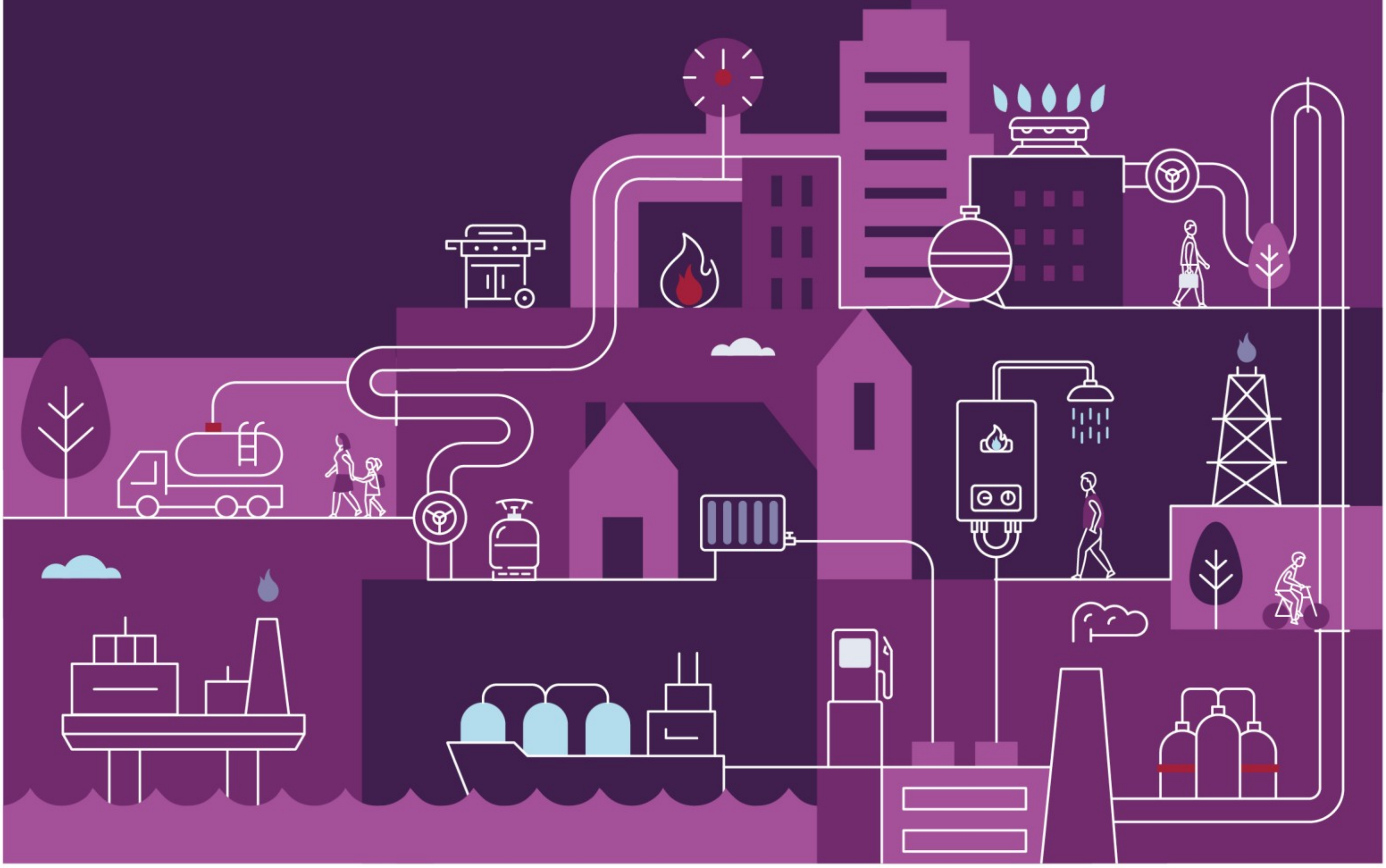
Victorian Gas Planning Report Update

March 2026

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 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 2026 *Victorian Gas Planning Report Update* (VGPR Update) provides information about the supply demand balance over the next five years (2026-30, called the outlook period) in Victoria and the Victorian Declared Transmission System (DTS). This VGPR Update also provides some relevant data for forecast supply and demand from 2031 to 2035 as contained in AEMO's 2026 *Gas Statement of Opportunities* (GSOO)[1] supporting data pack and GSOO survey data or produced for the GSOO, to compile more comprehensive information for the Victorian DTS in a single document in response to stakeholder requests for information that supports strategic planning and analysis, especially considering the extended lead times associated with major projects. The 2026 VGPR Update complements AEMO's 2026 GSOO, which assesses wider gas supply adequacy in central and eastern Australia.

- Victoria's annual production forecast remains relatively similar to the 2025 VGPR, and from 2029, Victoria is projected to become a net importer of gas as Victorian consumption exceeds Victorian production.
  - Victorian annual production is forecast to decline by 52.8% over the five-year outlook period, from 242 petajoules (PJ) in 2026 to 114 PJ in 2030, and to reduce to 9 PJ by the end of 2035.
  - Compared to the 2025 VGPR, annual Victorian production in 2027 and 2028 is forecast to be slightly higher, by 15 PJ and 4 PJ, respectively, while forecast production in 2026 and 2029 is slightly lower, by 4 PJ and 13 PJ respectively.
- Annual Victorian system consumption is forecast to reduce by 10.5% over the outlook period, consistent with the 10.7% reduction forecast in the 2025 VGPR.
  - Actual residential and small commercial (Tariff V) consumption in 2025 was 106 PJ, a 2% decrease from the 2024 Tariff V consumption of 108.4 PJ, despite 2025 having a colder winter and being a colder year overall than 2024[2].
  - Industrial and large commercial (Tariff D) consumption declined by 6% in 2025 to 53.2 PJ (56.7 PJ in 2024). This is consistent with the continued decline in Tariff D consumption, which has reduced by 22% since 2021.
- Victoria's maximum daily supply capacity (including storage facilities) is projected to decline by 27.3% in the five-year outlook period, falling from 1,969 terajoules per day (TJ/d) in 2026 to 1,431 TJ/d in 2030. Gippsland's peak day production capacity is forecast to decline from 766 TJ/d to 302 TJ/d over the five-year outlook period, and to zero by 2034. Port Campbell's peak day supply forecast (including the Iona Underground Gas Storage [UGS] facility) declines from 785 TJ/d in 2026 to 671 TJ/d in 2030; however, actual peak supply into the DTS will be constrained by the South West Pipeline's (SWP's) capacity of 515 TJ/d.
  - Due to the SWP constraint and a portion of Gippsland production being required for supply to neighbouring jurisdictions, expected peak day supply capacity to the DTS is lower than Victoria's total supply capacity, at 1,389 TJ/d in 2026 and 945 TJ/d in 2030.

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

[2] See Bureau of Meteorology (BoM), Victoria in winter 2025, at https://www.bom.gov.au/climate/current/season/vic/archive/202508.summary.shtml.

- Forecast 1-in-2 year **system demands decline** from 958 TJ/d in 2026 to 836 TJ/d in 2030, while 1-in-20 year system demands decline from 1,032 TJ/d to 900 TJ/d over the outlook period – both representing a 12.8% reduction[3]. These forecast peak day demands are lower than the 1-in-2 and 1-in-20 system demand forecasts in the 2025 VGPR.
- **Forecast Victorian expected supply exceeds 1-in-2 and 1-in-20 year system demand for the five-year outlook period.** Supply adequacy is, however, forecast to remain tight, with supply into the DTS from Culcairn and the Dandenong Liquefied Natural Gas (LNG) facility likely to be required to support peak day demand and even low levels of gas-powered electricity generation (GPG) on a peak day. There is a high risk of shortfalls due to unexpected conditions including higher than forecast demand and unplanned supply restrictions.
- Victorian annual and winter peak GPG requirements are forecast to fluctuate over the five-year outlook period.
  - Annual GPG consumption is projected to reduce as increased renewable generation and more electrical storages become operational, declining from 13.3 PJ in 2025 to 11.6 PJ in 2026, then decreasing to a minimum of 4.7 PJ in 2028. Later in the outlook period, the planned closure of coal power stations is forecast to increase GPG, with annual GPG consumption reaching 12.0 PJ in 2030.
  - GPG peak day demand is forecast to remain similar to recent winters until 2028, then increase following the planned 1 July 2028 closure of Victoria's Yallourn coal power station and April 2029 closure of the Eraring coal power station in New South Wales.
  - After the April 2029 Eraring closure, Victorian GPG peak day demand is forecast to increase in winter 2029. Without additional investment to increase gas supply capacity or infrastructure, GPG units may need to operate on secondary fuels during the most significant peak gas demand periods.
- The 2026 GSOO highlights a peak day shortfall risk in the southern states[4] in 2029 under sustained high gas usage conditions, and a structural gap from 2030 under most weather conditions with new gas supply required to address the projected annual supply shortfall. The forecast shortfalls could impact any of the southern states, including Victoria[5].
- Since last year's GSOO and VGPR, more peak day supply is expected to be available to southern states, including increased access to supply from the northern states. APA's newly committed East Coast Gas Grid (ECGG) Expansion Plan Stage 3A[6] project includes an additional compressor station on the Young to Culcairn section of the Moomba to Sydney Pipeline (MSP) which is expected to provide an additional 39 TJ/d southern capacity towards Victoria at Young. This supply capacity is shared with Southern New South Wales demand and Uranquinty Power Station, so the full increase may not be available for supply into the Victorian DTS at Culcairn.

[3] Peak day demand forecasts are provided as probability of exceedance (POE) forecasts, which means the statistical probability the forecast will be met or exceeded. The forecasts are 1-in-2 peak day forecasts, which are expected statistically to be met or exceeded one year in two, and are based on average weather conditions, and 1-in-20 peak day forecasts, based on more extreme conditions that could be expected only one year in 20.

[4] "Southern states" in the GSOO means Victoria, South Australia, New South Wales and Tasmania.

[5] 2026 GSOO, Section 4: Gas supply adequacy assessment, at https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[6] APA media release, "APA to deliver pipeline capacity needed to solve projected east coast gas shortfalls", at https://www.apa.com.au/news/asx-and-media-releases/apa-to-deliver-pipeline-capacity-needed-to-solve-projected-east-coast-gas-shortfalls.

Gas consumption forecasts

The forecasts for the 2026 VGPR and the 2026 GSOO focus on the *Step Change* scenario outlined in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[7]. This *Step Change* scenario, identified in the 2025 IASR as the most likely pathway for Australia's energy sector, is a refinement of the 2023 IASR S*tep Change* scenario, centred around achieving a scale of transformation that achieves the objectives of Australia's government policies in transitioning the energy system while supporting Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels.

Victoria's Gas Substitution Roadmap[8] policies and schemes continue to provide incentives for consumers to electrify homes and business, through:

- 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,
- banning gas distribution businesses from offering incentives to connect residential buildings to gas or to purchase and install gas appliances,
- implementation of new electrification and efficiency standards for Victorian Buildings, to be phased in from January 2027[9], that require:
  - all new homes and commercial buildings to be built all-electric,
  - existing residential owner occupiers to replace a broken gas hot water appliance with an electric alternative if it cannot be repaired, and
  - rental providers to provide electric upgrades to hot water and space heating appliances when they break and cannot be repaired, as well as ensuring insulation and draughtproofing is installed and meets specific standards, and
- development of the Industrial Renewable Gas Guarantee, a market funded scheme commencing in 2027 that will target 4.5 PJ of renewable gas production by 2035[10], to be used exclusively in the industrial sector, where electrification is not currently commercially or technically feasible.

In addition to these Victorian Government policies, the Australian Government's Safeguard Mechanism will require most of Australia's largest emitters to reduce emissions help achieve Australia's emission reduction targets of 43% below 2005 levels by 2030[11].

Due to these policies continuing to incentivise homes and businesses to reduce gas usage, AEMO forecasts a 10.5% reduction in annual Victorian gas system consumption over the five-year outlook period. This rate of decline is similar to the forecast in the 2025 VGPR, but the starting point is reduced due to a stronger than expected impact from electrification of Tariff V demand. Peak day system demand is forecast to reduce 12.8% over the outlook period. The 1-in-20 year peak day demand forecast for 2026 of 1,032 TJ/d is lower than that forecast in the 2025 VGPR (1,157 TJ/d).

[7] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[8] See https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap.

[9] See https://www.energy.vic.gov.au/households/electric-and-efficiency-standards-for-buildings.

[10] Victorian Department of Energy, Environment and Climate Action, Victoria's Renewable Gas Directions Paper, at https://engage.vic.gov.au/download/document/37987.

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

Actual DTS system consumption reduced again in 2025. Industrial and large commercial customer (Tariff D) actual consumption decreased by 6% from 2024 to 2025 (from 56.7 PJ to 53.2 PJ) due to additional industrial closures in 2025. Tariff V consumption fell marginally from 2024 to 2025 (from 108.4 PJ to 106.0 PJ), despite a colder winter and a colder year overall[12]. This downward trend is considered to be due to the electrification of some gas use as well as reduced small commercial customer demand. Government policies are also likely to be having an impact on reducing Tariff V gas consumption, with reductions in Tariff V consumption in 2024 and 2025 correlating with increased registrations of Victorian Energy Efficiency Certificates (VEECs) for space heating, water heating and weather sealing applications[13].

Table 1 Actual and forecast Victorian annual gas consumption, 2023-30 (PJ per year [PJ/y])

	Actual			Forecast					Change over outlook
	2023	2024	2025	2026	2027	2028	2029	2030	
System consumption	172.3	165.0	159.2	158.4	155.6	152.3	147.7	141.7	-10.5%
DTS GPG consumption	3.8	7.8	7.2	3.2	1.8	1.3	2.7	5.3	67.4%
DTS total consumption	176.8	173.4	167.0	161.6	157.4	153.6	150.5	147.0	-9.0%
Non-DTS system consumption	0.28	0.26	0.26	0.25	0.24	0.24	0.23	0.23	-8.2%
Non-DTS GPG consumption	3.6	7.1	6.1	8.4	5.5	3.4	4.6	6.7	-20.7%
Victorian GPG consumption	7.4	14.9	13.3	11.6	7.3	4.7	7.3	12.0	3.4%
Victorian total consumption*	180.7	180.7	173.4	170.2	163.1	157.3	155.3	153.9	-9.6%

Note: totals and change over outlook percentage may not add up due to rounding.
* Victorian total consumption includes DTS total 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 2026 VGPR Update and the 2026 GSOO forecasts align with the optimal development path identified in the Draft 2026 *Integrated System Plan* (Draft 2026 ISP)[14,15] and the *Step Change* scenario. The Draft 2026 ISP shows GPG as an essential enabler in the optimal development path, providing flexible, fast-response backup and system security as the National Electricity Market (NEM) transitions to high levels of renewables and storage, and the Draft 2026 ISP says that "after coal-fired generators retire, gas will increasingly be needed to back up renewable supply (during periods of renewable lulls and peak demand), as well as for power system security services".

AEMO also assessed the impact of key coal power plant outages similar to those observed in 2022 in a modelled sensitivity, *Lower Coal Availability*. The impact of this sensitivity reduces later in the outlook period as coal generation is projected to retire and be replaced with alternative forms of generation and, as such, the availability of the remaining fleet has a lower impact on forecast GPG requirements.

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 *Lower Coal Availability* sensitivity. In the *Step Change* scenario, annual GPG gas consumption is forecast to fluctuate over the outlook period:

[12] BoM, Victoria in 2025, at https://www.bom.gov.au/climate/current/annual/vic/summary.shtml.

[13] At http://www.energy.vic.gov.au/victorian-energy-upgrades/installers/industry-market-update-work-program#heading-3.

[14] The Draft 2026 ISP is at https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation.

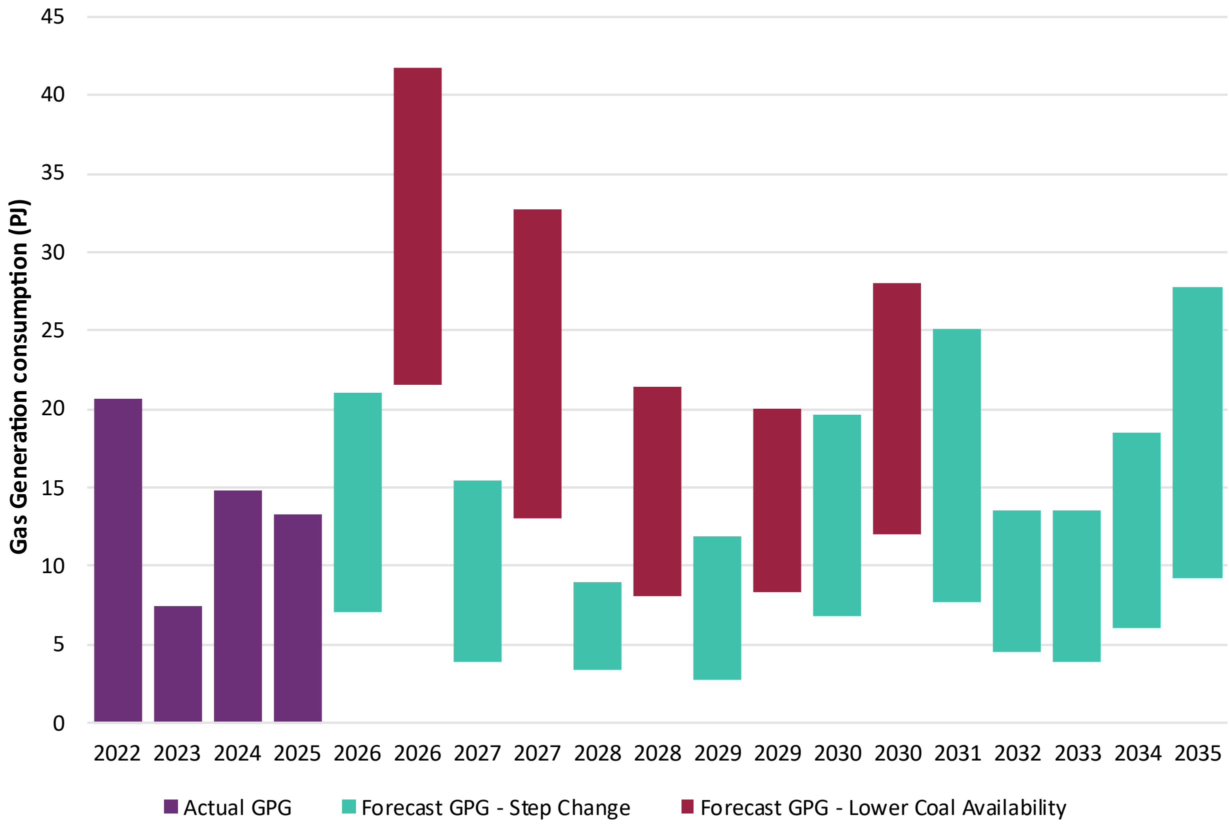
[15] The gas generation forecasts differ marginally to those presented in the Draft 2026 ISP; the 2026 GSOO/VGPR forecasts included existing, committed and anticipated generation capacity information from NEM October 2025 Generation Information (https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information), including Eraring's closure data in 2029, and 2025 ACIL Allen fuel price forecasts.

- GPG consumption is forecast to reach 11.6 PJ in 2026, before reducing to 7.3 PJ in 2027 and 4.7 PJ in 2028. This reduction is due to expected increases in renewable generation capacity from the continued installation of large amounts of rooftop solar and more battery energy storage systems (BESS) becoming operational.
- GPG consumption is then forecast to rise in 2029 to 7.3 PJ, and again in 2030 to 12 PJ. These increases are forecast due to the planned closure of Victoria's Yallourn coal power station (July 2028) and New South Wales' Eraring coal power station (April 2029), and an assumption of the closure of Victoria's two Loy Yang units by 2030[16].

GPG yearly consumption over the outlook period is likely to be heavily impacted by the operation of the end-of-life coal generator power stations in New South Wales and Victoria. Any extended outages or fuel supply issues are likely to result in higher GPG consumption during the winter months. Should any coal power stations that are scheduled to close after the winter period bring forward their closure date to pre-winter, there is likely to be a significant increase to the amount of GPG consumption in that year.

In 2025, actual total Victorian GPG consumption was 10% less than in 2024 (13.3 PJ in 2025 from 14.9 PJ in 2024). Similar to 2024, there was significant GPG consumption during June, resulting in a monthly consumption of 3 PJ in June 2025 alone[17]. This elevated consumption was brought about by cold weather, limited wind generation, and coal generator outages.

Figure 1 Actual and projected range of annual Victorian gas-powered generation consumption forecasts, *Step Change* scenario and *Lower Coal Availability* sensitivity, 2022 to 2035 (PJ)



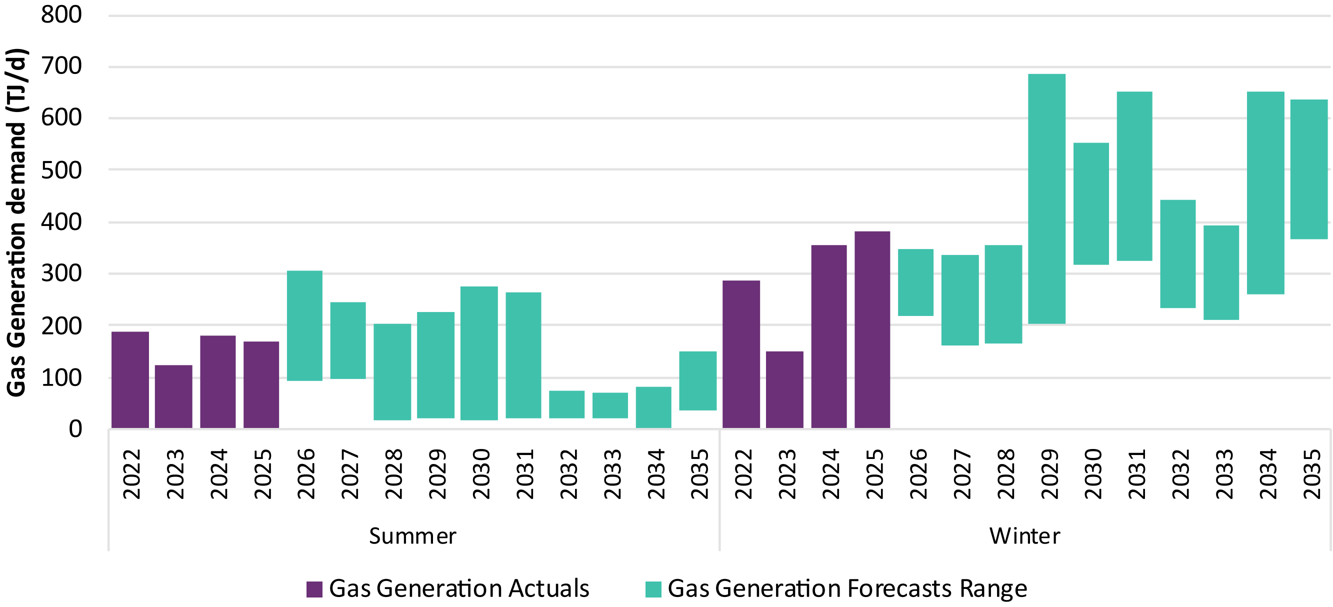
[16] Coal generator closure timings are aligned with the schedule assumed in the Draft 2026 ISP.

[17] For more information, see AEMO, *Quarterly Energy Dynamics* Q2 2025, at https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q2-2025.pdf?rev=8732b44ba628445da5883f92e84cd87d&sc_lang=en.

Figure 2 shows seasonal peak GPG demand forecasts for the *Step Change* scenario. The peak GPG demand is forecast to be greater in winter months than in the summer, continuing the trend observed since 2022. Maximum winter GPG demand is forecast to remain similar to levels observed in recent years before rising sharply to 685 TJ/d in 2029 due to the announced closures of the Yallourn and Eraring coal power stations. As with the GPG consumption forecasts, the GPG peak day demand forecast will be impacted by any shift to the timing of coal generator closures.

Coal generators have the potential to face reliability issues as they approach end-of-life, which increases the difficulty in forecasting peak GPG demand. Increased coal generation outages coinciding with cold conditions and low renewables output are likely to significantly increase the output required from GPG. This was observed in 2025, when cold and still weather conditions occurred coincidently with outages at Yallourn and Loy Yang A coal generators, resulting in GPG demand reaching 382 TJ on 26 June 2025, setting a new winter record for GPG demand in Victoria.

Figure 2 Actual and projected range of seasonal maximum and minimum peak Victorian gas-powered generation demand forecasts in summer and winter, 2022 to 2035 (TJ/d)



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

Annual supply adequacy

Figure 3 shows that Victoria's annual production is forecast to exceed projected annual consumption[18] for most of the five-year outlook period.

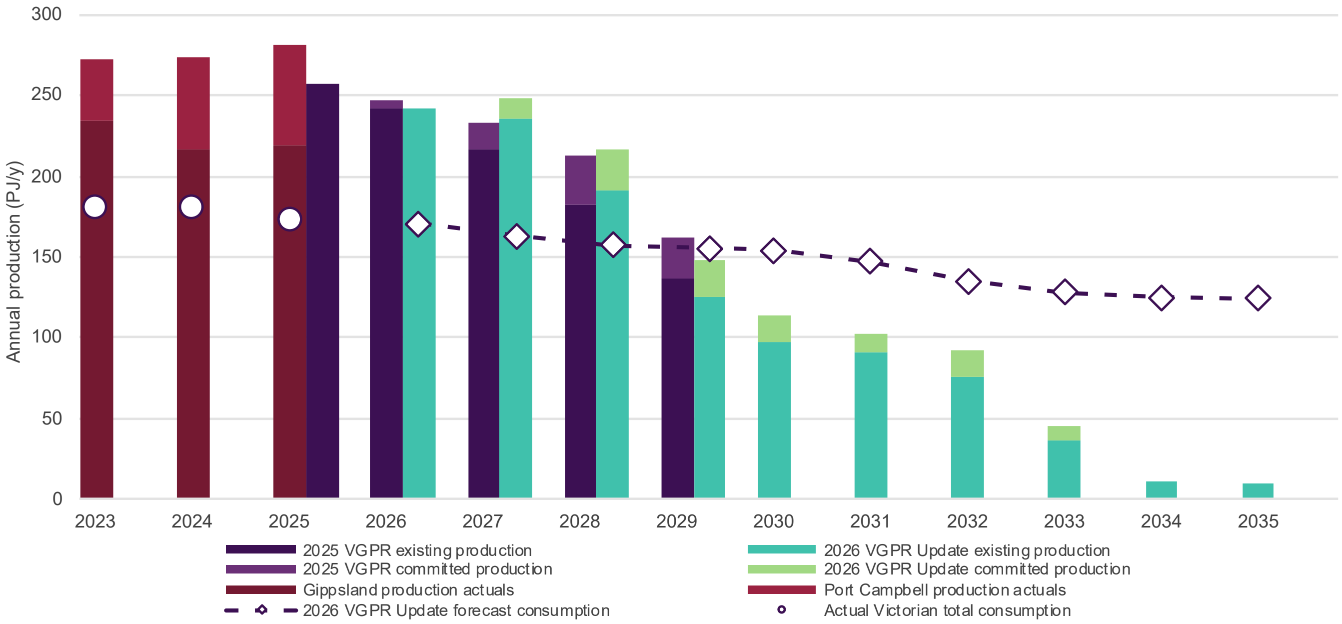
Compared to the 2025 VGPR:

- Total forecast Victorian production quantities for 2026 and 2029 are 1.8% lower (242 PJ from 246 PJ) and 8.3% lower (148 PJ from 162 PJ), respectively – while 2027 and 2028 production quantities are forecast to be 6.6% higher (248 PJ from 233 PJ) and 1.8% higher (216 PJ from 213 PJ), respectively.
- The forecast Victorian supply surplus remains the same in 2026 at 72 PJ, but in 2027 and 2028 it is higher by 34.0% (85 PJ from 64 PJ) and 49.9% (59 PJ from 40 PJ), respectively.

[18] Inclusive of system and GPG consumption.

- Victorian total consumption is forecast to exceed available[19] supply in 2029 by 7 PJ, slightly more than the quantity forecast in the 2025 VGPR. The forecast exceedance becomes more pronounced in 2030, reaching 40 PJ, and is projected to rise further to 115 PJ by 2035.

Figure 3 Actual and forecast supply and total consumption, and compared to the 2025 VGPR, 2023 to 2035 (PJ/y)



Gippsland region[20] actual production for 2025 reached 219 PJ, surpassing the 198 PJ forecast in the 2025 VGPR and reflecting a stronger than anticipated supply performance. Forecast Gippsland production for 2026 (190 PJ), 2028 (175 PJ) and 2029 (127 PJ) remains broadly consistent with the levels projected in the 2025 VGPR. In 2027, forecast annual production is 5.6% higher than previously reported, driven by additional supply from the committed Turrum Phase 3 project and the reprofiling of developed reserves.

Gippsland's production is projected to decline to 97 PJ by 2030, a 48.9% reduction from 2026 levels. Expected output continues to fall to 33 PJ in 2033, which is projected to be the final year of operation for the Longford Gas Plant, resulting in zero available production from the Gippsland region from 2034 onward.

Port Campbell's 2025 production was 61 PJ, 2 PJ above the level forecast in the 2025 VGPR. Differences between the forecast in this report and the 2025 VGPR forecast for Port Campbell production are minor across 2026 to 2028 – 4 PJ lower in 2026, then 5 PJ higher in 2027 and 2 PJ higher in 2028. These adjustments reflect declining reserves at Enterprise and Thylacine West, offset by improved production performance in other Otway Basin fields. The impact of the Enterprise and Thylacine West decline becomes more pronounced in 2029, when forecast production falls by 14 PJ (39.7% lower than the 2025 VGPR forecast). Over the subsequent five years, Port Campbell production is projected to decline sharply, decreasing by 66.9% from 52 PJ in 2026 to 17 PJ in 2030, before falling further to 9 PJ by 2035.

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

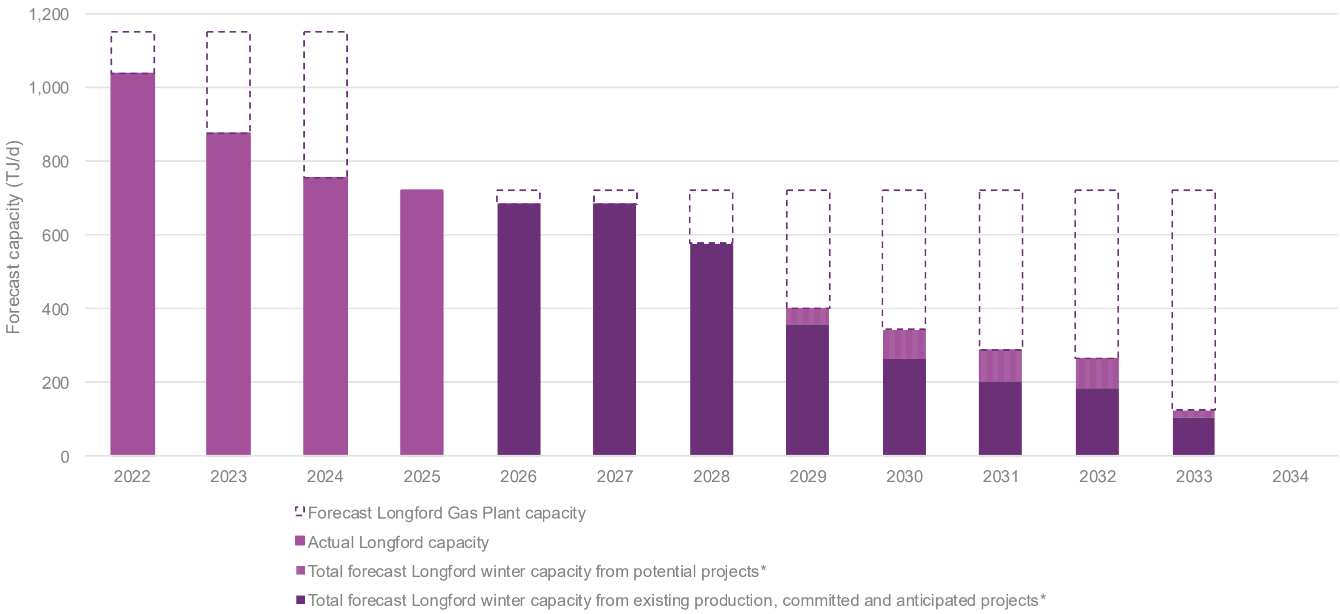
[20] Gippsland region includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, Eastern Gas Pipeline (EGP) and Tasmanian Gas Pipeline (TGP).

The forecast decline in both Gippsland and Port Campbell contributes to the growing shortfall in Victorian production, which reaches 40 PJ in 2030. The shortfall is then forecast to rise further, reaching 115 PJ by 2035. This trajectory highlights an increasingly constrained gas supply outlook for Victoria.

No projects are classified as 'anticipated' in this report. Production from the Golden Beach gas field remains classified as a potential supply project for late 2028, ahead of its proposed conversion to gas storage service in mid-2029. Several additional potential projects have been reported by Beach Energy, Amplitude Energy, and ConocoPhillips, which have formed a consortium[21] that also includes Woodside Energy to share a drilling rig to progress exploration, development and abandonment activities in the offshore Otway Basin.

Figure 4 provides actual production capacity and updates the long-term capacity outlook for the Longford Gas Plant. Compared with the 2025 VGPR, Longford's nameplate capacity increased from 700 TJ/d to 720 TJ/d during 2026. In addition, to improve plant reliability, Gas Plant 3, which was planned to cease operating in 2028, is now planned to be in operation until 2033, and Esso advised of a current plan to maintain two trunklines from offshore platforms to Longford until 2033. The operating extension of Gas Plant 3 results in the Longford Gas Plant nameplate capacity increasing from 420 TJ/d to 720 TJ/d from 2029 until 2033.

Figure 4 Actual and forecast Longford Gas Plant winter capacity, 2022 to 2034 (TJ/d)



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

Monthly supply adequacy

Figure 5 presents actual monthly total consumption and available supply for 2025 and 2026 YTD (as at February 2026), with forecast monthly available Victorian production and forecast total consumption[22] and Iona UGS net injection into the DTS[23] over the five-year outlook period:

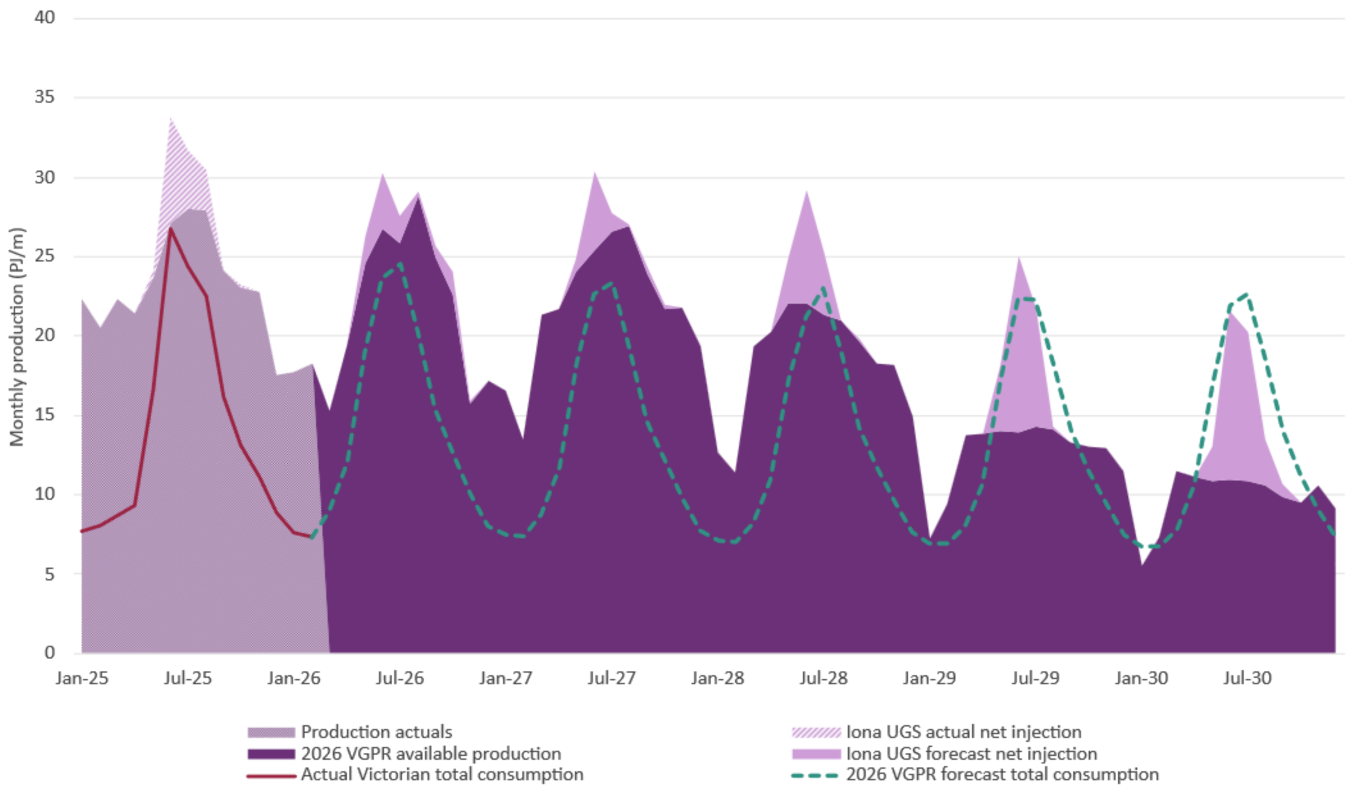
[21] Upstream Online, "Transocean rig arrives to start major Australian gas exploration campaign", 10 April 2025, at https://www.upstreamonline.com/exploration/transocean-rig-arrives-to-start-major-australian-gas-exploration-campaign/.

[22] Inclusive of system and GPG consumption.

[23] Iona storage forecast net injection flows are from modelling performed for the 2026 GSOO, which considered demand across the entire east coast and pipeline flows between states.

- Compared to the 2025 VGPR, there was lower Victorian available production combined with higher Victorian consumption during winter 2025. As a result, supply from the Iona UGS facility was required to support Victorian consumption and neighbouring jurisdictions.
- Available production in 2026 and 2027 is forecast to exceed total monthly Victorian consumption in both summer and winter, which aligns with the 2025 VGPR.
- Victorian production is forecast to be insufficient to meet winter 2028 demand. This mismatch between production and demand is smaller than projected in the 2025 VGPR, due to lower forecast Tariff V and Tariff D consumption and higher forecast winter production in 2028. This will increase the reliance on Iona UGS and supply from Queensland to neighbouring jurisdictions.
- As forecast total consumption increasingly exceeds Victorian forecast production towards the end of the outlook period, supply from Iona UGS is projected to be insufficient to meet Victorian consumption in winter 2029 and 2030. Additional gas supply will be required to supply Victoria and neighbouring jurisdictions; more discussion on southern supply adequacy is in the 2026 GSOO.
- A forecast reduction of supply in January 2030 is the result of plant maintenance. It is expected that there will be sufficient supply available from Queensland during this period.

