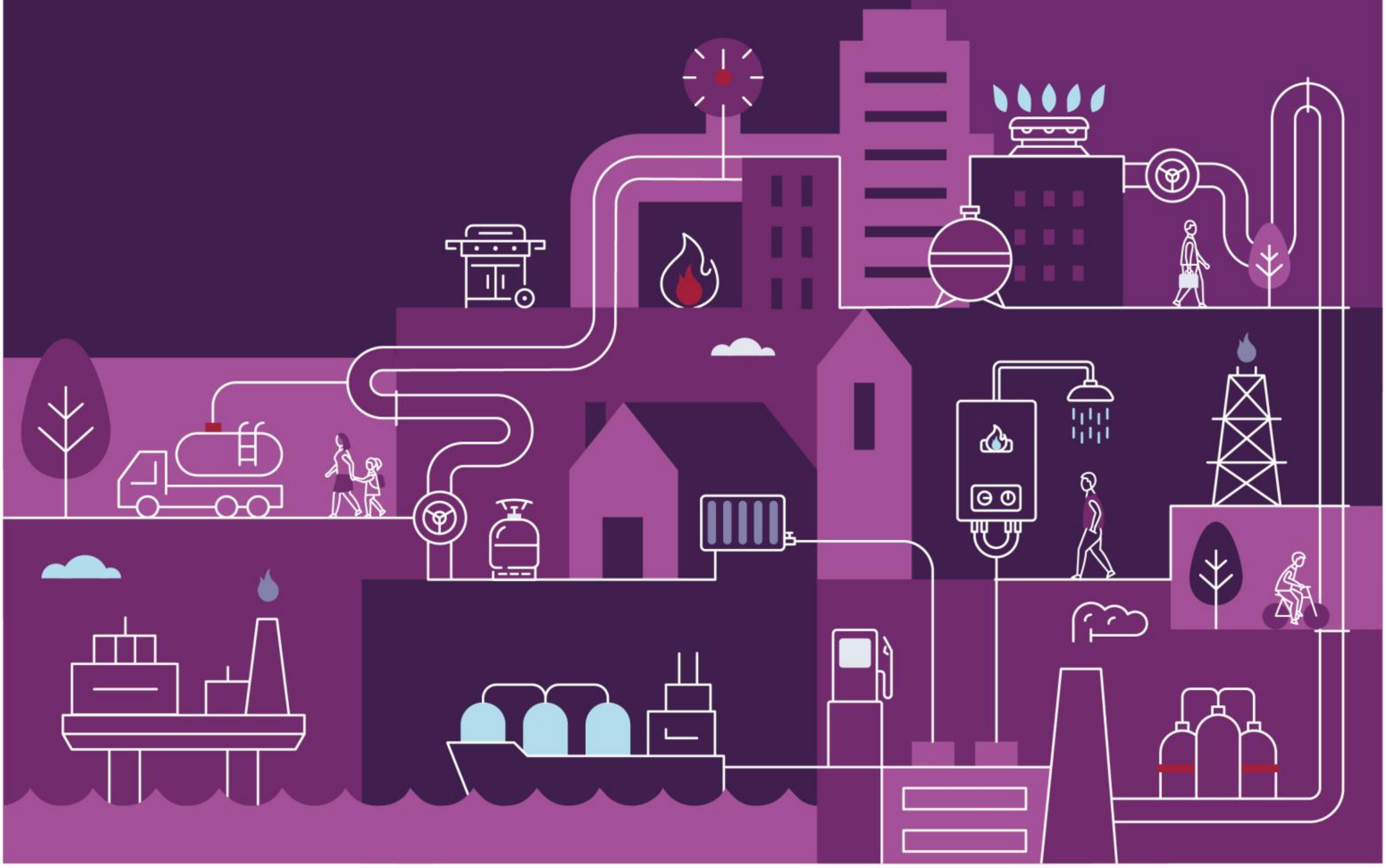
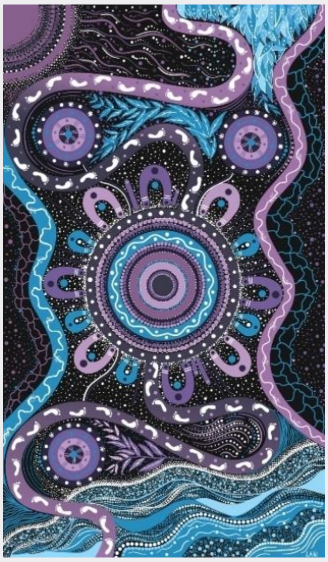
Victorian Gas Planning Report

March 2025

Gas transmission network planning for Victoria





We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

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Executive summary

The 2025 *Victorian Gas Planning Report* (VGPR) provides information about the supply demand balance over the next five years (2025-29, called the outlook period) in Victoria and the Victorian Declared Transmission System (DTS). The 2025 VGPR complements AEMO's 2025 *Gas Statement of Opportunities* (GSOO)[1], which assesses wider gas supply adequacy in central and eastern Australia.

- **Victorian annual production outlook continues to decline.**
  - Forecast 2025 Victorian production has fallen from 296 petajoules (PJ) in the 2024 VGPR Update to 257 PJ, a 39 PJ (13%) reduction. Production is forecast to reduce 37% during the outlook period to 162 PJ in 2029.
  - Reduced forecast production in 2025 is mainly due to lower forecast Gippsland production, reducing 16% from 235 PJ in the 2024 VGPR Update to 198 PJ. The main causes are longer duration Longford planned maintenance, and production impacts associated with Turrum Phase 3 project mobilisation.
  - From 2027 to 2029, the available Gippsland production forecast is higher than in the 2024 VGPR Update, primarily due to increased Longford volumes from the now committed Kipper Stage 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves. These reserves remain available due to lower than forecast production in 2023 and 2024, driven by lower gas consumption. This also enabled the deferral of the Longford Gas Plant 3 retirement from December 2027 to December 2028.
  - Port Campbell production during the outlook period is forecast to be lower than in the 2024 VGPR Update, predominantly due to reduced Enterprise and Thylacine North reserves.
- **The forecast reduction in annual gas system consumption is consistent with the 2024 VGPR Update**, with a slightly higher reduction (10.7% compared to 9.6%) over the outlook period.
  - Residential and small commercial (Tariff V) consumption in 2024 was 4.5% lower than in 2023, a smaller decline than the 13.5% drop between 2022 and 2023. The more moderate decline in 2024 was partly influenced by a colder winter compared to 2023, although temperatures were mild relative to other years.
  - Industrial and large commercial (Tariff D) consumption declined by 4.1% in 2024, continuing a recent trend. Tariff D consumption has reduced by 16.5% (11 PJ) in the three years since 2021.
- AEMO projects an **annual supply shortfall in 2029, one year later than identified in the 2024 VGPR Update**, due to the forecast increased and reprofiled Gippsland production and reduced gas consumption.
- **Expected peak day supply capacity to the DTS (including from storage facilities) is forecast to decline** by 31% from 1,296 terajoules a day (TJ/d) in winter 2025 to 895 TJ/d in winter 2029. Forecast peak day supply capacity in winter 2028 has increased from 882 TJ/d in the 2024 VGPR Update to 1,094 TJ/d due to increased Gippsland production capacity, including the delayed retirement of Longford Gas Plant 3.

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

- **A peak day supply adequacy gap is forecast for both 1-in-2 and 1-in-20 system demand days during winter 2029**, despite a forecast 12% reduction in Victorian peak day system demand across the outlook period. The peak day system demand shortfalls forecast in the 2024 VGPR Update have been delayed until winter 2029, primarily due to the increased Gippsland production. Supply adequacy is, however, forecast to remain tight, with supply from the Dandenong Liquefied Natural Gas (LNG) facility likely to be required to support the peak day demand and even low levels of gas-powered electricity generation (GPG) on a peak day. There is a high risk of shortfalls forecast due to unexpected conditions such as demand surges and unplanned supply restrictions.
- **Victorian GPG requirements are forecast to increase from winter 2028**, following the planned August 2027 closure of the Eraring coal power station in New South Wales, and the July 2028 closure of Victoria's Yallourn coal power station. The maximum GPG demand is forecast to increase to 528 TJ/d in winter 2028, which is likely to result in total demand that is above the 1,094 TJ/d supply capacity forecast under sustained high gas usage conditions, for example due to cold weather combined with low variable renewable energy (VRE) generation. The 2029 winter maximum GPG demand is forecast to increase to 562 TJ/d, while the summer maximum GPG demand forecast is 272 TJ/d. Over the outlook period, GPG is forecast primarily for peak electricity demand and backing up electricity storage technology when renewable generation is low. The peak GPG forecast demand can coincide with peak system demand conditions, creating very high total demand conditions where existing gas supply capacity is not sufficient.
- **The 2025 GSOO highlights peak day shortfall risk and seasonal supply gaps in the southern states[2] in 2028 under sustained high gas usage conditions. From 2029, this is a structural gap with new gas supply required to address the projected annual supply shortfall.** The forecast shortfalls could impact any of the southern states, including Victoria.
- **There are no anticipated production or supply projects[3] to offset the forecast production decline and increased GPG demand, resulting in a heavy reliance on potential projects.** Investment uncertainty in gas production and supply infrastructure projects remains high, as all projects currently underway or proposed in the VGPR outlook period face a range of challenges to reach investment decisions, maintain schedules, and reach completion.
- AEMO forecasts **uncertainty about the refilling of Dandenong LNG beyond winter 2025 posing a risk to system resilience as early as 2026.** This storage facility (680 TJ storage capacity) is needed to provide quick response to unforecast demand increases and gas plant and compressor trips to maintain gas supply. The facility comprises a storage tank owned by APA and a liquefaction plant owned by BOC. APA has advised that the BOC liquefaction facility requires investment to address the risk of a prolonged outage. In addition, the interim rule that requires AEMO to ensure that the LNG tank is kept full expires at the end of 2025. Supply adequacy assessments in the VGPR and GSOO assume that Dandenong LNG will continue to be available after 2025.

[2] "Southern states" means Victoria, South Australia, New South Wales and Tasmania.

[3] Existing and committed' means gas fields and production facilities that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway. 'Anticipated' means developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made. "Potential" projects have been publicly announced and may proceed in the outlook period, but have not met the criteria to be classed as anticipated. For detailed criteria descriptions, see Chapter 3.

- The Gippsland Basin Joint Venture (GBJV) has advised AEMO of Turrum Phase 3 development activities, which require a full depressurisation of the Marlin B production platform during mobilisation of the jack-up rig. The activities are planned in a two-week window in September 2025, during which low Longford production capacity is expected. AEMO will continue to work with GBJV on the timing of the activity.

Gas consumption forecasts

The forecasts for the 2025 VGPR and the 2025 GSOO focus on the *Step Change* scenario outlined in AEMO's Draft 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[4].

The *Step Change* scenario requires ongoing policy support and investment to further enable electrification (switching from other fuels to electricity) and the decline of gas consumption. Victoria's Gas Substitution Roadmap Update 2024[5] policy and schemes align with this requirement:

- A gas connection ban, effective from 1 January 2024, which prohibits new homes and residential subdivisions that require a planning permit from connecting to the gas networks.
- A requirement, from 1 January 2025, for residential and developer applicants to pay a full upfront charge for new gas connections.
- Banning gas distribution businesses from offering incentives to connect residential buildings to gas or to purchase and install gas appliances.
- An extension to the end date of the Victorian Energy Upgrades (VEU) program, from 2030 to 2045.
- Victorian Large Energy User Electrification Support that provides funding for approved specialists to complete electrification feasibility assessments on commercial and industrial business facilities that use between 10 TJ and 100 TJ of gas per year.

In addition to these Victorian Government actions, the Federal Government's Safeguard Mechanism will require most of Australia's largest emitters to reduce emissions by 4.9% each year to 2030[6].

The combination of these policies has resulted in AEMO forecasting a 10.7% reduction in annual Victorian gas system[7] consumption[8] and a 12% reduction in peak day system demand over the outlook period.

The actual DTS system gas consumption continued to reduce in 2024. Industrial and large commercial customer (Tariff D[9]) actual consumption decreased by 4.1% compared to 2023, while residential and small commercial customer (Tariff V[10]) consumption decreased by 4.5%. The reduction is expected to be due to a range of factors including electrification of some gas use and lower consumption due to cost of living factors and reduced commercial activity. In comparison to the 2024 VGPR Update, the rate of decline for Tariff D was observed to be

[4] At https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-inputs-assumptions-and-scenarios-report-stage-1.pdf?la=en.

[5] Victorian Government, *Victoria Gas Substitution Roadmap Update 2024*, at https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap/gas-substitution-roadmap-update-2024.pdf.

[6] Australian Government, Department of Climate Change, Energy, the Environment and Water (DCCEEW), Safeguard Mechanism scheme, at https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

[7] System demand includes gas use by industry, business and household consumers (it does not include GPG).

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

[9] Tariff D customers have annual gas consumption of at least 10 TJ or an hourly consumption rate of more than 10 gigajoules (GJ).

[10] Tariff V customers are loads which do not meet the annual or hourly consumption rate of the Tariff D criteria.

consistent with 2023. However, the decline in Tariff V was less steep, which is likely due to the colder winter conditions experienced in 2024 compared to 2023.

Despite the colder weather in 2024, Tariff V gas consumption continued to decline, indicating less usage of residential gas heating and reduced small commercial customer gas demand. Further analysis is required to quantify the how much of this reduction was due to electrification, compared to economic pressures.

The 10.7% reduction in system consumption forecast over the outlook period (see **Table 1**) is a slightly steeper decline than in the 2024 VGPR Update (9.6%).

Table 1 Actual and forecast Victorian annual gas consumption, 2022-29 (PJ a year [PJ/y])

	Actual			Forecast					Change over outlook
	2022	2023	2024	2025	2026	2027	2028	2029	
System consumption	194.8	173.3	165.6	173.1	169.3	165.9	161.0	154.6	-10.7%
DTS GPG consumption	13.8	3.8	7.8	2.6	2.3	1.6	6.6	6.5	149.0%
DTS total consumption	208.6	177.1	173.4	175.7	171.7	167.4	167.6	161.1	-8.3%
Non-DTS system consumption	0.32	0.28	0.26	0.25	0.25	0.24	0.24	0.23	-8.1%
Non-DTS GPG consumption	6.9	3.6	7.1	3.0	2.6	1.7	5.2	5.4	78.7%
Victorian GPG consumption	20.7	7.4	14.9	5.6	4.9	3.3	11.9	11.9	111.2%
Total Victorian consumption*	215.8	181.0	180.7	179.0	174.5	169.4	173.1	166.8	-6.8%

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 GPG consumption at Bairnsdale and Mortlake.

Gas-powered generation forecasts

The 2025 VGPR and the 2025 GSOO forecasts align with the optimal development path (ODP) identified in the 2024 ISP [11].

Figure 1 shows the range of forecast GPG consumption for Victoria in each year of the outlook period under both the *Step Change* scenario and the *High Coal Generation Outages* sensitivity, for supporting peak electricity demand and backing up storage technology when renewable generation is low.

In the *Step Change* scenario, annual GPG gas consumption is forecast to:

- Initially decrease by 31.9% from 2025 to 2027 compared to recent years, driven by increases in renewable generation due to the continued installation of large amounts of rooftop solar and of energy storage capacity.
- Increase by 334% in 2028 from the level forecast in 2027, after the planned closure of the Eraring coal power station in New South Wales (August 2027), and to remain at this higher level with the closure of Victoria's Yallourn coal power station (July 2028).

[11] The gas generation forecasts differ marginally to those presented in the 2024 ISP. The least-cost dispatch assumptions applied in core ISP modelling have been replaced with assumptions regarding updated coal retirements, generator bidding, operational constraints, new generating capacity build timelines, transmission augmentation timelines, and availability of other generators to predict GPG consumption more accurately. For more information see Generation Information - July 2024, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/nem-generation-information-july-2024.xlsx and NEM Transmission Augmentation Info - August 2024, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

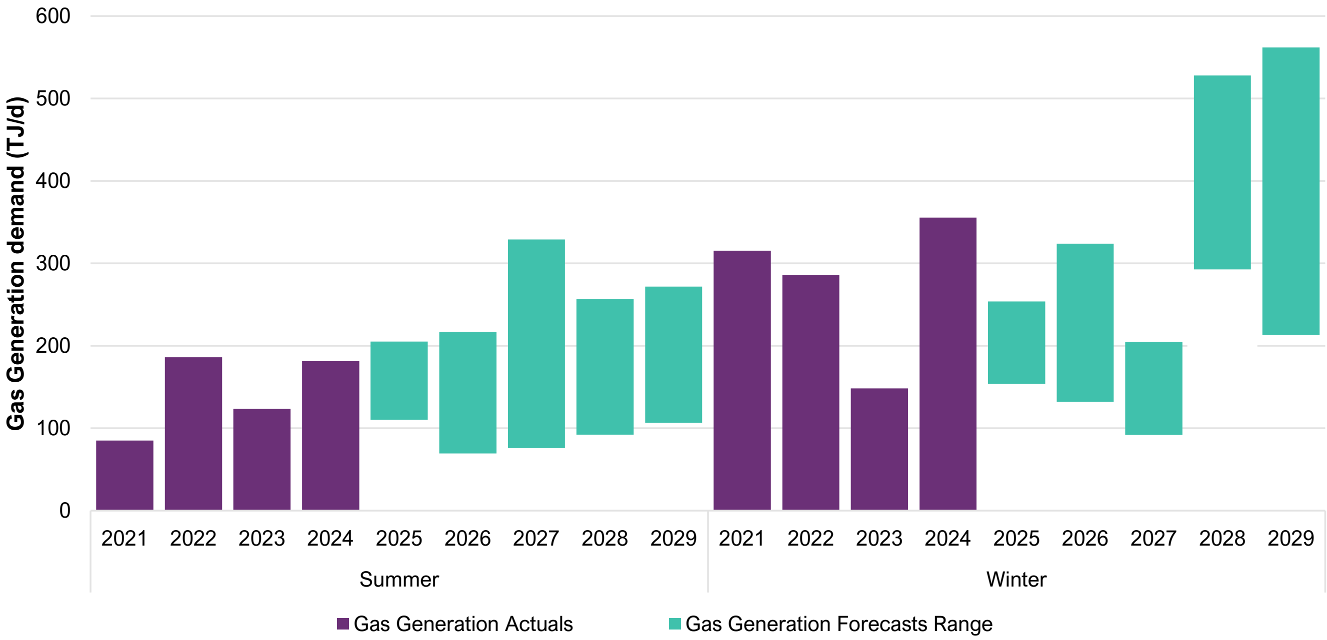
If coal generation was reduced due to an extended outage or fuel supply issue (modelled in the *High Coal Generation Outages* sensitivity), GPG consumption is forecast to be up to 528% higher in the VGPR outlook period from 2025 to 2029 than in the *Step Change* scenario.

In 2024, actual GPG consumption increased by 96.5% compared to 2023. High early winter GPG consumption in 2024 was due to several compounding factors, including a wind drought in June, cold weather and increased electricity demand due to electrification leading to record-breaking maximum electricity demand in July.

Figure 1 Actual and projected range of annual Victorian GPG consumption forecasts, *Step Change* scenario and *High Coal Generation Outages* sensitivity, 2021 to 2029 (PJ)

Figure 2 shows seasonal peak GPG demand forecasts for the *Step Change* scenario, highlighting that summer GPG peak demand forecasts are generally lower than winter peak demand forecasts. Maximum winter GPG demand is forecast at 528 TJ/d in 2028, rising to 562 TJ/d in 2029, significantly higher than the maximum GPG summer demand of 257 TJ/d and 272 TJ/d for 2028 and 2029, respectively.

Figure 2 Actual and projected range of seasonal maximum and minimum peak Victorian GPG demand forecasts in summer and winter, 2021 to 2029 (TJ/d)



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

Winter peak GPG demand has the potential to coincide with a peak system demand day when there is a high demand for heating and solar generation usually reduces. GPG demand is forecast to reduce due to the entry of increased renewable electricity and storage capacity into the market until the closure of the Eraring coal power station in August 2027 and the Yallourn coal power station in July 2028. These closures result in much higher forecast GPG maximum demands during winter 2028 and 2029, with wider variance between the minimum and maximum forecast GPG demand. This forecast highlights an increased reliance on GPG following coal power station retirements during periods of lower renewable generation output, particularly in winter.

Annual supply adequacy

Figure 3 shows that Victoria's annual production is forecast to exceed projected declining annual consumption[12] for most of the outlook period.

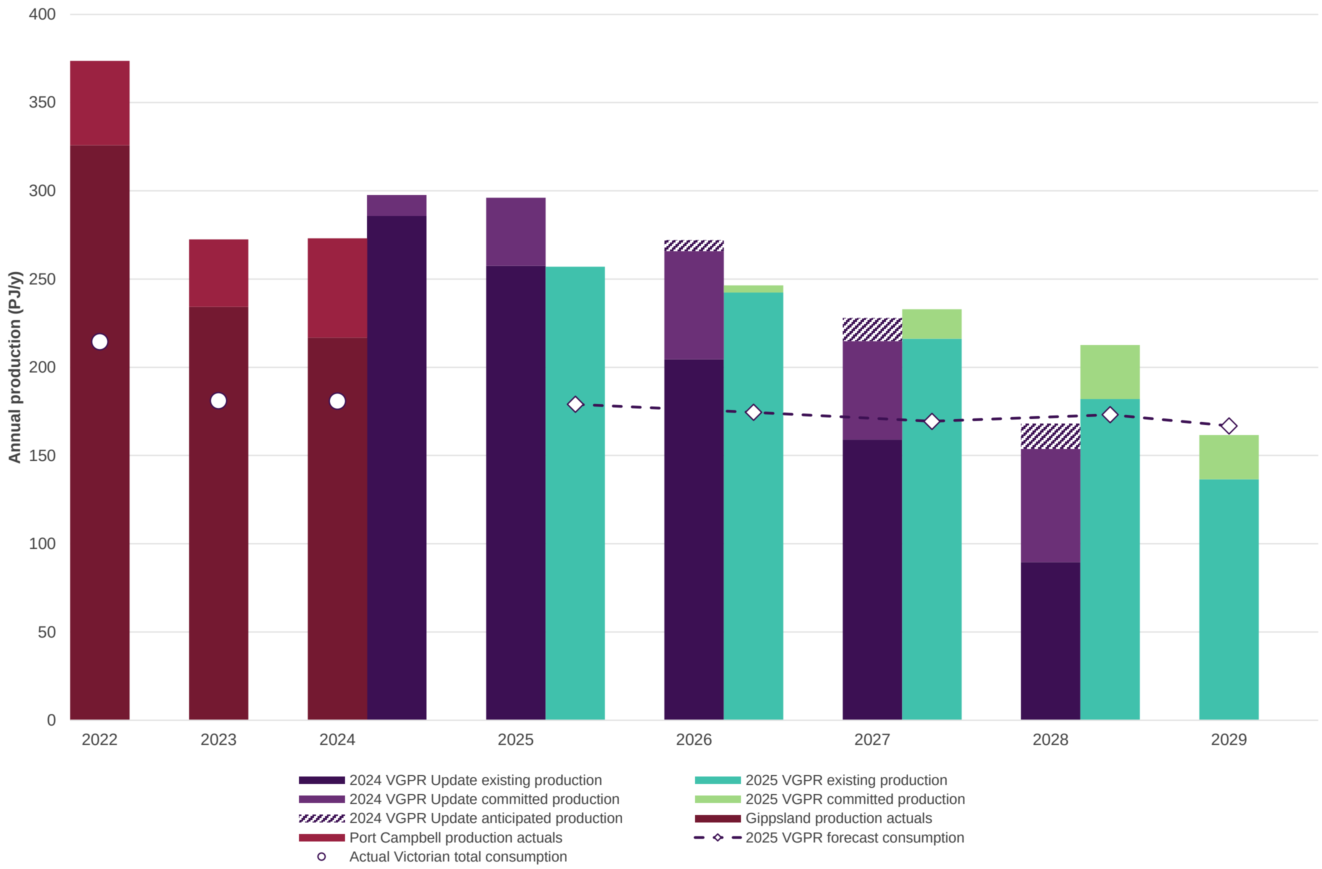
Compared to the 2024 VGPR Update:

- Forecast annual surplus supply quantities in 2025 and 2026 are lower, by 30% (from 111 PJ to 78 PJ) and 14% (from 84 PJ to 72 PJ) respectively.
- The forecast annual surplus supply quantity in 2027 and 2028 is higher, removing the 2028 annual supply shortfall that was forecast in the 2024 VGPR Update.
- Victorian total consumption is forecast to exceed available[13] supply in 2029, resulting in a forecast supply shortfall one year later than reported in the 2024 VGPR Update.

[12] Inclusive of system and GPG consumption.

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

Figure 3 Actual and forecast supply and total consumption, and compared to the 2024 VGPR Update, 2022 to 2029 (PJ/y)



Producers forecast that Gippsland[14] region production will reduce by 36% from 198 PJ in 2025 to 127 PJ in 2029. Forecast production includes the contribution of Longford Gas Plant supply projects. This includes the GBJV Kipper Compression project[15], which came online in October 2024, along with the committed KUJV Kipper Stage 1B and GBJV Turrum Phase 3 projects. These projects are not sufficient to overcome the projected reduction in Gippsland supply that is mainly due to the decline of the GBJV and KUJV fields that supply the Longford Gas Plant.

The 2024 VGPR Update reported that projected total available Gippsland region production for 2024 was 243 PJ. Actual production in 2024 was 216 PJ, reflecting reduced overall consumption, market participant behaviour, and reduced production due to an unplanned extension of pre-winter maintenance.

Available forecast Gippsland production for 2025 and 2026 is lower than the 2024 VGPR Update forecast. Forecast Gippsland production for 2025 has reduced from 235 PJ to 198 PJ, primarily due to longer duration planned maintenance, and the impacts on production associated with Turrum Phase 3 project mobilisation activities. Gippsland production from 2027 to 2029 is higher compared to the 2024 VGPR Update due to increased Longford volumes from the Kipper 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves. These reserves remain available due to lower than forecast production

[14] Gippsland region includes the Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, Eastern Gas Pipeline (EGP) and Tasmanian Gas Pipeline (TGP).

[15] The Kipper compression project has been included as a committed project since the 2022 VGPR Update.

in 2023 and 2024, driven by lower gas consumption. This increased production has enabled the deferral of the expected retirement of Longford Gas Plant 3 from December 2027 to December 2028.

Production from Port Campbell[16] is forecast to decline by 41% by the end of the outlook period (from 59 PJ in 2025 to 35 PJ in 2029). This is steeper than 18% decline forecast in the 2024 VGPR Update, due to the decrease in Enterprise and Thylacine North field reserves after Beach Energy's evaluations indicated a smaller resource pool than initially anticipated[17]. This has resulted in the Otway Gas Plant production forecast reducing by 23% and 27% for 2026 and 2027 respectively, followed by 12% and 22% reductions for 2028 and 2029 compared to the 2024 VGPR Update.

There are no anticipated production projects to offset the production decline. Production from the Golden Beach gas field is classified as a potential supply project for winter 2028, ahead of its proposed conversion to gas storage service for winter 2029. Potential supply projects are being explored through the formation of a consortium as operators which includes ConocoPhillips, Woodside, Amplitude Energy, and Beach Energy, who are securing a drilling rig for planned exploration, well development and well decommissioning campaigns in the Otway Basin from 2025.

Monthly supply adequacy

Figure 4 shows actual monthly total consumption and available supply in 2024, and forecast monthly available Victorian production, against forecast total consumption[18], during the five-year outlook period. The graph shows:

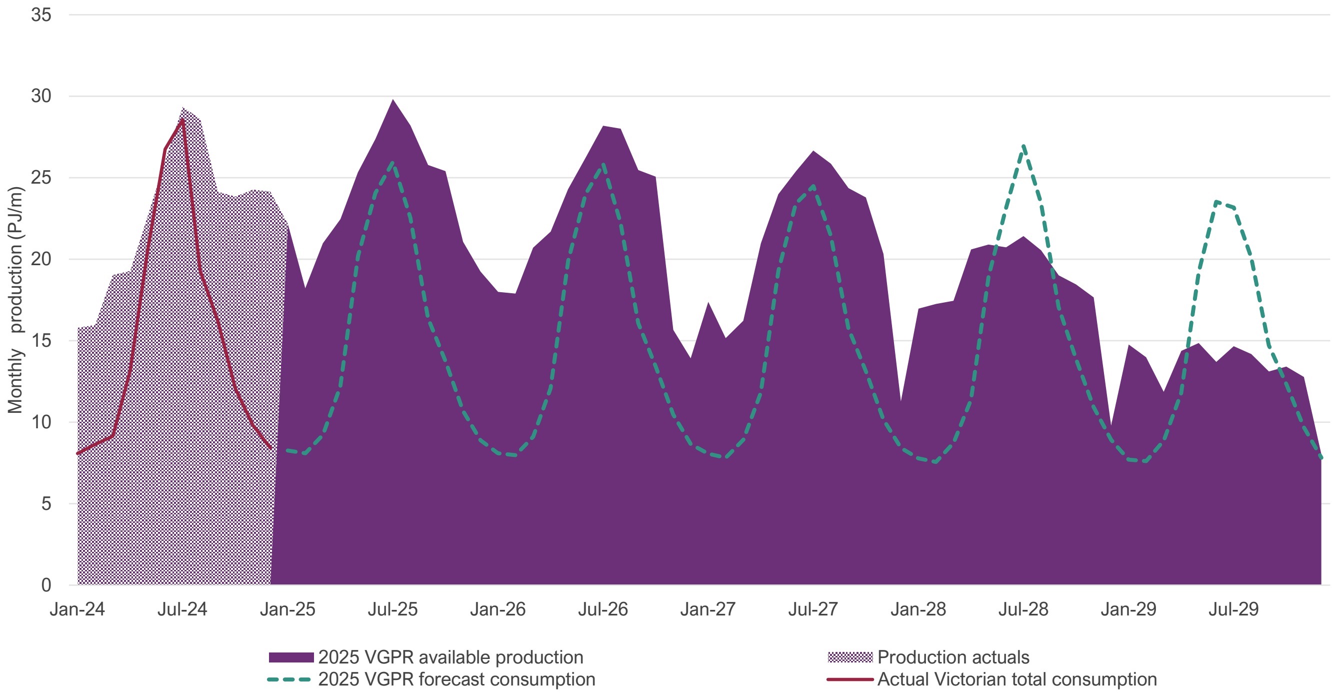
- Victorian supply was tight in winter 2024. The draw down of Iona Underground Storage (UGS) early in winter 2024 due to high gas demand resulted in an East Coast Gas System potential threat notice on 19 June 2024. In the outlook period, Victorian supply is forecast to remain tight with Longford production declining. Should similar market scenarios of prolonged high gas usage occur, the state would continue to rely heavily on storage, especially during winter months, and this would potentially lead to a threat notice being issued.
- Forecast monthly available production exceeds forecast monthly consumption for 2025 to 2027, noting that Victorian production is also used to supply the other southern states. The graph shows a smaller gap between production and consumption during winter when gas supplies from Iona UGS and from Queensland are relied on to support monthly gas consumption.
- The Victorian total consumption forecast exceeds total available forecast production during the winter months from winter 2028. The flatter Victorian production profile, which reduces seasonal and peak day supply adequacy, would result in an increased reliance on gas supplied by Iona UGS and imports from Queensland to meet demand. A seasonal shortfall is likely, particularly if consumption is higher than forecast. The retirement of the Eraring and Yallourn coal power stations are forecast to result in increased GPG consumption during winter 2028.

[16] Port Campbell region includes the Otway and Athena production facilities. Combined production is gas available to the DTS, South Australia and Mortlake Power Station. The Iona Underground Gas Storage (UGS) facility is also in Port Campbell.

[17] Beach, Annual Report 2024, 12 August 2024, at https://beachenergy.com.au/wp-content/uploads/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

[18] Inclusive of system and GPG consumption.

Figure 4 Actual and forecast monthly supply and total consumption, *Step Change* scenario, 2024 to 2029 (PJ a month [PJ/m])



Note: Forecast consumption is the total of annual system consumption and average GPG consumption forecasts.

Peak day supply adequacy

Figure 5 shows forecast peak day supply and DTS adequacy during the outlook period. Available Victorian peak day supply capacity is forecast to decline by 31% over the outlook period, from 1,296 TJ/d in 2025 to 895 TJ/d in 2029. The peak day supply capacity includes 87 TJ/d of firm supply from the Dandenong LNG storage facility[19].

Gippsland producers have advised that maximum peak day production capacity will reduce from 746 TJ/d in 2025 to 345 TJ/d in 2029. This includes the committed Kipper Stage 1B and Turrum Phase 3 projects. The reduction is mainly due to the decline of GBJV and KUJV fields that supply the Longford Gas Plant. As noted above, Gippsland supply capacity for 2027 and 2028 is higher that the forecast provided in the 2024 VGPR Update, due to higher Longford production that is enabled by the reprofiling of existing reserves and the committed development of the Kipper and Turrum projects. This has also enabled the retirement of Gas Plant 3 to be delayed by one year, with its closure expected after winter 2028.

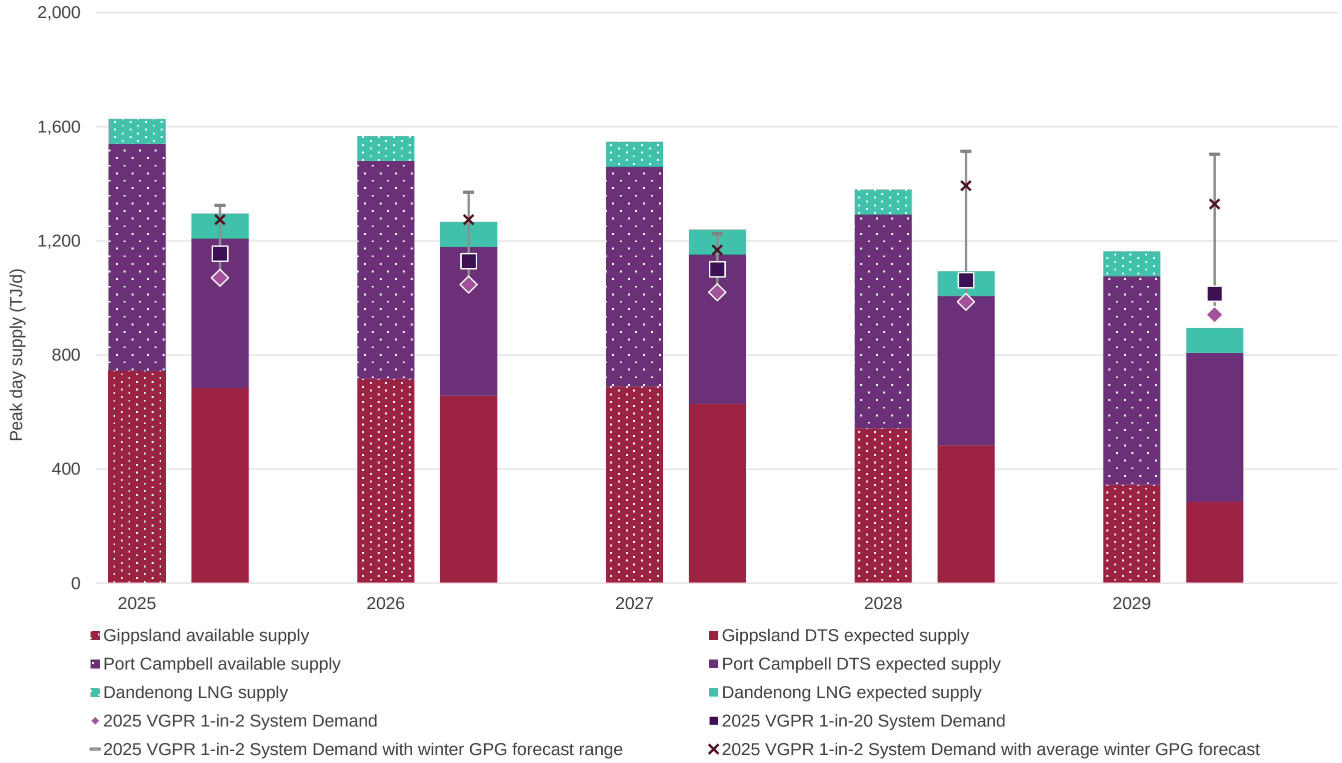
Port Campbell producers and the Iona UGS operator have advised that maximum daily supply capacity will reduce by 8%, from 795 TJ/d in 2025 to 732 TJ/d in 2029. The connection of Thylacine West and Enterprise-1 wells returned the Otway Gas Plant to its nameplate capacity of 205 TJ/d in late 2024. From 2026 onwards, available peak day production forecasts are between 6% to 15% lower than reported in the 2024 VGPR Update, due to producers' revision of available reserves. From 2027 the capacity of Iona UGS facility will be increased by 45 TJ/d, from 570 TJ/d to 615 TJ/d through the development of the Heytesbury Underground Storage (HUGS) project.

Port Campbell peak day supply capacity into the DTS will continue to be limited by capacity of the South West Pipeline (SWP), with the impact of this restriction evident in Figure 5 that shows the difference between available

[19] Firm Dandenong LNG is up to 5.5 terajoules per hour (TJ/h) for approximately 16 hours, and non-firm LNG is up to 9.9 TJ/h.

and expected Port Campbell supply. AEMO capacity modelling has determined that SWP peak day capacity will also reduce from 530 TJ/d to 523 TJ/d due to reduced demand connected to the SWP.

Figure 5 Forecast peak day supply and DTS adequacy, 2025 to 2029 (TJ/d)



Note: The forecast peak day system demand shortfall assessment does not include the additional impact of GPG demand. Events in the National Electricity Market (NEM) could result in high GPG demand and total demand higher than a 1-in-20 year peak day system demand. Figure 5 shows the Victorian winter GPG demand forecast range coinciding with a 1-in-2 peak day system demand (marked x and -) to illustrate the possible range of resultant total demands.

Figure 5 also shows the reduction in peak day system demand, which is forecast to reduce by 12% during the outlook. The 1-in-2 year system demand is forecast to reduce from 1,071 TJ/d in 2025 to 942 TJ/d in 2029, while the 1-in-20 year system demand is forecast to reduce from 1,156 TJ/d in 2025 to 1,016 TJ/d in 2029.

The assessment of peak day supply and system demand shows that:

- In 2025, there is sufficient peak day supply to meet forecast peak system demand, although supply adequacy is 8% lower for 1-in-2 demand and 15% lower for 1-in-20 demand than the outlook in the 2024 VGPR Update.
- Figure 5 also shows that if a 1-in-2 system demand day was to coincide with winter forecast GPG demand, total demand could exceed expected supply capacity as early as 2025 (refer to Figure 2 for historical and forecast seasonal maximum and minimum Victorian GPG demand).
- Peak day supply adequacy has increased for 2026 to 2028 compared to the 2024 VGPR Update, primarily due to increased Longford production capacity. The available supply from Kipper Stage 1B and Turrum Phase 3 is included in peak day supply capacity (Kipper Stage 1B from winter 2026 and Turrum Phase 3 from winter 2027).
- Supply is forecast to be tight for winter 2028, with Dandenong LNG injections required to support a 1-in-20 system demand day, and a risk of shortfall if even low quantities of GPG demand are required to be met.

- Forecast system demand is projected to exceed available supply on both 1-in-2 and 1-in-20 system demand days in 2029.
- Development of potential supply projects is forecast to be required to avert GPG supply shortfalls during winter 2028 and on peak system demand days in 2029.

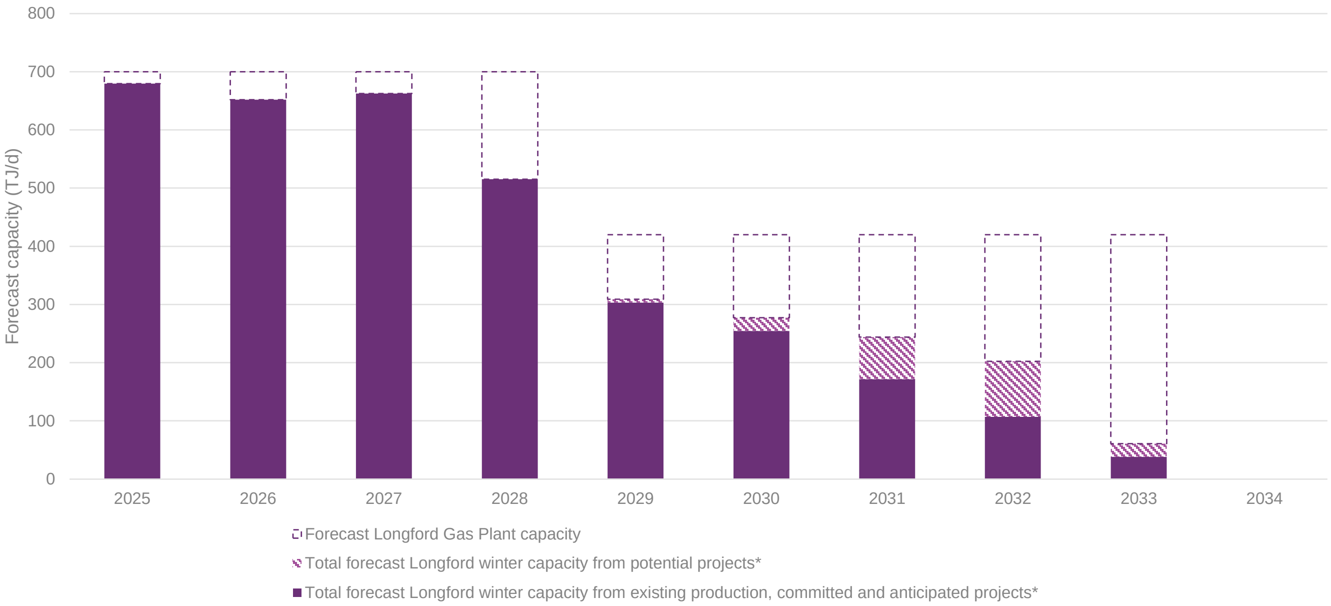
The 2025 GSOO highlights peak day shortfall risk and seasonal supply gaps in the southern states in 2028 under sustained high gas usage conditions. From 2029, a structural need for new gas supply is forecast to be required to address the projected annual supply gap. The forecast shortfalls could impact any of the southern states, including Victoria.

Insufficient gas supply capacity to support GPG demand on peak system demand days may result in gas supply for GPG being curtailed. The use of alternative resources (such as electricity demand response, alternative secondary generation fuels, and stored electrical energy) would be needed to maintain reliability in the National Electricity Market (NEM). The 2025 GSOO further discusses east coast gas supply adequacy including GPG supportability.

Longer-term adequacy

Figure 6 updates the 10-year capacity outlook for the Longford Gas Plant that was published in the 2024 VGPR Update. Longford's nameplate capacity reduced to 700 TJ/d from 1,150 TJ/d after the retirement of Gas Plant 1 in October 2024. The retirement of Gas Plant 3 has been delayed by one year to after winter 2028 due to the reprofiling of existing reserves and the committed Kipper and Turrum project that have increased Longford production in 2027 and 2028. The retirement of Gas Plant 2, and the end of Longford gas production, is still forecast for the end 2033.

Figure 6 Forecast Longford Gas Plant winter capacity, 2025 to 2034 (TJ/d)



* Aggregates of proven and probable, contingent and prospective resources.

Figure 6 shows an indicative forecast only that is intended to highlight the extent of Longford's expected decline over the next 10 years in a best-case scenario. Investment in potential projects and the final retirement plan of plant assets later in the decade remain subject to GBJV investment decisions.

Project updates

AEMO recognises that the current investment environment for projects is challenging and uncertain. The 2025 VGPR supply forecast includes some potential projects with timelines that are subject to change based on risk and uncertainties, making analysis of system adequacy difficult. All projects currently underway or proposed in the VGPR outlook period – including gas supply projects, LNG regasification terminal projects, pipeline projects, distributed supply projects and renewable gas projects – face a range of challenges to reach investment decisions, maintain schedules and reach completion.

Key project updates since the 2024 VGPR Update include:

- **Committed** supply projects:
  - **The Heytesbury Underground Storage (HUGS)** development, which will increase Iona UGS capacity to 615 TJ/d and increase storage inventory, reached final investment decision (FID) in July 2024 after Lochard Energy and Snowy Hydro signed a 25-year gas storage agreement, beginning in 2028[20]. This was classified as a potential project in the 2024 VGPR Update. Lochard Energy is also proposing further expansions to increase capacity to 765 TJ/d, which will need additional SWP capacity.
  - **Kipper Stage 1B** has reached FID in February 2025 with drilling planned to kick off later in 2025 and production to come online from June 2026.
  - **Turrum Phase 3** reached FID in March 2025 and drilling activities are expected to commence in September 2025, targeting first gas prior to winter 2027.
  - **Hydrogen Park Murray Valley** by AGI Renewables, part of Australian Gas Infrastructure Group (AGIG), commenced construction in October 2024. The project is targeted to be online in late 2025.
- **Potential** supply projects:
  - **Golden Beach Energy** has begun offshore geotechnical investigations in the project area to assess the seabed's suitability for supporting a drilling rig and the offshore pipeline route[21]. Production at 125 TJ/d is targeted for winter 2028 then transition to 375 TJ/d of storage supply capacity ahead of winter 2029.
  - On 24 February 2024, APA announced further plans to **East Coast Grid Expansion stages**, which includes conversion of Moomba Sydney Ethane Pipeline (MSEP) to transport natural gas, additional compressors on the MSP, Bullo interlink to transport gas from northern basin, Riverina Storage Pipeline (RSP) and expansion of Young to Wollert segment. The FID for MSEP was announced on the same day. The project will add 20-25 TJ/d of supply capacity from Moomba to Victoria.
  - Viva Energy has submitted the supplementary data request for the Environment Effects Statement (EES) required for the **Viva Energy Gas Terminal Project**. The terminal is targeted to be operational and

[20] Snowy Hydro, "Snowy Hydro signs Lochard gas storage agreement", 15 July 2024, at https://www.snowyhydro.com.au/news/snowy-hydro-signs-lochard-gas-storage-agreement/.

[21] GB Energy, Upcoming operations, at https://gbenergy.com.au/upcomingoperations.

available to the market ahead of winter 2028. Viva is also considering the conversion of the Westernport Altona Geelong crude pipeline to a high-pressure gas transmission pipeline as an option for terminal connection. This would provide an additional gas flow path from Geelong to Altona and onwards through to Newport and Dandenong.

