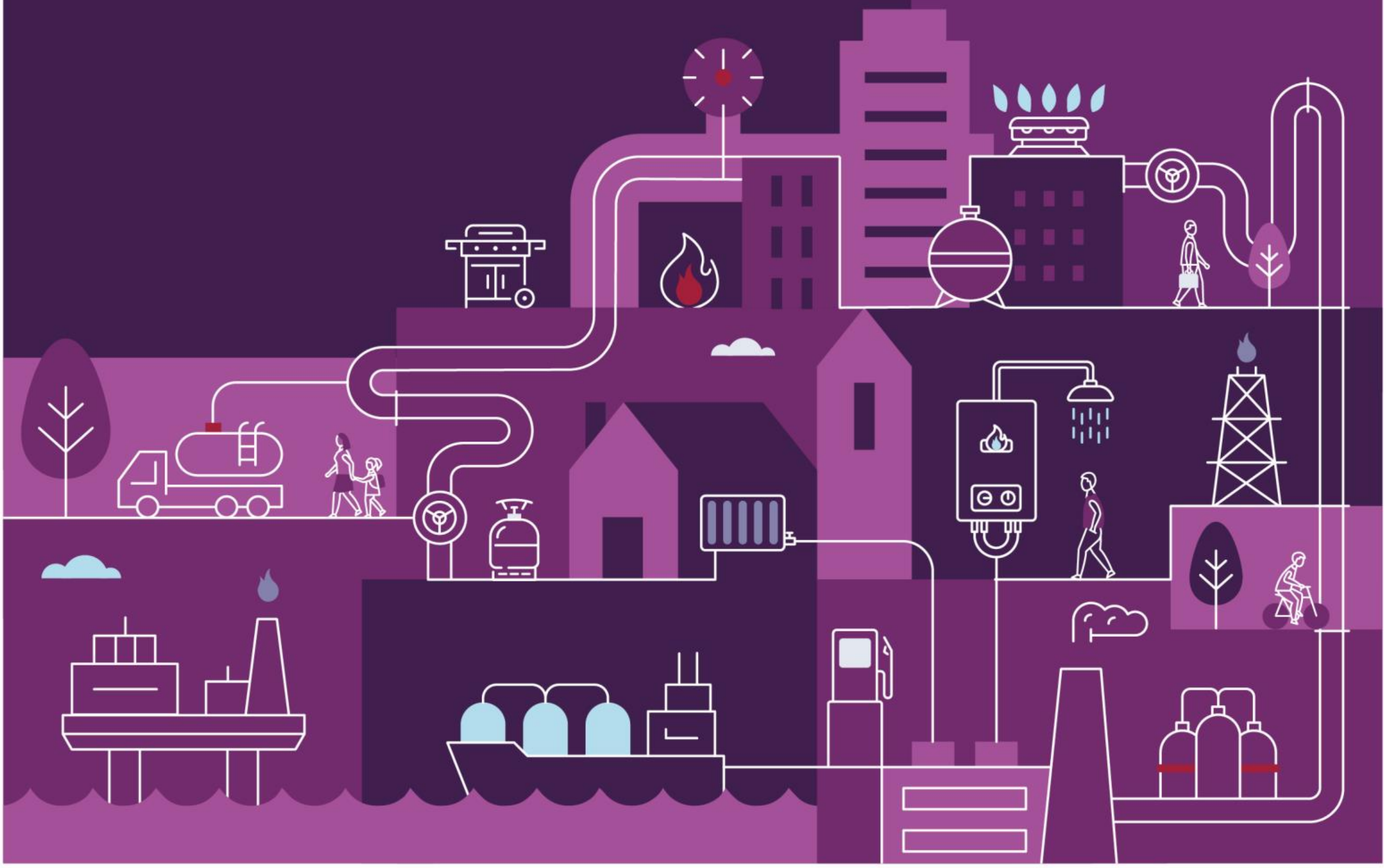
Victorian Gas Planning Report Update

March 2024

Gas transmission network planning for Victoria



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Executive summary

The 2024 *Victorian Gas Planning Report Update* (VGPR Update) provides information about the supply demand balance over the next five years (2024-28, called the outlook period) in Victoria and the Victorian Declared Transmission System (DTS). The 2024 VGPR Update complements AEMO's 2024 *Gas Statement of Opportunities* (GSOO)[1], which assesses wider gas supply adequacy in central and eastern Australia.

Key findings

- **This VGPR Update reinforces the need for more supply in Victoria**, as forecast supply declines faster than forecast consumption, and increased supply capacity is required to support future gas-powered generation (GPG), as highlighted in the Draft 2024 *Integrated System Plan* (ISP).
- **Investment uncertainty in gas supply and infrastructure projects remains high**, and many of the potential projects identified in the 2023 VGPR have not materially progressed and face the same challenges identified in that report.
- **Victoria's production outlook has decreased since the 2023 VGPR**, with less supply available from 2024 through to 2026. The total available gas supply is forecast to reduce by 48% over the outlook period**,** from 297 petajoules (PJ) in 2024 to 154 PJ in 2028.
  - The stepped reduction in forecast production capacity is caused by a reduction in offshore field production capacity in the Gippsland Basin, driven by the decline of the large legacy fields. The Gippsland Basin Joint Venture (GBJV) has advised of planned closures of gas plants at Longford Gas Plant, starting with Gas Plant 1 in July 2024, followed by Gas Plant 3 later in the decade, reducing Longford's maximum daily supply capacity to 700 terajoules per day (TJ/d) and then to 420 TJ/d.
- Retirement of infrastructure at the Longford Gas Plant and the decline of the large legacy fields **reduces redundancy and supply flexibility, which increases the probability of outages**. The tight peak day supply demand balance leaves a small margin for even brief supply issues, where any plant trips or equipment outages in winter within Victoria may result in a gas load curtailment event.
- **Forecast annual gas consumption is lower** under the 2024 *Step Change* scenario than was forecast in the 2023 VGPR under the 2023 *Orchestrated Step Change (1.8°C)* scenario. Forecast 2024 system consumption[2] of 184 PJ is 4.5% lower than the 193 PJ forecast for 2024 in the 2023 VGPR, and AEMO now forecasts a 9.6% reduction in annual system consumption over the outlook period.
  - The lower consumption forecast is partly due to the considerable reduction in industrial and large commercial load in Victoria in recent years, with two of the biggest year-on-year gas consumption decreases on record in the 2022 and 2023 calendar years (decreases of 7.6% and 5.8% respectively).
  - Gas consumption by residential and small commercial users in 2023 also reduced by 13.5% compared to 2022, driven by warm weather conditions, cost-of-living pressures, and electrification of some gas usage.

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

[2] System consumption comprises residential, commercial, and industrial customers, as well as compressor and heater fuel gas, and unaccounted for gas.

- The 2024 GSOO forecasts indicate the potential for **small seasonal supply gaps from 2026**[3], one year earlier than projected in the 2023 GSOO. The supply gaps can likely be managed by industry and if necessary by AEMO, through the development of potential projects, conserving gas storages and by switching gas powered generators to secondary fuels.
- From 2028, **the forecast supply gap in the 2024 GSOO becomes consistent and larger**, with Victoria forecast to become a net importer of gas as Victorian consumption exceeds Victorian production and available storage inventory unless additional potential Victorian supply and storage projects are developed.
- **Peak day supply capacity, including from storage facilities, is forecast to decline by 10%** from the 1,471 TJ/d available in 2023 to 1,324 TJ/d in 2024, and to continue to decline during the outlook period to 882 TJ/d in 2028 (40% lower than capacity in 2023).
- The 1-in-20 peak day shortfall for winter 2027 that was forecast in the 2023 VGPR remains and is now little more than three years away. In winter 2028, forecast system demand exceeds expected supply on both a 1-in-2 and 1-in-20 peak day[4].
  - This shortfall is despite a **forecast 11% reduction in Victorian peak day system demand** across the outlook period.
  - The 2024 GSOO highlights the **risk of peak day shortfalls from 2025 in the event of high coincident system and GPG demand across the southern states**. Peak day gas shortfall risks may be lower if reliance on gas use for electricity generation during periods of peak gas demand is reduced, including through the use of liquid fuels or the management of electricity demand.

Gas consumption forecasts

The forecasts for the 2024 VGPR Update and the 2024 GSOO focus on the *Step Change* scenario outlined in the 2023 *Inputs, Assumptions and Scenarios Report* (IASR). This *Step Change* scenario, identified in AEMO's Draft 2024 ISP as the most likely pathway for Australia's energy sector[5], is a refinement of the 2021 IASR *Step Change* scenario and similar to the *Orchestrated Step Change (1.8°C)* scenario used for the 2023 VGPR, representing a future with rapid consumer-led transformation of the energy sector.

Both the *Step Change* scenario in the 2023 IASR and the 2023 *Orchestrated Step Change (1.8°C)* scenario require new policy to be developed to further enable the electrification (switching from other fuels to electricity) and decline of gas consumption. This requirement for new policy is aligned with Victoria's Gas Substitution Roadmap Update[6] policy and schemes including:

- 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.

[3] "Southern regions" in the GSOO are New South Wales, South Australia, Tasmania and Victoria combined.

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

[5] AEMO, Draft 2024 ISP, pg. 8, at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. *Step Change* was identified as the most likely scenario through extensive engagement with industry, government and consumer stakeholders.

[6] Victorian Government, *Victoria Gas Substitution Roadmap Update*, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

- An expansion of the Victorian Energy Upgrades (VEU) program to include electric induction cooktops, in addition to gas space heating and hot water heaters that were already covered.
- Initiating a Notice of Intent to prevent the offering of inducements for consumers to retain or implement gas connections.

In addition to actions aimed at residential gas use, proposed reforms to the Federal Government's Safeguard Mechanism will require most of Australia's largest emitters to reduce emissions by 4.9% each year to 2030[7]. The combination of these policies has resulted in AEMO forecasting a 6.2% reduction in annual gas consumption, including for GPG[8] and an 11.1% reduction in peak day system demand[9] (excluding gas used for GPG) over the outlook period.

In 2023, DTS gas consumption was very low compared to recent years. Industrial and large commercial customer (Tariff D[10]) consumption decreased by 5.8% compared to 2022, while residential and small commercial customer (Tariff V[11]) consumption decreased by 13.1%, likely due to a combination of factors including near record warm winter conditions[12] reducing the need for space heating[13], and electrification of some existing gas use. Further analysis is required to understand which proportion of the reduction in consumption was due to electrification, compared to the impact of economic and weather conditions.

Table 1 Actual and forecast Victorian annual gas consumption, 2021-28 (PJ/y)

	Actual			Forecast					Change over outlook
	2021	2022	2023	2024	2025	2026	2027	2028	
System consumption	200.9	194.8	173.3	184.4	182.3	177.0	172.7	166.6	-9.6%
DTS GPG consumption	6.2	13.8	3.7	1.7	1.5	2.8	2.5	5.6	227.3%
DTS total consumption	207.1	208.6	177.1	186.1	183.8	179.8	175.2	172.2	-7.5%
Non-DTS system consumption	0.32	0.32	0.28	0.31	0.31	0.31	0.31	0.32	1.6%
Non-DTS GPG consumption	4.3	6.9	3.6	1.1	1.0	2.1	1.7	3.3	216.5%
Victorian GPG consumption	10.5	20.7	7.4	2.8	2.5	4.9	4.2	8.9	223.1%
Total Victorian consumption*	211.7	215.8	181.0	187.4	185.1	182.2	177.2	175.8	-6.2%

* Total Victorian consumption includes total DTS consumption, non-DTS Tariff V and Tariff D consumption at Bairnsdale, and non-DTS GPG consumption at Bairnsdale and Mortlake.

Gas-powered generation forecasts

Figure 1 shows the range of forecast GPG outcomes for Victoria in each year of the outlook period under both the *Step Change* scenario and the *High Coal Generation Outages* sensitivity, compared to actual GPG consumption

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

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

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

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

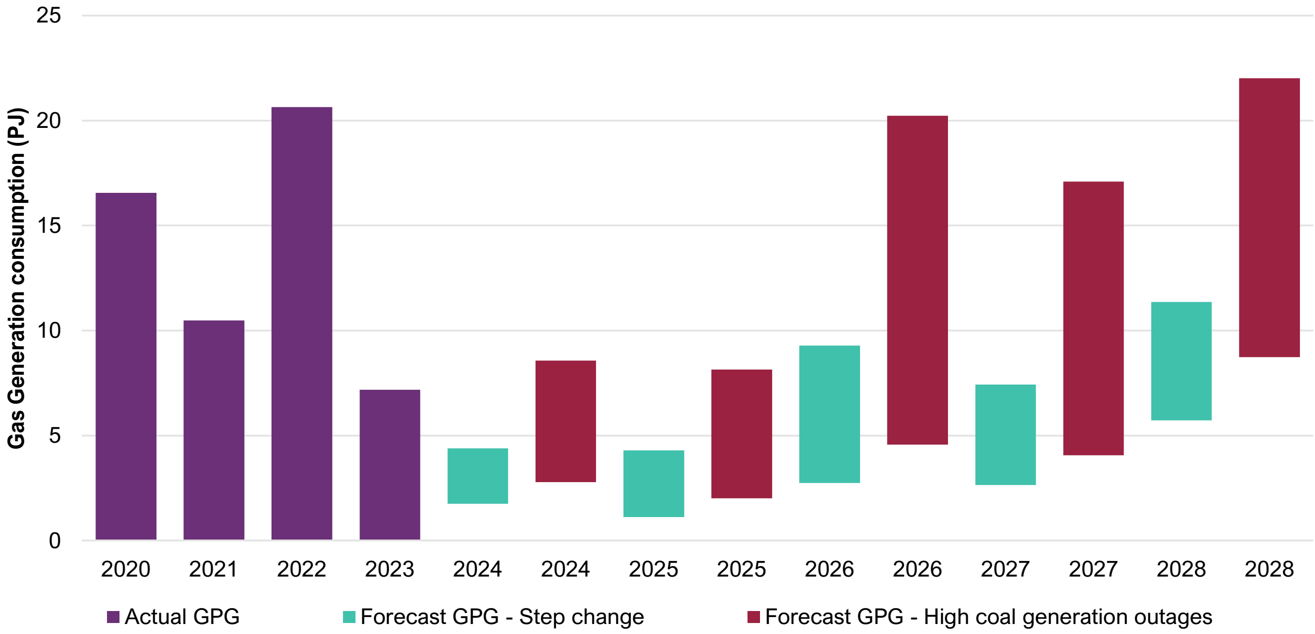
[11] Tariff V customers are loads which do not meet the annual or hourly consumption rate of the Tariff D criteria.

[12] Bureau of Meteorology, Australia climate summary in Winter 2023, at http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml.