Figure 5 Actual and forecast monthly supply and total consumption, *Step Change* scenario, 2025 to 2030 (PJ per month [PJ/m])

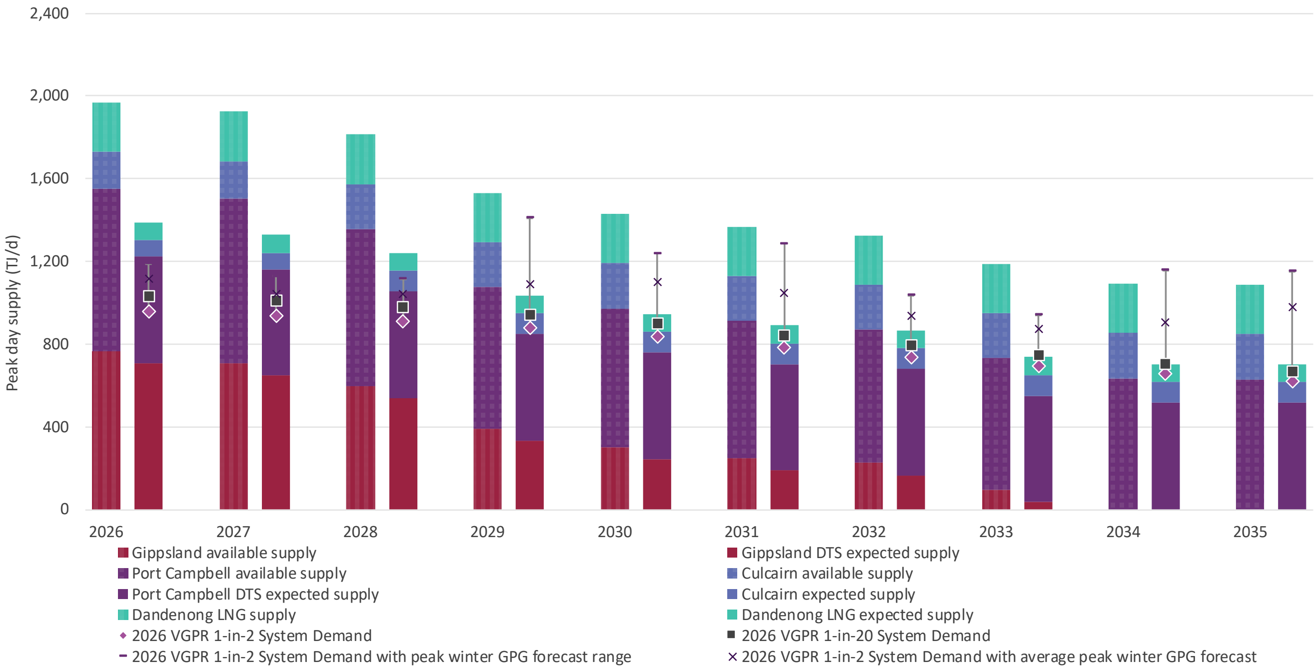


Note: Forecast consumption is the total of annual system consumption and average GPG consumption forecasts.

Peak day supply adequacy

Figure 6 presents forecast peak day supply and DTS adequacy over a 10-year period.

Figure 6 Forecast peak day supply and Declared Transmission System adequacy, 2026 to 2035 (TJ/d)



Note: the forecast peak day system demand shortfall assessment does not include the additional impact of GPG demand. **Figure 6** 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.

In this period:

- Victoria's maximum daily supply capacity (including storage facilities) is projected to decline by 27.3% during the outlook period, falling from 1,969 TJ/d in 2026 to 1,431 TJ/d in 2030, and falling further to 1,087 TJ/d in 2035.
- Expected DTS peak day supply capacity is forecast to decline from 1,389 TJ/d in 2026 to 945 TJ/d in 2030, and 702 TJ/d in 2035. This capacity includes 87 TJ/d of firm supply from the Dandenong LNG storage facility[24].
- Gippsland producers have advised that maximum available production capacity will decline from 766 TJ/d in 2026 to 302 TJ/d in 2030, and zero in 2034. The reduction is primarily driven by declining output from the Gippsland Basin Joint Venture (GBJV) and Kipper Unit Joint Venture (KUJV) fields that supply the Longford Gas Plant, followed by its expected retirement at the end of 2033. However, compared to the 2025 VGPR forecast, Gippsland supply capacity over the outlook period is generally higher, due to the addition and reprofiling of developed reserves and the committed development of the Turrum Phase 3 project.
- Port Campbell producers have advised that maximum daily production capacity will decline by 73.8%, falling from 215 TJ/d in 2026 to 56 TJ/d in 2030, and further falling to 15 TJ/d in 2035. This includes a sharp reduction of 76 TJ/d between 2028 and 2029, driven by declining reserves in Enterprise and Thylacine West. In addition to the supply from Port Campbell producers, the Iona UGS is forecast to provide 570 TJ/d in 2026, bringing total Port Campbell supply capacity to 785 TJ/d in that year. From 2027, the capacity of the Iona UGS facility will increase by 45 TJ/d to 615 TJ/d, following the development of the Heytesbury Underground Gas Storage (HUGS) Phase 1 project.
- Port Campbell peak day supply into the DTS will continue to be constrained by the capacity of the SWP. This constraint is evident in **Figure 6**, which shows the difference between available and expected Port Campbell supply. AEMO's capacity modelling forecasts SWP peak day capacity also declining slightly, from 523 TJ/d to 515 TJ/d, due to reduced DTS demand.

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

Figure 6 also illustrates the forecast reduction in peak day system demand, which is projected to decline by 12.8% over the five-year outlook period. The 1-in-2 year system demand is projected to decrease from 958 TJ/d in 2026 to 836 TJ/d in 2030, and to 621 TJ/d in 2035, while the 1-in-20 year system demand is forecast to decline from 1,032 TJ/d in 2026 to 900 TJ/d in 2030, and to 667 TJ/d in 2035. Compared to the 2025 VGPR, peak day demand forecasts are lower across the entire outlook period. For example, for 2026, the 1-in-2 and 1-in-20 year system demands are forecast to be 8.5% and 8.7% lower than forecast in the 2025 VGPR due to the increased electrification of gas demand.

In 2025, the actual maximum peak day demand was 933 TJ/d, which was lower than the 2025 1-in-2 year peak day demand forecasts published in the 2024 VGPR Update (1,084 TJ/d) and the 2025 VGPR (1,071 TJ/d), highlighting the continued decline in peak day consumption.

Figure 6 also shows that from winter 2029, if a 1-in-2 year system demand day was to coincide with forecast peak winter GPG demand, total demand could exceed expected supply capacity (see **Figure 2** for historical and forecast seasonal maximum and minimum Victorian GPG demand). Without additional investment to increase gas supply capacity or infrastructure, GPG units may need to operate on secondary fuels during the most significant peak gas demand periods during winter 2029 and subsequent years.

The 2026 GSOO highlights peak day shortfall risks and seasonal supply gaps in the southern states in 2029 under sustained high gas usage conditions. From 2030, a structural need for new gas supply is forecast to be required to address the projected annual supply gap in most scenarios.

Project updates

AEMO recognises that the current investment environment for projects is challenging and uncertain. Additional supply is forecast to be required to prevent annual and peak day shortfalls, and projects currently underway or proposed during the VGPR outlook period – including gas production and storage projects, LNG regasification terminal projects, pipeline projects, distributed supply projects, and renewable gas projects – face a range of challenges to reach investment decisions, maintain implementation schedules and reach completion.

Below is a list of projects that have materially progressed since the publication of the 2025 VGPR:

- **Committed** supply projects:
  - **The HUGS Phase 1 Project** will increase Iona UGS supply capacity to 615 TJ/d and increase storage capacity by 1.8 PJ. Early works commenced in December 2025 and are scheduled for completion by winter 2027.
  - A jack-up rig was mobilised in December 2025 for the **Turrum Phase 3 project.** Drilling activities are underway and will continue through the first half of 2026 with the new wells online prior to winter 2027. The production profile for the Turrum Phase 3 project has changed compared to the 2025 VGPR, but in aggregate, total production over the life of the project is similar. Turrum Phase 3 is expected to supply higher quantities of gas than reported in the 2025 VGPR from 2027 to 2029, lower quantities from 2030 to 2032, and higher quantities in 2033.
  - **Hydrogen Park Murray Valley** by AGI Renewables, part of Australian Gas Infrastructure Group (AGIG), commenced construction in October 2024. The target online date for the project has been pushed back to late 2026.
  - APA has reached final investment decision (FID) on Stage 3A of the **ECGG Expansion Plan** and is continuing pre-FID work for Stage 3B.

  - Stage 3A consists of the installation of three new compressors – on the South West Queensland Pipeline (SWQP) at Meadows, on the MSP at Gilgunnia, and on the Young to Culcairn lateral at Uranquinty. APA is targeting Stage 3A completion by winter 2028. The completion of this stage will boost capacity by 39 TJ/d towards Victoria via Culcairn; however, this capacity increase is shared with southern New South Wales demand and Uranquinty Power Station so the full capacity increase may not be fully available to Victoria.
  - APA has also purchased line pipe and is continuing pre-FID work for ECGG Expansion Plan Stage 3B Bulloo Interlink pipeline. Stage 3B is targeted for completion by the end of 2028, subject to FID timing.
  - The Moomba to Sydney Ethane Pipeline (MSEP) received approval from the New South Wales Government in October 2025 to transport natural gas and is expected to be commissioned prior to winter 2026, which will add 20-25 TJ/d of supply capacity from Moomba to Young.
- **Potential** supply projects:
  - **Golden Beach Energy Storage Project** is targeting FID during the second half of 2026 and gas production of up to 125 TJ/d is targeted for late Q3 or early Q4 2028 before transitioning to a storage facility in 2029. Gas supply capacity will be 300 TJ/d in early 2029 before transitioning to full capacity of 375 TJ/d in late 2029. The underground gas storage capacity has been increased from 30 PJ to 42 PJ based on the latest well data and modelling by Golden Beach Energy (GB Energy). GB Energy has advised that some long lead time items have been ordered.
  - Viva Energy's **Viva Energy Gas Terminal Project** at Geelong has had its FID pushed back to the second half of 2026. The project is targeted to be operational and available to the market ahead of winter 2029. The Westernport-Altona-Geelong (WAG) Joint Venture (Viva Energy and Mobil) is investigating the conversion of the WAG pipeline to gas service during 2026, with initial pipeline testing activities already underway. This could provide an additional gas flow path from Geelong to Altona and onwards through to Newport and Dandenong.
  - Vopak signed an agreement with Seapeak in September 2025 for the procurement of a floating storage regasification unit (FSRU)[25] as a key component of the **Vopak Victoria LNG project** which is currently progressing through the EES process with the Victorian Government. Vopak is targeting to have the terminal operational prior to winter 2029.
  - Squadron Energy has completed physical mechanical construction of the **Port Kembla Energy Terminal (PKET)**, however the terminal will not be in operation until at least 2027[26]. The contracted FSRU is currently deployed in Egypt on a temporary basis.
  - Jemena is progressing stage one of the Eastern Gas Pipeline (EGP) reversal project, which will enable bi-directional flow on the pipeline, enabling flows of up to 200 TJ/d south towards Victoria, with targeted completion for prior to winter 2026.
  - Atlantic, Gulf & Pacific (AG&P) LNG is continuing to progress the **Outer Harbor LNG Project** in South Australia, with terminal commissioning scheduled for late 2027 in preparation for winter 2028. The interim Adelaide Energy Bridge project completion date has been pushed back, with supply of gas now planned to commence in 2027. To support this project, SEA Gas proposes additional compression and reverse flow capacity on the Port Campbell to Adelaide (PCA) pipeline which will support transportation of gas from the Outer Harbor LNG facility towards Port Campbell. In

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

[26] Squadron Energy, Flexible gas: the energy insurance Australia can't afford to delay – Rob Wheals, Squadron Energy CEO, 14 October 2025, at https://squadronenergy.com/news/flexible-gas-the-energy-insurance-australia-cant-afford-to-delay-rob-wheals-squadron-energy-ceo/.

addition to reverse flows on the PCA, SEA Gas is proposing construction of a new pipeline from Port Campbell to Brooklyn connecting into the DTS.

- Amplitude Energy, Beach Energy, and ConocoPhillips are currently undertaking exploration and development activities in the offshore Otway Basin using the Transocean Equinox drilling rig. ConocoPhillips, with joint venture partners the Korea National Oil Corporation and 3D-Energi, has completed a drilling campaign that resulted in the discovery of two new gas fields, Essington and Charlemont. These fields were estimated to hold approximately 385 PJ of gas prior to drilling.

Increased production or storage capacity at Port Campbell will not provide additional peak day supply capacity to the DTS due to the existing SWP capacity constraint. APA submitted a proposal in October 2025 for an advanced capex determination under rule 80 of the NGR. This proposed project would increase SWP capacity to 615 TJ/d through the installation of two new compressors at new locations (Irrewillipe and Stonehaven), and modification of the existing compressor station at Winchelsea. An alternative option of looping a section of the SWP has also been proposed[27].

Operational resilience

Victorian supply adequacy is projected to continue declining over the outlook period as available supply capacity reduces, alongside the possibility of unexpected events such as increase GPG demand due to the retirement of coal-fired power generation. **Table 2** and **Table 3** summarise identified risks to supply adequacy and operational resilience, and provide an update on operational resilience issues impacting the DTS since the publication of the 2025 VGPR.

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. The Longford Gas Plant has reduced resilience and redundancy following the October 2024 retirement of Gas Plant 1 and the Crude Stabilisation Plant. The two remaining Longford gas plants have a combined capacity of 720 TJ/d. If either of the two remaining plants were unavailable, the total production capacity of the Longford Gas Plant could be reduced by up to 350 TJ/d.
Gas generation	The increasing reliance on GPG during extreme weather events and power system 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 be insufficient to meet both electricity generation and gas system demands.
Reduction in gas made available from Queensland to the southern states	Winter gas supply from Queensland 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 reduced Moomba Gas Plant production capacity and the SWQP running at reduced capacity (including due to a repeat of the inland flooding observed during winter 2025), lower Queensland production or higher Queensland demand including LNG exports, 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 inventory depletion risk. The recent geopolitical events in the Middle East have the potential to impact gas supply in the southern states. AEMO will continue to monitor gas adequacy for this winter under its Victorian declared system functions and East Coast Gas System (ECGS) functions.
Gas plant trip due to declining deliverability of Gippsland Basin Fields	Esso undertook offshore maintenance outages during 1-6 December and 14-17 December 2025 which resulted in a reduction in Longford capacity to 200 TJ/d. As this approached the 150 TJ/d minimum turndown threshold for the plant, an unplanned outage impacting the remaining offshore production facilities that remained online during the maintenance period could have resulted in the Longford Gas Plant being offline for the duration of the maintenance period. AEMO assessed the potential threat to gas supply adequacy and convened an ECGS gas supply adequacy and reliability conference leading up to the maintenance period to advise participants. This outage risk is expected to increase as the large legacy gas fields are depleted.

[27] AER, Public Forum, APA VTS – r80 application for the South West Pipeline, Combined presentation slides, at https://www.aer.gov.au/system/files/2025-12/AER%20-%20Public%20Forum%20-%20APA%20VTS%20-%20r.80%20application%20for%20the%20South%20West%20Pipeline%20-%20Combined%20presentation%20slides%20-%2011%20December%202025.pdf.

Table 3 Updates on operational resilience risks since 2025 VGPR

Risk	Description
Longford Gas Plant 3 retirement delay	In 2025, the nameplate capacity of the Longford Gas Plant was revised up from 700 TJ/d to 720 TJ/d. The 2025 VGPR included an update that the retirement of Gas Plant 3, which would reduce Longford Gas Plant capacity to approximately 400 TJ/d, had been deferred from December 2027 until December 2028. Gas Plant 3 is now expected to remain in operation until at least 2033, maintaining Longford Gas Plant's forecast capacity at 720 TJ/d until that time. In addition, Esso now plans to continue to operate two trunklines from offshore platforms to Longford until 2033.

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1 Introduction

The VGPR is published every two years in accordance with Rule 323 of the NGR. The report assesses the adequacy of the Victorian DTS to supply peak day gas demand and annual consumption over a five-year outlook period. This VGPR Update also provides some relevant data, as described in Section 1.4.2 below, for forecast supply and demand from 2031 to 2035.

The most recent VGPR was published in March 2025. Where AEMO becomes aware of any information that materially alters the most recently published VGPR, the NGR require AEMO to update the report as soon as practicable. The material changes since the 2025 VGPR that prompted this VGPR Update are:

- updated gas production and consumption forecasts, and
- updates to projects impacting DTS supply adequacy.

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/y of gas, and
- **Tariff D** – industrial and large commercial customers, each normally consuming over 10 TJ/y of gas or an hourly consumption rate of more than 10 gigajoules per hour (GJ/h).

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:

- 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.

1.1 DTS gas consumption in 2025 and recent years

Key findings

- Gas consumption in Victoria continued to decrease across residential, commercial and industrial sectors, with 2025 having the lowest annual gas consumption since at least 1982.
- Despite annual gas consumption decreasing, the DTS peak day total demand increased year-on-year due to record winter GPG demand.
- Supply sources in the DTS have shifted, with gas supply from Longford reducing in line with forecasts provided in previous VGPRs.
- Supply from Port Campbell continued its increased contribution to peak day supportability via the SWP, which was expanded prior to winter 2024 through the commissioning of the Western Outer Ring Main (WORM) pipeline and the second compressor at Winchelsea.

1.1.1 2025 gas consumption and cumulative Effective Degree Day

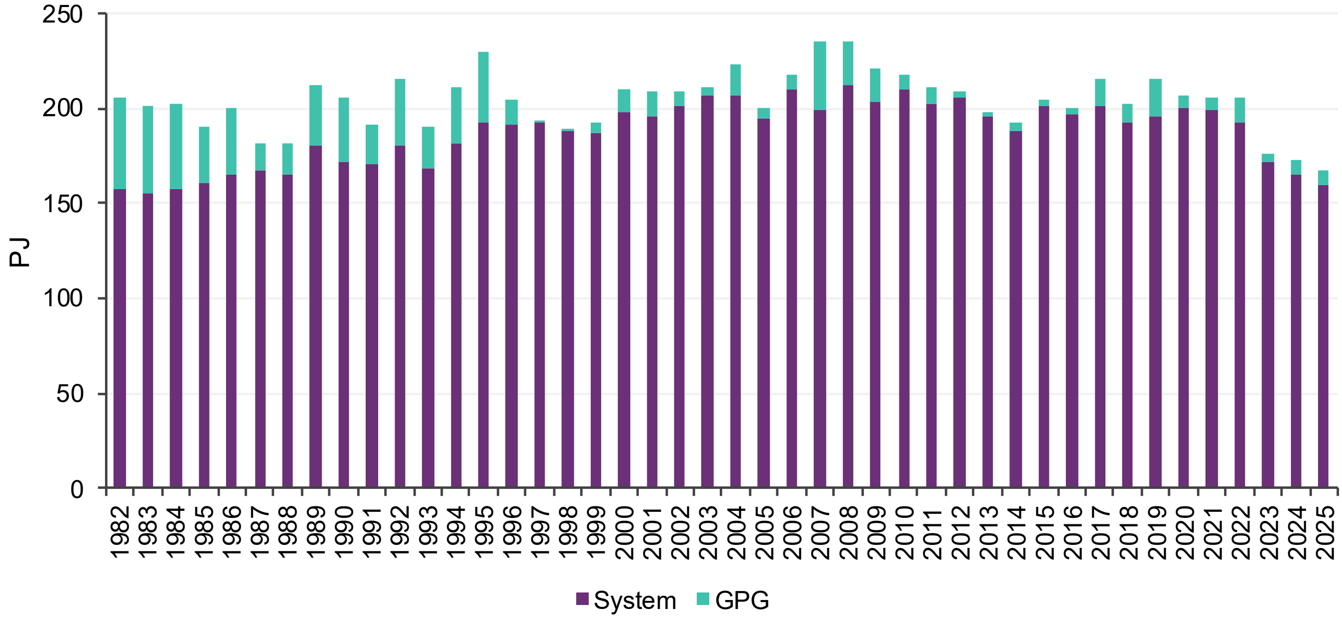
Gas consumption in Victoria has been declining in recent years, and 2025 saw the lowest DTS gas consumption since at least 1982, with a total consumption of 167 PJ, as **Figure 7** below shows. This was a 3.7% (6.4 PJ) decrease from 2024, despite cooler weather during 2025 (the cumulative EDD was 2.8% higher).

There were only four days in 2025 that exceeded 1,000 TJ of DTS total demand (which includes GPG demand), which is historically low (**Table 4**). DTS system demand has not exceeded 1,000 TJ since 2022.

Table 4 Peak day total demand and Effective Degree Day

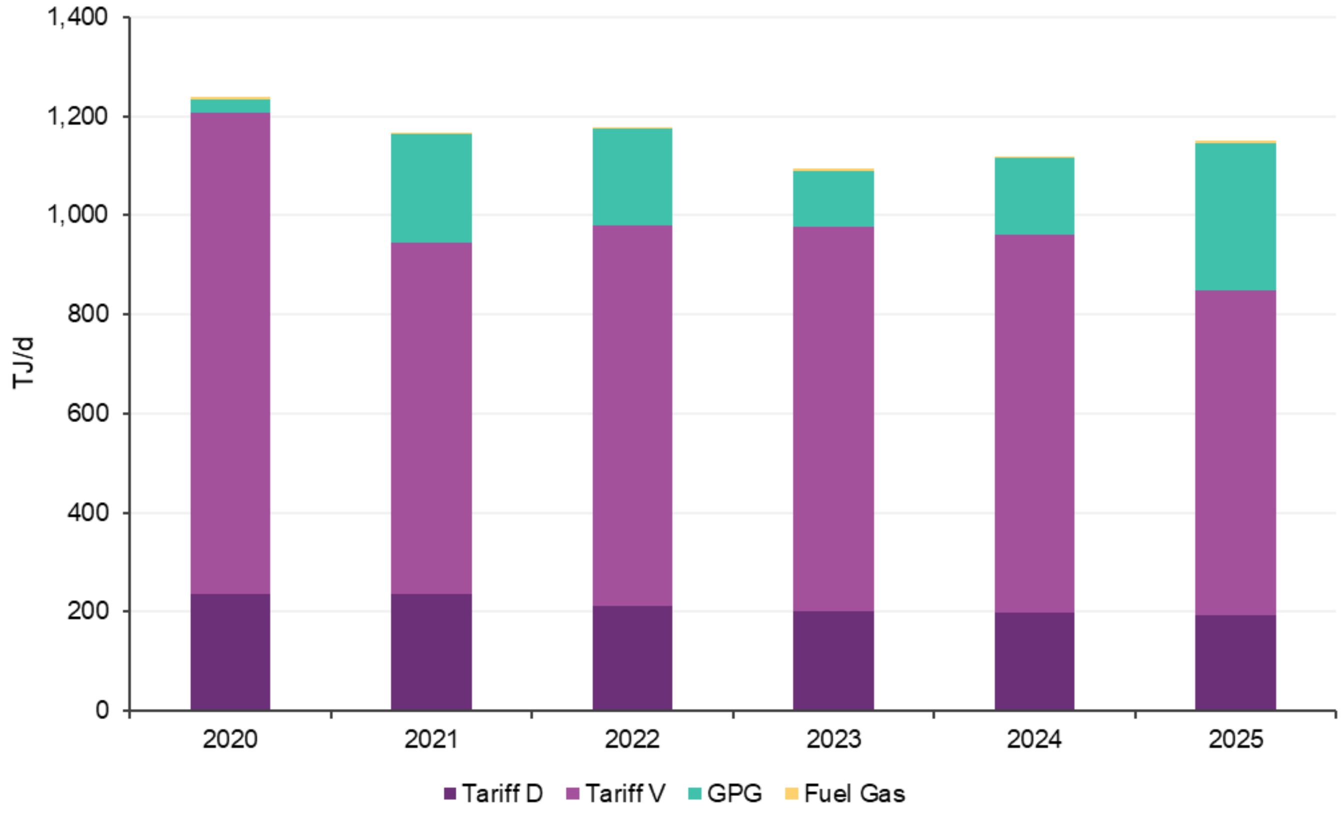
	2021	2022	2023	2024	2025
Days exceeding 1,000 TJ total DTS demand	21	25	2	13	4
Actual peak total demand (TJ)	1,168	1,179	1,094	1,120	1,152
Annual cumulative EDD	1,471.7	1,519.0	1,335.7	1,355.7	1,393.7

Figure 7 Declared Transmission System annual consumption 1982-2025 (PJ)



Despite annual consumption being historically low in 2025, the peak total demand day (on 26 June) was higher than recent years. This can be attributed to a record winter DTS GPG demand (299 TJ) on 26 June, seen in **Figure 8**. Total Victorian GPG demand, which includes GPG not connected to the DTS, also set a winter record of 382 TJ on 26 June.

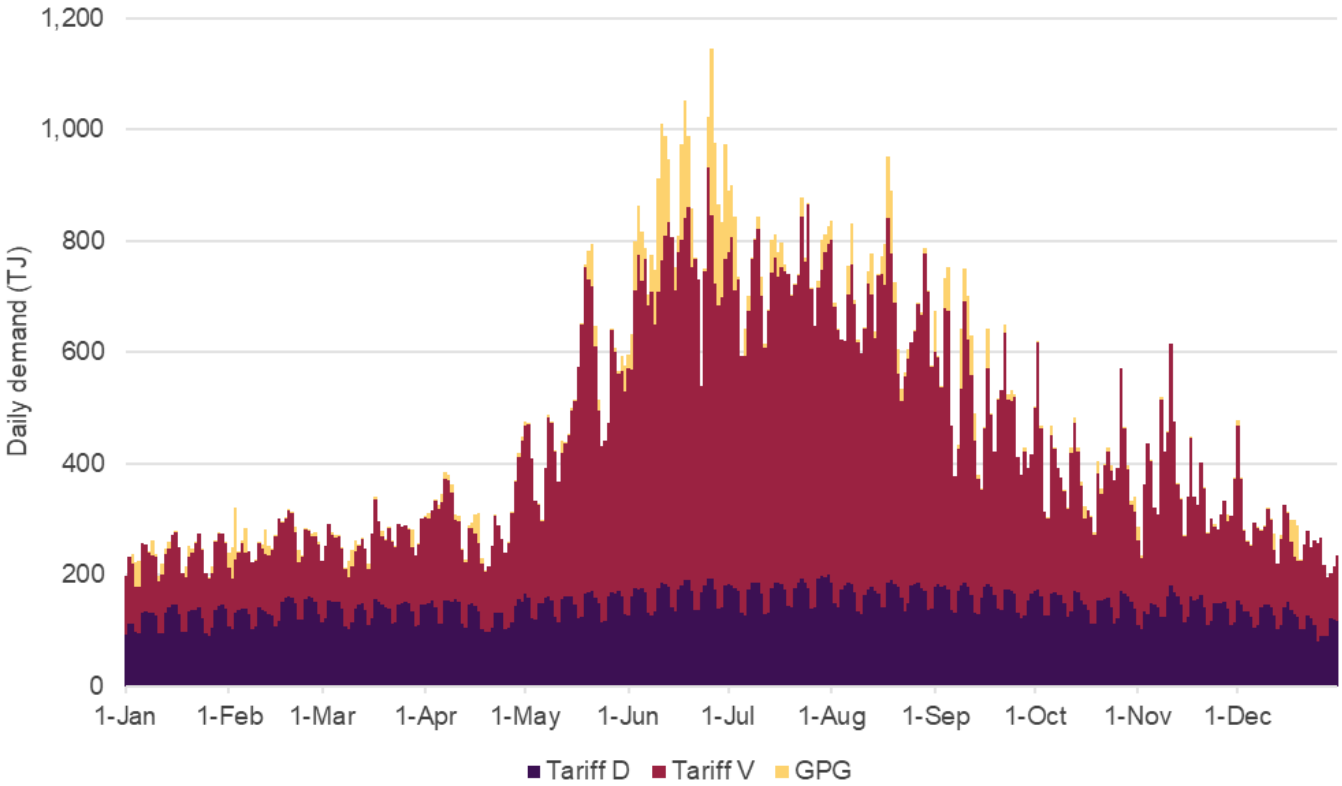
Figure 8 Declared Transmission System peak day demand 2020 to 2025 (TJ/d)



Tariff V demand was notably lower on the 2025 peak day than in previous years. While the difference was less significant, Tariff D demand also continued to make up less of the peak day total demand. This is consistent with the overall decline in Tariff V and Tariff D demands. The highest system demand day during winter 2025 was the day earlier, on 25 June with a system demand of 932.8 TJ.

The daily DTS demand profile, shown in **Figure 9**, highlights the seasonal nature of Tariff V, Tariff D and GPG demand in Victoria. Tariff V has historically made up the majority of demand, and in 2025 accounted for 64% of annual total consumption. In 2025, Tariff D followed at 32%, with GPG and fuel gas[28] comprising 4% and <1% of annual total consumption, respectively. While GPG only accounts for a low portion of DTS total consumption, on peak winter days[29] GPG represented up to 12% of DTS total demand.

Figure 9 Declared Transmission System daily demand profile, 2025 (TJ)



1.1.2 Historic DTS gas consumption

Tariff V consumption

Tariff V customers are typically residential and small commercial gas users, and make up the majority of gas consumers in the DTS. Tariff V gas use, particularly for residential customers, 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 days with a zero EDD is typically low.

[28] Fuel gas is the gas consumed to facilitate transmission of gas in the DTS, through compressors and heaters. Fuel gas costs are spread across the market.

[29] Defined here as days exceeding 800 TJ of total demand.

As **Table 5** shows, for a second consecutive year, annual Tariff V consumption decreased despite the higher cumulative EDD than the year prior. AEMO believes this is due to a combination of the electrification of gas loads and cost of living pressures, noting the downward step change that occurred between 2022 and 2023. AEMO is currently not able to quantify each of the components.

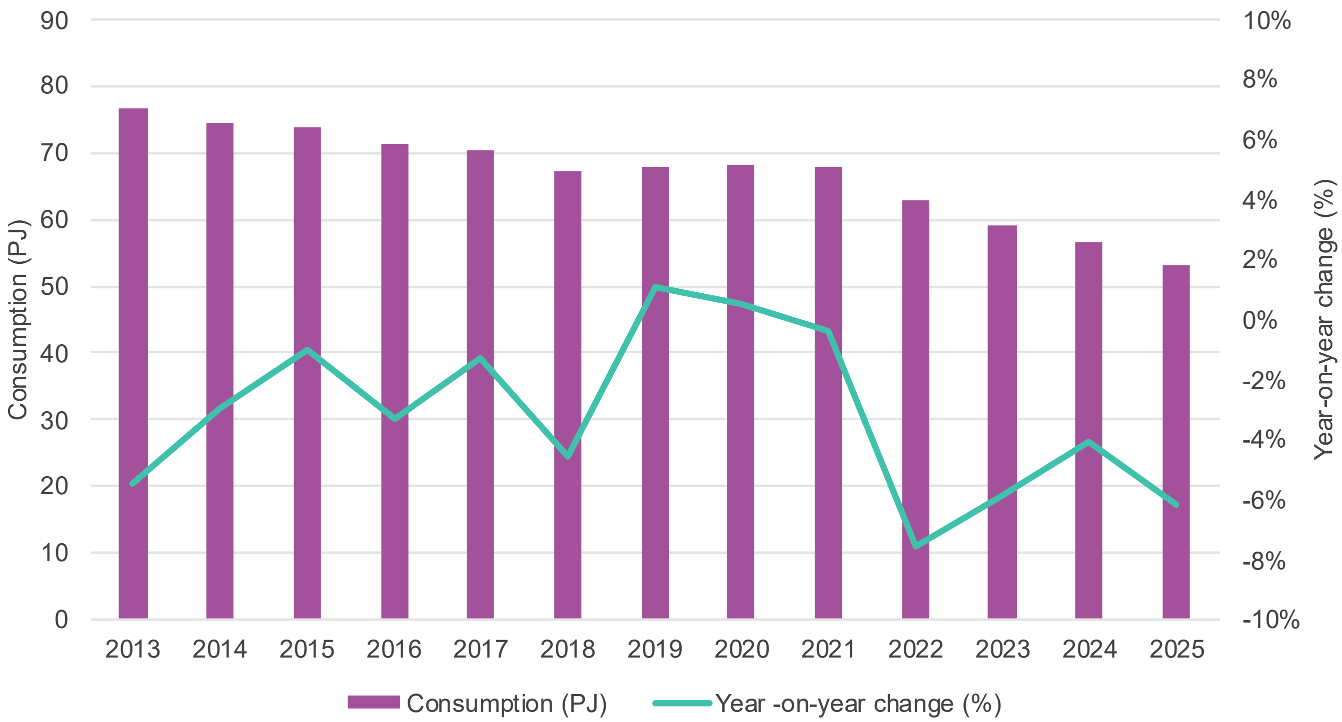
Table 5 Annual Tariff V consumption and cumulative Effective Degree Day with year-on-year changes, 2019 to 2025

Year	Annual cumulative 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%	113.2	-13.3%
2024	1,355.7	1.5%	108.4	-4.2%
2025	1,393.7	2.8%	106.1	-2.1%

Tariff D consumption

Tariff D customers typically have stable consumption profiles across a year, with their gas consumption often linked to economic conditions. The largest users, that make up most of the consumption, are less sensitive to weather conditions than Tariff V customers. Tariff D consumption continued to decline in 2025, as **Figure 10** shows, making a 24 PJ (31%) reduction since 2013. The past year alone saw Tariff D consumption decline by 3.6 PJ (6.3%).

Figure 10 Declared Transmission System Tariff D annual consumption and year-on-year percentage change, 2013-25 (PJ)



The decline has been discussed in previous VGPRs and can be partially attributed to the continuing decline in Victorian manufacturing. Notable closures in recent years include:

- plant closures of large heavy industries including Oceania Glass, Qenos and the Mobil Altona refinery,
- dairy closures from Saputo, Murray Goulburn, Fonterra and Lactalis, and
- other smaller closures across the food and paper manufacturing industries.

It is difficult for AEMO to forecast Tariff D consumption, as Tariff D customers do not have to provide AEMO with advanced notice of expected closures. However, it is plausible that Tariff D demand in the DTS will continue to reduce due to a combination of closures, reduced activity, and a push for businesses to reduce emissions, including moving to fully electric operations where possible.

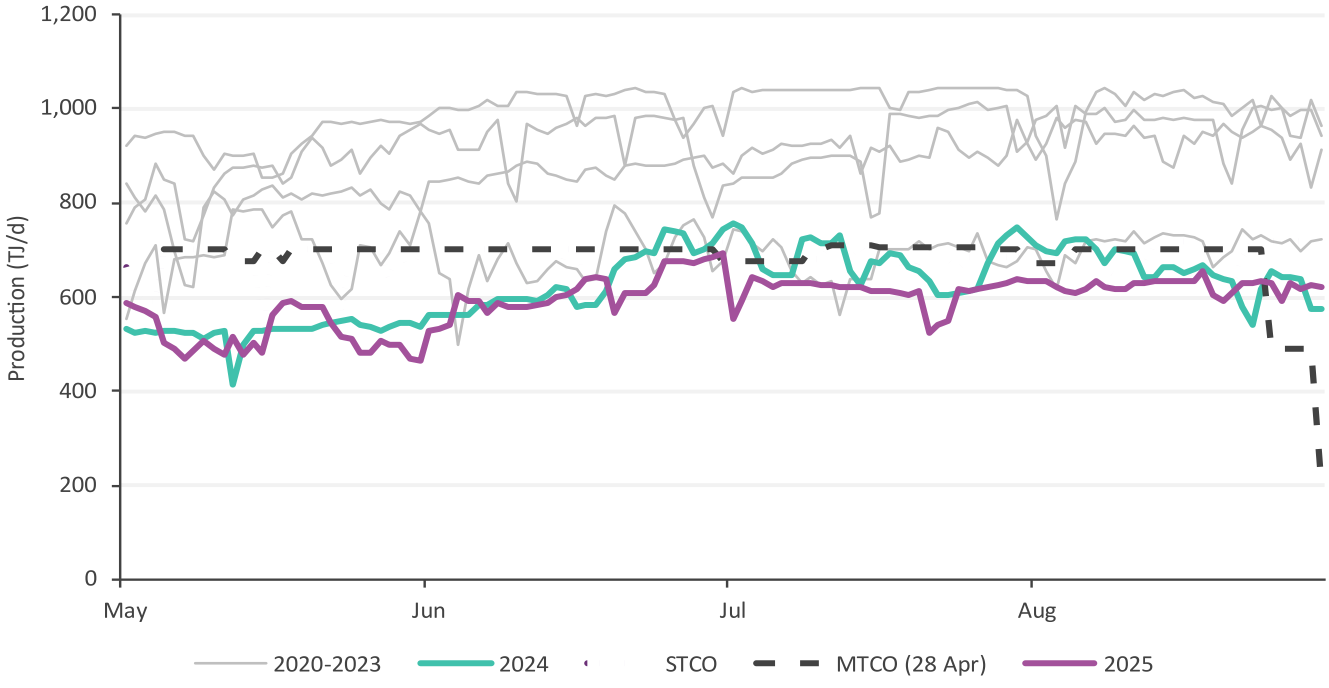
1.2 2025 challenges

1.2.1 Longford production

Declining Longford supply

Winter 2025 was the first during which the Longford Gas Plant operated without Gas Plant 1 and the Crude Stabilisation Plant, which were decommissioned in October 2024. At the start of winter 2025, the Longford operator reported the plant's total nameplate capacity at 700 TJ/d[30], the lowest since the commissioning of Gas Plant 3 in 1983. Longford production was well below the reported capacity for most of the winter period, as **Figure 11** shows, with the highest daily production of 694 TJ achieved on 1 July.

Figure 11 Longford capacity outlooks (TJ/d)



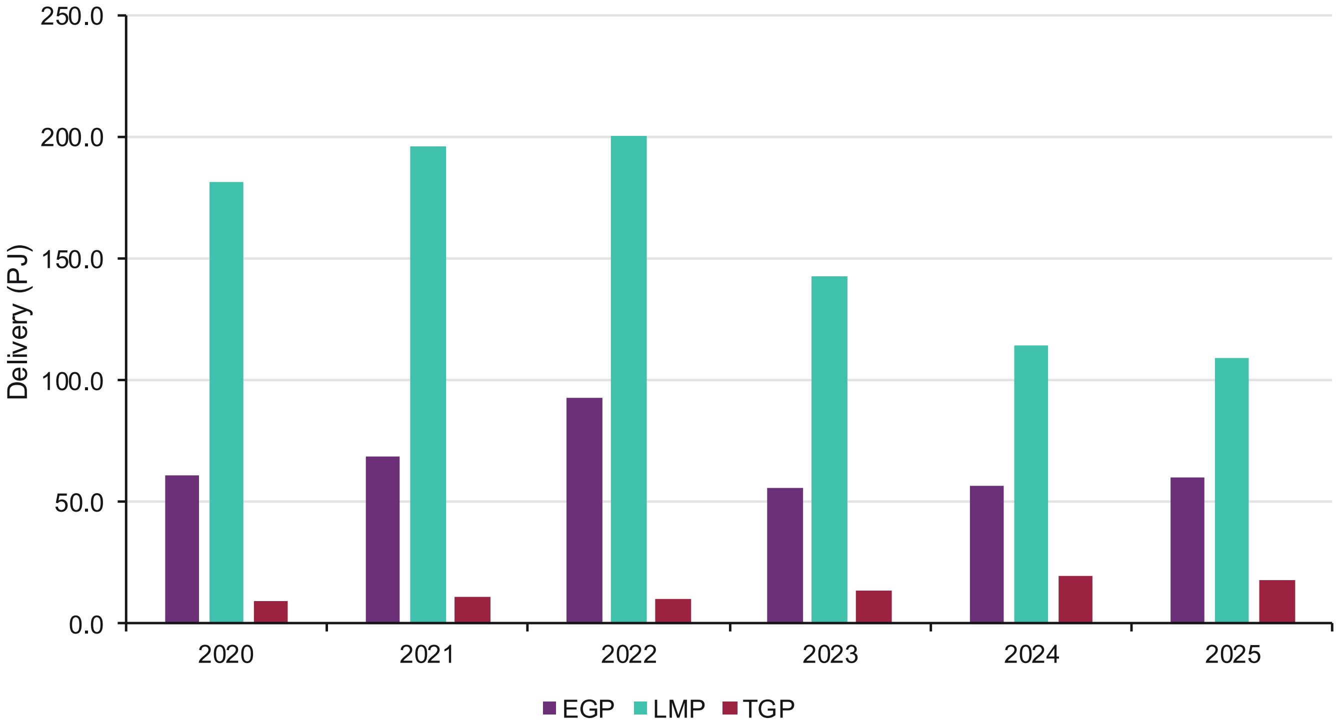
[30] Longford Gas Plant's capacity has since been updated to 720 TJ/d by the plant operator, citing improved plant performance.