- The Victorian Minister of Planning published a decision on Vopak's referral submission requiring an EES, and Vopak is currently in the process of preparing a consultation plan for the **Vopak Victoria LNG** project. Vopak has advised that it plans to have the terminal operational in the second quarter of 2028.
- Squadron Energy completed physical mechanical construction of **Port Kembla Energy Terminal** in December 2024[22]. The company is currently in the process of negotiating contracts with long-term customers to achieve the expected launch date for winter 2026.
- In October 2024, AP&G LNG acquired Venice Energy[23] to continue developing the **Outer Harbor LNG Project**. The acquisition will be formalised by mid-2025. Terminal construction is planned to finish in 2027 and negotiations are ongoing with all potential terminal users with first gas targeted for winter 2028. To support this project, SEA Gas is proposing additional compression and reverse flow capability on the Port Campbell to Adelaide Pipeline, as well as extending the SEA Gas Pipeline to Melbourne. AG&P LNG has also proposed an interim project called Adelaide Energy Bridge which aims to commence in Q4 2025 to supply South Australian customers via a nearby regasification facility.
- A drilling consortium – operators Amplitude Energy, Beach Energy, ConocoPhillips, and Woodside – has secured the Transocean Equinox drilling rig, currently operating in Western Australia, to undertake **exploration and well decommissioning activities in the Otway Basin** during 2025 and 2026. The work program for each company is subject to an agreed schedule within the consortium and regulatory approvals.
- GBJV is considering the **Longford Late Life Optimisation** project which aims to maximise production from declining reserves later in the decade.

Increased Otway Basin production and supply from the Venice LNG regasification terminal would not provide additional peak day supply capacity to the DTS without a major expansion of the SWP, although they are likely to reduce Iona UGS depletion and refilling risks. The Viva and Vopak LNG regasification terminals would provide additional DTS supply capacity, however this capacity could not be achieved without significantly reducing supply from Port Campbell, including from the Iona UGS facility, unless the SWP is expanded.

Dandenong Liquefied Natural Gas risk

Dandenong LNG is a 680 TJ storage facility connected to the DTS at Dandenong, which is the highest flow location into the Melbourne inner ring main network. The facility plays a critical role in gas supply resilience. During periods of supply interruptions, higher than forecast demand including GPG, or transmission equipment outages, it can respond quickly to inject gas into the network, preventing the curtailment of customers. The facility comprises a storage tank owned by APA and a liquefaction plant owned by BOC.

[22] Squadron Energy, "Port Kembla Energy Terminal ready to supply gas to Australia's eastern states", 12 December 2024, at https://www.squadronenergy.com/news/port-kembla-energy-terminal-ready-to-supply-gas-to-australias-eastern-states.

[23] AG&P, "AGP LNG agrees to acquire Venice Energy", 24 October 2024, at https://agplng.com/press-releases/agp-lng-agrees-to-acquire-venice-energy-a-2-mtpa-lng-import-terminal-developer-at-outer-harbor-in-port-adelaide-australia.pdf.

In accordance with the Australian Energy Market Commission (AEMC) interim rules published on 15 December 2022[24], AEMO is required to contract any uncontracted capacity to ensure that Dandenong LNG storage inventory is maximised. The current interim rules will remain effective until the end of 2025. The Victorian Government is seeking to extend the interim rule requirement, through a rule change with the AEMC.

BOC's aging liquefaction plant has been experiencing increased issues with reliability. The liquefaction facility remains in operation; however, unplanned outages continue to occur and there is an increased risk of a major failure occurring, posing a risk for refilling the Dandenong LNG tank. APA has advised that investment in BOC's liquefaction facility is required to address the reliability and failure risks.

Operational resilience

Victorian supply adequacy continues to deteriorate due to reducing supply capacity over the five-year outlook period, coupled with increased Longford outage risks following the retirement of Gas Plant 1 and the decline in the large legacy gas fields. Peak day shortfalls are projected from 2028 with annual shortfalls forecast from 2029 without additional gas supply. **Table 2** and **Table 3** provide updates on operational resilience issues impacting the DTS since the publication of the 2024 VGPR Update.

Table 2 Risks to supply adequacy and operational resilience

Risk	Description
Production infrastructure outages	Production, storage, and transmission facilities in Victoria are aging and unplanned outages may occur more frequently. Following the Gas Plant 1 closure in 2024, Longford has two gas plants remaining with a combined capacity of 700 TJ/d. If either of the two remaining plants were unavailable, the total production capacity of Longford Gas Plant could be reduced by up to 350 TJ/d. The retirement of the Longford Crude Stabilisation plant in 2024 has increased the time it takes for offshore production to ramp up following an outage, due to liquids management in the offshore pipelines. Even short outages have an increased risk of a peak day gas supply shortfall due to the small margins in the supply demand balance.
Production lower than forecast and unpredictable decline of producing reserves	Rapid pressure decline could impact the size of remaining reserves leading to lower actual production. Aquifer-driven reservoirs at Gippsland Basin create uncertainty due to their characteristics at the end of their field life. As these fields approach final depletion, production can decline rapidly, making it challenging to accurately forecast the production capacity and remaining reserves.
Gas generation	The increasing reliance on GPG during extreme weather events and unexpected market disruptions, compounded with declining gas supply, poses risks to gas supply adequacy and operational resilience, particularly during winter peak demand periods when gas supply may struggle to meet both electricity generation and system demands.
Production project delay and uncertainty	Additional production from committed projects is expected to assist with peak day and seasonal supply (Kipper from 2026 and Turrum from 2027). A delay in the development of these projects would create more uncertainties towards bridging the supply gap later in the outlook period.
Depletion of Iona UGS inventory	Tight supply coinciding with extended periods of high demand can lead to a steep draw down of Iona UGS inventory. In winter 2024, AEMO issued an East Coast Gas System potential threat notice due to rapid Iona storage inventory depletion. This was caused by high GPG demand, which was a response to low wind generation, combined with an unplanned extension of Longford planned maintenance that reduced production capacity. This risk is heightened by Iona UGS supply capacity reducing when the storage inventory is low.
Reduction in gas made available from Queensland to the southern states	Winter gas supply from the Queensland LNG producers is an essential component of managing southern states' gas supply during these high demand months. However, the volumes available at the Moomba hub via the South West Queensland Pipeline (SWQP) may be reduced due to several factors, including the SWQP running at capacity*, lower Queensland production due to increased depletion of existing reserves, higher Queensland demand, favourable international LNG conditions, or no supply from Northern Territory via the Northern Gas Pipeline (NGP), including the possibility of reverse flow to the Northern Territory from Queensland. If sufficient Queensland gas is not made available to the southern states in response to supply tightening, the reliance on Iona UGS would increase and result in an elevated storage depletion risk.

[24] AEMC, Declared Wholesale Gas Market (DWGM) interim LNG storage measures, 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

Risk	Description
Liquefaction uncertainty	BOC's LNG liquefaction plant is used to fill APA's Dandenong LNG storage tank. The uncertainty around the liquefaction facility due to aging equipment poses a risk to refilling Dandenong LNG. APA is investigating options for liquefaction arrangements.

* SWQP linepack/capacity adequacy (LCA) was flagged as "Amber" on the Gas Bulletin Board (GBB) during certain periods in winter 2024, indicating that pipeline was flowing at full capacity.

Table 3 Updates on operational resilience risks

Risk	Description
Longford to Melbourne Pipeline operation	Longford Gas Plant 1 had no compression capability, whereas Gas Plants 2 and 3 have compression. The retirement of Gas Plant 1 is expected to enable Longford to maintain DTS injections at higher Longford to Melbourne Pipeline (LMP) pressures. This has enabled an increase in the available linepack in the LMP which has improved operational flexibility and enhanced the DTS's ability to respond to plant and equipment trips and unforecast increases in demand (particularly GPG) without materially impacting Longford operations.
Longford Gas Plant retirement delay	Gas Plant 3 retirement has been delayed, maintaining forecast Longford Gas Plant capacity at 700 TJ/d towards the end of 2028.
Ethane constraint	The Longford production system produces an ethane by-product stream that was used by a downstream customer that has since closed. Reduced customer ethane offtake constrained Longford production. GBJV has constructed a power generation facility at Hastings, adjacent to the Long Island Point facility, that consumes this ethane stream. The facility officially commenced operations in November 2024*.

* ExxonMobil, "Official opening ceremony of Esso Australia's Hastings Generation Plant", 12 November 2024, at https://corporate.exxonmobil.com/locations/australia/australia-newsroom/esso-community-outreach/2024/official-opening-ceremony-of-esso-australias-hastings-generation-plant.

Contents

1 Introduction

The VGPR is published every two years and assesses the adequacy of the Victorian DTS to supply peak day gas demand and annual consumption over a five-year outlook period. The most recent VGPR was published in March 2023. Due to material changes in the DTS and gas production and consumption forecasts, a VGPR Update was published in March 2024.

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

Definitions used in the VGPR

Demand describes hourly and daily usage of gas, and **consumption** refers to monthly and annual usage of gas.

Annual consumption for the DTS includes:

- System consumption (residential, commercial, and industrial customers, as well as compressor and heater fuel gas, and unaccounted for gas [UAFG]), and
- GPG 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. GPG demand is not included in system demand.

Total demand refers to the sum of system demand and GPG 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 a year (TJ/y) of gas.
- **Tariff D** – large commercial and industrial customers, each normally consuming over 10 TJ/y of gas.

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.

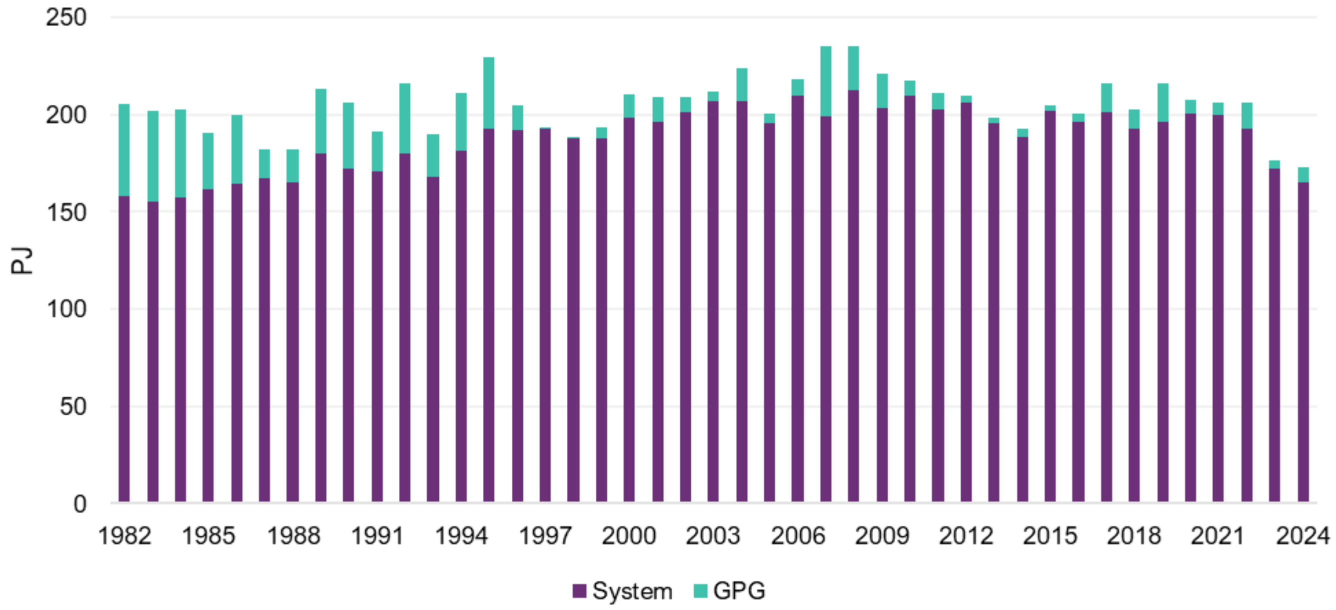
1.1 Review of Declared Transmission System gas consumption in 2024 and recent years

- **Victorian gas consumption has been decreasing**, due to a combination of electrification of residential loads, cost of living pressures, and declining commercial and industrial gas use.
- While **Victorian DTS peak day system demand has significantly decreased, total peak day demand has remained similar to historical levels**, due to an increase in winter peak GPG as the electrification of gas loads and transport has created higher winter electricity peaks.
- **Gas production has decreased more than demand, creating risks of Iona Underground Gas Storage (UGS) storage inventory depletion** that led to AEMO issuing threat notices in two of the last three winters.

1.1.1 2024 gas consumption and cumulative Effective Degree Days

Total DTS gas consumption in 2024 was 173 PJ, a further decrease from 177 PJ in 2023, which had experienced the largest year-on-year reduction since natural gas use began in Victoria in 1969. As **Figure 7** shows, 2024 had the lowest annual consumption for any year since at least 1982.

Figure 7 DTS annual consumption, 1982 to 2024 (PJ)



There were 13 occurrences in 2024 where DTS total demand exceeded 1,000 TJ (or 1 PJ), with the highest demand day of 1,120 TJ occurring on 31 July, comprising 965 TJ of system demand and 115 TJ of GPG. As **Figure 8** shows, Tariff V[25] and Tariff D[26] demand on peak days decreased with a step change in 2021, also

[25] Tariff D customers, which comprise of industrial and large commercial gas users, have an annual gas consumption of at least 10 TJ or an hourly consumption rate of more than 10 gigajoules per hour (GJ/h).

[26] Tariff V customers, which comprise of residential and small commercial gas users, are connections which do not meet the annual or hourly consumption rate of the Tariff D criteria.

reflected in reduced annual consumption, however on peak demand days system demand has been mostly replaced by demand from GPG, which has increased.

Figure 8 DTS peak day demand, 2019 to 2024 (TJ/d)

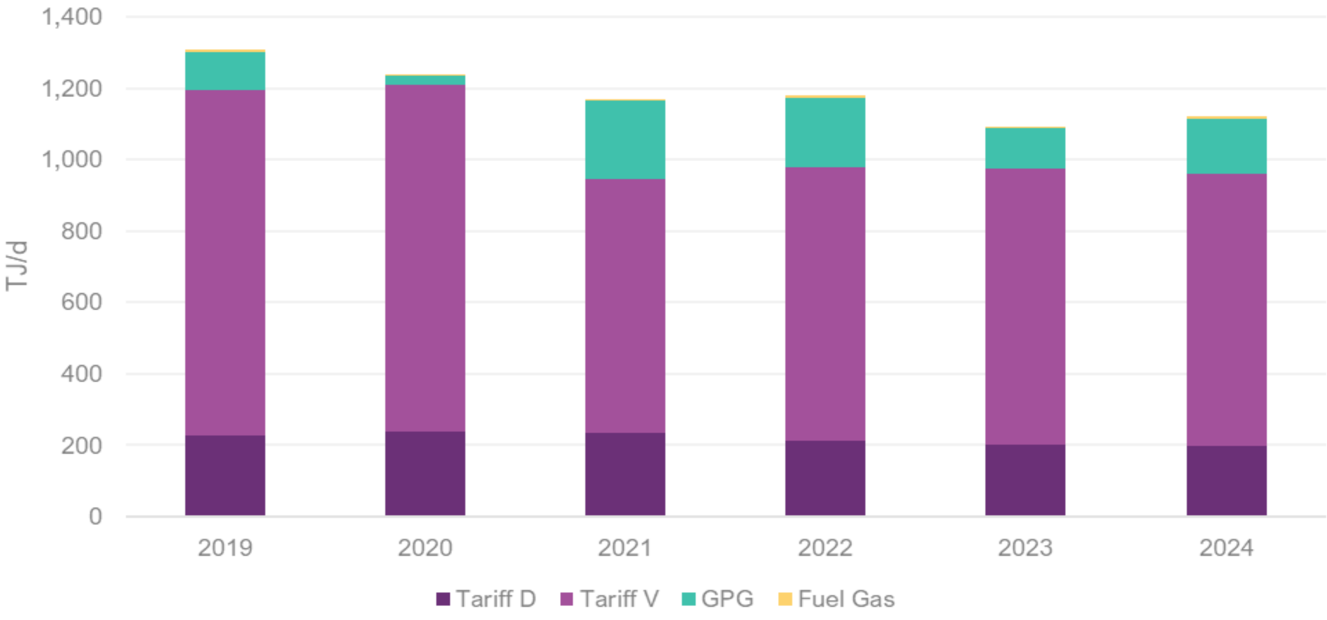
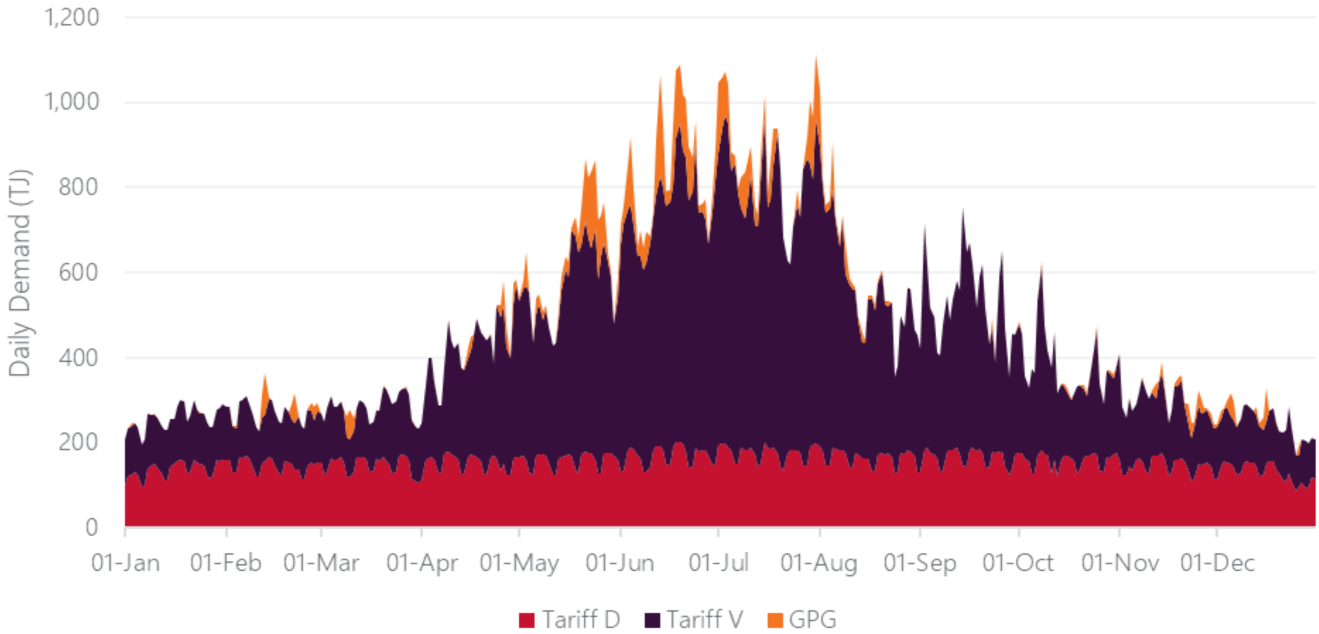


Figure 9 shows the daily DTS demand profile for 2024. The largest contributor to annual DTS consumption was Tariff V customers (62%), then Tariff D (33%) customers, GPG (5%) and fuel gas (<1%). While GPG comprised only 5% of annual DTS demand in 2024, it accounted for up to 14% of DTS demand on peak winter[27] days.

Figure 9 DTS daily demand profile, 2024 (TJ)



[27] Winter months include June, July, August

1.1.2 Historic Declared Transmission System gas consumption

Tariff V consumption

Tariff V customers – residential and small commercial gas users (using less than 10 TJ/y and less than 10 gigajoules per hour [GJ/h]) – have historically consumed the largest proportion of gas in the DTS (66% of DTS consumption in 2024).

Tariff V consumption, particularly for residential use, is largely driven by weather conditions and is typically correlated with EDD. Consequently, cumulative annual EDD or total monthly EDD can be used to correlate Tariff V consumption to the weather conditions experienced in the DTS at the time. This demand-EDD relationship is particularly strong for the peak demand months where the occurrence of non-zero EDD values is typically low.

Despite an increase in EDD during 2024 compared to 2023, Tariff V consumption decreased 4.5% compared to 2023, continuing the downward trend (**Table 4**). AEMO believes this is due to a combination of the electrification of gas loads, cost of living pressures and reduced commercial activity, however at this stage AEMO cannot quantify each of these components.

Table 4 Annual Tariff V consumption and cumulative EDD with year-on-year changes, 2019 to 2024

Year	EDD		Consumption (PJ)	
	Total	Year-on-year change	Total	Year-on-year change
2019	1,432.0		128.7	
2020	1,498.0	4.6%	132.6	3.0%
2021	1,471.6	-1.8%	131.8	-0.6%
2022	1,519.0	3.2%	130.6	-0.9%
2023	1,335.7	-12.1%	113.4	-13.1%
2024	1,355.7	1.5%	108.3	-4.5%

Tariff D consumption

Tariff D customers are large commercial and industrial users that consume more than 10 TJ/y or more than 10 GJ/h of gas. These customers typically have stable consumption profiles across a year, with their gas consumption often linked to economic conditions, and they are generally less sensitive to weather conditions than Tariff V customers. As noted in the 2023 VGPR and 2024 VGPR Update[28], DTS Tariff D consumption has been declining due to a combination of large industrial closures and the decrease in the number of businesses in Victoria[29].

Figure 10 shows the impact of these closures with annual Tariff D consumption decreasing from approximately 77 PJ in 2013 to 57 PJ in 2024, including large year-on-year consumption decreases of 5.91% and 4.1% in 2023 and 2024, respectively.

[28] 2023 VGPR, sections 1.1 and 2.1.2, at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2023/2023-victorian-gas-planning-report.pdf?la=en.

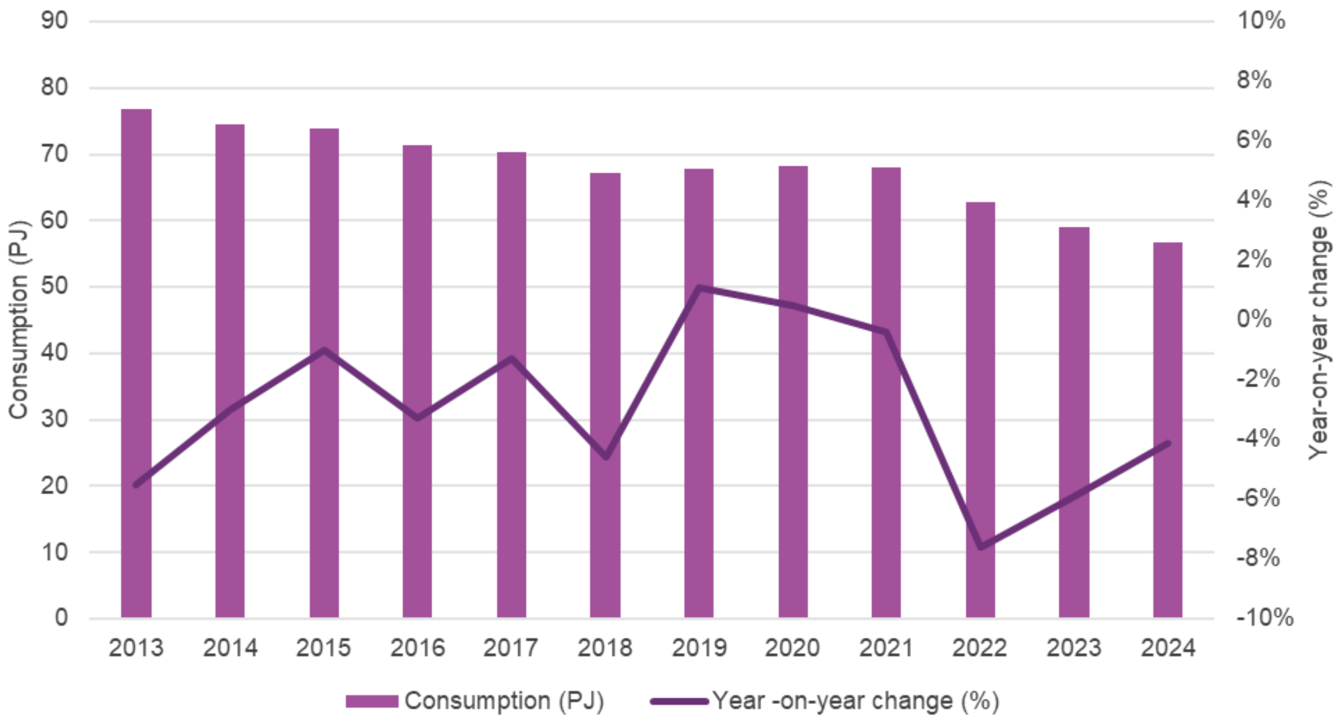
[29] Australian Bureau of Statistics, Counts of Australian Businesses, at https://www.abs.gov.au/statistics/economy/business-indicators/counts-australian-businesses-including-entries-and-exits/latest-release.

Aside from very small consumption increases in 2019, 2020 and 2021, the long-term trend has been a consistent reduction in Tariff D consumption for over a decade. Tariff D customers do not have to provide AEMO with advanced notice of expected closure, which makes modelling Tariff D demand difficult, but it is plausible that DTS Tariff D demand will continue to reduce due to a combination of electrification and energy efficiency but also plant closures.

Victoria has seen significant declines in manufacturing[30], and the majority of the demand reduction (11 PJ decrease from 2021 to 2024) appears to be due to:

- Plant closures of large heavy industries such as Qenos and the Altona refinery. Another industrial gas user, Oceania Glass, ceased production in February 2025.
- Dairy closures including Saputo, Murray Goulbourn, Fonterra and Lactalis facilities.
- Closures across the food manufacturing and paper industries.

Figure 10 DTS Tariff D annual consumption (PJ) and year-on-year percentage change, 2013-24



1.2 Winter 2024 challenges

The start of winter 2024 saw many simultaneous challenges in the Australian East Coast Gas Market, leading to tight supply and demand conditions.

Increased GPG demand, colder weather, and an extension of planned Longford maintenance led to a rapid emptying of Iona UGS storage inventory to supply southern states demand. This led to higher prices in June 2024

[30] See https://www.aumanufacturing.com.au/crisis-in-victorian-manufacturing-opposition-calls-for-action-amid-rising-insolvencies#:~:text=Victoria%20recorded%20the%20highest%20number,costs%20and%20extensive%20regulatory%20burdens.

compared to 2023, which experienced lower GPG demand and milder temperatures. The risk of Iona inventory depletion led to AEMO issuing an East Coast Gas System risk or threat notice on 19 June 2024.

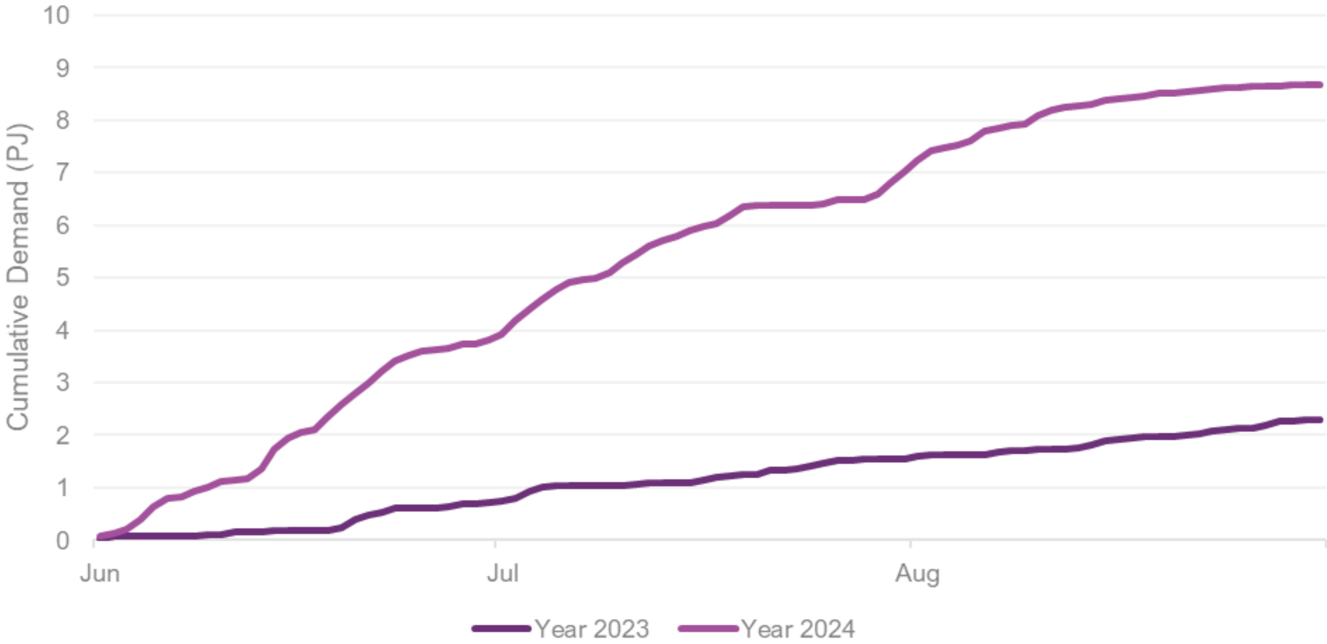
To offset decreased Gippsland production and increased GPG demand, Victoria saw an increase in supply from the Otway Gas Plant, including record flows on the recently expanded South West Pipeline (SWP), and record flows from Queensland on the recently expanded South West Queensland Pipeline (SWQP) into the southern states.

1.2.1 Tight supply-demand

Impact of reduced renewable generation and colder weather

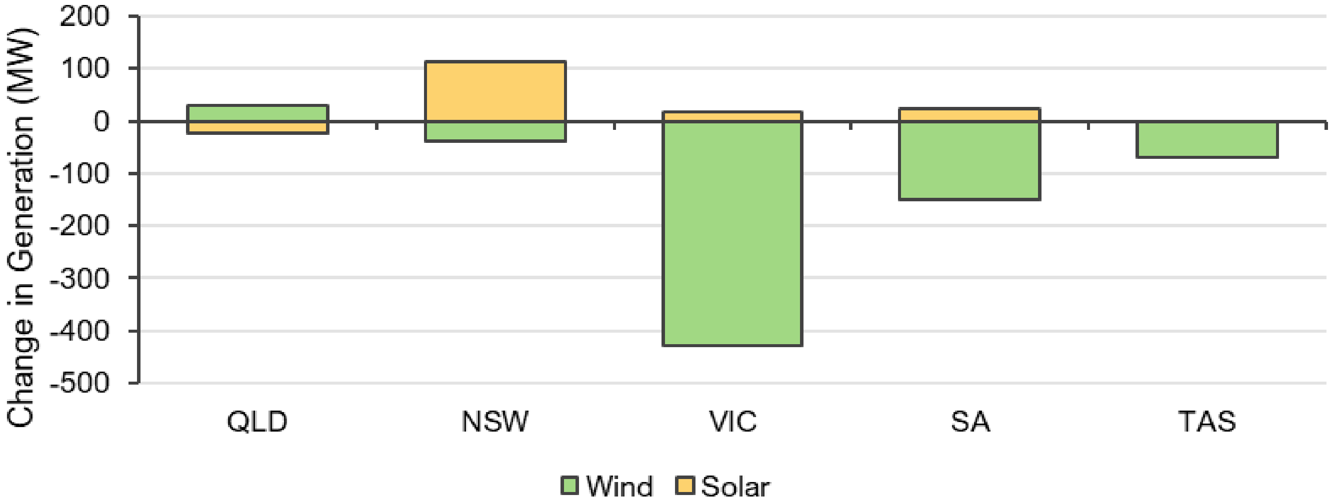
In winter 2024, Victorian GPG consumption was 8.6 PJ, up 274% from 2.3 PJ in winter 2023, as **Figure 11** shows. This increase was due to reduced wind and hydro generation, and higher National Electricity Market (NEM) demands. Victoria set a new winter record for daily GPG demand on 13 June 2024 of 356 TJ, the highest daily demand for any time of the year since 25 January 2019 when demand was 447 TJ. Total east coast GPG demand on 13 June was 911 TJ, also a new winter record.

Figure 11 Victorian gas generation winter 2023 and 2024



There was a notable decline in grid-scale VRE generation in Victoria in Q2 2024 compared to 2023, as shown in **Figure 12**.

Figure 12 Average change in VRE output by region – Q2 2024 vs Q2 2023 (megawatts [MW])



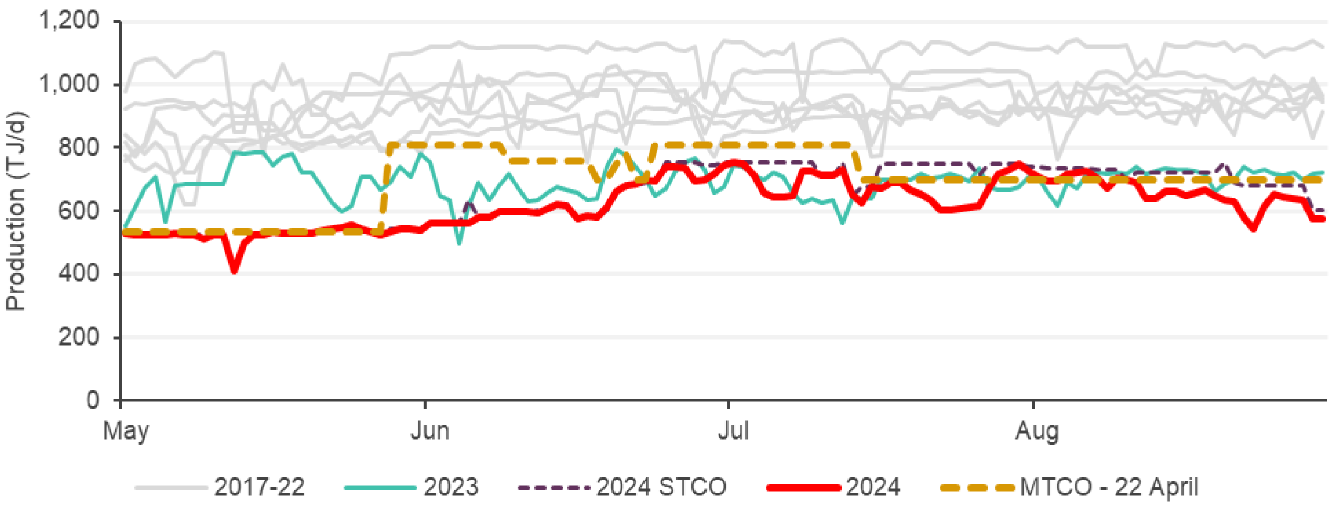
Longford production and capacity

The Longford Gas Plant has operated since 1969, beginning with one gas plant and expanding to a second in 1976 and a third in 1983, enabling daily production of at least 1,150 TJ/d and making it the largest gas production facility in Australia. Longford has played a critical role in supporting demand in Victoria, Tasmania and New South Wales. In October 2024 the original Gas Plant 1 was retired along with the Crude Stabilisation Plant (marking the end of Gippsland Basin crude oil production). This leaves only gas plants 2 and 3 operational, reducing Longford's maximum daily capacity to 700 TJ/d. AEMO has reported this decline in production since the 2018 VGPR Update.

Reflecting this decline, Longford's peak production and average daily production in 2024 was 756 TJ/d and 523 TJ/d respectively, with an average daily utilisation of 80.7%. This compares to an average of 584 TJ/d in 2023 and 937 TJ/d in 2017 when Longford had its record highest annual production of 345 PJ.

Longford's daily production leading up to winter and through most of June 2024 was lower than the same period in 2023, due to an unexpected extension of planned maintenance. **Figure 13** shows the medium-term capacity outlook (MTCO) on 22 April 2024 against actual capacity (dashed lines) and production (solid lines) during winter.

Figure 13 Impact of unplanned maintenance in June 2024 on Longford supply (TJ/d)



Longford's capacity was scheduled to increase to 775 TJ/d by the end of May 2024, but unplanned offshore issues delayed this increase, with Longford's production averaging 630 TJ/d in June, exacerbating the tight supply conditions experienced at the start of winter 2024. Capacity and production gradually increased through June and peaked at 742 TJ on 25 June 2024, after which scheduled Longford production was less than the short-term capacity outlook (STCO), indicating that there was sufficient supply available.

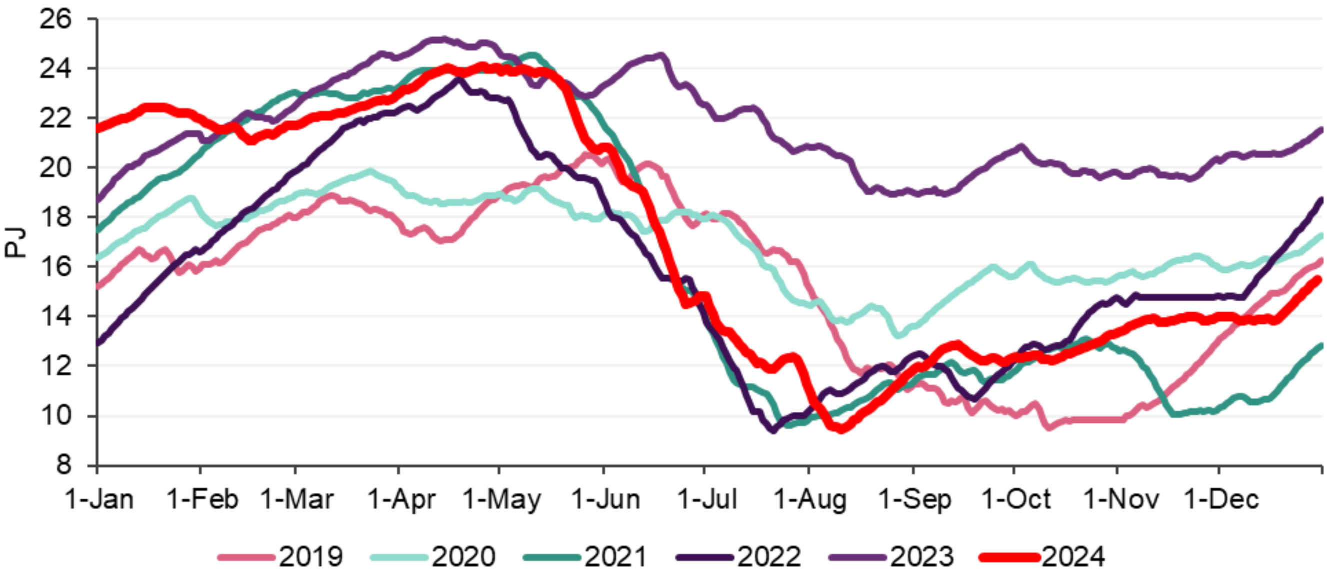
Record southern gas flows from Queensland

Q2 2024 saw 20.9 PJ flow south to Moomba from the SWQP, representing a new record for any second quarter. A daily SWQP southerly flow record was also observed, with a 559 TJ flow recorded from Wallumbilla into the SWQP on 4 June 2024, against an increased nameplate capacity of 512 TJ/dy. SWQP daily flows exceeded the previous record of 480 TJ (set in July 2021) on 14 occasions across May and June. The capacity of the SWQP has been expanded by approximately 25%, from 404 TJ/d in 2022, over the past two years.

Risk of Iona storage depletion

Iona UGS storage inventory followed a similar pattern to winter 2021 and 2022, with very fast depletion rates in June and early July due to colder weather reflecting higher demand, low renewables and high GPG demand, and delays with the completion of planned maintenance works at Longford. The second half of July and all of August saw an easing of these factors, including an increase in Longford supply, which enabled Iona storage levels to recover as shown in **Figure 14**.

Figure 14 Iona storage inventory, 2019 to 2024 (PJ)



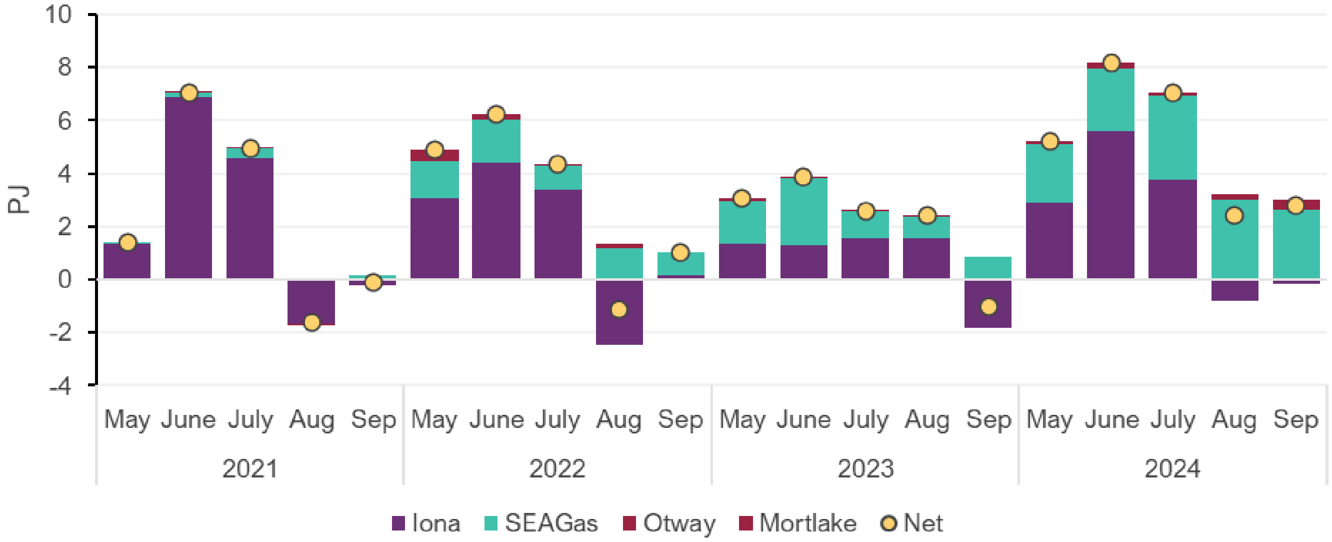
Iona supplied 2.7 PJ from storage between 17 June and 23 June 2024, a weekly record. This was driven by high GPG due to strong NEM electricity demand and low wind generation, combined with constrained gas supply from Longford. This occurred despite coinciding with record southerly flows on the SWQP.

These factors led to significant concerns about Iona UGS inventory depletion during winter 2024. The reservoir withdrawal capacity can start to decline when the storage inventory falls below 6 PJ, reducing the facility's supply capacity into the market.

Increase in Otway production leading to higher SWP flows

In June 2024, the Otway Gas Plant increased production due to the Enterprise gas field commencing production. This led to an increase in SWP flows towards Melbourne, which continued into August even when Iona began refilling storage inventory. Before this increase in Otway capacity, it was normal for the SWP to flow towards Port Campbell if Iona was refilling, as **Figure 15** shows.

Figure 15 Monthly flows on the South West Pipeline in May-September, 2021 to 2024 (PJ)



1.2.2 East Coast Gas System risk or threat notice

On 1 June 2023, AEMO's functions were extended in response to projected supply shortfalls in the East Coast Gas Market from winter 2023.

On 19 June 2024, AEMO issued an East Coast Gas System risk or threat notice due to the potential for gas supply shortfalls caused by the high rate of depletion of southern storage inventories, particularly Iona UGS (refer to Section 1.2.1). The notice was issued due to the risk that low or depleted storage inventory would result in reduced gas supply capacity in the southern jurisdictions.

AEMO requested the following response from industry to mitigate the threat:

- Producers (including Queensland producers), transmission pipeline operators, storage providers, shippers and market participants in the gas supply chain delivering gas to end users in the southern jurisdictions, to take reasonable measures to maximise production and supply from Queensland to the southern jurisdictions to reduce the rate of storage inventory depletion.
- Relevant entities (as defined in the National Gas Law [NGL]) to consider their demand requirements (including GPG) and sources of supply to meet that demand for the remainder of the winter period in the following locations:

- Offtakes located within the southern jurisdictions.
- Offtakers located on the SWQP and the Carpentaria Gas Pipeline

The East Coast Gas System threat or risk notice was revoked on 23 August 2024, as gas supply and demand trends had improved in New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania.

1.2.3 Higher Declared Wholesale Gas Market (DWGM) prices

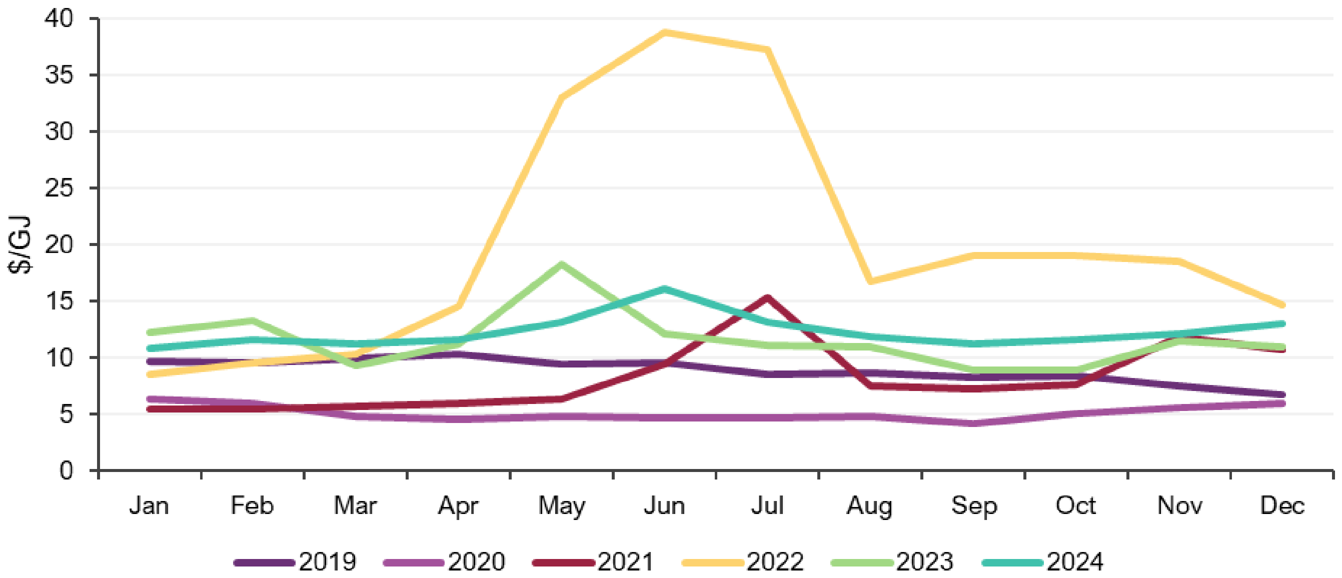
Periods of high DWGM prices during winter have occurred during the last few winters. During winter 2021, contributors to high prices included the Callide Power Station incident in Queensland, a Yallourn Power Station coal mine issue, and a three-week outage of Longford Gas Plant 3. Winter 2022 saw the Russian invasion of Ukraine and coal generation outages in New South Wales and Victoria. The DWGM price was set at the $40/GJ Administered Price Cap from 30 May until 1 August.

