2**	**4.1**	**4.1**	**0.0%**

Table 25 Annual 1-in-2 peak daily demand by System Withdrawal Zone (Tariff V and Tariff D split) (PJ/y)

SWZ		2023	2024	2025	2026	2027	Change over outlook
Ballarat	Tariff V	60.2	60.6	60.3	59.1	56.5	-6.2%
	Tariff D	5.5	5.4	5.6	5.6	5.6	1.5%
	SWZ total	**65.8**	**66.0**	**65.9**	**64.7**	**62.1**	**-5.5%**
Geelong	Tariff V	77.6	78.1	77.7	76.2	72.8	-6.2%
	Tariff D	34.7	34.0	35.0	35.4	35.3	1.5%
	SWZ total	**112.3**	**112.1**	**112.7**	**111.6**	**108.1**	**-3.8%**
Gippsland	Tariff V	42.6	44.8	46.6	47.8	47.8	12.4%
	Tariff D	27.8	27.3	28.0	28.1	18.8	-32.3%
	SWZ total	70.4	72.1	74.6	76.0	66.7	**-4.9%**
Melbourne	Tariff V	646.1	635.0	616.9	590.2	550.4	-14.8%
	Tariff D	118.6	116.6	118.4	118.4	119.0	0.4%
	SWZ total	**764.7**	**751.6**	**735.3**	**708.6**	**669.5**	**-12.5%**

SWZ		2023	2024	2025	2026	2027	Change over outlook
Northern	Tariff V	73.7	72.7	70.8	68.0	63.6	-13.7%
	Tariff D	27.6	27.1	27.9	28.3	28.1	1.9%
	SWZ total	**101.3**	**99.8**	**98.7**	**96.2**	**91.8**	**-9.4%**
Western	Tariff V	8.3	8.4	8.4	8.2	7.9	-4.6%
	Tariff D	8.3	8.1	8.3	8.3	8.3	-0.2%
	SWZ total	**16.6**	**16.5**	**16.7**	**16.6**	**16.2**	**-2.4%**

Table 26 Annual 1-in-20 peak daily demand by System Withdrawal Zone (Tariff V and Tariff D split) (PJ/y)

SWZ		2023	2024	2025	2026	2027	Change over outlook
Ballarat	Tariff V	65.6	65.5	65.4	64.3	61.6	-6.2%
	Tariff D	5.6	5.6	5.8	5.9	5.7	1.2%
	SWZ total	**71.3**	**71.2**	**71.1**	**70.1**	**67.3**	**-5.6%**
Geelong	Tariff V	84.6	84.5	84.3	82.8	79.4	-6.2%
	Tariff D	35.4	35.4	36.1	36.9	35.8	1.2%
	SWZ total	**120.0**	**119.9**	**120.3**	**119.7**	**115.2**	**-4.0%**
Gippsland	Tariff V	46.3	48.3	50.5	51.9	52.0	12.4%
	Tariff D	28.4	28.4	28.8	29.3	19.1	-32.6%
	SWZ total	**74.6**	**76.8**	**79.3**	**81.2**	**71.1**	**-4.3%**
Melbourne	Tariff V	703.9	686.9	669.0	641.8	599.6	-14.8%
	Tariff D	121.0	121.4	122.2	123.4	121.0	0.0%
	SWZ total	**824.9**	**808.3**	**791.2**	**765.2**	**720.6**	**-12.6%**
Northern	Tariff V	80.3	78.6	76.8	73.9	69.3	-13.7%
	Tariff D	28.2	28.2	28.7	29.5	28.6	1.6%
	SWZ total	**108.5**	**106.8**	**105.5**	**103.4**	**97.9**	**-9.7%**
Western	Tariff V	9.0	9.1	9.1	9.0	8.6	-4.6%
	Tariff D	8.4	8.5	8.6	8.7	8.4	-0.6%
	SWZ total	**17.5**	**17.5**	**17.7**	**17.6**	**17.0**	**-2.7%**

Table 27 Annual peak hourly demand by System Withdrawal Zone (TJ/hr)

	SWZ	2023	2024	2025	2026	2027
Max. hourly demand on 1-in-2 peak day	Ballarat	5.0	5.0	5.0	4.9	4.7
	Geelong	6.6	6.6	6.6	6.6	6.4
	Gippsland	4.6	4.7	4.8	4.9	4.3
	Melbourne	50.7	49.8	48.7	46.9	44.4
	Western	6.5	6.4	6.3	6.2	5.9
	Northern	1.1	1.1	1.1	1.1	1.1
	System total	**74.4**	**73.6**	**72.6**	**70.6**	**66.7**
Max. hourly demand on 1-in-20 peak day	Ballarat	5.5	5.5	5.5	5.4	5.2
	Geelong	7.2	7.2	7.2	7.1	6.9
	Gippsland	4.9	5.1	5.2	5.4	4.7
	Melbourne	55.5	54.4	53.2	51.5	48.5
	Western	7.1	7.0	6.9	6.7	6.4

	SWZ	2023	2024	2025	2026	2027
	Northern	1.2	1.2	1.2	1.2	1.1
	System total	**81.3**	**80.2**	**79.2**	**77.3**	**72.7**

Table 28 Annual 1-in-2 DTS and non-DTS peak day demand forecast (TJ/d)

	2023	2024	2025	2026	2027	Change over outlook
Tariff V (non-DTS)	1.19	1.17	1.16	1.15	1.14	-4%
Tariff D (non-DTS)	0.51	0.54	0.58	0.62	0.65	28%
System demand (non-DTS)	1.70	1.72	1.74	1.76	1.79	5%
System demand (DTS)	1,131	1,118	1,104	1,074	1,014	-10.3%
System demand (Victoria)	1,131	1,118	1,104	1,074	1,014	-10.3%

Table 29 Annual 1-in-20 DTS and non-DTS peak day demand forecast (TJ/d)

	2023	2024	2025	2026	2027	Change over outlook
Tariff V (non-DTS)	1.25	1.23	1.22	1.21	1.19	-4%
Tariff D (non-DTS)	0.53	0.57	0.61	0.65	0.68	28%
System demand (non-DTS)	1.78	1.80	1.83	1.85	1.88	5%
System demand (DTS)	1,213	1,197	1,182	1,154	1,086	-10.5%
System demand (Victoria)	1,217	1,201	1,185	1,157	1,089	-10.5%

A2.2 Monthly consumption and demand for 2023

Table 30 Monthly gas consumption for 2023 by System Withdrawal Zone (PJ/m)

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	0.37	0.37	0.47	0.69	1.21	1.55	1.70	1.56	1.07	0.79	0.60	0.44
Geelong	1.11	1.16	1.27	1.55	2.27	2.67	2.75	2.59	2.01	1.69	1.38	1.22
Gippsland	0.94	0.86	0.96	1.15	1.58	1.84	2.00	1.97	1.57	1.31	1.16	1.01
Melbourne	5.17	5.11	6.31	8.33	13.54	16.64	18.03	16.72	11.8	8.98	7.16	5.73
Western	0.78	0.88	1.08	1.35	2.08	2.46	2.61	2.50	1.85	1.33	1.05	0.85
Northern	0.25	0.22	0.24	0.28	0.37	0.43	0.46	0.44	0.41	0.40	0.34	0.31
System consumption	**8.62**	**8.60**	**10.33**	**13.35**	**21.05**	**25.59**	**27.55**	**25.78**	**18.71**	**14.50**	**11.69**	**9.56**

Table 31 Monthly gas generation consumption for 2023 by System Withdrawal Zone (TJ/m)

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	132	50	58	51	139	248	157	122	83	43	58	33
Gippsland	138	10	22	2	31	60	59	16	5	0	2	4
Melbourne	577	440	554	467	700	1,067	705	576	507	384	577	276
Western	-	-	-	-	-	-	-	-	-	-	-	-
Northern	-	-	-	-	-	-	-	-	-	-	-	-
System consumption	847	499	634	521	870	1,375	920	715	595	427	637	313

Table 32 Monthly peak daily demand in 2023 by System Withdrawal Zone (TJ/d)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day demand	Ballarat	16	17	23	35	52	61	63	60	49	42	32	21
	Geelong	50	52	56	70	94	105	109	105	90	78	66	54
	Gippsland	34	34	37	47	58	65	70	66	59	53	48	37
	Melbourne	236	247	288	443	618	721	741	726	600	497	392	272
	Western	37	41	45	60	87	97	101	94	81	66	49	38
	Northern	9	10	9	12	14	15	16	16	17	15	13	11
	System demand	**383**	**401**	**458**	**666**	**923**	**1,065**	**1,100**	**1,066**	**896**	**750**	**600**	**434**
1-in-20 peak day demand	Ballarat	18	20	35	44	61	67	69	69	57	49	40	29
	Geelong	55	57	71	81	105	114	117	116	100	88	77	64
	Gippsland	37	37	45	53	64	71	75	72	65	59	55	42
	Melbourne	267	281	419	544	710	784	800	823	688	574	484	362
	Western	41	45	58	70	98	105	108	105	91	75	58	46
	Northern	10	11	11	13	15	17	17	17	18	17	15	12
	System demand	**428**	**452**	**639**	**806**	**1,053**	**1,157**	**1,187**	**1,202**	**1,019**	**860**	**728**	**556**