Longford production during 2025 was 189 PJ, slightly lower than the 191 PJ for 2024, which was expected with the reduced production capacity. This is substantially less than the Longford total annual production of 327 PJ and 358 PJ during 2016 and 2017, respectively.

Several unplanned outages (indicated by reductions in the short-term capacity outlook [STCO][31]) occurred during the winter period, highlighting the declining resilience of the Longford production system that has been reported in the VGPR for several years.

The Longford Gas Plant can supply gas into the EGP towards Sydney and the Tasmanian Gas Pipeline (TGP) via the VicHub compression facility, or into the Longford to Melbourne Pipeline (LMP) which forms part of the DTS. As Longford production has declined since 2022, when capacity was 1,040 TJ/d, supply into the EPG and TGP has remained reasonably constant while the supply into the DTS via the LMP has reduced by approximately 45%, as **Figure 12** shows.

Figure 12 Longford delivery split between the Eastern Gas Pipeline, Longford to Melbourne Pipeline, and Tasmanian Gas Pipeline (PJ)



The consistent flow up the EGP is considered to be due to a combination of commercial factors (contracted EGP capacity) and physical supply limitations, as large facilities connected to the EGP as well as some towns in south-east New South Wales can only be supplied from Victoria. Similarly, the TGP can only be supplied from the VicHub facility adjacent to the Longford plant.

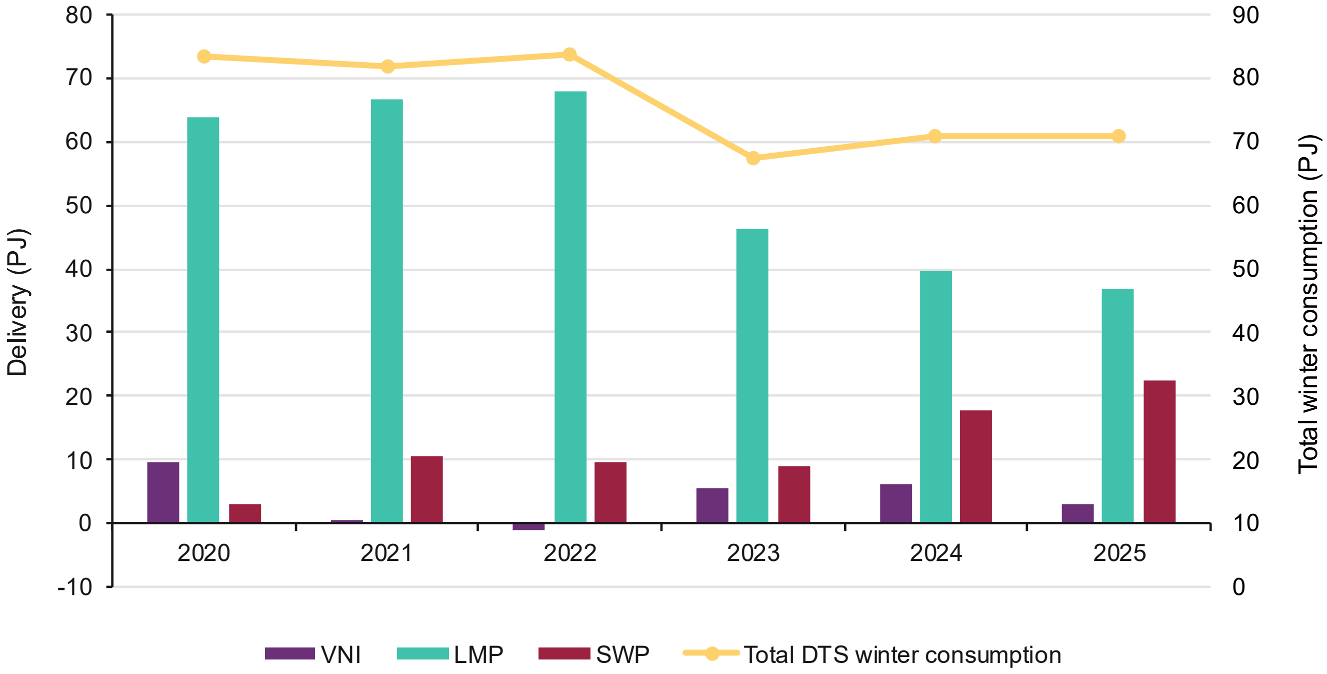
The reduced Longford supply into the LMP has resulted in the Gooding Compressor Station being bypassed, as it has not been required for managing LMP linepack and gas cannot reverse flow through the station (which ultimately prevents

[31] The STCO is a daily public Bulletin Board submission where injection facilities provide a seven-day outlook of expected capacity, in accordance with rule 178 of the NGR. The graph shows the latest STCO submission relating to each gas day.

backflow on the LMP). Backflow to the eastern end of the LMP may be required in the event of an unplanned full Longford plant outage during winter[32].

To counteract reduced Longford supply into the LMP, supply into the DTS from Port Campbell via the SWP, and from New South Wales via Culcairn into the Victorian Northern Interconnect (VNI) which also forms part of the DTS, has increased during the peak winter months (June, July and August), as shown in **Figure 13**. This rise in actual SWP supply, alongside a declining trend of LMP supply, occurred even though actual DTS total winter consumption since 2022 has stayed relatively flat. While supply from New South Wales via Culcairn has increased, Victoria has remained a net supplier to New South Wales due to higher flows north via the EGP.

Figure 13 Historical Declared Transmission System pipelines delivery split for winter months and winter Declared Transmission System total consumption (PJ) for 2020 to 2025



Increased supply via the SWP has been enabled through increased Otway Basin production at the Otway and Athena gas plants, along with increased utilisation of the Iona UGS facility, which has increased its storage capacity from 23.5 PJ in 2020 to 24.4 PJ currently. Increased supply capacity via Culcairn has been recently committed for winter 2028 as part APA's ECGG Expansion Plan Stage 3A. Lochard Energy also has a committed expansion of the Iona UGS facility (HUGS Phase 1), however an expansion of the SWP has not yet been committed.

Lower Longford capacity during outages

The reduction in Longford Gas Plant capacity since 2022 has also resulted in lower production capacity being available during major outages. A major four-week maintenance outage between 19 January 2024 and 17 February 2024 resulted in Longford capacity being reduced to as low as 285 TJ/d.

[32] 2025 VGPR, Section 5.1, at https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

During 1-6 December 2025 and 16-19 December 2025, offshore maintenance to facilitate Turrum Phase 3 project works at Longford decreased gas production capacity to 180-200 TJ/d. This is understood to be the lowest planned capacity since the 1970s. Prior to the works commencing, the Longford operator advised AEMO of a credible (but low) risk of the gas plant tripping during this maintenance and being unable to return to production until the end of the maintenance period. This would have resulted in a prolonged period with no supply from the Longford Gas Plant. The first Longford capacity reduction coincided with Otway Gas Plant maintenance from 1-12 December 2025, which saw Otway plant capacity reduced to 66-115 TJ/d.

Under AEMO's Victorian and East Coast Gas System (ECGS) responsibilities, supply adequacy risks were reviewed and AEMO determined that while risk was increased, there was not a gas supply threat[33] because gas supply from Queensland could be increased to support demand. Delaying either the Longford or the Otway outage would have resulted in substantial additional costs for the production joint venture parties at these facilities.

To inform stakeholders of the supply assessment, AEMO briefed the National Gas Emergency Response Advisory Committee (NGERAC) and called an ECGS Gas Supply Adequacy and Reliability Conference on 26 November 2025. AEMO advised that gas supply from Queensland would be required during the 1-6 December outage and that increased supply from Port Campbell via the SWP, particularly from the Iona UGS facility, would be also required in the event of a trip and full Longford Gas Plant outage during this period[34]. The WORM and the Winchelsea compressor station (noting one compressor was on a long-term unplanned outage) would have been essential for ensuring supply adequacy to eastern parts of the DTS if a full Longford outage was to occur.

No full plant outage was experienced at Longford during these periods, however this period coincided with some days of unseasonably cool weather, which drove up demand. Imports into the DTS from New South Wales via Culcairn were scheduled on many of the days during the first outage. The supply deficit during the second outage was covered by gas supply via the SWP as the Otway Gas Plant had returned to normal capacity. **Figure 14** shows supply to the system during these periods.

Periods of very low Longford production capacity are likely to become more common in future years as supply from the offshore gas fields continues to decline, and production also becomes increasingly more dependent on the Longford Gas Conditioning Plant. The SWP including the WORM and the Winchelsea compressor station is expected to play an increasingly important role as supply sources continue to shift in the DTS.

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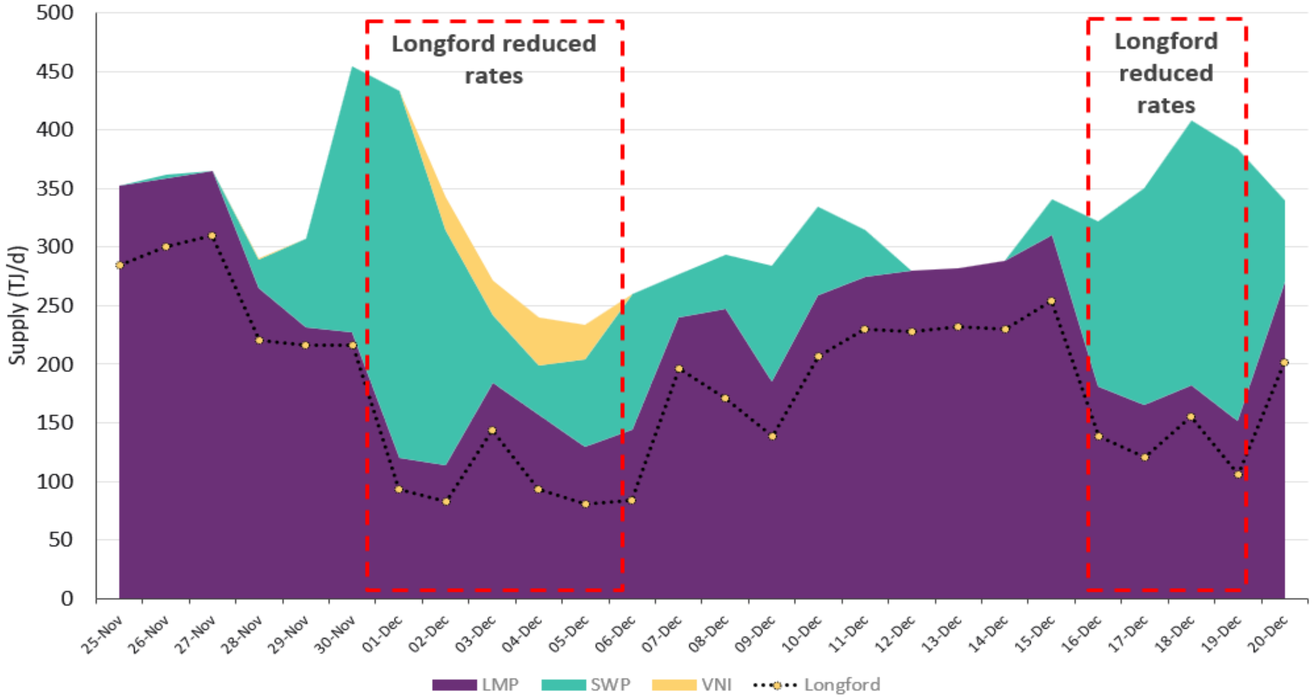
[33] AEMO may issue a direction(s) in response to a gas supply threat.

[34] See https://www.aemo.com.au/-/media/files/gas/east-coast-gas-system/ecgs-notices/2025/aemo-ecgs-gsar-minutes-26-november-2025.pdf?rev=ddb9fdceea6c4a6e8ad04194453cbd30&sc_lang=en.

Figure 14 Gas supply during Longford very low rates periods (TJ/d)



Note: the LMP transports gas produced in the Gippsland region, the SWP transports gas from facilities in south-western Victoria, and the VNI transports gas flowing via Culcairn from the MSP.

1.2.2 Gas-powered generation demand

Highest winter GPG demand day

In 2025, the DTS saw the highest June GPG demand since 2007[35]. This was due to several sustained unplanned outages in Victoria's coal-fired power generation fleet[36], coinciding with low renewable electricity generation, and record winter electricity demand.

The GPG peak day on 26 June marked the highest winter GPG demand day for the DTS at 299 TJ. Three of the top 10 DTS winter GPG demand days of all time were observed during 2025; 26 June (highest at 299 TJ), 27 June (third-highest at 255 TJ), and 11 June (seventh-highest at 244 TJ).

GPG facilities connected to the DTS consumed 1.5 PJ of gas over a nine-day period between 25 June and 3 July 2025 (highlighted in **Figure 15**). **Figure 15** also shows that, despite the high GPG demand days, cumulative winter 2025 DTS GPG demand was similar to winter 2024.

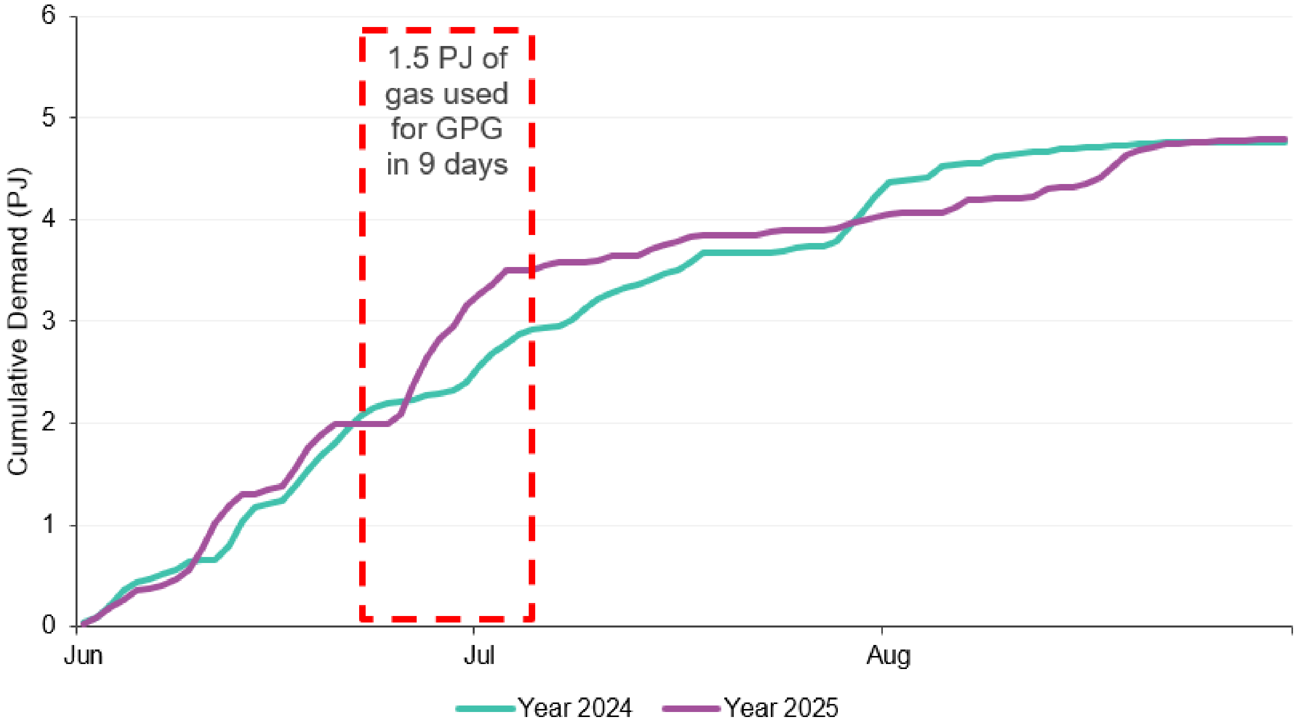
Overall Victorian GPG demand, which includes the Mortlake and Bairnsdale power stations, has also been at record levels. During winter 2024, Victorian GPG demand was 356 TJ on 13 June, which was the highest daily GPG demand for any time of the year since 25 January 2019 (when GPG demand was 447 TJ, during a period when Victoria was experiencing its hottest weather in five years). Victorian GPG demand was then higher at 382 TJ on 26 June 2025, and total east coast gas demand for GPG totalled 1,049 TJ on this day, setting a new winter record and the fourth-highest daily total on record for any time of year.

[35] High GPG demand during 2007 was due to drought conditions that impacted generation from hydro and coal (due to cooling water restrictions).

[36] See https://www.abc.net.au/news/2025-06-09/yallourn-power-station-outage-air-duct-collapse/105394406 and https://www.abc.net.au/news/2025-05-16/coal-reliability-report-outages-loy-yang-yallourn-latrobe-valley/105296552.

A contributor to the increasing winter GPG demand is higher winter electricity demand. During winter 2024, Victorian winter electricity demand peaked on 15 July at 8,612 megawatts (MW), which broke the previous winter demand record of 8,351 MW set on 17 July 2007 (which was also a record Victorian gas demand day). This winter electricity demand record was exceeded on 25 June 2025 when Victorian electricity demand peaked at 8,818 MW (this was also the highest DTS system demand day during winter 2025).

Figure 15 Declared Transmission System cumulative winter GPG demand in 2024 and 2025 (TJ)



1.2.3 Supply from Port Campbell

Port Campbell production

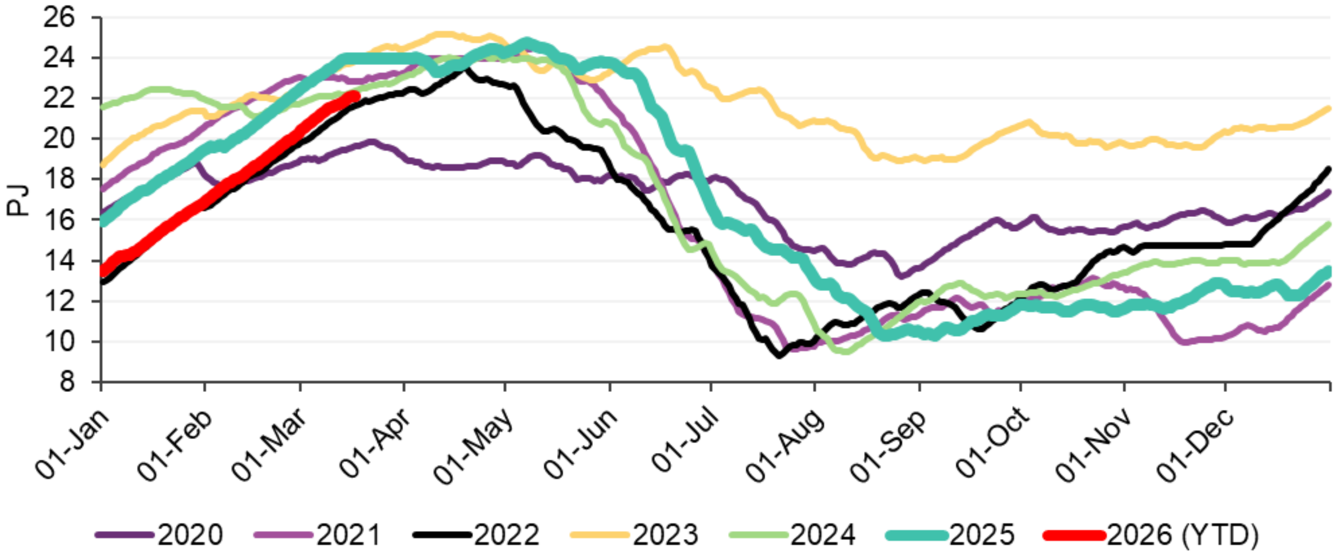
Annual Port Campbell production in 2023, 2024, and 2025 was 38 PJ, 56 PJ, and 61 PJ, respectively. This reflects a 60% increase in production from Port Campbell over two years. The increase has offset the reduction in Gippsland production, resulting in a slight increase of 8 PJ in total annual Victorian production from 2023 to 2025.

Steady supply from the Iona UGS facility

Iona UGS filled to a maximum of 24.7 PJ prior to the 2025 winter. The facility maintained high inventory until after the start of June, then experienced a high rate of depletion due to periods of high GPG demand and colder weather driving heating demand. This rapid Iona depletion during June was like the trends observed during 2021, 2022, 2024 and 2025 as shown in **Figure 16**, which were due to a combination of high GPG demand due to low renewable generation and reduced gas supply.

The rate of Iona depletion eased from the second week of July 2025, with inventory steadily reducing to a minimum of 10.3 PJ in late September, when it began to slowly refill. Iona UGS also supplied gas to the DTS on some gas days in December 2025, with the Longford Gas Plant at very low rates for offshore project works.

Figure 16 Iona Underground Gas Storage inventory, 2020 to 2026 (YTD) (PJ)



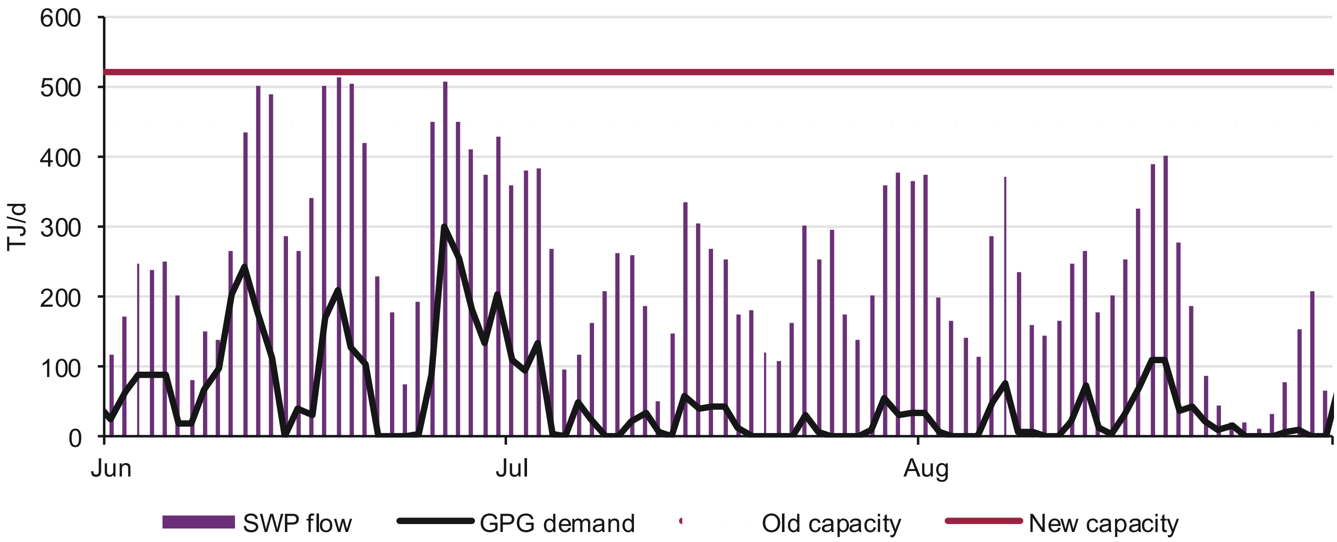
Increased SWP capacity enhances GPG supportability

The SWP flows bi-directionally between Port Campbell and Melbourne, which enables gas from the Otway and Athena gas plants and Iona UGS to support DTS demand during the winter, and supply gas to Port Campbell outside of winter to support the refilling of the Iona UGS facility.

In February 2024, the winter peak capacity of the SWP was increased from 447 TJ/d to 523 TJ/d with the commissioning of the WORM pipeline (running from Rockbank to Wollert) and a second compressor at Winchelsea, which can run in-series with the initial compressor.

In 2025, the SWP flowed above the previous maximum capacity for a total of eight days (see **Figure 17**). These all occurred in June, when GPG demand in the DTS was abnormally high. The increased SWP capacity provided by the WORM and Winchelsea Unit 2 prevented the SWP from being capacity-constrained during this period of high GPG demand.

Figure 17 Daily South West Pipeline flows during winter (towards Melbourne), 2025 (TJ/d)



1.2.4 Supply from Culcairn

During winter 2025, supply into the DTS from Culcairn reached the highest daily injection quantity since 2001, reaching 179 TJ on 7 June and 167 TJ on 8 June. During winter 2024, supply from Culcairn into the DTS was at least 147 TJ on three days during July. This highlights the increasing utilisation of supply from Culcairn during winter peak demand conditions.

However, these high flows into the DTS from Culcairn are typically achieved during periods of lower New South Wales system demand and low utilisation of the Uranquinty Power Station near Wagga Wagga. The peak Culcairn supply quantities noted above were achieved when the Uranquinty Power Station was either offline (on 7 June) or used less than 10 TJ of gas (on 8 June). On these two days, MSP supply to Sydney via the Wilton delivery station was approximately 200 TJ/d, compared to typical peak supply of approximately 250 TJ/d, due to mild winter weather in Sydney with the maximum temperature exceeding 20°C on 7 June[37].

This highlights the existence of a capacity trade-off between supply into the DTS from Culcairn, against supply to the Uranquinty Power Station and Sydney.

APA has committed to a further increase in MSP capacity as part of ECGG Expansion Plan Stage 3A. This project includes a 10 TJ/d increase in MSP capacity and a 39 TJ/d increase in the Young to Culcairn lateral capacity. The Stage 3A expansion is expected to increase overall supply into the DTS from Culcairn.

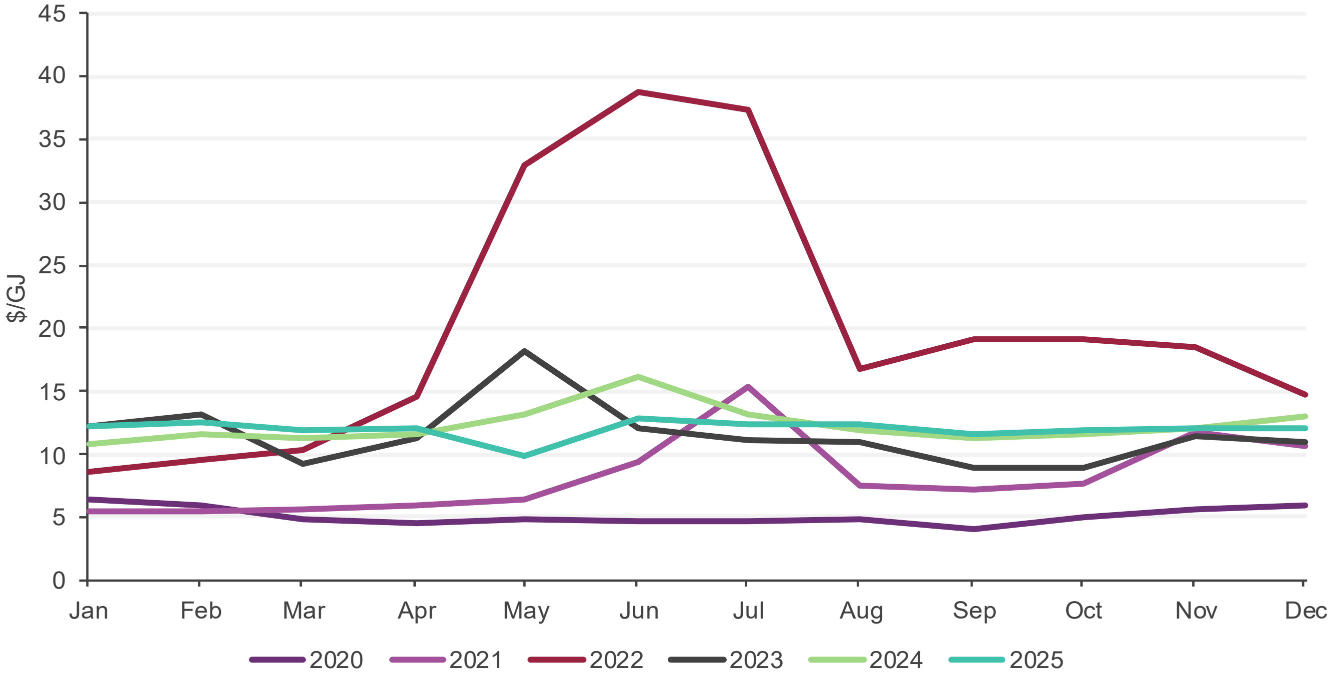
1.2.5 Declared Wholesale Gas Market (DWGM) prices

Steadier prices in 2025

Prices in the DWGM have been elevated in recent winters (**Figure 18**) due to numerous factors, including domestic coal generator outages and international gas price volatility. While winter prices remained elevated compared to pre-2021 prices, the 2025 winter average price of $12.53/GJ was 8% lower than the previous winter. On 2 July 2025, during a period of high GPG demand, the DWGM price peaked at $19.70/GJ, considerably lower than the 2024 peak of $28.00/GJ.

[37] BOM, Sydney June 2025 Daily Weather Observations, at https://www.bom.gov.au/climate/dwo/202506/html/IDCJDW2124.202506.shtml.

Figure 18 Average monthly prices in the Declared Wholesale Gas Market, 2020 to 2025 ($/GJ)

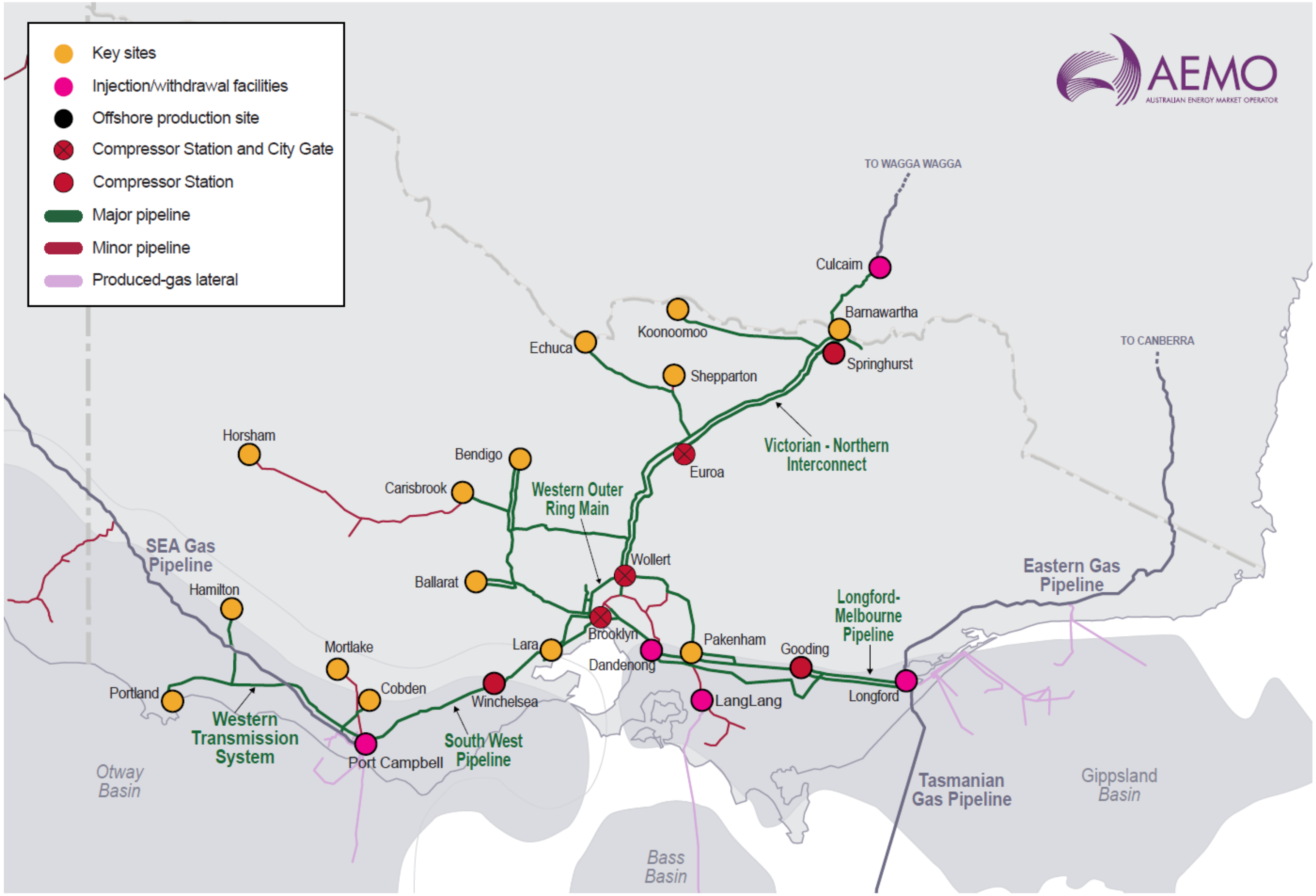


1.3 The Victorian Declared Transmission System

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 PCA).

Figure 19 shows a high-level map of the Victorian gas transmission network, including the DTS and other gas transmission pipelines.

Figure 19 The Victorian Declared Transmission System and other gas transmission pipelines



1.4 Gas planning in Victoria

1.4.1 Roles and responsibilities

AEMO operates the Victorian DTS and provides information about gas supply and demand, system constraints, capability, and development proposals, to assist in the efficient planning and development of gas markets and facilities.

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

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

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

1.4.2 Planning basis and definitions

Under section 91BA(1)(d) of the NGL, AEMO's declared system functions include providing information and other services to facilitate decisions for economically efficient investment in the covered gas industry in the adoptive jurisdiction.

As part of AEMO's declared system functions, 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 324(A) of the NGR, participants are required to provide AEMO with forecast information. Under rule 324(6), AEMO must keep this forecast information confidential except to the extent of the information that AEMO is required to provide in the VGPR.

Under NGR rule 135KH(1A), AEMO may also use information provided to it in connection with a GSOO survey to prepare and publish the VGPR.

In producing the VGPR, AEMO assesses DTS supply and system adequacy to meet a forecast 1-in-2 and 1-in-20 peak system demand day over the outlook period.

As part of AEMO's declared system functions, this VGPR Update also provides some relevant data for forecast supply and demand from 2031 to 2035, including:

- production forecast data from 2031 to 2035 from Victorian producers' survey data,
- system demand forecast data from 2031 to 2035 as available in the 2026 GSOO Gas forecasting data portal, and
- GPG demand forecast data from 2031 to 2035 produced as part of the development of the 2026 GSOO.

System demand does not include supply for GPG[38]. Under rule 323(3), AEMO is also required to assess the impact of gas generation demand on 1-in-2 peak system demand days.

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

The *Gas Industry Act 2001* (Vic) and the *Gas Safety Act 1997* (Vic) impose obligations on network operators and owners relating to the reliability of gas supply. The reliability of gas supply refers to the continuity of supply to customers. Energy Safe Victoria (ESV) regards an unplanned loss of supply (or interruption) to a customer in any circumstance as a potentially dangerous and undesirable event.

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

1.4.3 Threat to system security

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

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

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

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

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

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

2 Gas consumption and demand forecasts

Key findings

The gas consumption and demand forecasts for the 2026 VGPR Update, 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 10.5% over the outlook period**, from 158 PJ in 2026 to 142 PJ in 2030.
- **Annual total DTS consumption (which includes GPG) is forecast to decrease by 9% over the outlook period**, from 162 PJ in 2026 to 147 PJ in 2030.
- The **forecast peak day system demands** are:
  - 958 TJ/d for a 1-in-2 year system demand day in 2026, reducing by 12.7% to 837 TJ/d in 2030, and
  - 1,032 TJ/d for a 1-in-20 year system demand day in 2026, reducing by 12.8% to 900 TJ/d in 2030.
  - This is a larger reduction in the peak day demand forecast than in the 2025 VGPR, driven by an increased level of electrification in the residential heating load.
- **Victorian GPG peak day demand is forecast to remain at the levels seen in recent years, before increasing from 2029 due to coal power station retirements that have been announced for towards the end of the decade.**
  - Actual Victorian GPG consumption during 2025 was 13.3 PJ. This is forecast to reduce during the first three years of the outlook period, due to increased energy storage capacity connecting to the NEM. The impact of the closure of coal power stations in Victoria and New South Wales is forecast to lead to an increase in GPG consumption from 2029 onwards.
  - The Draft 2026 *Integrated System Plan* (ISP) outlines the forecast GPG required for firming to meet the emissions reductions targets set by Australian governments. It forecasts Victorian GPG capacity increasing from the existing 2.4 gigawatts (GW) to 3.9 GW during the 2030s, with the assumption that Victorian brown coal power stations will progressively shut down over the next decade.

2.1 Gas usage forecast

Scenario and sensitivity forecasts

The forecasts for the 2026 VGPR Update and the 2026 GSOO focus on the *Step Change* scenario outlined in the 2025 IASR. This *Step Change* scenario, identified in AEMO's Draft 2026 ISP as the most likely pathway for Australia's energy sector, is a refinement of the 2023 IASR *Step Change* scenario. It is centred around achieving a scale of transformation that achieves the objectives of Australian governments' policies in transitioning the energy system while supporting Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels.

GPG usage under the *Step Change* scenario is forecast to remain at the levels observed in recent years before starting to increase in 2029. During the five-year outlook period, the Yallourn and Eraring coal power stations are scheduled to close, in

July 2028 and April 2029, respectively. These coal generator closures are forecast to offset the impact of additional energy storage connecting to the NEM, and result in an overall increase of GPG requirements in Victoria.

AEMO also studied the impact of lower coal generator availability in a sensitivity, *Lower Coal Availability*. 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 assumed ongoing policy support to enable consumers to electrify many of their existing gas appliances and reduce their overall gas consumption. Victoria's Gas Substitution Roadmap policies and schemes continue to provide incentives for this fuel-switching, through:

- 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,
- banning gas distribution businesses from offering incentives to connect residential buildings to gas or to purchase and install gas appliances,
- implementing new electrification and efficiency standards for Victorian Buildings, to be phased in from January 2027, that will require:
  - all new existing homes and commercial buildings to be built all-electric,
  - existing residential owner occupiers must replace a broken gas hot water appliance with an electric alternative if it cannot be repaired, and
  - rental providers to provide electric upgrades to hot water and space heating appliances when they break and cannot be repaired, as well as ensuring insulation draughtproofing is installed and meets specific standards, and
- development of the Industrial Renewable Gas Guarantee, a market funded scheme commencing in 2027 that will target 4.5 PJ of renewable gas production by 2035[39], to be used exclusively in the industrial sector, where electrification is not currently commercially or technically feasible.