The biggest contributing factor to elevated DWGM prices in May 2023 was GPG demand. GPG demand eased in June 2023 when eastern Australia experienced above-average temperatures and coal-fired generation availability improved, which resulted in lower DWGM prices.

In contrast to 2023, in 2024 GPG began increasing from mid-May and increased again in June, leading to a very high draw down of Iona storage inventory and record levels of supply from Queensland to southern markets. DWGM prices increased considerably in June 2024, peaking at $28/GJ in the DWGM on 20 June.

Prices remained higher to start July, before easing slightly in August and September (**Figure 16**), reflecting above average temperatures across the east coast, reduced GPG, and less reliance on Iona to supply the market.

Figure 16 Average monthly DWGM price, 2019 to 2024 ($/GJ)

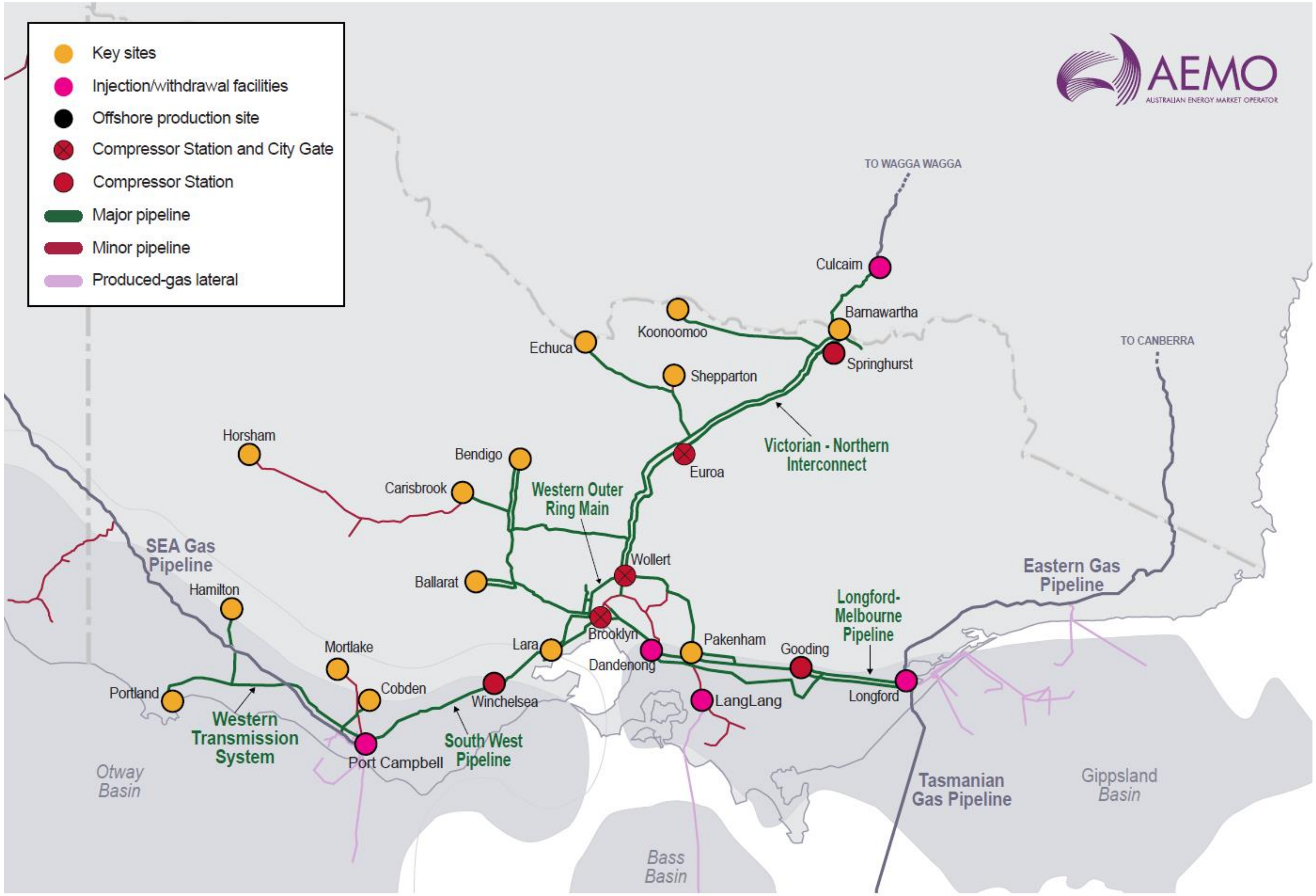


1.3 The Victorian Declared Transmission System

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 Port Campbell to Adelaide (PCA)).

Figure 17 is a high-level map of the Victorian gas transmission network, including the DTS and other gas transmission pipelines.

Figure 17 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 NGL and the National Gas Rules (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 and 324A, 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 year and 1-in-20 year 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% 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 GPG[31]. Under rule 323(3), AEMO is also required to assess the impact of gas generation demand on 1-in-2 peak system demand days.

[31] Total demand is the sum of system demand and GPG demand.

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.

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 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 consumption and demand forecasts

The gas consumption and demand forecasts for the 2025 VGPR, produced using the *Step Change* scenario, project decreasing system consumption and demand due to increasing electrification:

- **Annual DTS system consumption is forecast to decrease by 10.7% over the outlook period**, from 173 PJ in 2025 to 155 PJ in 2029
- **Annual DTS total consumption (which includes GPG) is forecast to decrease by 8.3% over the outlook period**, from 176 PJ in 2025 to 161 PJ in 2029.
- The **forecast peak day system demands** are:
  - 1,071 TJ/d for a 1-in-2 year system demand day in 2025, reducing by 12.0% to 942 TJ/d in 2029.
  - 1,156 TJ/d for a 1-in-20 year system demand day in 2025, reducing by 12.1% to 1,016 TJ/d in 2029.
- **Victorian GPG consumption is forecast to experience an initial decline from historical levels as renewable energy generation continues to be commissioned, before increasing due to coal retirements**:
  - Actual Victorian GPG consumption during 2024 was 14.9 PJ, which was much higher than the forecast of 2.8 PJ. Victorian GPG consumption is forecast to reduce to as low as 3.3 PJ in 2027. It is then forecast to increase in 2028, due to the planned retirements of Eraring coal power station in New South Wales and the Yallourn coal power station, reaching 11.9 PJ in 2029.
  - Beyond the outlook period, the 2024 *Integrated System Plan* (ISP) projects Victorian GPG capacity increasing from the existing 2.4 gigawatts (GW) to 3.6 GW during the 2030s, coinciding with the assumed shutdown of Victorian brown coal generators over the next decade.

2.1 Gas usage forecast

All forecasts in Chapter 2 are for **covered gas** including natural gas, biomethane and hydrogen. No breakdown is presented.

Scenario and sensitivity forecasts

The forecasts for the 2025 VGPR and the 2025 GSOO focus on the *Step Change* scenario outlined in the Draft 2025 IASR[32]. This scenario focuses on a large-scale energy transformation to support Australia's contribution to limiting global temperature rise below 2°C, aligning with international efforts. It is refined from the 2023 IASR *Step Change* scenario while maintaining that consumer investments in energy efficiency, electrification and distributed energy resources will remain strong. The scenario also considers ambitions in developing hydrogen associated opportunities, reflecting the economic challenges of establishing this new industry.

[32] At https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-inputs-assumptions-and-scenarios-report-stage-1.pdf?la=en.

Forecast GPG usage under the *Step Change* scenario shows a decreasing trend early in the VGPR outlook period, then an increasing trend due to planned coal generator retirements after 2027. AEMO also studied the impact of extended coal generator outages (similar to NEM system conditions in 2022) in a sensitivity, *High Coal Generation Outages*. Under this sensitivity, with coal generation reduced due to extended outages or fuel supply issues, GPG consumption could increase significantly during the outlook period.

Government policies and schemes update

The *Step Change* scenario requires continued policy incentives and ongoing investment to further facilitate electrification (switching from other fuels to electricity) and reduced gas consumption. Victoria's Gas Substitution Roadmap Update 2024[33] policy and schemes align with this requirement:

- A gas connection ban effective from 1 January 2024 which prohibits new homes and residential subdivisions that require a planning permit from connecting to gas networks.
- From 1 January 2025, a requirement for residential and developer applicants to pay a full upfront charge for new gas connections.
- Banning gas distribution businesses from offering incentives to connect residential buildings to gas or to purchase and install gas appliances.
- An extension to the end date of the Victorian Energy Upgrades (VEU) program from 2030 to 2045.
- Victorian Large Energy User Electrification Support, that provides funding for approved specialists to complete electrification feasibility assessments on commercial and industrial business facilities that use between 10 TJ/y and 100 TJ/y of gas per annum. Application to this program closed 20 August 2024[34].

In addition to the actions above, the Federal Government's Safeguard Mechanism will require most of Australia's largest emitters to reduce emissions by 4.9% each year to 2030[35].

The combination of these policies resulted in AEMO forecasting a 6.8% reduction in annual Victorian gas total consumption and 12% reduction in peak day system demand (excluding gas used for GPG) over the outlook period.

2.2 Annual consumption

Tariff V and Tariff D gas consumption forecasts are discussed in Section 2.2.1 and Section 2.2.2 below. Section 2.4 discusses drivers and uncertainties related to forecasts for gas generation consumption.

Under the *Step Change* scenario, annual DTS total consumption (Tariff V, Tariff D and GPG) is forecast to decrease by 8.3% over the outlook period, from 176 PJ in 2025 to 161 PJ in 2029, as shown in **Table 5** and **Figure 18**. The forecast decrease is driven by projected reduced gas use by residential, commercial and industrial customers, which is larger than the forecast increase in GPG consumption.

[33] At https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap/gas-substitution-roadmap-update-2024.pdf.

[34] At https://www.sustainability.vic.gov.au/grants-funding-and-investment/grants-and-funding/large-energy-user-electrification-support-program.

[35] At https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

The forecast decrease in system consumption from 173 PJ in 2025 to 161 PJ in 2028 represents a reduction of between 5% and 4% from the *Step Change* scenario forecast in 2024 VGPR Update across the five-year outlook period, which forecast system consumption of 182 PJ in 2025 and 167 PJ in 2028.

Tariff V consumption is forecast to decrease by 14.2% over the five-year VGPR outlook, from 120 PJ in 2025 to 103 PJ in 2029.

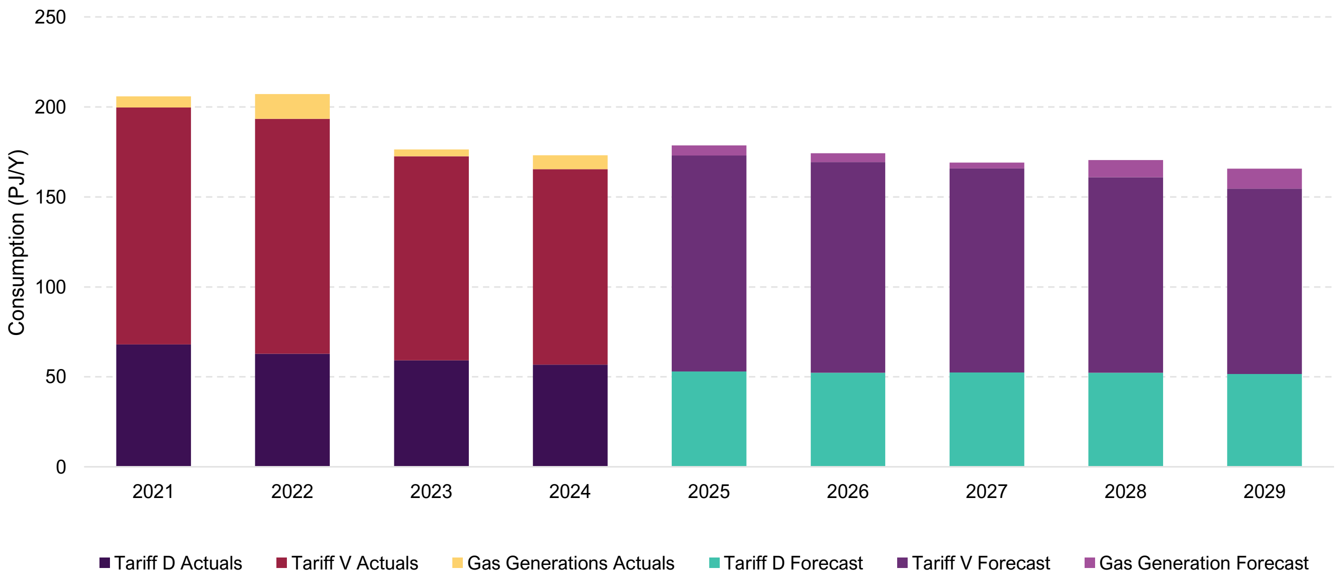
Tariff D consumption is predicted to reduce by 2.6% over the five-year VGPR outlook, from 53 PJ in 2025 to 51 PJ in 2029.

Table 5 Actual and forecast Victorian annual gas consumption, *Step Change scenario*, 2022-29 (PJ/y)

	Actual			Forecast					Change over outlook
	2022	2023	2024	2025	2026	2027	2028	2029	
Tariff V	130.6	113.4	108.3	120.1	117.0	113.4	108.7	103.0	-14.2%
Tariff D	62.8	59.2	56.8	53.0	52.3	52.4	52.3	51.6	-2.6%
System consumption	194.8	173.3	165.6	173.1	169.3	165.9	161.0	154.6	-10.7%
DTS GPG consumption	13.8	3.8	7.8	2.6	2.3	1.6	6.6	6.5	149.0%
DTS total consumption	208.6	177.1	173.4	175.7	171.7	167.4	167.6	161.1	-8.3%
Non-DTS system consumption	0.32	0.28	0.26	0.25	0.25	0.24	0.24	0.23	-8.1%
Non-DTS GPG consumption	6.9	3.6	7.1	3.0	2.6	1.7	5.2	5.4	78.7%
Victorian GPG consumption	20.7	7.4	14.9	5.6	4.9	3.3	11.9	11.9	111.2%
Total Victorian consumption*	215.8	181.0	180.7	179.0	174.5	169.4	173.1	166.8	-6.8%

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 GPG consumption at Bairnsdale and Mortlake.

Figure 18 Actual and forecast total annual gas consumption, *Step Change* scenario, 2021 to 2029 (PJ/y)



2.2.1 Tariff V consumption

The forecast decline of Tariff V (residential and small commercial) consumption, shown in **Figure 19**, is driven by cost of living pressures, the uptake of fuel-switching via electrification, reduced commercial activity and, to a lesser degree, energy efficiency savings under the VEU scheme that was expanded to cover electric induction cooktops, and the Home Heating and Cooling Upgrades Program packages.

It is anticipated that the electrification of gas load will lead to a permanent reduction in gas usage. While reductions in gas consumption due to cost of living pressures and decreased commercial activity are considered elastic, there remains some uncertainty regarding any recovery of gas consumption if these pressures ease. This uncertainty, coupled with recent mild winters, has resulted in a higher gas Tariff V consumption forecast for 2025 compared to actual consumption in 2024.

The Victorian gas connection ban policy in place since 1 January 2024 will also contribute to continued reduction in forecast consumption. This reduction is accounted for in the forecast with increased electrification expected as more new homes are covered by this policy (that is, they are required to have a planning permit).

While these policy initiatives are forecast to reduce gas consumption for both residential and small commercial customers, continuing the forecast reduction to realise the level of electrification assumed under the *Step Change* scenario would require sustained strong policy incentives and significant industry investment.

Figure 19 Actual and forecast DTS Tariff V consumption, *Step Change* scenario, 2021 to 2029 (PJ/y)

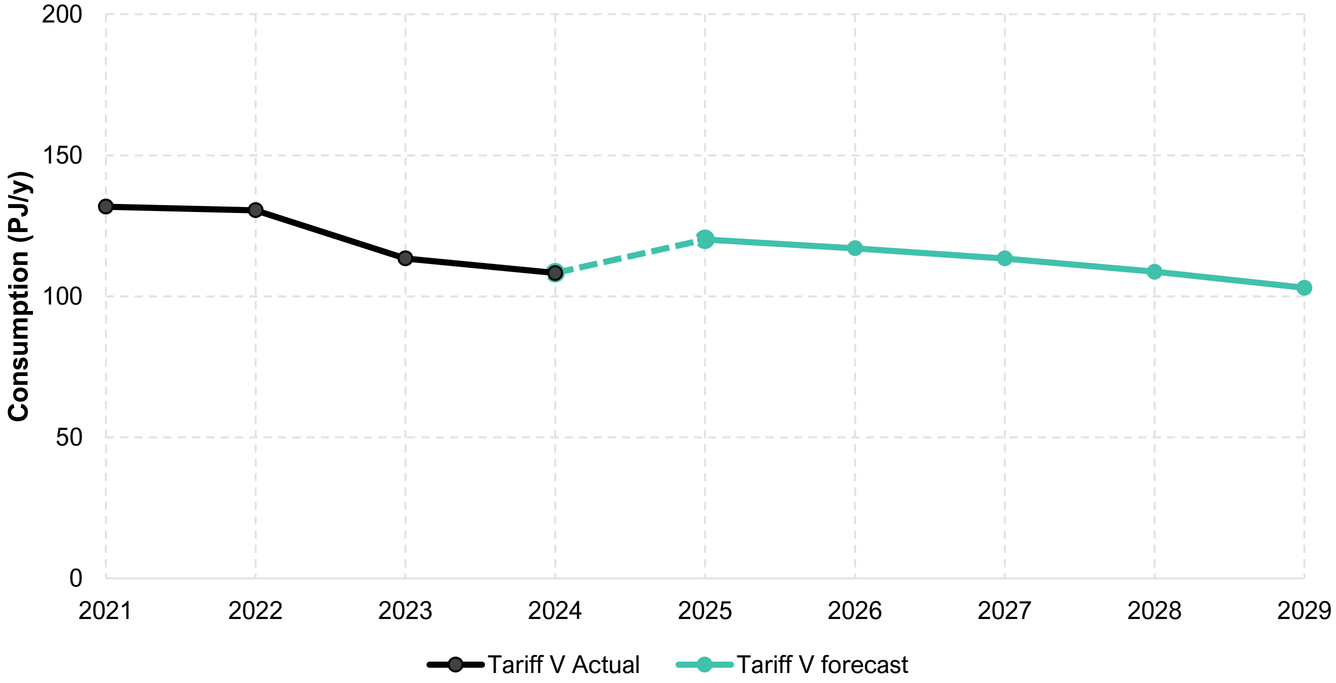


Table 6 shows projected Tariff V consumption by System Withdrawal Zone (SWZ) for the *Step Change* scenario:

- There is a significant forecast reduction in Tariff V consumption across all zones expect the Gippsland zone. Forecast consumption in the Gippsland zone remains relatively flat and experiences a small reduction of 2.5% over the outlook period, due to expected new connections in housing estates in the region which already have approved planning permits.

- Tariff V consumption in the Ballarat, Geelong and Northern zones is forecast to decline by between 7.2% and 11.0% over the outlook period. The projected decrease is due to the projected lower number of new connections already approved in these regions being offset by the adoption of electrification and the government policies described above.
- The Western and Melbourne zones have forecast Tariff V reductions of 20.6% and 16.7% respectively, the highest forecast reduction of all zones over the outlook period as these zones have no identified new builds that could facilitate additional new residential gas connections.

Table 6 Actual and forecast annual Tariff V consumption by System Withdrawal Zone, *Step Change* scenario, 2024 to 2029 (PJ/y)

	2024 (Actual)	2025	2026	2027	2028	2029	Change over outlook
Ballarat	8.2	8.9	8.8	8.6	8.3	7.9	-11.0%
Geelong	10.0	11.0	10.8	10.6	10.3	9.8	-11.0%
Gippsland	5.3	6.2	6.2	6.2	6.1	6.0	-2.5%
Melbourne	75.3	82.1	79.5	76.5	72.7	68.4	-16.7%
Northern	8.3	10.8	10.7	10.6	10.3	10.0	-7.2%
Western	1.1	1.2	1.1	1.0	1.0	0.9	-20.6%
DTS Tariff V system consumption	108.3	120.1	117.0	113.4	108.7	103.0	-14.2%
Non-DTS Tariff V system consumption	0.2	0.16	0.16	0.15	0.15	0.14	-12.6%
Total Victorian Tariff V	108.6	120.3	117.2	113.6	108.9	103.2	-14.2%

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

2.2.2 Tariff D consumption

Tariff D (large commercial and industrial) consumption is forecast to remain steady at near current consumption levels throughout the outlook period across all zones, expect for the Melbourne zone which has a forecast reduction of 4.2% largely due to the closure of Qenos. As **Table 7** shows, total Victorian Tariff D consumption is projected to decline by 2.6% over the outlook period. This is similar to the forecast in the 2024 VGPR Update, which projected a decline in annual Tariff D consumption of 2.1% over the report's outlook period.

Over the next five years, large commercial and industrial customers are not expected to commence large-scale electrification of their processes, due to complexities associated with electrifying heat-intensive processes.

Tariff D customers are not required to provide AEMO with advance notice of expected closures, which adds complexity to modelling Tariff D consumption. It is plausible that Tariff D gas use could continue to reduce across the DTS as demonstrated by the decline in recent years, which is discussed in Section 1.1.2.

Table 7 Actual and forecast annual Tariff D consumption by System Withdrawal Zone, *Step Change* scenario, 2024 to 2029 (PJ/y)

	2024 (Actual)	2025	2026	2027	2028	2029	Change over outlook
Ballarat	1.6	1.3	1.2	1.3	1.3	1.3	-0.3%
Geelong	9.1	8.8	8.8	8.8	8.9	8.8	-0.2%
Gippsland	5.9	6.7	6.6	6.7	6.6	6.5	-2.0%
Melbourne	28.4	26.2	25.6	25.6	25.4	25.1	-4.2%
Northern	8.9	7.5	7.5	7.5	7.5	7.4	-1.5%
Western	2.8	2.5	2.5	2.6	2.6	2.5	0.4%
DTS Tariff D system consumption	56.8	53.0	52.3	52.4	52.3	51.6	-2.6%
Non-DTS Tariff D system consumption	0.10	0.1	0.1	0.1	0.1	0.1	-0.6%
Total Victorian Tariff D	56.8	53.0	52.4	52.5	52.3	51.7	-2.6%

2.3 Peak day demand

This section reports annual DTS peak day system demand forecasts (excluding GPG forecasts) over the outlook period, and monthly peak day gas demand forecasts for the year January 2025 to December 2025.

2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 peak day system demand forecasts display a similar declining trend to the annual consumption forecast, with a 12% reduction forecast over the outlook period, as shown in **Table 8**. This is driven by the uptick in forecast electrification under the *Step Change* scenario that significantly impacts Tariff V peak day demand, which declines by 14.2% for both 1-in-2 and 1-in-20 peak day over the outlook period.

This is a larger reduction in peak day system demand forecast than in the 2024 VGPR Update, which forecast a decrease from 2024 to 2028 of 11.1% and 11.2% for 1-in-2 and 1-in-20 peak days, respectively. Similar to the annual consumption forecasts, the peak day demand forecasts in the 2025 VGPR indicate a gradual decline in the early years, followed by a more pronounced decrease in the later stages of the outlook period, driven by assumptions regarding the timing of the electrification of gas networks, including the impact of the Victorian gas connection ban policy.

Table 8 Forecast annual peak day system demand, 2025 to 2029 (TJ/d)

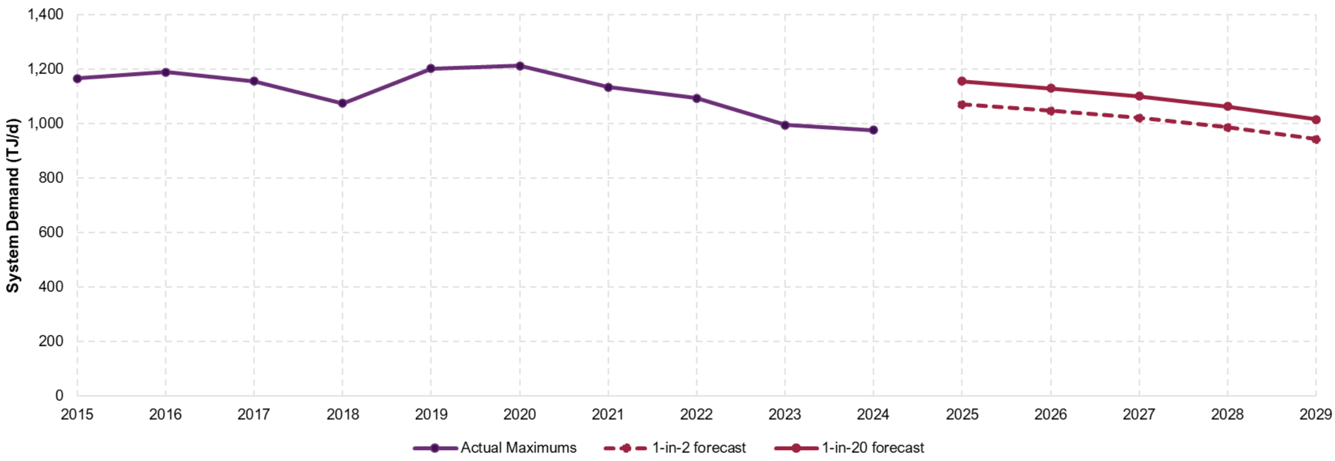
		2025	2026	2027	2028	2029	Change over outlook
1-in-2 peak day	Tariff V	868	845	819	787	745	-14.2%
	Tariff D	203	202	202	200	197	-2.7%
	System demand	1071	1047	1021	987	942	-12.0%
1-in-20 peak day	Tariff V	945	921	891	854	810	-14.2%
	Tariff D	211	209	210	210	205	-2.8%
	System demand	1156	1130	1101	1064	1016	-12.1%

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

As **Figure 20** shows:

- The peak day demand forecasts represent a decrease compared to historical levels from 1,071 TJ/d forecast for 1-in-2 peak day, and 1,156 TJ/d for a 1-in-20 peak day in 2025, down to 942 TJ/d and 1,016 TJ/d respectively in 2029.
- The 2024 peak system demand of 974 TJ/d was Victoria's lowest winter peak day system demand since 2001, and marked the second subsequent year with a peak system demand below 1,000 TJ/d. This peak occurred on 3 July 2024 and was consistent with the broader lower consumption trend during 2024, driven by the factors described in Section 1.1.2.

Figure 20 Actual and forecast peak day maximum system demand, 2015 to 2029 (TJ/d)



2.3.2 Monthly peak day system demand for 2025

Table 9 shows the forecast peak day system demand for each month during 2025 for the *Step Change* scenario. The actual peak system demand day is forecast to occur during the three coldest winter months: June, July and August.

Table 9 Forecast monthly peak day demand for 2025 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day	361	378	425	622	861	1,015	1,047	1,000	839	691	570	406
1-in-20 peak day	421	442	532	744	981	1,107	1,144	1,102	953	798	702	498

2.4 Gas-powered generation forecasts

GPG is forecast to play a crucial role in complementing energy storage capacity (battery and pumped hydro) to support peak electricity demand periods when the output from VRE generation is limited, including during extended periods of low sunlight and wind (renewable droughts) as experienced during the winters of 2022 and 2024. The 2024 ISP forecasts the critical need for peaking GPG increasing during the winter months of June, July and August, representing a shift from historical summer GPG peaks to increased winter demand peaks through to 2040.

The 2025 VGPR and the 2025 GSOO forecasts align with the optimal development path (ODP) identified in the 2024 ISP [36]. Following the closure of the Eraring coal power station in New South Wales (currently announced to retire on 19 August 2027), and the closure of Victoria's Yallourn coal power station (currently announced to retire on 1 July 2028), GPG requirements are forecast to increase, resulting in an overall increase during the outlook period.

As GPG is varied and depends on actual weather conditions as well as generator and electricity network outages, AEMO produces GPG forecasts for a variety of scenarios and sensitivities that account for a range of weather patterns and generator outages.

The GPG peak demands for the five-year outlook period are expected to gradually decline by approximately 42% over the first three years from 2025 to 2027, followed by a steep increase of 175% to a maximum forecast of 528 TJ/d and 562 TJ/d in winter 2028 and 2029 respectively, driven by the closure of Eraring and Yallourn power stations. GPG demand peaks during summer months are forecast to increase by 33%, from 205 TJ/d in 2025 to 282 TJ/d in 2029.

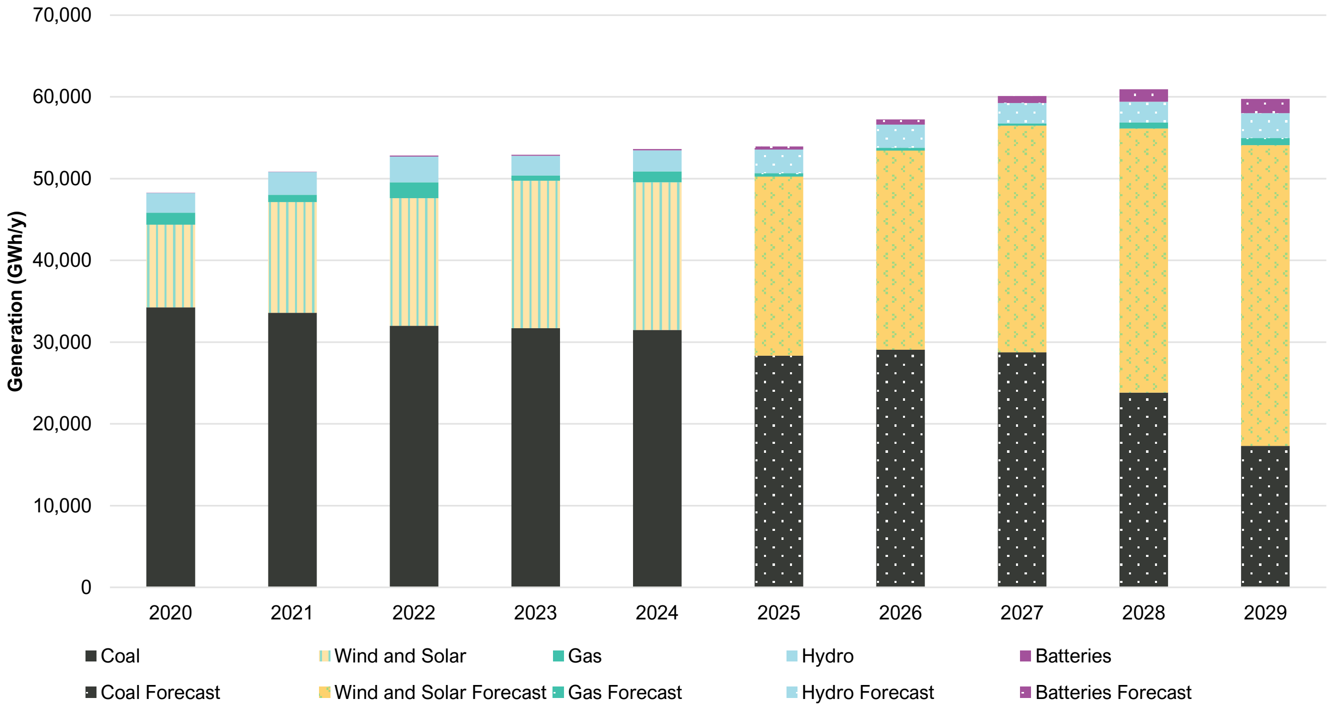
The 2024 ISP highlights the generation, firming and electricity transmission infrastructure required to meet the emissions reductions targets set by Australian governments. The amount of gas required for GPG in the next decade will be influenced by the timing of coal generator closures in the NEM. Victorian coal generators are assumed in the *Step Change* scenario to progressively shut down over the next decade. The 2024 ISP forecasts Victorian GPG capacity needing to increase from the existing 2.4 GW to 3.6 GW during the 2030s, which is expected to lead to new GPG connections in the Victorian DTS. The supportability and availability of gas supply to these new generator connections would depend on which parts of the DTS they connect to and from where the new gas supplies are sourced. The 2025 GSOO discusses GPG consumption and demand forecasts up to 2044.

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

- **Timing of installation of renewable energy projects** – the 2024 ISP forecasts a large amount of large-scale and behind-the-meter VRE being commissioned in Victoria from 2025, as shown in **Figure 21**. If forecast VRE investments are delayed or do not proceed, GPG gas consumption is likely to be higher than in **Table 10** (in the next section).
- **Weather variability** – GPG 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 GPG consumption are presented in Section 2.4.1.
- **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. If the completion of these projects is delayed, Victorian gas generation consumption is likely to be higher than reported in Table 10.

[36] The gas generation forecasts differ marginally to those presented in the 2024 ISP report. The least-cost dispatch assumptions applied in core ISP modelling is replaced with assumptions regarding updated coal retirements, generator bidding, operational constraints, new generating capacity build timelines, transmission augmentation timelines, and availability of other generators to predict GPG consumption more accurately. The forecasts in the GSOO are also primarily presented on a calendar year rather than a financial year basis. For more information see Generation Information - July 2024, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/nem-generation-information-july-2024.xlsx and NEM Transmission Augmentation Info - August 2024, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Figure 21 Actual and forecast Victorian electricity generation, *Step Change* scenario, 2020 to 2029 (gigawatt hours per year [GWh/y])



2.4.1 Annual gas-powered generation consumption forecast

Figure 22 shows actual annual Victorian GPG consumption from 2021 to 2024, and the GPG consumption forecasts from 2025 to 2029 for the *Step Change* scenario and a *High Coal Generation Outages* sensitivity. The maximum and minimum forecasts in this figure relates to forecast variability due to weather. The average GPG forecast for all scenarios is presented in Table 10.

The figure and table show the following key points:

- Victorian GPG consumption is forecast to decline slightly in 2025 and 2027, then increase in 2028 and 2029. From the lowest level of 3.3 PJ average in 2027, consumption is forecast to ramp up to an average of 11.9 PJ in 2028. This results in forecast Victorian GPG consumption increasing over the outlook period by 111.2%.
- The reduction in forecast GPG consumption early in the outlook period (to 2027) is influenced by increasing solar and wind generation, and energy storage capacity.
- Weather uncertainty and coal generator retirements create a broad range in forecast annual GPG consumption, particularly later in the outlook period (2028 to 2029).
- Extended coal generation outages significantly increase the potential GPG forecast resulting in a peak of 20.6 PJ in 2027, relative to 4.6 PJ in the *Step Change* scenario in the same year. The GPG consumption peak forecast for the outlook period is in 2029 at 29.5 PJ, under the *High Coal Generation Outages* sensitivity.
- The increase in forecast GPG consumption over the outlook period is influenced by the increased electrification in the *Step Change* scenario, which results in higher electricity consumption during winter. GPG is forecast to be required to support winter electricity demand during extended periods of low solar and wind generation.

Figure 22 Actual and forecast range of annual Victorian GPG consumption forecasts, *Step Change* scenario and *High Coal Generation Outages* sensitivity, 2021 to 2029 (PJ)

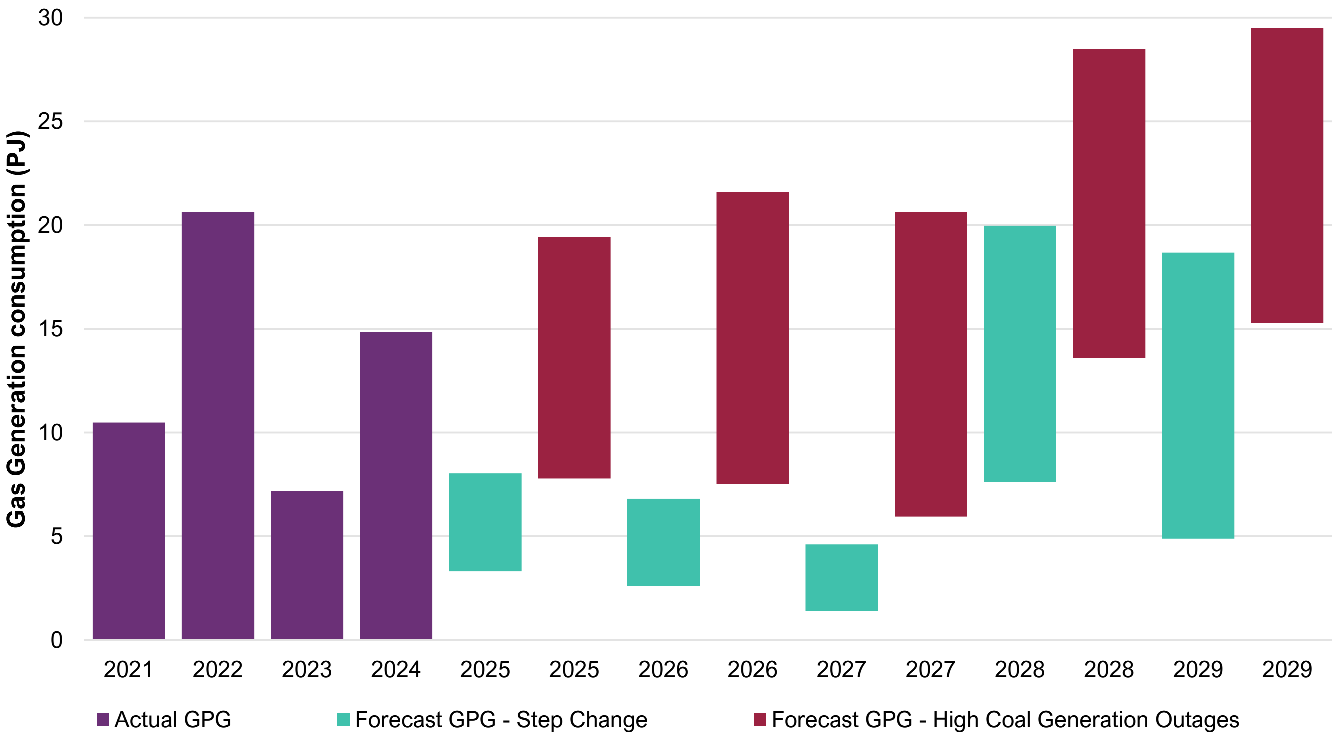


Table 10 Actual and forecast average annual Victorian GPG consumption forecasts, 2024 to 2029 (PJ)

	2024 (Actual)	2025	2026	2027	2028	2029	Change over outlook
DTS GPG consumption	7.8	2.6	2.3	1.6	6.6	6.5	149.0%
Non-DTS GPG consumption	7.1	3.0	2.6	1.7	5.2	5.4	78.7%
Victorian GPG consumption	14.9	5.6	4.9	3.3	11.9	11.9	111.2%
Victorian GPG consumption (*High Coal Generation Outages* sensitivity)	-	14.4	14.5	13.4	23.1	22.8	59.1%

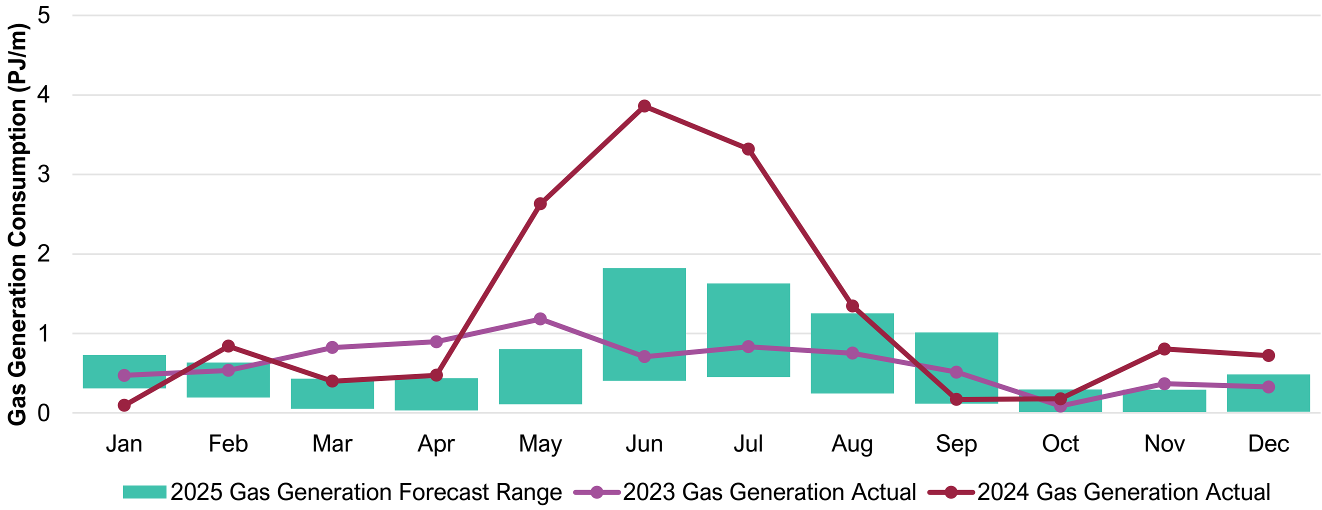
Note: totals and change over outlook percentage may not add up due to rounding.

2.4.2 Monthly gas-powered generation forecast for 2025

Figure 23 shows actual monthly Victorian GPG consumption in 2023 and 2024, and the forecast monthly consumption range for 2025.

Monthly GPG consumption is usually higher during winter, with the potential to coincide with a 1-in-2 or 1-in-20 peak day winter system demand likely to result in very high total demand conditions. The forecast shows that monthly GPG consumption in 2025 is projected to be higher during the winter months relative to the summer period, driven by a combination of higher NEM demand and lower VRE output (particularly solar). Coal generation outages during winter continue to be a risk, which could drive GPG consumption much higher than this forecast.

Figure 23 Actual and forecast monthly Victorian GPG consumption, 2023 to 2025 (PJ/m)

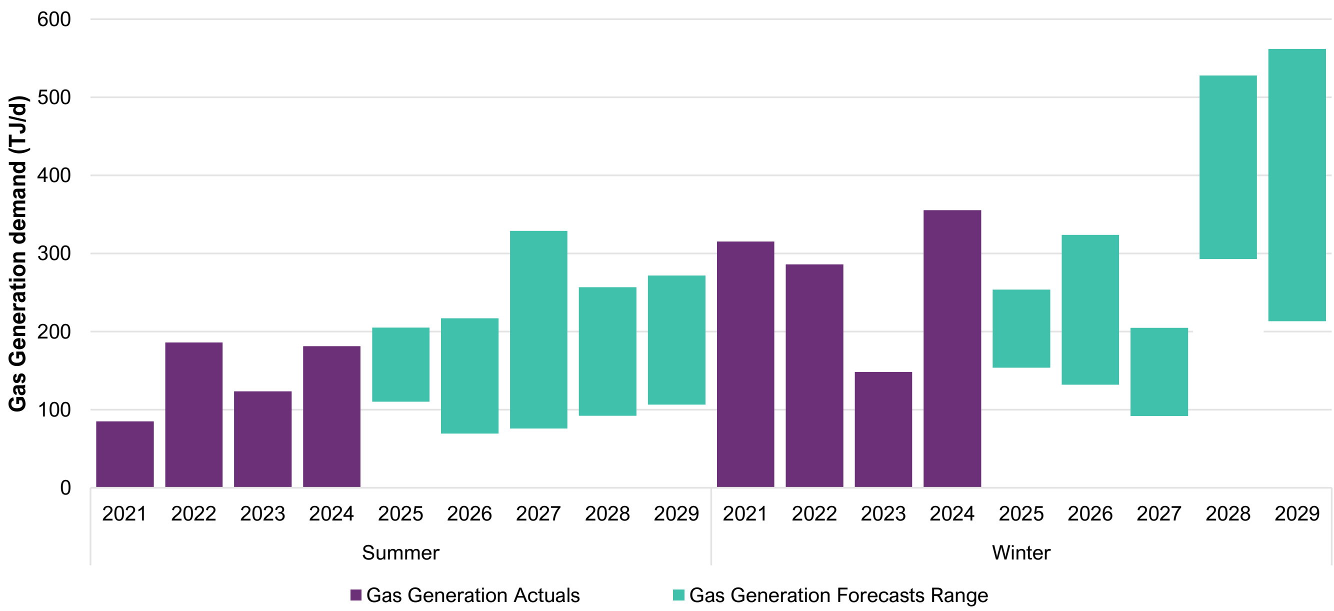


2.4.3 Seasonal peak gas-powered generation demand forecast

Peak GPG demand in winter is predicted to increase by approximately 121% over the outlook period, from a forecast maximum of 254 TJ/d in 2025 to 562 TJ/d in 2029. Annual increases in forecast peak GPG demand vary between 6% (summer 2025 to summer 2026) and 158% (winter 2027 to winter 2028). This increase in forecast GPG demand (and consumption) corresponds to the planned retirement of Eraring and Yallourn coal power stations during the outlook period, as well as the expected electrification of winter heating loads resulting in increased winter electricity demand.

Figure 24 shows seasonal peak forecasts where summer GPG peak demand forecast is comparatively lower than winter peak demand forecasts.

Figure 24 Actual and forecast range of seasonal maximum and minimum peak Victorian GPG demand, summer and winter, 2021 to 2029 (TJ/d)



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

Due to the entry of increased renewable and energy storage capacity into the market, winter 2027 is forecast to have lower GPG demand. However, forecast GPG demand increases from 2028 and peaks for the outlook period in winter 2029, with wider variance between the minimum and maximum forecast peak GPG demand. This highlights the expected increased reliance on GPG following coal power station retirements during periods of lower renewable generation output, particularly in winter.

In 2029, the forecast winter maximum peak GPG demand of 562 TJ/d is 108% higher than the forecast summer maximum of 272 TJ/d. The seasonal peak gas generation has the potential to coincide with a peak system demand day, especially during winter when there is high demand for heating and production from solar generation usually reduces. If winter system demand in 2029 is above approximately 800 TJ/d – which is less than the 1-in-2 peak day system demand forecast for that year – total demand would exceed the current DTS total demand record of 1,308 TJ/d set on 9 August 2019, and exceed the forecast DTS supply capacity of 895 TJ/d.