Table 33 Forecast hourly peak day demand for 2023 (TJ/hr)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	25	32	37	48	63	72	74	72	61	54	43	35
1-in-20	34	36	46	55	71	78	80	81	69	59	52	44

Table 34 Monthly peak hourly demand in 2023 by System Withdrawal Zone (TJ/hr)

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max. hourly demand on 1-in-2 peak demand day	Ballarat	1.13	1.45	1.98	2.62	3.73	4.34	4.48	4.34	3.68	3.00	2.38	1.65
	Geelong	3.16	3.99	4.32	4.81	5.93	6.79	7.02	6.80	5.77	5.46	4.69	4.33
	Gippsland	1.85	2.34	2.56	2.94	3.45	3.86	3.98	3.86	3.27	3.16	2.92	2.65
	Melbourne	15.90	20.43	23.69	32.47	43.54	50.15	51.81	50.22	42.59	37.00	29.18	22.26
	Western	2.24	3.14	3.49	4.22	5.44	6.00	6.19	6.00	5.09	4.29	3.09	2.99
	Northern	0.55	0.72	0.65	0.76	0.90	0.90	0.93	0.90	0.77	0.97	0.83	0.83
	System demand	**24.82**	**32.07**	**36.69**	**47.83**	**62.99**	**72.03**	**74.42**	**72.13**	**61.17**	**53.88**	**43.09**	**34.71**
Max. hourly demand on 1-in-20 peak demand day	Ballarat	1.60	1.76	2.64	3.13	4.28	4.73	4.85	4.91	4.16	3.81	3.03	2.36
	Geelong	4.28	4.19	5.09	5.34	6.63	7.36	7.54	7.64	6.48	5.89	5.39	5.02
	Gippsland	2.49	2.36	2.89	3.16	3.80	4.17	4.27	4.32	3.67	3.41	3.30	2.88
	Melbourne	22.11	23.80	30.40	37.89	49.48	54.57	55.94	56.66	48.04	39.94	36.07	29.88
	Western	3.05	3.32	4.12	4.69	6.06	6.51	6.67	6.75	5.73	4.63	3.59	3.47
	Northern	0.74	0.72	0.74	0.82	1.00	0.97	1.00	1.01	0.86	1.04	0.92	0.88
	System demand	**34.25**	**36.16**	**45.88**	**55.02**	**71.24**	**78.29**	**80.27**	**81.29**	**68.94**	**58.73**	**52.31**	**44.49**

A3. Gas supply forecast

Totals and change over outlook percentages may not add up due to rounding.

A3.1 Victorian supply sources

Table 35 Victorian facilities by SWZ

SWZ	Supply source	Project	Project ownership
Gippsland	**Longford Gas Plant**	Gippsland Basin Joint Venture	• Esso Australia Resources, 50% • Woodside Energy, 50%
		Kipper Unit Joint Venture	• Esso Australia Resources, 32.5% • Woodside Energy, 32.5% • Mitsui E&P Australia, 35%
	Lang Lang Gas Plant	BassGas Project	• Beach Energy Limited, 88.75% • Prize Petroleum International, 11.25%
	Orbost Gas Plant	Sole Gas Project	• Cooper Energy, 100%
Melbourne	**Dandenong LNG**	Dandenong LNG	• APA Group, 100%
Port Campbell (Geelong)	**Otway Gas Plant**	Otway Gas Project	• Beach Energy Limited, 60% • O.G Energy, 40%
		Thylacine, Geographe, Halladale, Black Watch, Speculant, Enterprise Project	• Beach Energy Limited, 60% • O.G Energy, 40%
	Iona Gas Plant	Iona UGS	• QIC, 100%
	Athena Gas Plant	Casino Henry Joint Venture	• Cooper Energy, 50% • Mitsui E&P Australia, 50%

A3.1.1 Infrastructure changes since the 2022 VGPR Update

Iona UGS storage capacity increased from 23.5 PJ to 24.0 PJ in January 2023 and will further increase to 24.5 PJ in 2024. The facility injection MDQ increased from 545 TJ/d to 558 TJ/d in January 2023 and will further increase to 570 TJ/d in 2024.

A3.2 Annual production by SWZ

Table 36 Annual Victorian production by SWZ, 2023-27 (PJ/y)

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
Gippsland [A]	Existing	284	229	201	146	90	-68%
	Committed	0	5	37	55	40	-
	Total available	**284**	**234**	**238**	**201**	**130**	**-54%**
	Anticipated	0	0	0	13	14	-
	Total available plus anticipated	**284**	**234**	**238**	**213**	**144**	**-49%**
Port Campbell (Geelong) [B]	Existing	28	16	22	17	11	-62%
	Committed	4	57	49	51	50	1,150%
	Total available	**32**	**73**	**71**	**68**	**60**	**90%**

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**32**	**73**	**71**	**68**	**60**	**90%**
Total Victorian Production	Existing	312	245	223	163	101	-68%
	Committed	4	62	85	106	90	2,150%
	Total available	**315**	**307**	**308**	**269**	**190**	**-40%**
	Anticipated	0	0	0	13	14	-
	Total available plus anticipated	**315**	**307**	**308**	**281**	**204**	**-35%**

A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Port Campbell zone includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station. Iona UGS in not included in annual supply assessments (as it is assumed to fill and empty during the year).

Table 37 Victorian annual available supply and anticipated supply balance by SWZ, 2023-27 (PJ/y)

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
Gippsland [A]	Existing	284	229	201	146	90	-68%
	Committed	0	5	37	55	40	-
	Total available	**284**	**234**	**238**	**201**	**130**	**-54%**
	Anticipated	0	0	0	13	14	-
	Total available plus anticipated	**284**	**234**	**238**	**213**	**144**	**-49%**
Port Campbell [B] **(Gippsland)**	Existing	28	16	22	17	11	-62%
	Committed	4	57	49	51	50	1,150%
	Total available	**32**	**73**	**71**	**68**	**60**	**90%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**32**	**73**	**71**	**68**	**60**	**90%**
Total Victorian production	Existing	312	245	223	163	101	-68%
	Committed	4	62	85	106	90	2,150%
	Total available	**315**	**307**	**308**	**269**	**190**	**-40%**
	Anticipated	0	0	0	13	14	-
	Total available plus anticipated	**315**	**307**	**308**	**281**	**204**	**35%**
Total Victorian consumption [C]		214	206	201	200	195	-9.1%
Surplus quantity with Victorian available supply		**101**	**100**	**107**	**68**	**-4**	**-**
Total Victorian consumption without electrification		214	208	206	210	213	-0.7%
Surplus quantity without electrification and with Victorian available supply		101	99	102	58	-22	-

A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Port Campbell zone includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station. Iona UGS in not included in annual supply assessments (as it is assumed to fill and empty during the year).
C. Total consumption includes system demand and gas generation demand.

A3.3 Monthly production by System Withdrawal Zone

Table 38 Victorian monthly production by System Withdrawal Zone, 2023-27 (PJ/m)

SWZ	Year	Supply source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gippsland[A]	2023	Available	18.6	18.3	24.3	25.7	27.5	27.5	27.9	27.9	26.1	25.7	16.1	20.9
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2024	Available	16.5	15.4	19.3	22.1	23.9	23.1	23.9	23.9	23.1	23.8	22.8	17.3
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2025	Available	20.8	18.5	19.2	22.0	23.8	23.0	23.8	23.8	23.0	20.1	16.0	21.4
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2026	Available	16.3	15.0	16.7	20.4	20.8	20.1	20.6	19.0	18.2	18.6	17.6	11.9
		Anticipated	0.0	0.0	0.0	1.3	1.3	1.3	1.4	1.5	1.5	1.7	1.7	1.0
	2027	Available	14.4	12.9	9.8	12.6	12.9	12.7	12.9	12.7	12.1	12.3	8.4	10.6
		Anticipated	0.7	0.7	0.1	1.4	1.5	1.4	1.5	1.6	1.6	1.7	1.5	1.5
Port Campbell (Geelong)[B]	2023	Available	3.6	3.1	3.3	3.1	3.1	2.9	7.0	7.0	6.8	7.0	6.8	7.0
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2024	Available	7.0	6.5	7.0	6.8	7.0	6.8	7.0	7.0	6.8	7.0	6.8	7.0
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2025	Available	6.9	6.2	6.9	6.7	6.9	6.7	6.9	6.9	6.7	6.9	6.7	6.9
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2026	Available	6.9	6.2	6.9	6.6	6.8	6.4	6.5	6.3	6.0	6.0	5.7	5.8
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2027	Available	5.8	5.1	5.5	5.2	5.3	5.0	5.0	5.0	4.7	4.7	4.5	4.5
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Victorian production	2023	Available	22.2	21.4	27.6	28.8	30.6	30.3	34.9	34.9	32.9	32.7	22.9	27.9
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2024	Available	23.5	21.9	26.3	28.8	30.9	29.9	30.9	30.8	29.8	30.8	29.6	24.3
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2025	Available	27.7	24.7	26.1	28.7	30.7	29.7	30.7	30.7	29.7	27.0	22.7	28.3
		Anticipated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2026	Available	23.2	21.2	23.6	27.1	27.6	26.5	27.1	25.3	24.2	24.7	23.3	17.7
		Anticipated	0.0	0.0	0.0	1.3	1.3	1.3	1.4	1.5	1.5	1.7	1.7	1.0
	2027	Available	20.2	18.0	15.3	17.8	18.2	17.7	18.0	17.7	16.8	17.0	12.9	15.0
		Anticipated	0.7	0.7	0.1	1.4	1.5	1.4	1.5	1.6	1.6	1.7	1.5	1.5