In addition to these Victorian Government policies, the Australian Government's Safeguard Mechanism will require most of Australia's largest emitters to reduce emissions by 4.9% each year to 2030[40]. The combination of these policies resulted in AEMO forecasting a 9.6% reduction in annual Victorian total gas consumption, which includes all Victorian GPG, and a 12.8% reduction in peak day system demand (which excludes 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 9% over the outlook period, from 162 PJ in 2026 to 147 PJ in 2030, as shown in **Table 6** and **Figure 20**. The forecast decrease is

[39] Victorian Department of Energy, Environment and Climate Action, Victoria's Renewable Gas Directions Paper, at https://engage.vic.gov.au/download/document/37987.

[40] Australian Government, DCCEEW, Safeguard Mechanism scheme, at https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

driven by reduced gas use by residential and small commercial customers (Tariff V) due to electrification, continuing the trend observed in recent years. There is a modest increase in industrial and large commercial customer (Tariff D) consumption over the outlook period, which reflects a lower forecast 2026 starting position than the 2025 actual consumption. Forecast consumption over the 2025-2030 period shows a 4.7% decrease.

As **Figure 20** shows, the year-on-year decrease in forecast annual consumption is largely due to the Tariff V component, which comprises the largest portion of gas used in Victoria. The forecast decrease in system consumption from 158 PJ in 2026 to 148 PJ in 2029 represents a reduction of between 4% and 6% from the five-year *Step Change* scenario forecast in the 2025 VGPR, which projected system consumption of 169 PJ in 2026 and 155 PJ in 2029:

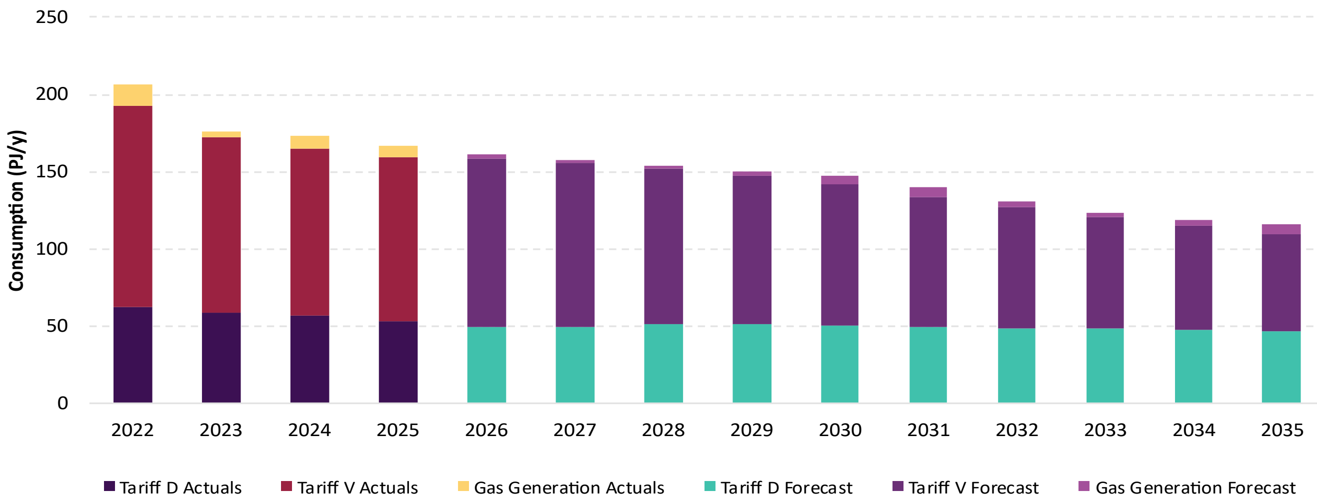
- Tariff V consumption is forecast to decrease by 16.5% over the five-year outlook, from 108.9 PJ in 2026 to 91.0 PJ in 2030.
- Tariff D consumption is predicted to increase by 2.6% over the five-year outlook, from 49.5 PJ in 2026 to 50.7 PJ in 2030.

Table 6 Actual and forecast Victorian annual gas consumption, *Step Change* scenario, 2023-30 (PJ/y)

	Actual			Forecast					Change over outlook
	2023	2024	2025	2026	2027	2028	2029	2030	
Tariff V	113.2	108.4	106.1	108.9	105.8	101.2	96.7	91.0	-16.5%
Tariff D	59.1	56.6	53.1	49.5	49.8	51.1	51.1	50.7	2.6%
System consumption	172.3	165.0	159.2	158.4	155.6	152.3	147.7	141.7	-10.5%
DTS GPG consumption	3.8	7.8	7.2	3.2	1.8	1.3	2.7	5.3	67.4%
DTS total consumption	176.8	173.4	167.0	161.6	157.4	153.6	150.5	147.0	-9.0%
Non-DTS system consumption	0.28	0.26	0.26	0.25	0.24	0.24	0.23	0.23	-8.2%
Non-DTS GPG consumption	3.6	7.1	6.1	8.4	5.5	3.4	4.6	6.7	-20.7%
Victorian GPG consumption	7.4	14.9	13.3	11.6	7.3	4.7	7.3	12.0	3.4%
Total Victorian consumption*	180.7	180.7	173.4	170.2	163.1	157.3	155.3	153.9	-9.6%

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.

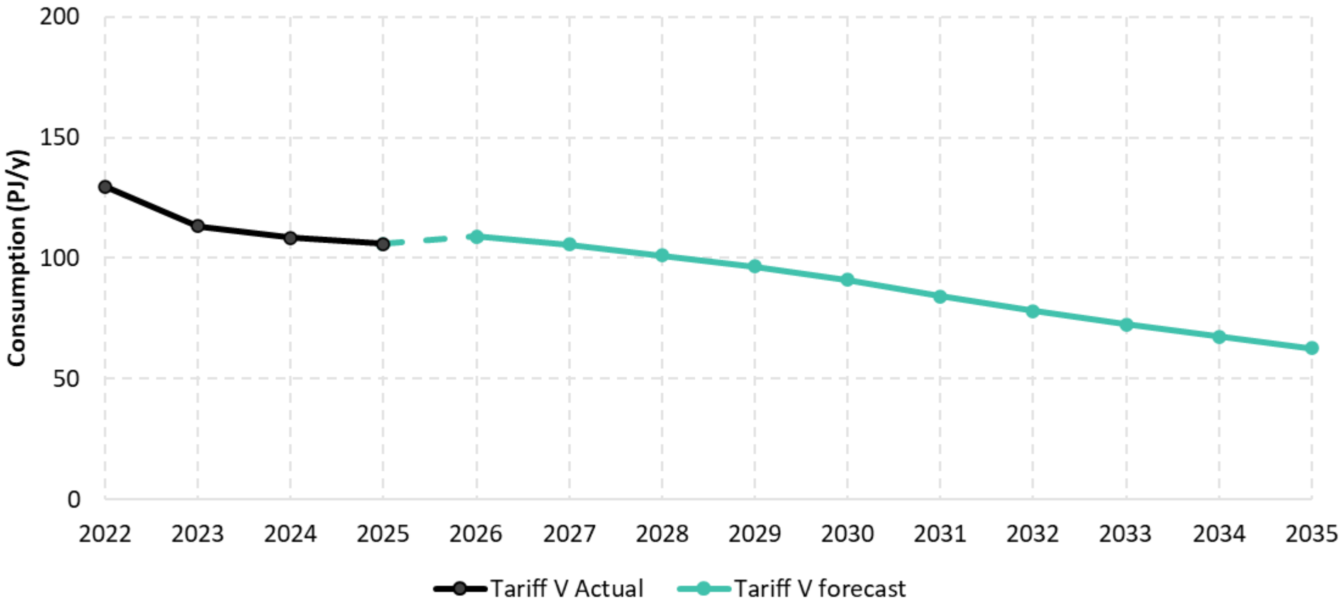
Figure 20 Actual and forecast total annual gas consumption, *Step Change* scenario, 2022 to 2035 (PJ/y)



2.2.1 Tariff V consumption

Tariff V consumption is forecast to continue to decline over the outlook period, with electrification of residential heating load being the main driver. Fuel-switching is already well underway, as evidenced by a 255% increase in the number of Victorian energy efficiency certificates (VEECs) issued for space heating and hot water applications in the 12 months to November 2025[41]. This is further evidenced by a reduction in annual Tariff V consumption in Victoria during 2025 despite a colder than average winter.

Figure 21 Actual and forecast Declared Transmission System Tariff V consumption, *Step Change* scenario, 2022 to 2035 (PJ/y)



Although Tariff V gas consumption is forecast to increase modestly from 2025 to 2026, which assumes average weather conditions, the broader forecast shows a decline over the outlook period. New gas connection restrictions are contributing to residential and small commercial customer electrification, which is expected to lead to a permanent reduction in consumption. Gas consumption is also impacted by cost-of-living pressures.

Table 7 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 except the Northern zone.
- Tariff V consumption in the Ballarat, Geelong and Gippsland zones is forecast to decline by between 11.1% and 13.1%.
- The largest decreases in Tariff V consumption are the Western and Melbourne zones, with forecast reductions of 22.1% and 19.5%, respectively.
- The variation in decline rates between zones is driven by the historical year-on-year changes observed over the last 10 years in each zone.

[41] See https://www.esc.vic.gov.au/sites/default/files/documents/Presentation%20slides_Victorian%20Energy%20Upgrades%20Forum_251127.pdf.

Table 7 Actual and forecast annual Tariff V consumption by System Withdrawal Zone, *Step Change* scenario, 2025 to 2030 (PJ/y)

	2025 (Actual)	2026	2027	2028	2029	2030	Change over outlook
Ballarat	8.2	8.1	7.9	7.6	7.4	7.0	-13.1%
Geelong	10.0	10.1	9.9	9.6	9.3	8.8	-13.1%
Gippsland	5.4	5.6	5.5	5.4	5.2	5.0	-11.1%
Melbourne	73.1	74.2	71.5	67.8	64.2	59.8	-19.5%
Northern	8.4	9.9	9.9	9.9	9.8	9.6	-2.8%
Western	1.0	1.1	1.0	0.9	0.9	0.8	-22.1%
DTS Tariff V system consumption	106.1	108.9	105.8	101.2	96.7	91.0	-16.5%
Non-DTS Tariff V system consumption	0.16	0.16	0.15	0.15	0.14	0.14	-13.0%
Total Victorian Tariff V	106.3	109.1	105.9	101.4	96.8	91.1	-16.5%

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

2.2.2 Tariff D consumption

Tariff D (industrial and large commercial) consumption is forecast to remain steady and increase slightly in some zones over the outlook period, informed by AEMO surveys of large industrial loads (LILs). From 2025 to 2030, consumption is forecast to decline by around 4.7%.

The recent closures of Qenos and Oceania Glass have resulted in a lower starting point for the forecasts compared to the 2025 VGPR and 2024 VGPR update. **Table 8** shows total Victorian Tariff D consumption is projected to remain flat with a slight increase of 2.6% over the five-year VGPR outlook period due to a lower starting forecast in 2026.

Tariff D customers are not required to provide AEMO with advance notice of expected closures, which adds complexity to modelling Tariff D consumption.

Table 8 Actual and forecast annual Tariff D consumption by System Withdrawal Zone, *Step Change* scenario, 2025 to 2030 (PJ/y)

	2025 (Actual)	2026	2027	2028	2029	2030	Change over outlook
Ballarat	1.6	1.3	1.3	1.3	1.3	1.3	2.6%
Geelong	9.6	8.6	8.6	8.9	8.9	8.8	2.6%
Gippsland	5.4	5.8	6.1	6.7	6.7	6.6	13.6%
Melbourne	24.8	23.8	23.7	23.9	23.9	23.7	-0.1%
Northern	8.8	7.4	7.4	7.5	7.5	7.5	1.3%
Western	2.9	2.7	2.7	2.9	2.9	2.8	6.3%
DTS Tariff D system consumption	53.1	49.5	49.8	51.1	51.1	50.7	2.6%
Non-DTS Tariff D system consumption	0.09	0.09	0.09	0.09	0.09	0.09	0.0%
Total Victorian Tariff D	53.2	49.5	49.9	51.2	51.2	50.8	2.6%

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

2.3 Peak day demand

This section reports DTS peak day system demand forecasts (excludes GPG demand) for each year during the outlook period, and monthly peak day gas demand forecasts for the year from January 2026 to December 2026.

2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 year peak day system demand forecasts show a declining trend over the outlook period, as **Table 9** shows. The decline is due to the continuing electrification of Tariff V load, which historically has comprised around 80% of demand on a peak day. The Tariff D portion of peak day demand is forecast increase slightly over the outlook period, in line with the increased Tariff D consumption forecast.

Table 9 Forecast annual peak day system demand, 2026 to 2030 (TJ/d)

		2026	2027	2028	2029	2030	Change over outlook
1-in-2 peak day	Tariff V	767	747	714	679	639	-16.7%
	Tariff D	191	191	197	197	197	2.9%
	System demand	958	938	911	877	837	-12.8%
1-in-20 peak day	Tariff V	834	811	774	739	697	-16.5%
	Tariff D	198	199	204	204	203	2.5%
	System demand	1,032	1,010	979	943	900	-12.8%

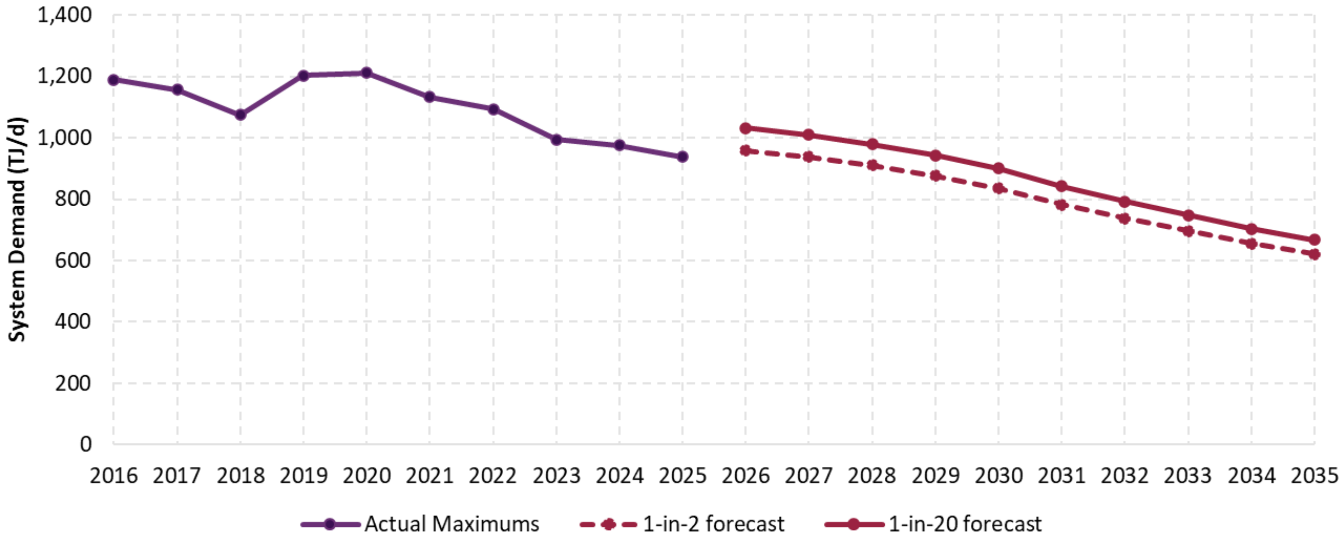
Note: totals and change over outlook percentage may not add up due to rounding.

There is a large reduction in forecast peak day system demand in this year's VGPR Update compared to the 2025 VGPR. The 1-in-20 year peak day system demand for 2026 of 1,032 TJ/d is 11% lower than the 1,156 TJ forecast in the 2025 VGPR. This reduction is predominantly due to a larger proportion of the Tariff V load that has been assessed as having undergone electrification instead of a temporary demand reduction due to cost of living pressures. The reduction is also informed by the observation of ongoing demand reductions despite several cold days with high EDDs. There was only one day during 2025 that had a system demand of over 900 TJ.

As **Figure 22** shows:

- The peak day system demand forecasts are expected to decrease compared to historical demand levels, from 958 TJ/d forecast for a 1-in-2 year peak day and 1,032 TJ/d for a 1-in-20 peak day in 2026, down to 836 TJ/d and 900 TJ/d, respectively, in 2030.
- 2025 was the third year in a row with a peak system demand under 1,000 TJ/d. The peak system demand of 933 TJ was the only day during 2025 that was above 900 TJ. These lower peak system demand days appear to be driven by the factors described in Section 2.2.1.
- The difference between the 1-in-2 and 1-in-20 year peak day demand forecasts is projected to reduce over the extended outlook period, as the Tariff V component of a peak day demand decreases due to the continuing electrification of residential heating load.

Figure 22 Actual and forecast peak day maximum system demand, 2016 to 2035 (TJ/d)



2.3.2 Monthly peak day system demand for 2026

Table 10 shows the forecast peak day system demand for each month during 2026 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 10 Forecast monthly peak day demand for 2026 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 year peak day	347	362	404	569	777	915	939	875	798	668	553	401
1-in-20 year peak day	404	416	501	681	881	1,000	1,024	970	902	769	673	485

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 output from variable renewable energy (VRE) generation is limited, including during extended periods of low sunlight and wind (renewable droughts), as experienced during the winters of 2022 and 2024. Analysis in the Draft 2026 ISP forecasts that gas usage for GPG in the NEM will become increasingly peakier and more seasonal, as GPG changes from more regular, mid-merit operations to a flexible, back-up role. Victorian GPG demand has shifted in recent years to become winter-peaking, and this trend is forecast to continue during the outlook period.

AEMO's GPG forecasts were developed in line with the *Step Change* scenario in the 2025 IASR[42] to consider thermal fuel limitations on coal generators and apply limitations on electricity generation capacity build, as set out in the *Electricity Statement of Opportunities* (ESOO) methodology[43].

The GPG forecasts presented in this section cover all the NEM-connected GPG within Victoria (unless otherwise stated), which includes two generators outside the DTS alongside the five DTS-connected generators.

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

[43] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

GPG requirements are forecast to increase following the closure of Victoria's coal-fired Yallourn Power Station, with the currently announced date of 1 July 2028, and the April 2029 closure of the Eraring coal-fired power station in New South Wales. The extension of the operating life of the Eraring Power Station has contributed to lower GPG consumption and peak day forecasts for 2028 compared to the 2025 VGPR.

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

The Draft 2026 ISP highlights the generation, firming and electricity transmission infrastructure forecast to be 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. Under the *Step Change* scenario, Victorian coal-fired power stations are assumed to progressively shut down over the next decade. Increases in electrical storage capacity from batteries and hydro generation connecting to the NEM over the outlook period are anticipated to reduce the GPG that is called on to cover periods of low VRE output.

The Draft 2026 ISP forecasts Victorian GPG capacity needing to increase from the existing 2.4 GW to 3.9 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 that new GPG connects to, and where the new gas supplies are sourced from. Section 4 of this VGPR Update presents an assessment of the existing gas infrastructure's ability to support future proposed GPG connections in the DTS.

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

- **Timing of coal generation closures.** In forecasting GPG requirements, AEMO has applied the specific coal closure date when one has been provided by the power station operator, and has applied a post-winter closure timing for power stations when the closure date is not yet specified (but identified as either a closure year, or forecast to close ahead of the formal closure year in the Draft 2026 ISP). Should any of the upcoming coal generation closures occur before a winter period, the GPG requirements over that winter period are anticipated to be greater.
- **Availability and operation of electrical storages.** Electrical storages are forecast to provide high levels of intraday and interday firming in the NEM over the outlook period and into the 2030s. Should there be a slower rollout of these technologies or operational challenges that prevent maximum utilisation, there are likely to be larger amounts of GPG called on to meet NEM demand during periods of low VRE output.
- **Timing of installation of renewable energy projects,** both large-scale and behind-the-meter. A large amount of VRE is forecast to be commissioned in Victoria over the outlook period and into the 2030s. If forecast VRE investments are delayed or do not proceed, GPG gas consumption is likely to be higher than in **Table 11** (in Section 2.4.1).
- **Weather variability**. Gas generation consumption is highly sensitive to variations in weather conditions. Weather patterns (rainfall, wind, and sun) affect not only consumer demand for electricity, but also the output of renewable (hydro, wind, and solar) generation in the NEM, which subsequently impacts the amount of gas generation. Possible impacts of weather variability on gas generation consumption are presented in 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 in **Table 11**.

2.4.1 Annual GPG consumption forecast

Figure 23 shows actual annual Victorian GPG consumption (DTS and non-DTS) from 2022 to 2025, and forecast GPG consumption ranges from 2026 to 2035 for the *Step Change* scenario. It also shows forecast GPG consumption ranges from 2026 to 2030 for the *Lower Coal Availability* sensitivity, which assessed the impact of key coal power plant outages. The Draft 2026 ISP forecasts that most of the coal generation in the southern states is planned to cease operation by 2031, which leads to there being no material impact in the sensitivity data compared to the *Step Change* data from 2031.

The GPG forecasts are presented as a range, which highlights the increased impact of weather variability on GPG requirements for the lower coal availability scenario. The average GPG forecast for all scenarios is in **Table 11**.

Figure 23 Actual and forecast range of annual Victorian gas-powered generation consumption forecasts, *Step Change* scenario and *Lower Coal Availability* sensitivity, 2022 to 2035 (PJ)

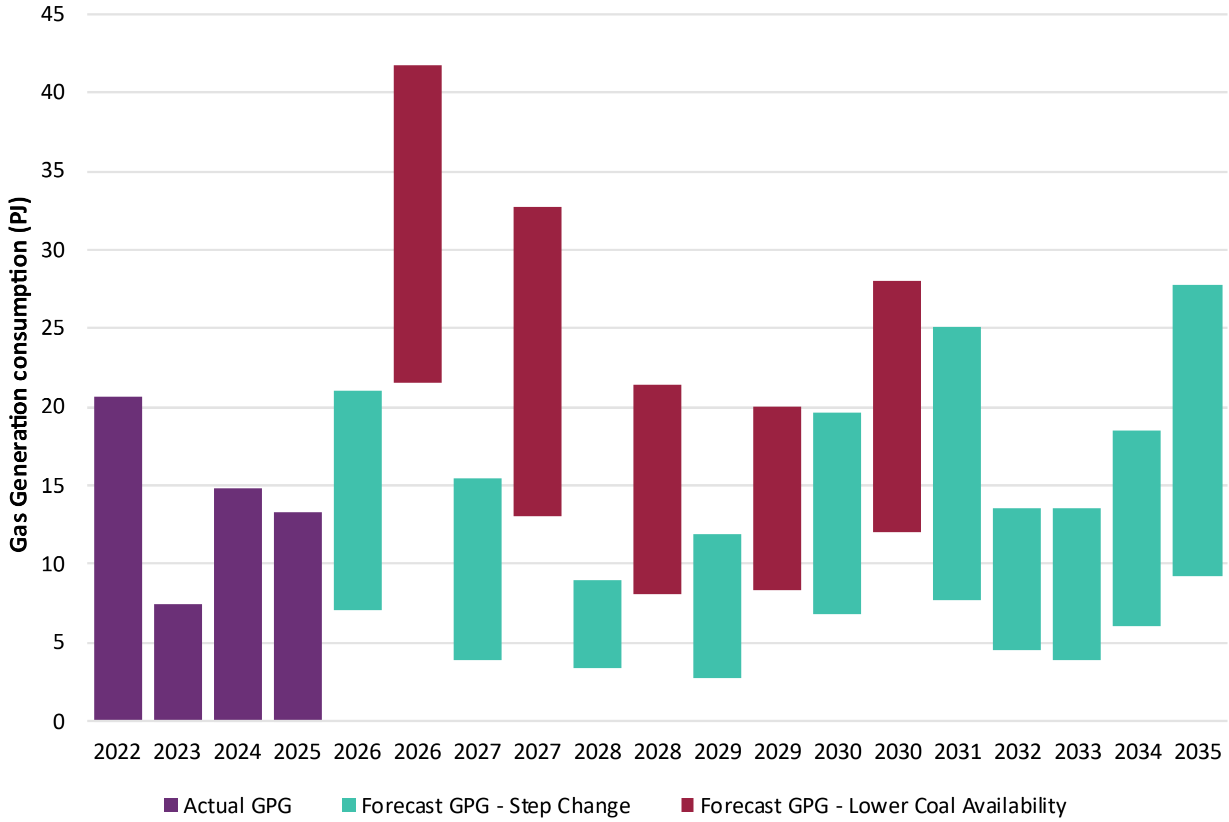


Table 11 Actual and forecast average annual Victorian GPG consumption forecasts, 2025 to 2030 (PJ)

	2025 (Actual)	2026	2027	2028	2029	2030	Change over outlook
DTS GPG consumption	7.2	3.2	1.8	1.3	2.7	5.3	67.4%
Non-DTS GPG consumption	6.1	8.4	5.5	3.4	4.6	6.7	-20.7%
Victorian GPG consumption	13.3	11.6	7.3	4.7	7.3	12.0	3.4%
Victorian GPG consumption (*Lower Coal Availability* sensitivity)	-	30.2	20.5	12.8	14.3	19.9	-34.2%

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

Figure 23 and **Table 11** show the following key points:

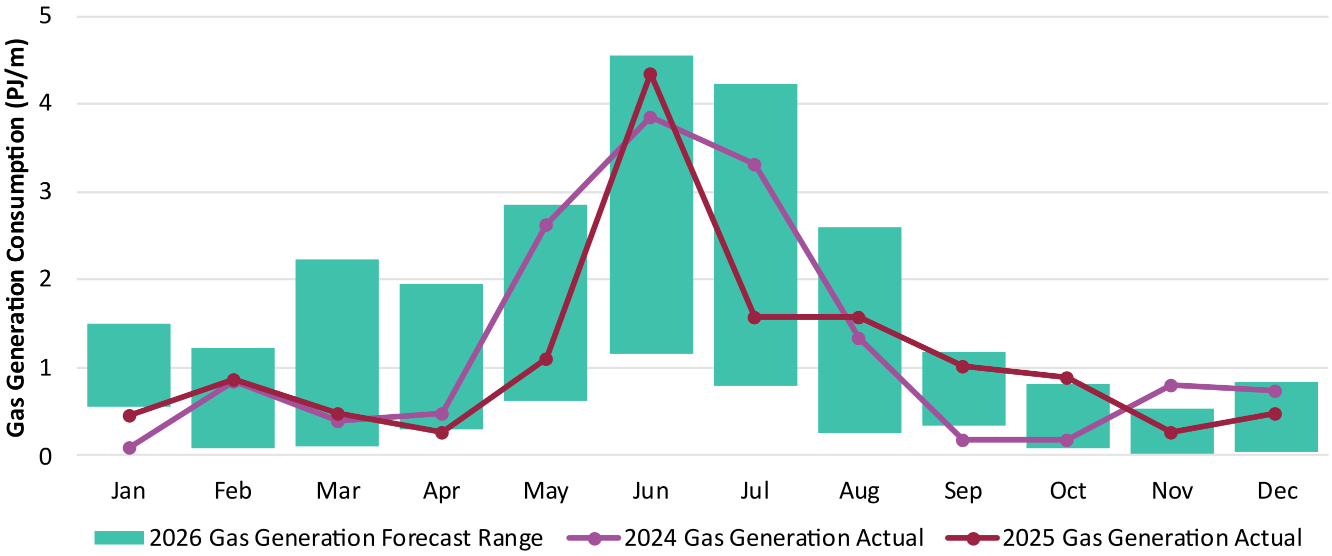
- Victorian GPG consumption is forecast to remain at a similar level in 2026 to that observed in 2025. Should the state experience a significantly colder winter and cold year overall, GPG consumption could climb to as much as 21 PJ. If this was coupled with lower coal generator availability or fuel shortages, total GPG consumption could be as high as 41 PJ.
- A reduction in gas generation consumption is forecast for 2027 and again in 2028. This forecast reduction is due to a forecast increase in solar and wind generation as well as additional energy storage capacity that is scheduled to come online in the NEM, coupled with annual increases in NEM operational electricity consumption of less than 1.2% forecast during these two years[44]. Operational electricity consumption is forecast to increase at an increased rate from 2029.
- The planned retirements of Yallourn in July 2028 and Eraring in April 2029 result in GPG requirements in the *Step Change* scenario increasing in 2029 and 2030, returning to the levels forecast at the beginning of the five-year outlook period. This forecast increase is despite Snowy Hydro 2.0 being scheduled to become operational and provide additional large-scale energy storage capacity from 2028.
- There is a significant potential increase in the GPG consumption forecasts compared to *Step Change* for the modelled *Lower Coal Availability* sensitivity, particularly during the earlier years of the outlook period.

The Draft 2026 ISP forecasts that Victorian GPG consumption during the 2030s will continue to fluctuate, as additional electrical storages become operational and electricity demand increases due to the electrification of existing gas loads and transport. Significant increases in consumption are forecast for years in which the remaining coal power stations in the southern states were assumed to cease operation.

2.4.2 Monthly GPG forecast for 2026

Figure 24 shows actual monthly Victorian GPG consumption in 2024 and 2025, and the forecast monthly consumption range for 2026.

Figure 24 Actual and forecast monthly Victorian gas-powered generation consumption, 2024 to 2026 (PJ/m)



[44] See AEMO, 2025 ESOO, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

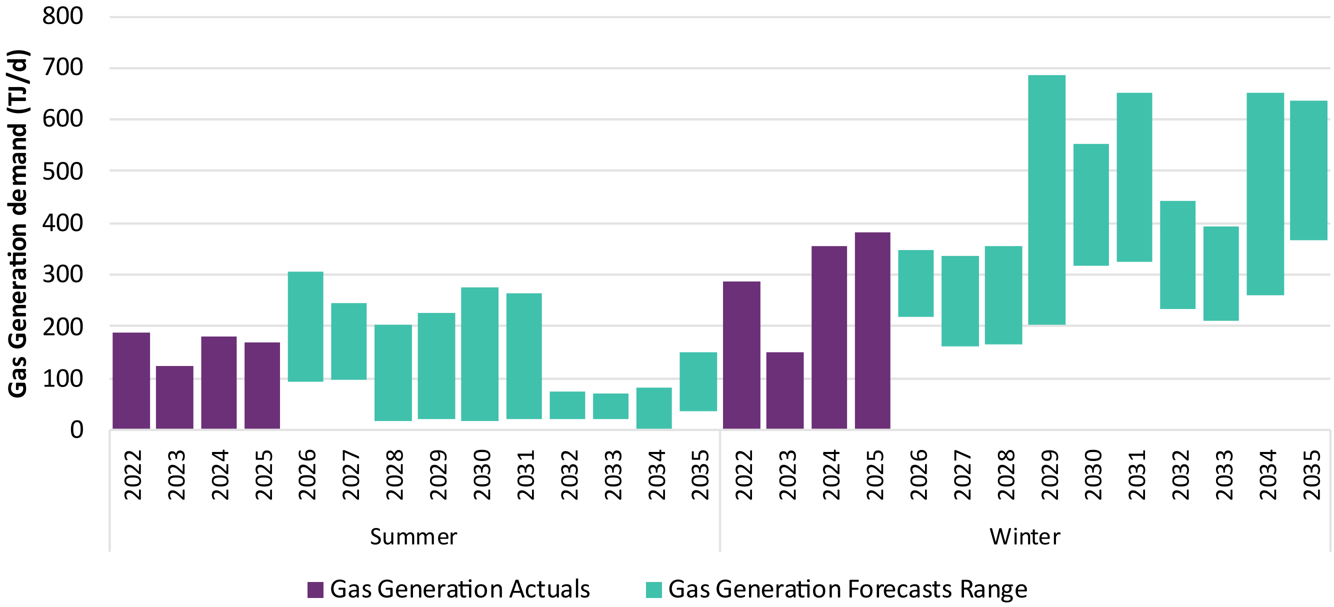
The chart shows the now-established trend of much higher GPG consumption during the winter months, particularly in June and July, and that monthly GPG consumption for 2026 is again forecast to be much higher during the winter months. During these months, heating demand is high as residential customers adjust to the onset of winter, while lower wind and solar generation output is also usually observed during June. This combination of higher heating demand, which is being electrified thereby increasing NEM demand, and lower VRE output leads to the higher likelihood of a high GPG demand day coinciding with a peak system demand day.

The reduced VRE output and higher demand also increases the amount of GPG required to respond to coal generation outages, which was observed during June 2025 with significant outages at the Yallourn and Loy Yang A power stations. As a contrast, during May and June 2024 wind generation output was abnormally low for an extended period, which resulted in high GPG consumption.

2.4.3 Seasonal peak GPG demand forecast

Figure 25 shows the trends of actual and forecast summer and winter GPG peak demands.

Figure 25 Actual and forecast range of seasonal maximum and minimum peak Victorian gas-powered generation demand, summer and winter, 2022 to 2035 (TJ/d)



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

Victorian peak winter GPG demand has increased yearly since 2022 (except for 2023 which was much milder than average[45]). The GPG peak day demands for 2026 to 2028 are forecast to remain at a similar level to actual demand peaks observed during 2023 and 2024. During the outlook period, Victorian peak winter GPG demand is forecast to increase from a maximum of 348 TJ/d in 2026 (which is lower than actual maximum Victorian GPG demand of 382 TJ during winter 2025) to a forecast maximum peak GPG demand of 685 TJ/d during winter in 2029 – a 97% increase due to the planned closure of the Yallourn and Eraring coal power stations. Victorian GPG demand is then forecast to reduce to 552 TJ/d in 2030, which is a 59% increase over the five-year outlook period.

[45] At https://www.bom.gov.au/climate/current/season/vic/archive/202308.summary.shtml.

The continuation of significant amounts of energy storage systems connecting to the NEM is predicted to reduce GPG demand, but this is projected to be offset by the impact of planned coal generator closures. As a result, winter GPG peak demand is forecast to continue to increase over the outlook period.

A slight reduction in winter peak GPG demand is forecast in 2030 due to increases in electrical storage capacity, particularly Snowy 2.0, which is scheduled to be completed towards the end of the decade. The main drivers of the increased peak day forecasts from 2034 are the assumed closures of the Bayswater and Loy Yang A coal power stations.

Winter peak GPG demand has the potential to coincide with a peak system demand day, especially where there is high demand for heating, and solar generation usually reduces. This was nearly the case in 2025, where a peak system demand of 933 TJ on 25 June was followed by a peak DTS GPG demand of 299 TJ on 26 June. These days resulted in high total demands of 1,025 TJ and 1,152 TJ respectively.

While winter GPG demand is forecast to increase significantly during the outlook period and beyond, summer peak GPG demand is forecast to remain relatively flat over the outlook period, due to the changing role of GPG in the NEM. As a result, summer peak GPG demand is forecast to be lower than the winter peak demand forecasts for the outlook period and for the following five years. This is in line with the trend observed in recent years of GPG demand peaking at higher levels during the winter months than during summer.

Increasing solar generation and longer duration batteries are resulting in the continued decline in the daily amount of GPG use during the summer months.

3 Gas supply adequacy

Key findings

Victoria's annual gas outlook shows stable supply in the near term but a steep structural decline emerging from 2029 onward:

- Forecast Gippsland annual production, which is mainly supplied by the Longford Gas Plant, is broadly in line with the 2025 VGPR forecast, with production steady to 2028, then reducing significantly, by 49% between 2026 and 2030. The Longford Gas Plant is forecast to cease production at the end of 2033.
- Forecast Port Campbell annual production remains steady for 2026 and 2027, before reducing in 2028, and again in 2029, with output falling 67% between 2026 and 2030 due to the depletion of reserves at the Enterprise and Thylacine West developments.
- Victorian annual gas supply is forecast to remain higher than annual consumption through most of the outlook period. Forecast annual consumption is expected to exceed available production, with the shortfall widening to 40 PJ in 2030 and 115 PJ by 2035. This occurs despite forecast reductions in gas consumption, because production is forecast to decline faster than gas use.

Monthly gas production during winter is forecast to decline at a high rate over the five-year outlook period:

- Reduced winter production capacity is expected to increase reliance on Iona UGS and require supply from outside Victoria to maintain supply adequacy during winter.
- The commissioning of the Turrum Phase 3 Project in early 2027 provides a temporary uplift in monthly production.

Peak day gas supply capacity also reduces during the outlook period, with a large reduction between 2028 and 2029:

- Victoria's maximum peak day gas supply capacity is forecast to fall by 27.3% over the five-year outlook period, despite modest upward revisions to Gippsland and Port Campbell deliverability in relative to the 2025 VGPR. While these forecast revisions improve supply capacity in the short term, long-term structural production declines are driving a substantial reduction in overall peak day gas supply.
- Peak day supply adequacy is materially improved compared to the 2025 VGPR, due to higher forecast supply and lower peak day demand, eliminating the previously forecast expected 1-in-2 and 1-in-20 year peak day system demand shortfall in the 2025 VGPR. However, as the peak day supply continues to decline over the outlook period, DTS supply adequacy is increasingly reliant on Dandenong LNG and imports from Culcairn.

Victorian expected gas supply capacity is forecast to meet 1-in-2 and 1-in-20 year peak day system demand alongside the maximum peak winter GPG demand in 2026, 2027, and 2028. From 2029 onward, supply capacity is forecast to reduce significantly and is projected to become insufficient to meet peak winter GPG demand, which is forecast to almost double following the retirement of the Yallourn and Eraring coal-fired power stations.

As gas availability continues to decline, periods of high electricity system demand with low VRE generation are forecast to increasingly require curtailing GPG, which will need to rely on alternative fuels (such as diesel).

3.1 Background

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

AEMO assessed 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[46]. Supply from storages and pipeline constraints was not considered.
- **Seasonal (monthly) winter consumption (1 May to 30 September inclusive)** – a seasonal supply demand imbalance indicates that a combination of Victorian production, Iona UGS, and interconnected pipeline flows is projected to be insufficient to meet forecast winter consumption[46]. Supply from Iona UGS (deep storage) and pipeline constraints are considered.
- **Peak day demand (1-in-2 and 1-in-20)** – a peak day shortfall indicates that supply is projected to be insufficient to meet forecast demand[47] on peak days only. Supply from Iona UGS (deep storage) and Dandenong LNG (shallow storage) as well as pipeline capacity constraints are considered.

3.2 Gas supply classification

Table 12 defines gas supply classifications[48] used in this 2026 VGPR Update, with notes on the differences between these classifications in the 2026 GSOO and the Petroleum Resources Management System (PRMS)[49].

Table 12 Gas supply classifications

VGPR	2026 VGPR Update 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 the ability to provide firm commencement date[A], • have successfully passed FID, • have finalised and executed commercial contracts, • have obtained all necessary planning approvals, and • are 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

[46] Inclusive of system and GPG consumption.

[47] Excluding GPG demand.