3 Gas supply adequacy

Victorian annual production outlook continues to decline:

- Forecast 2025 Victorian production has fallen from 296 PJ in the 2024 VGPR Update to 257 PJ, a 39 PJ (13%) reduction. Production is forecast to reduce 37% during the outlook period to 162 PJ in 2029.
- The reduced forecast production in 2025 is mainly due to lower forecast Gippsland production, reducing 16% from 235 PJ in the 2024 VGPR Update to 198 PJ. The main causes are longer duration Longford planned maintenance, and production impacts associated with Turrum Phase 3 project mobilisation.
- From 2027 to 2029, the available Gippsland production forecast is higher than in the 2024 VGPR Update, primarily due to increased Longford volumes from the now committed Kipper Stage 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves. These reserves remain available due to lower than forecast production in 2023 and 2024, driven by lower gas consumption. This also enabled the deferral of the Longford Gas Plant 3 retirement from December 2027 to December 2028.
- Port Campbell production during the outlook period is forecast to be lower than in the 2024 VGPR Update, predominantly due to reduced Enterprise and Thylacine North reserves.

An **annual supply shortfall is identified in 2029**, one year later than identified in the 2024 VGPR Update. Compared to last year's forecast, the projected surplus for 2025 is 30% lower (from 111 PJ to 78 PJ) and for 2026 is 14% lower (from 84 PJ to 72 PJ), while the total forecast surplus supply in 2027 and 2028 is higher (from 38 PJ to 64 PJ in 2027 and increasing from a 22 PJ shortfall to a 40 PJ surplus in 2028), removing the supply gap forecast for 2028 in the 2024 VGPR Update.

GBJV has advised AEMO of Turrum Phase 3 project activities, which require a full depressurisation of the Marlin B production platform during mobilisation of the jack-up rig. The activities are planned for a two-week window in September 2025, during which low Longford production capacity is expected. AEMO will continue to work with GBJV on the timing of the activity.

Expected peak day supply capacity to the DTS, including from storage facilities, is forecast to decline by 31% from 1,296 TJ/d in 2025 to 895 TJ/d in 2029. This is due to volumes from the Turrum Phase 3 project and the reprofiling of forecast Gippsland Basin production, and the Gas Plant 3 closure at Longford Gas Plant being delayed by one year, allowing an increase in available peak day production capacity for winter 2028.

Peak day supply adequacy gaps are identified in both 1-in-2 and 1-in-20 system demand days in 2029, despite a forecast 12% reduction in Victorian peak day system demand across the outlook period. Peak day supply adequacy gaps identified in the 2024 VGPR Update for a 1-in-20 peak day for 2027 and both 1-in-2 and 1-in-20 peak days for 2028 no longer exist, primarily due to increased Gippsland Basin production. Supply adequacy is forecast to remain tight, with Dandenong LNG potentially required to support a 1-in-20 peak day in 2028 or even low levels of GPG on a peak day. There is a high shortfall risk for unexpected conditions including unforecast demand increases (particularly GPG) and unplanned supply restrictions.

More supply for Victoria is required and the timely completion of committed supply projects and the progression of potential supply sources is critical.

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[37]. Supply from storages and pipeline constraints are not considered.
- **Seasonal (winter) monthly consumption (1 June to 31 August inclusive)** – a seasonal supply demand imbalance indicates that the combined supply from Victorian production and Iona UGS (deep storage) facilities, and from interconnected pipeline (imports from New South Wales via Culcairn) is projected to be insufficient to meet forecast winter consumption[37]. Depletion of gas storage inventory and pipeline capacity constraints are considered for this analysis.
- **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[38] on a peak day. Supply from Iona UGS and Dandenong LNG (shallow storage) as well as pipeline capacity constraints are considered.

Gas supply classification

Table 11 defines the gas supply classifications[39] used in this 2025 VGPR. This includes notes on the differences between the classifications in the 2025 GSOO and the Petroleum Resources Management System (PRMS)[40].

Table 11 Gas supply classifications

VGPR	2025 VGPR description	PRMS	GSOO
Existing supply	Comprises facilities that are already in operation and injecting to the transmission/distribution network.	Reserves: On Production	Existing supply
Committed supply	Developments or projects which have: • Ability to provide firm commencement date[A]. • Successfully passed a final investment decision (FID). • Finalised and executed commercial contracts. • Obtained all necessary planning approvals. • Progressing through the EPC (engineering, procurement, and construction) 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

[37] Inclusive of system and GPG consumption.

[38] Excluding GPG demand.

[39] Updated Project Commitment Classification Classes (consulted in Gas Wholesale Consultative Forum (GWCF) held on 5 June 2024 - Meeting #43, under business agenda "Update to GSOO/VGPR project classifications".

[40] 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	2025 VGPR description	PRMS	GSOO
Anticipated supply	Developments or projects which have: • Ability to provide firm commencement date[A]. • Have not reached FID but a firm date for FID has been provided. • Secured upstream supply contracts[B] for the outlook period. • Finalised legal proceedings for land acquisition. • Firm contractual agreements including the supply of gas, tolling arrangements, storage or transport services with customers[B]. • Midstream infrastructure/connection agreement established. • All necessary environment and planning approvals have been approved. • Detailed engineering works completed. Preferably early construction preparation work has been started where applicable.	Reserves: Justified for Development	Anticipated supply
Potential projects	Publicly announced projects that are going through early engineering studies but have not met one or more criteria in anticipated category.	Contingent Resources: Development Pending, Development on Hold, Development Unclarified	Uncertain supply

A. Date the facility is fully operational and ready for commercial usage.
B. Such as feedstock for renewable gases, FSRU contract for LNG regasification terminal, electrolyser procurement, renewable power supply (where applicable).

3.1 Changes impacting the supply demand balance

This section highlights updates to key projects that have impacted the supply demand balance since the publication of the 2024 VGPR Update (more details on the ongoing projects are in Section 4.1):

- **Enterprise and Thylacine** – an evaluation conducted by Beach Energy for Enterprise and Thylacine North reservoirs shows that pressures are declining faster than expected, indicating a smaller resource pool than initially anticipated[41], impacting the available supply quantity from the Port Campbell region from 2026 onwards. Beach Energy's connection of the nearshore Enterprise-1 well and the two remaining Thylacine West wells to the Otway Gas Plant were completed in June 2024[42] and October 2024[43] respectively. This returned the Otway Gas Plant to its nameplate capacity of 205 TJ/d. These projects were already classified as committed in the 2024 VGPR Update.
- **Kipper Compression** – GBJV completed the Kipper Compression project in October 2024, increasing offshore supply to the Longford Gas Plant in the Gippsland region[44].

[41] Beach Energy,"2024 Annual Report", 12 Aug 2024, at https://beachenergy.com.au/wp-content/uploads/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

[42] Beach Energy, "First gas from the Enterprise field", 13 June 2024, at https://announcements.asx.com.au/asxpdf/20240613/pdf/064jhcfqfvvv28.pdf.

[43] Beach Energy, "First gas from Thylacine West", 25 October 2024, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1557782/BPT_First_gas_from_Thylacine_West.pdf.

[44] ExxonMobil, "Esso Australia delivers crucial project for Australian natural gas supplies", 18 October 2024, at https://corporate.exxonmobil.com/locations/australia/australia-newsroom/news-releases/2024/esso-australia-delivers-crucial-project-for-australian-natural-gas-supplies.

- **Kipper Stage 1B** – the KUJV will drill a third subsea well in the Kipper field as part of the Kipper Stage 1B project. The project will increase gas available from the Kipper field for processing at Longford from mid-2026.
- **Turrum Phase 3** – this GBJV project consists of a five well development in the Turrum and North Turrum fields. It is expected to add additional gas supply for processing through the Longford Gas Plant prior to winter 2027.

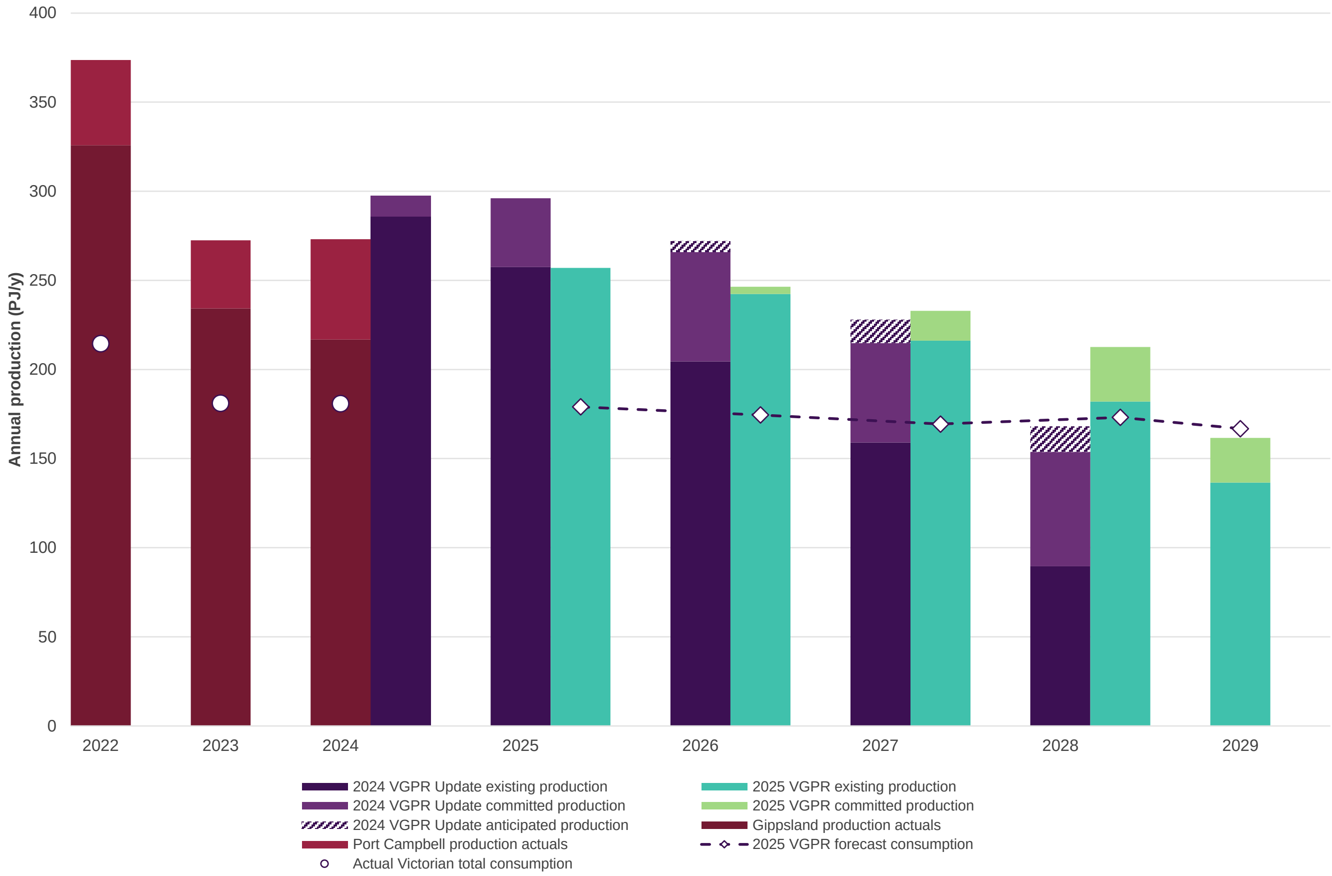
3.2 Annual supply demand balance

This section discusses the reported Victorian annual gas supply and its forecast adequacy during the outlook period. This assessment 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 25 shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2024 VGPR Update.

Figure 25 Actual and forecast supply and total consumption, and compared to the 2024 VGPR Update, 2022 to 2029 (PJ/y)



Gippsland[45]

The 2024 VGPR Update projected total available Gippsland region production for 2024 to be 243 PJ, while actual production was 217 PJ. This lower production reflects reduced overall consumption and market participant behaviour, rather than a constraint on available production capacity noting that May and June Longford production was impacted by an unplanned extension of a planned pre-winter maintenance outage.

Compared to the 2024 VGPR Update, forecast Gippsland production in 2025 is 16% lower (from 235 PJ to 198 PJ) and in 2026, it is 2% lower (from 196 PJ to 191 PJ). This is mainly due to longer duration of planned maintenance, and the impacts on production associated with Turrum Phase 3 project mobilisation activities.

From 2027 to 2029, the available production forecast is higher than in the 2024 VGPR Update, primarily due to volumes from the Kipper Stage 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves. These reserves remain available due to lower than forecast production in 2023 and 2024, driven by lower gas consumption (refer to Section 1.1 for review of DTS gas consumption). This also enabled the deferral of the Longford Gas Plant 3 retirement from December 2027 to December 2028.

Overall Gippsland available production is forecast to drop by 36% over the outlook period, from 198 PJ in 2025 to 127 PJ in 2029, mainly due to the forecast decrease in production associated with the decline of GBJV and KUJV fields that supply the Longford Gas Plant. This forecast includes supply from the Kipper Compression project which came online in October 2024, the committed Kipper Stage 1B project which will add supply from winter 2026 and the committed Turrum Phase 3 project which will add supply prior to winter 2027.

Despite the additional supply from the committed Kipper Stage 1B and Turrum Phase 3 projects, Victorian annual consumption is forecast to exceed production in 2029. There are currently no anticipated projects in the Gippsland region.

Potential Gippsland region projects that could increase the production forecast include the Late Life Optimisation projects at the Longford Gas Plant, development of the Trefoil field to supply the Lang Lang Gas Plant, the Manta field for the Orbost Gas Plant, and the Golden Beach production and storage facility. Project updates are discussed in Section 4.1.

Port Campbell[46]

In 2024, total Port Campbell region production was 56 PJ, which aligned with the total available production forecast in the 2024 VGPR Update. The completion of the Enterprise-1 well and the connection of the two remaining Thylacine West wells returned the Otway Gas Plant to its nameplate capacity of 205 TJ/d.

Over the outlook period, Port Campbell production is expected to decline, and by 2029, production is forecast to be 41% lower than in 2025 (reduction from 59 PJ in 2025 to 35 PJ in 2029), which is a steeper decline than in the 2024 VGPR Update (18%). This reduction is primarily due to revised Otway Basin reserve numbers following

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

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

Beach Energy's evaluation of Enterprise and Thylacine North, where pressures are declining faster than expected, indicating a smaller resource pool than initially anticipated[47].

Additional investment will be required to reduce this production decline. Potential projects include Amplitude Energy's East Coast Supply Project (ECSP) and Beach Energy's Artisan field development, both discussed in Section 4.1.

Woodside, Amplitude Energy, Beach Energy and ConocoPhillips have formed a consortium as operators to secure a drilling rig for planned drilling and decommissioning campaigns in the Otway Basin from 2025. This is discussed in Section 4.1.

3.2.2 Annual supply adequacy

Table 12 shows the annual supply adequacy forecast over the outlook period, which indicates:

- Forecast available supply exceeds forecast consumption for most of the outlook period, with surplus Victorian production, ranging between 78 PJ in 2025 and 40 PJ in 2028, being available to supply New South Wales, South Australia, and Tasmania.
- Compared to the 2024 VGPR Update, the surplus quantities forecast for 2025 and 2026 have dropped by 30% (from 111 PJ to 78 PJ) and 14% (from 84 PJ to 72 PJ) respectively. The total surplus quantities forecast in 2027 and 2028 have been increased (from 38 PJ to 64 PJ in 2027 and from a 22 PJ shortfall to 40 PJ surplus in 2028), eliminating the supply gap in 2028 forecast in the 2024 VGPR Update. This is due to the production shifts discussed in Section 3.2.1.
- Victorian annual consumption is forecast to exceed available supply in 2029 by 5 PJ, creating a forecast supply gap one year later than reported in the 2024 VGPR Update.

[47] Beach Energy, Annual Report 2024, 12 Aug 2024, at https://beachenergy.com.au/wp-content/uploads/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

Table 12 Victorian annual available supply and anticipated supply balance, 2025-29 (PJ/y)

Supply source		2025	2026	2027	2028	2029
Gippsland [A]	Existing	**198**	**187**	**170**	**142**	**102**
	Committed	0	4	17	31	25
	Total available	**198**	**191**	**187**	**173**	**127**
	Anticipated	0	0	0	0	0
	Total available plus anticipated	198	191	187	173	127
Port Campbell [B]	Existing	**59**	**56**	**46**	**40**	**35**
	Committed	0	0	0	0	0
	Total available	**59**	**56**	**46**	**40**	**35**
	Anticipated	0	0	0	0	0
	Total available plus anticipated	59	56	46	40	35
Total Victorian production	Existing	**257**	**242**	**216**	**182**	**137**
	Committed	0	4	17	31	25
	Total available	**257**	**246**	**233**	**213**	**162**
	Anticipated	0	0	0	0	0
	Total available plus anticipated	257	246	233	213	162
Total Victorian consumption [C]		**179**	**175**	**169**	**173**	**167**
Surplus quantity with Victorian available supply		**78**	**72**	**64**	**40**	**-5**

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, Eastern Gas Pipeline (EGP) and Tasmanian Gas Pipeline (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 GPG demand.

Seasonality and interconnection with other jurisdictions

The annual adequacy assessment is limited due to variation in production and consumption throughout the year:

- During the summer months, Victorian production is higher than Victorian consumption, with the excess gas used to refill Iona UGS and supply other jurisdictions.
- If Victorian consumption exceeds production, especially during the winter months, Iona UGS is used to support increased Victorian gas usage, with supply also continuing to other jurisdictions during winter.
- Monthly (seasonal) adequacy is discussed in Section 3.3.

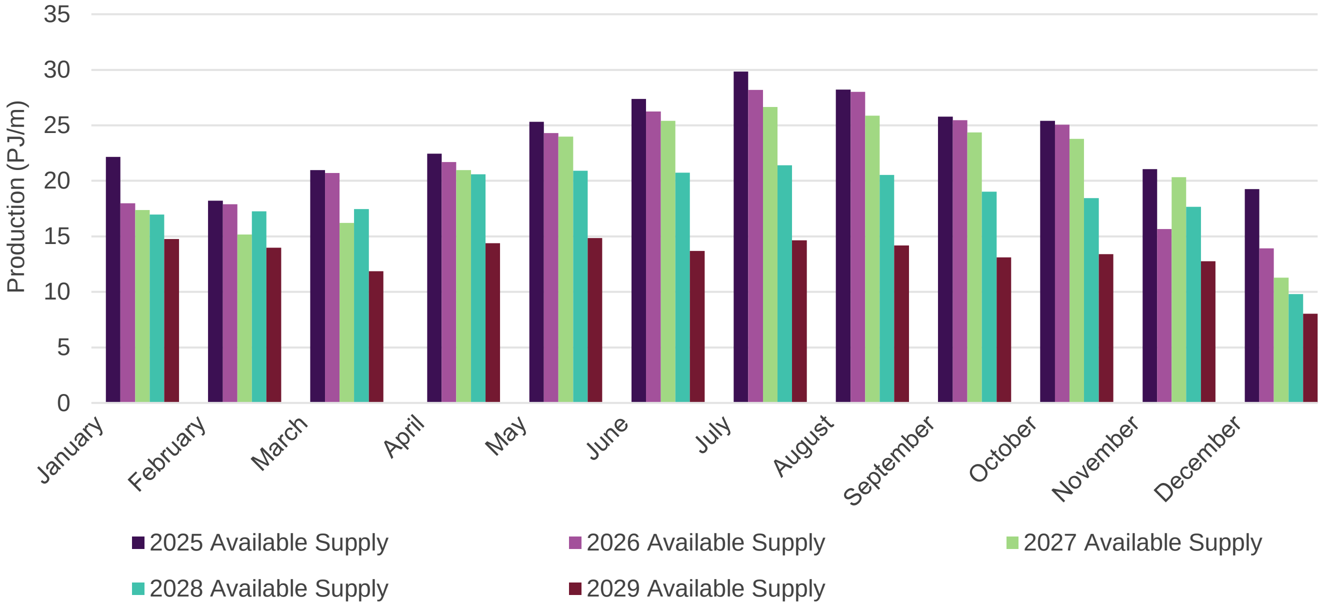
3.3 Monthly supply demand balance

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.

3.3.1 Monthly production forecasts

Figure 26 shows forecast monthly production for the outlook period.

Figure 26 Monthly production forecast, 2025 to 2029 (PJ/m)



It highlights that:

- The overall seasonal production fluctuation, with higher quantities produced in the winter months[48], reflects increased winter gas consumption.
- Forecast monthly gas production is expected to decline over the outlook period, with supply levels dropping across all months. By 2029, there is a notable decline in available supply.
- Timely delivery of committed supply is crucial in keeping the seasonal supply balanced (storage refill in summer and winter adequacy). Delays in project developments could exacerbate shortfalls.
- There is no forecast anticipated production during the outlook period.
- GBJV has advised AEMO of Turrum Phase 3 project activities planned to take place post-winter 2025 which will reduce Longford Gas Plant production capacity. More detail and impact of the activities is discussed in sections 3.3.2 and 3.3.3.

3.3.2 Monthly supply adequacy

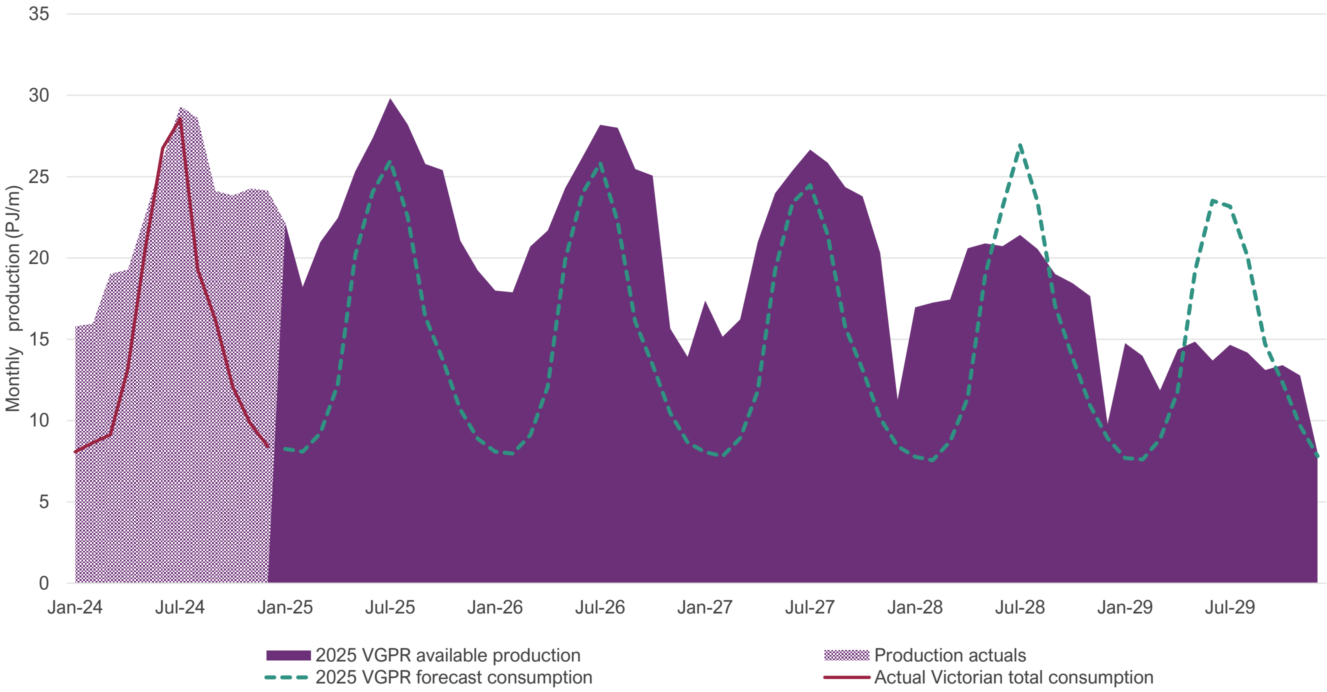
Monthly Victorian production has historically peaked during winter, as Longford Gas Plant production has been able to increase in line with the seasonal demand profile. Most other production facilities operate with a flatter production rate all year, with production limited by either the processing capacity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

Figure 27 analyses actual monthly total consumption and available supply in 2024, and forecast monthly available and anticipated Victorian production, against the forecast total consumption[49], over the five-year outlook period.

[48] Winter months include June, July, August.

[49] Inclusive of system and GPG consumption.

Figure 27 Actual and forecast monthly supply and total consumption, *Step Change* scenario, 2024 to 2029 (PJ/m)



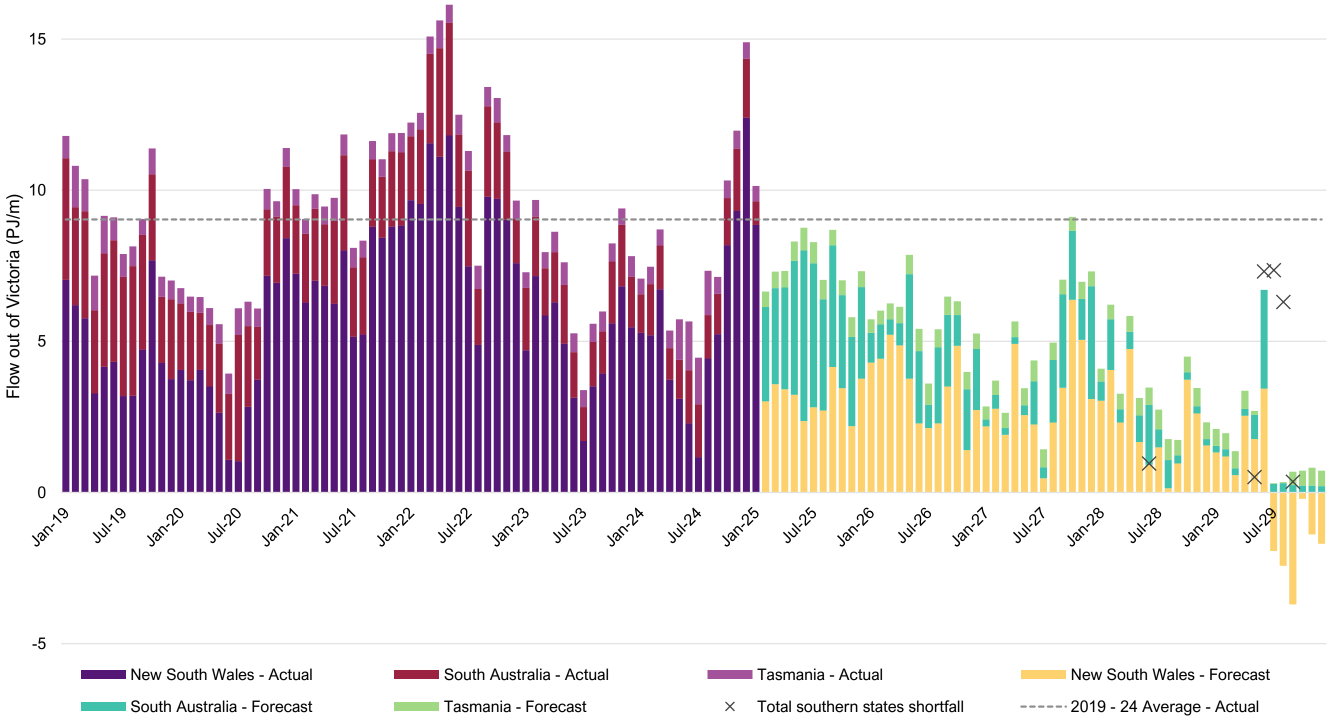
Note: The consumption is the total of annual system consumption and average GPG consumption forecast.

Key observations on monthly supply adequacy are:

- Historically, total Victorian monthly production exceeded total consumption. Monthly Victorian GPG consumption in 2024 peaked (3.9 PJ in total) in June, primarily due to low renewable electricity generation output, and represented 14.5% of June 2024 total consumption (26.8 PJ). Victorian supply was tight during that period, resulting in draw down of Iona storage early in winter and leading up to the East Coast Gas System potential threat notice on 19 June 2024 discussed in Section 1.2.2. In the outlook period, Victorian supply remains tight with Longford production declining, and should similar market scenarios of prolonged high gas usage occur, the state would continue to rely heavily on storage, especially during winter months, and will potentially lead to a threat notice being issued.
- GBJV has advised AEMO of Turrum Phase 3 commissioning activities, which are expected to require a full depressurisation of the Marlin B production platform during mobilisation of the jack-up rig. The activities are planned in a two-week window in September 2025, during which low Longford production capacity is expected. AEMO will continue to work with GBJV on the timing of the activity. Refer to Section 3.3.3 for more detail of the impact on Longford Gas Plant production capacities in 2025.
- From 2028, forecast Victorian production shows a flatter profile, as opposed to the historical trend of production ramping up for winter demand. The low summer production (including extended maintenance outages) could impact southern storage refilling, increasing the risks of winter seasonal shortfalls with flatter seasonal production profiles. However, these forecasts are less certain for later years due to the uncertainty introduced by potential production projects.

Figure 28 shows actual monthly flows out of Victoria to neighbouring states from January 2019 to January 2025, and the forecast flow out of Victoria from February 2025 to December 2029. The forecast flows are from modelling performed for the 2025 GSOO, which considered demand across the entire east coast and pipeline flows between states. The modelling assumed that all production facilities and transmission assets would be available at forecast capacities and included supply from committed and anticipated projects.

Figure 28 Actual and forecast flows out of Victoria, 2019 to 2029 (PJ/m)



Note: A sudden spike in exports in June 2029 represents the GSOO model trying to resolve southern states shortfall surges. Actual exports will depend on Iona storage levels and actual production capacities during that time.

As the figure shows:

- The actual flow out of Victoria is generally high, with peaks during the winter months. Most of the flow is towards New South Wales and South Australia, while Tasmania has a smaller but consistent offtake.
- Forecast flows indicate a significant reduction in total gas flow out of Victoria compared to historical levels, especially during winter, reflecting the forecast decline in Victorian production. Victoria is on a trajectory to become a net importer of gas from 2029 as Victorian consumption is forecast to exceed Victorian production and available storage inventory (unless potential Victorian supply and storage projects are developed).
- Historical levels of exports from Victoria to South Australia are forecast to be maintained for longer than exports to New South Wales. The flow to Tasmania remains similar, because Tasmania has no alternate supply source. The sustained high flows out of Victoria combined with declining Victorian production highlights the southern states' increasing reliance on Iona UGS, even with supply from Queensland maximised. Complete utilisation of Iona UGS would mean there is no longer a supply buffer to cover unplanned outages or unforecast increases in Victorian demand. Utilising all Iona UGS inventory also means that the peak day supply capacity provided by the Iona facility is substantially reduced.
- The 2025 GSOO highlights the peak day shortfall risk and seasonal supply gaps in the southern states[50] in 2028 under sustained high gas usage conditions. From 2029, a structural need for new gas supply is required

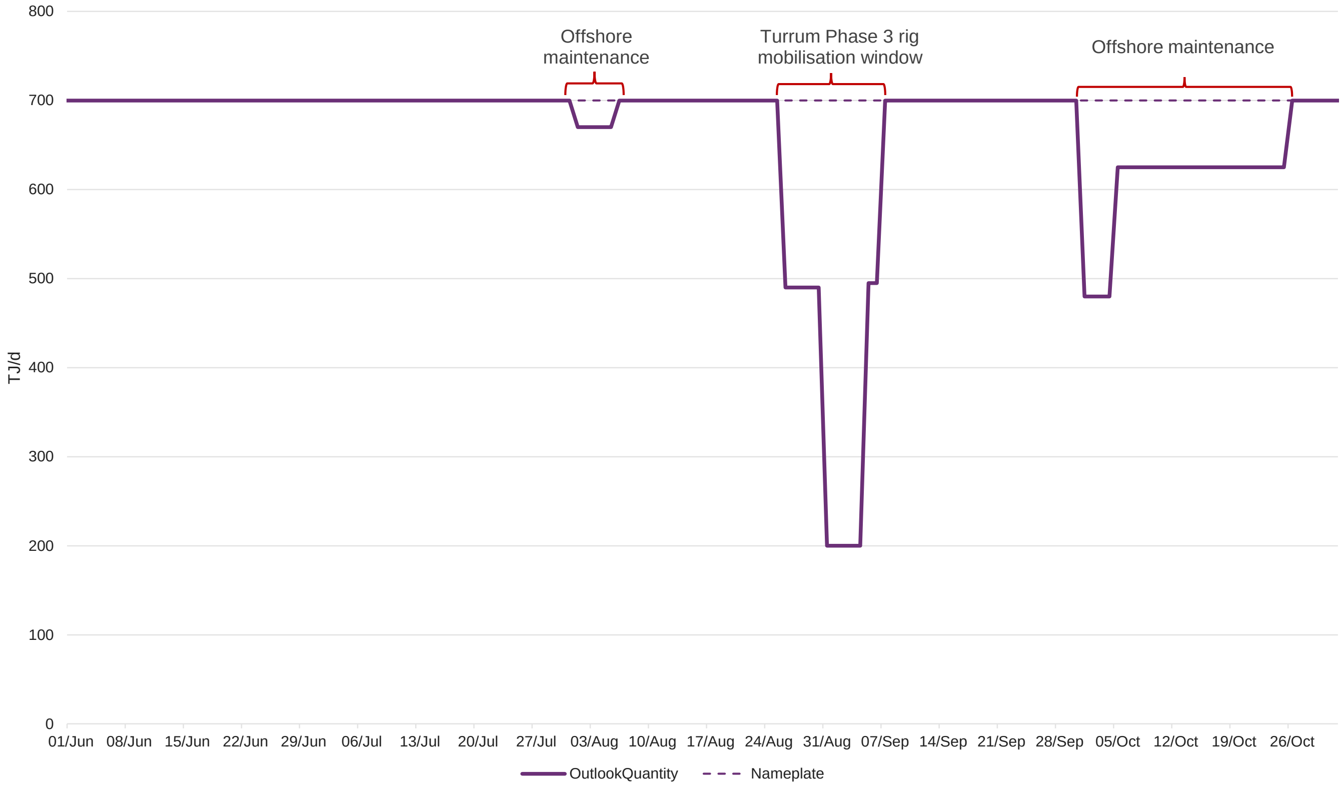
[50] "Southern states" means Victoria, South Australia, New South Wales and Tasmania.

to address the projected annual supply gap. The forecast shortfalls could impact any of the southern states, including Victoria. The 2025 GSOO has further discussion on east coast supply adequacy.

3.3.3 Turrum Phase 3 mobilisation activities

GBJV plans to use the Valaris 107 jack-up rig to drill five wells from the Marlin B platform. Mobilisation of the jack-up rig to the platform is expected to impact Longford production capacity for approximately 12 days, including four days with Longford production reduced to 200 TJ/d due to the Marlin B platform being fully depressurised while the jack-up rig is moved into position. **Figure 29** shows the current timing of this activity and Longford's Medium Term Capacity Outlook (MTCO) from the Gas Bulletin Board as at 6 March 2025.

Figure 29 Longford Medium Term Capacity Outlook (MTCO) for second half of 2025 as at 6 March 2025 (TJ/d)



3.4 Peak day supply demand balance

3.4.1 Forecast Victorian peak day supply capacity

The forecast maximum daily Victorian supply capacity by SWZ, including capacity from the Iona UGS and Dandenong LNG storage facilities, is shown in **Table 13**. The actual supply available to the DTS from each zone is lower, due to DTS capacity constraints for Port Campbell and gas flows from Gippsland to other jurisdictions that can only be supplied from Victoria see Section 3.4.2.

Based on information from gas producers and storage providers, the available Victorian peak day supply capacity is forecast to decline by 28% over the outlook period:

- Gippsland producers have advised that the maximum available peak day production capacity will reduce by 54%, from 746 TJ/d in 2025 to 345 TJ/d in 2029.
  - The reduction in forecast peak day production capacity is caused by a reduction in offshore field production capacity, mostly driven by the decline of GBJV and KUJV fields.
  - Gippsland region available peak day production is observed to have increased compared to the 2024 VGPR Update from 2026 onwards. This is primarily due to volumes from the Kipper Stage 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves that are available due to lower production in 2023 and 2024 driven by low consumption. This enabled the deferral of the expected retirement of Gas Plant 3 from December 2027 to December 2028.
  - GBJV has previously advised AEMO of the planned progressive retirement of gas processing plants at the Longford Gas Plant to match onshore production capacity with reduced offshore field production capacity as GBJV and KUJV fields decline. Gas Plant 1 retired in October 2024.
  - Available Gippsland production includes supply from the Kipper Compression project that came online from October 2024, the Kipper Stage 1B project planned to be online from winter 2026, and the Turrum Phase 3 project planned to be online from winter 2027.
- Port Campbell producers and the Iona UGS operator have advised that maximum daily supply capacity will reduce by 8%, from 795 TJ/d in 2025 to 732 TJ/d in 2029:
  - Available production is projected to increase from the actual maximum production of 218 TJ/d in 2024 to 225 TJ/d in 2025, mainly due to supply from the connection of the Thylacine West and Enterprise-1 wells to the Otway Gas Plant, which returned the plant to its nameplate capacity of 205 TJ/d in late 2024. The 2025 peak day available production remains similar to that reported in 2024 VGPR Update.
  - From 2026 onwards, available peak day production is forecast to reduce between a range of 6% and 15% compared to reported in 2024 VGPR Update due to the downward revision of the reserves available in the Otway Basin.
  - No anticipated Port Campbell production forecast for the outlook period.
- Port Campbell peak day supply capacity into the DTS is forecast to reduce to 523 TJ/d, less than the 530 TJ/d forecast in the 2024 VGPR Update due to updated capacity modelling results for the SWP. More details on capacity modelling discussed in Section 6.2. Available Port Campbell capacity is combined supply to the DTS, South Australia and Mortlake Power Station.
- Lochard Energy will expand Iona UGS capacity by up to 45 TJ/d through HUGS, expected to provide this additional supply capacity from winter 2027. Supply into DTS will continue to be constrained by the capacity of the SWP.

Table 13 Peak day maximum daily quantity (MDQ) by System Withdrawal Zone, 2025-29 (TJ/d)

SWZ	Supply source	2025	2026	2027	2028	2029
Gippsland [A]	Available	746	717	690	544	345
	Anticipated	0	0	0	0	0
	Total available plus anticipated	746	717	690	544	345
	Available	795	764	771	750	732

SWZ	Supply source	2025	2026	2027	2028	2029
Port Campbell (Geelong) [B]	Anticipated	0	0	0	0	0
	Total available plus anticipated	795	764	771	750	732
Melbourne	Available	87	87	87	87	87
Total Victorian supply	Total Victorian available	1,628	1,568	1,548	1,380	1,164
	Total Victorian anticipated	0	0	0	0	0
	Total Victorian available plus anticipated	1,628	1,568	1,548	1,380	1,164

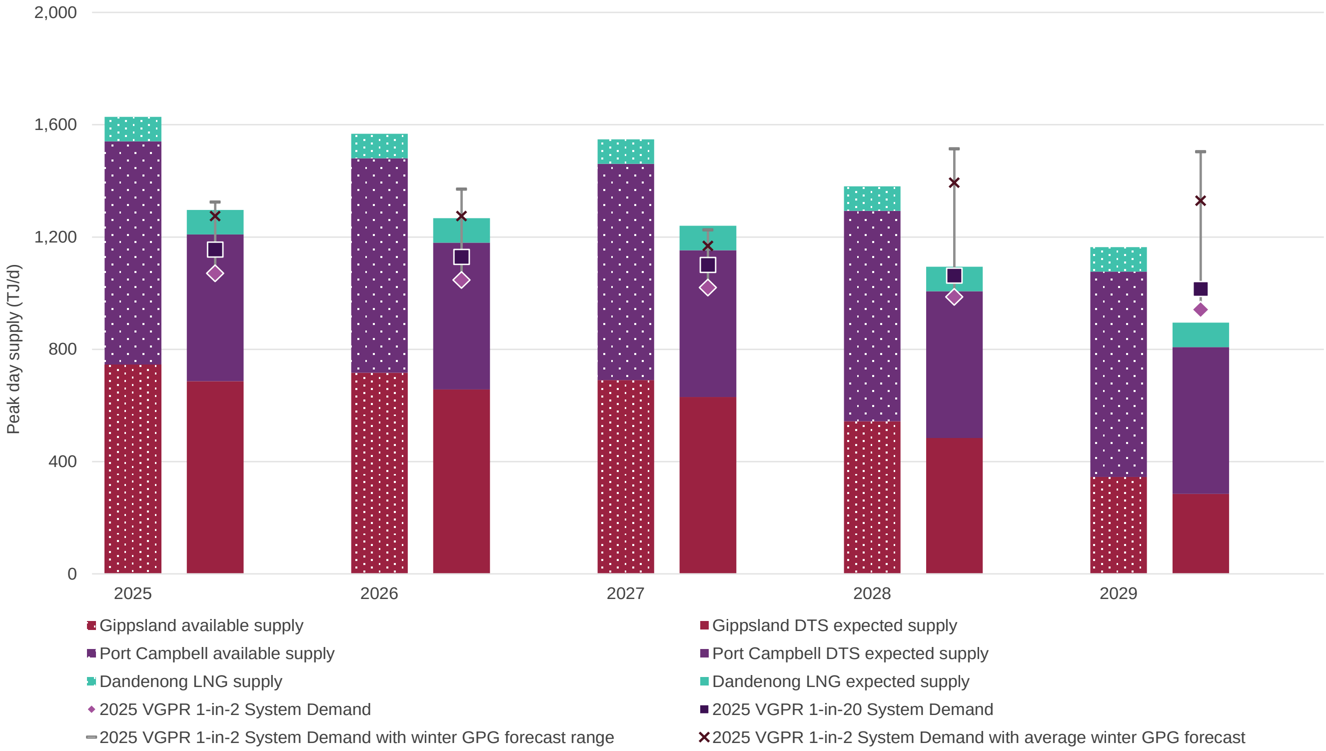
Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP so all of this capacity cannot be supplied to the DTS because of EGP and TGP demand.
B. Port Campbell zone includes the Otway and Athena production facilities and Iona UGS. 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.

3.4.2 Peak day supply adequacy

AEMO's peak day supply adequacy assessment used 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 for Victorian customers. The forecasts shown in **Figure 30** and **Table 14** used the following data and assumptions:

- Forecast annual 1-in-2 and 1-in-20 year 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.
- This forecast peak day system demand shortfall assessment does not include the additional impact of GPG demand. Events in the NEM could result in high GPG demand and total demand that is higher than a 1-in-20 year peak day system demand. Figure 30 includes the Victorian winter GPG demand forecast range coinciding with a 1-in-2 peak day system demand to illustrate the possible range of resultant total demands.
- The assessment only considered 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, including from the Tasmanian Gas Pipeline (TGP) supplied via the TasHub facility, was also not considered.

Figure 30 Forecast peak day supply and DTS adequacy, 2025 to 2029 (TJ/d)



Note: The forecast peak day system demand shortfall assessment does not include the additional impact of GPG demand. Events in the NEM could result in high GPG demand and total demand that is higher than a 1-in-20 year peak day system demand. Figure 30 includes the Victorian winter GPG demand forecast range coinciding with a 1-in-2 peak day system demand to illustrate the possible range of resultant total demands.

Table 14 Forecast peak day system demand supply adequacy, 2025 to 2029 (TJ/d)

Supply source		2025	2026	2027	2028	2029
Gippsland A	Expected B	686	657	630	484	285
	Anticipated	0	0	0	0	0
	Total available plus anticipated	686	657	630	484	285
Port Campbell (Geelong) D	Expected E	523	523	523	523	523
	Anticipated	0	0	0	0	0
	Total available plus anticipated	**523**	**523**	**523**	**523**	**523**
Melbourne	Expected	87	87	87	87	87
Total Victorian supply	Total Victorian expected	1,296	1,267	1,240	1,094	895
	Total Victorian anticipated	0	0	0	0	0
	Total Victorian expected plus anticipated	**1,296**	**1,267**	**1,240**	**1,094**	**895**
1-in-2 system demand		1,071	1,047	1,021	987	942
1-in-20 system demand		1,156	1,130	1,101	1,064	1,016
1-in-2 day surplus quantity with Victorian expected supply		**226**	**220**	**219**	**107**	**-47**
1-in-20 day surplus quantity with Victorian expected supply		**140**	**137**	**139**	**30**	**-121**

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.
D. Expected Port Campbell supply is limited by the capacity of the SWP.

Figure 30 and Table 14 highlight the following key points:

- Peak day surplus supply quantity for 2025 is 8% lower for 1-in-2 and 15% lower for a 1-in-20 demand day compared to the 2024 VGPR Update. There is still sufficient peak day supply to meet system demand.
- The surplus supply quantity has increased from 2026 compared to the 2024 VGPR Update, primarily due to Longford production reprofiling and an increase in available production from recently committed projects.
- The peak day supply adequacy gaps identified in the 2024 VGPR Update for a 1-in-20 peak day for 2027 and both 1-in-2 and 1-in-20 peak days for 2028 have been removed. This is due to increased and reprofiled Gippsland Basin production, and the deferral of the expected retirement of Gas Plant 3 from December 2027 to December 2028. Supply remains tight, however, with the Dandenong LNG injections required to support a 1-in-20 peak day in 2028 and there is risk of shortfall even if a low quantity of GPG demand is required to be met.
- Forecast system demand is projected to exceed available supply on both 1-in-2 and 1-in-20 system demand days in 2029:
  - Available supply from committed Kipper Stage 1B and Turrum Phase 3 is included in peak day adequacy (Kipper Stage 1B from 2026 and Turrum Phase 3 from 2027).
  - Potential projects that could address the 2029 peak day supply adequacy gap include supply from the proposed 375 TJ/d Golden Beach storage development (after development as a 125 TJ/d gas production gas facility in 2028), increased Iona UGS and SWP capacity, or an LNG regasification facility. More details on the projects can be found in Section 4.1.
  - The 2029 forecast gas supply shortfall (and the tight capacity during 2028) may also be mitigated by non-firm sources including 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 from interconnected pipelines.
  - A large amount of new supply capacity is required from pre-winter 2029 to offset large forecast reduction in production capacity, mainly due to the step down in Longford Gas Plant capacity, and additional supply capacity is also required to support the large forecast increase in GPG demand following the closure of the Yallourn Power Station in July 2028.