A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Port Campbell zone includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station.

A3.4 Peak day production by System Withdrawal Zone

Table 39 Peak day maximum daily quantity (MDQ) supply capacity by System Withdrawal Zone, 2023-27 (TJ/d)

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
Gippsland[A]	Available	915	771	767	670	425	-54%
	Anticipated	0	0	0	49	51	-

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
	Total available plus anticipated	**915**	**771**	**767**	**719**	**476**	**-48%**
Port Campbell (Geelong) [B]	Available	785	795	792	783	737	-6%
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**785**	**795**	**792**	**783**	**737**	**-6%**
Melbourne	Available	87	87	87	87	87	-
Total Victorian Supply	Total Victorian available	1,787	1,653	1,647	1,541	1,249	-30%
	Total Victorian anticipated	0	0	0	49	51	-
	Total Victorian available plus anticipated	**1,787**	**1,653**	**1,647**	**1,590**	**1,300**	**-27%**

A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP so all of this capacity cannot be supplied to the DTS because of EGP and TGP demand.
B. Port Campbell zone includes the Otway and Athena production facilities. The combined supply is available to the DTS, South Australia and Mortlake Power Station. All of this supply cannot be supplied into the DTS due to the SWP capacity constraint.

Table 40 Peak day supply adequacy (TJ/d), 2023-27

SWZ	Supply source	2023	2024	2025	2026	2027	Change over outlook
Gippsland [A]	Expected [B]	854	709	706	609	363	-57%
	Anticipated	0	0	0	49	51	-
	Total expected plus anticipated	**854**	**709**	**706**	**658**	**414**	**-51%**
Port Campbell (Geelong) [C]	Expected [D]	530	530	530	530	530	-
	Anticipated	0	0	0	0	0	-
	Total expected plus anticipated	**530**	**530**	**530**	**530**	**530**	**-**
Melbourne	Expected	87	87	87	87	87	-
Total Victorian supply	Total Victorian expected	1,471	1,326	1,323	1,226	980	-33%
	Total Victorian anticipated	0	0	0	49	51	-
	Total Victorian expected plus anticipated	**1,471**	**1,326**	**1,323**	**1,275**	**1,031**	**-30%**
1-in-2 system demand		1,131	1,118	1,104	1,074	1,014	-10%
1-in-20 system demand		1,217	1,201	1,185	1,157	1,089	-11%
1-in-2 day surplus quantity with Victorian expected supply		340	208	219	152	-34	-
1-in-20 day surplus quantity with Victorian expected supply		254	126	137	69	-109	-
1-in-2 system demand, no electrification		1,129	1,125	1,133	1,143	1,138	0.8%
1-in-20 system demand, no electrification		1,219	1,212	1,218	1,229	1,226	0.6%
1-in-2 day surplus quantity with Victorian expected supply, no electrification		342	201	190	83	-157	-
1-in-20 day surplus quantity with Victorian expected supply, no electrification		252	115	105	-3	-246	-

A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Expected Gippsland zone supply excludes the portion of available Gippsland supply that is needed to supply Tasmanian demand and demand along the EGP, including in south-east New South Wales, that cannot be supplied from any other source.
C. Port Campbell zone includes the Otway and Athena production facilities and Iona UGS. Combined supply is gas available to the DTS, South Australia and Mortlake Power Station. All of this supply cannot be supplied into the DTS due to the SWP capacity constraint.
D. Expected Port Campbell supply is limited by the capacity of the SWP.

A3.5 Storage facility operating parameters

A3.5.1 Dandenong LNG

The Dandenong LNG storage facility has a capacity of 12,400 tonnes (680 TJ); approximately 10,940 tonnes (600 TJ) of this capacity is available to market participants. Dandenong LNG is usually scheduled for either:

- Intraday peak shaving purposes when additional supply is required to maintain critical system pressures. It is usually scheduled from 2.00 pm or 6.00 pm but can be scheduled at any time if AEMO intervenes in the Victorian gas market.
- Market response by market participants to balance their supply and demand. This can occur during any schedule, including at 6.00 am.

The LNG storage provider requires one hour pre-notification (by AEMO) ahead of commencing injections into the DTS. This is to enable preparation and plant cool-down due to the low temperatures of the LNG process. Injections of LNG in the first and last hour need to be equal or less than 5.5 TJ/h, to assist with the cool-down and warm-up of the re-liquidation process. The assumed maximum firm daily LNG quantity is based on a scheduled firm rate of 5.5 TJ/h for 14 hours after the first hour at 5 TJ/h and the last hour at 5 TJ/h, which equates to the firm contracted rate of 87 TJ/d.

Table 41 LNG operating parameters

Year	Min hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. down rate (TJ/h/h)	Pressure range (kPa)[A]
2023-27	0.36	10.81	5.5	5.5	2,760-2,700 kPa

A. The minimum and maximum pressure is based on injection in the 2,800 kPa system.

A3.5.2 Iona Underground Storage

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports gas generation demand in South Australia via the SEA Gas Pipeline and can supply the Mortlake Power Station. The current total Iona UGS storage reservoir capacity is 24.0 PJ. The injection capacity into the storage reservoirs is 155 TJ/d[115].

Iona UGS requires two hours' notification to switch between withdrawals to storage and injection into the DTS. The storage operating parameters shown in **Table 42**, including injection and withdrawal rate and pressures, have been historically and are foreseeably sustainable. These may, however, be impacted by a combination of maintenance, peak demand conditions, and a low total storage inventory.

Table 42 Iona UGS operating parameters

Year	Min hourly injection rate (TJ/h)	Max. hourly injection rate (TJ/h)	Max. hourly withdrawal rate (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure range (kPa)
2023	1.0	23.25	6.46	5.8	11.6	4,500-10,000
2024	1.0	23.75	6.46	5.9	11.9	4,500-10,000
2025	1.0	23.75	6.46	5.9	11.9	4,500-10,000
2026	1.0	23.75	6.46	5.9	11.9	4,500-10,000
2027	1.0	23.75	6.46	5.9	11.9	4,500-10,000

[115] See https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb.

A4. System operating parameters

A4.1 Critical system pressures

AEMO operates the system to maintain connection pressure obligations across the DTS, where gas flows are maintained within the limits specified in the relevant connection deed and agreement schedules.

As gas demand increases, however, there is a risk that critical minimum pressures may be breached, potentially requiring customer curtailment to return the system to a secure state.

The system is in a secure state when the following conditions apply:

- The system is operating within the requirements of the gas quality procedures, and breaches of the gas quality procedures do not require intervention by AEMO.
- There is no threat to public safety.
- There is no threat to the supply of gas to customers, and system pressures and flows are within, and are forecast to remain within, the agreed operating limits (see **Table 36**).

Table 43 lists key critical locations and associated pressure obligations (MAOP and minimum operating pressure [MinOP]). This table is required to be published under Rule 323(3)(g), and can also be found in AEMO's Wholesale Market Critical Location Pressures[116].

Table 43 Critical location pressure in the Declared Transmission System

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

[116] At http://aemo.com.au/-/media/Files/PDF/AEMO-Wholesale-Market-Critical-Location-Pressures-NGR-10.pdf.