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

[49] 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	2026 VGPR Update description	PRMS	GSOO
Anticipated supply	Developments or projects which: • have the ability to provide firm commencement date[A], • have not reached FID but a firm date for FID has been provided, • have secured upstream supply contracts[B] for the outlook period, • have finalised legal proceedings for land acquisition, • have firm contractual agreements including the supply of gas, tolling arrangements, storage or transport services with customers[B] , • have a midstream infrastructure/connection agreement established, • have had all necessary environment and planning approvals approved, and • have completed detailed engineering works (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).

3.3 Changes impacting the supply demand balance

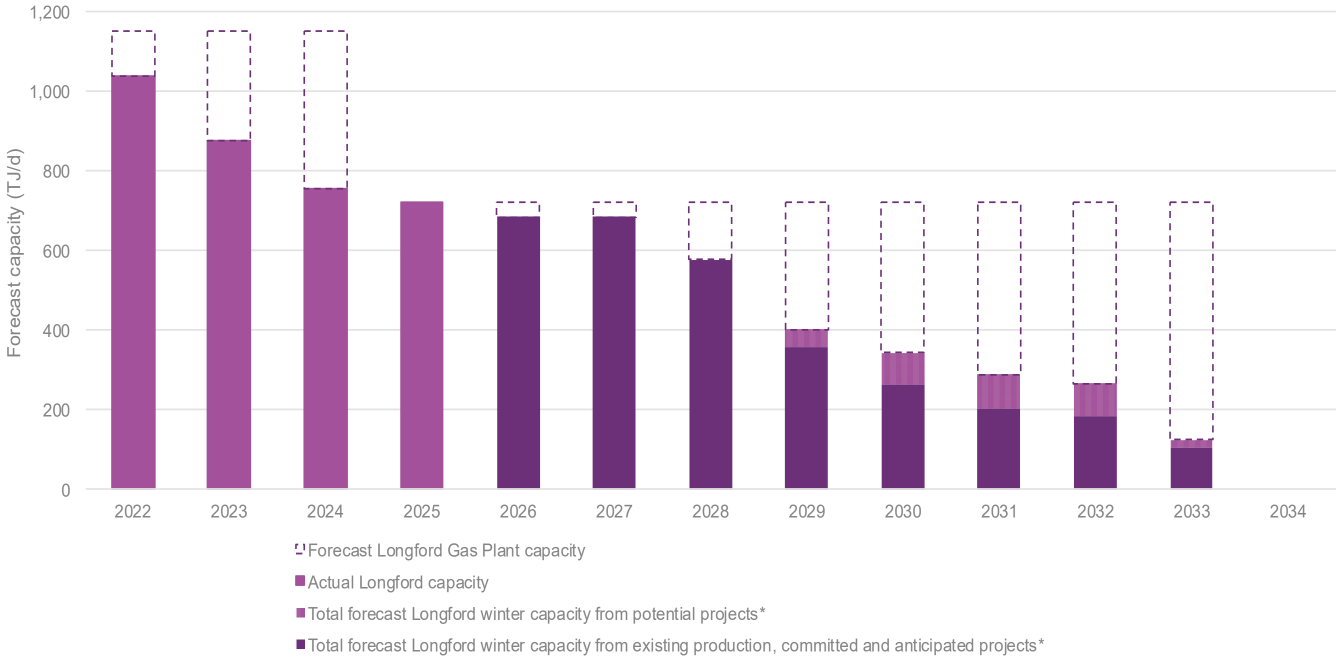
This section highlights updates to key projects that have impacted the supply and demand balance since the publication of the 2025 VGPR (more details on the ongoing projects are in Section 5.1):

- **Enterprise and Thylacine West** – the connection of the Enterprise field in June 2024 and the Thylacine West development wells in October 2024 was a key driver to higher production at Beach Energy's Otway Gas Plant, which increased by 2.7 million barrels of oil equivalent (Mmboe) in 2024-25[50]. However, the latest survey data from Beach Energy shows that reserves at both Enterprise and Thylacine West had declined in 2025, which impacts future gas production in the Port Campbell region[51]. More details on annual and peak capacity changes in the region are in Section 3.4.
- **Longford Gas Plant Capacity** – **Figure 26** updates the yearly historical and forecast production capacity, including a long-term capacity outlook for the Longford Gas Plant. Esso Australia has reported that from 2025 the Longford Gas Plant's nameplate capacity increased from 700 TJ/d to 720 TJ/d. In addition, to improve plant reliability, Esso plans to operate Gas Plant 3 until at least 2033, an extension of five years compared with what was reported in the 2025 VGPR. This extension will maintain Longford's nameplate gas processing capacity at 720 TJ/d until the end of 2033. The forecast in **Figure 26** is indicative only, highlighting the extent of Longford's expected decline until its forecast end-of-life in 2033.

[50] Otway Gas Plant production increased from 30 PJ in 2023, to 49 PJ in 2024, and 55 PJ in 2025 – source: AEMO Gas Bulletin Board.

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

Figure 26 Actual and forecast Longford Gas Plant winter capacity, 2022 to 2034 (TJ/d)



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

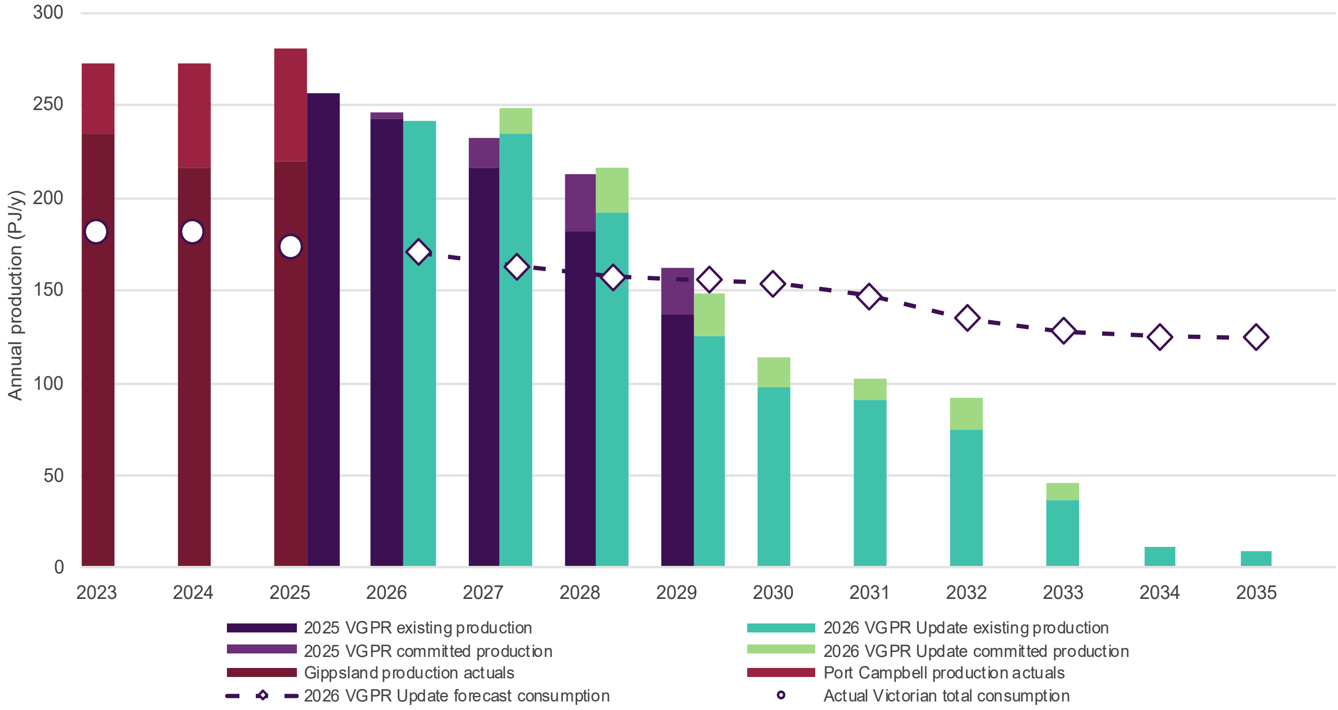
3.4 Annual supply demand balance

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

3.4.1 Annual production forecasts

Figure 27 shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2025 VGPR. Victorian annual production is forecast to decline by 52.8% over the five-year outlook period, from 242 PJ in 2026 to 114 PJ in 2030, and to reduce to 9 PJ by the end of 2035. Compared to the 2025 VGPR, annual Victorian production in 2027 and 2028 is forecast to be higher, by 15 PJ and 4 PJ, respectively, while forecast production in 2026 and 2029 is slightly lower, by 4 PJ and 13 PJ respectively

Figure 27 Actual and forecast supply and total consumption, and compared to the 2025 VGPR, 2023 to 2035 (PJ/y)



Gippsland[52]

Actual Gippsland production for 2025 was 219 PJ, exceeding the 2025 VGPR forecast by 21 PJ due to higher than forecast production at the Longford, Orbost, and Lang Lang Gas Plants. Production for 2026 is forecast to be 190 PJ, close to the 191 PJ forecast in the 2025 VGPR. Forecasts for 2028 and 2029, at 175 PJ and 127 PJ respectively, are also consistent with the 2025 VGPR forecast.

The 2027 Gippsland production forecast is higher – increasing from 187 PJ in the 2025 VGPR to 197 PJ – reflecting additional supply that is now expected from the committed Turrum Phase 3 Project, which is expected to deliver additional gas to the market via the Longford Gas Plant.

From 2029 to 2030, annual Gippsland production is forecast to decrease by 30 PJ, from 127 PJ to 97 PJ, driven mostly by reduced output from the Longford Gas Plant. Production from the Yolla gas field in the Bass Basin that supplies the Beach Energy Lang Lang Gas Plant is also forecast to cease. Beach Energy has provided a forecast of potential additional Bass Basin production.

After 2030, Gippsland production is forecast to continue its steep decline, falling 66% from 97 PJ in 2030 to 33 PJ in 2033. In 2032, production from Amplitude Energy's Sole field is forecast to cease based on booked proved and probable reserves and current production rates, resulting in no production from the Orbost Gas Plant from 2033 onward unless supply from other fields, including Manta and Patricia-Baleen, is developed. Production from these fields is classified as a potential project so it was not included in forecast available production for the Gippsland region.

With production from the Longford Gas Plant also forecast to cease in 2033, there is forecast to be no production in the Gippsland region from 2034 unless a potential project is developed.

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

Overall, Gippsland available production (excluding anticipated and potential projects) is forecast to decrease from 190 PJ in 2026 to 97 PJ in 2030, which is a 49% reduction, before reducing to 33 PJ in 2033 and zero in 2034.

Port Campbell[53]

Actual Port Campbell production for 2025 was 61 PJ, which is close to the 59 PJ forecast in the 2025 VGPR. Compared to the 2025 VGPR forecasts, production is forecast to be 4 PJ lower in 2026, 5 PJ higher in 2027 and 2 PJ higher in 2028. These adjustments reflect the decreased Enterprise and Thylacine West reserves, which are offset by improved production at other Otway Basin fields.

In 2029, the annual Port Campbell forecast production is 21 PJ, which is 14 PJ (40%) lower than the 2025 VGPR forecast. This highlights the larger future impact of the reduction in Enterprise and Thylacine West reserves. Production is forecast to decline further to 17 PJ in 2030, which represents a 67% reduction over the five-year outlook period. By 2035, annual Port Campbell production is forecast to reduce to 9 PJ.

There are several potential projects from Amplitude Energy, Beach Energy, and Conoco Phillips in the Port Campbell region. However, as these projects are not yet committed, they were excluded from the supply adequacy assessment. These projects are discussed in Section 5.

3.4.2 Annual supply adequacy

Table 13 shows the annual supply adequacy forecast over the 10-year period.

The annual supply adequacy assessment indicates:

- Forecast available annual supply exceeds forecast consumption by 72 PJ, 85 PJ, and 59 PJ in 2026, 2027, and 2028, respectively. These forecast surplus quantities would be expected to be supplied to New South Wales, South Australia, and Tasmania.
- Compared to the 2025 VGPR, the surplus quantity remains the same in 2026. However, the surplus quantities in 2027 and 2028 are higher, by 34.0% (85 PJ from 64 PJ) and 49.9% (59 PJ from 40 PJ), respectively. This reflects the changes in production forecasts discussed in Section 3.4.1, and the reduction in total forecast Victorian consumption.
- Victorian annual consumption is forecast to exceed available supply in 2029 by 7 PJ on an annualised basis, slightly higher than the quantity reported in the 2025 VGPR. The imbalance is forecast to increase to 40 PJ in 2030 and to continue to rise to 115 PJ by 2035. Despite the forecast reduction in annual consumption, annual production declines at a higher rate, resulting in an increasing annual deficit year-by-year.

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

Table 13 Victorian annual production and consumption, from 2026 to 2035 (PJ/y)

Supply source		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gippsland [A]	Existing	**190**	**184**	**150**	**104**	**80**	**74**	**61**	**24**	**0**	**0**
	Committed	0	13	25	23	17	11	17	9	0	0
	Total available	**190**	**197**	**175**	**127**	**97**	**85**	**79**	**33**	**0**	**0**
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	190	197	175	127	97	85	79	33	0	0
Port Campbell [B]	Existing	**52**	**51**	**42**	**21**	**17**	**17**	**14**	**13**	**11**	**9**
	Committed	0	0	0	0	0	0	0	0	0	0
	Total available	**52**	**51**	**42**	**21**	**17**	**17**	**14**	**13**	**11**	**9**
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	52	51	42	21	17	17	14	13	11	9
Total Victorian production	Existing	**242**	**235**	**192**	**125**	**98**	**91**	**75**	**37**	**11**	**9**
	Committed	0	13	25	23	17	11	17	9	0	0
	Total available	**242**	**248**	**216**	**148**	**114**	**102**	**92**	**46**	**11**	**9**
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	242	248	216	148	114	102	92	46	11	9
Total Victorian consumption [C]		**170**	**163**	**157**	**155**	**154**	**147**	**135**	**128**	**125**	**124**
Surplus quantity with Victorian available production		**72**	**85**	**59**	**-7**	**-40**	**-45**	**-43**	**-82**	**-114**	**-115**

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

Seasonality and interconnection with other jurisdictions

The annual adequacy assessment is limited due to the 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, and Victoria is projected to become a net importer.
- The 2026 GSOO identifies supply gaps in southern states from 2030 under most weather conditions (one year later than reported in the 2025 GSOO) are most likely to occur during winter when gas consumption is highest. This indicates that there are risks of seasonal shortfalls occurring during winter from 2030 onwards in the southern states, including Victoria.
- Monthly (seasonal) adequacy is discussed in Section 3.5.

3.5 Monthly supply demand balance

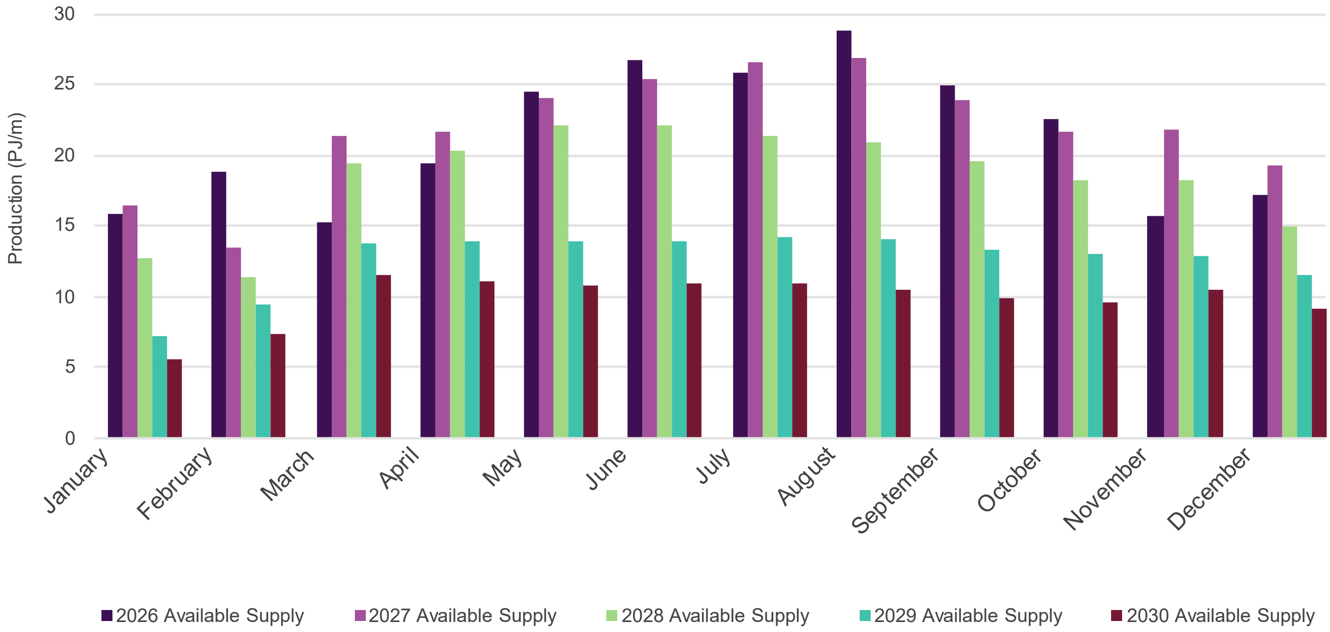
This section outlines the forecast Victorian monthly gas supply over the five-year outlook period and assesses its adequacy to meet projected monthly and seasonal consumption.

3.5.1 Monthly production forecasts

Figure 28 shows the forecast monthly gas production for the next five years, highlighting that:

- Seasonal increases remain evident, with higher production during winter months[54] to meet peak winter demand.
- Overall monthly gas production is projected to decline over the next five years. An exception occurs in 2027, where several months show higher production forecasts than in 2026 due to additional output from the committed Turrum Phase 3 Project that supplies the Longford Gas Plant.
- Consistent with the 2025 VGPR, the 2029 monthly production forecast indicates a notable decline relative to preceding years.
- By 2030, monthly production is forecast to fall further, with all months producing less than 12 PJ.

Figure 28 Monthly production forecast, 2026 to 2030 (PJ/m)



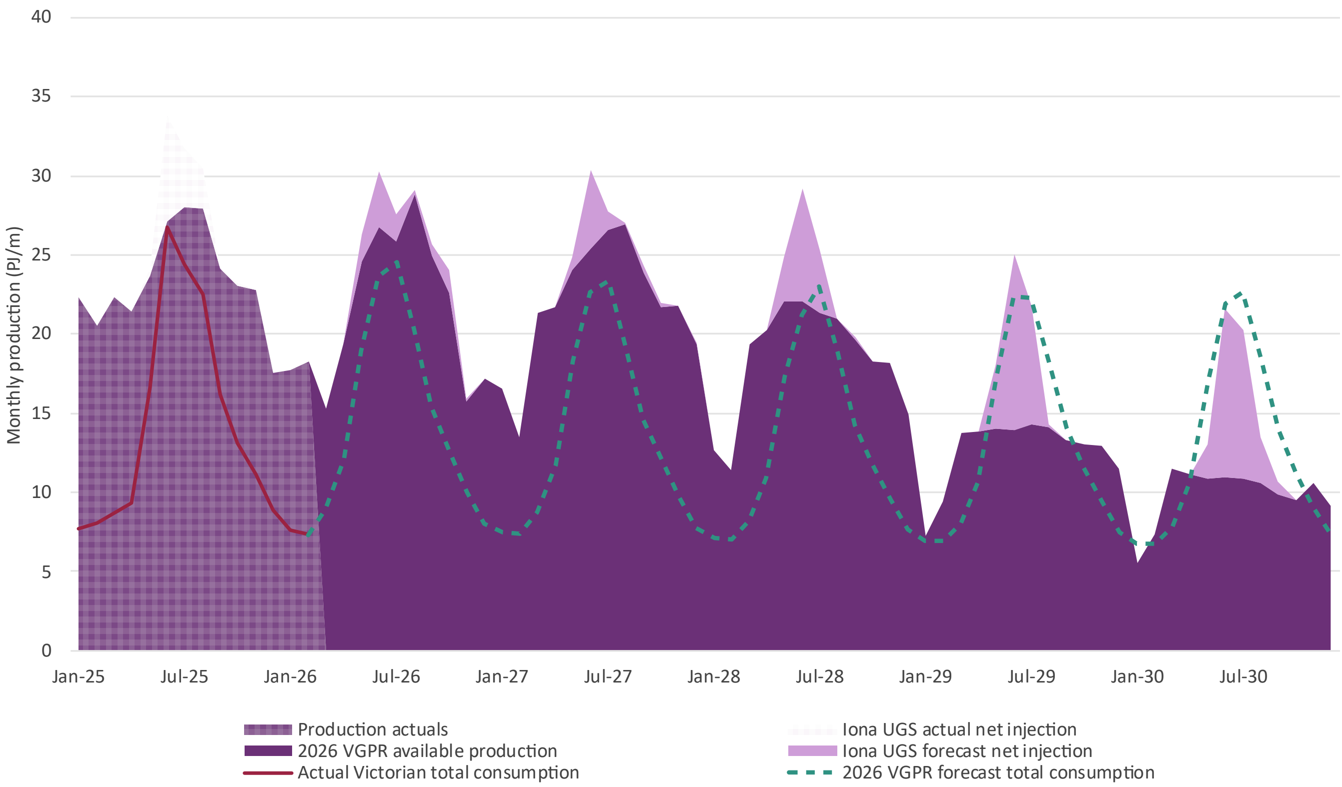
3.5.2 Monthly supply adequacy

Historically, Victorian production has peaked during winter, with the Longford Gas Plant able to scale output to match the seasonal increase in demand. In contrast, most other production facilities maintain relatively steady year-round output, constrained by processing capacity, available supply from connected fields, or commercial operating considerations.

[54] Winter months are June, July and August.

Figure 29 analyses actual monthly total consumption and available supply in 2025, forecast monthly available and anticipated Victorian production, and actual and forecast Iona net injections[55], against forecast total consumption[56] over the five-year outlook period.

Figure 29 Actual and forecast total Victorian monthly production and total consumption, 2025 to 2030 (PJ/m)



Note: Total Victorian monthly consumption is the sum of monthly system consumption and monthly GPG consumption (including non-DTS GPG).

Key observations on monthly supply adequacy are:

- Actual winter production in 2025 was below the levels forecast in the 2025 VGPR by 1-2 petajoules per month (PJ/m); meanwhile, actual total consumption exceeded the 2025 VGPR forecast for June by 3 PJ. This combination resulted in high gas withdrawals from the Iona UGS facility to balance supply and demand.
- The 2025 VGPR anticipated that peak winter total consumption would occur in July; however, actual data shows that the highest 2025 total consumption occurred in June, indicating an earlier than expected seasonal peak. This was caused by a high Victorian GPG consumption of 4.4 PJ during June 2025 compared to 1.6 PJ during July 2025.
- Available production in 2026 and 2027 is forecast to exceed total monthly Victorian consumption in both summer and winter, which aligns with the 2025 VGPR.
- Victorian production is forecast to be insufficient to meet winter 2028 demand. This mismatch between production and demand is smaller than projected in the 2025 VGPR, due to lower forecast Tariff V and Tariff D consumption and higher forecast winter production in 2028.

[55] Iona UGS forecast net injection flows are from modelling performed for the 2026 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.

[56] Inclusive of system and GPG consumption.

- Both forecast monthly production and forecast total consumption decline over the outlook period, but production is projected to fall at a faster rate. Forecast Victorian production flattens out from 2029 instead of increasing to meet winter demand compared to prior years. Reduced summer output and maintenance shutdowns could impact southern storage refilling, which may increase the likelihood of shortages during winter. These predictions become less certain in later years, largely because new production projects that might emerge.
- The forecast reduction of supply in January 2030 is the result of planned gas production facility maintenance. There is expected to be adequate supply during this period due to supply via interconnected pipelines from other states.
- Victorian gas supply adequacy and that of neighbouring jurisdictions are interconnected; a more detailed assessment on southern supply adequacy is provided in the 2026 GSOO.

3.6 Peak day supply demand balance

3.6.1 Forecast Victorian peak day supply capacity

The forecast maximum daily Victorian supply capacity by SWZ, including contributions from Iona UGS and the Dandenong LNG storage facility, is shown in **Table 14**. Actual supply available to the DTS is lower than these headline values, due to transmission system constraints restricting supply from Port Campbell, and the requirement for Gippsland production to support demand in Tasmania and southeast New South Wales that can only physically flow from Victoria (see Section A1.3).

Table 14 Peak day maximum daily quantity (MDQ) by System Withdrawal Zone, from 2026 to 2035 (TJ/d)

SWZ	Supply source	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gippsland [A]	Available	766	707	598	393	302	248	225	94	0	0
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	766	707	598	393	302	248	225	94	0	0
Port Campbell (Geelong) [B]	Available	785	799	758	682	671	663	644	639	634	630
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	785	799	758	682	671	663	644	639	634	630
Melbourne [C]	Available	238	238	238	238	238	238	238	238	238	238
Culcairn	Available	180	180	219	219	219	219	219	219	219	219
Total Victorian Supply	Total Victorian available	1,969	1,924	1,813	1,532	1,431	1,368	1,326	1,190	1,091	1,087
	Total Victorian anticipated	0	0	0	0	0	0	0	0	0	0
	Total Victorian available plus anticipated	1,969	1,924	1,813	1,532	1,431	1,368	1,326	1,190	1,091	1,087

Notes: 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 the Gippsland 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 Port Campbell capacity cannot be supplied into the DTS due to the SWP capacity limit.
C. Melbourne zone available supply is from Dandenong LNG injection point which has a non-firm supply capacity of 9.9 terajoules per hour (TJ/h) for a 24-hour period.

Supply capacity into the DTS from the MSP in New South Wales via the Young to Culcairn lateral is also forecast to increase for winter 2028. APA has recently committed to increase supply capacity as part of the ECGG Stage 3A Expansion Plan Project, which includes a capacity 39 TJ/d increase in capacity for the Young to Culcairn lateral. This supply capacity can be impacted by the amount of MSP flow to Sydney as well as New South Wales demand between supplied from the Young to Culcairn lateral including the Uranquinty Power Station.

Over the five-year outlook period:

- Victoria's maximum total daily supply capacity is projected to decline by 27.3%, from 1,969 TJ/d in 2026 to 1,431 TJ/d in 2030. The projected supply capacity continues to decline to 1,087 TJ/d in 2035.
- Gippsland producers have advised that maximum available production capacity will decline by 60.5%, from 766 TJ/d in 2026 to 302 TJ/d in 2030. The projected production capacity will decline to zero in 2034 onward. The reduction is primarily driven by declining output from the Gippsland Basin Joint Venture (GBJV) and Kipper Unit Joint Venture (KUJV) fields that supply the Longford Gas Plant, followed by its expected retirement at the end of 2033.
- Port Campbell producers have advised that maximum daily production capacity will decline by 73.8%, falling from 215 TJ/d in 2026 to 56 TJ/d in 2030, with a sharp reduction of 76 TJ/d between 2028 and 2029, driven by declining reserves in Enterprise and Thylacine West. The forecast production continues to decline to 15 TJ/d in 2035. In addition to the supply from Port Campbell producers, the Iona UGS is forecast to provide 570 TJ/d in 2026, bringing total Port Campbell supply capacity to 785 TJ/d in that year. From 2027, the capacity of the Iona UGS facility will increase by 45 TJ/d to 615 TJ/d, following the development of the HUGS Phase 1 project.

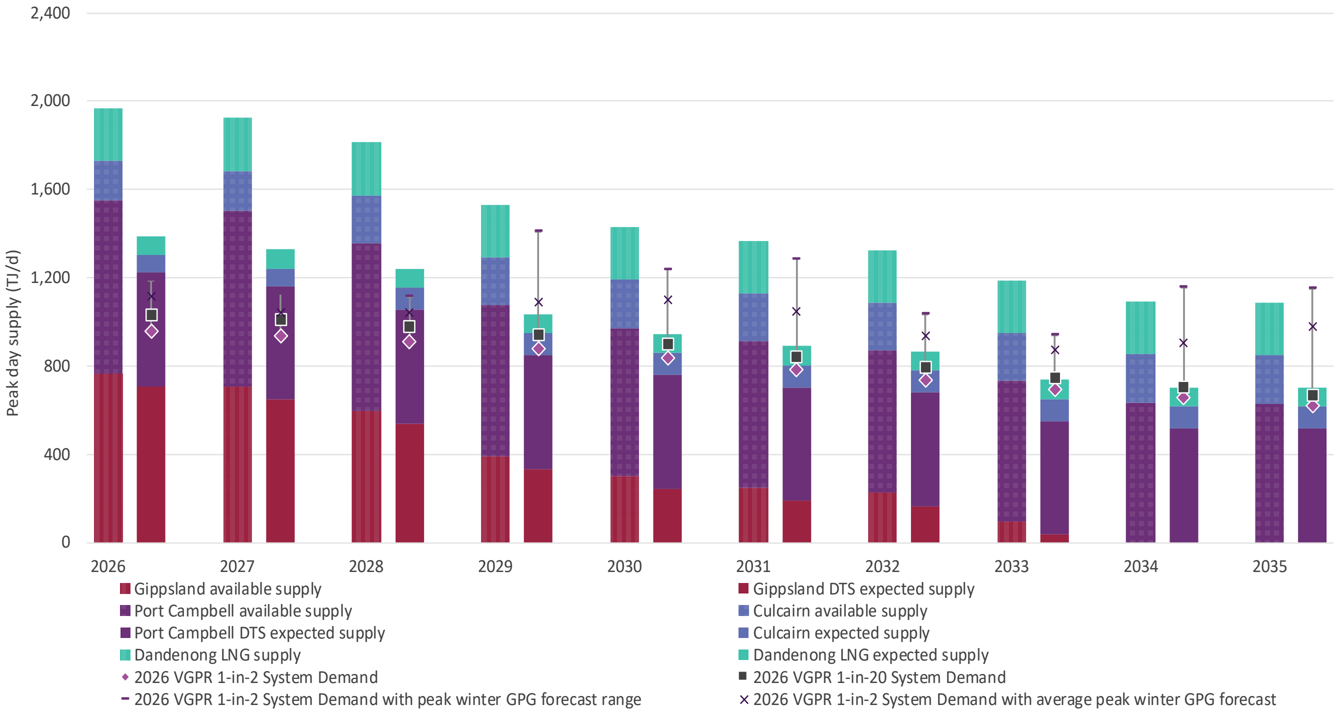
Despite these long-term downward trends, the updated outlook shows higher forecast supply quantities than those published in the 2025 VGPR:

- Gippsland's peak day production forecast has been revised upward across the outlook period, ranging from 2% higher in 2027 to 14% higher in 2029, compared to the 2025 VGPR. These revisions reflect improved deliverability across all major Gippsland fields and indicate a stronger predicted production capability despite the region's structural decline.
- The Port Campbell region shows a similar pattern in the early years of the outlook period, with peak day production revised upwards by 1-4%, compared to the 2025 VGPR, following a revised assessment of several Otway Basin gas fields by the field operators. However, from 2029 onward, the region's production capacity has been revised down, with forecasts around 50 TJ/d lower than the 2025 VGPR, driven by more pronounced declines for the Enterprise and Thylacine West developments.
- Forecast available supply from the Dandenong LNG facility in Melbourne is revised to 238 TJ/d to reflect the non-firm supply capacity of 9.9 TJ/h for a 24-hour period.

3.6.2 DTS peak day supply adequacy

AEMO has assessed peak day supply adequacy using a mass-balance approach supported by hydraulic pipeline modelling to estimate the level of peak day supply capacity available to the DTS, and to determine whether this capacity is sufficient to maintain continuous supply for Victorian customers.

Figure 30 Forecast peak day supply and Declared Transmission System adequacy, 2026 to 2035 (TJ/d)



Notes: 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.

The forecasts presented in **Figure 30** and **Table 15** were based on the following inputs and assumptions:

- Forecast annual 1-in-2 and 1-in-20 year peak day system demands were as discussed in Section 2.3.
- Full capacity was assumed to be available from the Iona UGS and Dandenong LNG storage facilities, with no limitations assumed due to low inventory levels.
- The peak day system demand shortfall assessment excluded any additional demand from GPG. **Figure 30** includes the range of DTS[57] peak winter GPG demand forecasts coinciding with a 1-in-2 year peak day system demand to illustrate the possible range of resultant total demands.
- Forecast expected firm supply from the Dandenong LNG facility in Melbourne is at 87 TJ/d throughout the period.

[57] This is a DTS peak day adequacy assessment so it does not include non-DTS GPG demand.

Table 15 Forecast Declared Transmission System peak day supply adequacy, from 2026 to 2035 (TJ/d)

Supply source		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gippsland [A]	Expected [B]	707	648	539	334	243	189	166	35	0	0
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	707	648	539	334	243	189	166	**35**	**0**	**0**
Port Campbell (Geelong) [C]	Expected [D]	515	515	515	515	515	515	515	515	515	515
	Anticipated	0	0	0	0	0	0	0	0	0	0
	Total available plus anticipated	515	515	515	515	515	515	515	515	515	515
Melbourne	Expected [E]	87	87	87	87	87	87	87	87	87	87
Culcairn	Expected [F]	80	80	100	100	100	100	100	100	100	100
Total Victorian supply	Total Victorian expected	1,389	1,330	1,241	1,036	945	891	868	737	702	702
	Total Victorian anticipated	0	0	0	0	0	0	0	0	0	0
	Total Victorian expected plus anticipated	1,389	1,330	1,241	1,036	945	891	868	737	702	702
1-in-2 system demand		958	938	911	877	836	782	738	697	656	621
1-in-20 system demand		1,032	1,010	979	943	900	843	792	748	704	667
1-in-2 day surplus quantity with Victorian expected supply		430	392	330	159	109	109	129	41	46	81
1-in-20 day surplus quantity with Victorian expected supply		357	319	262	92	46	48	75	**-10**	**-2**	35
1-in-2 system demand with average peak winter GPG forecast		1,118	1,044	1,043	1,091	1,102	1,049	938	873	904	979
1-in-2 system demand with highest peak winter GPG forecast		1,190	1,127	1,116	1,411	1,240	1,287	1,035	942	1,157	1,151

Notes: 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.
E. Expected Melbourne supply from the Dandenong LNG facility is limited to the firm supply capacity of 5.5 TJ/d with the first and last injection hours are limited to 5.0 TJ/d for 16 hours due to low demand on the inner ring main system from 10pm to 6am.
F. Expected Culcairn supply is limited by expected peak day demand in New South Wales including the Uranquinty Power Station.

Expected DTS peak day supply capacity is forecast to decline from 1,389 TJ/d in 2026 to 945 TJ/d in 2030, and 702 TJ/d in 2035. **Figure 30** and **Table 15** show several notable changes in this year's assessment compared to the 2025 VGPR:

- The expected Port Campbell peak day supply into the DTS has reduced to 515 TJ/d, from 523 TJ/d in the 2025 VGPR, reflecting updated SWP capacity modelling (see Section 6.2 for further detail). As DTS system demand is forecast to decline, the expected Port Campbell peak day supply into the DTS is projected to continue to reduce unless there is capacity expansion on the SWP.
- Despite this reduction, stronger output from several Gippsland fields results in higher total Victorian forecast supply across all years of the outlook period compared to the 2025 VGPR.
- The utilisation of the import capacity from Culcairn via the VNI is increased, as evident by recent peak supply days into the DTS, with flows of 179 TJ/d and 167 TJ/d occurring on 7 June and 8 June 2025, respectively. However, these peak flows were achieved when the Uranquinty Power Station was offline and the MSP flow to Sydney was only

approximately 200 TJ/d on both days (compared to a typical flow of around 250 TJ/d). This highlights that Culcairn import capacity can be impacted by Uranquinty Power Station and New South Wales demand. As Longford production capacity declines further in 2029 and beyond, this is expected to reduce supply to New South Wales via the EGP (without new supply) and therefore increase the portion of MSP supply that is needed to supply New South Wales demand. This may result in reduced supply into the DTS via Culcairn if coincident peak demands occurred in both New South Wales and Victoria.

- Actual peak day demand in 2025 was 933 TJ/d, which was lower than the 2025 1-in-2 year peak day demand forecasts published in the 2024 VGPR Update (1,084 TJ/d) and the 2025 VGPR (1,071 TJ/d), highlighting the continued decline in peak day consumption.
- Forecast 1-in-2 and 1-in-20 year peak day system demands for the DTS are lower than the 2025 VGPR (as discussed in Section 2). For example, for 2026, the 1-in-2 and 1-in-20 system demands are forecast to be 8.5% and 8.7% lower than forecast in the 2025 VGPR due to the increased electrification of gas demand. Over the five-year outlook period, the peak day system demands are projected to decline by 12.8%. The 1-in-2 peak day system demand is projected to decrease from 958 TJ/d in 2026 to 836 TJ/d in 2030, while the 1-in-20 peak day system demand is forecast to decline from 1,032 TJ/d in 2026 to 900 TJ/d in 2030.
- Total expected DTS supply quantities are forecast to exceed both 1-in-2 and 1-in-20 year system demands, except in 2033 and 2034:
  - The 1-in-2 year peak day supply demand balance remains in surplus for the next 10 years. Due to Gippsland production decline, the 1-in-2 year peak day supply surplus reduces from 430 TJ/d in 2026 to 109 TJ/d in 2030, and further decreases to 81 TJ/d in 2035.
  - Similarly, the 1-in-20 year peak day supply surplus starts high at 357 TJ/d. However, as Gippsland production declines, the supply surplus falls to 46 TJ/d in 2030.
  - In 2033 and 2034, 1-in-20 year peak day system demand exceeds total expected DTS supply by 10 TJ/d and 2 TJ/d, respectively. These exceedances are largely driven by no forecast production at the Orbost Gas Plant from 2033 (unless supply from other fields is developed) and the forecast end of Longford production in late 2033.
  - Despite no Gippsland supply forecast from 2034, total expected DTS supply again exceeds 1-in-20 peak day system demand in 2035 due to the forecast decline in system demand. These peak day adequacy assessments do not include GPG demand, which is discussed in the next section.

Gas-powered generation demand and peak day adequacy

Figure 30 and **Table 15** above also illustrate the impact of GPG demand, particularly when it coincides with a 1-in-2 peak day system demand. GPG demand is shown as a range, with the lower bound reflecting a 1-in-2 system demand day with no GPG usage, while the upper bound represents the winter peak GPG forecast occurring simultaneously with a 1-in-2 system demand. The range represents different forecast peak winter GPG demand scenarios, with the average of the peak GPG demand that could occur during the year.

The analysis indicates that from 2026 to 2028, forecast DTS supply is sufficient to meet peak GPG demand occurring alongside a 1-in-2 and 1-in-20 year system demand day. From 2029 onward, peak GPG demand is forecast to increase (due to the closure of the Yallourn and Eraring coal-fired power stations) and exceed the forecast DTS supply.

Extreme weather or unplanned events, including outages at coal-fired power stations or periods of low renewable output, can reduce electricity reserves and drive a substantial increase in reliance on GPG to maintain power system reliability. As available gas supply continues to decline, Victoria is expected to face progressively tighter seasonal supply conditions, heightening the risk of shortfalls. This risk is most pronounced during prolonged periods of elevated GPG usage during the winter months.