[13] Monthly Consumer Price Index Indicator, at https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/monthly-consumer-price-index-indicator/oct-2023.

over the past four years. For actual GPG consumption, 2023 saw a considerable decrease in consumption compared to 2022. Consumption in 2023 is more aligned with the consumption profile from prior years; 2022 was an outlier for GPG consumption due to several compounding incidents including cooler weather, Victorian and New South Wales coal generator outages, and flooding impacting hydro generation.

Figure 1 Actual and forecast minimum and maximum annual Victorian GPG consumption, 2020-28 (PJ)



AEMO's GPG forecasting methodology was developed in line with the *Step Change* scenario in the 2023 IASR to consider thermal fuel limitations on coal generators, and to apply limitations on electricity generation capacity build as per the *Electricity Statement of Opportunities* (ESOO) methodology[14]. Forecast GPG is initially forecast to be lower in the *Step Change* scenario compared to recent years, driven by the continued installation of large amounts of rooftop solar in Victoria. GPG requirements are then forecast to increase from August 2025 following the planned closure of the Eraring coal power station in New South Wales and again after the 2028 closure of Victoria's Yallourn coal power station.

The Draft 2024 ISP sets out the required generation, firming and electricity transmission infrastructure to meet the emissions reductions targets set by Australian governments, and forecasts Victorian GPG capacity increasing from the existing 2.4 gigawatts (GW) to 3.6 GW during the 2030s. GPG is forecast to play a crucial role in complementing battery and pumped hydro generation to support peak demand periods when output from variable renewable energy is limited, including extended periods of low wind and solar generation output. The Draft 2024 ISP forecasts this critical need for peaking GPG increasing during the winter months of June, July and August, representing a shift from historically stable GPG peaks to increased winter demand peaks through to 2040[15].

For the five-year outlook period, GPG peak demands during the winter months are forecast to gradually increase by approximately 50% over the next four years from 2024 to 2027, then step up by over 266% to approximately

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

[15] AEMO, Draft 2024 ISP, pg. 65, at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

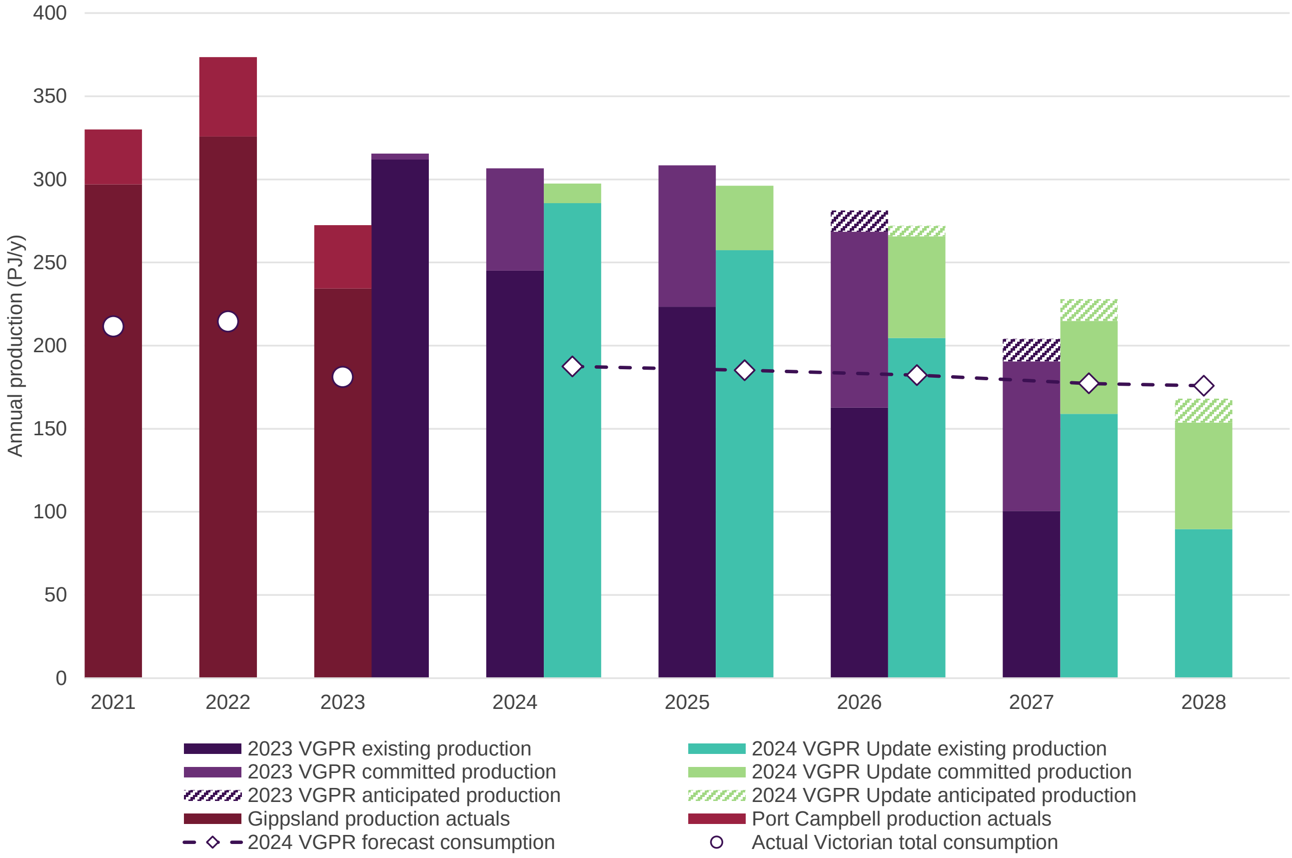
440 TJ/d during winter 2028 following the closure of the Yallourn coal power station[16]. GPG demand peaks during summer months are forecast to remain relatively flat over the outlook period.

The Draft 2024 ISP also highlights that the risk of unplanned generator outages is increasing, as the fleet ages and coal plant reliability is affected by reduced investment (particularly as closure dates approach) and high-impact weather events[17]. This can greatly increase GPG consumption, as evidenced by the high annual GPG consumption during 2022 that was primarily caused by coal generation outages and fuel supply issues. If coal generation was reduced due to an extended outage or fuel supply issue (modelled in the *High Coal Generation Outages* sensitivity), GPG consumption is forecast to increase by approximately 209% over the VGPR outlook period from 2024 to 2028.

Annual supply adequacy

Figure 2 shows that Victoria's annual production is forecast to exceed its declining annual consumption for most of the outlook period. The 2024 GSOO forecasts the potential for small seasonal supply gaps in the southern states to occur from winter 2026 (one year earlier than was reported in the 2023 GSOO) due to increased GPG consumption forecasts in the southern states.

Figure 2 Actual and forecast supply and total consumption, compared to the 2023 VGPR, 2021-28 (PJ/y)



[16] EnergyAustralia, *EnergyAustralia powers ahead with energy transition*, at https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

[17] AEMO, Draft 2024 ISP, pg. 74, at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

Victorian forecast annual supply adequacy has improved for all years compared to the 2023 VGPR (despite lower available[18] supply in 2024 to 2026), due to the lower consumption forecast in the *Step Change* scenario; for example, forecast total consumption for 2024 is 187 PJ, 9.1% lower than the 206 PJ forecast for 2024 in the 2023 VGPR.

Gippsland[19] region production is forecast to reduce by 55% from 243 PJ in 2024 to 109 PJ in 2028. This includes the committed Kipper compression project[20] which is expected to provide additional supply from October 2024. The 243 PJ available in 2024 is comparable to the 234 PJ of actual production in 2023, however the low 2023 production can be attributed to low gas consumption and increased winter supply from Queensland rather than reflecting available production capacity.

The reduction in Gippsland supply over the outlook period is mainly due to the forecast decrease in production associated with the depletion of the Gippsland Basin Joint Venture (GBJV) large legacy fields that supply the Longford Gas Plant. Large reductions in Gippsland production reported in the 2023 VGPR are still forecast to occur in 2024 and 2027, with an additional reduction in 2028.

Production from Port Campbell[21] is forecast to increase from the 38 PJ produced in 2023 to 55 PJ in 2024 with the connection of new gas supply to the Otway Gas Plant including the Enterprise field in mid-2024 and the Thylacine West wells later in 2024. Completion of these projects will return the Otway Gas Plant to nameplate capacity of 205 TJ/d. Connection of these wells has been delayed, reducing forecast Port Campbell production for 2024 from the 73 PJ reported in the 2023 VGPR.

Peak day supply adequacy

Peak day supply to the DTS is forecast to decline by 10% from the 1,471 TJ/d available in 2023 to 1,324 TJ/d in 2024, then to 882 TJ/d in 2028 (40% lower than 2023 supply capacity). The peak day supply capacity includes 87 TJ/d of firm supply from the Dandenong liquefied natural gas (LNG) storage facility[22].

Gippsland producers have advised that maximum peak day production capacity will reduce by 58%, from 767 TJ/d in 2024 to 325 TJ/d in 2028. The actual maximum Gippsland production in 2023 was 872 TJ, which was 4% lower than the forecast available 915 TJ/d published in the 2023 VGPR, and 14% lower than the 1,018 TJ/d available during winter 2022.

The stepped reduction in forecast peak day production capacity is caused by a reduction in offshore field production capacity, driven by the decline of the GBJV large legacy fields. GBJV has advised of the planned closures of gas plants at Longford, starting with Gas Plant 1 in July 2024 and followed by Gas Plant 3 later in the

[18] Available supply comprises existing gas supplies and committed new gas supply projects. Committed supply considers developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational.

[19] 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).

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

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

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

decade, to have onshore production capacity match reducing offshore production capacity as the large legacy fields decline. AEMO has assessed peak day supply adequacy for 2024 using the production capacity following the closure of Gas Plant 1. Prior to the closure of Gas Plant 1, planned for July 2024, up to 810 TJ/d of peak day capacity will be available from Longford in winter 2024[23].

Port Campbell production capacity is forecast to increase from the actual maximum production of 199 TJ/d in 2023 to 211 TJ/d in 2024 and then to 222 TJ/d in 2025, mainly due to supply from the committed connection of the Thylacine West and Enterprise-1 wells to the Otway Gas Plant. Committed Iona Underground Gas Storage (UGS) capacity is forecast to remain steady at 570 TJ/d.

Total Port Campbell supply capacity is also forecast to remain relatively stable over the outlook period, decreasing by 9% from 781 TJ/d in 2024 to 708 TJ/d in 2028. Port Campbell peak day supply capacity into the DTS is forecast to remain at 530 TJ/d due to the capacity of the South West Pipeline (SWP), which has increased following the addition of the second Winchelsea compressor and the construction of the Western Outer Ring Main (WORM) pipeline.

Figure 3 shows forecast peak day supply and DTS adequacy (excluding gas used for GPG), highlighting that in the latest assessment:

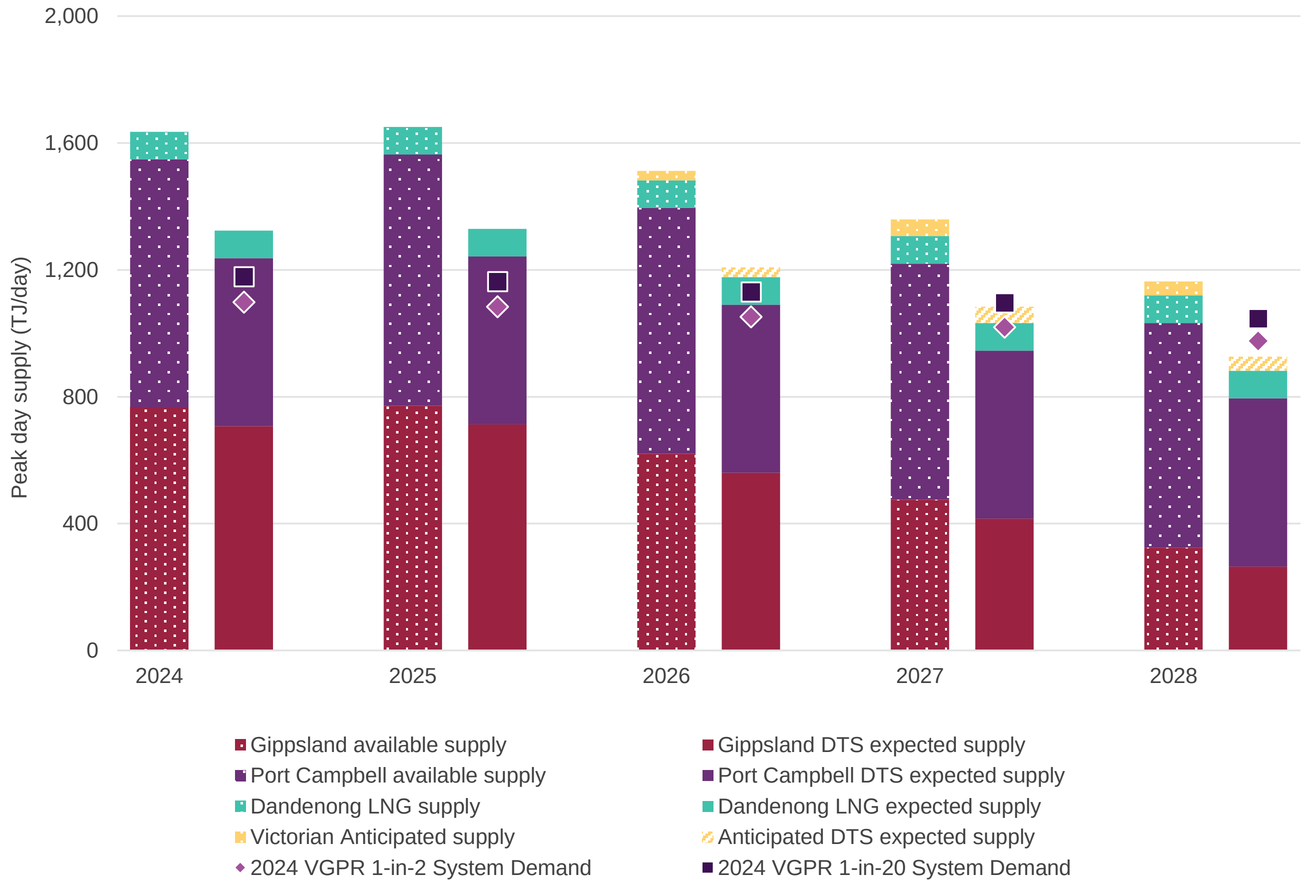
- Peak day supply adequacy for 2024, 2025 and 2027 has improved slightly compared to the outlook in the 2023 VGPR. This is mostly due to a reduction in the peak day demand forecast under the updated *Step Change* scenario.
- There is sufficient peak day supply to meet demand until 2027. Peak day adequacy is tight in 2026, with Dandenong LNG injections required to support a 1-in-20 year system demand day. There is likely to be insufficient supply capacity to support even moderate levels of GPG on a peak day during winter 2026.
- System demand exceeds available supply on a 1-in-20 peak system demand day in 2027, and on both a 1-in-2 and 1-in-20 system demand day in 2028:
  - The forecast peak day shortfall is now four years into the outlook period, instead of five years away as in the 2023 VGPR. As year one of the outlook period is this year, this leaves only three years for projects to be developed and commissioned to resolve these forecast shortfalls.
  - The shortfall quantity may be reduced by anticipated[24] projects, but these projects cannot resolve any of the forecast supply gaps identified in 2027 or 2028.
  - Development of potential[25] supply projects is forecast to be required to avert shortfalls on peak system demand days in 2027 and 2028.