Gas-powered generation demand and peak day adequacy

While GPG demand is not included in Table 14 above, any GPG demand occurring on peak system demand days would increase the risk of there being insufficient gas supply. The actual total gas demand on a winter day can vary significantly depending on how much GPG is required. Figure 30 above also shows the range of total demand if a 1-in-2 system demand coincides with GPG demand – the bottom of the range represents a 1-in-2 system demand with no GPG, and the top represents the winter peak GPG forecast for each year coinciding with a 1-in-2 system demand.

The analysis shows:

- From 2025 to 2027, DTS expected supply is observed to be sufficient for a mild winter with normal gas demand and moderate GPG demand. Supply is extremely tight for even low levels of GPG with Dandenong LNG required to support demand. The shortfall risk remains for unexpected conditions such as unforecast increases in demand and unplanned supply restrictions.

- From 2028 to 2029, GPG demand is forecast to increase following coal-fired generation retirements (Eraring Power Station in August 2027 and Yallourn Power Station in July 2028). As noted above, even system demand without GPG will be difficult to meet due to the decline in production capacities.
- The timely completion of committed supply projects and progression of potential supply projects is required to mitigate this risk.

Extreme weather conditions or unexpected events, such as coal-fired generation outages and low renewables, can lead to low electricity reserves that significantly increase reliance on GPG to meet demand. An example is the extended coal generation outages that occurred during 2019, 2021 and 2022, placing additional pressure on the gas system to provide flexible and reliable electricity generation. In 2024, Victoria experienced very low levels of wind generation during the first half of winter, which, combined with cold weather, resulted in increased GPG utilisation to support high winter electricity.

With declining available gas supply, Victoria will continue facing a tightening of seasonal supply adequacy, leading to an increased risk of shortfalls in Victoria. This is particularly concerning during extended period of high GPG consumption or unexpected spikes in demand especially during winter months.

Insufficient capacity to support GPG demand on peak system demand days may result in gas supply for GPG being curtailed. 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. The 2025 GSOO has further discussion on east coast gas supply adequacy including GPG supportability.

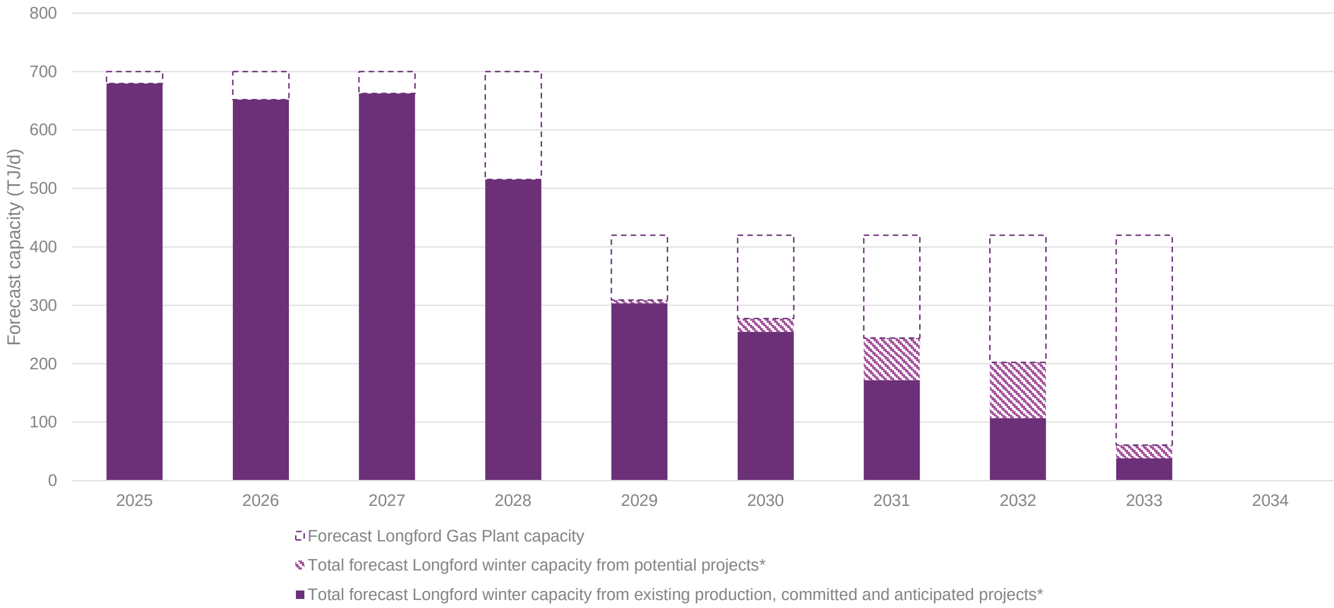
3.5 Longer-term supply adequacy

Figure 31 updates the 10-year capacity outlook for the Longford Gas Plant that was published in the 2024 VGPR Update. Longford's nameplate capacity reduced to 700 TJ/d from 1,150 TJ/d after the retirement of Gas Plant 1 in October 2024. The retirement of Gas Plant 3 has been delayed by one year to after winter 2028 due to the reprofiling of existing reserves and the committed Kipper and Turrum projects that have increased Longford production in 2027 and 2028. The retirement of Gas Plant 2, and the end of Longford gas production, is still forecast for the end 2033.

This is an indicative forecast only, intended to highlight the extent of Longford's expected decline over the next 10 years in a best-case scenario. Investment in potential projects (Late Life Optimisation project, see Section 4.1.2) and the final retirement plan of plant assets later in the decade remain subject to GBJV investment decisions.

Future supply options for Victoria are discussed in Chapter 4, and options to address supply challenges across the broader east coast are discussed in Chapter 5 of the 2025 GSOO.

Figure 31 Forecast Longford Gas Plant winter capacity, 2025 to 2034 (TJ/d)



*Aggregates of proven and probable, contingent and prospective resources

3.6 Operational resilience and supply risks

Victorian supply adequacy tightens due to reduced supply capacity as discussed in the earlier sections. **Table 15** outlines likely risks to the supply demand balance and operational resilience, and **Table 16** outlines improvements or other changes to the system resilience for the outlook period.

Table 15 Risks to supply adequacy and operational resilience

Risk	Description
Production infrastructure outages	Production, storage, and transmission facilities in Victoria are aging and unplanned outages may occur more frequently. Following the Gas Plant 1 retirement in 2024, Longford has two remaining gas plants with a combined capacity of 700 TJ/d. If either of the two remaining plants were unavailable, the total production capacity of Longford Gas Plant could be reduced by up to 350 TJ/d. The retirement of the Longford Crude Stabilisation Plant in 2024 has increased the time it takes for offshore production to ramp up following an outage, due to liquids management in the offshore pipelines. Even short outages are expected to increase the risk of a peak day gas supply shortfall due to the small margins in the supply demand balance.
Production lower than forecast and unpredictable decline of producing reserves	Rapid pressure decline could impact the size of remaining reserves leading to lower actual production. Aquifer-driven reservoirs at Gippsland Basin creates uncertainty due to their characteristics at the end of their field life. As these fields approach final depletion, production can decline rapidly, making it challenging to accurately forecast the production capacity and remaining reserves.
Gas generation	The growing reliance on GPG during extreme weather events, low renewable output and unexpected market disruptions, compounded with declining gas supply, poses risks to supply adequacy and operational resilience, particularly during peak demand periods when gas supply is more likely to be insufficient to meet both electricity generation and gas system demand requirements.
Production project delay and uncertainty	Additional production from committed projects is forecast to assist with meeting peak day and seasonal supply requirements (Kipper from 2026 and Turrum from 2027). Delayed development of these projects increases the risk of a supply gap later in the outlook period.
Depletion of Iona UGS inventory	Tight supply coinciding with high demand can lead to a steep drawn down of Iona UGS inventory. As mentioned in Section 1.2.2, an East Coast Gas System potential threat notice highlighting the gas storage inventory depletion risk was issued during winter 2024 due to high GPG demand combined with constrained Longford production capacity (due to an unplanned extension of planned maintenance). Adding to this risk was the reduction in Iona UGS supply capacity when the storage inventory was low.
Reduction in gas made available from Queensland to the southern states	Winter gas supply from the Queensland LNG producers is an essential component of managing southern states gas supply during these high demand months. However, the volumes available at the Moomba hub via the SWQP may be reduced due to several factors, including SWQP reaching its capacity limit*, lower Queensland or Moomba production due to increased depletion of existing reserves, higher Queensland demand, and high LNG exports. The continuation of requirement to physically supply Mt Isa from the SWQP due to the continued paused in NGP supply from the Northern Territory NGP, which is now able to reverse flow back to Northern Territory from Queensland, increases the criticality of the SWQP. If additional Queensland gas is not, or cannot be made available to the southern states in response to supply tightening, the reliance on Iona UGS would increase and result in an elevated storage depletion risk.
Liquefaction uncertainty	BOC's LNG liquefaction plant is used to fill APA's Dandenong LNG storage tank. APA has advised that there is uncertainty around the liquefaction facility due to aging equipment, which poses a risk to refilling Dandenong LNG. APA is investigating options for liquefaction arrangements.

* SWQP LCA (linepack/capacity adequacy) flagged as "Amber" on GBB during certain periods in winter 2024 indicating that pipeline is flowing at full capacity.

Table 16 Updates increasing operational resilience

Risk	Description
Longford to Melbourne pipeline operations	Longford Gas Plant 1 had no compression capability, whereas Gas Plants 2 and 3 have compression. The retirement of Gas Plant 1 is expected to enable Longford to maintain DTS injections at higher Longford to Melbourne Pipeline (LMP) pressures. This has enabled an increase in the available linepack in the LMP which has improved operational flexibility and enhanced the DTS's ability to respond to plant and equipment trips and unforecast increases in demand (particularly GPG) without materially impacting Longford operations.
Longford Gas Plants retirement delay	Due to the committed Kipper and Turrum projects, and the reprofiling of existing reserves, Gas Plant 3 retirement has been delayed, maintaining forecast Longford gas plant onshore capacity at 700 TJ/d, until the end of 2028.
Ethane constraint	The Longford production system produces an ethane by-product stream that was used by a downstream customer that has since closed. Reduced customer ethane offtake constrained Longford production. GBJV has constructed a power generation facility at Hastings, adjacent to the Long Island Point facility, that consumes this ethane stream. The facility officially commenced operations in November 2024*.

* ExxonMobil, "Official opening ceremony of Esso Australia's Hastings Generation Plant", 12 November 2024, at https://corporate.exxonmobil.com/locations/australia/australia-newsroom/esso-community-outreach/2024/official-opening-ceremony-of-esso-australias-hastings-generation-plant.

3.6.1 Dandenong Liquefied Natural Gas

The Dandenong LNG facility is a 680 TJ storage facility connected to the DTS at Dandenong, which is the highest flow location into the Melbourne inner ring main network. Its location enables the facility to be used as a flexible high-capacity supply source to rapidly respond to supply disruptions, equipment outages or failures, unforecast increases in demand and high gas generation. The facility is comprised of a storage tank owned by APA and a liquefaction plant owned by BOC.

The facility plays a critical role in gas supply resilience, particularly as an "operational response" to maintain DTS pressures to prevent supply disruptions within gas distribution networks. It also has an "emergency response" role to support demand during a major gas supply disruption (like the incident on 1 October 2016 when the Longford Gas Plant was offline for approximately seven hours) including during the implementation of customer curtailment.

In accordance with the Australian Energy Market Commission (AEMC) interim rules published on 15 December 2022[51], AEMO is required to contract any uncontracted capacity to ensure that Dandenong LNG storage inventory is maximised. The current interim rules will remain effective until the end of 2025. The Victorian Government is seeking to extend the interim rule requirement, through a rule change with the AEMC.

BOC's aging liquefaction plant has been experiencing increased issues with reliability. The liquefication facility remains in operation, however, unplanned outages continue to occur and there is an increased risk of a major failure occurring, posing a risk for refilling the Dandenong LNG tank. APA has advised that Investment in BOC's liquefaction facility is required to address the reliability and failure risks.

AEMO issued a Notice of a Threat to System Security in March 2022 with the publication for the 2022 VGPR that included a forecast of insufficient contracted Dandenong LNG inventory available (including AEMO contracted quantities) for all operational and emergency scenarios.

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

4 Future supply sources

Several committed, anticipated and potential projects may provide additional DTS supply during the outlook period. These include:

- Committed and potential production projects in the Gippsland and Otway basins.
  - GBJV advised AEMO that activity planning for the committed Kipper Stage 1B and Turrum Phase 3 projects is well underway. AEMO will continue to work with GBJV on the timing of the activities.
  - GB Energy announced that the withdrawal capacity (for supply into the DTS) at its proposed Golden Beach storage facility has increased to 375 TJ/d, from its initial design of 250 TJ/d.
  - The supply capacity of Iona UGS facility will increase from 570 TJ/d to 615 TJ/d for winter 2027, with storage capacity also increased. Beach Energy and Amplitude Energy are also progressing exploration and development activities.
- Pipeline expansion projects in Victoria and from other jurisdictions which increase supply into Victoria.
  - On 24 February 2024, APA announced further plans to **East Coast Grid Expansion stages**, which includes conversion of Moomba Sydney Ethane Pipeline (MSEP) to transport natural gas, additional compressors on the MSP, Bullo interlink to transport gas from northern basin, Riverina Storage Pipeline (RSP) and expansion of Young to Wollert segment.
  - Expansion of the SWP would increase supply from Port Campbell, including following the Iona UGS expansion. Victorian DTS pipeline expansions are discussed in Chapter 5.
- LNG regasification terminal projects in Victoria and in other jurisdictions.
  - **Port Kembla Energy Terminal (PKET)** completed construction in December 2024. Squadron Energy is in the process of negotiating contracts with long-term customers to achieve the expected launch date.
  - Viva Energy has submitted the supplementary data request for the Environment Effects Statement (EES) required for the **Viva Energy Gas Terminal Project**.
  - Vopak is currently preparing an EES consultation plan for the **Vopak Victoria LNG** project.
  - AP&G LNG acquired Venice Energy in 2024 to continue developing the **Outer Harbor LNG Project** and continues with contract negotiations ongoing with all potential terminal users.

Investment uncertainty in gas supply and infrastructure projects remains high as all projects currently underway or proposed in the VGPR outlook period face a range of challenges to reach investment decisions, maintain schedules and reach completion. The 2025 VGPR contains few committed and anticipated supply projects. Many projects do not have firm timelines, making analysis of system adequacy difficult.

The **transition to biomethane and hydrogen** is expected to play an important role in the decarbonisation of Australia's energy sector, but these distributed supply sources are not expected to produce significant volumes within the outlook period, as they still face a variety of barriers preventing their entry into the market.

4.1 Project updates

4.1.1 Committed supply projects

Iona UGS Expansion

Lochard Energy's HUGS development aims to increase the Iona UGS facility storage capacity by 1.8 to 3.5 PJ, and increase the supply capacity of the Iona facility by 45 TJ/d, from 570 TJ/d to 615 TJ/d from 2027. In July 2024, Snowy Hydro signed a 25-year gas storage agreement with Lochard Energy, beginning in 2028, which enabled the expansion of Iona UGS through the HUGS project[52]. The project has been moved to committed category – it was classified as a potential project in the 2024 VGPR Update.

Lochard is also considering further storage expansions including HUGS Phase 2, potentially increasing working storage volume at Iona UGS by up to 6.4 PJ and supply capacity by up to 150 TJ/d (from 615 TJ/d up to 765 TJ/d) from 2029 or 2030.

Kipper Stage 1B

There is ongoing planning for the drilling of a third well in the Kipper field as part of the Kipper Stage 1B project. The KUJV and GBJV participants took FID on the project in February 2025 and are proceeding with the project's development[53]. This project will increase the gas available from the Kipper field from mid-2026.

Turrum Phase 3

In February 2025, GBJV participants took FID on the Turrum Phase 3 project which involves drilling up to five wells[54] in the Turrum and North Turrum fields, referred to as the Turrum Phase 3 project[55]. This project will increase the gas available to be produced at Longford from prior to winter 2027.

Hydrogen Park Murray Valley

Hydrogen Park Murray Valley is a committed project by AGI Renewables, part of AGIG. The project consists of the construction of a 10 megawatts (MW) electrolyser to produce hydrogen and blend this with natural gas into the Albury-Wodonga gas distribution network. On 11 October 2024 the first sod was turned on site, and the project is targeted to be online in late 2025. This will be the first distribution connection gas supply facility in Victoria as well as being Victoria's first hydrogen injection facility. Hydrogen injection facilities are currently operating in Sydney, Adelaide and Perth.

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[52] Snowy Hydro, "Snowy Hydro signs Lochard gas storage agreement", 15 July 2024, at https://www.snowyhydro.com.au/news/snowy-hydro-signs-lochard-gas-storage-agreement/.

[53] ExxonMobil, "Esso, Mitsui and Woodside to invest nearly $200 million into the Gippsland Basin", 24 February 2025, at https://corporate.exxonmobil.com/locations/australia/australia-newsroom/news-releases/2025/esso-mitsui-and-woodside-to-invest-nearly-200-million-into-the-gippsland-basin.

[54] NOPSEMA, "Jack-Up Turrum Phase 3 Drilling", 21 January 2025, at https://info.nopsema.gov.au/environment_plans/695/show_public.

[55] The Australian, "Exxon and Woodside in $350m drilling tie-up to avert predicted east coast gas shortfall", 17 March 2025, at https://www.theaustralian.com.au/business/mining-energy/exxon-and-woodside-in-350m-drilling-tieup-to-avert-predicted-east-coast-gas-shortfall/news-story/7e2ae91ec80f443c5e068f47703d43d2?btr=3470b076cbf9ef135b8d256872e806ea.

4.1.2 Potential supply projects

Golden Beach

The Golden Beach Energy Storage Project involves development and production from the Golden Beach gas field in the Gippsland Basin. It is projected to supply up to 30 PJ at maximum rate of 125 TJ/d starting from winter 2028, before transitioning to a storage facility for winter 2029. On 21 January 2025, GB Energy announced the storage withdrawal capacity (supply into the DTS) would be increased to 375 TJ/d, from its initial design of 250 TJ/d.

On 6 November 2024, the Victorian Government amended the *Offshore Petroleum and Greenhouse Gas Storage Act 2010* to confirm that petroleum injection and storage is a permitted activity under a petroleum production licence[56].

In late November 2024, GB Energy began offshore geotechnical investigations in the project area to assess the seabed's suitability for supporting a drilling rig and the offshore pipeline route[57]. FID for the project is expected in the first half of 2025.

Longford Late Life Optimisation

GBJV is considering the Longford Late Life Optimisation project which aims to maximise production from declining reserves later in the decade.

East Coast Supply Project (ECSP)

Amplitude Energy's[58] ECSP, formerly known as the Otway Phase 3 Development (OP3D), is a potential new gas supply source for the southern states in the near term. The proposed 3-well drilling program targets backfilling declining Otway fields to supply into the existing Athena Gas Plant with a potential 90 TJ/d of production by 2028.

In Q1 FY24, Amplitude secured the Transocean Equinox rig for an Otway Basin drilling campaign as part of a consortium with three other operators[59]. The rig is expected to commence drilling its first firm well for Amplitude Energy in FY26[60] (July 2025 to June 2026). Amplitude Energy has advised AEMO that the actual timing of drilling and subsequent subsea construction is subjected to rig arrival, regulatory, joint venture and Board approvals. Refer to Section 4.1.5 for more detail on the Otway drilling campaign.

Manta

Amplitude Energy's Manta gas project requires the drilling of an appraisal well prior to a development decision. Gas from the Manta field would be processed at the Orbost Gas Plant as a backfill after Sole field production declines. Amplitude Energy also maintains an ongoing memorandum of understanding (MOU) with Emperor

[56] Resources Victoria, "Offshore gas storage", 19 November 2024, at https://resources.vic.gov.au/projects/offshore-petroleum-and-greenhouse-gas-storage-amendment-bill-2024.

[57] GB Energy, "Upcoming operations", at https://gbenergy.com.au/upcomingoperations.

[58] Formerly known as Cooper Energy.

[59] Amplitude Energy, "FY24 Annual Report", 4 October 2024, at https://app.sharelinktechnologies.com/announcement/asx/491d62785328a49a33b3eff882ca315c.

[60] Amplitude Energy, "Q1FY25 Quarterly Report", 15 October 2024, at https://app.sharelinktechnologies.com/announcement/asx/991bb5caaf851c076f2c06549e9f47c0.

Energy and Seven Group Holdings for potential future processing of the respective Judith prospect and Longtom field at the Orbost Gas Plant[61].

Trefoil and White Ibis

Following the conclusion of a strategic review in June 2024, Beach Energy determined that the Trefoil development would be kept on hold. Beach will make the economic evaluation going forward whether to resume the development. The same strategic decision was also made for White Ibis, Bass, and Yolla West due to the developments not meeting minimum investment requirements[62]. Gas from these fields would be processed at the Lang Lang Gas Plant (BassGas) as a back fill for Yolla gas.

Artisan

Beach Energy discovered Artisan 1 as part of the Otway drilling campaign completed in 2022[63]. Beach is participating in a consortium which secured the Transocean Equinox drilling rig[64]. Beach Energy's activity with the rig is anticipated to include the Artisan completion, exploration drilling and well decommissioning[65]. Beach advised AEMO that the potential development strategy will depend on the results of the full program and is subject to FID. Refer to Section 4.1.5 for more detail on Otway drilling campaign.

Longtom

The Longtom field in Gippsland basin is wholly owned by SGH (Seven Group Holdings) Energy, which is seeking to resume production from the field. Gas from the Longtom field was previously processed at the Orbost Gas Plant. SGH Energy has signed a MOU with Amplitude Energy to explore infrastructure access for the asset[66].

Wombat

The Wombat field, which has an estimated capacity of 10 TJ/d, is wholly owned by Lakes Blue Energy. As of 30 October 2024, an operation plan for the drilling of the Wombat-5 was submitted to the Victorian regulator (Earth Resources Regulation)[67]. Gas processing and compression facilities would need to be constructed to treat and transport any gas produced at Wombat.

[61] Emperor Energy, "September 2024 Quarterly Activities Report", 30 December 2024, https://emperorenergy.com.au/wp-content/uploads/2024/10/ASX-Version.pdf.

[62] Beach Energy, "Annual Report 2024", 12 August 2024, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1540360/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

[63] 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.

[64] Beach Energy, "Annual Report 2024", 12 August 2024, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1540360/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

[65] Beach Energy, "Interim Report for the Half Year ended 31 December 2023", 12 February 2024, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1504256/BPT_Interim_Report_for_the_Half_Year_Ended_31_December_2023.pdf.

[66] SGH, "2024 Annual Report", 14 August 2024, at https://wcsecure.weblink.com.au/pdf/SVW/02838288.pdf.

[67] Lakes Blue Energy, 30 October 2024, at 2924-02873913-3A654401.

Lakes Blue Energy was previously prioritising the evaluation of its prospect Enterprise North in the Otway Basin[68] but in October 2024, it sold its interest in Enterprise North and Otway-1 to ADZ Energy Pty Ltd [69].

4.1.3 Other supply projects

APA East Coast Gas Grid (ECGG) Expansion project[70,71]

On 5 May 2021, APA announced a 25% capacity expansion of the MSP and the SWQP in multiple stages. APA completed Stage 1 in 2023 and Stage 2 in 2024. Expansion activities consisted of adding two additional compressors on both the SWQP and MSP. This increased the nominal capacity of the SWQP from 404 TJ/d to 512 TJ/d, and the MSP from 446 TJ/d to 565 TJ/d.

On 24 February 2025, APA announced a further five-year capacity expansion plan for the ECGG:

- **MSEP (Moomba – Sydney Ethane Pipeline) conversion to natural gas** – on 24 February 2025, APA reached FID to convert the MSEP to transport natural gas. Completion of the project will add 20 TJ/d of capacity from Moomba to Victoria for 2025 (565 TJ/d to 585 TJ/d). Another initiative, the MSP off-peak capacity expansion project, reached FID at the same time as the MSEP project. The project will add two pressure regulation skids on the MSP to increase MSP summer capacity during its annual maintenance period. The first pressure regulation skid is planned to come online in November 2025 with the second following in 2026.
- **Stage 3** – currently in design stage, this consists of an additional compressor on the MSP between Moomba and Young, and between Young and Culcairn. This stage also includes the Bulloo Interlink to transport gas from northern basins such as Surat in Queensland and the Beetaloo in the Northern Territory, among others. The project stage aims to progressively increase MSP capacity from 590 TJ/d to 700 TJ/d, SWQP capacity from 512 TJ/d to 605 TJ/d, and Young to Melbourne to 229 TJ/d.
- **Stage 4** – a conceptual expansion, Stage 4 includes the Riverina Storage Pipeline (RSP) which is planned to provide 200 TJ of pipeline storage from 2028 with potential to expand to 500 TJ from 2029. This is proposed as supply source for GPG.
- **Stage 5** – a conceptual expansion, Stage 5 plans to expand the transportation capacity between Young and Wollert to 350 TJ/d by adding additional compression and other transmission infrastructure reconfigurations.

APA also has conceptual plans to expand the MSP capacity to 800 TJ/d as early as winter 2033.

These capacity expansions to increase supply to Victoria rely on additional gas supply being made available in the northern basins to supply the southern states, and on sufficient surplus being available above the quantities likely to be consumed by South Australia and New South Wales. With the Longford Gas Plant forecast to cease production in late 2033, this could be a replacement gas supply.

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[68] 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.

[69] Lakes Blue Energy, "Annual Report", 30 June 2024, at https://static1.squarespace.com/static/6287c98799a0cf2147462016/t/672806aeecb753374924be41/1730676414306/LKO+Annual+Report+2024.pdf.

[70] APA, East Coast Grid Expansion, at https://www.apa.com.au/operations-and-projects/gas/gas-transmission/east-coast-grid-expansion-ecge.

[71] APA, East Coast Gas Expansion Plan, 24 February 2025, at https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan.

LNG regasification terminal projects

- **Viva Energy Geelong Gas Terminal Project** – Viva Energy is awaiting the Ministerial Assessment from the EES regulatory process, having completed the additional information requested by the Victorian Government's Supplementary Statement in September 2024[72]. Viva Energy is also working with APA as the VTS[73] asset owner and AEMO on the connection application. The terminal is forecast to be able to supply up to 140 PJ/y and have a peak day capacity of 750 TJ/d. It is targeted to be operational and available to the market ahead of winter 2028.
  - As discussed in the 2024 VGPR Update, the addition of higher pressure gas to the SWP in the Geelong area will back out gas supply from Port Campbell including from Iona UGS. In additional to the information provided in the 2024 VGPR Update, this issue is discussed further in Section 5.2.2.
  - Viva Energy with JV partner ExxonMobil is also investigating the conversion of the approximately 130 km Westernport Altona Geelong (WAG) crude oil pipeline to a high-pressure gas transmission pipeline as an option to increase SWP capacity. The WAG gas pipeline would provide a new gas flowpath from Geelong to Brooklyn and onwards through to Newport and Dandenong. A preliminary capacity assessment is discussed in Section 5.2.2.
- **Vopak Victoria LNG** – following the Victoria's Minister of Planning's referral decision in August 2023 on the Vopak Victoria Energy Terminal requiring an EES, Vopak is currently preparing a consultation plan for the EES[74]. Vopak has advised that the terminal is planned to have a supply capacity of up to 778 TJ/d, supply around 270 PJ/y, and be operational in Q2 2028. This project intends to connect to the SWP, which raises the same issue of backing out Port Campbell gas supply unless the SWP capacity is significantly increased.
- **PKET** – Squadron Energy completed physical mechanical construction of the terminal in December 2024[75] in additional to Jemena completing construction of a pipeline lateral that connections PKET to the Eastern Gas Pipeline (EGP). The terminal will go into preservation for at least a year until the FSRU (Floating Storage Regasification Unit)[76] arrives for the remaining commissioning activities. The terminal has a forecast supply capacity of at least 500 TJ/d and aims to provide first gas in winter 2026. The company is currently in the process of negotiating contracts with long-term customers to achieve the expected launch date.
  - Jemena has committed to upgrade the EGP to enable reverse flow from PKET and become bi-directional in several stages. On 21 February 2025, Jemena announced that it had committed to complete the upgrade works to convert the EGP to a bi-directional pipeline. This will enable the EGP to supply 200 TJ/d from PKET south to Victoria[77]. This southern flow capacity could be upgraded to 325 TJ/d in future.
- **Outer Harbor LNG Project** – Venice Energy has proposed the development of an LNG regasification terminal in South Australia that it expects to commission by Q1 2027. Following the end of an exclusivity agreement

[72] Viva Energy, "Viva Energy LNG terminal critical infrastructure to secure Victoria's gas supply", 12 September 2024, at https://www.vivaenergy.com.au/media/news/2024/viva-energy-lng-terminal-critical-infrastructure-to-secure-victorias-gas-supply.

[73] Victoria Transmission System (VTS) is a name used by APA for the DTS.

[74] Department of Transport and Planning, Vopak Victoria Energy Terminal, at https://www.planning.vic.gov.au/environmental-assessments/browse-projects/referrals/Vopak-Victoria-Energy-Terminal.

[75] Squadron Energy, "Port Kembla Energy Terminal ready to supply gas to Australia's eastern states", 12 December 2024, at https://www.squadronenergy.com/news/port-kembla-energy-terminal-ready-to-supply-gas-to-australias-eastern-states.

[76] An FSRU receives, stores, and regasifies LNG onboard, converting it back into natural gas for direct injection into pipelines.

[77] Jemena, "Jemena takes crucial next step to avoid gas shortfall", https://www.jemena.com.au/media/jemena-takes-crucial-next-step-to-avoid-gas-shortfall/.

with Origin Energy, that was initially signed in October 2023 and expired in February 2024, Venice Energy advised that negotiations are ongoing with all potential terminal users.

- In October 2024, AG&P LNG acquired Venice Energy[78]. The acquisition will be formalised in the first half of 2025. The terminal is advised to have a supply capacity of up to 405 TJ/d or 144 PJ/y. The SEA Gas Pipeline would be converted to enable reverse flow from Adelaide to Port Campbell in Victoria, although flows through to the DTS would be limited by the SWP capacity, so the project would not increase DTS supply capacity (as discussed in Section 6.2). SEA Gas has advised that it is discussing its proposal to extend the SEA Gas Pipeline from Port Campbell to Melbourne, which would increase Victorian supply capacity, if connected in a suitable location, with potential customers. SEA Gas has also advised that this would be an option to increase supply from Port Campbell to Melbourne even if the Venice Energy LNG regasification terminal does not proceed. Venice Energy is targeting FID in late 2025 with first gas targeted for winter 2028.
- If the Outer Harbor LNG Project does not proceed as proposed, SEA Gas has proposed an interim option to install a compressor at the Adelaide end of the SEA Gas Pipeline to enable the reverse flow of gas received from the Moomba to Adelaide Pipeline System (MAPS) to Port Campbell that would support Iona UGS inventory conservation and refilling during times when the MAPS is not flowing at capacity to support South Australian demand.
- AG&P LNG is also working on an interim project called Adelaide Energy Bridge which aims to commence in the last quarter of 2025, to supply gas for South Australia through the transportation of LNG cargoes from the port using cryogenic ISO tank containers loaded onto trucks to transport the LNG to a regasification facility at Bolivar. The interim project would run until Outer Harbor LNG Project is ready for commencement. AG&P advised that the project is currently going through approvals and commercial agreements. SEA Gas has advised that it is investigating options to transport gas supplied from the Adelaide Energy Bridge project to Port Campbell.

4.1.4 Proposed Victorian renewable gas projects

Renewable gases are expected to be an important component of the energy transition to a low-carbon energy system as it is currently the only available technology to help decarbonise many industries while also supporting energy security, and integrating with the existing natural gas infrastructure. The Victorian Government has, through the *Climate Change Act 2017*, committed to a 28-33% emissions reduction target on 2005 levels by 2025, 45-50% by 2030, 75-80% by 2035 and net zero emissions by 2045[79].

To assist in these emission reduction targets, in addition to the Victoria's Gas Substitution Roadmap Update 2024[80], the Victorian Government has released the Victoria's Renewable Gas Directions Paper[81] on 9 December 2024. The paper outlines a policy model which includes the Industrial Renewable Gas Guarantee, a Victorian market-funded certificate scheme commencing in 2027 with a 4.5 PJ/y target by 2035.

[78] AG&P LNG, "AGP LNG agrees to acquire Venice Energy", 24 October 2024, at agp-lng-agrees-to-acquire-venice-energy-a-2-mtpa-lng-import-terminal-developer-at-outer-harbor-in-port-adelaide-australia.pdf.

[79] See https://www.climatechange.vic.gov.au/climate-action-targets.

[80] Victorian Government, *Victoria Gas Substitution Roadmap Update 2024*, at https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap/gas-substitution-roadmap-update-2024.pdf.

[81] Victorian Government, *Victoria's Renewable Gas Directions Paper,* at https://engage.vic.gov.au/victorias-renewable-gas-future.

Historically regulations and standards have either prohibited or hindered the development of renewable gases in Australia, however many of these roadblocks are now progressively being resolved, including:

- Amendments to the NGL[82] and subsequently the NGR to facilitate other gases including hydrogen and biomethane being supplied into the regulated gas networks that commenced between March 2024 and March 2025.
- Amendments to the DWGM rules[83] completed by the AEMC and implemented by AEMO in May 2024.
- Amendments to the Australian Standard AS4564 - Specifications for general purpose natural gas[84] currently under consultation to include enabling hydrogen blending and facilitating biomethane supply by introducing specific limits on biomethane impurities.
- Continued progressive updates[85] to the National Greenhouse Emissions Reporting Scheme (NGERS) to recognise the benefits of hydrogen and biomethane with the latest consultation commencing on 28 February 2025[86].

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 Vally project, which was discussed in Section 4.1.1. Below are some proposed projects for development in Victoria based on information submitted to AEMO (in some cases, the supply outlook of these renewable gas projects is limited):

- Ararat Bioenergy, led by Valorify in partnership with local Council and farmers, is proposed to be developed in Ararat, Victoria.
  - The project aims to inject biomethane into the Carisbrook to Horsham pipeline, which could then contractually flow into the DTS and the broader east coast gas system. The production facility will use cereal straw and other agricultural waste as feedstock to produce biomethane and other renewable products[87]. As of April 2024, the project has secured enough feedstock for the first stage of a commercial demonstration facility[88] targeting up to 0.5 PJ/y, with two further expansion stages planned to achieve up to 4.5 PJ/y in total. The target date for the first stage is first quarter 2027 with offtake agreements ongoing for end use.
  - Valorify is also working on the Goulburn Murray Woka Yurringa Energy Project with Yurringa Energy in Benalla, Victoria, along with local Council and feedstock partners. The project is currently preparing to enter the Front End Engineering Design (FEED) phase with support from Regional Development Victoria.
- Melbourne Water is investigating the operational and commercial feasibility of a BioEnergy Hub at its Eastern Treatment Plant (ETP) in Carrum Downs in Melbourne. The majority of biogas produced by the wastewater

[82] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/extending-national-gas-regulatory-framework-hydrogen-and-renewable-gases#:~:text=On%2028%20October%202022%2C%20Energy,the%20national%20gas%20regulatory%20framework.

[83] See https://www.aemc.gov.au/rule-changes/dwgm-distribution-connected-facilities#:~:text=Rule%20Change%3A%20Completed&text=On%208%20September%202022%2C%20the,effect%20on%201%20May%202024.

[84] See https://www.standards.org.au/standards-catalogue/standard-details?designation=as-4564-2020.

[85] See https://cer.gov.au/schemes/national-greenhouse-and-energy-reporting-scheme/report-emissions-and-energy/amendments-to-national-greenhouse-and-energy-reporting-legislation.

[86] See https://www.dcceew.gov.au/about/news/share-thoughts-on-nger-updates-and-future-work-program#:~:text=Key%20amendments%20include%3A,oil%20and%20natural%20gas%20operations.

[87] Ararat Bioenergy, at https://araratbio.com.au/.

[88] Valorify, “Ararat Bioenergy reaches key project milestone”, 18 April 2024, at https://valorify.com.au/2718-2/.

treatment process at ETP is used by an onsite power station that generates renewable electricity and heat. A potential BioEnergy Hub would upgrade the unused biogas, currently flared, into biomethane for injection into the gas network. Melbourne Water began a tender in 2024 aiming to engage a third party to design, own and operate the facility while establishing long-term agreements with Melbourne Water for site access and biogas supply[89].

- LMS Energy is pursuing two urban biogas from waste projects in Victoria with an end use aim to inject biomethane into the gas network. Initial feasibility work has been undertaken, including gas flow rates, quality, and upgraded gas quality, and proximity to gas distribution infrastructure.
- Optimal Renewable's Goulburn Valley Biohub aims to convert organic waste to biomethane to supply into the gas network. The project is currently in the feasibility study stage.

4.1.5 Offshore exploration program

Otway Basin

The Transocean Equinox[90] semi-submersible drill rig has been contracted to perform exploration and well decommissioning activities in the Otway Basin by a consortium of operators (ConocoPhillips, Amplitude Energy, Beach Energy, and Woodside). The activities of the consortium members will be a sequence of independent campaigns by each of the operators and their respective JV partners. The activities are set to begin in 2025, with an initial activity window between 2025 and 2026. The activity duration can extend depending on each consortium member's decision to drill further optional wells. The wells are expected to connect to existing gas plant infrastructure in the Port Campbell region, subject to further agreements. The gas from any successful wells could contribute supply into the southern market later in the decade.

In addition to the exploration activities above, Viridien (formerly known as CGG) is planning a seismic survey in the Otway Basin[91], which is currently pending approvals.

Table 17 gives an overview of the planned Otway Basin activities.

Table 17 Otway basin activities

Company	Activity	Field	Targeted wells*	Production facility to be processed at
Amplitude Energy	Exploration well drilling	Annie, Juliet, Isabella	3	Athena
Beach Energy	Exploration well drilling and Artisan completion	Artisan, Hercules	1	Otway
ConocoPhillips	Exploration well drilling and seismic survey	**Essington, Charlemont	2	TBD
Woodside	Well plugging	Minerva	-	-

*Excludes additional potential well slots.
**Field names subject to change.

[89] Victoria Tenders, at https://www.tenders.vic.gov.au/tender/view?id=266972.

[90] Offshore, "Transocean rig heads to Australia for multi-year campaign", 4 April 2024, at https://www.offshore-mag.com/rigs/article/55002120/transocean-rig-heads-to-australia-for-multi-year-campaign.

[91] Viridien, "Regia 3D Marine Seismic Survey Information", at https://www.viridiengroup.com/data/seismic-data/regia-3d-marine-seismic-survey-information.

4.2 Project risks and uncertainties

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. The 2025 VGPR contains no anticipated and few potential projects with timelines that are subject to change based on risk and uncertainties, making the analysis of supply adequacy difficult. All projects currently underway or proposed in the VGPR outlook period – including gas supply projects, LNG regasification terminal projects, pipeline projects, distributed supply projects and renewable gas projects – face a range of challenges to reach investment decisions, maintain schedules and reach completion.

Table 18 summarises uncertainties that could impact project progression.

Table 18 Covered gas project uncertainties

Factor	Description
Inflation	Capital costs remain high, and the cost of key materials, offshore and land rigs, equipment, and labour will continue to play a critical role in investment decisions. The rate of inflation has eased after the steep increase in 2022 and is expected to stabilise with the interest rate cut in February 2025.
Financing	Natural gas, as a fossil fuel, is becoming less appealing to some investors who are screening investments based on environment, social and governance (ESG) issues. This creates a challenge for smaller industry players with limited capital who depend on external financing. Listed companies may also face challenges on ESG grounds from their shareholder base for any investment in gas. This affects to all gas projects, including production, storage, GPG development, and in some cases even renewable gas projects.
Regulatory approvals	Regulatory processes for gas projects are becoming increasingly stringent and can take extended periods of time to complete, depending which body is reviewing the project application. This can be complicated by court challenges which can greatly extend project timelines and costs.
Market dynamic uncertainty	Supply projects require a certain quantity of firm demand contracts to commit to first gas. Most industry participants agree that residential gas demand is declining and the reliance on GPG will increase in future. However, uncertainty around the timing of these structural changes in demand makes it difficult for industry to know when to commit to projects, both on the supply side and on the demand side.
Competing investment interests for renewable gases	Renewable gas projects continue to face challenging conditions regarding funding availability, policy support, investment confidence, and project economics. Policies and investments, mostly centred around hydrogen projects, including the GO scheme, GreenPower, Hydrogen Headstart program, and Hydrogen Production Tax Incentive (HPTI), are available to support renewable gas projects. There has been a lower level of policy supply for biomethane projects previously, with interest and support now increasing.

5 Declared Transmission System adequacy

AEMO undertook capacity modelling of the DTS for the proposed project to enable withdrawals at Longford from the DTS in the scenario of any outages at the Longford Gas Plant. The modelling results with the Gooding Compressor Station (CS) line-valve open show that:

- Longford to Melbourne Pipeline (LMP) withdrawals are achievable only on low to moderate system demand days; if demand increases, minimum injections are required from the Longford CPP to maintain system security.
- Demand at either Jeeralang and Valley Power GPG will reduce the LMP withdrawal capacity or increase the minimum Longford CPP injections with a one-to-one impact

AEMO has conducted modelling of the DTS to determine the transportation capacity adequacy for potential supply projects and options to increase capacity where the capacity is not adequate. This modelling presents the potential supply options and does not represent the lowest cost supply or consider the economics of potential options.

- Viva Energy's WAG pipeline capacity was modelled to have a transportation capacity of 200 TJ/d. This creates an increase in the SWP transportation capacity of up to 120TJ/d where the full 200 TJ/d is unavailable due to pipeline interactions without some further debottlenecking.
- APA's proposal to expand SWP transportation capacity involving installation of two new compressor stations located near Pirron Yallock and Stonehaven was modelled to achieve an increase of SWP capacity up to 113 TJ/d, showing an effective alternative option without pipeline looping.

The DTS peak day system capacity is 1,670 TJ/d when there is LNG injection at Dandenong LNG facility. 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 GPG on low and peak system demand days. Peak shaving gas from the Dandenong LNG facility may be utilised to maintain system pressures when high GPG coincides with periods of high system demand or if GPG is unforecast.

5.1 Longford Gas Plant full plant outages

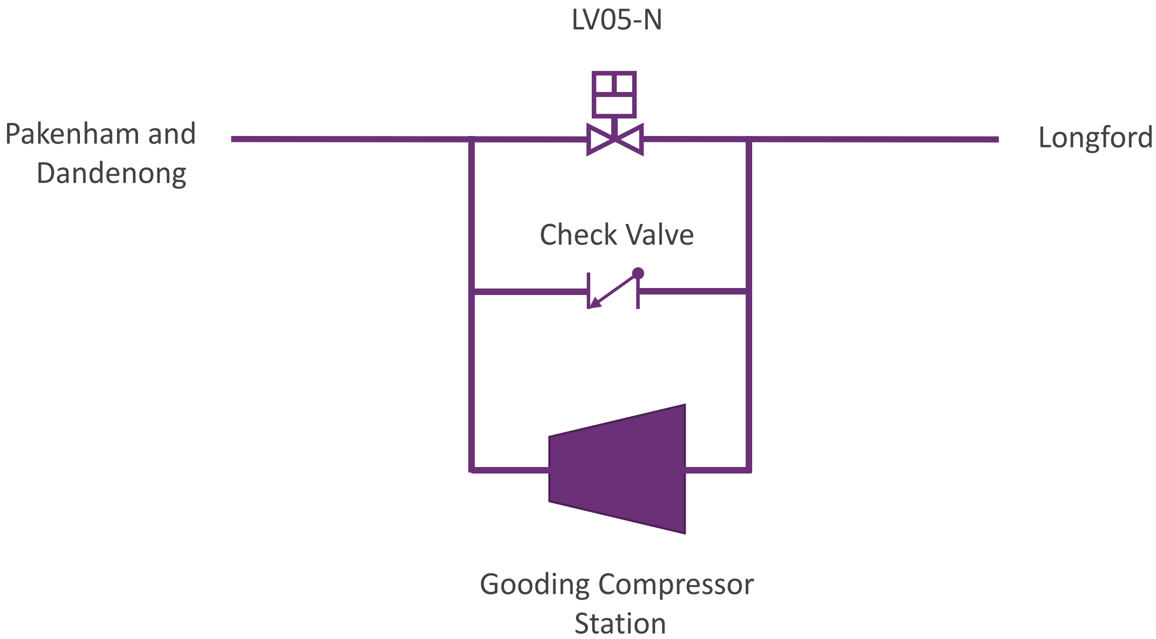
The retirement of Gas Plant 1 in October 2024 and other infrastructure at the Longford Gas Plant has reduced redundancy at the facility, which increases the likelihood of a full plant outage. This risk of an outage will increase further when Gas Plant 3 is retired later in the decade. Esso, the Longford operator, has informed AEMO that in the event of a full plant outage, the Longford facility requires a small quantity of gas to maintain the plant in a safe condition and then an additional small quantity of gas to restart production. If gas production is stopped at the plant, this gas must be supplied by another source.

While Esso has advised AEMO that there are no planned full plant outages at the Longford Gas Plant, GBJV and APA have a proposed project to enable withdrawals at Longford from the DTS to support any unplanned full plant outages. The project includes adding a withdrawal metering skid at the Longford Metering Station and a remotely actuatable, automated valve around the Gooding CS, as shown in **Figure 32**.

Gooding CS is located near the mid-point of the LMP and provides compression towards Dandenong from Longford to manage DTS pressures and move linepack towards the Melbourne demand centre during periods of high demand. The station has a single direction bypass valve that enables gas to free flow from Longford towards Dandenong when the compressors are not operating. This bypass includes 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 manually by APA on site.

AEMO first highlighted the need for an automated valve around Gooding CS to enable west to east flow in the 2021 VGPR.