If available DTS supply capacity is insufficient to support GPG requirements on peak system demand days, curtailment of gas supply to GPG may be required. In such circumstances, GPG may utilise an alternative fuel source (usually diesel), or alternative power system resources – including non-market sources of electricity generation and electricity demand response – would need to be deployed to maintain power system reliability. Further discussion on East Coast gas supply adequacy and GPG supportability is provided in the 2026 GSOO.

3.7 Changes impacting operational resilience

DTS supply adequacy is projected to continue declining over the outlook period and beyond as available supply capacity reduces, alongside the forecast increase GPG demand, including extreme demands driven by events in the power system. **Table 16** and **Table 17** provide a summary of identified risks to supply adequacy and system resilience, and an update since the publication of the 2025 VGPR on an operational resilience issue impacting the DTS.

Table 16 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. The Longford Gas Plant has reduced resilience and redundancy following the October 2024 retirement of Gas Plant 1 and the Crude Stabilisation Plant. The two remaining Longford gas plants have a combined capacity of 720 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.
Gas generation	The increasing reliance on GPG during extreme weather events and power system 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 be insufficient to meet both electricity generation and gas system demands.
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 reduced Moomba Gas Plant production capacity and the SWQP running at reduced capacity (including due to a repeat of the inland flooding observed during winter 2025), lower Queensland production or higher Queensland demand including LNG exports, or no supply from Northern Territory via the 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 inventory depletion risk. The recent geopolitical events in the Middle East have the potential to impact gas supply availability in the southern states. AEMO will continue to monitor gas adequacy for this winter under its ECGS functions.
Gas plant trip due to declining deliverability of Gippsland Basin Fields	Esso performed offshore maintenance outages on 1-6 December and 14-17 December 2025 which resulted in a reduction in Longford capacity to 200 TJ/d. As this approached the 150 TJ/d minimum turndown threshold for the plant, an unplanned offshore outage at any of the offshore fields that remained online during the maintenance period could have resulted in the Longford Gas Plant being offline for the duration of the maintenance period. AEMO assessed the potential threat to gas supply adequacy and convened an ECGS gas supply adequacy and reliability conference leading up to the maintenance period to advise participants. This outage risk is expected to increase as the large legacy gas fields are depleted.

Table 17 Updates on operational resilience risks

Risk	Description
Longford Gas Plant 3 retirement delay	In 2025, the nameplate capacity of the Longford Gas Plant was revised up from 700 TJ/d to 720 TJ/d. The 2025 VGPR included an update that the retirement of Gas Plant 3, which would reduce Longford Gas Plant capacity to approximately 400 TJ/d, had been deferred from December 2027 until December 2028. Gas Plant 3 is now expected to remain in operation until at least 2033, maintaining Longford Gas Plant's forecast capacity at 720 TJ/d until that time. In addition, Esso now plans to continue to operate two trunklines from offshore platforms to Longford until 2033.

4 Locational gas-powered generation supportability

Key findings

- As GPG demand is forecast to increase significantly following the closure of major coal-fired power stations through the next decade and increasing rates of electrification, AEMO has conducted modelling of the DTS to assess locational supportability if any potential GPG loads were to connect on the DTS. The locational supportability for potential GPG was analysed from a theoretical technical perspective of gas system adequacy only and does not represent the lowest cost supply and does not represent a merits or cost-benefit assessment of any project or investment at any location and the analysis does not amount to a recommendation or endorsement of any project or of any investment.
- AEMO analysed the near-term supportability of GPG demand in 2029, which is within the VGPR outlook period, to assess existing DTS supportability for potential GPG loads aligning with the forecast increase in GPG demand. The analysis showed:
  - a high relative GPG supportability rating for locations along the LMP for potential GPG loads connecting the eastern regions of Victoria, given the existing high capacity of the LMP and minimal impact on the transportation capacity of other pipelines, although the GPG supportability rating of the LMP is projected to decrease as forecast supply from the Longford Gas Plant declines in the early 2030s, and
  - lower GPG supportability ratings for possible locations along the SWP and VNI, due to the limited transportation capacity of these pipelines and possible impact on Iona UGS refilling and export flow to other states.
- In addition to the near-term outlook, AEMO modelled various supply expansion sensitivities, each corresponding to the three major supply locations for the DTS, to assess the potential impact of expansion projects on locational GPG supportability within the DTS. This analysis showed:
  - potential supply capacity expansion in Gippsland, including the Golden Beach Energy Storage project and PKET, significantly improves GPG supportability for locations along the LMP and VNI, with higher supply capacity from Gippsland effectively using existing gas infrastructure to support potential additional GPG loads, and
  - capacity expansion of the SWP, either from a potential Geelong LNG regasification terminal or APA's proposed SWP expansion options, increases GPG supportability for locations along on the SWP, BLP, BCP and the section of the BBP near Brooklyn with the increase in the overall SWP transportation capacity.
    - A potential Geelong LNG regasification terminal is projected to increase the overall SWP capacity to as much as 770 TJ/d as reported in the 2025 VGPR, with locations along the SWP, BLP, BCP and small sections of the BBP near Brooklyn having a substantial increase in GPG supportability rating.
    - APA's proposed SWP expansion option comprising of 88 km of pipeline looping is projected to increase the SWP capacity to 615 TJ/d and provide the benefit of increased linepack, which is discussed in Section 5. This would also provide increased GPG supportability for locations along the SWP. If the SWP was expanded through the proposed compression option (also outlined in Section 5), the operational envelope would be narrower compared to the pipeline looping options due to the minimum flow requirements of the new large

compressors. Therefore, the GPG supportability index for the compression option is projected to be lower because less GPG demand could be supported.

– APA has proposed a further increase in supply capacity into the northern section of the DTS via Culcairn, enabled by APA's recently approved ECGG Expansion Plan Stage 3A, and the potential Expansion Plan Stage 3B that consists of the Bulloo Interlink and a future stage consisting of the Riverina Storage pipeline (see Section 5). This is projected to increase supply capacity into the DTS from the MSP via Young to Culcairn lateral including decoupling operation of the Uranquinty Power Station from southerly peak day flows into the DTS via Culcairn. Despite these expansions north of Culcairn, the improvement in GPG supportability for locations along the VNI is forecast to be moderate because the supply capacity via Culcairn could be limited by the capacity of the VNI.

4.1 Gas-powered generation forecast increase

As reported in the 2026 Draft ISP, GPG is expected to play an increasingly important role as legacy coal generation exits the NEM. In Victoria, the Yallourn Power Station is currently scheduled to close on 1 July 2028[58] and Loy Yang A before winter 2035[59]. The announced Yallourn closure and April 2029 closure of New South Wales' Eraring Power Station triggers a large forecast increase in GPG demand during winter 2029, which is discussed in Section 2. The 2026 Draft ISP forecasts that 4 GW of additional GPG capacity will be required across New South Wales and Victoria from 2030 to 2050 to help replace retiring coal generation, support the electrification of transportation and gas heating, and manage increased electricity demand from data centres. Currently, the NEM has 4 GW of mid-merit and 8 GW of peaking GPG capacity, of which 9 GW is forecast or announced to retire between now and 2050. The 2026 Draft ISP also notes that any existing GPG that retires would need to be replaced on a like-for-like generation capacity basis, in addition to the 4 GW of additional GPG in the southern states.

AEMO conducted modelling of the supportability of new GPG by location to develop locational supportability rating maps of the DTS for the approximately 2 GW of new Victorian GPG that is expected to be required (along with the retention of GPG at its current locations in the DTS).

4.2 Potential gas-powered generation connection locations in Victoria

AEMO determined potential GPG connection points in Victoria by overlaying the location of current DTS pipeline systems onto generator location data from the 2025 *Enhanced Locational Information Report* (ELI Report) for sites across the NEM. AEMO identified the most suitable theoretical GPG locations from a NEM perspective along each pipeline system in the DTS (the LMP, SWP and VNI), and analysed these locations, overlapping existing DTS infrastructure, and publicly available information on potential GPG projects, to project GPG supportability from the gas infrastructure capacity perspective:

- **La Trobe Valley** – potential GPG connection locations are currently concentrated in the Gippsland region, due to the LMP running through this area. This would make La Trobe Valley a suitable location for new GPG connections, due to its proximity to existing gas infrastructure and existing electrical grid connection points. EnergyAustralia has announced that it is investigating converting the Yallourn Power Station site to a low carbon emissions hub called the Yallourn

[58] Energy Australia, EnergyAustralia powers ahead with energy transition, at https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition.

[59] See https://www.agl.com.au/about-agl/operations/agl-in-the-latrobe-valley.

Energy Security Precinct. The potential first stage of the new precinct includes an 8-hour BESS and a new 1 GW gas power plant which could come online by the middle of the next decade[60]. The Hazelwood Terminal Station, which is the planned location for the proposed Marinus Link Victorian converter station[61], is also located near Yallourn and close to the LMP.

- **Northern Victoria** – possible GPG connections locations near the existing VNI are limited to the north-east area of Victoria near Winton. In February 2023, Lochard Energy sought planning approval for the development of its proposed Winton Energy Reserve 1 facility that included a new 200 MW GPG facility and BESS with 400 megawatt hours (MWh) of storage capacity[62].
- **Western Victoria** – potential GPG locations in the western region of Victoria are broadly distributed along existing 500 kilovolts (kV) and 220 kV transmission lines. The most suitable area assessed is locations connecting to the SWP near Geelong, where the power system has a high reliability factor according to the 2025 ELI Report.

4.2.1 Locational gas-powered generation supportability of existing infrastructure

AEMO conducted a technical assessment of existing gas infrastructure within the DTS to determine its capacity to accommodate up to 2 GW of projected GPG requirements in the DTS. This evaluation of future GPG supportability was analysed from a theoretical perspective of gas system adequacy, and was based on three primary supportability factors:

- **transmission availability** – gas infrastructure capacity available to accommodate more large gas demand,
- **supply availability** – dependence on current gas supply sources, and
- **operational flexibility** – vulnerability to nearby gas demand or operational changes in the gas network.

Using these three factors, AEMO determined a gas infrastructure locational supportability factor for potential GPG loads, if any GPG project was to proceed, for each of the major pipelines in the DTS.

This modelling was completed using the forecast 1-in-20 year system demand for 2029 in Section 2. This was chosen because it coincides with the forecast increase in peak winter GPG demand due to the forecast retirement of major coal generation.

Figure 31 shows the locational supportability for potential new GPG demand for existing major DTS pipelines (shown as a colour gradient along existing gas pipelines) overlaid with the reliability benefit of generators for the power system connection points from the 2025 ELI Report, using the medium-term operating conditions assessment (shown as a colour gradient for each electricity transmission connection point studied in Victoria).

For the 2029 medium-term operating conditions, the GPG supportability analysis for existing gas infrastructure shows low to medium GPG supportability factors across the DTS:

- The three major pipelines – LMP, VNI and SWP – are projected have sufficient transmission pipeline capacity to accommodate new GPG loads, provided sufficient supply is available from potential projects. However, when actual supply adequacy was assessed, the DTS is forecast to have limited supportability due to the decline in supply from Longford in the near-term condition modelled.

[60] AFR, "EnergyAustralia plots $5b-plus transformation of ageing Yallourn plant", 24 November 2025, at https://www.afr.com/companies/energy/energyaustralia-plots-5b-plus-transformation-of-ageing-yallourn-plant-20251008-p5n0vr.

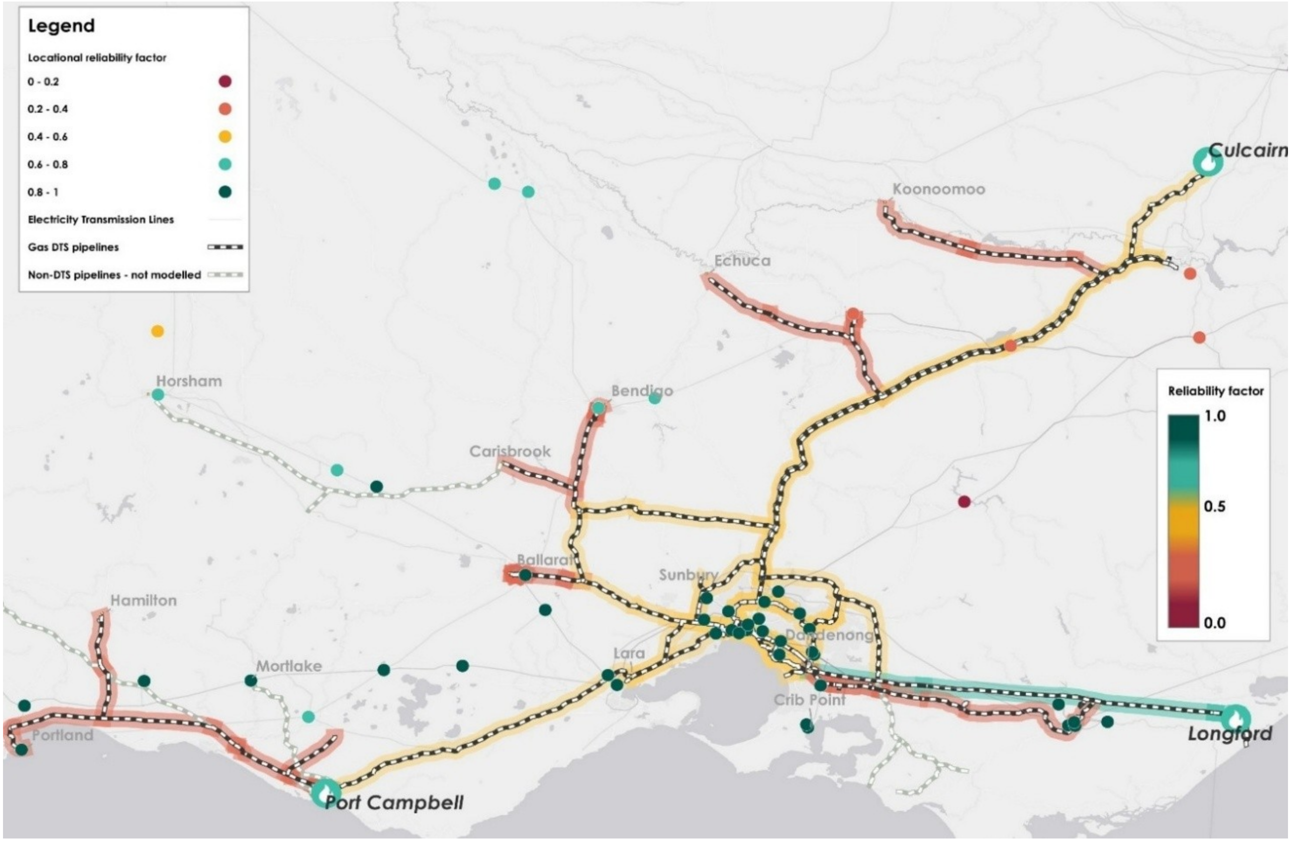
[61] Marinus Link Overview, at https://www.marinuslink.com.au/overview/.

[62] See https://www.lochardenergy.com.au/wp-content/uploads/2023/03/04.-Lochard-Energy-WER1-Planning-Assessment-Report-Feb-2023.pdf.

  - The potential additional GPG loads along VNI and SWP could also impact export capacities when supply to New South Wales and Iona UGS refilling are required, respectively. In addition to the impact on export capacity, the operation of potential additional GPG at high rates over an extended period could also reduce supply capacity for the Melbourne demand centre. The combination of these factors are projected to influence the operational flexibility of the existing VNI and SWP, and lower GPG supportability ratings at these locations. For the operation of potential GPG locations on the LMP, supply capacity for the Melbourne demand centre may also be affected, however the impact is assessed to be less significant compared to other potential locations along the VNI and SWP due to higher existing transportation capacity available on the LMP.
  - The current VNI consists of two parallel pipelines (T74 and T119). If new GPG was to be connected onto the VNI, GPG supportability would be different between these two pipelines, because the T74 is currently operated at a lower pressure rating than the T119 and it has a lower diameter. If the connection of GPG to the VNI was possible for either pipeline, the T119 pipeline would offer enhanced supportability compared to the T74. While the connection of GPG to the T119 offers enhanced supportability, the operation of the GPG at high rates would impact exports to New South Wales via Culcairn and supply towards Melbourne as mentioned above. The impact to Culcairn exports could be mitigated by connection of the GPG to the T74 pipeline, however this would come at the expense of lower GPG supportability.
  - Melbourne's central metropolitan area is supplied by lower-pressure transmission pipelines with maximum allowable operating pressures (MAOP) of up to 2,760 kilopascals (kPa). Because these pipelines have limited capacity, paired with existing high system demand, central Melbourne locations have low to medium GPG supportability ratings. The Newport Power Station is the only GPG located in this section of the DTS and is located close to Brooklyn City Gate (CG), which has high pressure gas supply from the SWP and the WORM.
  - Although the current GPG supportability rating for the existing LMP is higher than that of the SWP or VNI, it is projected to decrease as Longford supply continues to decline.
  - While the Lurgi Pipeline runs parallel to the existing LMP, it has a lower MAOP of up to 2,760 kPa compared to 7,070 kPa for the LMP, and requires a high minimum supply pressure to meet the demand along its route. The Jeeralang Power Station is connected to the eastern end of the Lurgi Pipeline, close to the high-pressure supply from the LMP. Other locations along the Lurgi Pipeline are considered to have a low GPG supportability rating.
- Potential GPG locations at the western fringes of the DTS, including the Ballarat and Bendigo supply laterals and adjacent areas, are projected to have low GPG supportability, primarily due to existing low pipeline capacity, combined with limited supply adequacy.
- For new potential GPG locations that are further away from existing gas infrastructure, a gas supply lateral for the GPG development could be developed with a compressor and a larger diameter gas pipeline to act as a gas storage vessel to supply the GPG. This approach would be similar to the Kurri Kurri storage pipeline infrastructure connected to the recently commissioned Hunter Power Station in New South Wales.

While gas bottle storage may smooth out the gas demand profile of the GPG facility, it is less effective during extended wind droughts coinciding with periods of lower solar output that continue for more than a few days.

Figure 31 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generators' connection points' reliability benefits for Victoria



4.2.2 Locational GPG supportability of potential expansion projects

As reported in the 2026 GSOO, several possible expansion projects have been identified to address expected supply gaps in the southern states during the five-year outlook period. These include an LNG regasification terminal, expanding north-to-south transportation capacity from Queensland, and developing contingent resources within the southern states. Further details of these supply projects are in Section 5.

The locational GPG supportability within the DTS was assessed to evaluate how expansion projects might affect the capacity to support GPG loads (assuming the potential expansion project receives final investment approval to proceed).

The potential expansion projects that AEMO has considered for locational GPG supportability modelling are summarised in **Table 18** below.

Table 18 Potential expansion projects analysed for locational gas-powered generation supportability

Scenario	Expansion projects	Summary of system opportunity for GPG supportability
Potential supply expansion in Gippsland	• PKET via EGP reversal and a VicHub expansion • Golden Beach Energy Storage Project • Gippsland Basin development of contingent resources	• Improve supply adequacy for GPG • Improve GPG supportability rating for locations along the LMP to a very high rating
Potential Geelong LNG regasification	• Geelong LNG regasification terminal project	• Improve supply adequacy for GPG • Improve GPG supportability rating for locations along the SWP and western Melbourne to a very high rating
Potential SWP expansion by looping	• Iona UGS expansion • Otway Basin developments and Port Campbell gas plant capacity expansion(s) • AP&G Venice Energy Adelaide Outer Harbor LNG regasification terminal project	• Improve supply adequacy for GPG • Improve GPG supportability rating for locations along the SWP to a high rating
Potential SWP expansion by compression	• Iona UGS expansion • Otway Basin developments and Port Campbell gas plant capacity expansion(s) • AP&G Venice Energy Adelaide Outer Harbor LNG regasification terminal project	• Improve supply adequacy for GPG • Improve GPG supportability rating for locations along SWP to a medium rating
Potential supply expansion from Culcairn	• **Committed** – ECGG Stage 3A Expansion Plan (three additional compressor stations, located on the SWQP, MSP, and Young to Culcairn lateral) • ECGG Stage 3B Expansion Plan (Bulloo Interlink) • ECGG future stage Expansion Plan (Riverina Storage Project)	• Improve supply adequacy for GPG • Improve GPG supportability rating for locations along VNI to a medium -high rating

Potential supply expansion in Gippsland

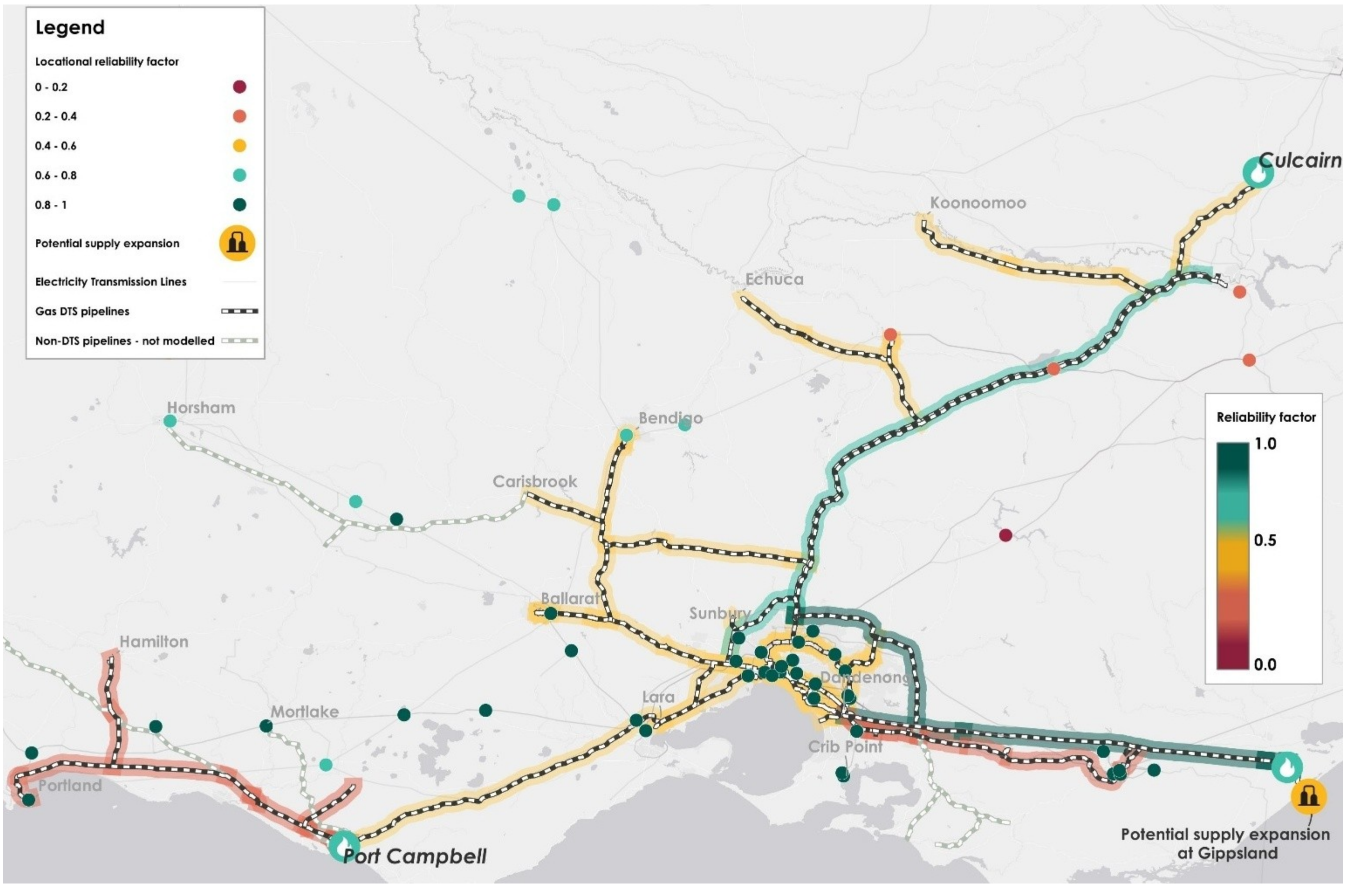
AEMO analysed the possible increase in supply capacity from Gippsland to evaluate how it would affect GPG supportability within the existing DTS. The potential increase in injection capacity from the Longford supply point has been evaluated for transport via the existing LMP, which currently has sufficient existing capacity to flow approximately 1,100 TJ/d on a 1-in-20 year peak day system demand. Increasing the supply capacity at the Longford supply point could increase the utilisation of the existing pipeline and both the Gooding and Wollert compressor stations, facilitating increased supply capacity across the DTS.

Figure 32 shows the DTS GPG supportability rating with the potential additional Gippsland supply projects at the Longford supply point including the Golden Beach Energy Storage and PKET projects.

Modelling the increased Gippsland supply capacity from these potential projects shows a significant projected improvement of GPG supportability throughout the DTS, particularly in Victoria's east and north regions:

- Potential locations along the LMP, VNI and WORM are projected to achieve high and very high GPG supportability ratings. This is due to the increased supply from the Longford supply point resulting in increased supply adequacy for the DTS. Combined with the existing pipeline infrastructure, this enables the effective movement of gas from the east to the north via compression facilities at Gooding and Wollert.
- Other potential locations in the DTS – including locations along the Lurgi Pipeline, Melbourne inner ring main pipelines, and other pipelines at the fringes of the DTS – are forecast to be limited by the lower operating pressure of these pipelines, resulting in lower GPG supportability ratings.

Figure 32 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generator connection point reliability benefits for the Declared Transmission System – potential supply expansion in Gippsland



Potential Geelong liquefied natural gas regasification

As reported in the 2025 VGPR, the potential supply expansion project of a Geelong LNG regasification terminal could increase the total SWP capacity, up to approximately 770 TJ/d, noting that this would significantly impact supply from Port Campbell without an expansion of the SWP, which is discussed later in this section.

AEMO modelled this increase in capacity alongside potential additional GPG loads at different locations within the DTS, to evaluate its effects on DTS GPG supportability. There are two proposed Geelong LNG regasification terminals, the Viva Energy Terminal and the Vopak Energy Terminal. Both are expected to behave similarly in terms of DTS capacity and supply, so they have been considered collectively as a Geelong LNG regasification terminal.

Figure 33 shows DTS GPG supportability ratings with the potential supply expansion project of a Geelong LNG regasification terminal. Modelling the potential increased SWP supply capacity and an additional injection at Geelong resulted in a significant improvement of GPG supportability throughout the SWP and western region of Melbourne:

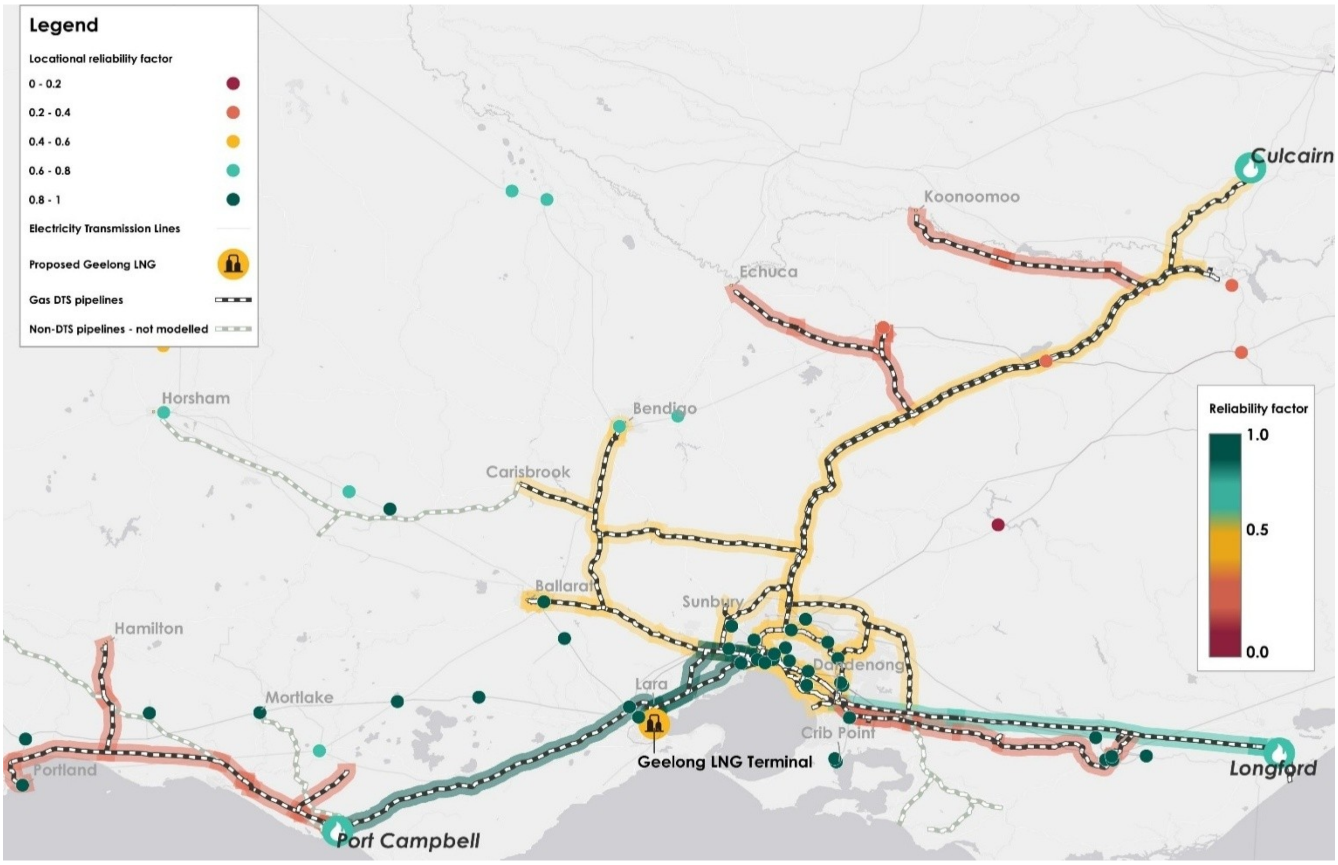
- The significant increase in SWP capacity is forecast to greatly improve the potential locations of GPG along the SWP, to a very high rating. This is due to the modelled increase in capacity and supply adequacy with a potential additional supply to accommodate additional GPG loads along the SWP.
  - The improvement of GPG supportability on the SWP is similar to the improvement on the LMP for the potential supply expansion at Gippsland. However, as reported in the 2025 VGPR, the maximum increase in SWP capacity

provided by a potential Geelong LNG regasification terminal is achieved by substantially reducing Port Campbell supply.

  – Potential new GPG demand near Moorabool, which is the closest theoretical connection to the proposed Geelong LNG regasification terminal, could partially mitigate the back-off effect. However, Port Campbell injections are expected to remain constrained below its current capacity.

- Analysis indicates that other possible GPG locations within the DTS would only see a moderate improvement in GPG supportability, as the current infrastructure is limited in its ability to transport supply away from the western system.

Figure 33 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generator connection point reliability benefits for the Declared Transmission System – potential Geelong liquefied natural gas regasification



Potential capacity expansion from South West Pipeline expansion project

As discussed in the 2025 VGPR, the potential supply expansion capacity from Port Campbell is currently limited by the existing SWP transportation capacity. In October 2025, APA formally submitted a rule 80 application to the AER[63] for the expansion of the SWP capacity. The current proposed SWP capacity expansion includes two initial options[64], both aligned with Lochard Energy's committed HUGS Phase 1 project capacity that increases the capacity of the Iona UGS facility to 615 TJ/d prior to winter 2028. These options include:

[63] APA VTS rule 80 application for the expansion of the South West Pipeline, at https://www.aer.gov.au/industry/registers/access-arrangements/apa-victorian-transmission-system-rule-80-application-expansion-south-west-pipeline.

[64] AER public forum 11 December 2025, combined slides, at https://www.aer.gov.au/documents/aer-public-forum-apa-vts-r80-application-south-west-pipeline-combined-presentation-slides-11-december-2025.

- **APA's preferred compression option** – two greenfield compressor stations at Irrewillipe and Stonehaven and modifying the Winchelsea compressor station, and
- **APA's alternative pipeline looping option** – duplicating (looping) of 88 km of the SWP and modifying the Winchelsea compressor station.

AEMO has completed sensitivity modelling for both compression and looping options to assess their impact on GPG supportability on the DTS.

Figure 34 shows the supportability rating map of the DTS with SWP expansion by alternative looping 88 km of the SWP. Analysis shows minor improvements to the SWP supportability of potential additional GPG:

- Looping of the SWP is projected to increase pipeline capacity, allowing higher injections from Port Campbell compared to the existing system, and improving the supportability rating of potential GPG locations along the SWP to a medium rating. Further potential additional looping may be considered if an additional capacity increase was to be required, which could also further increase SWP capacity and GPG supportability in the DTS, as discussed in Section 5.
- The potential GPG supportability of the SWP is projected to have a lower rating compared to the LMP with Golden Beach UGS or PKET sensitivity, due to operational flexibility issues such as limited SWP flow capacity towards Port Campbell, and overall to provide less supply to the system.

Figure 34 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generator connection point reliability benefits for the Declared Transmission System – South West Pipeline expansion by looping

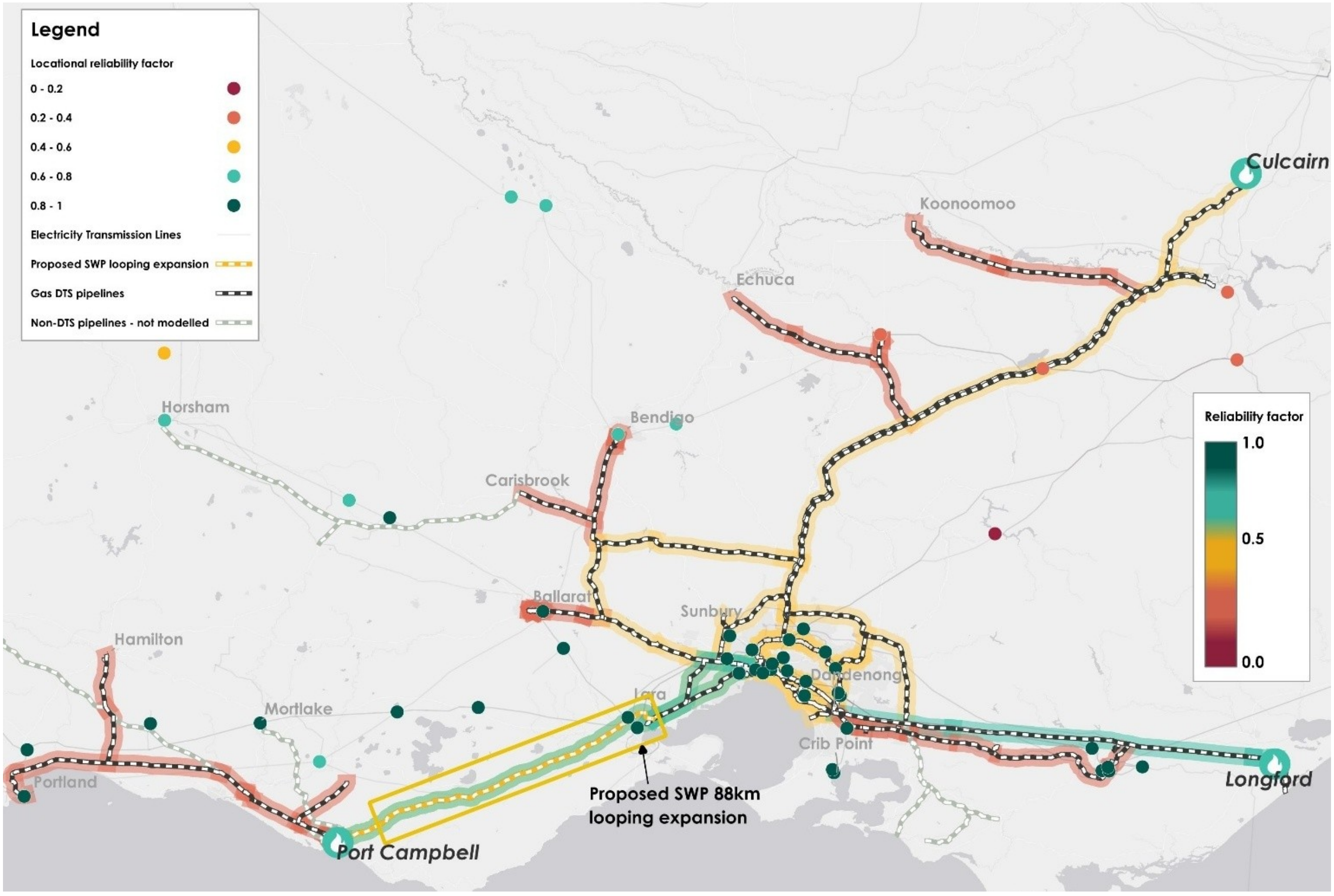
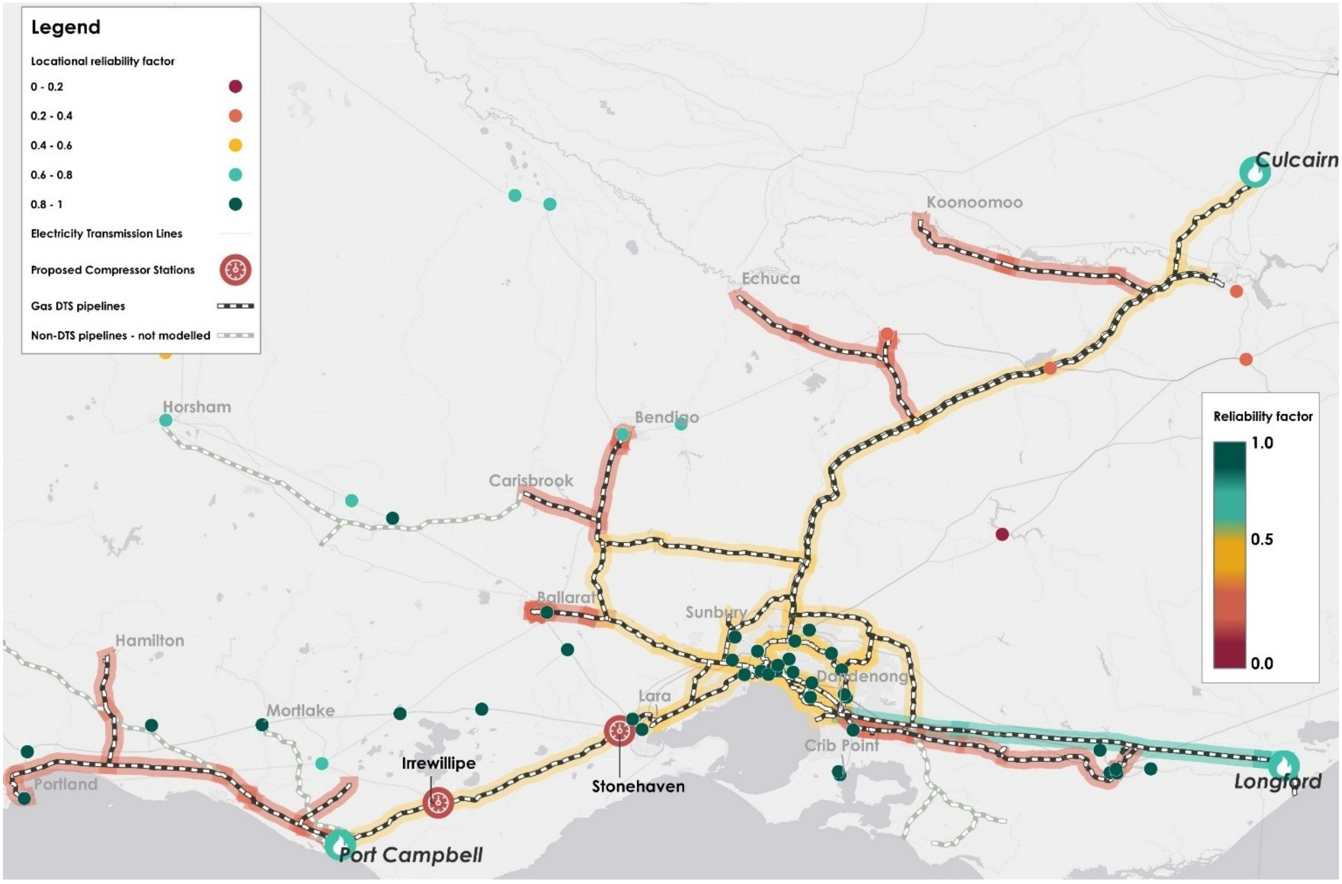


Figure 35 shows the supportability rating map of the DTS with SWP expansion by two greenfield compressor stations on the SWP. The analysis indicates only minimal improvements in the ability of the SWP to support potential additional GPG:

- Both SWP expansion options (compression and pipeline looping) are projected to increase SWP capacity and improve GPG supportability. However, modelling indicates that the alternative SWP expansion pipeline looping option would provide additional linepack and enable the SWP to support higher GPG demand compared to the compression option.
  - Typically, usable linepack is low during peak winter days. The Victorian DTS has approximately 350 TJ of usable linepack[65], compared to daily system demand which may exceed 1,000 TJ/d and GPG demand that may exceed 300 TJ/d. The additional pipeline looping would increase total available linepack, which is important for supporting the response to unplanned Longford Gas Plant outages which are increasingly likely due to then depletion of legacy gas fields and increased dependence on the Gas Conditioning Plant outlined in the 2025 VGPR.
  - Linepack will also continue to be important to support response to major power system incidents, such as the 13 February 2024 storm event that resulted in the collapse of several 500 kV transmission towers near Anakie north of Geelong, the trip of the entire Loy Yang A coal power station, and the immediate unscheduled start-up of several GPG units connected to the DTS.