Pipeline	Pipeline MAOP (kPa)	Location	MinOP (kPa)	Source of data and comments
		Dandenong North	2,500	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation
		Brooklyn (Melbourne side)	1,700 1,800	AEMO-Distributor Connection Deed Brooklyn compressor suction min pressure requirement
		Keon Park	2,200	AEMO-Distributor Connection Deed
		Newport	1,800	Gas-powered generator
		Somerton	2,000	Gas-powered generator
Wollert to Euroa	8,800	Wandong PRS inlet	3,700	APA design parameter
Euroa to Wodonga	7,400	Wodonga	2,400	AEMO-Distributor Connection Deed
		Shepparton	2,400	AEMO-Distributor Connection Deed
		Echuca	1,200	AEMO-Distributor Connection Deed
		Rutherglen	2,400	AEMO-Distributor Connection Deed
		Koonoomoo	1,200	AEMO-Distributor Connection Deed
Victorian Northern Interconnect	10,200	Euroa CS Inlet	4,500	APA design parameter
		Springhurst CS Inlet	4,500	APA design parameter
		Culcairn	2,700	Connection Agreement
Brooklyn Corio Pipeline	7,390 5,150 MOP	Corio (Avalon, Lara and Werribee)	2,300 w 1,900 s	7,390 kPa Pipeline licence pressure 2,300 kPa during high flow (winter), 1,900 kPa during low flow (summer), Distributor Connection Deed
		Coogee Methanol	1,800	
		Laverton North	1,700	Gas-powered generator
Brooklyn Lara Pipeline	10,200	Qenos	3,800	3,800 kPa approved AEMO-Distributor Connection Deed (Wyndham Vale & Qenos) Usually controlled >4,500 kPa by BLP CG
Brooklyn Ballan Pipeline	7,400	Sunbury	2,000	AEMO-Distributor Connection Deed
		Ballarat	2,100	AEMO-Distributor Connection Deed
		Plumpton PRS	4,500	APA design minimum pressure
South West Pipeline	10,200	Iona	4,500	Operating Agreement Operational maximum pressure of 9,700 kPa applies due to operating limits at the plant
		SEA Gas	3,800	Connection Agreement
		Winchelsea Inlet	4,000	APA Design Parameter
		Colac	3,800	APA Group-Distributor Connection Deed
Western Transmission System	7,400	Iluka	2,500	APA Group-Distributor Connection Deed
		Portland	2,800	AEMO-Distributor Connection Deed
Wandong to Bendigo	7,390	Bendigo	3,000	AEMO-Distributor Connection Deed
		Maryborough	3,000	AEMO-Distributor Connection Deed
		Carisbrook	3,000	AEMO-Distributor Connection Deed

A4.2 Compressor utilisation in 2022

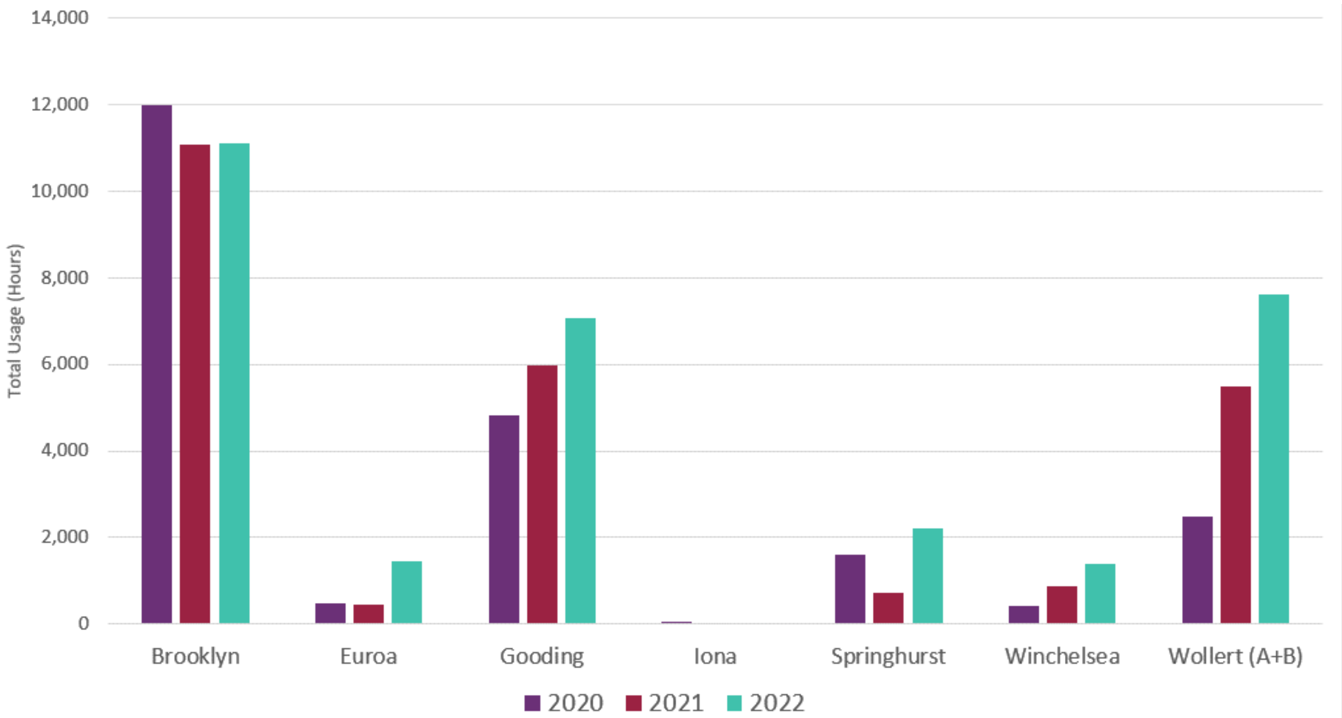
Table 44 lists the hours of usage for each DTS compressor station by month for 2022, and **Figure 39** compares the total operating hours by compressor stations from 2020 to 2022. Key points are:

- The most utilised compressors in the DTS in 2022 were the Brooklyn compressors, which have been heavily used to support Iona UGS refill over the lower demand periods and are also used to support Ballarat and Geelong demand during winter.
- The usage of Wollert, Springhurst and Euroa compressors increased to support higher VNI withdrawals, particularly in April-May 2022.
- Gooding compressors were heavily utilised during winter 2022 to support higher Longford injections.

Table 44 Total operating hours by compressor station, 2022

Compressor station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn	1,357	1,193	1,180	641	370	192	756	1,905	861	1,211	354	1,084
Euroa	0	32	1	431	342	160	104	2	172	81	104	33
Gooding	2	5	3	2	975	1,319	1,422	1,479	1,188	621	46	3
Iona	0	1	0	1	1	0	0	2	0	0	0	0
Springhurst	57	103	147	481	325	216	122	179	305	147	56	68
Winchelsea	160	232	43	8	190	241	204	83	88	174	1	0
Wollert	581	581	720	817	904	615	539	328	735	750	526	526

Figure 39 Total operating hours by compressor station, 2020-22



A5. DTS service provider assets, maintenance and system augmentations

A5.1 Critical DTS assets

Critical assets in the DTS are the assets required to maintain system security on peak demand days. **Table 45** outlines these assets by SWZ and operational purpose.

Table 45 Critical DTS assets

SWZ	Asset	Description	Purpose/role
Melbourne	Brooklyn Compressor Station	• Two Saturn compressors: Unit 8 rated at 850 kW and Unit 9 rated at 950 kW. • Two Centaur compressors: Unit 11 rated at 2,850 kW and Unit 12 rated at 3,500 kW. • Unit 10 (Centaur compressor) is only available to AEMO to operate under certain conditions as stated in the Service Envelope Agreement.	• Provides compression to the Brooklyn–Corio pipeline, SWP and the Brooklyn–Ballan pipeline. • The Centaur machines are used to supply the Laverton gas-powered generator and Iona UGS withdrawals. • The Saturn machines are used only to supply system demand.
	Wollert Compressor Station	• Station B: Three Centaur compressors; Unit 4, Unit 5 and Unit 6 rated at 4,550 kW. • Station A: Three Saturn compressors; Unit 1 and Unit 2 rated at 950 kW and Unit 3 rated at 850 kW.	• Provides compression to the Wollert to Wodonga pipeline, to the Western Outer Ring Main and assists supply to New South Wales via the VNI at Culcairn. Exports to New South Wales are generally not possible without Wollert Centaur compression.
	Dandenong LNG Facility	• The LNG facility has a maximum capacity of 180 tonnes per hour (t/h), requiring the availability of three vaporisers, three pumps and one boil off compressor. The LNG contracted rate is 100 t/h for 16 hrs, which provides up to 87 TJ/d.	• The LNG facility is used mainly to supplement supply on days of high peak gas demand. LNG can be used also by participants throughout the year to balance their portfolio (market scheduled LNG).
	Brooklyn–Lara Pipeline CG (BLP CG)	• Five regulator runs • Two water bath heaters • Station inlet and outlet isolation valves	• One of the three main supply sources to the Melbourne Metropolitan Region along with Wollert CG and Dandenong CG. • It supplies gas from Port Campbell gas fields. The station regulates high pressure gas supply from the Brooklyn–Lara Pipeline to supply either the Brooklyn–Corio Pipeline (BCP) or the Brooklyn–Corio Pipeline CG.
	Brooklyn–Corio Pipeline CG (BCP CG)	• Five regulator runs • Two water bath heaters • Two station inlet isolation valves	• Brooklyn–Corio Pipeline CG primarily regulates gas supply from the BCP to supply the South Melbourne system. The BCP CG also incorporates a bypass run to facilitate reverse flow from the South Melbourne system to supply to the BCP when compression is not needed.
	Dandenong CG	• Eight regulator runs, which are categorised into Station A (3 regulator runs) and Station B (5 regulator runs) • Station inlet and outlet isolation valves	• Dandenong CG is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Wollert CG. • The station provides pressure regulation of gas being supplied into Dandenong to