Figure 32 Gooding compressor station valving arrangement



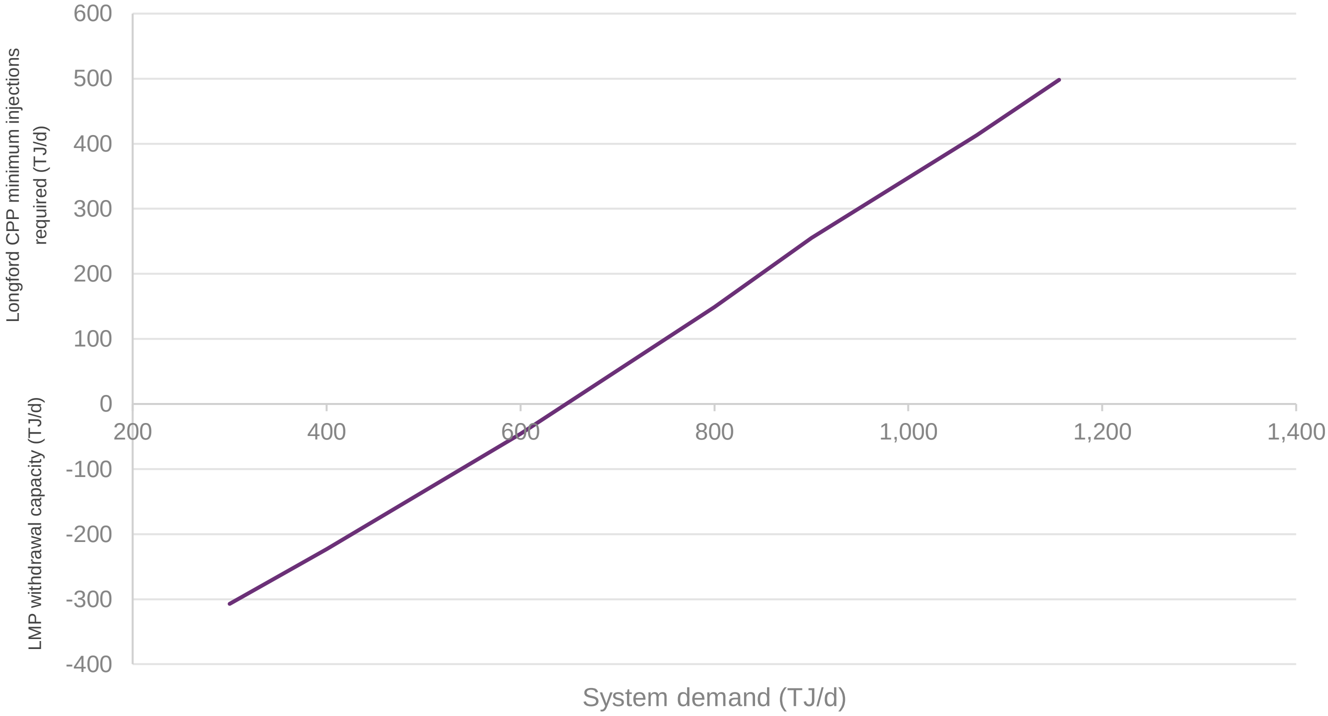
In previous VGPRs, system capability modelling for LMP withdrawals indicated that flows in this direction were not possible. The addition of an automated line valve around the Gooding CS changes this assumption and AEMO completed modelling to determine the withdrawal capacity at the Longford close proximity point (CPP)[92]. LMP withdrawals are only possible on low to moderate system demand days and as demand increases a minimum injection quantity is required at the Longford CPP to maintain system security.

Figure 33 shows both the LMP withdrawal capacity at low system demands and the minimum injections required at the Longford CPP at higher system demands. The crossover point between withdrawals and injections on this chart is at 650 TJ/d, however this considers demand in the DTS only and does not contemplate the required gas flows from Longford to support demand in Tasmania, New South Wales, and the Australian Capital Territory.

[92] The Longford CPP consists of the Longford, VicHub and TasHub injection points.

In the event of a sustained full plant outage at the Longford Gas Plant on a moderate or high demand day, curtailment of some gas demand would likely be required. As the daily gas demand increases, the amount of time the system can be supported without Longford CPP injections decreases. If supply from Dandenong LNG is available, this reduces the amount of curtailment that would be required.

Figure 33 LMP withdrawal capacity and Longford CPP minimum injections (TJ/d)



The Jeeralang and Valley Power GPG facilities are both supplied from the LMP. Valley Power is directly connected to the LMP, while Jeeralang is supplied off the eastern end of the Lurgi Pipeline. Modelling indicates that demand at either GPG facility will reduce the LMP withdrawal capacity or increase the minimum Longford CPP injections by a one-to-one ratio. Therefore, for every 1 TJ of Valley Power or Jeeralang demand, the LMP withdrawal capacity decreases by 1 TJ or the minimum Longford CPP injection quantity increases by 1 TJ.

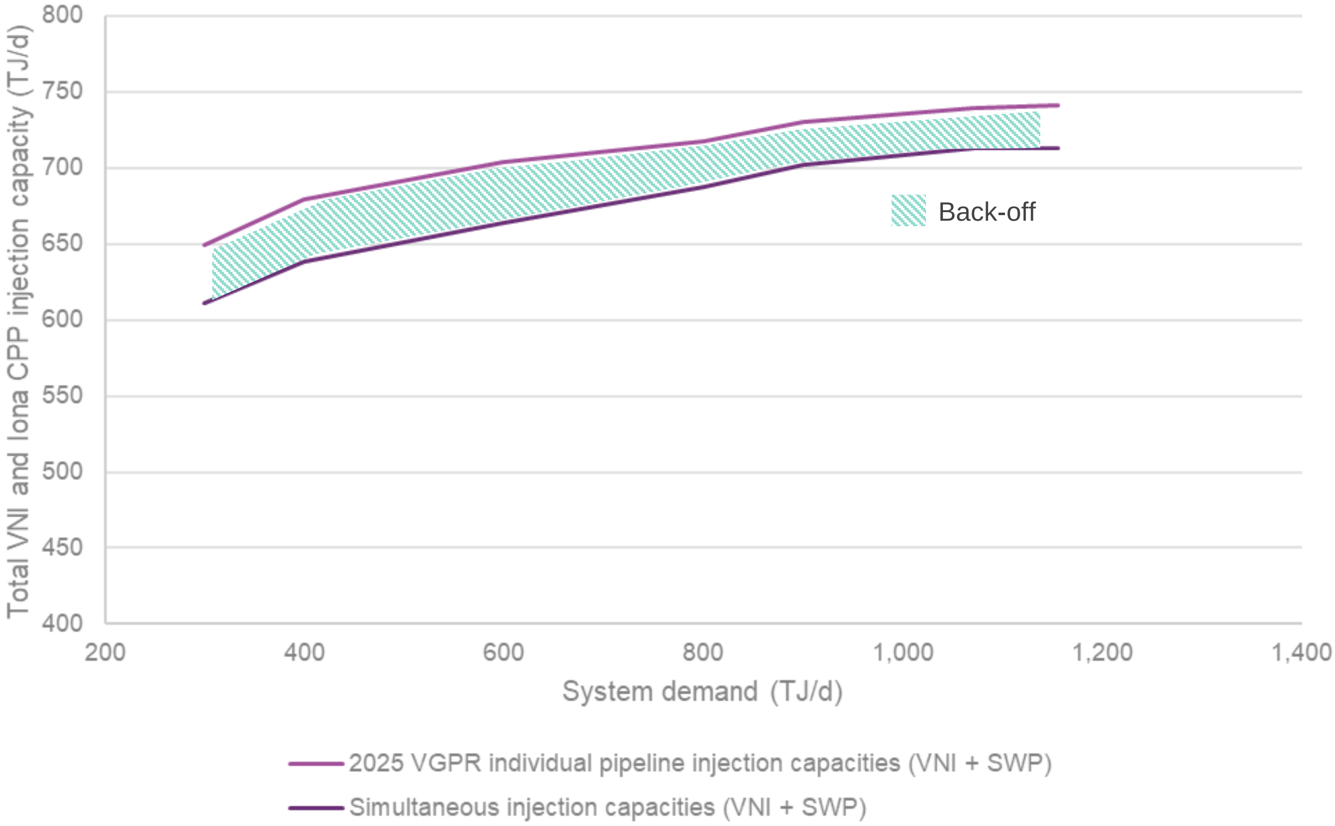
Back-off between Culcairn and Iona CPP injections

To maximise LMP withdrawals or minimise Longford CPP injections, flows from Iona CPP[93] and Culcairn into the DTS must be maximised simultaneously. Modelling indicates that there is a back-off effect between injections into the SWP at the Iona CPP and into the VNI at Culcairn when both supply sources are injecting into the DTS simultaneously. This results in a lower combined DTS supply quantity than the sum of the individual pipeline capacities for the system operating conditions. If during the scheduling process, the net aggregated injections scheduled from VNI and Iona CPP exceed the simultaneous injection capacities curve in **Figure 34**, AEMO will apply a zonal flow transportation constraint (ZFTC) to prevent the transportation capacity of the transmission system being exceeded. The ZFTC can also be applied to withdrawal meters on the VNI and Iona. This is discussed in more detail in Appendix A2.

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

Figure 34 shows the back-off between Iona CPP and Culcairn injections. The range of the back-off effect is between 26 TJ/d and 41 TJ/d in total across the two pipelines compared to the total of the individual pipeline capacities.

Figure 34 2025 VGPR total VNI and Iona CPP injection capacity and total simultaneous VNI and Iona CPP capacity (TJ/d)



Sale City Gate (CG) minimum operating pressure

Sale CG supplies the Australian Gas Networks (AGN) owned distribution network that supplies gas to the towns of Sale and Maffra. Due to its geographical proximity to the Longford Gas Plant, the connection point is susceptible to a minimum supply pressure breach during periods of very high demand, depleted system linepack or low Longford CPP injection flows.

Since 2022, AEMO and AGN have implemented a temporary process for AGN to consider reducing the Sale CG minimum operating pressure to 4,500 kilopascals (kPa) on days when there is a forecast pressure breach on a non-peak day demand. This 4,500 kPa minimum operating pressure is consistent with other connection point pressure requirements along the LMP.

Following the closure of the Saputo dairy in Maffra in early 2023[94], AGN conducted modelling that indicated that the higher minimum operating pressure at Sale CG was no longer required. The reduced minimum operating pressure of 4,500 kPa was made permanent in October 2024 following agreement between AGN, APA, and AEMO.

[94] ABC News, "Saputo closes dairy factory in Maffra, scales down others in Victoria and South Australia, with 75 jobs lost", https://www.abc.net.au/news/rural/2022-11-09/saptuo-dairy-factory-closures-victoria-sa-jobs-lost/101632758.

5.2 Potential supply project options to increase Declared Transmission System capacity

The 2025 GSOO has identified various potential new supply options to resolve the forecast supply gaps in the southern states for the 2025 VGPR outlook period, including LNG regasification terminal, increased north to south transportation capacity, and the development of contingent resources in the southern states.

AEMO has conducted a technical capacity assessment of the DTS to determine what, if any, DTS augmentation would be required to transport the gas supply from these various potential new supply options to customers supplied by the DTS (assuming the potential supply project reaches FID). This was a technical assessment of possible augmentations only, it did not contemplate economics, ease of project approvals, social license or other considerations.

These future supply projects have been grouped by connection location to the DTS, then the impact on the DTS was assessed on a transmission pipeline basis as summarised in **Table 19**:

- For potential projects that add supply into the DTS from the Gippsland region via the LMP, the LMP is assessed to be adequate to support additional supply capacity from any of the potential supply projects. This includes the Golden Beach production and gas storage facility and the PKET.
- The existing VNI pipeline capacity is sufficient to receive additional supply of up to 229 TJ/d via Culcairn from the proposed APA ECGG Expansion Stage 3. Stage 5 is proposed to further increase Culcairn's injection capacity up to 350 TJ/d involving additional compression and other transmission infrastructure reconfigurations.
- In contrast, if supply capacity was to be added to the Port Campbell region – from projects including a further Iona UGS expansion or connection of new Otway Basin fields, particularly projects that increase the production capacity of the Athena Gas Plant, or the Venice Energy South Australian LNG regasification terminal – further expansion of the SWP would be required to transport this increased supply capacity to Melbourne.
  - The available Port Campbell peak day supply for 2025 is forecast at 795 TJ/d. This capacity is utilised to supply DTS demand, the Mortlake Power Station and South Australia via the SEA Gas Pipeline (which is mainly GPG demand).
  - APA's SWP expansion proposal involves the installation of two additional compressor stations located at Stonehaven and Pirron Yallock to increase the SWP transportation capacity towards Melbourne.
  - A potential LNG regasification terminal project connecting to the SWP near Geelong would also increase DTS supply capacity. However, this additional capacity is only achieved when the LNG regasification terminal is injecting at near the maximum operating pressure of the SWP. This limits the simultaneous supply from facilities in Port Campbell as they are backed out of the SWP by the higher supply pressure of an LNG regasification terminal connected closer to Melbourne. Options to expand the SWP, including limiting the impact on the capacity of simultaneous supply into the SWP at Port Campbell (when there is high pressure supply from a Geelong LNG regasification terminal), are discussed in Section 5.2.2.
- An approximately 130 km crude oil pipeline, the WAG pipeline, is currently under consideration for potential conversion into a natural gas transmission pipeline to further increase supply capacity in the DTS.

Table 19 Future potential supply projects and DTS expansion summary

Future supply sources	Projects	Supply expansion location (relative to the DTS)	Impacted DTS pipeline	Potential future DTS pipeline capacity expansion required
Potential supply projects	• Golden Beach • Trefoil and White Ibis • Manta • Longtom • Wombat	Gippsland	Longford to Melbourne	No
	• Athena plant supply increase • Iona UGS expansion	Port Campbell	South West Pipeline	Yes
Potential LNG regasification terminal projects	• Viva including WAG pipeline conversion • Vopak	Geelong	South West Pipeline	Yes
	• Outer Harbor (Venice) and SEA Gas Pipeline bi-directional flow	Port Campbell	South West Pipeline	Yes
	• PKET and EGP bi-directional flow	Gippsland	Longford to Melbourne	No
APA East Coast Grid Expansion project	• Stage 3 & 4 • Stage 5	Culcairn	Victorian Northern Interconnect	No (Stage 3 & 4) Yes (Stage 5)

For more information about SWP capacity including a Geelong LNG regasification terminal, see the 2024 VGPR Update which included AEMO's technical assessment of the two different scenarios for potential additional supply connecting at Port Campbell or at Geelong, and how the DTS can be augmented to provide additional SWP supply capacity.

In this analysis:

- The SWP and the Brooklyn Lara Pipeline (BLP) are referred to as a single pipeline system (SWP) unless otherwise specified.
- Current Port Campbell supply includes the Otway Gas Plant, Athena Gas Plant and the Iona UGS facility, and this is referred to as a single supply location: the Iona CPP. Iona CPP could also include supply from Venice Energy's LNG regasification terminal at Outer Harbor, Adelaide, that would be transported to Port Campbell via reverse flow along the SEA Gas Pipeline.

5.2.1 Port Campbell supply expansion scenario

This scenario considers augmentation options where the available supply capacity is increased from Port Campbell and the Iona CPP remains the sole source of supply into the DTS from the west of Melbourne (that is, no Geelong LNG regasification terminal). As reported in 2024 VGPR Update, the identified augmentation options that could materially increase SWP capacity for this scenario involve possible incremental SWP looping options and the installation of new compressor units near Lara.

However, the pipeline looping options identified (and discussed in the 2024 VGPR Update) did not extend to the entire length of BLP ending at Rockbank. By modelling a further BLP looping option consisting of approximately 47 km of additional BLP looping and the installation of new compressor units near Lara, modelling results indicate a total increase of up to 250 TJ/d in SWP transportation capacity to 780 TJ/d is possible, as shown in **Table 20** below. The modelling of this option shows that additional looping to cover entire BLP (as well as the SWP) could provide additional supply to Melbourne from Port Campbell.

Stonehaven and Pirron Yallock compressor stations expansion project

AEMO also modelled APA's SWP expansion project proposal with the installation of two additional compressor stations, at Stonehaven and Pirron Yallock. This modelling indicates a possible further increase of SWP transportation capacity compared to the pipeline looping augmentations options reported in 2024 VGPR Update. Utilising the same inputs as the 2024 VGPR Update (for comparative purposes only), the corresponding SWP capacity increase for this two additional compressors option was modelled to compare against the previous augmentation options identified in the 2024 VGPR Update, as shown in Table 20.

The increase in SWP capacity modelled for the addition of the Stonehaven and Pirron Yallock compressor stations indicates an increased SWP transportation capacity of approximately 113 TJ/d, to 643 TJ/d. While this results in a possible increase of approximately 93 TJ/d compared to **Option 1** with 18 km of SWP pipeline looping upstream of the Winchelsea CS, the Stonehaven and Pirron Yallock compressor stations option delivers less capacity (643 TJ/d versus 660 TJ/d) than **Option 2** that consists of 108 km of SWP looping plus Winchelsea compression upgrades**.**

Each option (Stonehaven and Pirron Yallock compressor stations versus **Option 2**) has advantages and corresponding disadvantages. The Stonehaven and Pirron Yallock compressor stations are likely to have a lower capital cost, but higher ongoing maintenance costs and fuel gas emissions, while **Option 2** would provide more system linepack, which will be increasingly important for supporting forecast increases in GPG demand.

Figure 35 Diagram of the DTS showing key locations

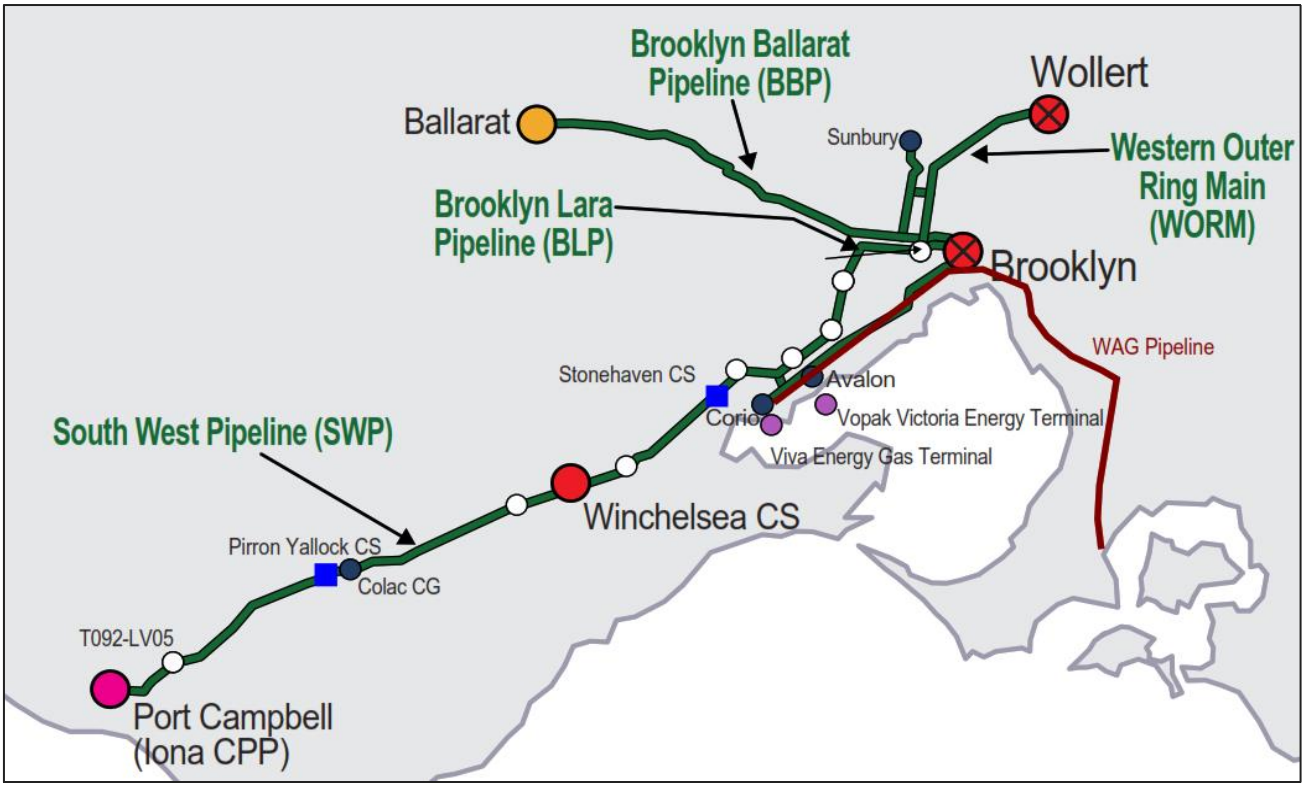


Table 20 Potential options for scenario with no new LNG supply at Geelong

	Option	Augmentation description	SWP capacity (TJ/d)	SWP capacity increase from existing (TJ/d)
Augmentation options identified in 2024 VGPR Update	1	Looping of the existing 18 km SWP from Colac to Winchelsea	550	20
	2	Option 1 plus: Looping of the existing 90 km SWP from Iona UGS to Lara and Winchelsea Winchelsea Compressor modifications for parallel operation	660	130
	3	Option 2 plus: Additional 47 km looping of BLP from Lara to Rockbank Compressor station with two compressor units at Lara	780	250
APA's Stonehaven CS and Pirron Yallock CS expansion option without pipeline looping	4	Stonehaven CS and Pirron Yallock CS	643	113

5.2.2 Viva Energy's Westernport – Altona – Geelong (WAG) pipeline project scenario

AEMO has conducted preliminary modelling of the DTS capacity impact for the potential WAG pipeline conversion project in combination with the proposed Viva Energy LNG regasification terminal project. The WAG pipeline, which is currently a crude oil (now condensate since the end of Longford crude oil production) pipeline, was constructed in 1972 and has a length of approximately 130 km running from Westernport to Altona and onward to Viva Energy's refinery at Geelong. The WAG pipeline has an maximum allowable operating pressure (MAOP) of up to 5,500 kPa and has a nominal pipeline diameter of 400 mm from Geelong to Altona that increases to a 600 mm diameter from Altona to Westernport, near Hastings, as shown above in Figure 35.

Preliminary modelling results shows that the WAG pipeline has a transportation capacity of approximately 200 TJ/d if converted to transport natural gas. The modelling results are based on the same inputs as the 2024 VGPR Update and have not been updated to match the VGPR 2025 guidelines, to provide a comparison against other modelling results. The pipeline capacity modelling shows that the main limiting factor for the capacity of the WAG pipeline in natural gas service is the pressure loss in the Geelong to Altona section of the pipe, which has a diameter of 400 mm.

The modelling of the WAG pipeline indicates an improvement to the overall SWP injection capacity, but not at a 1:1 ratio. The modelled results show an increase in SWP transportation capacity of up to 120 TJ/d. With the Viva LNG regasification terminal injecting at maximum rate of 750 TJ/d, with the inclusion of the WAG pipeline, Iona CPP can also supply up to 140 TJ/d as shown in **Table 21**.

Table 21 Potential options for scenario with a new LNG supply at Geelong

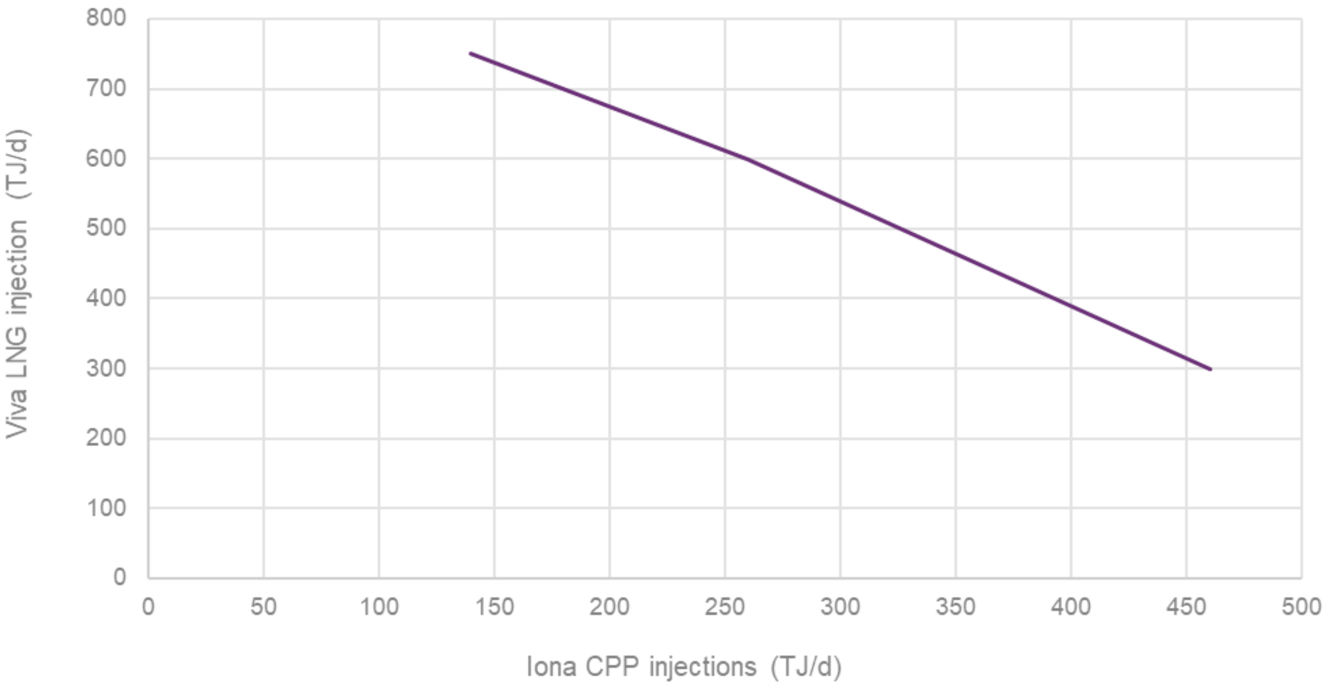
	Option	Augmentation description	SWP capacity (TJ/d) with LNG delivery prioritised	SWP capacity increase from existing (TJ/d)
Port Campbell to Melbourne augmentation options with Geelong LNG regasification terminal	1	Viva LNG Regasification Terminal connects to current system	770	240
	2	Viva LNG Regasification Terminal and WAG pipeline	890	360

As **Figure 36** shows, the limitation of this solution is that the maximum increase in peak day capacity is only achieved by backing off Iona CPP supply and maximising Viva LNG regasification injections. This would introduce market complexities, because the LNG regasification terminal and Iona CPP would compete for capacity on the SWP. Ultimately, without augmentation of the SWP, Iona CPP injections would be backed out by the high pressure supply from the LNG regasification terminal.

The primary limiting factor for further SWP injections is the capacity for the DTS to effectively transport the increased SWP flow to system offtakes to the north and east of Melbourne. Additional modelling analysis is required to identify the augmentation options that can address the effects of backing off the Port Campbell supply. These options are focused primarily on enabling more gas from the southwest section of the DTS to flow to the eastern side of the network.

Modifications to the DTS to enable increased supply from the southwest would include, first, an expansion of the Western Outer Ring Main (WORM) Pressure Reduction Station (PRS) to enable more flow into the Pakenham to Wollert (T61) pipeline that would allow for more SWP gas to flow around and through Wollert towards the east as well as to the north. Further expansion options include more compression on the SWP to increase flows through the expanded WORM PRS. A connection from the WAG Pipeline to the Dandenong City Gate (DCG) outlet (or to major distribution mains that cross the WAG pipeline, including the Mornington Peninsula and Edithvale pipelines) would allow the WAG to inject into the eastern side of the Inner Ring Main. A flow on impact is that this connection(s) could enable DCG to operate at a lower outlet pressure, which could enable more SWP gas to flow through Brooklyn City Gate.

Figure 36 SWP back-off with WAG pipeline



5.3 Peak day system adequacy

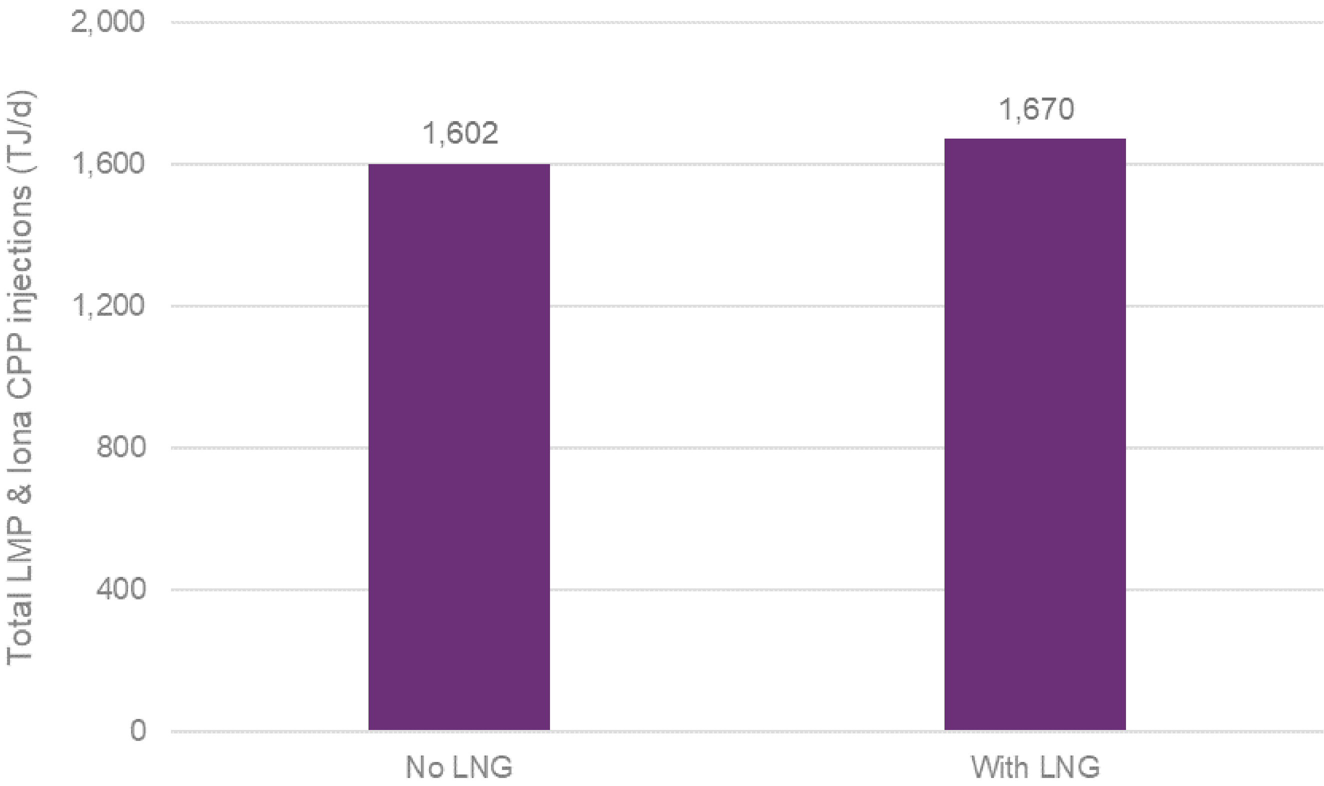
Peak day system adequacy modelling was conducted by quantifying the main sources of DTS injections – the LMP, Iona CPP and Dandenong LNG injections – required to meet total DTS demand (including gas generation).

The DTS peak day system capacity results shown in **Figure 37** are achievable as follows:

- The maximum capacity of 1,670 TJ/d is achieved with Dandenong LNG injecting at a rate of 57 TJ/d, and 1,602 TJ/d without Dandenong LNG injections.
- Culcairn injections or withdrawals are not included in system capacity modelling.

This analysis assumed that there is sufficient gas supply available to inject these quantities into the DTS.

Figure 37 DTS peak day system capacity (TJ/d)



5.4 Gas-powered generation supportability

GPG peak demand is forecast to increase during the VGPR outlook period as outlined in Section 2.4.3, with GPG demand during winter periods forecast to significantly increase in the later years of the outlook period. This increase in forecast winter peak GPG demand is due to the planned closure of coal-fired power stations (Eraring and Yallourn), the expected electrification of winter heating loads, and periods of low VRE production (particularly solar). Due to this increased GPG demand, there is a growing potential for peak GPG demand to coincide with a peak system demand day. Assessing the ability of the DTS to support DTS-connected GPG demand is therefore critical.

Operational challenges occur when high GPG demand is not accurately forecast at the beginning of the gas day during the winter peak system demand period, because:

- The DTS has lower useable linepack during winter due higher pipelines flows. This results in higher pressure drops along DTS pipelines, which reduces the operating pressure ranges between minimum and maximum pressures, and therefore the amount of useable linepack that is available.

- High instantaneous GPG demand, which tends to occur following incidents in the power system (including coal generation and transmission line trips), reduces linepack quickly, especially during the morning and evening peak periods when hourly gas demand is already high.

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

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

AEMO modelling has determined that the DTS can support 414 TJ of DTS-connected GPG demand on a 1-in-20 peak winter day (assuming that sufficient gas supply is available).

5.4.1 Peak gas generation in winter

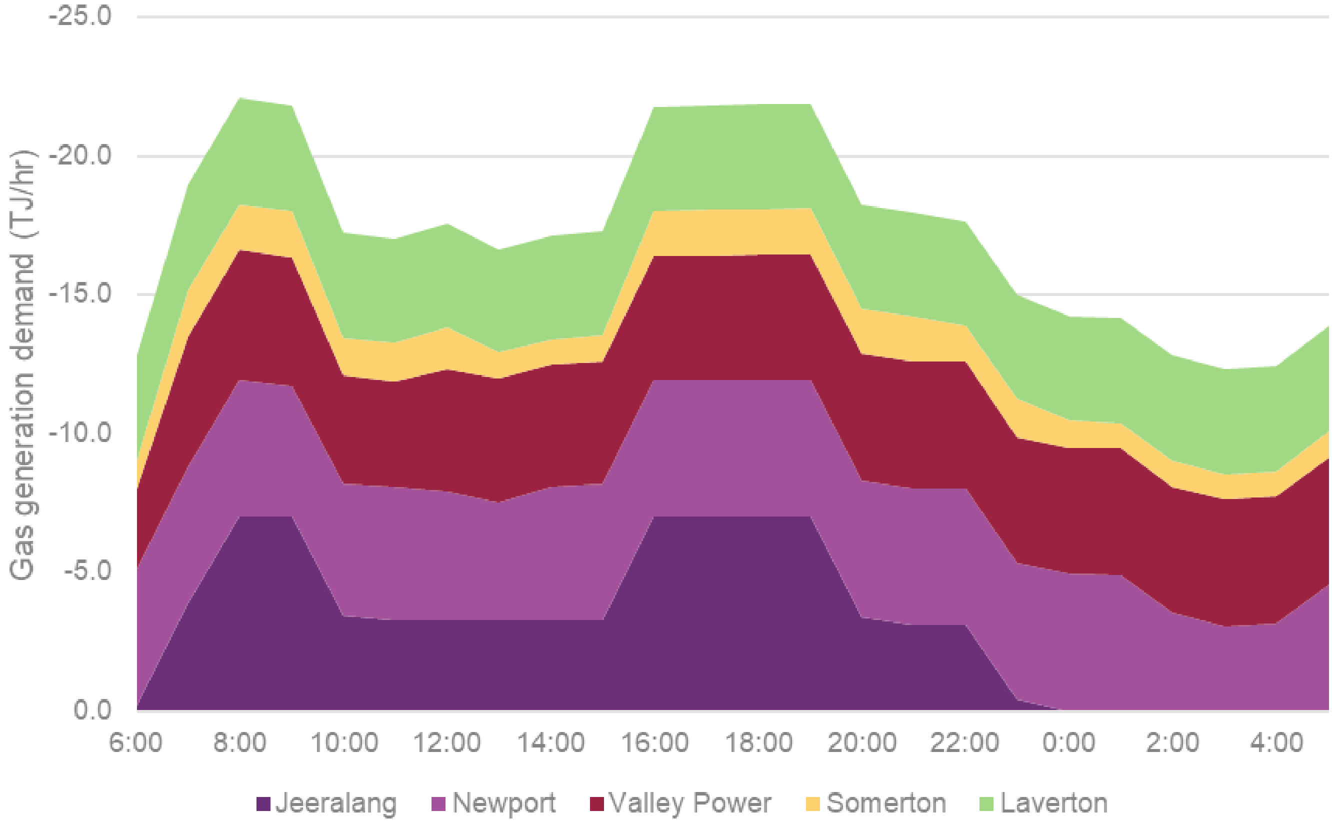
AEMO modelled peak GPG demand scenarios that coincide with a forecast peak system demand day to determine the physical DTS supportability for existing GPG facilities. A modelling scenario for a 1,155 TJ (1-in-20) peak system demand day was completed which determined that 414 TJ of DTS-connected GPG demand, with all units operating, could be supported. Additional information about the results is as follows:

- Injections were required at Iona CPP.
- Longford CPP injections were used to balance supply and demand[95].
- There is sufficient physical DTS infrastructure capacity to support all current DTS-connected GPG units with historical non-coincident peak hourly profiles at 414 TJ/d of total demand.

The DTS can support the modelled GPG demand profile in **Figure 38**, however if GPG or system demand is not accurately forecast at the beginning of the day, additional Dandenong LNG injections are likely to be required and the supportable GPG demand may be lower.

[95] Refer to Appendix Section A1.3.1 for LMP injection capacity to Melbourne.

Figure 38 Modelled peak gas generation profile



6 Declared Transmission System pipeline capacities

The **reduction in peak day demand forecast has caused a slight reduction in various DTS pipeline capacities** due to the lower peak demand impacting the modelled transportation capacity.

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.
- For the auctioning of entry and exit capacity certificates.

This section outlines the DTS pipeline capacities as at the publication date of this VGPR. See Appendix A7 for more detail on AEMO's modelling approach for this VGPR and all 2025 capacity modelling assumptions.

Table 22 Summary of DTS pipeline capacities

Pipeline		Maximum capacity (TJ/d)	Comment
Longford to Melbourne	To Melbourne	1,126	
	To Longford	307	Reduced on a one-to-one basis by GPG demand at Jeeralang or Valley Power.
South West Pipeline	To Melbourne	523	Includes 17 TJ of Western Transmission System (WTS) demand. Slight capacity decrease compared to the 530 TJ/d in the 2024 VGPR Update due to reduced overall system demand.
	To Port Campbell	341	
Victorian Northern Interconnect	To Melbourne	224	Limited to 180 TJ/d due to capacity constraints in the New South Wales transmission network.
	To New South Wales via Culcairn	218	

6.1 Longford to Melbourne Pipeline

The 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 and the BassGas injection point at Pakenham.

With the capability to bypass the Gooding CS, modelling indicates that flow from Dandenong to Longford and withdrawals at Longford CPP are possible. Physical withdrawals at Longford CPP are likely to only occur in the event of an unplanned outage at the Longford Gas Plant. Refer to Section 5.1 for further discussion on Longford full plant outages and LMP withdrawal capability.

6.1.1 Longford to Melbourne import capacity

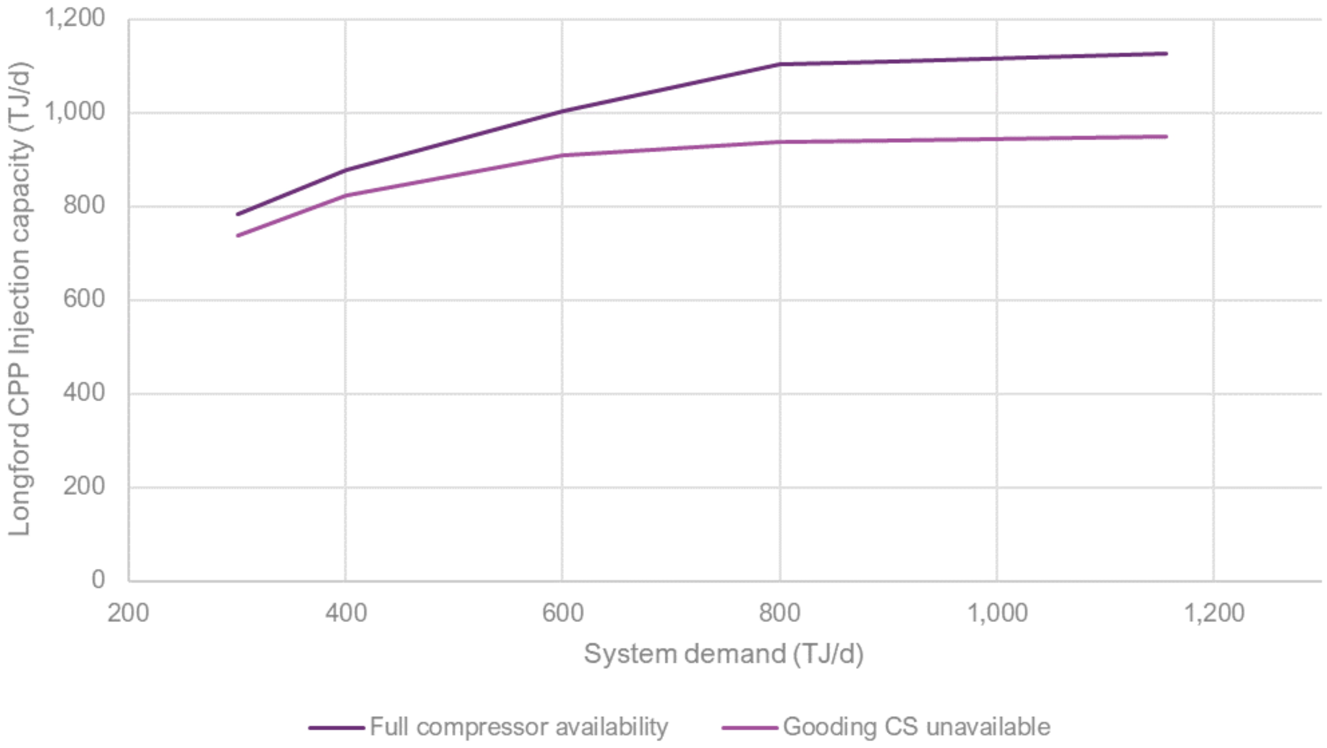
Figure 39 shows the LMP injection capacity to Melbourne. The LMP transportation capacity varies with system demand and asset availability.

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 176 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 remains above 1,100TJ/d on peak demand days but has reduced slightly compared to the 2024 VGPR Update by between 33 TJ/d and 39 TJ/d. This is due to the reduction in overall system demand forecasts slightly reducing the LMP's injection requirement, resulting in a decrease in the 1-in-20 system demand day capacity from 1,160 TJ/d to 1,126 TJ/d. This can be attributed to an updated modelling assumption for the BassGas connection point in 2024 (see **Appendix A7**).

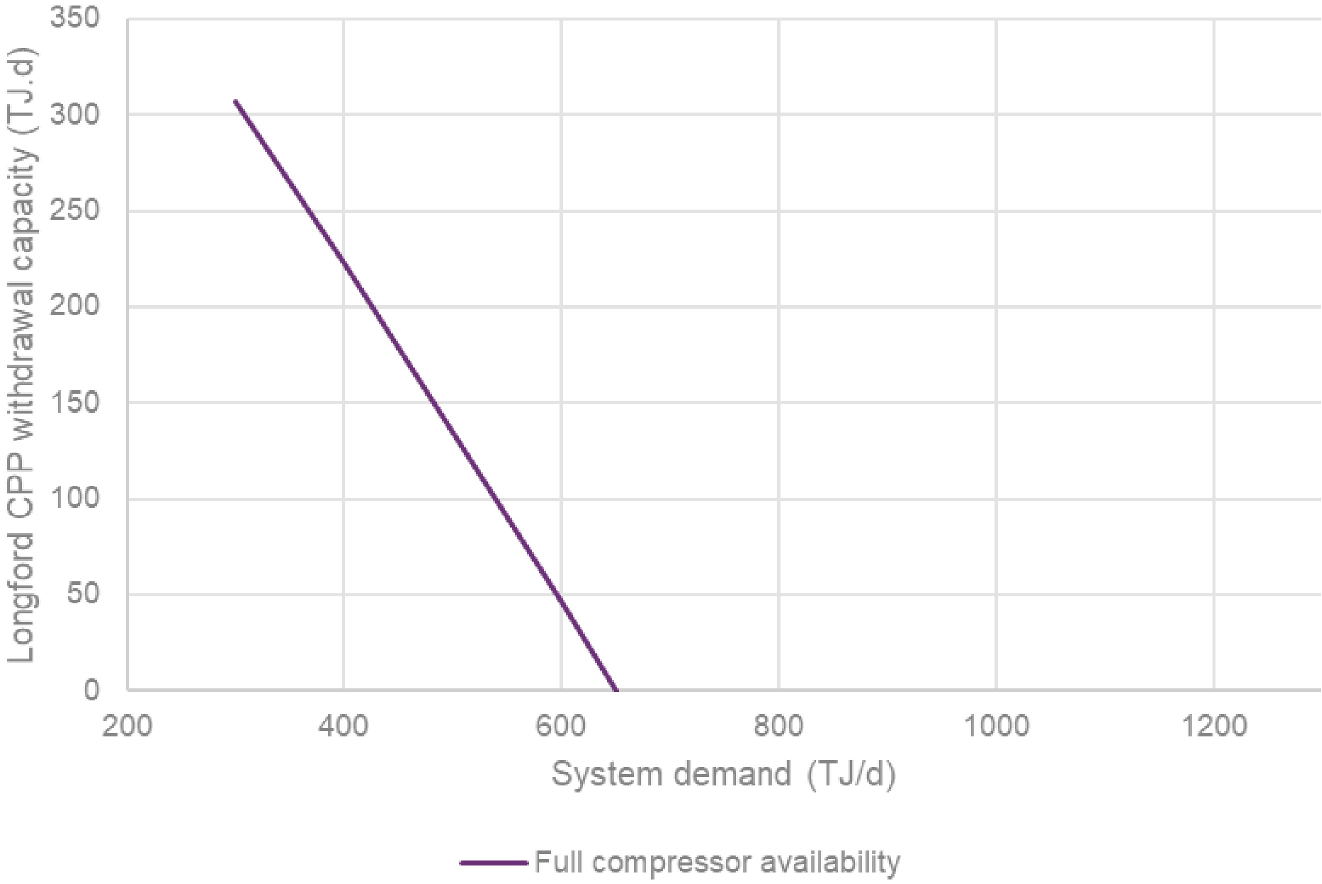
Figure 39 LMP injection capacity (TJ/d) with varying Gooding CS availability



6.1.2 Longford to Melbourne export capacity

Figure 40 shows the LMP withdrawal capacity to Longford. The LMP transportation capacity varies with system demand and is impacted by GPG demand at Valley Power and Jeeralang GPG on a one-to-one basis. The LMP withdrawal capacity is dependent on high simultaneous injections at the Iona CPP and Culcairn, which may be impacted by asset availability on the SWP and VNI. LMP withdrawals are not possible when demand is greater than 650 TJ/d.