[23] Forecast capacities for winter 2024 are available in the Medium Term Capacity Outlook on the Gas Bulletin Board at: https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb.

[24] Anticipated supply considers gas supply from undeveloped reserves or contingent resources that producers forecast to be available as part of their best production estimates provided to AEMO. It includes projects or developments which have not reached FID but are considered likely to proceed during the outlook period.

[25] Potential projects are uncommitted gas supply projects that have not reached FID but could potentially proceed during the outlook period.

Figure 3 Forecast peak day supply and DTS adequacy, 2024-28 (TJ/d)



The 2024 VGPR Update demand forecasts include an assumption that there is an increasing amount of electrification of mostly residential and small commercial customer gas demand during the outlook period. Sensitivity modelling forecasts that delaying this electrification to beyond the outlook period would bring forward the peak day shortfall year to 2026 and the magnitude of the shortfalls in 2027 and 2028 would increase. This is unchanged from the 2023 VGPR.

The 2024 GSOO highlights the risk of peak day shortfalls in the southern states from 2025 on winter days when extremely cold weather and high system demand for heating load coincides with high gas demand for GPG. The projected frequency of these high demand days increases later in the outlook period, after the planned closure of Eraring coal power station in August 2025. GPG demand is not included in **Figure 3**, and as noted above there is insufficient capacity to support even moderate levels of GPG demand on peak system demand days from winter 2026, which may result in gas supply for GPG being curtailed. The 2024 GSOO has further discussion on east coast gas supply adequacy including GPG supportability.

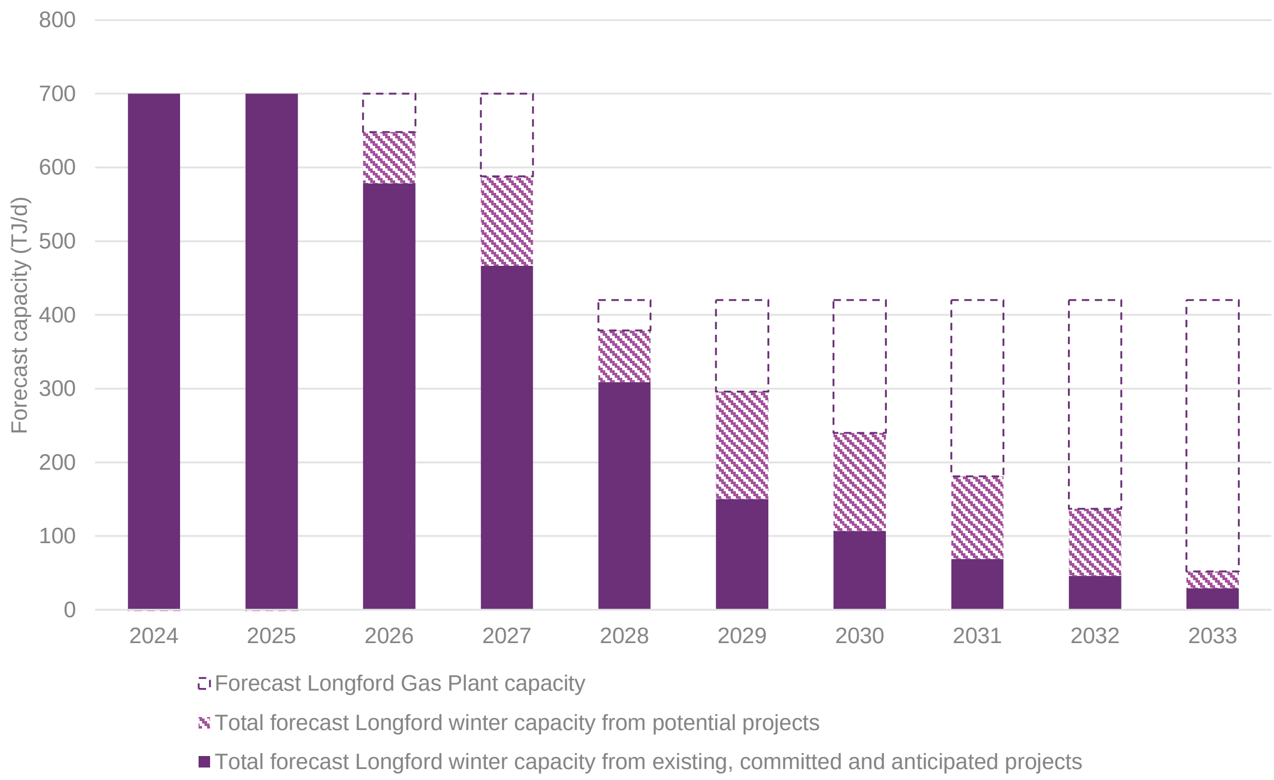
Longer-term adequacy

The VGPR outlook period is five years and this 2024 VGPR Update considers the period from 2024 to 2028. Lead times for production and infrastructure projects now often extend to five years from project initiation to the completion of construction and commissioning. This makes the identification and analysis of supply adequacy solutions in the VGPR difficult, however it is clear that more gas supply is required because the forecast decline in production is faster than the forecast decline in gas consumption. The adequacy assessment for the southern states in the 2024 GSOO reaches the same conclusion.

The key driver of Victorian production capacity decline is the reducing capacity of the Longford Gas Plant, with the 10-year capacity outlook shown in **Figure 4**. Longford is currently the largest gas production facility in the southern states, however capacity has been declining due to the depletion of the GBJV large legacy fields and the subsequent retirement of Longford infrastructure, including the inlet section of Gas Plant 1 which was retired at the end of 2021.

This chart shows the further reductions in Longford capacity that are discussed above, along with supply from all existing, committed, anticipated, and potential projects and includes production from contingent[26] resources. This is an indicative forecast only, intended to highlight the extent of Longford's decline over the next 10 years in a best case scenario. Investment in anticipated and potential projects and the final retirement plan of plant assets later in the decade remain subject to GBJV investment decisions.

Figure 4 Forecast Longford Gas Plant winter capacity, 2024-33 (TJ/d)



Updates to potential projects

AEMO recognises that the investment environment for supply and infrastructure projects remains challenging and uncertain. Many potential projects identified in the 2023 VGPR have not materially progressed due to regulatory

[26] Quantities estimated to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable due to one or more contingencies.

approval requirements, difficulty acquiring financing for natural gas projects, and market participants' resistance to making long-term commitments in an uncertain investment environment in the energy sector.

Key project updates since the 2023 VGPR include:

- **Golden Beach Energy** drilled an appraisal well in July 2023 and has completed a post-drilling evaluation program. The well has allowed further detailed planning and the project is proposed to be online prior to winter 2027.
- GBJV has proposed the Longford **End of Life Optimisation** project to undertake a number of workover programs at Longford Gas Plant to maximise production from depleting reserves later in the decade. This is in addition to the **Turrum Phase 3**[27] project, which could provide additional gas from Longford from 2026. GBJV participants have each been granted a conditional Ministerial exemption from the price cap provisions of the Federal Government's Gas Market Code[28], as announced in January 2024[29].
- Beach Energy and Cooper Energy are undertaking drilling programs in the Otway Basin from 2025 to support Beach's **Artisan** field and Cooper's **Otway Phase 3 Development Project**.
- Viva Energy is continuing to progress the supplementary data request for the Environment Effects Statement (EES) required for the **Viva Energy Gas Terminal Project**.
- In August 2023, Victoria's Minister of Planning published a decision on Vopak's referral submission requiring an EES to be completed for the **Vopak Victoria LNG** project.
- APA is currently in the design stages of the **East Coast Grid Expansion** Stage 3, which has been split into two parts: Stage 3a and 3b. Stage 3a will add an additional compressor on the MSP between Moomba and Young, and Stage 3b another compressor between Young and Culcairn.
- Jemena has completed construction of the pipeline connecting the **Port Kembla Energy Terminal** to the Eastern Gas Pipeline (EGP) and Squadron Energy is on track to complete construction of the LNG terminal wharf within 12 months.
- Venice Energy has completed Stage 1 Enabling Works for site preparation works for the **Outer Harbor LNG Project** in Adelaide and have entered a new commercial agreement that guarantees the project will receive a floating storage regasification unit (FSRU), as announced in February 2024[30].

Increased Otway Basin production and the Venice LNG import terminal do not provide additional peak day supply capacity to the DTS without significant augmentation of the SWP. The Viva and Vopak LNG terminals do provide additional DTS supply capacity, however this capacity cannot be achieved without impacting the simultaneous supply from Port Campbell, including from the Iona UGS facility, unless the SWP is augmented.

[27] Referred to as Turrum and North Turrum in the 2023 VGPR.

[28] More information is at https://www.accc.gov.au/business/industry-codes/gas-market-code#:~:text=The%20Gas%20Market%20Code%20is,prices%20and%20on%20reasonable%20terms.

[29] Minister for Resources and Minister for Northern Australia media release, "Gas market code secures supply for domestic market", 22 January 2024, at https://www.minister.industry.gov.au/ministers/king/media-releases/gas-market-code-secures-supply-domestic-market.

[30] Venice Energy, "*Chairman's Update*", at https://veniceenergy.com/2024/02/15/chairmans-update/

Operational resilience

Table 2 provides updates on the operational resilience issues impacting the DTS since the publication of the 2023 VGPR.

Table 2 Updates impacting operational resilience

Impact	Factor
Updates reducing resilience	**Retirement of infrastructure at Longford Gas Plant** – Gas Plant 1 is expected to cease production in July 2024. This will leave two remaining gas plants, with both required to achieve the post-July 2024 peak day capacity of 700 TJ/d. This reduced redundancy increases the risk of supply disruptions because, if either of the two remaining plants are unavailable, Longford production capacity could be reduced by up to 350 TJ/d.
	Depletion of legacy Gippsland Basin fields – the three large, water-driven legacy fields in the Gippsland Basin – Snapper, Marlin and Barracouta – have historically allowed GBJV to scale Longford production up and down on a seasonal basis, and to ramp production from these fields to respond to issues with other fields or platforms. As the production capacity of these legacy fields declines, the Longford Gas Plant will have reduced ability to maintain production by ramping up these fields to cover a reduction in capacity from other fields. Snapper's production capacity is expected to reduce significantly in the next 12 months.
Updates increasing resilience	**Completion of the Winchelsea Compressor 2 and Western Outer Ring Main (WORM) projects** – APA commissioned the second Winchelsea compressor in August 2023 and the WORM in February 2024. The second unit at Winchelsea adds to SWP capacity while also providing redundancy at this site. The WORM also increases SWP supply capacity and available DTS linepack to cover short outages and increased GPG demand.
	Increased available linepack in the Longford to Melbourne pipeline (LMP) – following the retirement of Longford Gas Plant 1, the two remaining gas plants will be more capable of maintaining injections into the DTS when there is higher pressure in the LMP. This will increase available linepack in the LMP and improve the operational flexibility of this pipeline without impacting Longford operations.
	Resolution of the ethane constraint at Longford Gas Plant – there is a risk to Longford Gas Plant production if the downstream customer is unable to accept the ethane product stream. GBJV is constructing a power generation facility at Hastings that is capable of consuming this ethane stream. Subject to regulatory approvals, the facility is expected to be operational from September 2024.

The Dandenong LNG storage facility inventory will remain maximised for winter 2024, as AEMO has contracted the remainder of the facility's capacity, in accordance with the Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[31] which is effective until the end of 2025.

Peak day risks to supply adequacy for 2024

The key resilience risks identified for peak day operational system security ahead of winter 2024 are:

- **Production facility outages** – the closure of Gas Plant 1 and the reduced production capacity of the large legacy fields increases the risk of an unplanned outage or reduction in supply from Longford Gas Plant. Other production, storage and transmission facilities in Victoria are aging and unplanned outages may occur more frequently.
- **Unforecast system or GPG demand** – winter GPG demand is forecast to increase and may coincide with high system demand.

These events may result in a threat to system security as demand would exceed supply.

[31] Australian Energy Market Commission (AEMC), "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

Seasonal risks to supply adequacy for winter 2024

The key resilience risks identified for supply adequacy ahead of winter 2024 are:

- **Reduction in Queensland gas made available to southern states** – Queensland LNG producers made gas available to the southern states during winter 2023. Volumes made available during winter 2024 may be reduced due to lower production, higher demand or favourable international LNG conditions. Modelling for the 2024 GSOO indicates that international market conditions are unlikely to cause a supply adequacy issue unless all uncontracted gas is exported and time swap arrangements are not utilised.
- **Production project delay, or prolonged gas production or storage facility outage** – gas supply could be lower than projected if start-up of a new production field was delayed, or if there was an unplanned gas facility outage (like the nearly three-week Longford Gas Plant 3 outage during winter 2021, and the Iona outage a week earlier).
- **Prolonged outages at coal-fired generators** – prolonged coal outages can lead to increased GPG demand. Extended coal generation outages occurred during 2019, 2021 and 2022, including the Yallourn mine issue in June 2021.

A reduction in available supply or an increase in GPG consumption across the winter months would result in a tightening of seasonal supply adequacy through winter 2024. If additional Queensland gas is not made available to the southern states in response to supply tightening, the reliance on Iona UGS would increase and result in an elevated storage depletion risk. Depletion of Iona inventory impacts both seasonal gas supply and the daily capacity to support peak day demands.

Renewable gas

There is potential for renewable gases to supply Victoria's large gas users and other users that cannot easily electrify their energy use while also helping to meet decarbonisation targets in a meaningful way. This would require sufficient policy and market settings to support the development of these projects, particularly initially.

Several small-scale pilot renewable gas projects across the east coast are currently under development or have recently been commissioned to demonstrate the technology's viability. These include small hydrogen production facilities already connected to the Adelaide and Sydney short term trading markets (STTMs), and the Malabar biomethane production facility connected to the Sydney STTM. The larger Murray Valley Hydrogen Park being built in Wodonga is expected to be Victoria's first renewable gas supply facility when it is commissioned in 2025[32].

Currently, the policy approach between federal and state governments regarding renewable gases is not uniform, and policy frameworks for hydrogen are significantly more advanced compared to biomethane. For example, federally there is a Hydrogen Strategy[33], a Guarantee of Origin scheme trial[34], and a $2 billion Hydrogen Headstart[35] program to support the development and recognition of renewable hydrogen, but there are no comparable biomethane counterparts.