SWZ	Asset	Description	Purpose/role
			Princess Hwy and Dandenong to West Melbourne pipelines.
	Wollert CG	• Four Regulator runs • One water bath heater • Station inlet and outlet isolation valves	• Wollert CG is one of the three main supply sources to the Melbourne Metropolitan Region along with Brooklyn CG and Dandenong CG. • It provides pressure regulation of gas being supplied into the Keon Park to Wollert transmission pipeline. The facility provides two sources of gas supply, one from Longford gas facility via Pakenham to Wollert pipeline and the other from Moomba gas facility via the Wollert to Wodonga pipeline.
Geelong (Port Campbell)	Winchelsea Compressor Station	• Two Taurus compressors rated at 5,740 kW.	• Provides compression to increase SWP network transportation capacity to Brooklyn. • Provides additional SWP capacity to support Iona UGS refilling. • Two-unit in-series operation only available in the west-to-east direction towards Melbourne.
Gippsland	Gooding Compressor Station	• Four Centaur compressors each rated at 2,850 kW. – Up to three compressor units can be operated simultaneously, with one redundant unit.	• Provides compression within LMP when total Longford injections exceed approx. 700 TJ/d. • Compression is utilised to increase transportation capacity of LMP, maintain DCG inlet pressure above its min operating pressure during peak period and to move gas away from Longford injection point to prevent backing off the Longford plant before the peak demand when linepack is low.
Northern	Euroa Compressor Station	• One Centaur compressor rated at 4,550 kW.	• Provides compression to the Euroa to Wodonga pipeline mainly for increasing export capacity to New South Wales when higher pressure is required at Culcairn. The compressor may be also used to increase import capacity into Victoria from New South Wales.
	Springhurst Compressor Station	• One Centaur compressor rated at 4,550 kW.	• Provides compression for imports or exports via the VNI at Culcairn.
Western	Iona Compressor Station	• Two reciprocating compressors rated at 300 kW each.	• Provides compression to Western Transmission Network from the SWP.

A5.2 DTS service provider proposed maintenance schedule

AEMO, under Rule 326, coordinates maintenance planning of the DTS with the DTS service provider on a weekly basis. The DTS service provider's maintenance schedule for 2023 and the capacity impact is shown in **Table 46**. This schedule and the associated capacity impacts assume that both the WORM and second Winchelsea compressor projects are complete and commissioned from winter 2023. The maintenance is scheduled to minimise impacts to DTS capacity.

Changes to the maintenance schedule are published to the Natural Gas Services Bulletin Board in the Short Term Capacity Outlook report for short-term maintenance, and Medium Term Capacity Outlook report for annual maintenance.

Table 46 Planned maintenance for 2023, as at 9 February 2023

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
Melbourne	Brooklyn Compressor Station	Full Station	1-5 April 2023	-	0	Total station outage for five days. 4hr recall time.
		Full Station	23-27 October 2023	-	-	Export capacity is not impacted once the WORM is complete.
		Unit 10	20-24 November 2023	-	-	Five-day unit outage. No impact to capacity – reduced redundancy at Brooklyn CS.
	Wollert Compressor Station	Station A + B	3-7 April 2023	-	0	Total stage outage of five days over the maintenance period. Recall time of 16 hours.
		Unit 4	18-22 September 2023	-	VNI:223 SWP: 235	Up to five days unit outage, with eight-hour recall.
		Unit 5	25-29 September 2023	-	VNI: 223 SWP: 235	Up to five days unit outage with eight-hour recall.
		Station A	2-6 October 2023	-	VNI: 224 SWP: -	Up to five days unit outage with four-hour recall.
		Station B	9-13 October 2023	-	VNI: 0 SWP: 140	Total station outage of five days over the maintenance period. Recall time of five hours.
		Station A + B	10-11 October 2023	-	VNI: 0 SWP: 140	Total station outage of five days over the maintenance period. Recall time of 16 hours.
Geelong	Winchelsea Compressor Station		8-12 May 2023	368	117	Total station outage for five days over the maintenance period. Recall time of 2 hours.
			30 October to 3 November 2023	402	235	Total station outage for five days over the maintenance period. Recall time of 8 hours.
			13-17 November 2023	402	235	Total station outage for five days over the maintenance period. Recall time of four hours.
Gippsland	Gooding Compressor Station		20-24 March 2023	982	-	Total station outage for five days over the maintenance period. Four hours recall time.
			2-6 October 2023	982	-	Total station outage for five days over the maintenance period. Recall time four hours.
Northern	Euroa Compressor Station		20-24 March 2023	198	150	Up to five days unit outage, with eight-hour recall time.

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
			4-8 September 2023	198	150	Total station outage for five days over the maintenance period. Recall time four hours.
	Springhurst Compressor Station		27-31 March 2023	158	150	Total station outage for five days over the maintenance period. Recall time four hours.
			23-27 October 2023	158	150	Total station outage for five days over the maintenance period. Recall time four hours.
			20-24 November 2023	158	150	Total station outage for five days over the maintenance period. Recall time eight hours.
Western	Iona Compressor Station	Full Station	15-19 April 2023	-	-	Total station outage five days over the maintenance period. Recall time eight hours.
		Unit 1	22-26 May 2023	-	-	Individual unit outage for up to five days. Eight-hour recall time.
		Unit 2	29 May to 2 June 2023	-	-	Individual unit outage for up to five days. Eight-hour recall time.
		Full Station	27 November to 1 December	-	-	Total station outage five days over the maintenance period. Recall time four hours.

Note: Dash line (“-“) indicates no impact to import or export capacity.

A5.3 Other proposed maintenance

The DTS service provider will be performing a series of pipeline inspections (pigging) works during 2023:

- T060 pipeline pigging continuing until February 2023.
- T016 Dandenong to West Melbourne pipeline pigging in October 2023.
- Other pigging activities may occur at the end of 2023, but the timing is still to be confirmed.

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

A6. Victorian gas planning approach

A6.1 DTS System Withdrawal Zones

The DTS is divided into six zones, shown in **Figure 40**:

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

The System Withdrawal Zones are used to report demand forecasts, and to assess adequacy by zone.