Figure 40 LMP withdrawal capacity (TJ/d) to Longford CPP



6.2 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. The SWP can also supply Wollert via the WORM, which runs from the connection to the BLP at Rockbank via Plumpton to Wollert.

The SWP is typically used to:

- Transport gas from the Port Campbell production and storage facilities at Iona CPP[96] towards Melbourne to support DTS demand, including supplying gas to northern and eastern Victoria via the WORM.
- Transport gas from Melbourne for withdrawal at the Iona CPP during the shoulder and summer low system demand periods for:
  - Iona UGS reservoir refilling,

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

- Supply to the Mortlake Power Station, and
- Transportation to South Australia via the SEA Gas Pipeline.

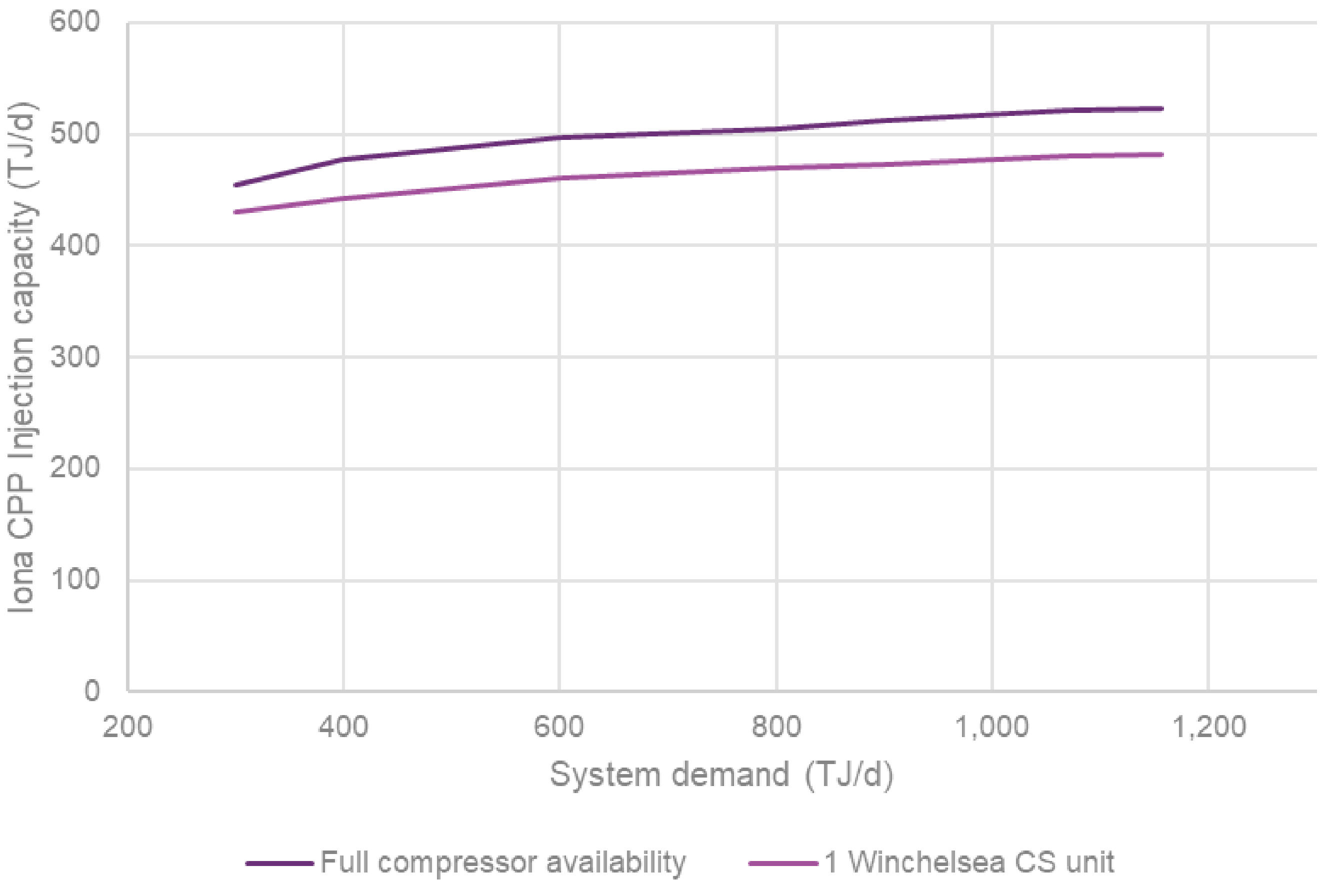
Physical withdrawals from the SWP at the Iona CPP require compression at the facility withdrawing the gas. Iona UGS is currently the only Port Campbell facility that physically withdraws gas from the SWP.

- 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.

6.2.1 South West Pipeline to Melbourne

The SWP injection capacity (including WTS demand), shown in **Figure 41**, 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 41 SWP injection capacity (TJ/d) (including WTS demand) toward Melbourne with varying Winchelsea CS availability



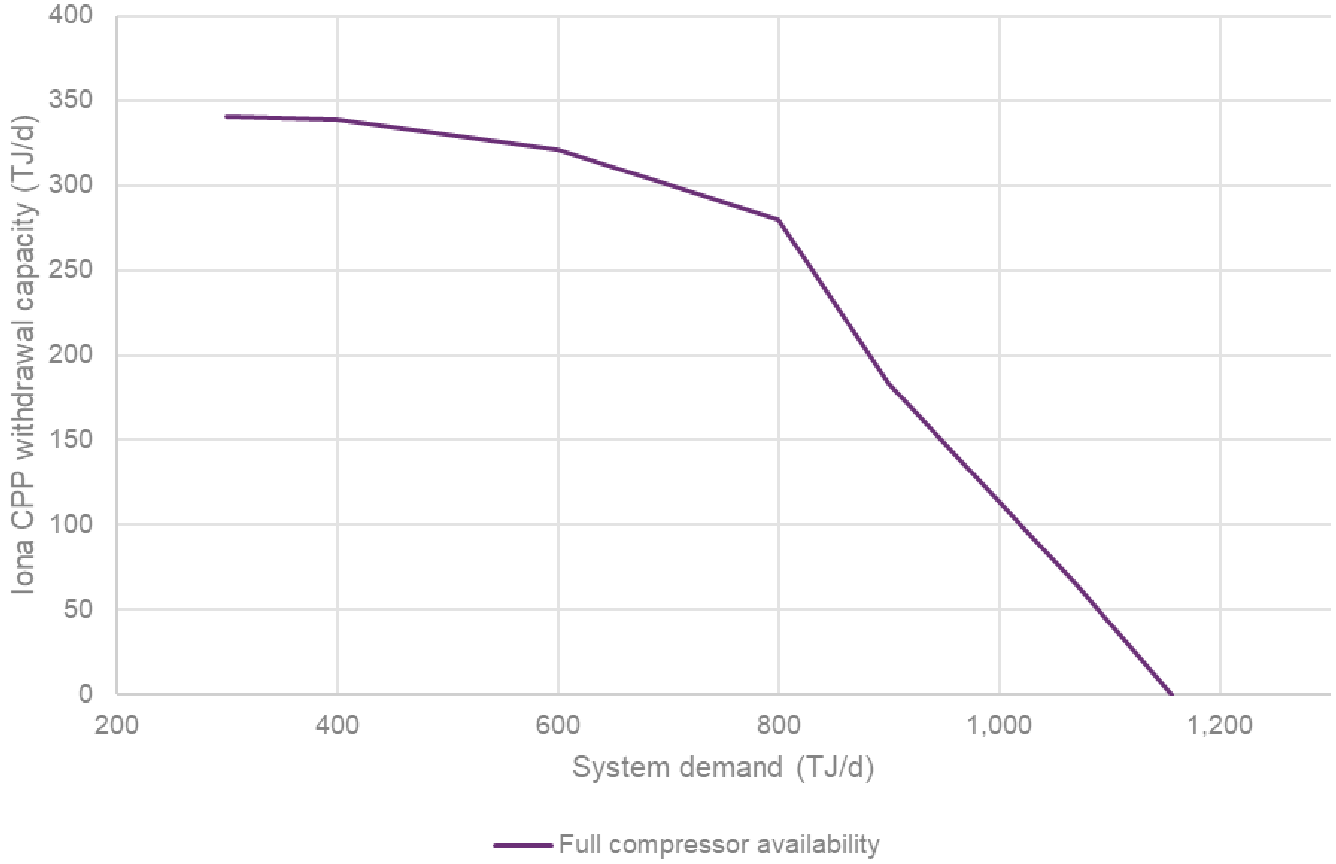
The SWP capacity is slightly reduced compared to the 2024 VGPR Update due to the overall drop in the system demand forecast impacting injection requirements at Iona CPP. This causes a reduction SWP transportation capacity on peak system demand days from 530 TJ/d in 2024 to 523 TJ/d in 2025 on a 1-in-20 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[97]; AEMO and APA finalised the SWP modelling assumptions since that time (see **Appendix A7**).

6.2.2 South West Pipeline to Port Campbell

The SWP capacity to support Iona UGS withdrawals is shown in **Figure 42**. The withdrawal capacity is maximised on low system demand days when Winchelsea CS and all three Wollert B CS units are available.

Figure 42 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 2024 VGPR Update due to a change in the assumptions at Culcairn, as discussed in **Appendix A7**. 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 B CS units and compression at Winchelsea CS reduces the SWP export capacity by approximately 80 TJ/d during shoulder and summer low system demand days.

SWP export capacity is also impacted by the change in DTS capacity dynamics due to WORM pipeline enabling Wollert B CS to support both Northern and Western withdrawals as detailed in **Appendix A2**. AEMO continues to

[97] 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.

monitor this relationship and implement necessary operational system changes to ensure maximum SWP export capacity can be achieved.

6.3 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 PRS, and the Echuca and Koonoomoo laterals. The pipeline has a section with an 8,800 kPa 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 as well as supplying the town of Walla Walla.

The planning assumptions for VNI capacity are outlined in **Appendix A7**.

6.3.1 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 43** 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[98]).

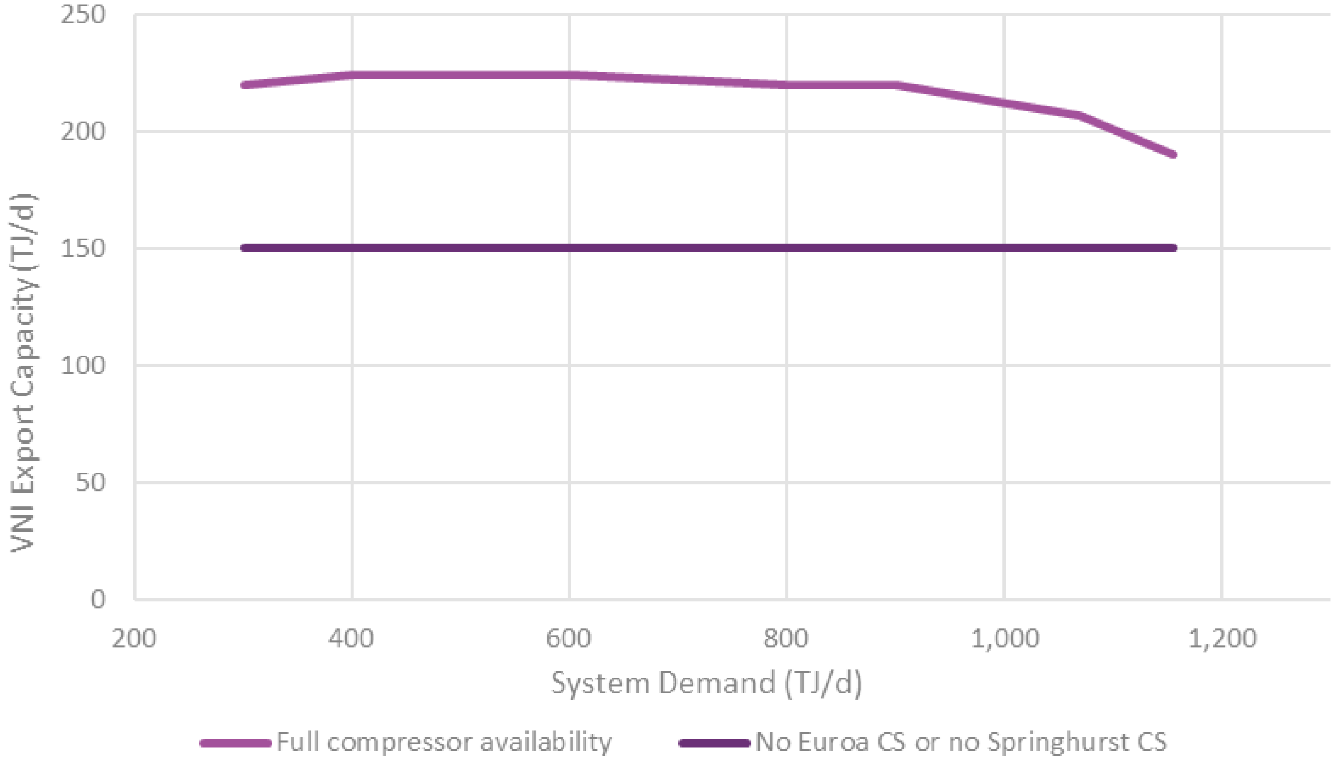
The effects of the commissioning of the WORM pipeline on DTS capacity dynamics also impact VNI export capacity from the relationship enabled with Wollert compressor supporting both Northern and Western withdrawals as detailed in **Appendix A2**. AEMO is continuing to monitor this relationship and implement necessary operational system changes to ensure maximum VNI export capacity can be achieved.

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.

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 B CS and only one of Euroa CS or Springhurst CS are available.

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

Figure 43 Victorian Northern Interconnect export capacity (TJ/d)



6.3.2 Victorian Northern Interconnect import capacity (to Victoria)

The VNI import capacity is shown in **Figure 44**, 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.

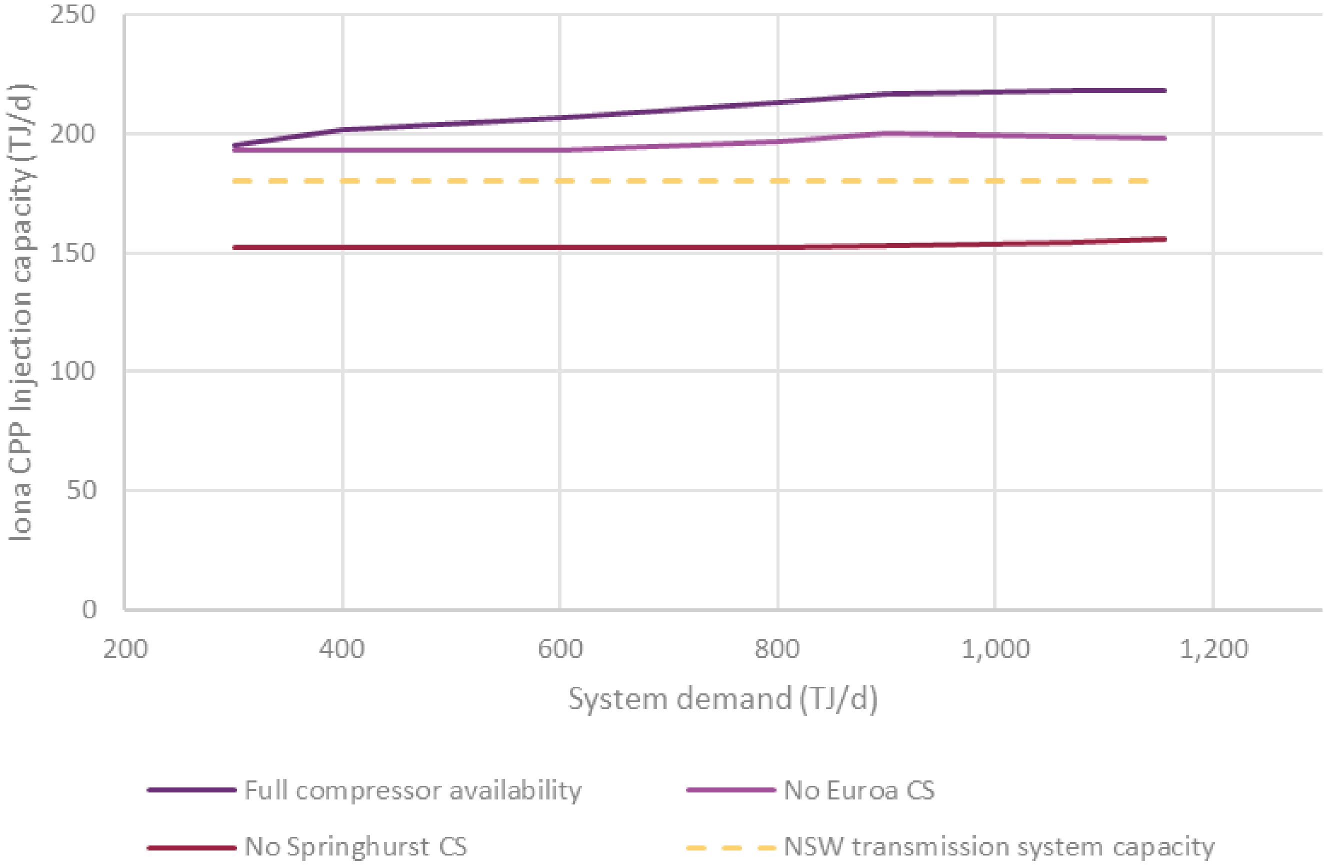
For most DTS compressor configurations, the VNI import capacity is higher than the Culcairn supply capacity.

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 2024 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.

Figure 44 Victorian Northern Interconnect import capacity (TJ/d)



A1. System capability modelling

A1.1 Monthly peak demand for 2025-2029

Table 23 shows forecast peak day system demand for each month from 2025 to 2029. The forecast peak day system demand will be used to inform the amount of capacity certificates for any month and capacity certificate type[99].

Table 23 Forecast monthly 1-in-20 peak day demand from 2025 to 2029 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2025	421	442	532	744	981	1,107	1,144	1,102	953	798	702	498
2026	411	430	522	729	964	1,074	1,118	1,079	934	780	680	485
2027	406	424	506	708	937	1,053	1,090	1,059	912	765	667	477
2028	394	410	489	691	904	1,016	1,053	1,018	878	741	646	468
2029	384	397	474	656	867	973	1002	977	839	710	618	449

A1.2 Capacity certificate zones

There is no change to the capacity certificate zones that AEMO determined and published in the 2024 VGPR Update. **Table 24** shows the capacity certificates zones and system points allocated to capacity certificates zones.

Table 24 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 45**)
Gippsland exit zone	VicHub withdrawal point TasHub withdrawal point	Longford Melbourne Pipeline to Longford (**Figure 46**)
Melbourne entry zone	Dandenong LNG injection point	(**Table 26**)
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 47**)
South west exit zone	Iona withdrawal point SEA Gas withdrawal point Otway withdrawal point	South West Pipeline to Port Campbell (**Figure 48**)
Northern entry zone	Culcairn injection point	Victorian Northern Interconnect to Melbourne (**Figure 49**)
Northern exit zone	Culcairn withdrawal point	Victorian Northern Interconnect to New South Wales via Culcairn (**Figure 50**)

[99] 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 2024 VGPR Update, except for the changes outlined in **Table 25**. For assumptions in the 2025 VGPR, see **Appendix A7**.

Table 25 Changes to Victorian gas planning approach from the 2025 VGPR

Location	Previous setting	Current setting	Reason for change
Corio City Gate	Minimum inlet pressure 2,300 kPa.	Minimum inlet pressure increased to 2,500 kPa	AEMO and Distributor's updated agreement

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 45 LMP injection capacity to Melbourne (TJ/d)

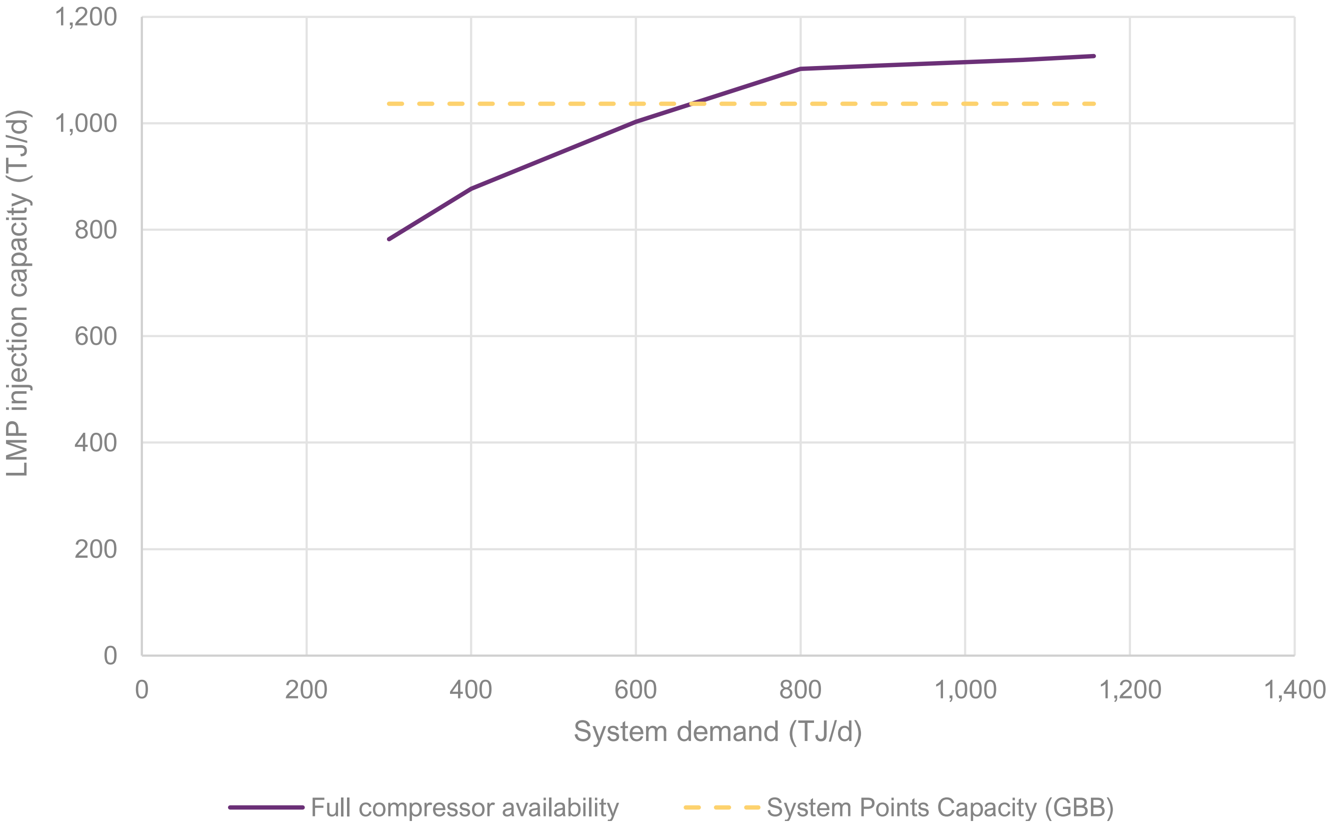
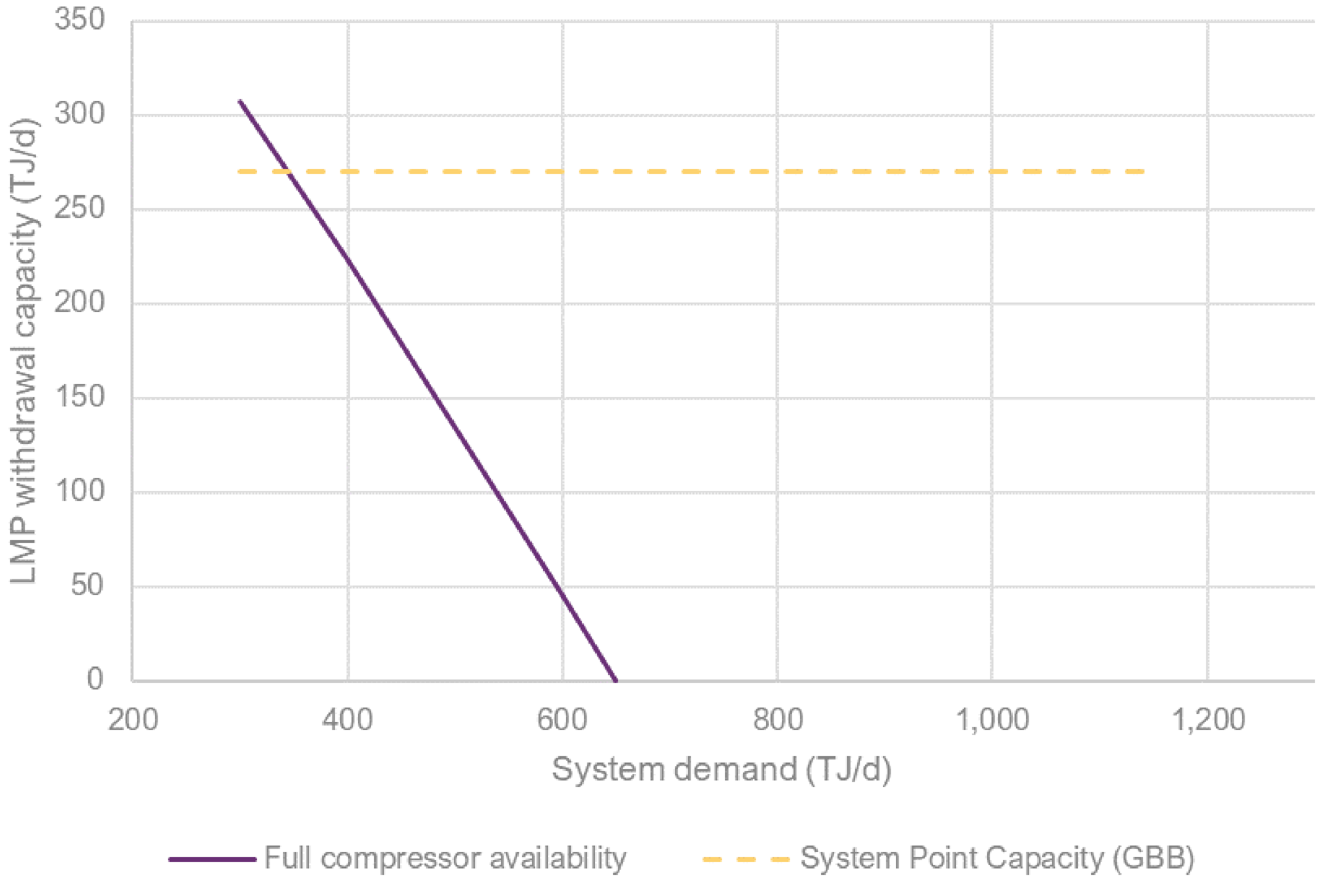


Figure 46 LMP withdrawal capacity to Longford (TJ/d)



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 26 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 47 SWP injection capacity to Melbourne (TJ/d)

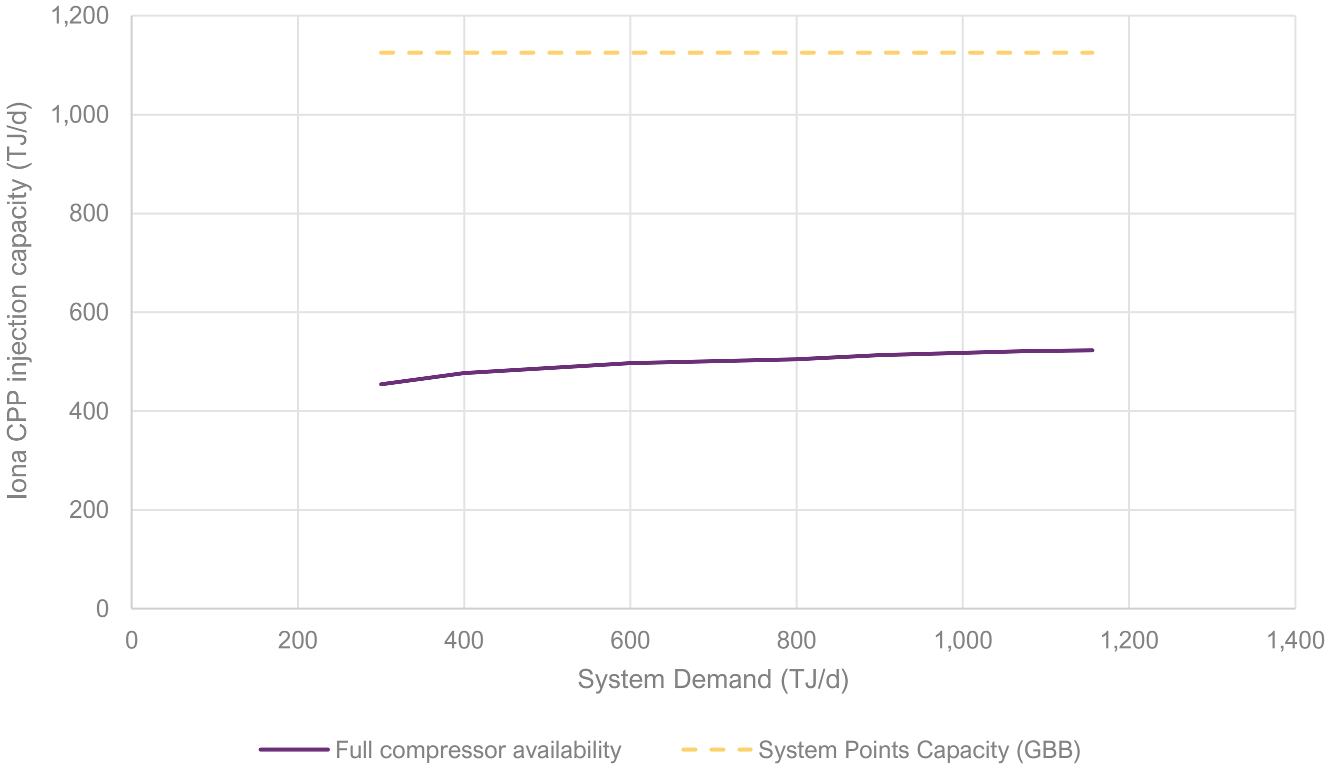
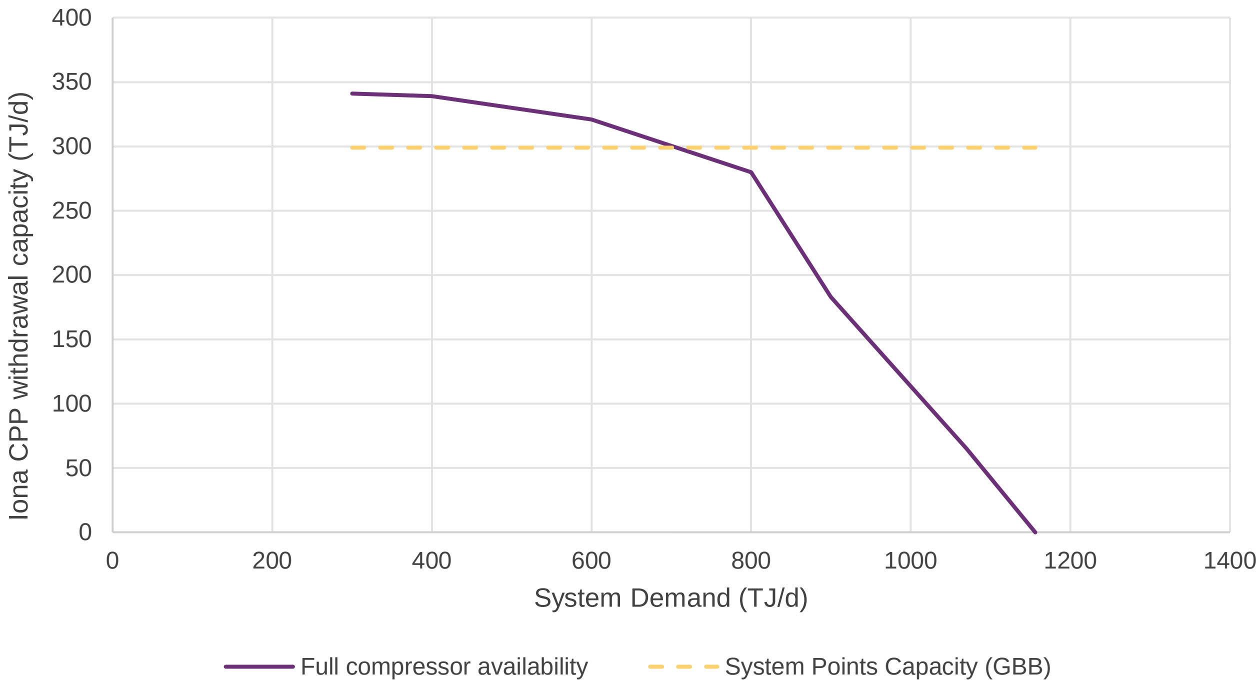


Figure 48 SWP withdrawal capacity to Port Campbell (TJ/d)



A1.3.4 Victorian Northern Interconnect

Figure 49 Victorian Northern Interconnect import capacity (TJ/d)

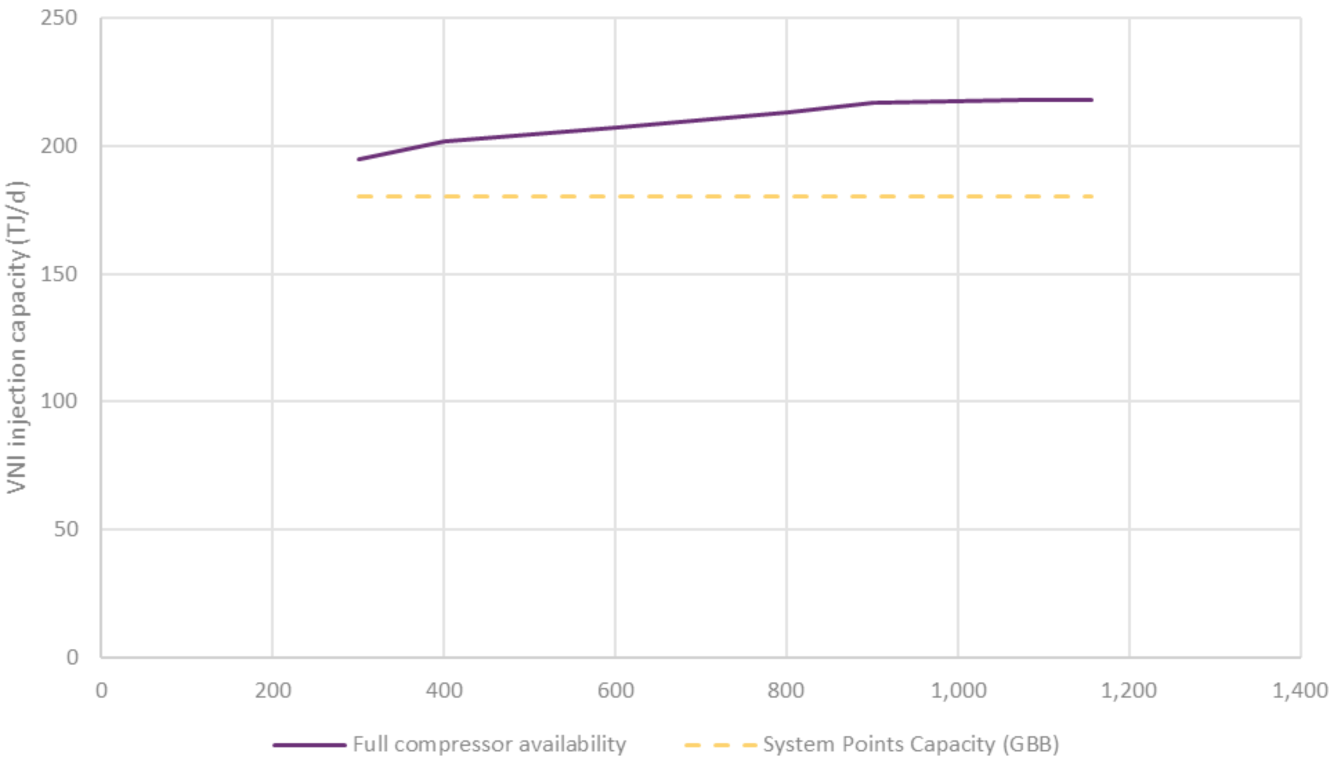
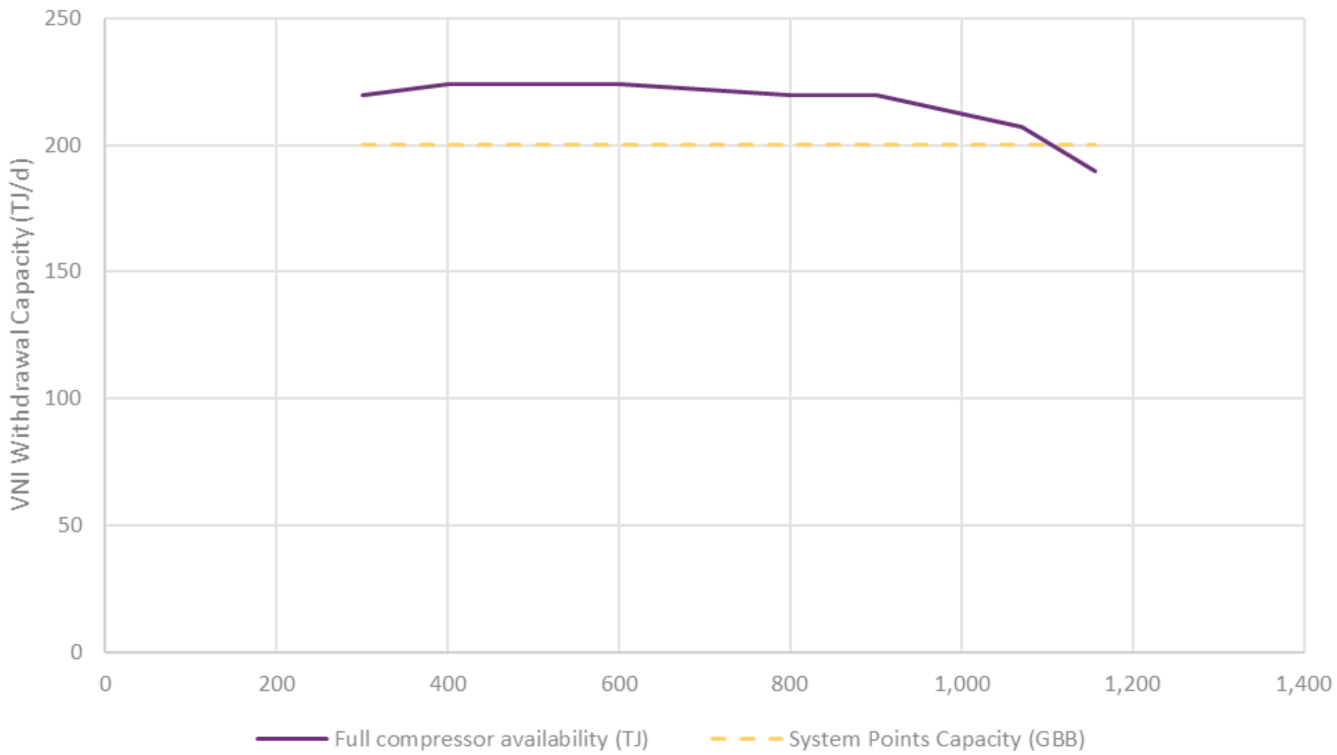


Figure 50 Victorian Northern Interconnect export capacity (TJ/d)



A2. Zonal Flow Transportation Constraint

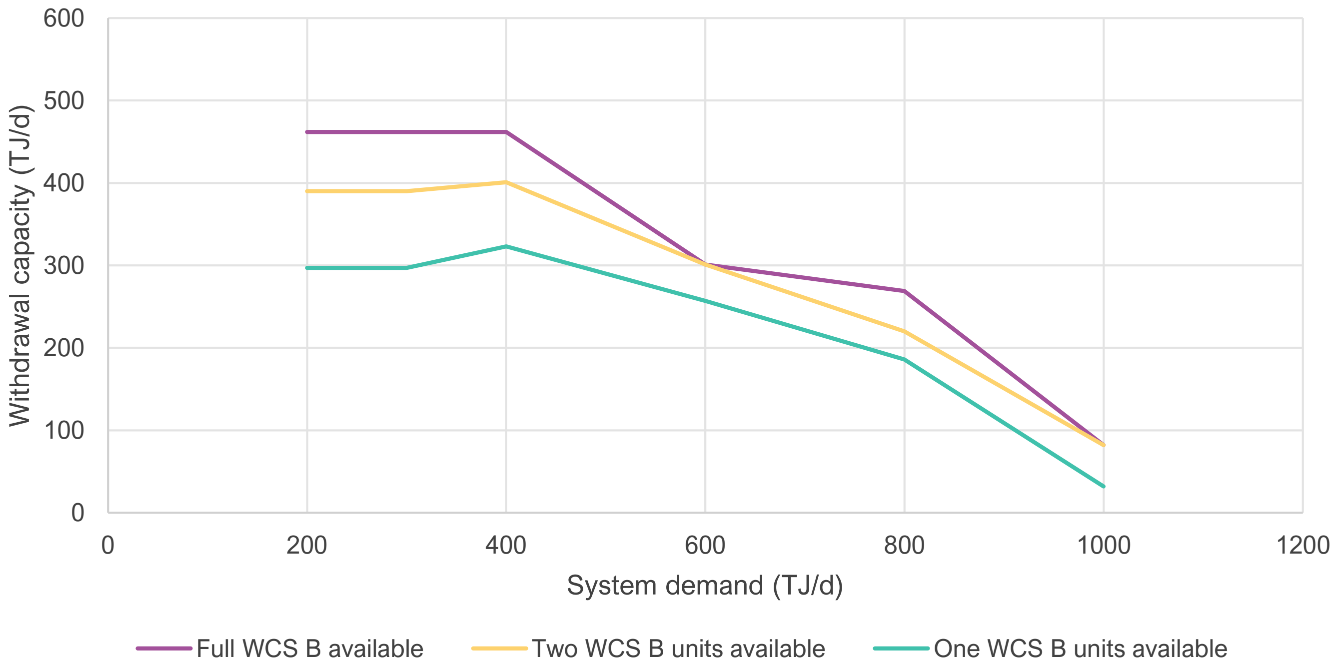
The Zonal Flow Transportation Constraint (ZFTC) is a new market constraint introduced as part of the DWGM MCE Update project[100]. A ZFTC can be applied to a group of injection or withdrawal meters on two or more pipeline systems to prevent the transportation capacity of the transmission system being exceeded. Its purpose is to ensure net aggregate flows remain within the physical capacity of the DTS.

The commissioning of the WORM changed the DTS capacity dynamics with the Wollert B Compressor Station (Wollert B CS) now supporting both SWP and Northern withdrawals at Culcairn. Net total withdrawals at both the Iona close proximity point (CPP) and Culcairn need to align with total Iona CPP and Culcairn withdrawal capacity, as well as individual pipeline transportation capacities, all of which will vary depending on Wollert compression availability.

Figure 51 shows the Iona CPP and Culcairn total withdrawal capacity curves with varying Wollert B CS unit availability. The curve indicates the total simultaneous withdrawal quantity of SWP and Culcairn that AEMO has modelled and validated as achievable within the DTS limits. These total quantities account for different combinations of withdrawals split between SWP and Culcairn.

During the scheduling process, the ZFTC withdrawal scheduled is checked against total withdrawal capacity curves in Figure 51. If the total withdrawal quantity is not within the total capacity curve, a ZFTC is applied to ensure total withdrawals remain within pipeline transportation limits and are physically achievable. The Net Flow Transportation Constraint (NFTC) process remains unchanged.

Figure 51 Total Iona CPP and Culcairn withdrawal capacity in relation to Wollert B Compressor Station (WCS B) availability



[100] At https://aemo.com.au/consultations/current-and-closed-consultations/dwgm-market-clearing-engine-update-project.