[32] See https://www.agig.com.au/hydrogen-park-murray-valley.

[33] See https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf.

[34] See https://www.dcceew.gov.au/energy/renewable/guarantee-of-origin-scheme.

[35] See https://www.dcceew.gov.au/energy/hydrogen/hydrogen-headstart-program.

The Australian Renewable Energy Agency (ARENA) suggests that up to 559 PJ of energy per year could be provided by bioenergy sources by the 2030s[36], and the *Electrification Alternatives* sensitivity in the 2023 IASR indicates that biomethane could support 7-8% of total domestic energy consumption across the National Electricity Market (NEM) regions (excluding transport) by 2050[37]. Victoria has bioenergy resources located in Echuca, Wodonga and Shepparton which could be developed to produce biomethane[38]. With appropriate policy and market frameworks, biomethane could provide additional, low-emission energy to meet southern states' demand and assist in reaching state and federal emission reduction targets.

In September 2023, the Victorian Government released its Victorian Renewable Gas consultation paper[39]. The consultation's focus is primarily on hard-to-abate industrial users and how renewable gases could assist these users in their decarbonisation efforts. Further policy work has been identified as necessary to support decarbonisation through the use of renewable gases – including expansion of the Guarantee of Origin Scheme's scope to include biomethane, and the recognition of the carbon abatement of renewable gases within the National Greenhouse and Energy Reporting (NGER) Measurement Determination[40,41]. The timeframe for future policy development work is uncertain.

[36] ARENA, Australia's Bioenergy Roadmap Report at https://arena.gov.au/knowledge-bank/australias-bioenergy-roadmap-report/.

[37] Based on data published in the 2023 IASR, biomethane is assumed to make up approximately 7-8% of the fuel consumption across the economy in National Electricity Market (NEM)-connected regions in 2050 in the *Green Energy Exports* and *Progressive Change* scenarios. Supporting materials are at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

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

[39] See https://engage.vic.gov.au/victorias-renewable-gas-consultation-paper.

[40] See Guarantee of Origin Scheme consultation materials, at https://consult.dcceew.gov.au/aus-guarantee-of-origin-scheme-consultations-on-design.

[41] See submissions by Bioenergy Australia for the Guarantee of Origin Scheme and Victoria's renewable gas consultation, at https://www.bioenergyaustralia.org.au/advocacy/submissions/.

1 Introduction

The *Victorian Gas Planning Report* (VGPR) is published every two years and assesses the adequacy of the Victorian Declared Transmission System (DTS) to supply peak day gas demand and annual consumption over a five-year outlook period. The most recent VGPR was published in March 2023. Where AEMO becomes aware of any information that materially alters the most recently published VGPR, the National Gas Rules (NGR) require AEMO to update the report as soon as practicable. The material changes since the 2023 VGPR was published that prompted this VGPR Update are:

- Updated gas production and consumption forecasts.
- Updates to projects impacting the DTS supply adequacy since the 2023 VGPR was published.

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

1.1 DTS gas consumption in 2023 and recent years

1.1.1 2023 gas consumption and cumulative EDD

Total DTS gas consumption in 2023 was 177 petajoules (PJ), which is the lowest demand year since the gas market started in 1999. Consumption was 18% lower than during 2022 when consumption was 209 PJ, and was 8% lower than the next lowest year, when consumption was 193 PJ in 2014.

There were only two occurrences in 2023 when DTS total demand exceeded 1,000 terajoules (TJ) (or 1 PJ) – the 2023 peak total[42] demand day of 1,109 TJ on 20 June (comprising 995 TJ of system demand and 114 TJ of gas-powered generation (GPG)), and 1,037 TJ on 21 June. **Table 3** shows the annual number of demand days above 1 PJ, and the DTS peak total demand and date, for the last five years, which highlights the absence of peak demand conditions during winter 2023.

Table 3 DTS peak total daily demand conditions, 2019 to 2023

	2019	2020	2021	2022	2023
Number of days exceeding 1 PJ of total DTS demand	35	25	21	26	2
Peak demand (TJ)	1,308	1,243	1,187	1,199	1,109
Peak demand date	9 August 2019	4 August 2020	21 June 2021	30 May 2022	20 June 2023

Figure 5 shows the daily DTS demand profile for 2023; the largest contributor to annual DTS consumption was Tariff V[43] customers (64%), then Tariff D[44] (33%) customers, GPG (2%) and fuel gas (<1%).

[42] Total demand is the sum of gas-powered generation (GPG) and system demand, where system demand is the sum of Tariff D, Tariff V and fuel gas demand.

[43] Tariff D customers have an annual gas consumption of at least 10 terajoules (TJ) or an hourly consumption rate of more than 10 gigajoules per hour (GJ/h).

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

Figure 5 DTS daily demand profile, 2023 (TJ)

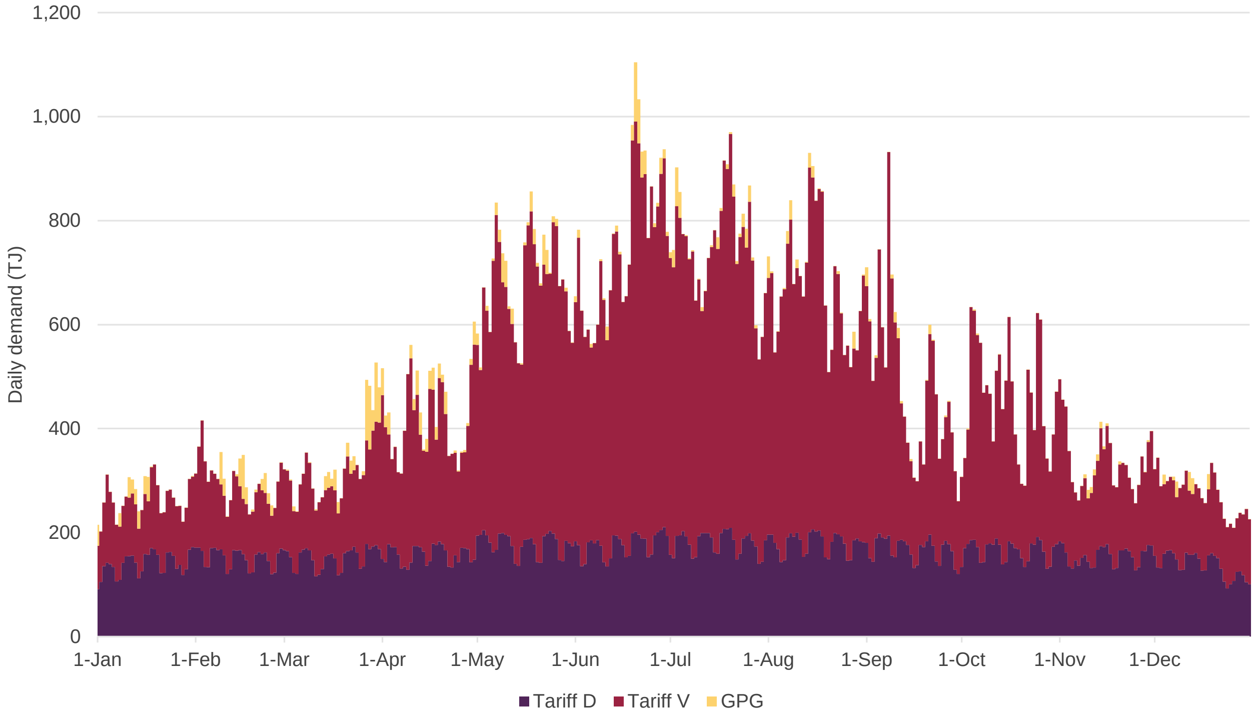
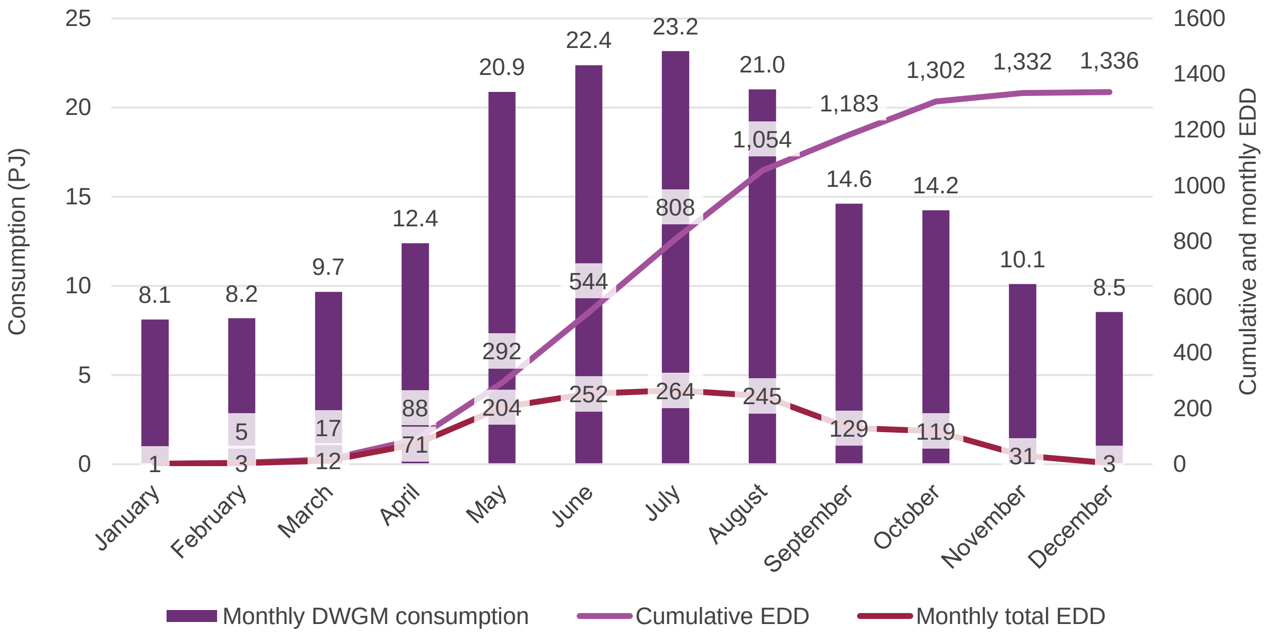


Figure 6 shows the impact of the effective degree day (EDD)[45] on the DTS monthly consumption profile.

Figure 6 Monthly DTS system consumption profile against 2023 cumulative EDD profile (PJ)



[45] EDD is a measure of perceived coldness based on temperature, sunlight and wind speed conditions. The higher the EDD value, the more gas is expected to be consumed for space heating.

As expected, DTS monthly consumption was highest from May to August, where demand exceeded 20 petajoules per month (PJ/m). While both consumption and cumulative EDD were lower in 2023 than in recent years, the reduction in cumulative EDD does not appear to completely account for the reduction in system consumption, as discussed further in Section 1.1.2.

1.1.2 Historic DTS gas consumption

Tariff V consumption

Tariff V customers – residential and small commercial gas users (using less than 10 TJ per year (TJ/y) and less than 10 gigajoules per hour (GJ/h)) – have historically consumed the largest proportion of gas in the DTS (64% of DTS consumption in 2023).

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

Table 4 shows that the cumulative EDD and DTS demand were both lower in 2023 than in recent years with a 13.1% reduction in consumption from 2022 to 2023. The table also shows that year-on-year Tariff V consumption has reduced each year since 2020 despite similar cumulative EDDs for 2020, 2021 and 2022.

Table 4 Annual Tariff V consumption and cumulative EDD with year-on-year changes, 2019 to 2023

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

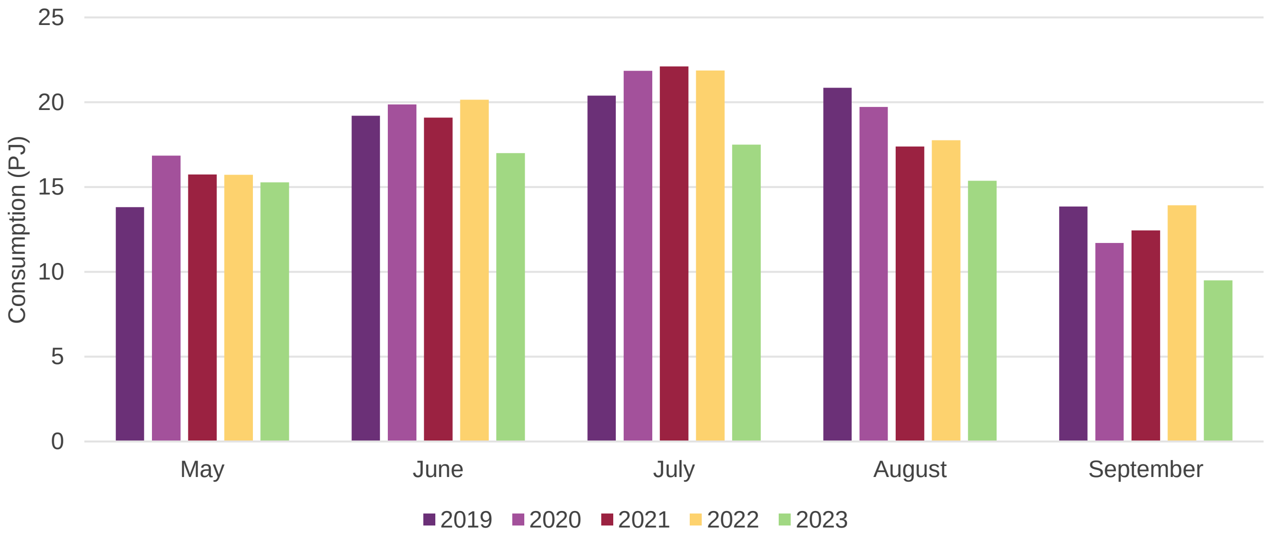
Figure 7 shows the monthly consumption profile for the winter peak demand period from 2019 to 2023, illustrating that the 2023 monthly gas use was significantly reduced compared to previous years. It also shows that August consumption from 2021 to 2023 is noticeably lower than August 2019 and 2020 when several very cold days occurred and system demand reached 1,200 TJ.

The decrease in consumption over the peak demand months in 2023 can be somewhat attributed to the suppressed total and cumulative EDD[46], as shown in **Figure 6**, and some demand reduction is likely to have been driven by adverse economic conditions and cost of living pressures[47], and electrification (switching from gas to electricity) of existing Tariff V customers. Further analysis is required to understand which proportion of the reduction in consumption was due to electrification, compared to the impact of economic and weather conditions.

[46] Bureau of Meteorology, Australia climate summary in Winter 2023, at http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml.

[47] Australian Bureau of Statistics, Monthly Consumer Price Index Indicator, at https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/monthly-consumer-price-index-indicator/oct-2023.