A6.2 Victorian gas planning criteria

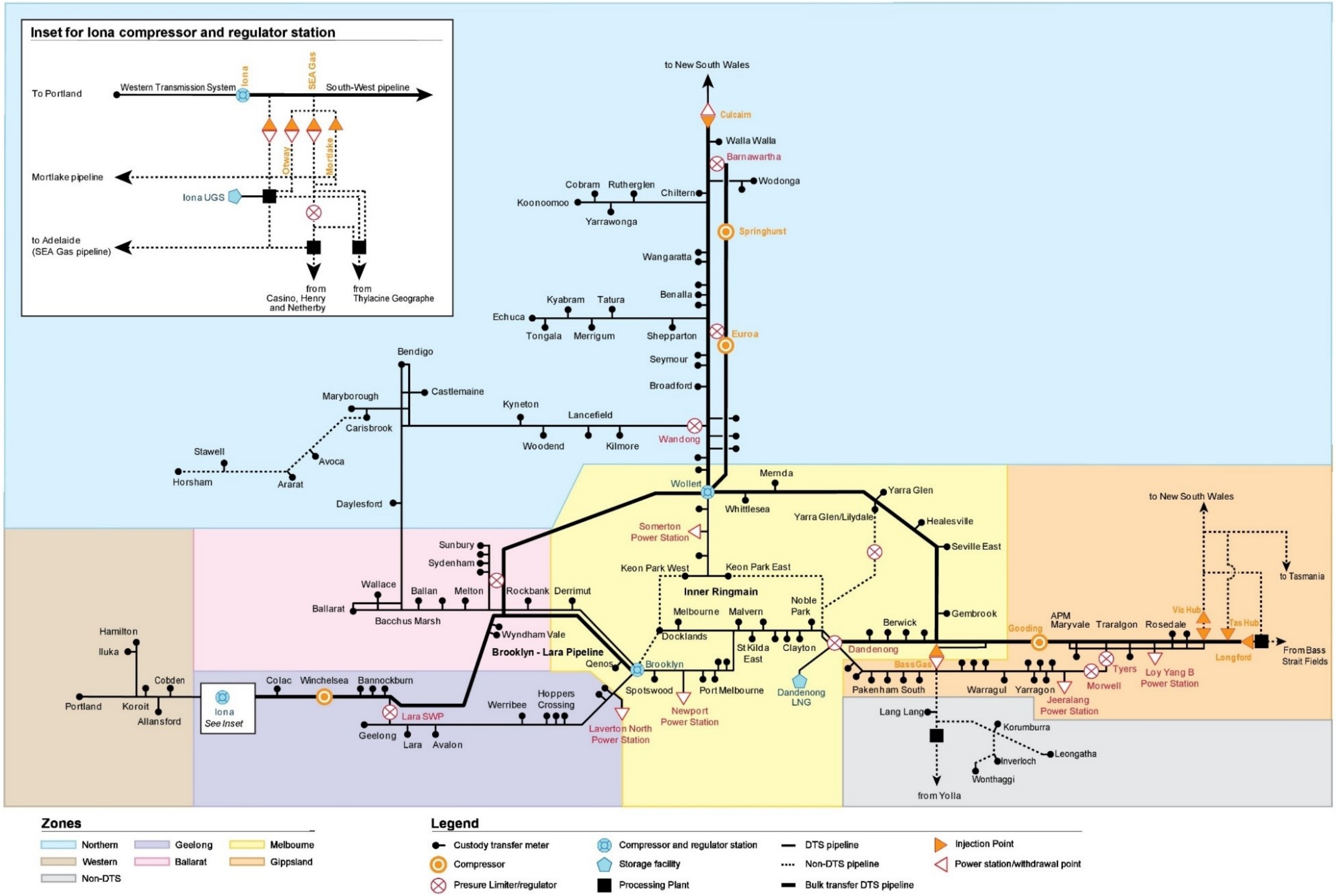
Under Rule 323(1), AEMO must publish a planning review "by no later than 31 March 2015 and by 31 March in every second year thereafter".

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

AEMO assesses and reports on the adequacy of the gas supply and transmission capacity to meet forecast demand by carrying out detailed computer simulations of the DTS.

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

Figure 40 System withdrawal zones in the DTS



A6.3 Victorian gas planning methodology

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

Figure 41 shows an overview of the gas planning methodology, and **Table 47** provides more detail for the numbered steps.

Figure 41 Gas planning methodology overview

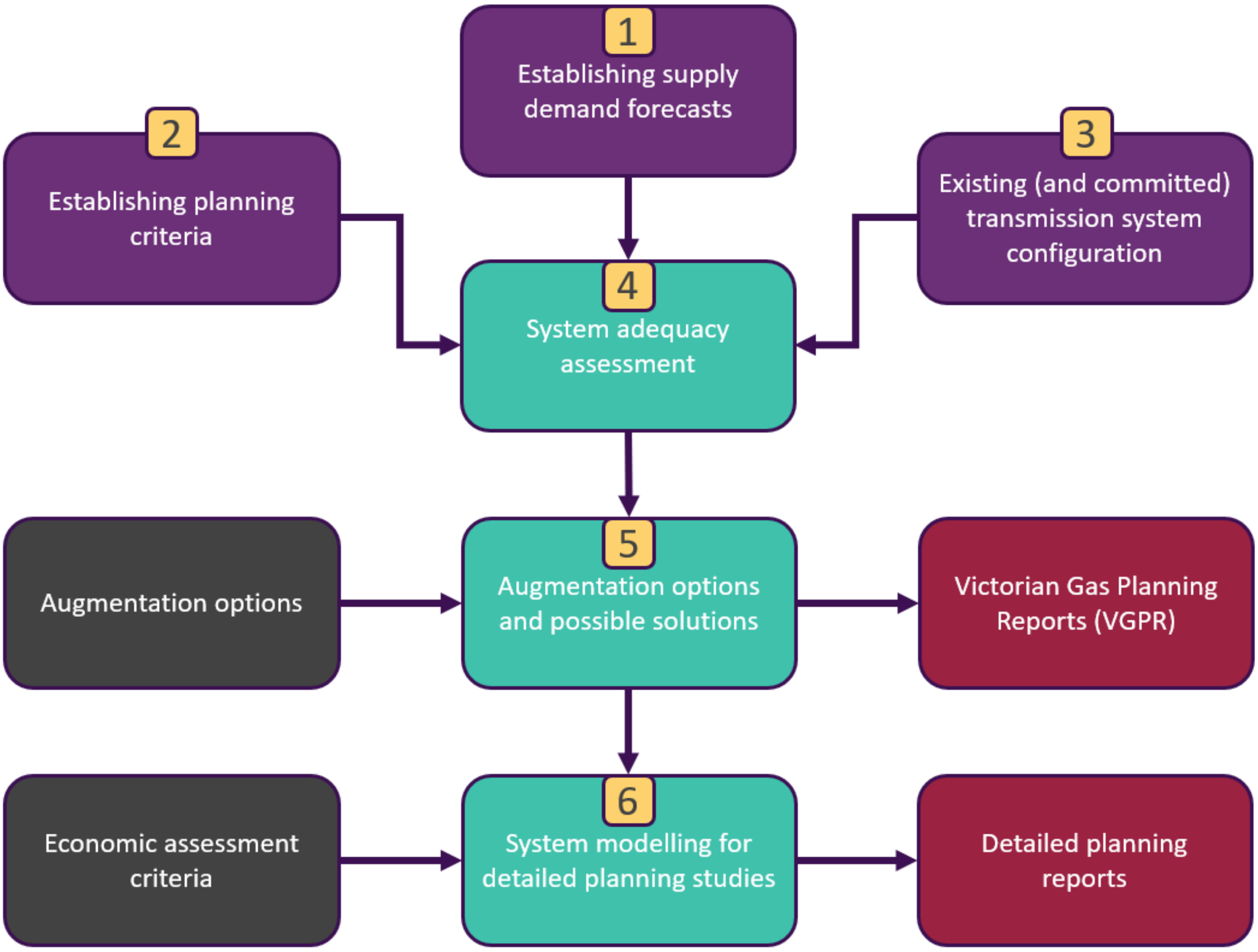


Table 47 Gas planning methodology summary

Process step	Detail
1. Establishing supply and demand forecasts	Planning assumptions consist of forecasts of gas supply, demand and other operational assumptions such as load profiles. These assumptions are validated based on historical data available in the database before commencing modelling work. As part of the VGPR process, five-year forecasts of peak day demand are prepared for each market sector, and for all system withdrawal zones (SWZ), based on a range of anticipated injection and withdrawal scenarios.
2. Establishing planning criteria	The planning criteria address the operating characteristics that must be satisfied over the planning period if the system is to be capable of safe and reliable operation. These include the critical minimum pressures at key locations from the Wholesale Market System Security Procedures (Victoria)[117], and a range of other operating criteria that need to be satisfied, such as linepack targets.
3. Existing and committed transmission system configuration	In conjunction with the DTS service provider, AEMO creates and maintain the DTS models representing the current system configuration. AEMO determines system capacity using a calibrated gas transmission system model (specifically, the Gregg Engineering NextGen software package). AEMO's gas transmission system model is calibrated using actual winter metered gas injections and withdrawals on selected high and moderate demand days. Model calibration refines the model to ensure that it accurately simulates the observed pressures and flows throughout the DTS. The methodology and a set of assumptions and pipelines parameters are set out in the Guidelines for the Determination of the Victorian Gas Declared Transmission System Capacity document, jointly owned by AEMO and the DTS service provider.
4. System adequacy assessment	AEMO assesses the system performance with the Gregg Engineering software and notifies the market about potential system constraints via the VGPR. The gas flows and pressures in the DTS are modelled under a range of demand and supply scenarios over a five-year outlook. A system constraint is identified when the secure system parameters are breached (representing a potential threat to system security).
5. Augmentation options and possible solutions	AEMO evaluates potential solutions, which involves considering several possible options available to restore the system to a secure state: • Augmentations or upgrades to the gas transmission system. • Additional or new supply capacity and storage. The adequacy assessment studies consider a range of solutions, to the extent this is feasible, given the availability of data and commercial confidentiality
6. System modelling for detailed planning studies	AEMO performs detailed planning studies under the following circumstances: • On request from the DTS Service Provider to help its access arrangement review. • When AEMO has identified a need for efficient augmentation investment, and the gas industry has not taken sufficient initiative. • By request from regulators or government agencies to independently review requirements for augmentations. The aim is to identify the economically efficient solution and facilitate the required investment(s). The planning reports for the detailed planning studies are published as required.