A3. Gas demand forecast data by System Withdrawal Zone

A3.1 Annual consumption and demand

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

Table 27 Annual system consumption by System Withdrawal Zone (Tariff V and Tariff D split) (PJ/y)

SWZ		2025	2026	2027	2028	2029	Change over outlook
Ballarat	Tariff V	8.9	8.8	8.6	8.3	7.9	-11.0%
	Tariff D	1.3	1.2	1.3	1.3	1.3	-0.3%
	SWZ total	**10.2**	**10.0**	**9.8**	**9.5**	**9.2**	**-9.7%**
Geelong	Tariff V	11.0	10.8	10.6	10.3	9.8	-11.0%
	Tariff D	8.8	8.8	8.8	8.9	8.8	-0.2%
	SWZ total	**19.8**	**19.6**	**19.4**	**19.1**	**18.6**	**-6.2%**
Gippsland	Tariff V	6.2	6.2	6.2	6.1	6.0	-2.5%
	Tariff D	6.7	6.6	6.7	6.6	6.5	-2.0%
	SWZ total	**12.8**	**12.8**	**12.9**	**12.8**	**12.5**	**-2.2%**
Melbourne	Tariff V	82.1	79.5	76.5	72.7	68.4	-16.7%
	Tariff D	26.2	25.6	25.6	25.4	25.1	-4.2%
	SWZ total	**108.3**	**105.1**	**102.0**	**98.1**	**93.5**	**-13.7%**
Northern	Tariff V	10.8	10.7	10.6	10.3	10.0	-7.2%
	Tariff D	7.5	7.5	7.5	7.5	7.4	-1.5%
	SWZ total	**18.3**	**18.2**	**18.1**	**17.8**	**17.4**	**-4.8%**
Western	Tariff V	1.2	1.1	1.0	1.0	0.9	-20.6%
	Tariff D	2.5	2.5	2.6	2.6	2.5	0.4%
	SWZ total	**3.7**	**3.6**	**3.6**	**3.5**	**3.4**	**-6.2%**

Table 28 Annual 1-in-2 peak daily demand by System Withdrawal Zone (Tariff V and Tariff D split) (TJ/d)

SWZ		2025	2026	2027	2028	2029	Change over outlook
Ballarat	Tariff V	56.3	55.4	54.5	52.6	50.2	-10.9%
	Tariff D	5.2	5.2	5.1	5.2	5.1	-0.7%
	SWZ total	**61.5**	**60.6**	**59.6**	**57.8**	**55.3**	**-10.1%**
Geelong	Tariff V	72.5	71.3	70.1	67.7	64.6	-10.9%
	Tariff D	33.2	33.4	33.6	33.4	33.2	0.0%
	SWZ total	**105.7**	**104.7**	**103.7**	**101.1**	**97.8**	**-7.5%**
Gippsland	Tariff V	38.5	38.8	39.0	38.5	37.7	-2.2%
	Tariff D	26.0	26.0	26.0	25.9	25.6	-1.4%
	SWZ total	**64.5**	**64.8**	**65.1**	**64.4**	**63.3**	**-1.9%**
Melbourne	Tariff V	600.9	580.9	561.0	531.4	498.1	-17.1%

SWZ		2025	2026	2027	2028	2029	Change over outlook
	Tariff D	105.7	103.2	103.3	102.5	101.5	-4.0%
	SWZ total	**706.6**	**684.0**	**664.3**	**634.0**	**599.6**	**-15.1%**
Northern	Tariff V	69.1	68.7	68.3	66.6	64.2	-7.0%
	Tariff D	25.5	25.2	25.3	25.2	25.0	-1.9%
	SWZ total	**94.5**	**93.9**	**93.6**	**91.8**	**89.2**	**-5.7%**
Western	Tariff V	7.4	7.1	6.8	6.3	5.9	-21.3%
	Tariff D	9.4	9.5	9.6	9.6	9.4	0.9%
	SWZ total	**16.8**	**16.6**	**16.4**	**15.9**	**15.3**	**-8.9%**

Table 29 Annual 1-in-20 peak daily demand by System Withdrawal Zone (Tariff V and Tariff D split) (TJ/d)

SWZ		2025	2026	2027	2028	2029	Change over outlook
Ballarat	Tariff V	67.7	66.7	65.5	63.7	61.0	-10.0%
	Tariff D	5.4	5.4	5.4	5.4	5.3	-0.6%
	SWZ total	**62.3**	**61.4**	**60.2**	**58.3**	**55.6**	**-10.8%**
Geelong	Tariff V	80.3	79.0	77.4	75.0	71.6	-10.8%
	Tariff D	34.9	34.8	35.2	35.4	35.1	0.5%
	SWZ total	**115.1**	**113.8**	**112.7**	**110.4**	**106.6**	**-7.4%**
Gippsland	Tariff V	42.6	43.0	43.1	42.7	41.8	-2.1%
	Tariff D	27.6	27.3	27.5	27.3	27.5	-0.4%
	SWZ total	**70.2**	**70.3**	**70.6**	**70.1**	**69.2**	**-1.4%**
Melbourne	Tariff V	665.1	643.2	619.4	589.1	552.1	-17.0%
	Tariff D	109.9	107.9	107.1	106.4	105.2	-4.3%
	SWZ total	**775.0**	**751.1**	**726.5**	**695.5**	**657.2**	**-15.2%**
Northern	Tariff V	76.5	76.1	75.4	73.8	71.2	-6.9%
	Tariff D	26.6	26.4	26.6	26.4	26.2	-1.6%
	SWZ total	**103.0**	**102.4**	**102.0**	**100.2**	**97.3**	**-5.5%**
Western	Tariff V	8.2	7.9	7.5	7.0	6.5	-21.2%
	Tariff D	9.7	9.7	9.8	9.9	9.8	0.4%
	SWZ total	**18.0**	**17.6**	**17.3**	**17.0**	**16.3**	**-9.5%**

Table 30 Annual peak hourly demand by System Withdrawal Zone (TJ/hr)

	SWZ	2025	2026	2027	2028	2029
Max. hourly demand on 1-in-2-year peak demand day	Ballarat	4.2	4.1	4.0	3.9	3.7
	Geelong	6.0	5.9	5.8	5.7	5.5
	Gippsland	3.9	3.9	3.9	3.9	3.8
	Melbourne	44.5	43.1	41.8	39.9	37.8
	Northern	5.4	5.3	5.3	5.2	5.1
	Western	0.9	0.9	0.8	0.8	0.8
	System total	**64.8**	**63.2**	**61.7**	**59.5**	**56.7**
Max. hourly demand on	Ballarat	4.6	4.5	4.4	4.3	4.1
	Geelong	6.5	6.4	6.3	6.2	6.0

	SWZ	2025	2026	2027	2028	2029
1-in-20-year peak demand day	Gippsland	4.2	4.3	4.3	4.2	4.1
	Melbourne	48.8	47.3	45.8	43.8	41.4
	Northern	5.9	5.8	5.8	5.7	5.5
	Western	0.9	0.9	0.9	0.9	0.9
	System total	**70.9**	**69.3**	**67.5**	**65.2**	**62.0**

Table 31 Annual 1-in-2 DTS and non-DTS peak day demand forecast (TJ/d)

	2025	2026	2027	2028	2029	Change over outlook
Tariff V (non-DTS)	1.21	1.20	1.18	1.16	1.14	-6%
Tariff D (non-DTS)	0.33	0.33	0.33	0.33	0.33	-1%
System demand (non-DTS)	1.54	1.52	1.51	1.49	1.47	-5%
System demand (DTS)	1071	1047	1021	987	942	-12%
System demand (Victoria)	1073	1049	1023	988	943	-12%

Table 32 Annual 1-in-20 DTS and non-DTS peak day demand forecast (TJ/d)

	2025	2026	2027	2028	2029	Change over outlook
Tariff V (non-DTS)	1.25	1.23	1.20	1.18	1.16	-7%
Tariff D (non-DTS)	0.41	0.41	0.41	0.41	0.40	-2%
System demand (non-DTS)	1.66	1.64	1.62	1.59	1.56	-6%
System demand (DTS)	1156	1130	1101	1064	1016	-12%
System demand (Victoria)	1158	1132	1103	1066	1018	-12%

A3.2 Monthly consumption and demand for 2025

Table 33 Monthly gas consumption for 2025 by System Withdrawal Zone (PJ/m)

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	0.59	0.48	0.48	0.68	1.27	1.67	1.79	1.56	1.10	0.83	0.64	0.56
Geelong	1.24	1.14	1.18	1.46	2.21	2.67	2.79	2.57	1.93	1.61	1.30	1.22
Gippsland	0.95	0.79	0.78	0.93	1.40	1.71	1.81	1.67	1.32	1.10	0.97	0.90
Melbourne	4.71	4.66	5.45	7.45	12.61	14.76	16.04	13.92	9.97	8.46	6.52	5.28
Northern	0.99	0.97	1.04	1.29	2.17	2.65	2.81	2.54	1.85	1.42	1.12	0.95
Western	0.47	0.32	0.24	0.26	0.40	0.59	0.59	0.59	0.50	0.41	0.38	0.41
System consumption	**7.73**	**7.74**	**9.03**	**12.00**	**19.70**	**22.94**	**24.85**	**21.81**	**15.97**	**13.59**	**10.57**	**8.66**

Table 34 Monthly gas generation consumption for 2025 by System Withdrawal Zone (TJ/m)

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ballarat	-	-	-	-	-	-	-	-	-	-	-	-
Geelong	43	24	3	2	15	70	74	34	11	1	3	17
Gippsland	44	24	2	0	3	29	42	13	4	3	2	17

SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Melbourne	208	143	77	92	210	478	400	245	128	38	44	64
Northern	-	-	-	-	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-	-	-	-	-
System consumption	**295**	**191**	**83**	**95**	**227**	**576**	**516**	**291**	**143**	**42**	**49**	**98**

Table 35 Monthly peak daily demand in 2025 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	22	35	50	60	61	58	47	40	31	20
	Geelong	46	48	52	66	87	100	103	97	84	73	61	50
	Gippsland	29	30	32	41	51	60	63	58	53	46	42	33
	Melbourne	225	235	266	410	575	685	706	682	560	455	375	256
	Northern	34	38	42	57	82	93	95	88	76	61	46	36
	Western	9	9	9	11	13	14	15	15	15	14	12	10
	System demand	**359**	**377**	**423**	**620**	**859**	**1012**	**1044**	**998**	**836**	**688**	**567**	**404**
1-in-20 peak day demand	Ballarat	20	21	29	43	58	65	68	64	55	47	39	26
	Geelong	52	54	61	77	98	108	112	106	94	83	72	57
	Gippsland	33	33	37	48	57	65	68	63	59	51	49	37
	Melbourne	266	279	342	494	658	749	774	753	641	530	469	322
	Northern	39	43	50	68	93	101	103	97	86	69	56	42
	Western	10	10	10	12	14	16	16	16	17	15	14	11
	System demand	**419**	**440**	**530**	**742**	**979**	**1104**	**1141**	**1099**	**950**	**795**	**699**	**495**

Table 36 Forecast hourly peak day demand for 2025 (TJ/hr)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	24	25	33	44	58	68	71	67	57	49	44	32
1-in-20	33	34	41	53	66	75	77	74	64	57	50	39

Table 37 Monthly peak hourly demand in 2025 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	1.06	1.14	1.71	2.53	3.40	4.03	4.16	3.90	3.20	2.85	2.40	1.56
	Geelong	3.02	3.16	4.03	4.71	5.87	6.75	6.96	6.55	5.67	5.25	4.73	3.88
	Gippsland	1.94	1.95	2.53	2.96	3.47	4.06	4.26	3.94	3.58	3.29	3.29	2.56
	Melbourne	14.80	15.45	20.72	29.44	38.89	46.33	47.75	46.09	37.91	32.72	29.23	19.96
	Western	2.23	2.48	3.31	4.10	5.57	6.29	6.39	5.98	5.17	4.35	3.62	2.79
	Northern	0.58	0.57	0.69	0.76	0.86	0.98	1.04	0.98	1.04	1.00	0.97	0.79
	System demand	**23.62**	**24.74**	**32.99**	**44.50**	**58.07**	**68.44**	**70.56**	**67.44**	**56.56**	**49.46**	**44.24**	**31.55**
Max. hourly demand on 1-in-20 peak demand day	Ballarat	1.52	1.63	2.29	3.09	3.92	4.41	4.58	4.33	3.69	3.35	2.82	2.04
	Geelong	4.04	4.24	4.74	5.51	6.60	7.32	7.56	7.15	6.33	5.94	5.16	4.48
	Gippsland	2.56	2.58	2.90	3.43	3.88	4.39	4.60	4.29	3.96	3.69	3.50	2.85

	SWZ	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Melbourne	20.78	21.76	26.68	35.49	44.51	50.60	52.35	50.92	43.33	38.06	33.71	25.14
	Western	3.01	3.35	3.92	4.85	6.30	6.84	6.95	6.56	5.81	4.96	3.99	3.25
	Northern	0.76	0.75	0.79	0.87	0.95	1.05	1.11	1.06	1.13	1.11	1.02	0.88
	System demand	**32.67**	**34.32**	**41.32**	**53.24**	**66.16**	**74.61**	**77.15**	**74.31**	**64.26**	**57.10**	**50.21**	**38.63**

A4. Gas supply forecast

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

A4.1 Victorian supply sources

Table 38 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	• Amplitude 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	• Amplitude Energy, 50% • Mitsui E&P Australia, 50%

A4.1.1 Infrastructure changes since the 2024 VGPR Update

Longford Gas Plant 1 was retired in October 2024, reducing the nameplate capacity of the gas plant from 1,150 TJ/d to 700 TJ/d. Beach Energy's connection to Otway Gas Plant with nearshore Enterprise-1 well and the two remaining Thylacine West wells were completed in June 2024[101] and October 2024[102] respectively, returning the gas plant to nameplate capacity of 205 TJ/d.

A4.2 Annual production by System Withdrawal Zone

Table 39 Annual Victorian production by SWZ, 2025-29 (PJ/y)

SWZ	Supply source	2025	2026	2027	2028	2029	Change over outlook
Gippsland [A]	Existing	198	187	170	142	102	-49%
	Committed	0	4	17	31	25	-
	Total available	**198**	**191**	**187**	**173**	**127**	**-36%**
	Anticipated	0	0	0	0	0	-

[101] See https://announcements.asx.com.au/asxpdf/20240613/pdf/064jhcfqfvvv28.pdf.

[102] See https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1557782/BPT_First_gas_from_Thylacine_West.pdf.

SWZ	Supply source	2025	2026	2027	2028	2029	Change over outlook
	Total available plus anticipated	**198**	**191**	**187**	**173**	**127**	**-36%**
Port Campbell (Geelong)[B]	Existing	59	56	46	40	35	-41%
	Committed	0	0	0	0	0	-
	Total available	**59**	**56**	**46**	**40**	**35**	**-41%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**59**	**56**	**46**	**40**	**35**	**-41%**
Total Victorian production	Existing	257	242	216	182	137	-47%
	Committed	0	4	17	31	25	25 PJ
	Total available	**257**	**246**	**233**	**213**	**162**	**-37%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**257**	**246**	**233**	**213**	**162**	**-37%**

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 40 Victorian annual available and anticipated supply balance by SWZ, 2025-29 (PJ/y)

SWZ	Supply source	2025	2026	2027	2028	2029	Change over outlook
Gippsland[A]	Existing	198	187	170	142	102	-49%
	Committed	0	4	17	31	25	-
	Total available	**198**	**191**	**187**	**173**	**127**	**-36%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**198**	**191**	**187**	**173**	**127**	**-36%**
Port Campbell (Geelong)[B]	Existing	59	56	46	40	35	-41%
	Committed	0	0	0	0	0	-
	Total available	**59**	**56**	**46**	**40**	**35**	**-41%**
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	**59**	**56**	**46**	**40**	**35**	**-41%**
Total Victorian production	Existing	257	242	216	182	137	-47%
	Committed	0	4	17	31	25	25 PJ
	Total available	**257**	**246**	**233**	**213**	**162**	**-37%**
	Anticipated	0	0	0	0	0	0 PJ
	Total available plus anticipated	**257**	**246**	**233**	**213**	**162**	**-37%**
Total Victorian consumption		**179**	**175**	**169**	**173**	**167**	**-7%**
Total surplus		**78**	**72**	**64**	**40**	**-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. 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.

A4.3 Monthly production by System Withdrawal Zone

Table 41 Victorian monthly production by System Withdrawal Zone, 2025-29 (PJ/m)

SWZ	Year	Supply source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gippsland[A]	2025	Available	18.5	13.8	17.4	18.1	20.6	21.6	23.1	22.1	20.6	20.0	15.5	16.2
		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	14.6	13.7	17.3	17.5	19.8	20.8	21.8	22.2	20.6	19.9	10.3	11.0
		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
	2027	Available	14.5	11.6	13.4	17.5	20.2	20.9	21.4	21.1	20.3	19.5	15.9	8.9
		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
	2028	Available	14.5	14.2	15.0	17.6	17.7	16.8	16.9	16.4	15.5	14.7	13.8	7.7
		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
	2029	Available	12.6	11.4	9.7	11.8	12.0	10.3	10.7	10.5	10.1	10.2	9.4	6.2
		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
Port Campbell (Geelong)[B]	2025	Available	3.6	4.4	3.6	4.4	4.7	5.8	6.7	6.1	5.2	5.4	5.6	3.1
		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	3.4	4.2	3.4	4.2	4.5	5.5	6.4	5.8	4.9	5.2	5.4	2.9
		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
	2027	Available	2.9	3.5	2.8	3.5	3.8	4.5	5.3	4.8	4.0	4.3	4.4	2.4
		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
	2028	Available	2.5	3.0	2.4	3.0	3.2	3.9	4.6	4.2	3.5	3.7	3.8	2.1
		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
	2029	Available	2.1	2.6	2.1	2.6	2.8	3.4	4.0	3.6	3.1	3.2	3.3	1.8
		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
Total Victorian production	2025	Available	22.2	18.2	21.0	22.5	25.3	27.4	29.8	28.2	25.8	25.4	21.1	19.2
		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	18.0	17.9	20.7	21.7	24.3	26.2	28.2	28.0	25.5	25.1	15.7	13.9
		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
	2027	Available	17.4	15.2	16.2	21.0	24.0	25.4	26.7	25.9	24.4	23.8	20.3	11.3
		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
	2028	Available	17.0	17.3	17.5	20.6	20.9	20.7	21.4	20.5	19.0	18.5	17.7	9.8
		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
	2029	Available	14.8	14.0	11.9	14.4	14.9	13.7	14.7	14.2	13.1	13.4	12.8	8.0
		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

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.

A4.4 Peak day production by System Withdrawal Zone

Table 42 Peak day maximum daily quantity (MDQ) supply capacity by System Withdrawal Zone, 2025-29 (TJ/d)

SWZ	Supply source	2025	2026	2027	2028	2029	Change over outlook
Gippsland [A]	Available	746	717	690	544	345	-54%
	Anticipated	0	0	0	0	0	0%
	Total available plus anticipated	746	717	690	544	345	-54%
Port Campbell (Geelong) [B]	Available	795	764	771	750	732	-8%
	Anticipated	0	0	0	0	0	-
	Total available plus anticipated	795	764	771	750	732	-8%
Melbourne	Available	87	87	87	87	87	-
Total Victorian supply	Total Victorian available	1,628	1,568	1,548	1,380	1,164	-28%
	Total Victorian anticipated	0	0	0	0	0	0%
	Total Victorian available plus anticipated	1,628	1,568	1,548	1,380	1,164	-28%

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 and Iona UGS. 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 43 Peak day supply adequacy (TJ/d), 2025-29

SWZ	Supply source	2025	2026	2027	2028	2029	Change over outlook
Gippsland [A]	Expected [B]	686	657	630	484	285	-58%
	Anticipated	0	0	0	0	0	0%
	Total expected plus anticipated	686	657	630	484	285	-58%
Port Campbell (Geelong) [C]	Expected [D]	523	523	523	523	523	0%
	Anticipated	0	0	0	0	0	0%
	Total expected plus anticipated	523	523	523	523	523	0%
Melbourne	Expected	87	87	87	87	87	0%
Total Victorian supply	Total Victorian expected	1,296	1,267	1,240	1,094	895	-31%
	Total Victorian anticipated	0	0	0	0	0	0%
	Total Victorian expected plus anticipated	1,296	1,267	1,240	1,094	895	-31%
1-in-2 system demand		1,071	1,047	1,021	987	942	-12%
1-in-20 system demand		1,156	1,130	1,101	1,064	1,016	-12%
1-in-2 day surplus quantity with Victorian expected supply		**226**	**220**	**219**	**107**	**-47**	-
1-in-20 day surplus quantity with Victorian expected supply		**140**	**137**	**139**	**30**	**-121**	-

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.

A4.5 Storage facility operating parameters

A4.5.1 Dandenong Liquefied Natural Gas

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 storage provider requires one hour pre-notification (by AEMO) ahead of commencing injections into the DTS, to enable preparation and plant cool-down due to the low temperatures of the LNG process. LNG injections in the first and last hour need to be equal or less than 5.5 TJ/h, to help cool-down and warm-up of the re-liquefaction 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 44 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]
2025-29	0.02	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.
Terajoules per hour per hour (TJ/h/h) indicates how much the energy delivery rate (in TJ/h) can ramp up per hour.

A4.5.2 Iona Underground Gas Storage

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports 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 24.4 PJ. Lochard Energy is progressing with the HUGS Project, which aims to increase Iona UGS facility storage capacity by 1.8 to 3.5 PJ and the supply capacity from 570 TJ/d to 615 TJ/d from 2027. Iona UGS requires two hours' notification to switch between withdrawals to storage and injection into the DTS. The storage operating parameters shown in **Table 45**, including injection and withdrawal rate and pressures, have been historically and are foreseeably sustainable, but may be impacted by a combination of maintenance, peak demand conditions, and a low total storage inventory.

Table 45 Iona UGS operating parameters

Year	Min hourly injection rate (TJ/h)	Max. hourly injection rate into the DTS (TJ/h)	Max. hourly withdrawal rate from the DTS (TJ/h)	Max. ramp up rate (TJ/h/h)	Max. ramp down rate (TJ/h/h)	Pressure range (kPa)
2025	1.0	23.750	6.46	5.9	11.9	4,500-10,000
2026	1.0	23.750	6.46	5.9	11.9	4,500-10,000
2027	1.0	25.625	6.93	6.4	12.8	4,500-10,000
2028	1.0	25.625	6.93	6.4	12.8	4,500-10,000
2029	1.0	23.625	6.93	6.4	12.8	4,500-10,000

Note: HUGS project aims to commence from 2027.

A5. System operating parameters

A5.1 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 46**).

This table lists the Wholesale Market Critical Location Pressures as required by the Wholesale Market System Security Procedures. This table is published in VGPR in accordance with Rule 323(3)(g).

Table 46 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	4,500	Agreed by AEMO-APA-Distributor in 2024 and will be updated in AEMO-Distributor Connection Deed 2025
		Gooding CS Inlet	3,500	APA design parameter
		Valley Power GPG	4,000	
		VicHub	4,200	Connection Agreement
		TasHub	4,200	Connection Agreement
		BassGas	3,500	Connection Agreement
		Dandenong CG Inlet	3,200	APA Design Parameter
		Wollert CG Inlet	3,000	APA Design Parameter
Lurgi	2,760	Morwell Porters Rd	2,650	AEMO-Distributor Connection Deed
		Clyde North	1,200	AEMO-Distributor Connection Deed
		Pakenham South	1,400	AEMO-Distributor Connection Deed
		Jeeralang GPG	2,500	
Metropolitan Ring Main	2,760	Dandenong Terminal Station	2,650	AEMO-Distributor Connection Deed Maintaining the Dandenong CG inlet guideline pressure ensures maintenance of Dandenong Terminal Station pressure obligation

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 GPG	1,800	
		Somerton GPG	2,000	
Wollert to Euroa (T74)	8,800	Wandong PRS inlet	3,700	APA design parameter
Euroa to Wodonga (T74)	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 (T119)	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 (winter) 1,900 (summer)	7,390 kPa Pipeline licence pressure 2,300 kPa during high flow (winter), 1,900 kPa during low flow (summer), Distributor Connection Deed
		Laverton North GPG	1,700	
Brooklyn Lara Pipeline	10,200	Qenos	-	Connection is not in use due to the closure of the Qenos facility
Brooklyn Ballan Pipeline	7,400	Sunbury	2,000	AEMO-Distributor Connection Deed
		Ballarat	2,100	AEMO-Distributor Connection Deed
		Plumpton PRS inlet	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 CS Inlet	4,500	APA Design Parameter
		Colac	3,800	AEMO-Distributor Connection Deed
Western Outer Ring Main	10,200	WORM PRS inlet	4,500	APA Design Parameter
Western Transmission System	7,400	Koroit	3,000	AEMO-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

A5.2 Compressor utilisation in 2024

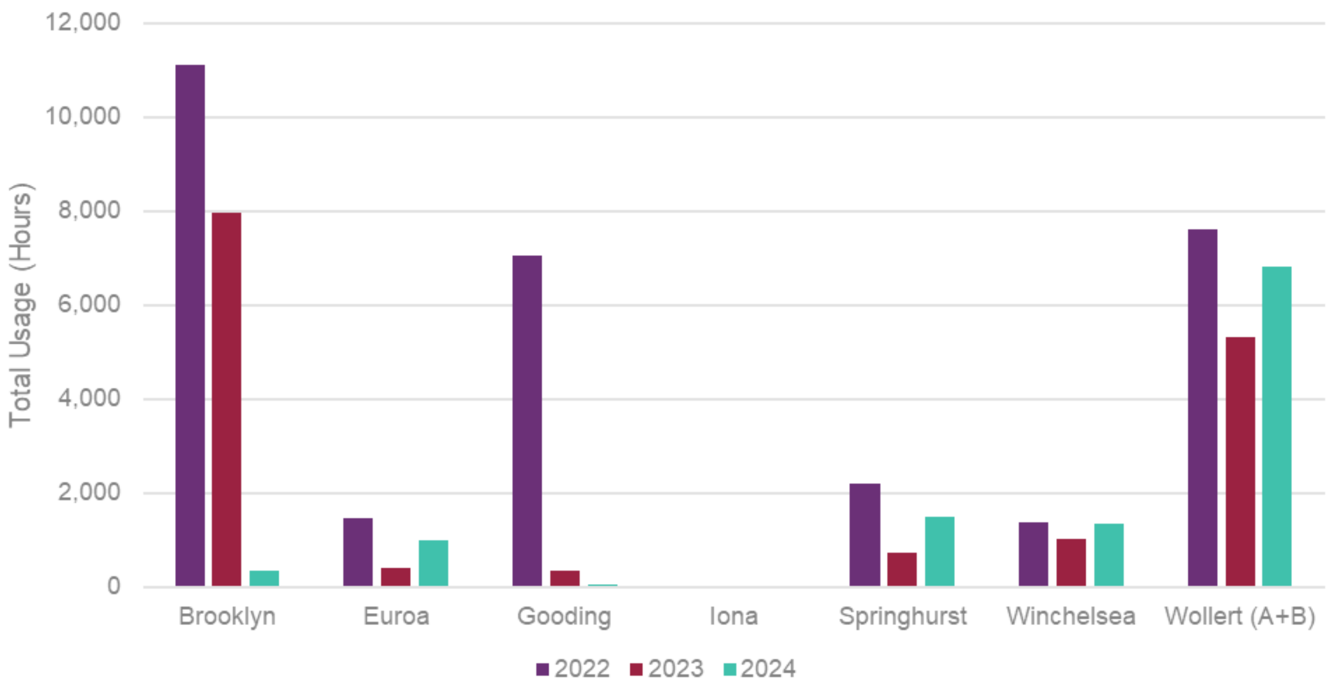
Table 47 lists the hours of usage for each DTS compressor station by month for 2024, and **Figure 52** compares the total operating hours by compressor station from 2022 to 2024. Key points are:

- Compared to 2023, the usage of Wollert, Springhurst and Euroa compressors increased to support higher VNI withdrawals out of the DTS, particularly in November-December.
- The usage of Brooklyn compressors has decreased due to the introduction of the WORM (Western Outer Ring Main) pipeline.
- The usage of Gooding compressors has decreased due to Longford capacity reductions.

Table 47 Total operating hours by compressor station, 2024

Compressor station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brooklyn	212	38	0	0	2	0	1	16	3	17	10	30
Euroa	0	6	1	2	0	36	71	4	2	15	417	431
Gooding	2	1	7	4	1	3	9	2	2	8	2	2
Iona	0	0	0	0	0	0	0	0	2	0	0	0
Springhurst	7	14	0	0	14	257	264	3	4	73	438	429
Winchelsea	2	5	2	0	193	580	402	109	47	2	3	1
Wollert	435	465	702	570	287	193	255	656	502	672	934	1,136

Figure 52 Total operating hours by compressor station, 2022-24



A6. DTS service provider assets, maintenance and system augmentations

A6.1 Critical Declared Transmission System assets

Critical assets in the DTS are the assets required to maintain system security on peak demand days. **Table 48** outlines these assets by SWZ and operational purpose.

Table 48 Critical DTS assets

SWZ	Asset	Description	Purpose/role
Melbourne	Brooklyn CS	• 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 Laverton GPG and Iona UGS withdrawals. • The Saturn machines are used only to supply system demand.
	Wollert CS	• 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 NSW via the NSW–Vic Interconnect at Culcairn. Exports to NSW are generally not possible without Wollert Centaur compression.
	Dandenong LNG Facility	• The LNG facility has a maximum capacity of 180 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.

SWZ	Asset	Description	Purpose/role
	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 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 CS	• 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 CS	• One Centaur compressor rated at 4,550 kW.	• Provides compression to the Euroa to Wodonga pipeline mainly for increasing export capacity to NSW when higher pressure is required at Culcairn. The compressor may be also used to increase import capacity into Victoria from NSW.
	Springhurst CS	• One Centaur compressor rated at 4,550 kW.	• Provides compression for imports or exports via NSW–VIC interconnect at Culcairn.
Western	Iona CS	• Two reciprocating compressors rated at 300 kW each.	• Provides compression to Western Transmission Network from the SWP.

A6.2 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 2025 and the capacity impact is shown in **Table 49**. 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 49 Planned maintenance for 2025, as at 10 December 2024

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
Melbourne	Brooklyn Compressor Station	Full Station	28 April to 2 May 2025	-	-	Total station outage for five days over the maintenance period.
		Unit 11	28 August to 1 September 2025	-	-	Unit outage for five days over the maintenance period.
		Unit 12	28 September to 2 October 2025	-	-	Unit outage for five days over the maintenance period.
		Full Station	27-31 October 2025	-	-	Total station outage for five days over the maintenance period.
	Wollert Compressor Station	Unit 4	17-21 February 2025	-	SWP: 292 VNI: 224	Unit outage for five days over the maintenance period.
		Station A + B	7-11 April 2025	-	SWP: 132 VNI: 0	Auxiliary equipment maintenance. Overnight availability.
		Unit 6	4-8 August 2025	-	SWP: 160 VNI: 220	Unit outage for five days over the maintenance period.
		Unit 5	11-15 August 2025	-	SWP: 160 VNI: 220	Unit outage for five days over the maintenance period.
		Unit 4	25-29 August 2025	-	SWP: 160 VNI: 220	Unit outage for five days over the maintenance period.
		Station B	15-19 September 2025	-	SWP: 132 VNI: 0	Unit outage for five days over the maintenance period.
Geelong	Winchelsea Compressor Station	Full Station	31 March to 4 April 2025	SWP: 364	SWP: 316	Total station outage for five days over the maintenance period.
		Unit 1	20-24 October 2025	SWP: 443	SWP: 339	Unit outage for five days over the maintenance period.
		Unit 2	10-14 November 2025	SWP: 443	SWP: 339	Unit outage for five days over the maintenance period.
		Full Station	17-21 November 2025	SWP: 364	SWP: 316	Total station outage for five days over the maintenance period.
Gippsland	Gooding Compressor Station		6-10 October 2025	-	-	Total station outage for five days over the maintenance period.

SWZ	Asset unavailable		Maintenance period	Import capacity (TJ/d)	Export capacity (TJ/d)	Comments
Northern	Euroa Compressor Station		10-14 March 2025	VNI: 193	VNI: 150	Total station outage for five days over the maintenance period.
			1-5 September 2025	VNI: 193	VNI: 150	Total station outage for five days over the maintenance period.
	Springhurst Compressor Station		31 March to 4 April 2025	VNI: 152	VNI: 150	Total station outage for five days over the maintenance period.
			24-28 November 2025	VNI: 152	VNI: 150	Total station outage for five days over the maintenance period.
Western	Iona Compressor Station	Full Station	19-23 May 2025	-	-	Total station outage for five days over the maintenance period.
		Full Station	1-5 December 2025	-	-	Total station outage for five days over the maintenance period.

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

A6.3 Other proposed maintenance

The DTS service provider has proposed a series of pipeline inspections (pigging) works during 2025:

- T16 Dandenong to West Melbourne.
- T119 Wollert to Barnawartha.
- T74 Wollert to Wodonga.
- T91 Curdievale to Cobden.
- T15 Oakleigh.

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.

A7. Victorian gas planning approach

A7.1 DTS System Withdrawal Zones

The DTS is divided into six zones, shown in **Figure 53**:

- 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.

A7.2 Victorian gas planning criteria

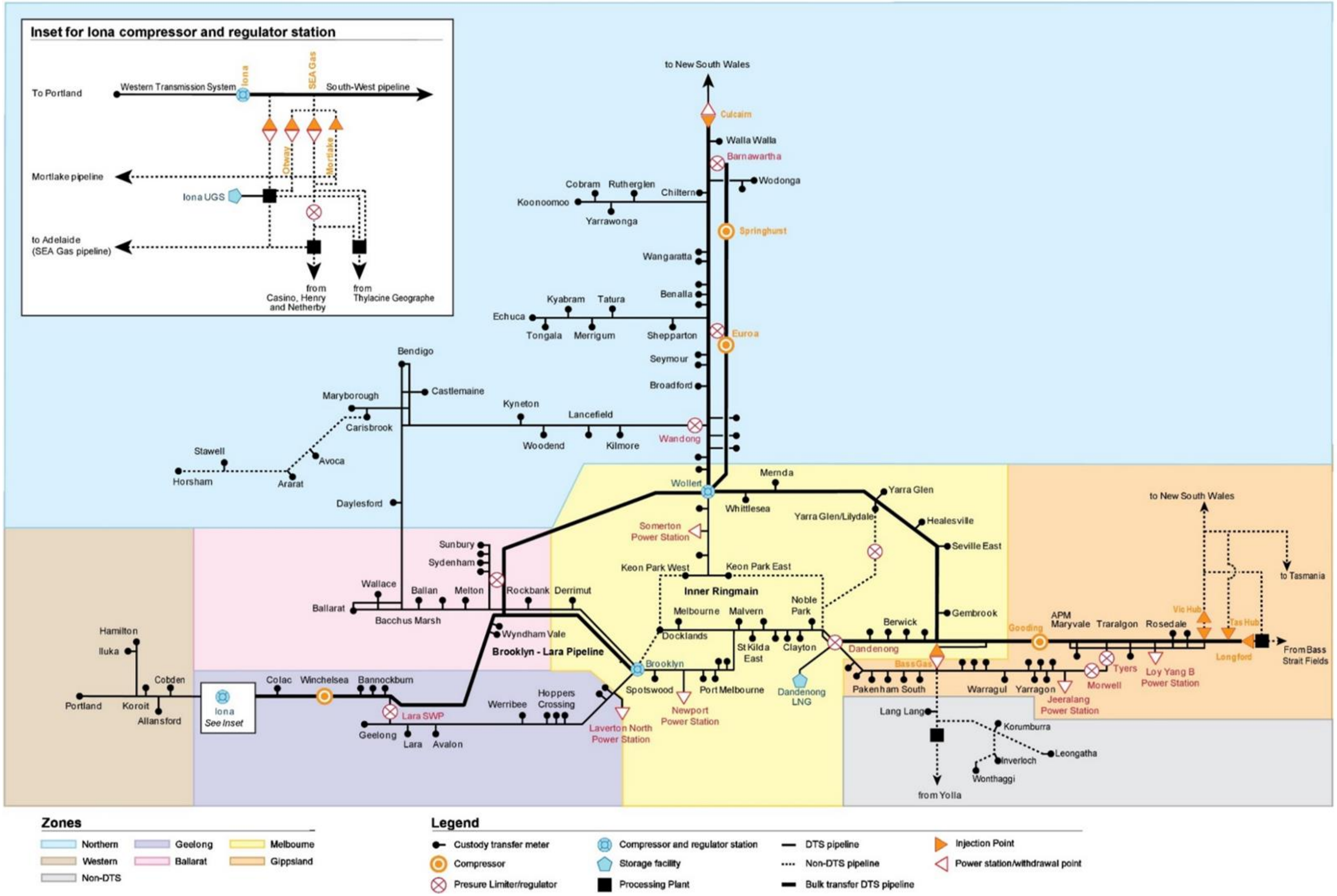
Under Rule 323(1), AEMO must publish a planning review "by no later than 31 March 2015 and by 31 March in every second year thereafter".

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 53 System withdrawal zones in the DTS



A7.3 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 54 shows an overview of the gas planning methodology, and **Table 50** provides more detail for the numbered steps.

Figure 54 Gas planning methodology overview

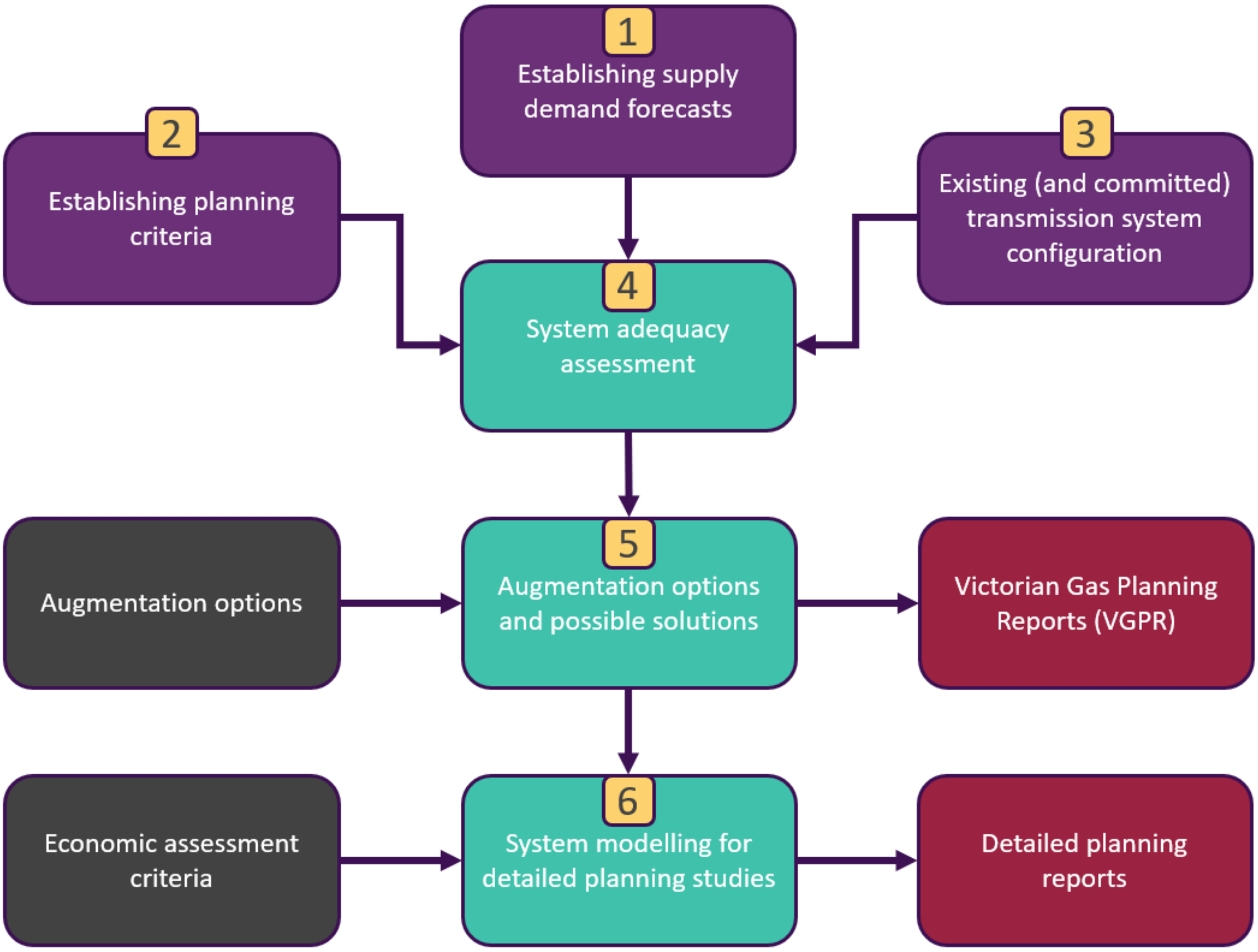


Table 50 Gas planning methodology summary

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)*, 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.

* At https://aemo.com.au/-/media/files/gas/emergency_management/victorian/aemo-wholesale-market-system-security-procedures-ngr-11.pdf.

A7.4 Planning assumptions

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

- **Table 51** to **Table 54** list the standard modelling assumptions used by AEMO.
- Additional modelling assumptions are listed in **Table 55** for SWP capacity, **Table 56** for Northern capacity and **Table 57** for LMP capacity respectively.

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.

A7.4.1 Supply assumptions

Table 51 and **Table 52** list assumptions relating to the supply of gas to the DTS.

Table 51 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.
NSW 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 52 DTS modelled heating values

Location	Heating value (megajoules/standard m^3)
Longford CPP	38.54
BassGas	39.85
Iona CPP (summer)	37.90
Iona CPP (winter)	37.73
NSW injection at Culcairn (summer)	38.67
NSW injection at Culcairn (winter)	38.21
Dandenong LNG	37.80

A7.4.2 Demand assumptions

Table 53 lists assumptions relating to gas demand in the DTS, which have a significant effect due to DTS topology.

Table 53 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.
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.

Demand assumptions and conditions	Notes
NSW 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.

A7.4.3 Demand assumptions

Table 54 lists the assumptions relating to operation of the DTS and assist with the management of linepack and constraints specified in various agreements.

Table 54 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.

A7.4.4 Capacity modelling assumptions

Modelling assumptions are listed in **Table 55** for SWP capacity, **Table 56** for Northern capacity and **Table 57** for LMP capacity. Under different operating conditions on the day, the capacity result may differ.

Table 55 SWP capacity modelling assumptions

SWP capacity assumptions		Notes
Injections		For SWP to Melbourne: • Maximum injection from Iona CPP. • Culcairn withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 10 TJ/d. • Longford CPP acting as balance of injections. For SWP withdrawal: • Maximum withdrawal to Iona. • Culcairn injecting, withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 10 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 to Iona: • 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	Minimum pressure is 2,000 kPa.
	Ballarat CG	Minimum pressure is 2,100 kPa.

Table 56 Northern capacity modelling assumptions

Northern 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 10 TJ/d.

Northern capacity assumptions		Notes
		• Longford CPP acting as balance of injections. For Culcairn withdrawal: • Maximum withdrawal from Culcairn. • Iona injecting, withdrawing or zero to suit individual model requirements. • BassGas injecting fixed quantity 10 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	Minimum pressure is 2,000 kPa.
	Bendigo CG	Minimum pressure is 3,000 kPa.

Table 57 LMP capacity modelling assumptions

LMP capacity assumptions	Notes
Injections	For Longford to Melbourne: • 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 10 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	For Longford to Melbourne: • Gooding compressors were run at maximum power. • Capacity with all Gooding units out of service was determined to manage outages. For Longford withdrawal: • Gooding compressors were off.
Linepack	BoD and EoD linepack are equal for system demand and Geelong zone. For capacity modelling, mining of linepack not allowed.

LMP capacity assumptions		Notes
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	Minimum pressure is 2,000 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 GPG), and weather forecast errors.
  - When actual demand is higher than forecast, this can result in a greater depletion of system linepack through the day, reducing system ability to meet demand. When actual demand is lower than forecast, this can result in excessively high linepack and system pressures, potentially leading to a back-off of injections at the injection points, generally only after the 10.00 pm scheduling horizon, to avoid breaching upper operating limits.
- Delivery pressure.
  - Supply pressure drives gas through a pipeline. The higher the supply pressure, 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 GPG, 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.

A7.4.5 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.

A7.4.6 Changes to capacity modelling assumptions for 2025

The 2025 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.

The Melbourne entry zone consists of the Dandenong LNG injection point. Firm injections at Dandenong LNG were not considered for 2025 pipeline capacity modelling.

The Northern entry zone consists of the HyP Murray Valley hydrogen production facility, which is considered a committed project. The facility intends to inject produced Hydrogen with natural gas in the Albury-Wodonga gas distribution network. The forecast production profile of the facility provided by AGI Renewables assumed to be offsetting Wodonga gas demand forecast profile for 2025 pipeline capacity modelling.

A7.5 Gas supply forecasts reporting

As part of the VGPR reporting obligations under NGR 323 (3)(d), production forecasts reported by the producers are disclosed by system withdrawal zone in the VGPR. However, given the confidentiality obligation under NGR 324(6), unless already published pursuant to other regulatory requirement such as the Gas Bulletin Board, the VGPR does not include production for a zone that is supplied by a single facility.

List of tables and figures

Tables

Figures

Measures, abbreviations and glossary

Units of measure

Term	Definition
CO_2-e	carbon dioxide equivalent
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/h/h	Terajoules per hour per hour
TJ/m	terajoules per month
TJ/y	terajoules per year

Abbreviations

Term	Definition
ACCC	Australian Competition and Consumer Commission
ACCU	Australian carbon credit units
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGIG	Australian Gas Infrastructure Group
ARENA	Australian Renewable Energy Agency
BCP	Brooklyn–Corio Pipeline
BLP	Brooklyn–Lara Pipeline
BoD	beginning of day
CG	city gate
CPP	close proximity point
CS	compressor station
DER	distributed energy resources
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market

Term	Definition
EDD	Effective Degree Day
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
EoD	end of day
EPBC	Environment Protection and Biodiversity Conservation
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
GPG	Gas-powered generation
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
MAPS	Moomba to Adelaide Pipeline System
MDQ	maximum daily quantity/ies
MHQ	maximum hourly quantity/ies
MinOP	minimum allowable operating pressure
MSP	Moomba Sydney Pipeline
NEM	National Electricity Market
NGER	National Greenhouse and Energy Reporting
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

Term	Definition
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zone
TGP	Tasmanian Gas Pipeline
UAFG	unaccounted for gas
UGS	Underground Gas Storage
VEU	Victorian Energy Upgrades
VGPR	*Victorian Gas Planning Report*
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.
2C Resources	The meaning given in the PRMS – that is, the best estimate of Contingent Resources.
2P Reserves	The sum of Proved Reserves and Probable Reserves.
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

Term	Definition
	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.
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-powered 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.
LNG regasification terminal	A facility that receives, stores, and processes LNG back into its gaseous state before injecting it into the gas transmission pipeline network.
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.

Term	Definition
pipeline injections	The injection of gas into a pipeline.
possible reserves	The meaning given in the PRMS – that is reserves that analysis of geological and engineering data suggest are less likely to be recoverable than Probable Reserves. The quantity actually recovered has a low probability of exceeding the 3P Reserves estimate. If probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the 3P Reserves estimate. For the avoidance of doubt, Possible Reserves should be the upside quantities to the 2P scenario.
PRMS	The Petroleum Resources Management System developed by the Society of Petroleum Engineers.
probable reserves	The meaning given in the PRMS – that is, reserves that analysis of geological and engineering data suggest are less likely to be recoverable than Proved Reserves but more likely to be recoverable than Possible Reserves. It is equally likely that the quantities actually recovered will be greater than or less than the 2P Reserves estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the 2P Reserves estimate.
prospective resources	The meaning given in the PRMS – that is, those quantities estimated to be potentially recoverable from undiscovered accumulations by application of future development projects.
proved reserves	The meaning given in the PRMS – that is, reserves that analysis of geological and engineering data suggest are reasonably certain to be commercially recoverable. If deterministic methods are used, the term "reasonably certain" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the 1P Reserves estimate.
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 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. • 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 GPG demand, exports, and gas withdrawn at Iona.
system injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas 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.

Term	Definition
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	June to August.
winter peak demand period	In this report is defined as 1 June to 31 August of a given calendar year.