Figure 7 Monthly Tariff V consumption for the winter peak demand period, 2019-23 (PJ)



Tariff D consumption

Tariff D customers are large commercial and industrial users that consume more than 10 TJ/y or more than 10 GJ/h of gas. These customers typically have stable consumption profiles across a year, with their gas consumption often linked to economic conditions, and they are generally less sensitive to weather conditions than Tariff V customers. As noted in the 2023 VGPR[48], DTS Tariff D consumption has been declining due to a combination of large industrial closures and the decrease in the number of businesses in Victoria[49].

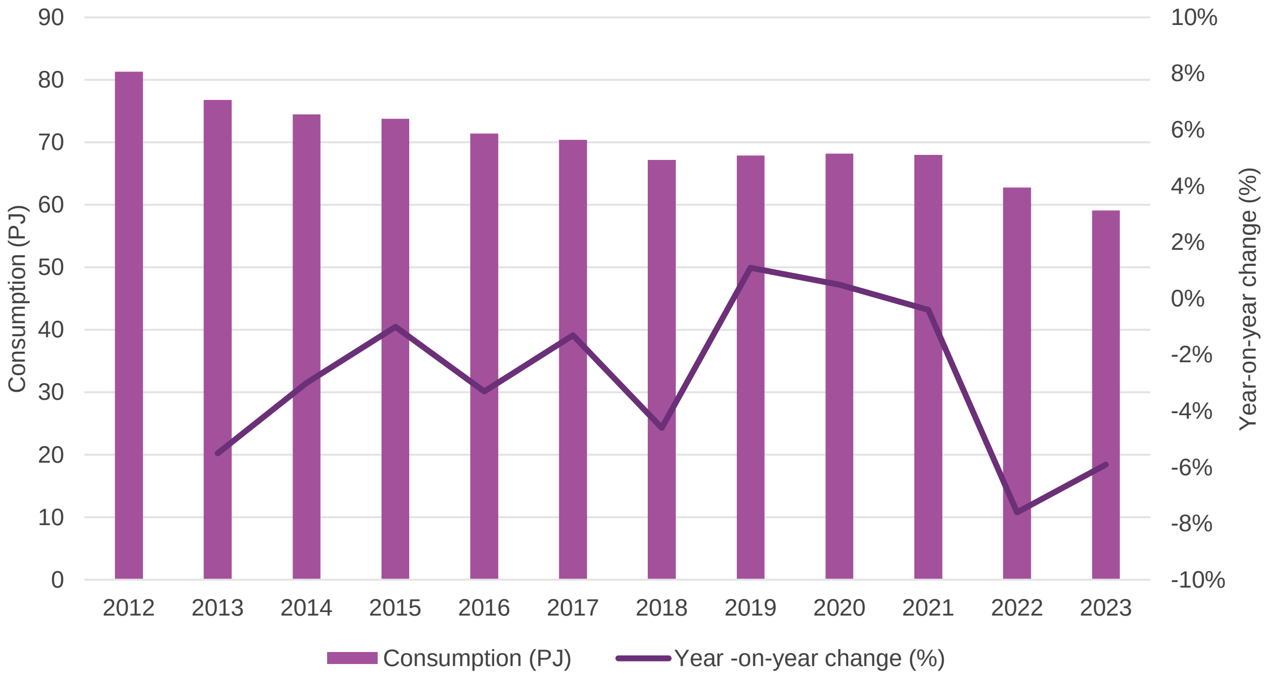
Figure 8 shows the impact of these closures with annual Tariff D consumption decreasing from approximately 81 PJ in 2012 to 59 PJ in 2023, including large year-on-year consumption decreases of 7.6% and 5.9% in 2022 and 2023, respectively.

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

[48] 2023 VGPR, sections 1.1 and 2.1.2, at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2023/2023-victorian-gas-planning-report.pdf?la=en.

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

Figure 8 DTS Tariff D annual consumption and year-on-year percentage change, 2012-23



1.2 Supporting DTS and southern states demand

1.2.1 Longford Gas Plant

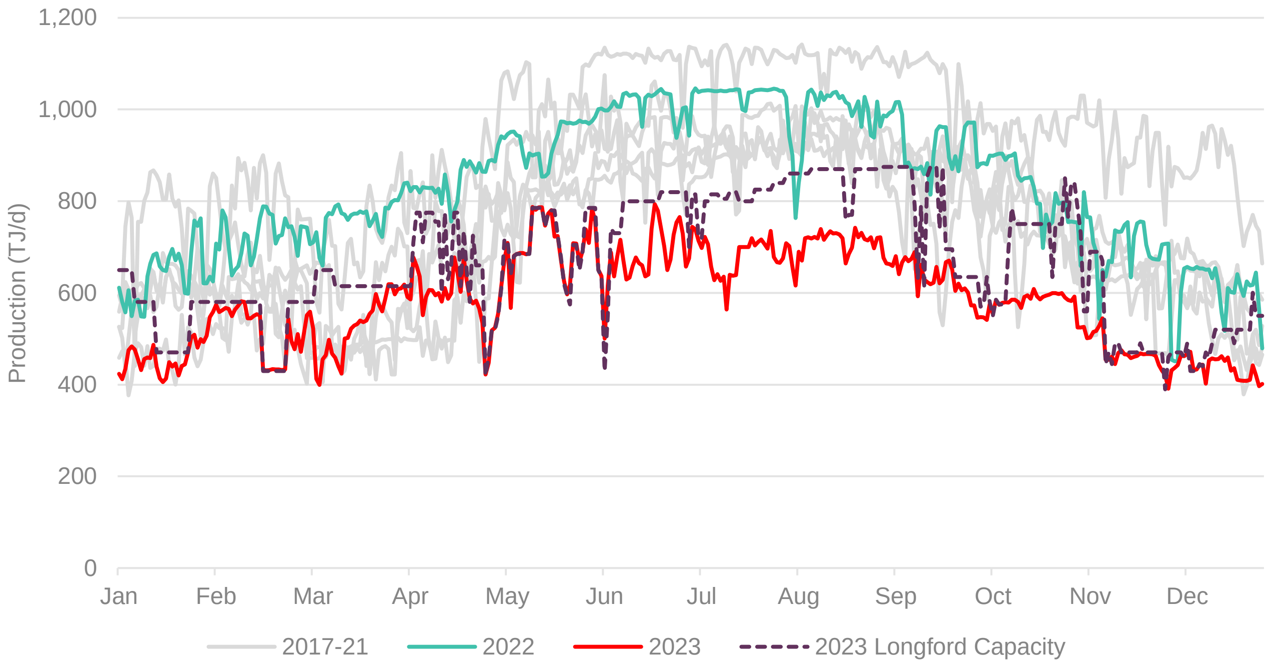
The Longford Gas Plant is the largest gas production facility in the southern states[50] and it has an essential role in supporting demand in the DTS and the neighbouring jurisdictions of Tasmania and New South Wales. Longford's peak production and average daily production in 2023 was 793 TJ/d and 594 TJ/d respectively, with an average daily utilisation of 88.5%[51]. This compares to an average of 835 TJ/d in 2022 and 937 TJ/d in 2017.

This decline in southern states' production has been forecast since the 2018 VGPR Update. An illustration of this decline is shown below in **Figure 9**.

[50] 'Southern states' in this VGPR Update means New South Wales, Tasmania, South Australia and Victoria.

[51] Detailed analysis is in AEMO's Quarterly Energy Dynamics report, October 2023, Section 2.3, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf?la=en&hash=165E68BF9A6DAF100B56CFAAC437CE20.

Figure 9 Longford production profile, 2017-23 (TJ/d)



1.2.2 Iona Underground Gas Storage

The DTS' reliance on Iona Underground Gas Storage (UGS) to supply gas, particularly during peak demand months[52], was reduced in 2023 compared to recent years.

The Iona inventory drawdown during winter 2023 was 6.3 PJ, from 25.2 PJ on 14 April to 18.9 PJ on 26 August. In the previous two winters:

- During winter 2022, the inventory drawdown was 14.2 PJ, from 23.5 PJ on 18 April to 9.3 PJ on 21 July.
- During winter 2021, the drawdown was 14.9 PJ, from 24.6 PJ on 10 May to 9.6 PJ on 25 July.

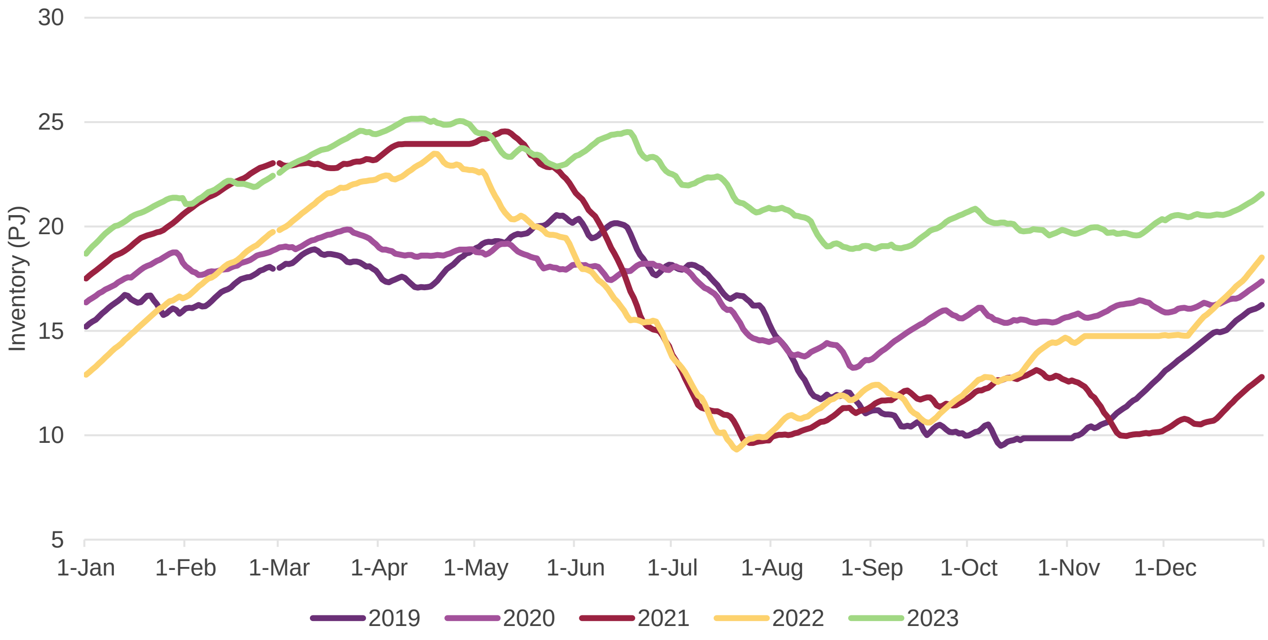
During both August 2021 and August 2022, Iona inventory began refilling due to a combination of mild weather and increased supply from Queensland coinciding with APLNG train outages.

The reduced reliance on Iona UGS to support southern state demand during the 2023 winter peak demand period can be attributed to lower DTS demand, reduced flows to South Australia via the Port Campbell to Adelaide Pipeline (PCA), and higher flows from Queensland into the southern markets[53]. Combined, these factors resulted in the Iona UGS facility ending 2023 with approximately 21.6 PJ of inventory, which is approximately 3 PJ higher than at the end of 2022, as shown in **Figure 10**.

[52] The peak demand months are defined as the months of May to September inclusive.

[53] Detailed analysis is presented in AEMO's Quarterly Energy Dynamics report, October 2023, Section 2.3, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf?la=en&hash=165E68BF9A6DAF100B56CFAAC437CE20.

Figure 10 Iona UGS inventory position, 2019-23 (PJ)



1.2.3 Flow through the South West Queensland Pipeline and Victorian Northern Interconnect

As **Figure 11** shows, net gas flows of approximately 5-8 PJ were directed to the southern states through the South West Queensland Pipeline (SWQP) during the peak winter demand months in 2023.

A net total of 20.6 PJ flowed south through the SWQP in winter 2023, which was more than the 18.3 PJ in winter 2022 and 14.4 PJ in winter 2021[54]. For the remainder of the year, net flow on the SWQP was from the southern states into Queensland and is likely the result of seasonal gas swaps between gas retailers and the Queensland LNG exporters.

The Victorian Northern Interconnect (VNI) is a bi-directional route for gas flows south from Queensland or Moomba into Victoria via the Moomba – Sydney Pipeline (MSP), and from Victoria to export to New South Wales. **Figure 12** shows that during peak demand months in 2023 the VNI had a net flow south into the DTS. This is consistent with the Queensland and Moomba supply providing net flow south during the same period. Outside of the 2023 peak demand period, when southern state consumption decreased, the VNI facilitated exports from Victoria to be consumed in New South Wales or flow via the MSP towards Queensland.

[54] SWQP flow quantities determined from Moomba Hub (transfer between Moomba – Sydney Pipeline (MSP), Moomba to Adelaide Pipeline System (MAPS) and SWQP).