Figure 35 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generator connection point reliability benefits for the Declared Transmission System – South West Pipeline expansion by compression



[65] The DTS has approximately 870 TJ of total linepack, of which 360 TJ is passive linepack to meet contractual pressures and 510 TJ is active linepack which is any gas in the DTS above the minimum contractual pressures for connection points. Of the 510 TJ of active linepack, ~350 TJ is usable linepack and ~160 TJ is not usable due to the pressure gradients in pipelines between the injection and withdrawal points.

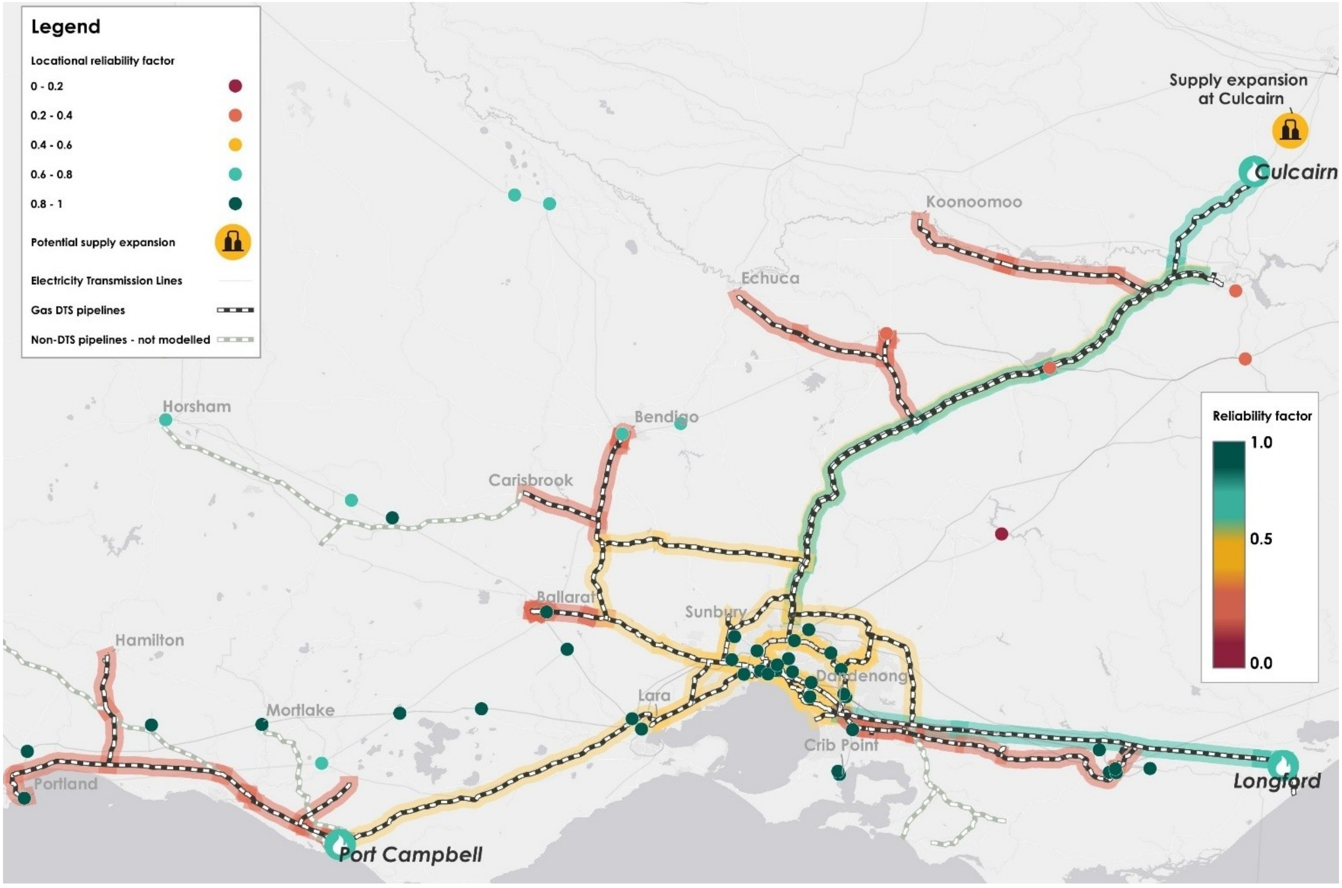
Increased supply from the East Coast Gas Grid Expansion projects

Further expansion of the APA ECGG is expected to increase supply capacity into the DTS via Culcairn. This includes the newly committed Stage 3A expansion that increases Young to Culcairn capacity by 39 TJ/d for winter 2028, followed by the potential Stage 3B expansion that comprises the Bulloo Interlink pipeline, and the potential Stage 4 Riverina pipeline storage solution.

The existing VNI pipeline has sufficient capacity to receive up to 229 TJ/d of supply via Culcairn. Therefore, the potential additional supply provided by further ECGG expansions beyond the committed Stage 3A project may be limited by the current VNI transportation capacity.

Figure 36 shows the supportability rating with APA ECGG Expansion Plan stages 3A, 3B and 4. This analysis shows that with the VNI potentially able to receive up to its maximum capacity of 229 TJ/d via Culcairn, there is projected to be a small increase to GPG supportability for locations along the VNI. This is due to the expected increase in the maximum supply capacity via Culcairn into the DTS, however any potential additional GPG load on the VNI would impact export flows to New South Wales via Culcairn.

Figure 36 Gas infrastructure locational supportability for future gas-powered generation and National Electricity Market generator connection point reliability benefits for the Declared Transmission System – Potential supply expansion from Culcairn



4.3 GPG project risks

AEMO recognises that the current investment environment for projects is challenging and uncertain. Natural gas, as a fossil fuel, is becoming less appealing to some investors due to risks of stranded assets, regulatory uncertainty and screening of investments based on environment, social and governance (ESG) issues.

Lead times for gas turbines have also increased significantly due to high demand and manufacturing capacity constraints from the world's largest gas turbine manufacturers – GE Vernova, Siemens Energy and Mitsubishi Heavy Industries (MHI). Lead times vary depending on the size of turbine, but manufacturers are quoting lead times of four years and the cost of a combined cycle gas turbine as high as $2,400/kilowatt (kW)[66]. Manufacturers have announced expansions for turbine manufacturing capacity, however this expanded capacity will likely not translate to a lead time of less than four years[67].

Global demand for gas turbines is largely driven by increases in power consumption, from data centres powering the expansion of AI, electrification and emissions reduction including retirement of coal-fired generation. In the United States, the annual energy use of data centres in 2023 was 176 terawatt hours (TWh), which equates to 4.4% of annual electricity consumption, and is projected to double or triple by 2028 accounting for up to 12% of electricity use[68]. In Australia, AEMO has forecast data centre consumption reaching 21.4 TWh by 2034-35 and 35.7 TWh by 2054-55 under the *Step Change* scenario, which is equivalent to around 9% and 12% respectively of the NEM's grid-supplied electricity[69].

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66 S&P Global, "US gas-fired turbine wait times as much as seven years; costs up sharply", 20 May 2025, at https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

67 Institute for Energy Economics and Financial Analysis (IEEFA), "Global gas turbine shortages add to LNG challenges in Vietnam and the Philippines", October 2025, at https://ieefa.org/sites/default/files/2025-10/IEEFA%20Report_Global%20gas%20turbine%20shortages%20add%20to%20LNG%20challenges%20in%20Vietnam%20and%20the%20Philippines_October2025.pdf. Institute for Energy Economics and Financial Analysis (IEEFA), "Global gas turbine shortages add to LNG challenges in Vietnam and the Philippines", October 2025, at https://ieefa.org/sites/default/files/2025-10/IEEFA%20Report_Global%20gas%20turbine%20shortages%20add%20to%20LNG%20challenges%20in%20Vietnam%20and%20the%20Philippines_October2025.pdf.

68 United States Congress, https://www.congress.gov/crs-product/R48646#:~:text=The%20Department%20of%20Energy%20(DOE,17.

69 AEMO, 2025 ESOO, August 2025, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

5 Future supply sources

Key findings

- Several committed, anticipated and potential projects may provide additional DTS supply during the outlook period. These include:
  - **Committed, anticipated and potential production projects in the Gippsland and Otway basins**.
    - GBJV has advised AEMO that drilling work has commenced on the Turrum Phase 3 development with the additional supply expected to be online prior to winter 2027. The annual supply profile for Longford production has changed from last year due to reprofiling of production from existing fields, but total production over the lifecycle of the project remains similar to the 2025 VGPR.
    - Storage capacity for the Golden Beach Energy Storage Project by GB Energy has increased from 30 PJ to 42 PJ due to positive preliminary data.
    - Amplitude Energy is proposing to expand the East Coast Supply Project (ECSP) by connecting the prospective Nestor gas field to boost supply to Athena Gas Plant with a potential capacity of up to 130 TJ/d during the initial production period.
  - **LNG regasification terminal projects in Victoria and in other jurisdictions.**
    - **PKET** is expected to stay in "care and maintenance" mode until at least mid-2027 with the terminal commissioning delayed until there is sufficient customer demand and after the arrival of the FSRU which is currently leased to the Egyptian state-owned company Egas[70].
    - Viva Energy has received a positive assessment for the EES for the proposed **Viva Energy Gas Terminal Project** and is targeting FID by the second half of 2026.
    - Vopak has submitted consultation and engagement plans for the EES for the proposed **Vopak Victoria LNG** project and procured a FSRU for the terminal from Seapeak.
    - AP&G LNG finalised the acquisition of Venice Energy in 2025, including the sale of the proposed Outer Harbor LNG Project. AG&P has advised that FID is expected in Q3 2026. Contract negotiations are ongoing with all potential terminal users.
  - **Pipeline expansion projects in Victoria and from other jurisdictions which increase** Victorian supply capacity.
    - APA has received approval from the New South Wales Government for the conversion of the MSEP to transport natural gas as part of the **ECGG Expansion Plan,** and is targeting commissioning prior to winter 2026. The completion of the project will boost supply from Moomba towards Young by 20 TJ/d.
    - APA has announced FID on APA's ECGG Expansion Plan Stage 3A and pre-FID on Stage 3B including procurement of line pipe. Stage 3A includes the installation of three new compressor stations on the SWQP, MSP, and Young to Culcairn lateral. This will increase Young to Culcairn capacity by 39 TJ/d, however this increase in capacity is shared with southern New South Wales demand and the Uranquinty Power Station.

[70] ABC News, "Port Kembla Energy Terminal delayed until 2027 amid shifting gas demand", 26 May 2025, at https://www.abc.net.au/news/2025-05-26/squadron-energy-delays-start-of-port-kembla-lng-terminal/105332468.

  - Stage 3B includes construction of the Bulloo Interlink pipeline which will connect to the SWQP in Queensland to increase the transportation capacity from northern Australia to the southern states. Stage 3A is targeting completion by winter 2028 and Stage 3B by the end of 2028.
  - APA has submitted an application to the AER seeking pre-approved capital expenditure under NGR rule 80 to expand the SWP by installing two new compressors at new locations (Irrewillipe and Stonehaven) and modifying the existing compressor station at Winchelsea, which would increase SWP capacity up to 615 TJ/d.
- **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. This 2026 VGPR Update contains few committed and anticipated supply projects. Many projects do not have firm timelines, making the analysis of system adequacy in Section 3 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 five-year outlook period, as they still face a range of barriers preventing their entry into the market.

5.1 Project updates

5.1.1 Committed supply projects

Iona Underground Gas Storage Expansion

Lochard Energy's HUGS development aims to increase the Iona UGS facility storage capacity by 1.8 PJ and increase supply capacity to 615 TJ/d from early 2027, prior to winter. APA has submitted a proposal to augment the SWP, either through compression or pipeline looping, to increase pipeline capacity to match the new Iona UGS supply capacity under an NGR rule 80 – advanced capex determination. More information about SWP expansion options is available in the AEMO submission to the AER in response to APA's rule 80 application.

Lochard Energy is also considering further storage expansion by developing its HUGS Phase 2 project, however the scope will depend on the outcome of APA's rule 80 submission and potential further increases in SWP capacity.

Turrum Phase 3

Work has commenced on this project, with a jack-up rig mobilised during December 2025. Drilling activities are in progress and are expected to continue through the first half of 2026. Turrum Phase 3 start-up is planned to occur prior to winter 2027. In aggregate, total supply from the project is similar to the forecast provided for the 2025 VGPR, however the annual supply profile has changed compared to last year due to the accelerated project schedule compared with what was advised for the 2025 VGPR. Compared with the 2025 VGPR, Turrum Phase 3 is expected to supply between 3.3 PJ and 7.2 PJ per year higher production from 2027 to 2029.

APA East Coast Gas Grid (ECGG) Expansion Plan[71,72]

APA completed Stages 1 and 2 of the ECGG Expansion Plan in 2023 and 2024 respectively, which comprised the installation of additional compression on the SWQP and MSP. This increased the capacity of the SWQP to 512 TJ/d and the MSP to 565 TJ/d. On 24 February 2025, APA announced further planned capacity expansion stages:

- **MSEP conversion to natural gas** – completion of this project will increase transportation capacity from Moomba to Young by 20 TJ/d. The New South Wales Government approved the conversion of the pipeline in October 2025[8], and commissioning of the pipeline for transporting natural gas is planned by winter 2026.
- **The MSP off-peak capacity expansion project** involves the installation of two additional pressure regulation skids which will increase MSP summer capacity during its annual maintenance period. This project is scheduled to be completed by November 2026.
- **ECGG Expansion Plan Stage 3A** – APA has announced FID on Stage 3A of the ECGG Expansion Plan[73]. Stage 3A includes the installation of three new gas compressor stations, which will be located on the SWQP at Meadows, on the MSP at Gilgunnia, and at Uranquinty on the Young to Culcairn lateral. These new compressors will boost SWQP westerly flow capacity by 58 TJ/d, MSP southerly flow capacity by 10 TJ/d and southerly flow capacity on the Young to Culcairn lateral by 39 TJ/d. The 39 TJ/d increase in capacity from Young to Culcairn is shared with southern New South Wales demand and the Uranquinty Power Station, so the full capacity increase may not be fully available to Victoria. APA is targeting completion of Stage 3A by winter 2028**.**

Hydrogen Park Murray Valley

Hydrogen Park Murray Valley is a committed project by AGI Renewables, part of AGIG. AGIG has procured two 5 MW electrolysers, however due to upstream and production facility activities, the commissioning date for this project has been pushed back to late 2026.

Beetaloo Basin

The Beetaloo Basin in the Northern Territory is estimated to hold more than 500 trillion cubic feet[74] (tcf) of discovered and prospective gas[75]. Beetaloo Energy (formerly Empire Energy Group)[76] has signed a 10-year binding gas sales agreement with the Northern Territory Government and is currently pursuing the Carpentaria Pilot Project, with first gas sales expected in late 2026[77]. Beetaloo Energy has drilled three production wells, purchased gas processing equipment with a capacity of up to 42 TJ/d, and is proposing to connect to the McArthur River Gas Pipeline owned by Power and Water Corporation.

Tamboran Resources has reached FID for the Shenandoah South Pilot Project located in the Beetaloo Basin and has signed an unconditional nine-year gas sales agreement with the Northern Territory government for sale of 40 TJ/d[78]. Both the

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

[72] 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.

[73] APA, HY26 Half year Financial Results – Presentation, 19 February 2026, at https://admin.apa.com.au/media/fx4omzgo/260219_asx_release_apa_1h26_results_presentation.pdf.

[74] 500 trillion cubic feet of natural gas is approximately equivalent to 525,000 PJ.

[75] Northern Territory Government, 21 January 2026, at https://territorygas.nt.gov.au/onshore/beetaloo-sub-basin.

[76] Beetaloo Energy Australia, 29 May 2025, at https://beetalooenergy.com/announcements/change-of-name-and-asx-code/.

[77] Beetaloo Energy Australia, Q4 2025 Quarterly Report, 30 January 2026, at https://beetalooenergy.com/investors/announcements/.

[78] Tamboran Resources, 13 November 2025, at https://ir.tamboran.com/_assets/_17b446254af27ea8c8375543d781f93b/tamboran/db/923/10424/pdf/251113+Tamboran+1Q+FY26+Result+Presentation+FINAL.pdf.

Beetaloo Energy and Shenandoah South projects are expected to backfill supply to the Northern Territory from the ENI Blacktip facility.

APA is constructing the Stuart Plateau Pipeline (SPP) which will connect gas from the project to the Amadeus Gas Pipeline (AGP), allowing gas transportation towards Darwin, Alice Springs or the east coast grid via Jemena's Northern Gas Pipeline (NGP) from Tennant Creek to Mt Isa. Supply to the ECGS via the NGP would reduce the supply required from the SWQP, increasing supply capacity to the southern states during the winter peak demand period. Construction of the SPP was completed during Q4 2025.

In September 2025, the Northern Territory Government granted construction approval for Tamboran to begin work on the Sturt Plateau Compression Facility (SPCF)[79], which will produce sales gas from the Shenandoah South Pilot Project. The project is on track for completion by Q3 2026[80]. Tamboran has also increased its acreage position over the Beetaloo Basin via the sale of Falcon Oil & Gas Australia[81].

5.1.2 Potential supply projects

Golden Beach

The Golden Beach Energy Storage project currently being developed by GB Energy has been delayed. FID is currently expected during the second half of 2026 and the initial gas production is now planned after winter 2028. After an initial short blowdown of the Golden Beach gas field, the facility is planned to operate as an underground gas storage facility (like Iona UGS). During the initial blowdown period, delivery capacity will be up to 125 TJ/d before converting to storage and increasing withdrawal capacity to 300 TJ/d in early 2029 and further increasing to withdrawal capacity to 375 TJ/d in late 2029. The underground gas storage capacity has increased from 30 PJ to 42 PJ due to positive preliminary well data and modelling results.

GB Energy has advised that is has ordered significant long lead time equipment, has completed Front End Engineering Design (FEED), and is in the final stages of detailed design. Early works covering the pipeline route and drilling sites have been undertaken, including surveys to determine the suitability of the seabed for supporting the drilling rig and the offshore pipeline route[82].

Longford Late Life Optimisation

Like Turrum Phase 3, production from this proposed project has been reprofiled and, compared with the forecast in the 2025 VGPR, the project is now expected to supply higher quantities of gas until 2030 and lower annual quantities thereafter, while in aggregate, total supply remains similar to last year's forecast. GBJV has advised AEMO that this project is dependent on the progression of the Turrum Phase 3 project.

[79] NT government, Sturt Plateau Pipeline approvals granted, at: https://dme.nt.gov.au/news/2025/sturt-plateau-pipeline-approvals-granted

[80] Tamboran Resources, Activities report for period ended 31 December 2025, at https://www.tamboran.com/asx-announcements/.

[81] Falcon Oil & Gas, 5 January 2026, at https://falconoilandgas.com/2026/01/05/approval-for-the-sale-of-falcons-98-1-interest-in-falcon-oil-gas-australia-limited-to-tamboran-group/.

[82] GB Energy, "Golden Beach Energy Storage Project Notification of Survey Works", March 2026, at https://gben-strapi-media-assets.s3.ap-southeast-2.amazonaws.com/GBE_Geophysical_Survey_Information_Flyer_Mar_2026_30986cc4c8.pdf.

East Coast Supply Project (ECSP)

Amplitude Energy has proposed to further expand the ECSP by connecting the prospective Nestor gas field to further boost supply to Athena Gas Plant with a potential capacity of up to 130 TJ/d during the initial period of production[83]. Amplitude Energy received the Transocean Equinox rig on 21 January 2026 and has completed drilling at the Elanora prospect which was found to be water bearing. The drill rig has moved on to drilling the Isabella prospect, which was found to intersect with a gas bearing reservoir[84]. Isabella is one of the four remaining wells Amplitude Energy intends to drill during this campaign. Amplitude Energy has received regulatory approval to commence drilling at Annie-2 as early as April 2026[85] and has signed a Gas Sales Agreement (GSA) with EnergyAustralia for 30 PJ of gas (7.5 PJ per annum) from the ECSP project over four years commencing during the second half of 2028[86]. See Section 5.1.7 for more information.

Judith

The Judith Gas Field is owned by Emperor Energy and was discovered in 1989. Emperor Energy is planning a program of works for 2026 which includes surveying the seabed and is in discussions with suppliers to secure a jack-up rig for the planned drilling of the Judith-2 appraisal well[87]. An environmental plan has been submitted to the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) and is currently under assessment. Due to the proximity of nearby infrastructure, gas may be processed either at Longford or the Orbost Gas Plant.

Artisan and La Bella

Beach Energy is scheduled to drill and complete the La Bella-2 development well and complete the Artisan-1 well during the first half of 2026. Final investment decision for the connection of the two wells to offshore pipeline infrastructure is targeted for the second half of 2026. Gas from these wells is expected to supply to the Otway Gas Plant. See Section 5.1.7 for more details on the Otway Basin drilling campaign.

Patricia-Baleen

Patricia-Baleen is a legacy field that was shut in during 2015 due to an electrical fault on the subsea umbilical at the linked Longtom field. The Patricia-Baleen field was considered to be significantly depleted, however Amplitude Energy is progressing with a feasibility study to potentially restart production from the existing wells with future potential to enable gas storage[88]. Amplitude Energy submitted an application to the National Offshore Petroleum Titles Administrator (NOPTA) on 23 December 2025 to convert the existing retention lease to a production lease.

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[83] Amplitude Energy, Investor Presentation, 23 September 2025, at https://app.sharelinktechnologies.com/announcement-preview/asx/97ad5b25f26acd1f1f63b65a692566b8.

[84] Amplitude Energy, "Sidetrack well into Isabella prospect intersects gas-bearing reservoir", 2 March 2026, at https://app.sharelinktechnologies.com/announcement-preview/asx/2f534335de43385454d611457bd41f38.

[85] NOPSEMA, Annie 2 Development Drilling", 11 September 2025, at https://info.nopsema.gov.au/environment_plans/724/show_public.

[86] Amplitude Energy, "Foundation GSA for the ECSP executed with EnergyAustralia", 2 March 2026, at https://app.sharelinktechnologies.com/announcement-preview/asx/3b0427be59f85840385b3fed48e919e9.

[87] Emperor Energy, Investor Presentation 21 September 2025, at https://emperorenergy.com.au/wp-content/uploads/2025/09/2950264.pdf.

[88] Amplitude Energy, Q2FY26 Quarterly Report, at https://app.sharelinktechnologies.com/announcement-preview/asx/365cf65b1025a47fed1567c0ba78d56f.

Longtom

The Longtom field in Gippsland Basin is wholly owned by Seven Group Holdings (SGH) Energy, which is seeking to resume production from the field. Gas from the field is proposed to flow through the Patricia-Baleen offshore gathering pipeline to the Orbost Gas Plant. Amplitude Energy has executed a technical service agreement with SGH. SGH will participate in the Patricia-Baleen feasibility study to assess gas processing options for the Longtom field with a decision to progress to FEED expected during FY26[5].

Wombat

Lakes Blue Energy received approval from the Victorian Minister for Energy and Resources in July 2025 and commenced drilling the Wombat-5 well in August 2025[5], and production testing commenced in January 2026[89]. Based on the latest modelling, the field is capable of producing 10 TJ/d, with a potential gas production of up to 3.5 PJ/y. Lakes Blue Energy has plans to develop the nearby Trifon/Gangell fields as the Wombat field declines.

APA East Coast Gas Grid (ECGG) Expansion Stage 3B

APA has announced pre-FID work has commenced for Stage 3B of the ECGG Expansion Plan, including purchasing of line pipe. This stage will see the construction of the Bulloo Interlink pipeline between the SWQP and the MSP which will increase MSP and westerly SWQP capacity by 100 TJ/d and 38 TJ/d respectively. Construction is expected to start in 2027 with completion targeted by 2028, subject to FID timing.

Essington and Charlemont

ConocoPhillips in partnership with 3D Energi and Korea National Oil Corporation has completed drilling the Essington-1 and Charlemont -1 wells using the Transocean Equinox drilling rig as part of its Otway Exploration Drilling Program. 3D Energi, which has a 20% interest in the joint venture, has defaulted on payment in relation to the drilling program and has received a buy-out notice from ConocoPhillips to purchase the company's participating interest in the VIC/P79 permit[90]. The two new gas fields, Essington and Charlemont, were both found to be gas-bearing. ConocoPhillips is currently performing further analysis to determine the commercial viability of these discoveries. No decision has been made to progress the development of these fields, however this gas could be processed at either the Athena or Otway gas processing facility in Port Campbell (subject to commercial agreement). See Section 5.1.7 for more details on the Otway Basin drilling campaign.

5.1.3 Other supply projects

Further APA East Coast Gas Grid (ECGG) Expansion Plan

APA has further expansion planned as part of the ECGG Expansion Plan, which includes:

- the Riverina Storage Pipeline project to support GPG at Uranquinty in New South Wales. Stage 1 is proposed to store up to 200 TJ as early as 2028. with the potential to expand to approximately 500 TJ as early as 2029[91],

[89] Lakes Blue Energy, Quarterly Activities/Appendix 5B Cash Flow Report. 30 January 2026, at https://wcsecure.weblink.com.au/clients/lakesblueenergy/headline.aspx?headlineid=3686236.

[90] 3D Energi, Buy-Out Notice Received, 17 March 2026, at https://wcsecure.weblink.com.au/pdf/TDO/03069576.pdf.

[91] APA's East Coast Gas Grid expansion plan, at https://www.apa.com.au/operations-and-projects/gas/gas-transmission/east-coast-grid-expansion-ecge.

- new compression and pipeline looping between the proposed Riverina Storage pipeline and the DTS, which increases Culcairn injection capacity up to 350 TJ/d, and
- a new compressor to enable flow from the MSP to the EGP and back towards Victoria via reversal of the EGP.

Beetaloo Basin

Beetaloo Basin is a potential future source of supply for the southern states to replace declining production from the Longford Gas Plant, which is forecast to close during the 2030s.

Santos is planning a drilling appraisal program in the EP 161 area in the Beetaloo Basin which is jointly owned by Santos and Tamboran Resources. The program of works includes construction of two new well pads and construction, operation, decommissioning, and dismantling of existing wells and other infrastructure[92]. Santos has signed a Memorandum of Understanding (MoU) to progress studies to expand Darwin LNG with a proposed Train 2 expansion[93] which would enable potential export of gas from the Beetaloo Basin.

Tamboran Resources, which is already developing the Shenandoah South Pilot Project, is also proposing to develop the NTLNG Project located in the Middle Arm Sustainable Development Precinct in Darwin. The NTLNG Project has been announced as targeting net zero scope one and two emissions for initial production of 6.6 million tonnes per year of LNG using gas sourced from Tamboran's low carbon dioxide reservoir natural shale gas in the Beetaloo Basin. FEED for the project has commenced with target commencement of LNG sale from 2030[94].

APA is proposing to construct the North to East Australia Pipeline (NEAP), which is a 1,580 km pipeline that would connect the Beetaloo Basin in Northern Territory to the SWQP at the start of the proposed Bulloo Interlink pipeline. This would enable larger volumes of Beetaloo Basin gas to be piped to the southern states. APA has announced that the pipeline could be in operation by the early 2030s, subject to planning approvals and FID timing[95].

Westernport-Altona-Geelong (WAG) Pipeline project

The WAG Joint Venture (Viva Energy/Mobil) is currently investigating the potential to convert the WAG crude oil pipeline to a high pressure gas transmission pipeline. AEMO has completed a preliminary technical assessment to determine the gas transportation capacity of the WAG Pipeline; this is discussed in the SWP Expansion section below.

LNG regasification terminal projects

- **Viva Energy Geelong Gas Terminal Project** – Viva Energy received a positive assessment for its EES from the Victorian Minister of Planning[96] on 26 May 2025 and is progressing with the remaining pre-approval works. The project expects to reach FID during 2026.
- **Vopak Victoria Energy Terminal Project** – following the Victoria's Minister of Planning's referral decision on the Vopak Victoria Energy Terminal requiring an EES in August 2023, Vopak has submitted consultation and engagement plans for

[92] Santos, September 2025, at https://www.santos.com/wp-content/uploads/2025/09/Santos-in-the-NT_Beetaloo-Basin-Appraisal-Activity_Fact-Sheet.pdf.

[93] Tamboran Resources, Tamboran and Santos execute MOU to progress studies for Darwin LNG expansion,22 January 2025, at https://ir.tamboran.com/news-events/press-releases/detail/16/tamboran-and-santos-execute-mou-to-progress-studies-for-darwin-lng-expansion.

[94] NTLNG: Fuelling a Sustainable Future, at: https://ntlng.com/

[95] APA, at https://www.apa.com.au/operations-and-projects/gas/gas-transmission/north-to-east-australia-pipeline-project.

[96] Victorian Government Department of Transport and Planning, 20 June 2025, at https://www.planning.vic.gov.au/environmental-assessments/browse-projects/viva-energy-gas-terminal.

the EES[97] and has signed an exclusive agreement with Seapeak to provide the FSRU for the project[98]. 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 2029.

- **PKET** – Squadron Energy completed physical mechanical construction of the terminal in December 2024[99]. The terminal is in care and maintenance mode until at least mid-2027, with the terminal commissioning delayed until there is sufficient customer demand. Once the FSRU arrives, the remaining commissioning activities can be completed. The terminal has a forecast supply capacity of 500 TJ/d and aims to provide first gas in winter 2028. Squadron Energy is currently in the process of negotiating contracts with long-term customers to achieve the expected launch date. Jemena is progressing stage one of two potential stages of the EGP reversal project, which will enable bi-directional flow on the pipeline. Completion of stage one will allow flows of up to 200 TJ/d south towards Victoria with the potential to increase to 320 TJ/d. Jemena is planning to complete stage one prior to winter 2026[100].
- **Outer Harbor LNG Project** – AG&P LNG has advised that it has completed enabling works for the project and negotiations are ongoing with all potential terminal users.
  - In October 2024, AG&P LNG acquired Venice Energy[101]. This acquisition was finalised in August 2025 and AG&P has advised that FID is expected in Q3 2026 with first gas targeted for winter 2028 subject to FID timing. The terminal is advised to have a supply capacity of up to 405 TJ/d or 110 PJ/y. Reversal of the SEA Gas Pipeline would allow flow from Adelaide to Port Campbell in Victoria, although flows from Port Campbell to Melbourne would be limited by the capacity of the SWP, so the project will not increase DTS supply capacity.
  - AG&P LNG is continuing to work on the interim Adelaide Energy Bridge project, which aims to supply gas for South Australia via a regasification facility at Bolivar. The interim project is expected to be available within 12 months of capacity reservation agreement being reached and will run until Outer Harbor LNG Project is ready for commencement.

5.1.4 SWP expansion options

The SWP is a major source of gas supply for Melbourne and the rest of Victoria, particularly during the winter peak demand period. Supply includes production from offshore Otway Basin gas fields and flexible supply from Iona UGS, which is critical for supporting demand during cold weather and periods of high GPG demand. The SWP is capacity-constrained, resulting in high prices being paid by market participants to secure access to this pipeline.

As production at the Longford Gas Plant continues to reduce due to depletion of the Gippsland Basin fields, and electrification and coal power station retirements result in increased GPG demands, particularly during winter, there is an increased need for reliable and flexible gas supplies. Additional supply capacity is proposed from the Iona UGS facility (in addition to the HUGS Phase 1 expansion to 615 TJ/d that reached FID in July 2024) and from a possible Geelong LNG regasification terminal, but limited SWP transportation capacity would restrict full access to this additional supply.

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[97] Victorian Government 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.

[98] Vopak, 30 September 2025, at https://victoriaenergyterminal.com.au/media-releases/vopak-secures-critical-vessel-for-port-phillip-bay-lng-import-terminal-project.

[99] Squadron Energy, "Port Kembla Eergy 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.

[100] Jemena, Jemena takes crucial next step to avoid gas shortfall, 21 February 2025, at https://www.jemena.com.au/media/jemena-takes-crucial-next-step-to-avoid-gas-shortfall/.

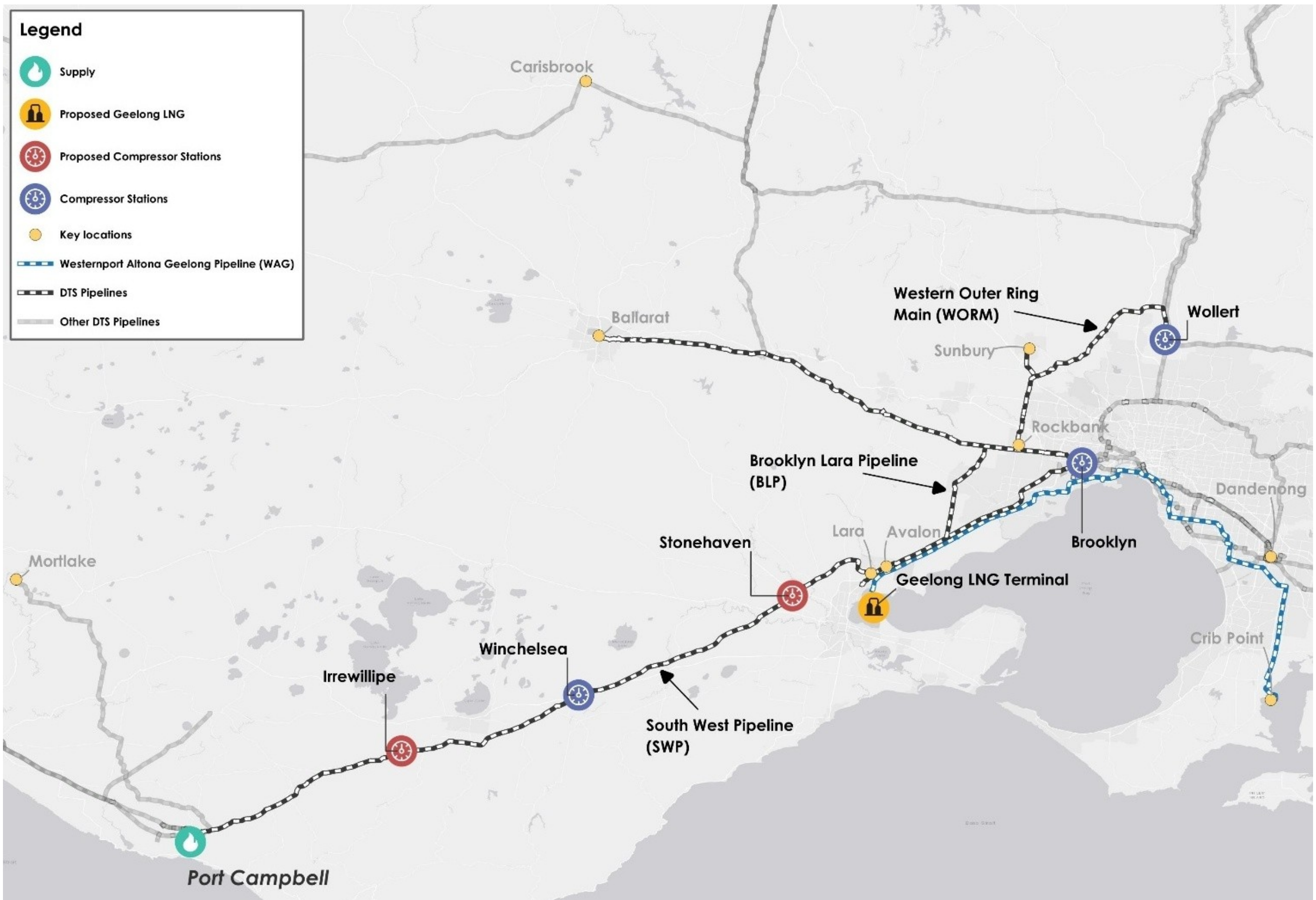
[101] AG&P LNG, AGP LNG agrees to acquire Venice Energy, 24 October 2024, at agp-lng-agrees-to-acquire-venice-energy-a-2-mtpa-lng-import-terminal-developer-at-outer-harbor-in-port-adelaide-australia.pdf.

APA, as the asset owner and planner of the DTS, lodged an application with the AER on 31 October 2025 seeking pre-approved capital expenditure to expand the SWP under rule 80[102] of the NGR. APA's proposed first stage expansion options involve either compression or looping focused solutions to increase SWP capacity to 615 TJ/d, aligning with the increased Iona UGS supply capacity. Additional capacity expansion strategies were also presented, including a potential Stage 2 option that could address potential future requirements for capacity increases in Port Campbell – for example, Lochard Energy's proposal to further expand the Iona UGS facility capacity by an additional 70 TJ/d to 685 TJ/d.

SWP capacity from Port Campbell expansion options

Figure 37 shows APA's proposed SWP expansion, existing DTS infrastructure and other potential project locations.