A6.4 Planning assumptions

AEMO applied a series of network assumptions and conditions in modelling:

- **Table 48** to **Table 51** list the standard modelling assumptions used by AEMO.
- Additional modelling assumptions are listed in **Table 52** for SWP capacity, **Table 53** for Northern capacity and **Table 54** for LMP capacity.

[117] Available at https://aemo.com.au/-/media/files/gas/emergency_management/victorian/aemo-wholesale-market-system-security-procedures-ngr-11.pdf

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

A6.4.1 Supply assumptions

Table 48 and **Table 49** list assumptions relating to the supply of gas to the DTS.

Table 48 DTS supply modelling assumptions

Supply assumptions and conditions	Notes
Longford CPP (Longford, VicHub and TasHub) injections at flat hourly profile	Normal operating condition.
BassGas injections at flat hourly profile	Normal operating condition.
Iona CPP (Iona UGS, SEA Gas, Otway and Mortlake) injections at flat hourly profile	Normal operating condition.
New South Wales injection at Culcairn at flat hourly profile	Normal operating condition.
Dandenong LNG contracted vaporisation rate at 100 tonne/hour for 16 hours	For peak shaving purposes to support critical system pressures, LNG is effective only up to 10.00 pm. Modelling assumed 16 hours LNG, equivalent to 87 TJ.

Table 49 DTS modelled heating values

Location	Heating value (megajoules/standard m^3)
Longford CPP	38.74
BassGas	38.65
Iona CPP (summer)	38.09
Iona CPP (winter)	38.16
New South Wales injection at Culcairn	37.75
Dandenong LNG	39.11

A6.4.2 Demand assumptions

Table 50 lists assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table 50 DTS demand modelling assumptions for 1-in-20 peak system demand day

Demand assumptions and conditions	Notes
Load profiles calculated by AEMO	Calculated from historical flow data for each custody transfer meter.
Load distribution as per AEMO forecasts	Based on historical custody transfer meter data and expected system configuration changes.
Supply to Horsham pipeline at Carisbrook	Carisbrook to Horsham pipeline modelled with demand at Ararat, Stawell, Horsham and Avoca. The minimum pressure requirement at Horsham is 1,200 kPa (AusNet design requirement).
Transmission UAFG determined at Longford	Calculated from calibrated model data.
BOC liquefaction operating, let-down gas operating	Full supply to this customer is normally required.

Demand assumptions and conditions	Notes
Gas generation demand and profile	Calculated from historical flow data for each DTS-connected gas generator. Quantities and profiles determined using a representative day in recent history.
New South Wales withdrawal at Culcairn at flat hourly profile	Normal operating condition.
Iona USG withdrawals at flat hourly profile	Normal operating condition.

Analysis for the five-year VGPR outlook is based on a 1-in-20 peak system demand day forecast, which is the agreed standard with the DTS service provider.

A6.4.3 Demand assumptions

Table 51 lists the assumptions relating to operation of the DTS and assist with the management of linepack and constraints specified in various agreements.

Table 51 Impact of operational factor modelling assumptions

Location	Operational assumptions	Notes
Longford	Maximum pressure is 6,750 kPa.	To conform to normal operating practice. Assumed to peak momentarily at 6,750 kPa before reducing again.
	Minimum pressure is 4,500 kPa.	
Iona	Maximum pressure is 9,700 kPa.	As per operating agreement.
	Minimum pressure is 4,500 kPa.	
Culcairn	For exports, minimum pressure is 8,600 kPa for free flow cases.	Used for capacity modelling purposes and may not be achievable under all operating conditions. For exports below 150 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports.
	For imports, maximum pressure is 6,500 kPa, and minimum pressure is 4,500 kPa.	
Brooklyn–Lara Pipeline	Minimum pressure is 4,500 kPa.	Pipeline design requirement for BLP.
Brooklyn CG	Minimum pressure is 3,200 kPa.	Normal operating condition.
Dandenong CG	Minimum pressure is 3,200 kPa.	Used for capacity modelling purposes and may not be achievable under all operating conditions.
	Maximum allowable operating pressure (MAOP) and delivery pressures in connection and service envelope agreements not infringed.	Service Envelope Agreement and Connection Deed requirements (for example, a minimum 3,100 kPa at the Dandenong CG).
Wollert CG	Minimum pressure is 3,000 kPa.	Normal operating condition.
Other factors	BoD and end-of-day (EoD) linepack are equal	For capacity modelling, mining of linepack not allowed.
	BoD linepack 20 TJ below target.	Used for lateral constraint modelling
	DTS service provider’s pipeline, regulator and compressor assets and operating conditions as specified in the Service Envelope Agreement.	Agreement between the DTS Service Provider and AEMO.
	BoD and EoD pressures similar at key network locations.	Required for system security.
	Regulators, compressors, and valves are set to reflect operational guidelines	Required for operational and system security reasons.
	Gas delivery temperature above 2°C.	Gas Quality Regulations requirement.

A6.4.4 Capacity modelling assumptions

Modelling assumptions are listed in **Table 52** for SWP capacity, **Table 53** for Northern capacity and **Table 54** for LMP capacity. Under different operating conditions on the day, the capacity result may differ.

Table 52 SWP capacity modelling assumptions

SWP capacity assumptions		Notes
Injections		For SWP to Melbourne: • Maximum injection from Iona. • Culcairn withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 15 TJ/d. • Longford CPP acting as balance of injections. For SWP withdrawal: • Maximum withdrawal from Iona. • Culcairn injecting, withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 15 TJ/d. • Longford CPP acting as balance of injections. No limit to Longford CPP injection capacity.
Gas generation demand		Gas generation demand for all cases varied as agreed between AEMO and the DTS Service Provider.
Dandenong LNG		No LNG injections were required. Dandenong LNG may increase the peak day withdrawal quantities however this would be considered a non-firm capacity due to the low contracted storage inventory quantities.
Compressors		For SWP to Melbourne: • The target Winchelsea compressor station outlet was set to 10,000 kPa; compressor would control on maximum power during model runs. • Models assumed both Winchelsea units available as required. • Capacity with one Winchelsea unit available was determined to manage outages. For SWP withdrawal: • Models assumed one Winchelsea unit available as required (in series operation of both units is only available in the west-to-east direction). • Models assumed all three Wollert B units available to compress into the WORM as required. • Capacity with two Wollert B units available was determined to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Iona	Maximum pressure is 9,700 kPa. Pressure not allowed to increase over the modelling period. Minimum pressure is 4,500 kPa.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1-in-2 is set to 2,550 kPa. System demand ≥ 1-in-2 is set to 2,650 kPa.
	Ballarat CG	Minimum pressure is 2,100 kPa.

Table 53 Northern capacity modelling assumptions

SWP capacity assumptions	Notes
Injections	For Culcairn to Melbourne: • Maximum injections from Culcairn. • Iona injecting, withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 15 TJ/d. • Longford CPP acting as balance of injections.

SWP capacity assumptions		Notes
		For Culcairn withdrawal: • Maximum withdrawal from Culcairn. • Iona injecting, withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 15 TJ/d. • Longford CPP acting as balance of injections.
Gas generation demand		Gas generation demand for all cases varied as agreed between AEMO and the DTS Service Provider.
Dandenong LNG		No LNG injections were required. Dandenong LNG may increase the peak day withdrawal quantities however this would be considered a non-firm capacity due to the low contracted storage inventory quantities.
Compressors		For Culcairn to Melbourne: • Euroa compressor and Springhurst compressor were run at maximum power or controlling on minimum inlet pressure (4,500 kPa). • Capacity with one compressor Euroa or Springhurst out of service was determined to manage outages. For Culcairn withdrawal: • Models assumed all three Wollert B units available to compress into the VNI as required. • Capacity with one compressor Euroa or Springhurst out of service was determined to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Culcairn	Modelled minimum pressure is 8,600 kPa for free flow. For exports below 150 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports. Modelled maximum pressure is 6,500 kPa for Northern import capacity modelling cases.
	DCG	Minimum pressure is 3,200 kPa.
	Wollert CG	System demand ≤ 1-in-2 is set to 2,550 kPa. System demand ≥ 1-in-2 is set to 2,650 kPa.
	Bendigo CG	Minimum pressure is 3,000 kPa.