Figure 11 Monthly SWQP northern, southern and net flow profile, 2023 (PJ)

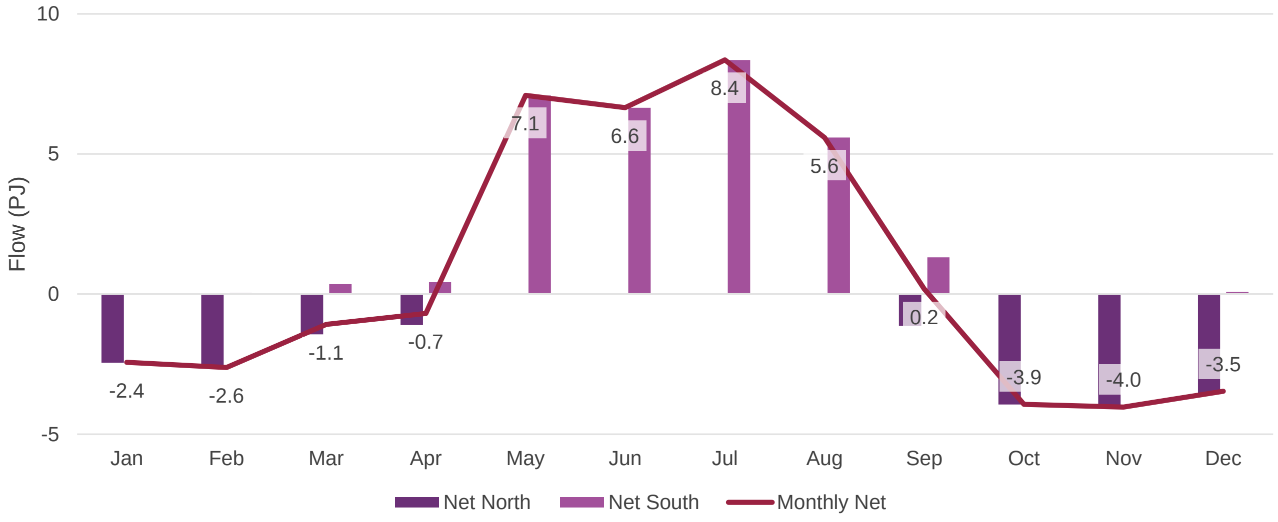
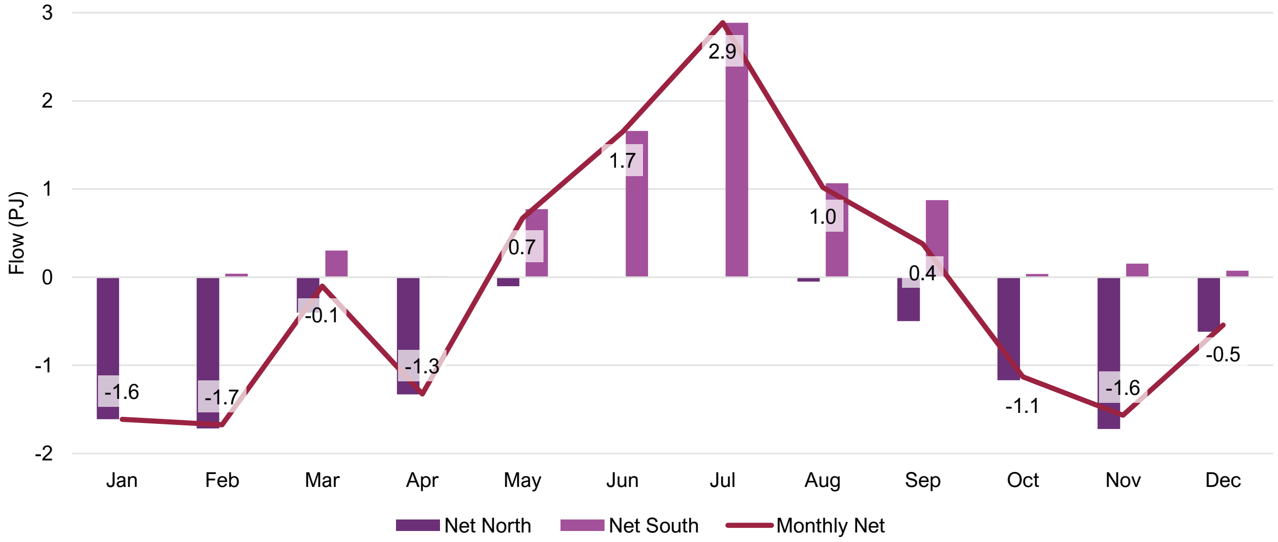


Figure 12 Monthly VNI northern, southern and net flow profile, 2023 (PJ)



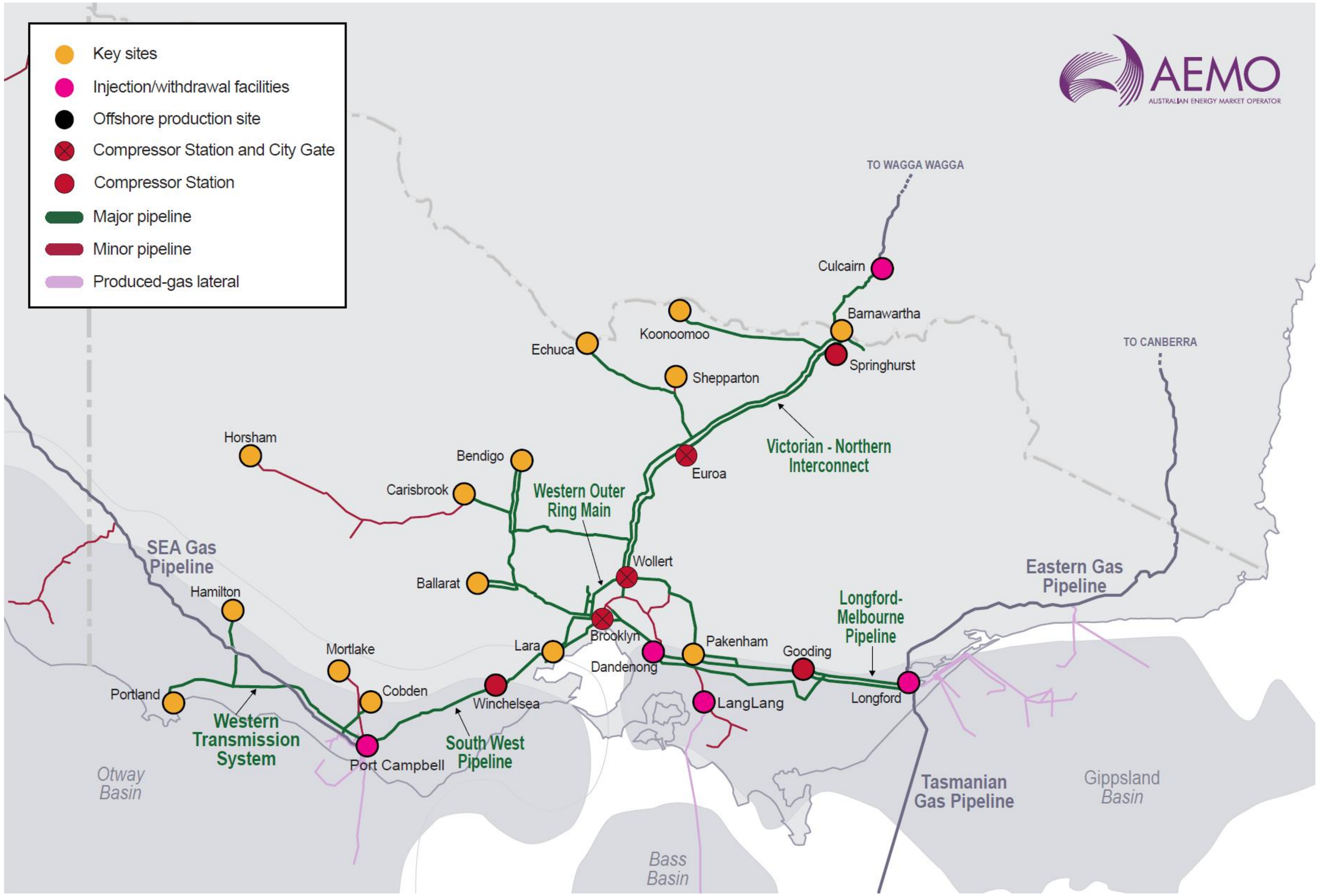
1.3 The Victorian Declared Transmission System (DTS)

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 to and from Port Campbell in the southwest, which includes the Otway and Athena gas production facilities and the Iona UGS facility.

Figure 13 is a high-level map of the Victorian gas transmission network, including the DTS and other gas transmission pipelines.

Figure 13 The Victorian DTS



1.4 Gas planning in Victoria

1.4.1 Roles and responsibilities

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

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

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

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

1.4.2 Planning basis and definitions

AEMO prepares and publishes a planning review (in the form of the VGPR) once every two years by 31 March, in accordance with NGR rule 323.

Where AEMO becomes aware of any information that materially alters the most recently published planning review, rule 323(5) requires AEMO to update the planning review as soon as practicable.

In accordance with rule 324 of the NGR, participants are required to provide AEMO with forecast information. Under rule 324(6), AEMO must keep this forecast information confidential except to the extent of the information that AEMO is required to provide in the VGPR.

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

- A 1-in-2 forecast is defined as a peak day system demand forecast with a 50% probability of exceedance (POE). This means the forecast is expected, on average, to be exceeded once in two years, and is considered the most probable peak day system demand forecast.
- A 1-in-20 forecast is defined as a peak day system demand forecast for severe weather conditions, with a 5% POE. This means the forecast is expected, on average, to be exceeded once in 20 years. This forecast is used for DTS capacity planning.

System demand does not include supply for GPG[55]. Under rule 323(3), AEMO is also required to assess the impact of GPG demand on 1-in-2 peak system demand days.

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

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

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

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

1.4.3 Threat to system security

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

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

- The system is operating within the requirements of the gas quality procedures, and breaches of the gas quality procedures do not require intervention by AEMO.
- There is no threat to public safety.
- There is no threat to the supply of gas to customers.
- 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. Relevantly, a threat to system security indicates that, in AEMO's reasonable opinion:

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

2 Gas consumption and demand forecasts

Key findings

The gas consumption and demand forecasts for the 2024 VGPR Update have been produced using the *Step Change* scenario and project decreasing system consumption and demand due to increasing electrification:

- Annual system consumption is forecast to decrease by 9.6% in the five-year outlook, from 184.4 PJ in 2024 to 166.6 PJ in 2028.
- The forecast peak day system demands are:
  - 1,098 TJ/d for a 1-in-2 year system demand day in 2024, reducing by 11.1% to 976 TJ/d in 2028.
  - 1,179 TJ/d for a 1-in-20 year system demand day in 2024, reducing by 11.2% to 1,047 TJ/d in 2028.

In a sensitivity testing the impact of delayed electrification, this 2024 VGPR Update forecasts little change in gas consumption and a small peak demand increase:

- Annual system consumption maintaining a relatively flat trend from 2024 to 2028.
- 1,099 TJ/d for a 1-in-2 year system demand day in 2024, increasing by 2.8% to 1,130 TJ/d in 2028.
- 1,179 TJ/d for a 1-in-20 year system demand day in 2024, increasing by 3.1% to 1,216 TJ/d in 2028.

Victorian GPG consumption is forecast to experience an initial decline from historical levels as renewable energy generation continues to be commissioned, before increasing back to typical levels due to coal retirements:

- Actual Victorian GPG consumption during 2023 was 7.4 PJ. This is forecast to reduce to as low as 2.8 PJ in 2024. It is then forecast to increase in two steps in 2026 and 2028, due to the planned retirements of Eraring coal power station in New South Wales and Victoria's Yallourn coal power station, resulting in a forecast of 9.5 PJ in 2028.
- If coal generation was reduced due to an extended outage or fuel supply issue, GPG consumption for that year could increase by approximately 209% over the VGPR forecasts.
- The Draft 2024 *Integrated System Plan* (ISP) outlines the GPG required for firming to meet the emissions reductions targets set by Australian governments. It projects Victorian GPG capacity increasing from the existing 2.4 gigawatts (GW) to 3.6 GW during the 2030s, with the assumption that Victorian brown coal generators will progressively shut down over the next decade (sooner than currently announced dates).
- Peak GPG demand during winter is also forecast to increase substantially – by more than 169% over this VGPR Update outlook period – as gas plays an increasingly critical role during periods of high electricity demand, particularly when there is low variable renewable energy (VRE) generation output or coal generation outages. This peak GPG demand increase may coincide with peak system demand conditions, creating very high total demand conditions.

2.1 Gas usage forecast

Scenario and sensitivity forecasts

The forecasts for the 2024 VGPR Update and the 2024 GSOO focus on the *Step Change* scenario outlined in AEMO's 2023 IASR.

The *Step Change* scenario is a refinement of the 2021 IASR *Step Change* scenario and represents a future with rapid consumer-led transformation of the energy sector. It assumes a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions (including electrification of gas heating load), driven by consumer-led change with a focus on energy efficiency, digitalisation and step change increases in global emissions policy above what is already committed.

The full effect of the electrification forecast under the *Step Change* scenario will require further strong policy incentives and industry investment. Uncertainty exists over the rate at which customers will switch their energy usage away from natural gas. Electrification of some existing gas loads has begun, however more work is needed to quantify the number of customers that have switched and the rate of change.

The impact of a conceptual electrification of gas use delay beyond the outlook period has been considered as a sensitivity – *Step Change, No Electrification* – to reflect no electrification. If no electrification is assumed, forecast consumption is forecast to maintain a relatively flat trend and slightly increase during the outlook period.

The forecast for GPG usage under the *Step Change* scenario shows an increasing trend during the outlook period, due to planned coal generator retirements. In addition, AEMO studied the impact of further extended coal generator outages in a sensitivity, *High Coal Generation Outages.* If coal generation was reduced due to an extended outage or fuel supply issues, GPG consumption is forecast to increase significantly during the outlook period.

Government policies and schemes update

Both the *Step Change* scenario in the 2023 IASR and the 2023 *Orchestrated Step Change (1.8°C)* scenario forecasts assumed new policy would be created to enable the electrification forecast and the forecast gas consumption decline. This forecast reduction in gas consumption is aligned with Victoria's recent Gas Substitution Roadmap[56] policy and with federal and state schemes including those described below.

The combination of these policies has contributed to AEMO forecasting a 6.2% reduction in annual gas consumption and approximately 11% reduction in peak day system demand[57] (excluding gas for electricity generation) over the outlook period.

[56] Victorian Government, *Victoria Gas Substitution Roadmap Update*, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

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

New residential gas connections ban

On 28 July 2023, the Victorian Government announced[58] that from 1 January 2024, planning permits for new homes and residential subdivisions, including public and social housing, will be prohibited from connecting to a gas network. Any permit application lodged before 1 January 2024 will not be affected by the gas connection prohibition. Therefore, new homes in existing residential subdivisions (that were approved before 1 January 2024) will be able to connect to the gas network, unless that new home requires a planning permit.

Gas Substitution Road Map update

The Victorian Government released an updated Gas Substitution Roadmap in December 2023 outlining the next steps for Victoria's transition from gas to electrical appliances.

As part of the roadmap, the Victorian Energy Upgrades (VEU) program will be expanded in 2024 to cover electric induction cooktops. As older gas appliances reach the end of their lives, the Victorian Government plans to undertake detailed industry engagement and public consultation in 2024 to test the following options:

- Cost and benefits of requiring existing gas appliances to be replaced with electric appliances when the current appliances reach end-of-life.
- Expanding minimum energy efficiency standards to cover ceiling insulation, draught sealing, hot water, and cooling.

The Victorian Minister for Energy and Resources also issued gas distribution network services providers with a Notice of Intent to prevent them offering inducements for consumers to retain or initiate new gas connections, or for the installation of gas appliances.

Gas disconnection fees

In response to price uncertainty and sometimes high prices to abolish residential and small commercial customer gas meters, the AER has capped fees to permanently disconnect from the gas network at $220 by as part of its 2023-2028 regulatory price reset process.

Safeguard Mechanism Scheme

In addition to actions aimed at residential gas use, reforms to the Federal Government's Safeguard Mechanism require Australia's largest emitters of greenhouse gases to reduce their emissions by 4.9% each year to 2030 with a reduction in five-year rolling average emissions required for the year commencing 1 July 2024[59].

Gas consumption in 2023

In 2023, DTS gas consumption was very low compared to recent years. Industrial and large commercial customer (Tariff D[60]) consumption decreased by 5.9% compared to 2022, while residential and small commercial customer

[58] Victorian Government, "New Victorian Homes To Go All Electric From 2024", at https://www.premier.vic.gov.au/new-victorian-homes-go-all-electric-2024.