Figure 37 South West Pipeline expansion options and other potential project locations



On 15 December 2025, the Victorian Minister for Energy and Resources formally requested that AEMO provide a comprehensive technical assessment and advice regarding APA's proposed expansion of the SWP. In response, AEMO undertook the requested technical and operational analysis, as opposed to an economic analysis, of APA's proposal. This

102 AER – Public Forum – APA VTS – r80 application for the south west pipeline, page 5 – Combined presentation slides, at https://www.aer.gov.au/system/files/2025-12/AER%20-%20Public%20Forum%20-%20APA%20VTS%20-%20r.80%20application%20for%20the%20South%20West%20Pipeline%20-%20Combined%20presentation%20slides%20-%2011%20December%202025.pdf.

analysis included an assessment of a range of options to increase SWP capacity including pipeline looping with various diameters, compression, or a combination of both.

A public version of this report, the *South West Pipeline Expansion Options Assessment Report*, was submitted to the AER[103] and will be published on the AEMO website with this VGPR[104]. The report evaluated APA's proposed options for expanding the SWP to increase supply from Port Campbell. **Table 19** provides a summary of the SWP expansion options involving compression and looping solutions.

At the AER Public Forum on 11 December 2025, APA advised that both of the Stage 1 compression only and looping only options to increase SWP capacity to 615 TJ/d could be operational by winter 2029[105]. APA has since advised AEMO that this timing was dependent on the AER making a final determination by February 2026.

APA has also since advised that the earliest that the Stage 1 looping only option could be brought online is mid-2030, with significant timing risk due to the expectation that an EES will be required. This is after the forecast large reduction in Longford Gas Plant capacity ahead of winter 2029 to approximately 350 TJ/d. AEMO has previously highlighted the time required to construct gas pipelines in Victoria, with the WORM Pipeline project taking over six years to reach completion, from approval by the AER in 2017 through to commissioning in February 2024[106]. However, unlike the WORM, there is the existing SWP pipeline easement which is understood to have space for a second pipeline.

At the AER Public Forum, APA outlined the long-term benefits of the looping only option including increased linepack and support for future GPG development, particularly when further looping is added, compared to the compression option. However, APA's cost estimation of the alternative Stage 1 looping only option presented at the forum was significantly higher at $331.2 million compared to the $195.3 million projected for the Stage 1 compression only option.

Due to the estimated project schedule and risk, and additional capital cost, APA prefers the Stage 1 compression only option, and it is the only option that is currently able to be completed prior to winter 2029 under existing project timelines.

Table 19 South West Pipeline compression and partial looping expansion options

Option	Expansion description	SWP capacity (TJ/d)
Base	Existing SWP import capacity from 2025 VGPR	523
Stage 1		
Compression only	Stonehaven compressor station and Irrewillipe compressor station Winchelsea modification for parallel operation	615
Looping only	88 km of pipeline duplication (looping) Winchelsea modification for parallel operation	615
Stage 2		
Compression and looping	Option 1 plus 55 km looping	705
Looping only	Option 2 plus 41 km looping (total 129 km of looping)	715

Note: The modelling in **Table 19** was completed using 2025 VGPR data input and assumptions. The base SWP import scenario capacity modelled is 523TJ/d as reported in 2025 VGPR compared to the SWP import capacity of 515 TJ/d modelled in 2026 VGPR Update.

[103] AEMO, Submission on APA's rule 80 application, February 2026, at https://www.aer.gov.au/system/files/2026-02/AEMO%20-%20Submission%20on%20APA%E2%80%99s%20rule%2080%20application%20-%20February%202026.pdf.

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

[105] AER Public Forum 11 December 2025 – APA VTS – R80 SWP combined slides, at https://www.aer.gov.au/documents/aer-public-forum-apa-vts-r80-application-south-west-pipeline-combined-presentation-slides-11-december-2025.

[106] 2024 VGPR Update, Section 4.2.4 Project uncertainties, at https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

The following is a high level summary comparing the SWP augmentation options listed in **Table 19** with additional information available in the *South West Pipeline Expansion Options Assessment Report*:

- APA's preferred Stage 1 compression only option to expand the SWP by installing two new compressors at new locations, Irrewillipe and Stonehaven, and modifying the existing compressor station at Winchelsea would introduce reliability risks and operational issues associated with the proposed single large unspared compressors.
- APA's Stage 2 compression and looping expansion option involves the addition of a total of 55 km of pipeline looping after construction of the Stage 1 compression only option. The looping would be constructed, upstream and downstream of both the proposed Irrewillipe and Stonehaven compressor stations, which would increase SWP capacity to 705 TJ/d (from 615 TJ/d). However, if either the Irrewillipe and Stonehaven compressor stations are not operating, the SWP capacity increase provided by these new compressors and the associated enhanced compression and looping is largely negated, and the resultant SWP capacity increase would be significantly diminished.
  - In comparison to APA's Stage 2 compression and looping expansion option, if the starting point was the Stage 1 looping only option, which adds a total 88 km of pipeline duplication upstream and downstream of the existing Winchelsea Compressor Station, adding an additional 41 km of looping to continue the 88 km pipeline duplication back to Port Campbell (129 km of total looping) would increase SWP capacity to 715 TJ/d (from 615 TJ/d).
  - A further stage after this Stage 2 looping only option (which increases SWP capacity to 715 TJ/d) could be adding 24 km to the looping downstream of the initial 88 km of looping. This would result in full duplication of the SWP from Port Campbell to Lara, and would increase SWP capacity to 770 TJ/d.

AEMO also undertook additional modelling of the four options in **Table 20** to demonstrate the SWP capacity impact if any of the compressors trip while in operation.

- The modelling results in **Table 20** show the SWP capacity impacts for the Irrewillipe and Stonehaven compression options (including looping around these new compressors) from **Table 19**. For APA's preferred Stage 1 compression only option, the scenario without a compressor running at Stonehaven would have a SWP capacity reduction of 100 TJ/d, which would increase the risk of a gas supply shortfall on a peak demand day. Similarly for the modelling of APA's Stage 2 compression and looping option, if either the Irrewillipe or the Stonehaven compressor was not available, SWP capacity would also reduce by over 100 TJ/d. This highlights that in the scenario of either the Irrewillipe or Stonehaven compressors being unavailable, the capacity benefits of these compression and looping options are negated.
- The modelling results in **Table 21** show the SWP capacity impacts of Winchelsea compressor trips for the looping only options. Compared to the Irrewillipe and Stonehaven compression options, the impact of a Winchelsea compressor trip is much lower, particularly for the Stage 2 looping only option (129 km of SWP duplication) where the capacity reduction is only 28 TJ/d.

Table 20 SWP capacity dependency for compression options with unit unavailability

Configuration	Irrewillipe	Winchelsea	Stonehaven	Stage 1 compression only	Stage 2 compression and 55 km of looping
1-2-1	Online	Online (2 units)	Online	615 TJ/d	705 TJ/d
0-2-1	Offline	Online (2 units)	Online	550 TJ/d	600 TJ/d
1-1-1	Online	Online (1 unit)	Online	570 TJ/d	650 TJ/d
1-2-0	Online	Online (2 units)	Offline	515 TJ/d	592 TJ/d

Table 21 SWP capacity dependency for looping options with unit unavailability

Configuration	Irrewillipe	Winchelsea	Stonehaven	Stage 1 looping only (88 km)	Stage 2 looping only (129 km)
0-2-0	-	Online (2 units)	-	615 TJ/d	715 TJ/d
0-1-0	-	Online (1 unit)	-	550 TJ/d	687 TJ/d

AEMO also modelled the potential expansion scenario option that starts with the two compressors at Irrewillipe and Stonehaven (APA's preferred Stage 1 compression only option) with 144 km of looping added to fully duplicate the SWP from Port Campbell to Lara. The modelling shows that the capacity added by the new compressor at Irrewillipe is heavily diminished; that is, the SWP capacity reduction caused by the Irrewillipe compressor being unavailable is minimal.

Impact of a potential LNG regasification terminal on SWP expansion options

As reported in the 2025 VGPR, a potential LNG regasification terminal project connecting to the SWP near Geelong in would increase SWP transportation 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 if an LNG regasification terminal connected to the SWP closer to Melbourne.

A requirement of the *South West Pipeline Expansion Options Assessment Report* (produced by AEMO at the request of the Victorian Minister) was to model the proposed SWP expansion options above, with a potential LNG regasification terminal project connected to the SWP at Lara or Avalon. Both the Stage 1 compression only and the Stage 1 looping only SWP expansion options generally provide similar SWP capacity increases with an LNG regasification terminal connected to the SWP. However, for some operating conditions the compression only option provides a limited increase in SWP capacity when the flow from Port Campbell is below the minimum capacity of the large compressors proposed to be installed at Irrewillipe and Stonehaven.

A substantial reduction of the back-off effect impacting Port Campbell supply due to the introduction of a Geelong LNG regasification terminal can be achieved by duplicating the pipeline between Lara and Rockbank, which is at the start of the WORM pipeline. This would result in a combined SWP supply capacity from Port Campbell and from an LNG terminal of over 1,000 TJ/d.

Further details are in the *South West Pipeline Expansion Options Assessment Report*[107].

5.1.5 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 this is currently the only available technology to help decarbonise many industries while also supporting energy security, and integrating with the existing natural gas infrastructure. While there are no material changes to the renewable gas projects listed in 2025 VGPR, there has been progress by Delorean Corporation on the development of the VIC1 Stanhope Bioenergy Plant where it is currently working on finalisation of design and completing preparatory work required to reach FID, which is expected in the first half of 2026.

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

To support the development of renewable gas and gas supply adequacy, the Victorian Government released a Gas Security Statement in June 2025[108]. It outlines the strategies the Victorian Government will be implementing to reduce gas demand, such as new energy efficiency schemes and the development of the Industrial Renewable Gas Guarantee (IRGG) scheme, a market-based certificate scheme. The Victorian Government is currently consulting on the design of the IRGG, which will aim to deliver renewable gas to the system and ensure the availability of high heat gas and methane feedstock to industries as required, with a target of 4.5 PJ by 2035[109].

5.1.6 Domestic Gas Reservation Policy

On 22 December 2025, the federal Energy Minister announced the introduction of the domestic gas reservation scheme requiring exporters to reserve between 15% and 25% of gas production for the domestic market. Detailed design of the scheme will be developed in consultation with industry, with the aim of commencing a gas reservation scheme in 2027[110].

5.1.7 Offshore exploration and development program

Beach Energy will resume its Otway drilling program (after the Hercules-1 well failed to intersect hydrocarbons in Q4 2025) during the first half of 2026. It includes a well intervention at Thylacine West, drilling and completing the La Bella 2 development well, and completing the Artisan discovery. FID on the connection of the La Bella 2 and Artisan wells is expected during the second half of 2026.

ConocoPhillips with joint venture partners completed its Otway drilling campaign in Q1 2026, resulting in significant gas discovery of two new gas fields, Essington and Charlemont, which were estimated prior to drilling to hold approximately 385 PJ of gas. ConocoPhillips may consider additional wells in the Otway region under the approved environmental plan[111]. The wells are expected to connect to existing gas plant infrastructure in the Port Campbell region, subject to further agreements.

Amplitude Energy is commencing wire line logging operation at the Isabella prospect to collect pressure and sample data which will inform estimated volumes and gas composition at the site. Amplitude Energy intends to drill prospective wells at Annie-2 and Juliet-1, then exercise its remaining drilling slot option for the Nestor prospect in Q3 2026 as part of its expanded ECSP. Amplitude is targeting first gas for these new wells in 2028[112], and potentially bringing the Athena Gas Plant capacity up to 130 TJ/d during the initial period of production. FEED for the Athena Plant upgrade and subsea development to tie in these new wells is nearing completion and FID is expected in Q3 FY26.

Gas from any successful wells could potentially contribute replacement supply into the southern market later in the decade.

Table 22 gives an overview of the remaining activities planned for the Otway Basin.

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[108] Victorian Government, Gas Security Statement, 24 June 2025, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0032/755771/Victorian-Gas-Security-Statement.pdf.

[109] Victorian Government, Victoria's Gas Substitution Roadmap, 31 December 2025, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0028/775612/victorian-gas-substitution-roadmap-2025.pdf.

[110] Minister for Industry and Innovation and Minister for Science, Affordable gas for Australian homes and business, 22 December 2025, at https://www.minister.industry.gov.au/ministers/timayres/media-releases/affordable-gas-australian-homes-and-businesses.

[111] ConocoPhillips, January 2026 Project Update, 21 January 2026, at https://conocophillipsaustralia.mysocialpinpoint.com/otway-exploration-drilling-program/january-2026-project-update.

[112] Amplitude Energy, Q2FY26 Quarterly Report, 21 January 2026, at https://app.sharelinktechnologies.com/announcement-preview/asx/365cf65b1025a47fed1567c0ba78d56f.

Table 22 Otway Basin activities

Company	Activity	Field	Targeted wells	Production facility to be processed at
Amplitude Energy	Exploration well drilling	Annie, Juliet, Isabella, Nestor	4	Athena
Beach Energy	Exploration well drilling and Artisan connection	La Bella, Artisan	1	Otway

On 11 December 2025, the Australian Government announced five new areas available for exploration in the Otway Basin[113], and on 10 December 2025, the Victorian Government announced two new areas available for petroleum exploration. The two new areas, VIC/25-1 and VIC/25-2, are in offshore Otway Basin and onshore Gippsland Basin respectively[114].

5.2 Project risks and uncertainties

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. The 2026 VGPR Update contains few potential projects, with timelines that are subject to change based on risk and uncertainties, making the analysis of system adequacy difficult. All projects currently underway or proposed in the VGPR outlook period – including gas supply projects, LNG receiving 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 23** summarises uncertainties that could impact project progression. The recent geopolitical events in the Middle East may create more uncertainty and risk for projects.

Table 23 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 been trending upwards since May 2025 leading to a 25 basis point interest rate hike in February 2026 and further interest rate hikes are likely in 2026.
Financing	Natural gas, as a fossil fuel, is becoming less appealing to some investors who are screening investments based on ESG issues. This creates challenge for smaller industry players with limited capital who depend on external financing. Listed companies may also face challenges on ESG grounds for any investment in gas from their shareholder base. This affects to all gas projects, including production, storage, GPG projects, 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	Progression of 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, such as the GO scheme, GreenPower, Hydrogen Headstart program, and Hydrogen Production Tax Incentive (HPTI) programs are available to support renewable gas projects.

[113] Minister for the Department of Industry, Science and Resources, Opening new areas for offshore gas exploration, 11 December 2025, at https://www.minister.industry.gov.au/ministers/king/media-releases/opening-new-areas-offshore-gas-exploration.

[114] Resources Victoria, at https://resources.vic.gov.au/geology-and-data/oil-gas/How-to-get-a-petroleum-exploration-permit/apply-for-a-petroleum-exploration-permit-tender-2025.

A1. System capability modelling

A1.1 Monthly peak demand for 2026-2030

Table 24 shows forecast peak day system demand for each month from 2026 to 2030. The forecast peak day system demand will be used to inform the amount of capacity certificates for any month and capacity certificate type[115].

Table 24 Forecast monthly 1-in-20 year peak day demand from 2026 to 2030 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2026	404	416	501	681	881	1,000	1,024	970	902	769	673	485
2027	396	411	489	665	860	972	1,000	947	882	754	662	476
2028	389	407	480	649	837	945	971	920	857	733	642	466
2029	377	396	471	623	807	913	937	889	824	710	621	457
2030	366	381	448	597	770	869	892	846	785	676	595	436

A1.2 Capacity certificate zones

There is no change to the capacity certificate zones that AEMO determined and published in the 2026 VGPR. **Table 25** shows the capacity certificate zones and the system points allocated to the capacity certificate zones.

Table 25 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	LMP to Melbourne (Figure 38)
Gippsland exit zone	VicHub withdrawal point TasHub withdrawal point	LMP to Longford (Figure 39)
Melbourne entry zone	Dandenong LNG injection point	(Table 27)
South west entry zone	Iona injection point SEA Gas injection point Otway injection point Mortlake injection point	SWP to Melbourne (including Western Transmission System [WTS] demand) (Figure 40)
South west exit zone	Iona withdrawal point SEA Gas withdrawal point Otway withdrawal point	SWP to Port Campbell (Figure 41)
Northern entry zone	Culcairn injection point	VNI to Melbourne (Figure 42)
Northern exit zone	Culcairn withdrawal point	VNI to New South Wales via Culcairn (Figure 43)

[115] 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 2025 VGPR except for the changes outlined in **Table 26**.

Table 26 Changes to Victorian gas planning approach from the 2025 VGPR

Location	Change description
Peak day system demand forecast	1-in-2 and 1-in-20 peak system demand forecasts for 2026 have decreased significantly compared to the 2025 VGPR.
Epping lateral	Recalibrated pipeline lateral to improve accuracy of delivery pressure in the model.

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 certificate zone.

A1.3.1 Longford to Melbourne Pipeline

Figure 38 Longford to Melbourne Pipeline injection capacity to Melbourne (TJ/d)

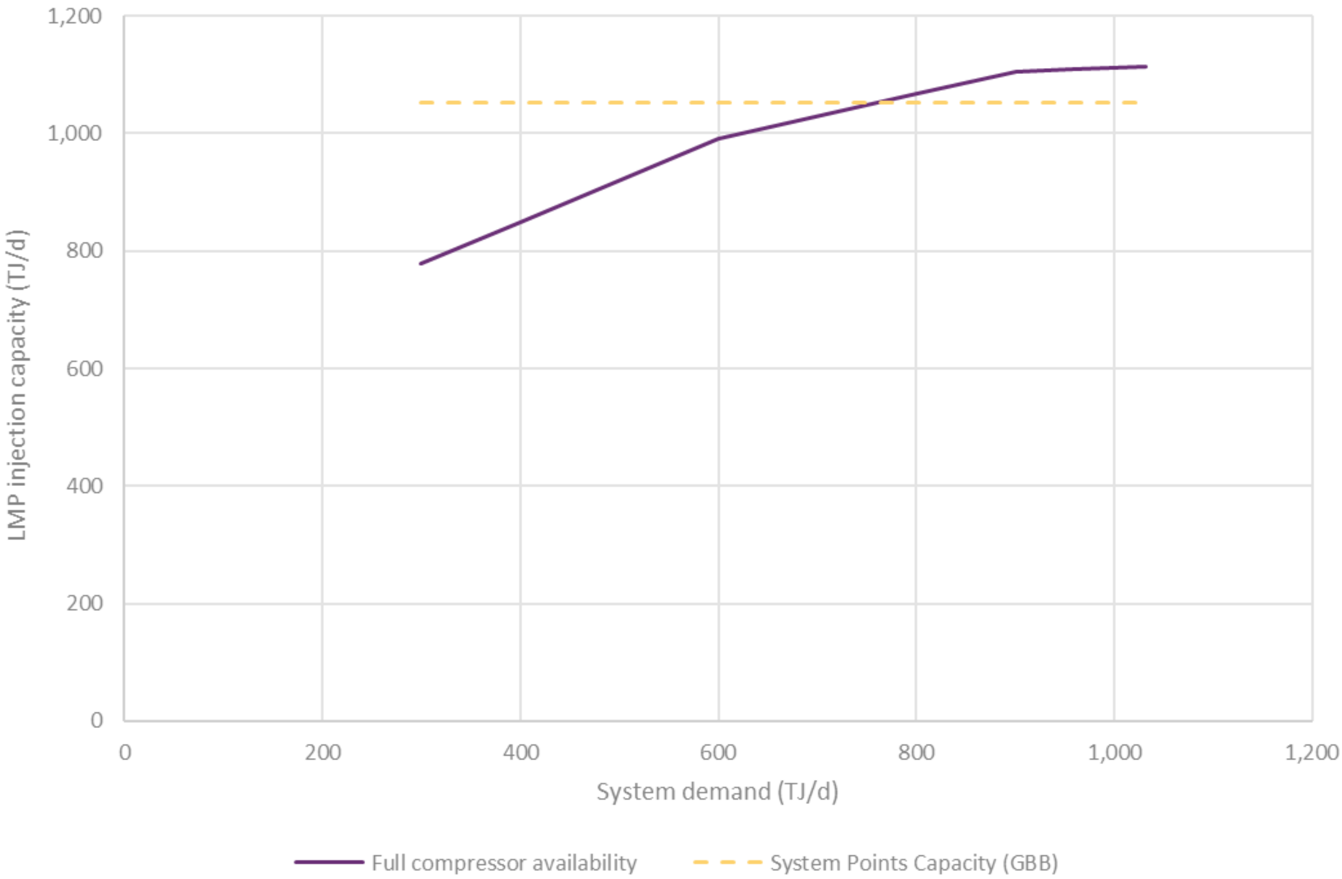
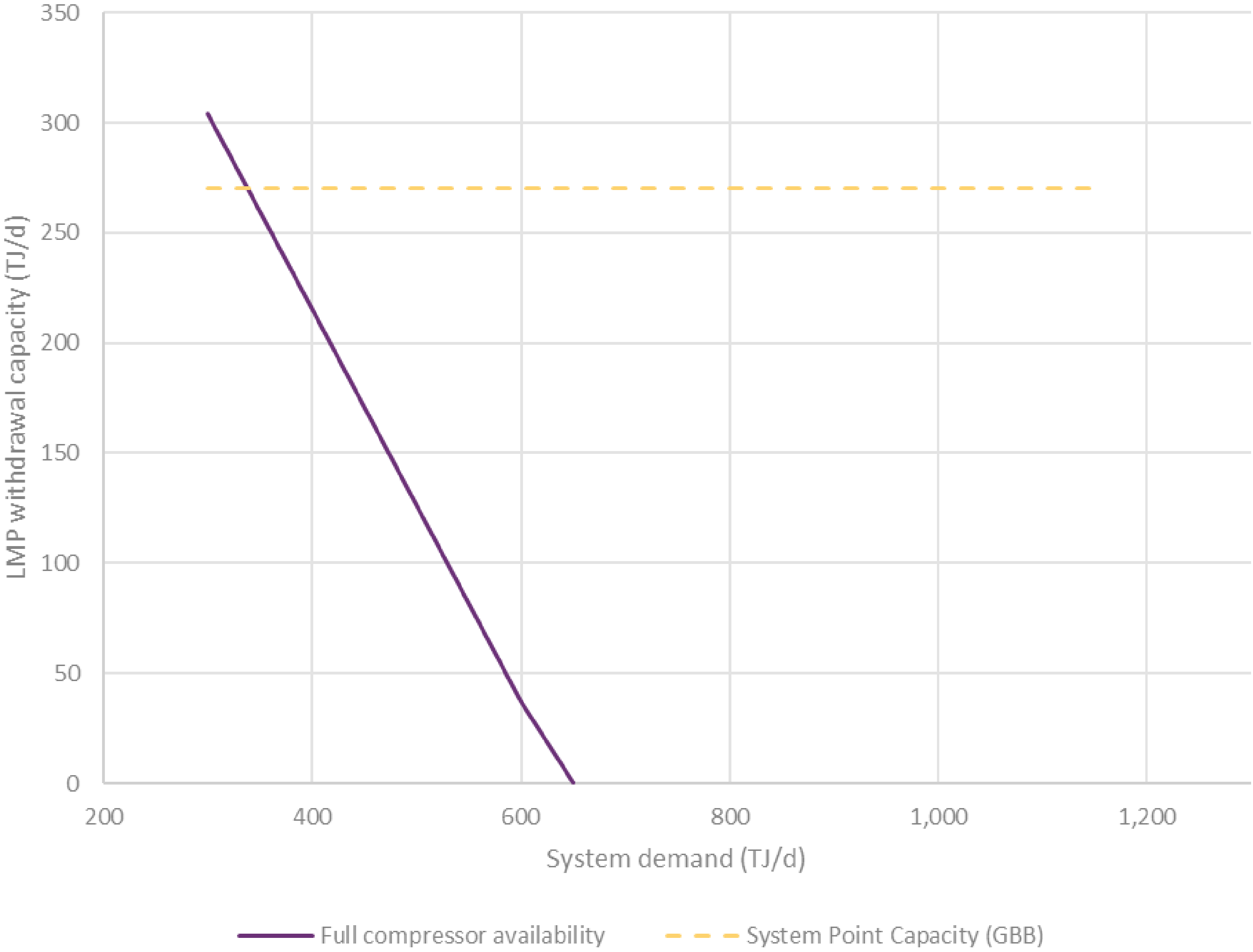


Figure 39 Longford to Melbourne Pipeline withdrawal capacity to Longford (TJ/d)



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 because the quantity of capacity certificates to be auctioned is the lower of the maximum pipeline capacity or the maximum facility capacity.

Table 27 Melbourne entry zone capacity

Capacity certificate zone	System capability modelling (TJ/d)	System points capacity (TJ/d)	Notes
Melbourne entry zone	238	238	This assumption will be reviewed if another system point connects to the Melbourne zone.

A1.3.3 South West Pipeline

Figure 40 South West Pipeline injection capacity to Melbourne (TJ/d)

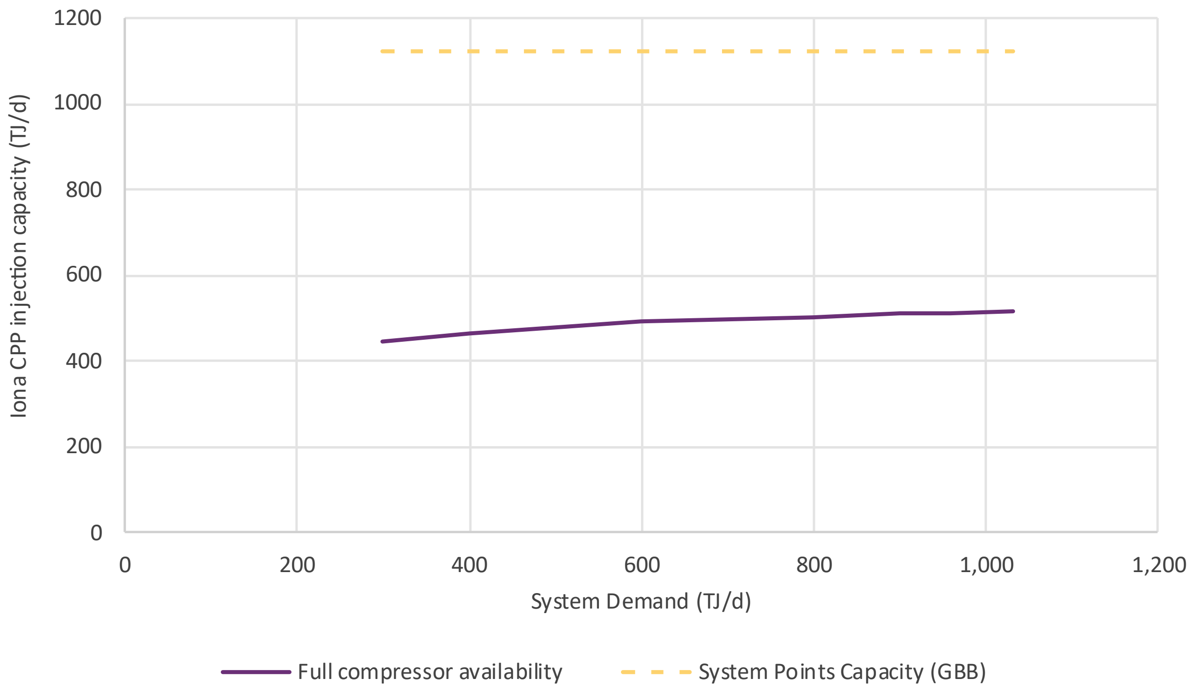
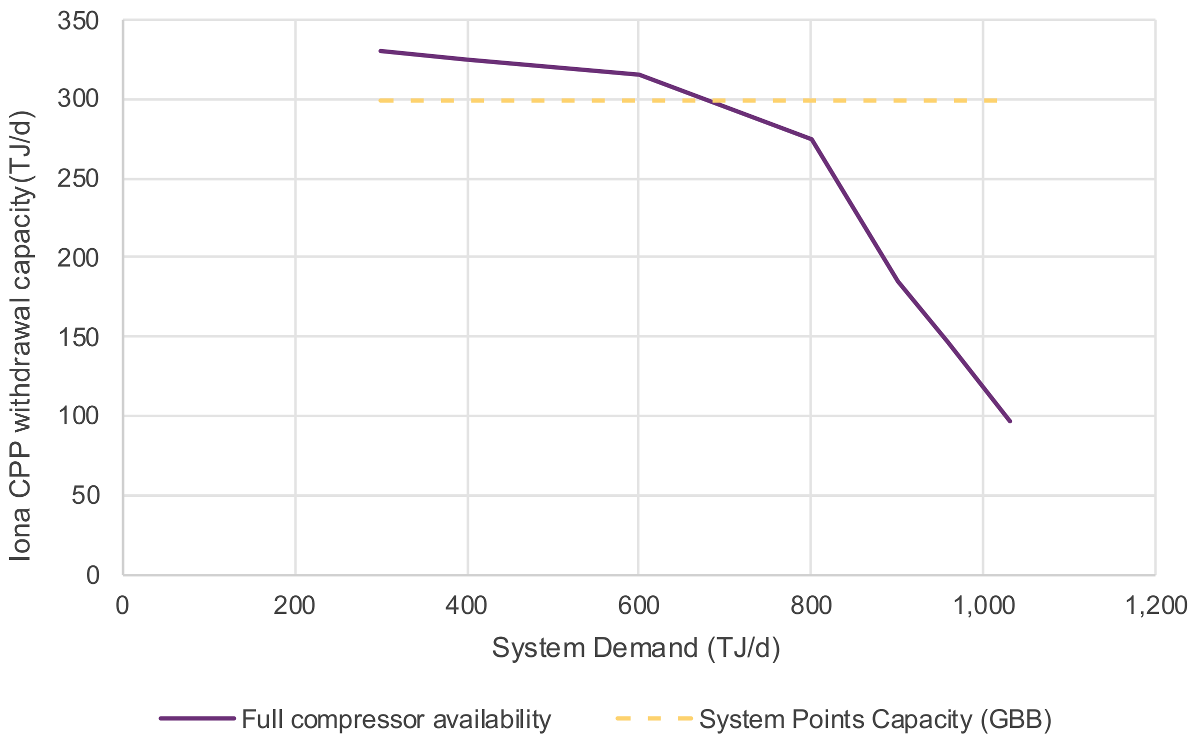


Figure 41 South West Pipeline withdrawal capacity to Port Campbell (TJ/d)



A1.3.4 Victorian Northern Interconnect

Figure 42 Victorian Northern Interconnect import capacity (TJ/d)

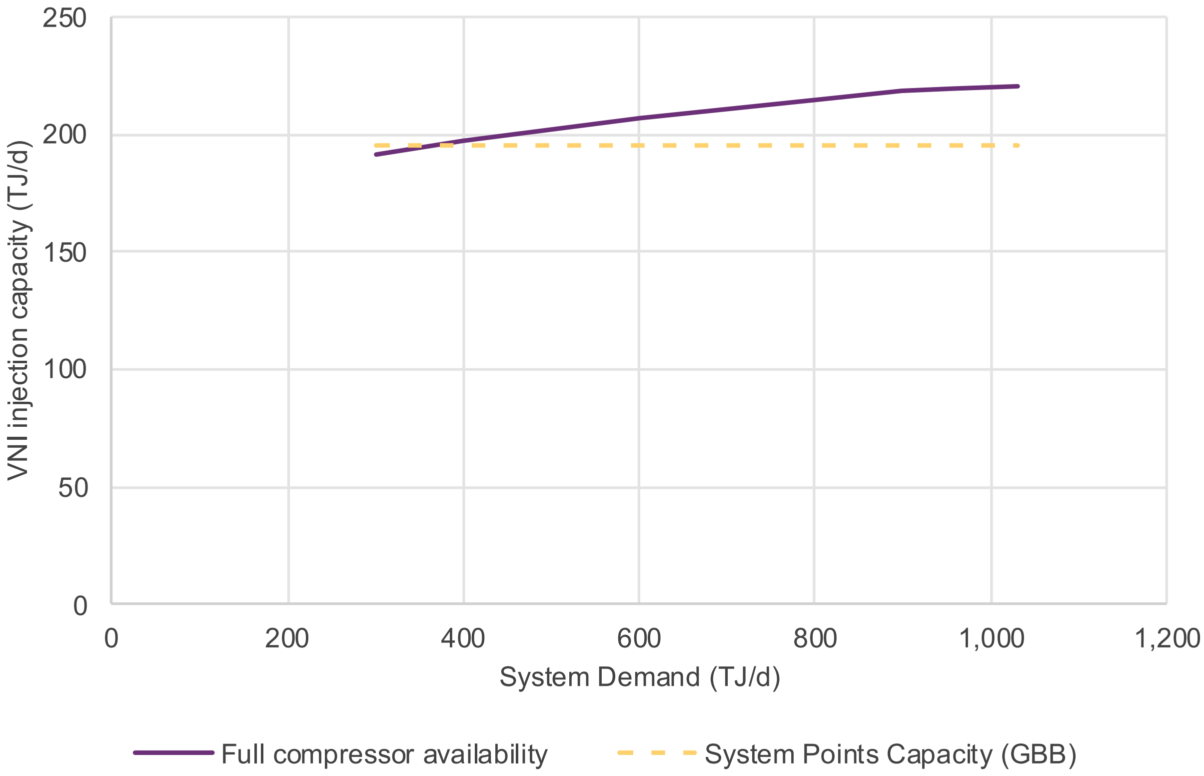
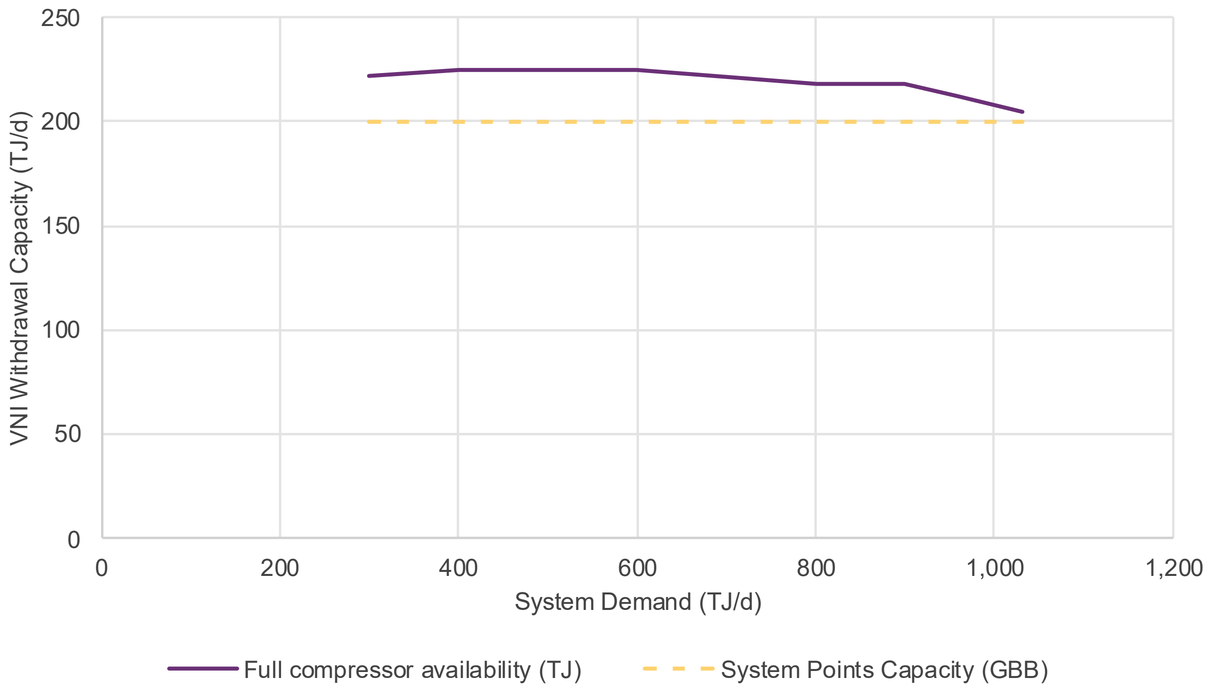


Figure 43 Victorian Northern Interconnect export capacity (TJ/d)



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Measures, abbreviations and glossary

Units of measure

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

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AMDQ	authorised maximum daily quantity
BBP	Brooklyn–Ballarat Pipeline
BCP	Brooklyn–Corio Pipeline
BLP	Brooklyn–Lara Pipeline
CG	city gate
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
ESG	environment, social and governance
ESV	Energy Safe Victoria
FEED	front end engineering design
FID	final investment decision
FSRU	floating storage and regassification unit
GBJV	Gippsland Basin Joint Venture
GSA	gas supply agreement
GSOO	Gas Statement of Opportunities
HUGS	Heytesbury Underground Gas Storage

Term	Definition
IASR	Inputs Assumptions and Scenarios Report
ISP	Integrated System Plan
KUJV	Kipper Unit Joint Venture
LNG	liquefied natural gas
MAOP	maximum allowable operating pressure
MDQ	maximum daily quantity/ies
MHQ	maximum hourly quantity/ies
MSP	Moomba Sydney Pipeline
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
PKET	Port Kembla Energy Terminal
POE	probability of exceedance
PRMS	Petroleum Resources Management System
SEA Gas	South East Australia Gas (pipeline)
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
SWZ	System Withdrawal Zone
TGP	Tasmania Gas Pipeline
UAFG	unaccounted for gas
UGS	Underground Gas Storage
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.
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.

Term	Definition
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.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the DWGM) or may be registered as market participants in their own right.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the National Gas (Victoria) Act, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Wholesale Gas Market	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.
distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The EDD is used to model the daily relationship between weather and gas demand.
electrification	The conversion of technologies or systems to use electrical power. In the context of the VGPR, this most often refers to converting appliances or industrial processes from using natural gas to electricity.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
gas consumption	Gas consumption refers to total gas demand used over longer periods (months and years)
gas demand	Gas demand refers to short-term gas use (hours and days).
gas generation	Where electricity is generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).
Gas Statement of Opportunities	Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia published annually by AEMO.
gas supply	The total volume of gas a facility is able to supply on an annual basis.
gas supply capacity	The maximum volume of gas a facility is able to supply in a single day.
gigajoule	An International System of Units (SI) unit. One GJ equals 1 x 10^9 joules.
injection	The physical injection of gas into the transmission system.
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is at Dandenong.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand.
maximum hourly quantity	Maximum hourly quantity (MHQ) of gas supply or demand.
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 loads	Short duration peaks in gas demand.
petajoule	An International System of Units (SI) unit. One PJ equals 1 x 10^{15} joules.

Term	Definition
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
retailer	A seller of bundled energy service products to a customer.
southern states	New South Wales, South Australia, Victoria, the Australian Capital Territory, and Tasmania.
storage facility	A facility for storing gas, including the LNG storage facility and Iona Underground Gas Storage (UGS).
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors; accordingly, a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • Load distribution across the system. • 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 (industrial and large commercial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas generation demand, exports, and gas withdrawn at Iona.
system injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas DTS connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
system withdrawal zone	Part of the gas DTS that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
Tariff D	The gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Tariff V	The gas transportation tariff applying to non-Tariff D load sites. This includes residential and small to medium sized commercial gas consumers.
TasHub	The interconnection between the Tasmania Gas Pipeline (TGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
terajoule	An International System of Units (SI) unit. One TJ equals 1 x 10^{12} joules.
unaccounted for gas	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising gas losses, metering errors, timing, heating value error, allocation error, and other factors.
underground gas storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date. The only UGS currently operational in the DTS is the Iona UGS located in the Port Campbell region.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
Western Transmission System	The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the DWGM and DTS.
Winter peak demand period	In this report is defined as 1 May to 30 September of a given calendar year.