Table 54 LMP capacity modelling assumptions

SWP capacity assumptions		Notes
Injections		• No limit to Longford CPP injection capacity. • VNI and SWP withdrawals maximised up to capacity. In the event maximum withdrawals were not possible, the withdrawals were reduced in a pro-rata fashion between the two points. • BassGas injecting fixed quantity 15 TJ/d.
Gas generation demand		Gas generation demand for all cases varied as agreed between AEMO and the DTS Service Provider
Dandenong LNG		No LNG injections were required.
Compressors		• Gooding compressors were run at maximum power. • Capacity with all Gooding units out of service was determined to manage outages.
Linepack		BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.
Critical pressure points	Longford	Maximum pressure is 6,750 kPa. Pressure not allowed to increase over the modelling period. Minimum pressure is 4,500 kPa.
	Wollert CG	System demand ≤ 1-in-2 is set to 2,550 kPa. System demand ≥ 1-in-2 is set to 2,650 kPa.
	Iona	Minimum pressure is 4,500 kPa.
	Culcairn	Modelled minimum pressure is 8,600 kPa for free flow. For exports below 150 TJ/d, upstream non-DTS operated compressors are utilised to achieve exports.

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

- Beginning-of-day linepack.
  - Linepack is the pressurised gas stored in transmission pipelines throughout the DTS. It varies considerably throughout the day, as it is drawn down from the start of the gas day to balance a fairly constant hourly injection rate with the morning and evening demand peaks. Linepack reaches a minimum by around 10.00 pm. Overnight, injections exceed demand and linepack is replenished until the start of the morning peak at around 6.00 am, when linepack is at its highest level.
- Demand forecast error.
  - Daily demand forecast errors occur due to changes in the weather, the inherent uncertainty in predicting system demand, large loads varying from the initial forecast (such as gas generation), and weather forecast errors.
  - When actual demand is higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system ability to meet demand. When actual demand is lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the injection points, generally only after the 10.00 pm scheduling horizon, to avoid breaching upper operating limits.
- Delivery pressure.
  - Supply pressure drives gas through a pipeline. The higher the supply pressure, the higher the average level of linepack and effective system capacity.
- Injection profiles.
  - For operational reasons, gas production plants generally operate at a constant injection rate.
  - Varying the injection rate to reflect demand throughout the day can increase the ability to supply demand. In particular, an injection profile with a higher injection rate during the first half of the day can increase gas transport capability.
  - Gas sources that can be injected for short periods at times of high demand, such as LNG, can assist overall system capacity.
- Demand profiles (temporal distribution).
  - During winter, peaking demand in the morning and evening (due to temperature-sensitive load) draws down system linepack. More severe demand profiles, including the presence of spike loads such as gas generation, will deplete linepack at a faster rate.
- Spatial distribution of demand.
  - System capacity is modelled using forecast load distributions across the DTS. If a specific load is located close to an injection point, the gas transport capability is higher than if the load is located further away.

A6.4.5 Seasonal variations in DTS capacity

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

- Residential demand is reduced due to lower space heating needs.

- Gas generation load increases due to increasing electricity demand for air conditioning and relatively low gas price.
- Compressors station have lower maximum compressor power available due to the downgraded performance of the gas turbines (and engines) in summer ambient temperature conditions.

When modelling summer or shoulder, some key system parameters need to be set differently from the winter assumptions. AEMO and the DTS Service Provider have discussed and agreed on seasonal conditions and parameters such as load distribution and load profiles for these periods.

A6.4.6 Changes to capacity modelling assumptions for 2023

Prior to the WORM, AEMO's capacity modelling assumption was to set the injection or withdrawal quantities at other injection points to a predefined quantity. With the WORM expected to be commissioned during winter 2023, AEMO's capacity modelling assumptions have changed to accommodate the different system dynamics and interactions at supply and withdrawal points. The 2023 capacity modelling assumptions for injections and withdrawals were determined by maximising and balancing injection or withdrawal quantities at the other system injection or withdrawal points.

Entry and exit capacity certificates have been implemented for 2023, and the Melbourne entry zone consists of the Dandenong LNG injection point. Firm injections at Dandenong LNG were not considered for 2023 pipeline capacity modelling.

List of tables and figures

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Measures, abbreviations and glossary

Units of measure

Term	Definition
EDD	effective degree days
GJ	gigajoules
kPa	kilopascals
mm	millimetre
MW	megawatts
PJ	petajoules
PJ/m	petajoules per month
PJ/y	petajoules per year
t/h	tonnes per hour
TJ	terajoules
TJ/d	terajoules per day
TJ/h	terajoules per hour
TJ/m	terajoules per month
TJ/y	terajoules per year

Abbreviations

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AMDQ	authorised maximum daily quantity
APC	administered price cap
BCP	Brooklyn–Corio Pipeline
BLP	Brooklyn–Lara Pipeline
BoD	beginning of day
CG	city gate
CPP	close proximity point
CPT	cumulative price threshold
CS	compressor station
DER	distributed energy resources
DFC	discharge flow controller
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EDD	Effective Degree Day
EES	Environmental Effects Statement

Term	Definition
EGP	Eastern Gas Pipeline
EoD	end of day
ESG	environment, social and governance
ESV	Energy Safe Victoria
FEED	front end engineering design
FID	final investment decision
FSRU	floating storage and regassification unit
GBJV	Gippsland Basin Joint Venture
GSA	gas supply agreement
GSOO	Gas Statement of Opportunities
HUGS	Heytesbury Underground Gas Storage
IASR	Inputs Assumptions and Scenarios Report
ISP	Integrated System Plan
KUJV	Kipper Unit Joint Venture
LNG	liquefied natural gas
LV	line valve
MAOP	maximum allowable operating pressure
MDQ	maximum daily quantity/ies
MHQ	maximum hourly quantity/ies
MinOP	minimum allowable operating pressure
MSP	Moomba Sydney Pipeline
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
PKET	Port Kembla Energy Terminal
POE	probability of exceedance
PRMS	Petroleum Resources Management System
PRS	pressure reduction station
PV	photovoltaic/s
RoLR	retailer of last resort
SEA Gas	South East Australia Gas (pipeline)
STTM	Short Term Trading Market
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zone
TGP	Tasmania Gas Pipeline
UAFG	unaccounted for gas
UGS	Underground Gas Storage
VEU	Victorian Energy Upgrades
VGPR	*Victorian Gas Planning Report*

Term	Definition
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
WORM	Western Outer Ring Main
WTS	Western Transmission System

Glossary

This document uses many terms that have meanings defined in the National Gas Rules (NGR). The NGR meanings are adopted unless otherwise specified.

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 (DTS) and injected at Pakenham.
biomethane	Methane captured from biological processes such as wastewater treatment, landfill or biodigesters (also known as biogas) and purified to meet gas quality standards. Biomethane can be used interchangeably with natural gas.
capacity certificate	A certificated right in respect of a specified capacity certificates zone that is allocated for the purposes of tie-breaking.
capacity certificate zone	A group of one or more system injection points or system withdrawal points in the DTS which comprise a capacity certificates zone, as determined by AEMO.
city gate	A facility which regulates gas pressure from a higher to a lower pressure.
connection point	A gas delivery point, transfer point, or receipt point.
Culcairn	The gas transmission network interconnection point between the DTS and the New South Wales transmission system (part of the MSP).
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.
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 Wholesale Gas 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.
effective degree day	A measure of coldness that includes temperature, sunshine hours, wind 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 EDD is used to model the daily relationship between weather and gas demand.
electrification	The conversion of technologies or systems to use electrical power. In the context of the VGPR, this most often refers to converting appliances or industrial processes from using natural gas to electricity.
facility operator	Operator of a gas production facility, storage facility, or pipeline.

Term	Definition
firm capacity	Guaranteed or contracted capacity to supply gas.
gas consumption	Gas consumption refers to total gas demand used over longer periods (months and years)
gas demand	Gas demand refers to short-term gas use (hours and days).
gas generation	Where electricity is generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).
Gas Statement of Opportunities	Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia published annually by AEMO.
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.
gigajoule	An International System of Units (SI) unit. One GJ equals 1 x 10^9 joules.
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 LNG storage facility is 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.
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 National Gas Rules (NGR).
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	Short duration peaks in gas demand.
peak shaving	Meeting a demand peak using injections of vaporised LNG.
petajoule	An International System of Units (SI) unit. One PJ equals 1 x 10^{15} joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
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 National Gas Rules (NGR), for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
shoulder season	The period between low (summer) and high (winter) gas demand. It includes the calendar months of March, April, October, and November.
southern states	New South Wales, South Australia, Victoria, the Australian Capital Territory, and Tasmania.
storage facility	A facility for storing gas, including the LNG storage facility and 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; accordingly, a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • Load distribution across the system.

Term	Definition
	• 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	A constraint applied in the DWGM.
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 generation 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 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 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 gas consumers.
TasHub	The interconnection between the Tasmania Gas Pipeline (TGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
terajoule	An International System of Units (SI) unit. One TJ equals 1 x 10^{12} joules.
unaccounted for gas	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising 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 operational 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 DTS at Longford, facilitating gas trading at the Longford hub.
Western Transmission System	The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the DWGM and DTS.
Winter peak demand period	In this report is defined as 1 May to 30 September of a given calendar year.