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

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

(Tariff V[61]) consumption decreased by 13.1%, which is likely due to a combination of factors including near record warm winter conditions[62] reducing the need for space heating, cost of living pressures[63], and electrification of existing gas use. Further analysis is required to understand which proportion of the reduction in consumption was due to electrification, compared to the impact of economic and weather conditions.

Renewable gas in the 2024 VGPR Update forecast

There is not yet a material quantity of renewable gas forecast in Victoria for the outlook period. Refer to the 2024 GSOO for longer-term renewable gas discussion. Further analysis on renewable gas in Victoria will be undertaken for the 2025 VGPR.

Definitions used in forecasts

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.

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

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

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

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

[62] Bureau of Meteorology, "Australia climate summary in Winter 2023", at http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml

[63] Monthly Consumer Price Index Indicator, at https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/monthly-consumer-price-index-indicator/oct-2023

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

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

2.2 Annual consumption

Under the *Step Change* scenario, annual DTS total consumption is forecast to decrease by 9.6% over the outlook period, from 186 PJ in 2024 to 172 PJ in 2028, as shown in **Table 5** and **Figure 14**. This forecast decrease in consumption is driven by reduced gas use by residential, commercial and industrial customers, which is more than the forecast increase in GPG consumption.

The forecast decrease in system consumption from 184 PJ in 2024 to 167 PJ in 2028 represents a reduction of between 3% and 5% from the *Orchestrated Step Change (1.8°C)* scenario forecasts in the 2023 VGPR[64] across the five-year outlook period, which forecast system consumption of 193 PJ in 2024 and 178 PJ in 2027 (compared to 173 PJ in this 2024 VGPR Update).

Table 5 Total annual gas consumption forecast, 2023-28 (PJ/y)

	Actual			Forecast					Change over outlook
	2021	2022	2023	2024	2025	2026	2027	2028	
Tariff V	131.8	130.6	113.5	124.7	122.7	118.7	114.1	108.2	-13.3%
Tariff D	68.0	62.8	59.2	59.7	59.7	58.3	58.7	58.4	-2.1%
System consumption	200.9	194.8	173.3	184.4	182.3	177.0	172.7	166.6	-9.6%
DTS GPG consumption	6.2	13.8	3.8	1.7	1.5	2.8	2.5	5.6	227.3%
DTS total consumption	207.1	208.6	177.1	186.1	183.8	179.8	175.2	172.2	-7.5%
Non-DTS system consumption	0.32	0.32	0.28	0.31	0.31	0.31	0.31	0.32	1.6%
Non-DTS GPG consumption	4.3	6.9	3.6	1.1	1.0	2.1	1.7	3.3	216.5%
Victorian GPG consumption	10.5	20.7	7.4	2.8	2.5	4.9	4.2	8.9	223.1%
Total Victorian consumption*	211.7	215.8	181.0	187.4	185.1	182.2	177.2	175.8	-6.2%

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.

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

Figure 14 Historical and forecast total annual gas consumption, 2020-28 (PJ/y)

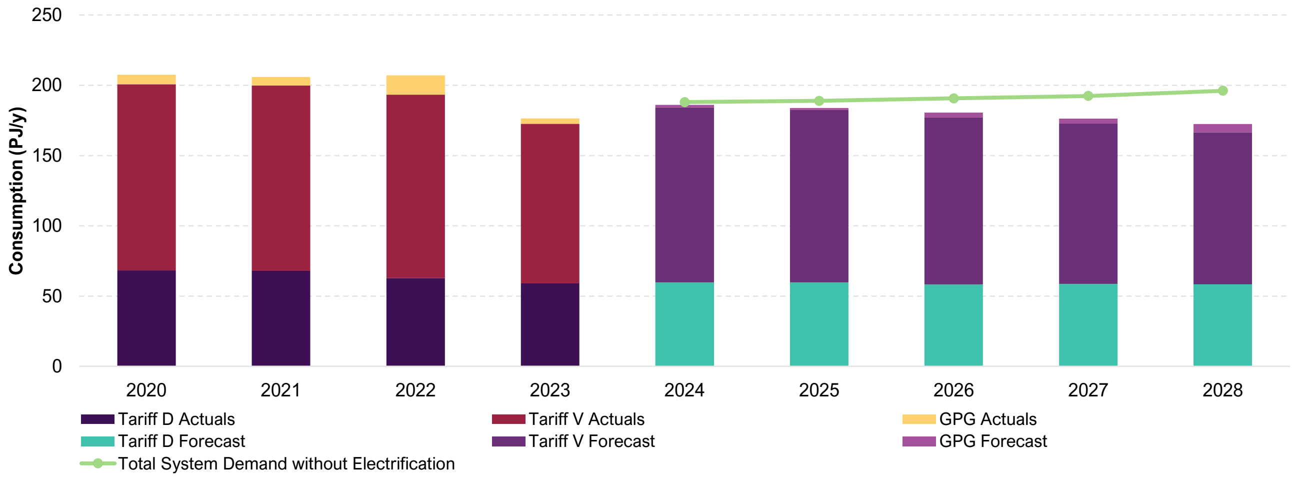


Table 6 shows the difference between the forecasts with and without electrification. The forecast impact of electrification is larger for Tariff V consumption than Tariff D:

- **Tariff V** consumption with electrification is forecast to decrease by 13.3% over the five-year VGPR outlook, from 124.7 PJ in 2024 to 108.2 PJ in 2028, compared to the 4.2% increase of Tariff V forecast without electrification over the same period.
- **Tariff D** consumption with electrification is predicted to reduce by 2.1%, similar to the forecast reduction of 1.8% without electrification.

Table 6 DTS total annual gas consumption forecast with and without electrification, 2024-28 (PJ/y)

	2024	2025	2026	2027	2028
DTS total consumption	186.1	183.8	179.8	175.2	172.2
DTS total consumption without electrification	188.0	188.9	190.0	191.3	195.9
Percentage difference	1.1%	2.8%	5.6%	9.2%	13.8%

2.2.1 Tariff V consumption

Figure 15 shows the Tariff V consumption forecast's gradual declining trend, from 124.7 PJ in 2024 to 108.2 PJ in 2028, with a relatively flat forecast trend in the first couple of years before electrification accelerates. **Table 7** details the percentage difference for the DTS Tariff V forecast without electrification.

The forecast initial moderate decline is driven by the gradual uptake of fuel switching via electrification and, to a lesser degree, energy efficiency savings under the VEU scheme[65] that was recently expanded to cover electric induction cooktops, and the Home Heating and Cooling Upgrades Program[66] packages.

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

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

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

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

Figure 15 Historical and forecast DTS Tariff V consumption, 2020-28 (PJ/y)

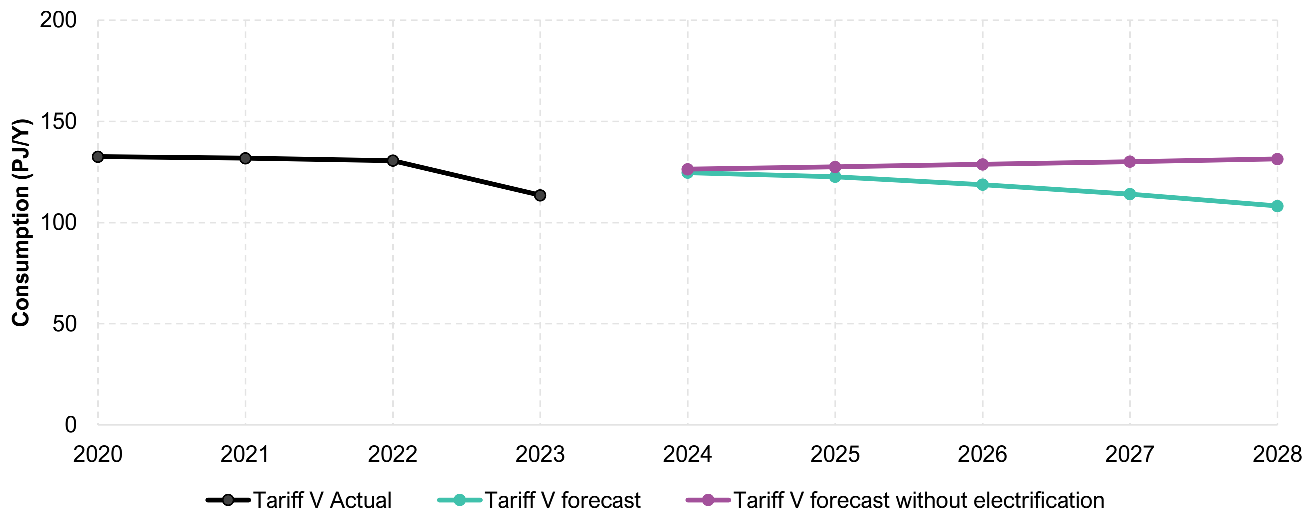


Table 7 DTS Tariff V gas consumption forecast with and without electrification, 2024-28 (PJ/y)

	2024	2025	2026	2027	2028
DTS Tariff V consumption with electrification	124.7	122.7	118.7	114.1	108.2
DTS Tariff V consumption without electrification	126.4	127.5	128.8	130.1	131.4
Percentage difference	1.4%	4.0%	8.4%	14.1%	21.5%

Table 8 below shows projected Tariff V consumption by System Withdrawal Zone (SWZ)[67] for the *Step Change* scenario, with and without electrification:

- There is a strong forecast reduction in Tariff V consumption across all zones except for the Gippsland zone. Forecast consumption in the Gippsland zone remains relatively flat, and is only expected to experience a slight reduction of 1.8% in 2028 at the end of the outlook period, due to some expected new connections in new estates in the region which already have a planning permit.
- Tariff V consumption in the Ballarat, Geelong and Northern zones are forecast to decline by similar amounts, between 5.6% and 5.8%. Tariff V consumption in these zones is forecast to decrease as the projected number

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

of new connections already approved is offset by the adoption of electrification and the energy efficiency programs described above.

- The zones with the greatest Tariff V consumption decreases are the Western and Melbourne zones, with forecast reductions of 21.6% and 16.7%, respectively.
- If electrification is delayed beyond the outlook period, Tariff V consumption is forecast to increase or remain near current levels in each zone over the VGPR period.

Table 8 Annual Tariff V consumption by System Withdrawal Zone, 2023-27 (PJ/y)

	2023 (Actual)	2024	2025	2026	2027	2028	Change over outlook
Ballarat	8.7	9.3	9.3	9.2	9.0	8.7	-5.8%
Geelong	10.4	11.0	11.1	10.9	10.7	10.4	-5.8%
Gippsland	5.7	6.5	6.6	6.6	6.6	6.4	-1.8%
Melbourne	78.5	85.8	83.6	80.1	76.2	71.5	-16.7%
Northern	9.0	10.8	10.9	10.8	10.6	10.2	-5.6%
Western	1.2	1.2	1.2	1.1	1.1	1.0	-21.6%
DTS Tariff V system consumption	113.5	124.7	122.7	118.7	114.1	108.2	-13.3%
Non-DTS Tariff V system consumption	0.18	0.22	0.21	0.22	0.22	0.22	1.6%
Total Victorian Tariff V	113.7	124.9	122.9	119.0	114.3	108.4	-13.2%
Total Victorian Tariff V without electrification	-	126.6	127.7	129.0	130.3	131.6	4.0%

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

2.2.2 Tariff D consumption

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

Over the next five years, large commercial and industrial customers are not expected to commence widespread electrification of their processes, due to complexities associated with electrifying heat-intensive processes. Therefore, there is not a large difference between the forecast Victorian Tariff D consumption with or without electrification, as shown in **Table 9**.

Table 9 Annual Tariff D consumption by System Withdrawal Zone, 2024-28 (PJ/y)

	2023 (Actual)	2024	2025	2026	2027	2028	Change over outlook
Ballarat	1.6	1.4	1.5	1.4	1.4	1.4	2.4%
Geelong	10.9	9.8	10.5	9.9	10.0	10.0	2.4%
Gippsland	7.0	8.4	7.9	7.5	7.0	6.5	-23.1%
Melbourne	29.1	30.4	29.9	29.6	30.2	30.3	-0.3%
Northern	8.5	7.3	7.4	7.5	7.7	7.7	5.4%
Western	2.6	2.3	2.4	2.4	2.4	2.5	6.1%
DTS Tariff D system consumption	59.1	59.7	59.7	58.3	58.7	58.4	-2.1%
Non-DTS Tariff D system consumption	0.10	0.10	0.10	0.10	0.10	0.10	1.6%

	2023 (Actual)	2024	2025	2026	2027	2028	Change over outlook
Total Victorian Tariff D	59.2	59.8	59.7	58.4	58.8	58.5	-2.1%
Total Victorian Tariff D without electrification	-	60.0	60.0	58.5	58.8	59.0	-1.8%

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

Tariff D consumption is forecast to remain near current levels at 59.8 PJ in 2024, which is comparable to the actual demand in 2023 of 59.2 PJ – with general changes in industrial load consumption – before reducing slightly in 2026, then remaining flat through to 2028 with a decrease of approximately 2.1% over the outlook period.

The forecast has a relatively flat trend in all zones except Gippsland, where a 23.1% reduction in consumption is expected over the outlook period, due to a forecast reduction for a large industrial customer in this region.

Tariff D customers are not required to provide AEMO with advance notice of expected closures, which adds complexity to modelling Tariff D consumption. It is plausible that Tariff D gas use could continue to reduce across the DTS.

2.3 Peak day demand

This section reports annual DTS peak day system demand forecasts (excluding GPG forecasts) over the outlook period, and monthly peak day gas demand forecasts for January 2024 to December 2024.

2.3.1 Annual peak day system demand

The 1-in-2 and 1-in-20 peak day system demand forecasts display a similar declining trend to the annual consumption forecast with an 11% reduction over the outlook period as shown in **Table 10.** This is driven by the strong electrification forecast under the *Step Change* scenario that impacts Tariff V peak day demand, which reduces by 13.6% and 13.1% for 1-in-2 and 1-in-20 peak day respectively over the outlook period.

This is a further reduction from the 2023 VGPR, which forecast decreases from 2023 to 2027 of 10.3% and 10.5% for 1-in-2 and 1-in-20 peak day system demand, respectively. Similar to the annual consumption forecasts, the peak day demand forecasts in the 2024 VGPR Update have a more gradual decreasing trend in the early years before a steeper decline in the later years. This change is driven by updated assumptions about the timing of electrification of gas networks including the Victorian gas connection ban policy.

If electrification is delayed beyond the outlook period, then the 1-in-2 and 1-in-20 peak day system demand forecasts increase by 2.8% and 3.1%, respectively, over the 2024 to 2028 outlook period.

Table 10 Annual peak day system demand forecast with and without electrification, 2024-28 (TJ/d)

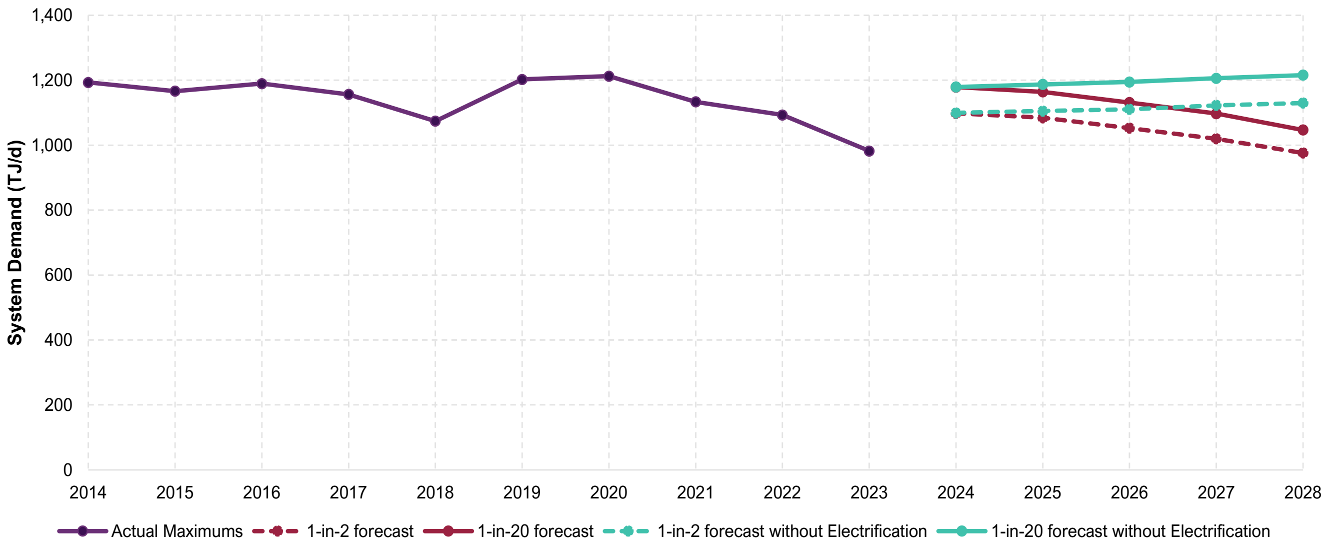
		2024	2025	2026	2027	2028	Change over outlook
1-in-2 peak day	Tariff V	892	875	847	812	771	-13.6%
	Tariff D	206	210	205	207	205	-0.4%
	System demand	1,098	1,084	1,053	1,020	976	-11.1%
	System demand without electrification	1,099	1,105	1,111	1,123	1,130	2.8%
1-in-20 peak day	Tariff V	960	947	917	881	834	-13.1%
	Tariff D	219	217	214	217	213	-2.8%
	System demand	1,179	1,164	1,131	1,097	1,047	-11.2%
	System demand without electrification	1,179	1,187	1,195	1,206	1,216	3.1%

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

As **Figure 16** shows:

- The peak day demand forecasts represent a decrease compared to pre-2023 historical levels, to forecast demands of 976 TJ/d and 1,047 TJ/d in 2028 for 1-in-2 peak day and 1-in-20 peak day, respectively.
- Winter 2023 saw Victoria's lowest winter peak day system demand since 2004, at 995 TJ/d. This peak occurred on 20 June 2023, and was consistent with the broader lower consumption trend experienced during 2023, driven by the factors described in Section 2.1.

Figure 16 Historical and forecast peak day maximum system demand, 2014-28 (TJ/d)



2.3.2 Monthly peak day demand for 2024

Table 11 shows the forecast peak day system demand for each month during 2024 for the *Step Change* scenario. Forecast monthly peak day demand in 2024 is similar in the *Step Change, No Electrification* sensitivity, because the impacts of electrification this year are expected to be small.

The actual peak system demand day is forecast to occur during the three coldest winter months: June, July, and August[68].

Table 11 Forecast monthly peak day demand for 2024, (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2 peak day	366	388	439	646	888	1,041	1,071	1,035	842	690	583	412
1-in-20 peak day	426	451	549	767	1,018	1,137	1,169	1,140	958	806	712	506

2.4 GPG forecasts

GPG is forecast to play a crucial role in complementing battery and pumped hydro generation to support peak electricity demand periods when the output from VRE generation is limited, including during extended periods of low sunlight and wind (renewable droughts). The Draft 2024 ISP forecasts this critical need for peaking GPG increasing during the winter months of June, July and August, representing a shift from historical stable GPG peaks to increased winter demand peaks through to 2040[69].

AEMO's GPG forecasts are developed in line with the *Step Change* scenario in the 2023 IASR to consider thermal fuel limitations on coal generators, and to apply limitations on electricity generation capacity build as outlined in the *Electricity Statement of Opportunities* (ESOO) methodology[70]. Following the closure of the Eraring coal power station in New South Wales in 2025, and again after the 2028 closure of Victoria's Yallourn coal power station, GPG requirements are forecast to increase during the outlook period.

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

The GPG peak demands for the five-year outlook period are expected to gradually increase by approximately 50% over the first four years from 2024 to 2027, followed by a step up by over 266% to approximately 440 TJ/d during winter 2028, driven by the closure of the Yallourn Power Station. GPG demand peaks during summer months are forecast to decrease by 16%, from a maximum forecast of 186 TJ/d in 2024 to 155 TJ/d in 2028.

The Draft 2024 ISP outlines the generation, firming and electricity transmission infrastructure required to meet the emissions reductions targets set by Australian governments. The amount of gas that is required for GPG in the next decade will be influenced by the timing of coal generator closures in the National Electricity Market (NEM), and Victorian coal generators are assumed in the *Step Change* scenario to progressively shut down over the next decade, sooner than the announced coal closure dates. The Draft 2024 ISP forecasts Victorian GPG capacity needing to increase from the existing 2.4 GW to 3.6 GW during the early 2030s from 2032 to 2035, which is expected to lead to new GPG connections in the Victorian DTS. The supportability and sustainability of gas supply

[68] Note that the monthly and annual 1-in-2 and 1-in-20 forecasts are derived from different distributions (annual peaks versus discrete monthly peaks) and therefore there will not be perfect alignment between the annual peak forecast and the highest monthly peak forecast.

[69] AEMO, Draft 2024 ISP, pg. 65, at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

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

to these new generator connections would depend on which parts of the DTS they connect to and where the new gas supplies are sourced.

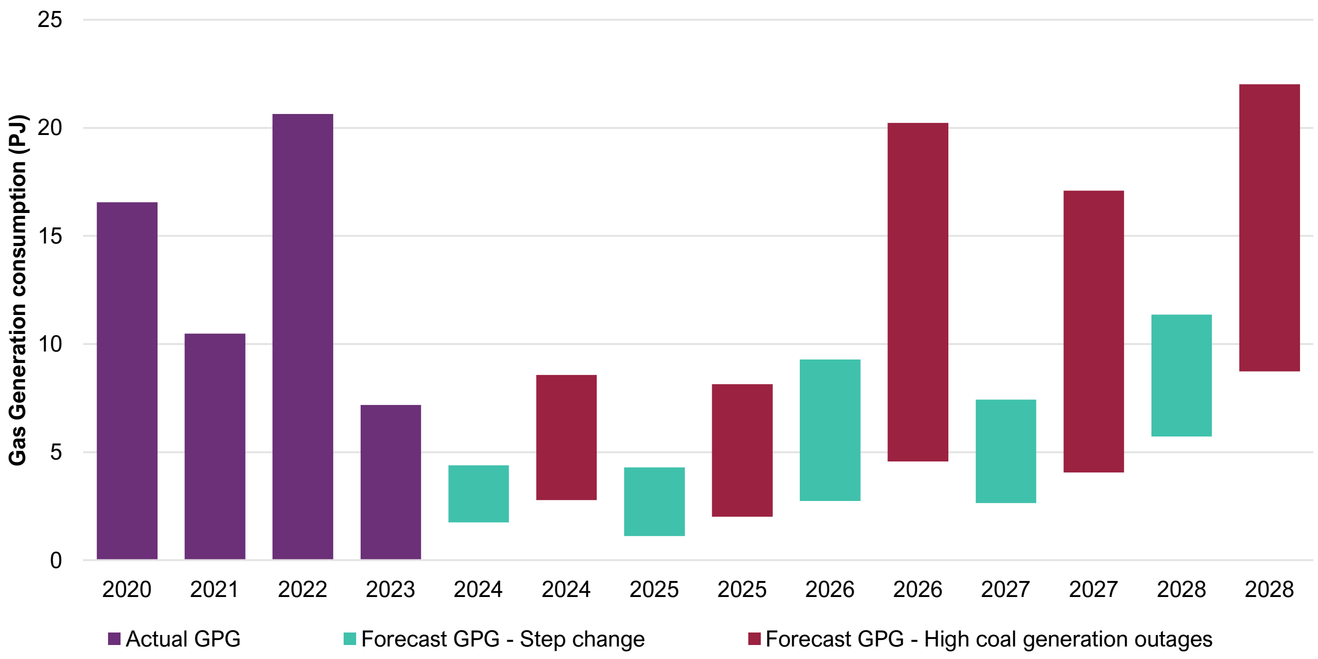
The Draft 2024 ISP also highlights that the risk of unplanned generator outages is increasing, as the fleet ages and coal plant reliability is affected by high-impact weather events and reduced investment leading up to closure[71]. This can greatly increase GPG consumption, as evidenced by the high annual GPG consumption in 2022 that was primarily caused by coal generator outages and fuel supply issues. If coal generation was to be reduced due to an extended outage or fuel supply issue (modelled in the *High Coal Generation Outages* sensitivity), GPG consumption is forecast to increase by approximately 209% over the 2024 to 2028 outlook period. This is between 50% and 78% higher than forecast GPG consumption under the *Step Change* scenario for the same period.

The sections below discuss a range of potential GPG forecast outcomes, rather than an average across all weather conditions.

2.4.1 Annual GPG consumption forecast

Figure 17 shows actual annual Victorian GPG consumption from 2020 to 2023, and the GPG consumption forecasts from 2024 to 2028 for the *Step Change* scenario and *High Coal Generation Outages* sensitivity. The maximum and minimum forecasts in this figure relate to forecast variability due to weather. The average GPG forecast for all scenarios is presented in **Table 12**.

Figure 17 Actual and forecast minimum and maximum annual Victorian GPG consumption, 2020-28 (PJ)



The figure and table show the following important points:

- Victorian GPG consumption is forecast to decline slightly in 2024 and 2025, then increase in the following three years. From the lowest level of 2.6 PJ in 2025, consumption is forecast to rise to 6.2 PJ in 2026, decline slightly

[71] AEMO, Draft 2024 ISP, pg. 74, at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

to 5.9 PJ in 2027, before experiencing a large step up to 9.5 PJ in 2028. This results in forecast Victorian GPG consumption increasing over the outlook period by 242.1%.

- Uncertainty about weather and generator availability results in a broad range in forecast annual GPG consumption, later in the outlook period.
- The increase in forecast GPG consumption over the outlook period is influenced by the increased electrification in the *Step Change* scenario, raising electricity demand in the NEM. GPG is also forecast to provide power system services for security and stability.

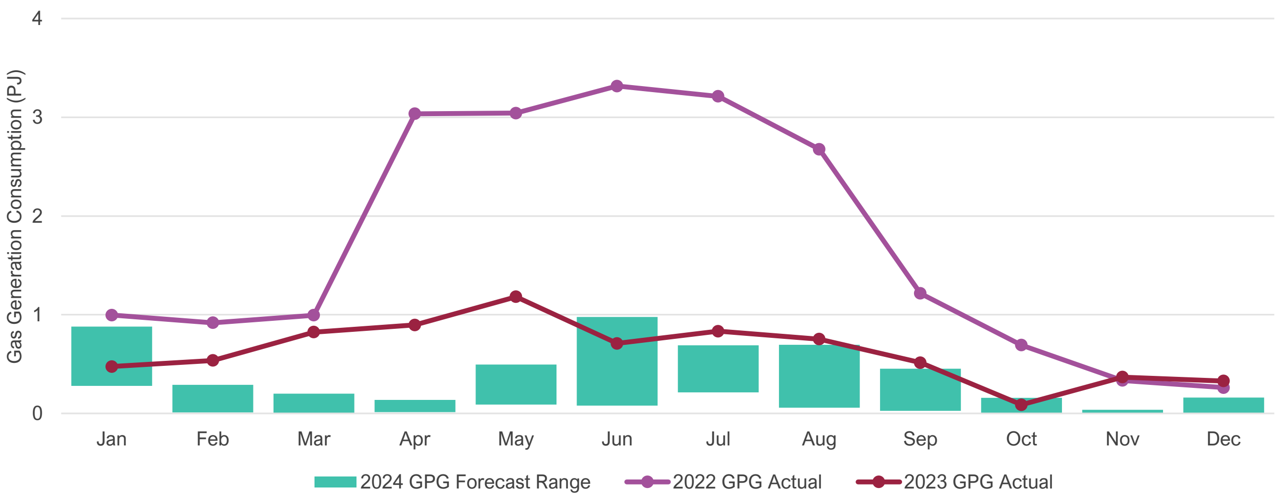
Table 12 GPG consumption forecast, 2024-28 (PJ/y)

	2023 (Actual)	2024	2025	2026	2027	2028	Change over outlook
DTS GPG consumption	3.8	1.7	1.5	3.6	3.5	5.8	241.4%
Non-DTS GPG consumption	3.6	1.1	1.1	2.7	2.3	3.6	243.3%
Victorian GPG consumption	7.4	2.8	2.6	6.2	5.9	9.5	242.1%
Victorian GPG consumption (*High coal generation outages* sensitivity)	-	4.6	4.6	10.6	9.3	14.2	208.8%

2.4.2 Monthly GPG forecast for 2024

Figure 18 shows actual monthly Victorian GPG consumption in 2022 and 2023, and the forecast monthly consumption range for 2024.

Figure 18 Actual and forecast monthly Victorian GPG consumption, 2022-24 (PJ/m)



Monthly GPG consumption can be significant during winter, with the potential to coincide with a 1-in-2 or 1-in-20 peak winter system demand day. The forecast shows that monthly GPG consumption in 2024 is projected to be higher during the winter months than the summer period, driven by a combination of high NEM demand and lower VRE output (particularly solar). Coal generation outages during winter continue to be a risk, which could drive GPG consumption much higher than this forecast, per the *High coal generation outages* sensitivity shown in **Figure 17** above.

For actual GPG consumption, 2023 saw a considerable decrease in monthly consumption compared to 2022 for most months. Consumption in 2023 is more aligned with the consumption profile from prior years; 2022 was an outlier for GPG consumption due to several compounding incidents including cooler weather, Victorian and New South Wales coal generator outages, and flooding impacting hydro generation.

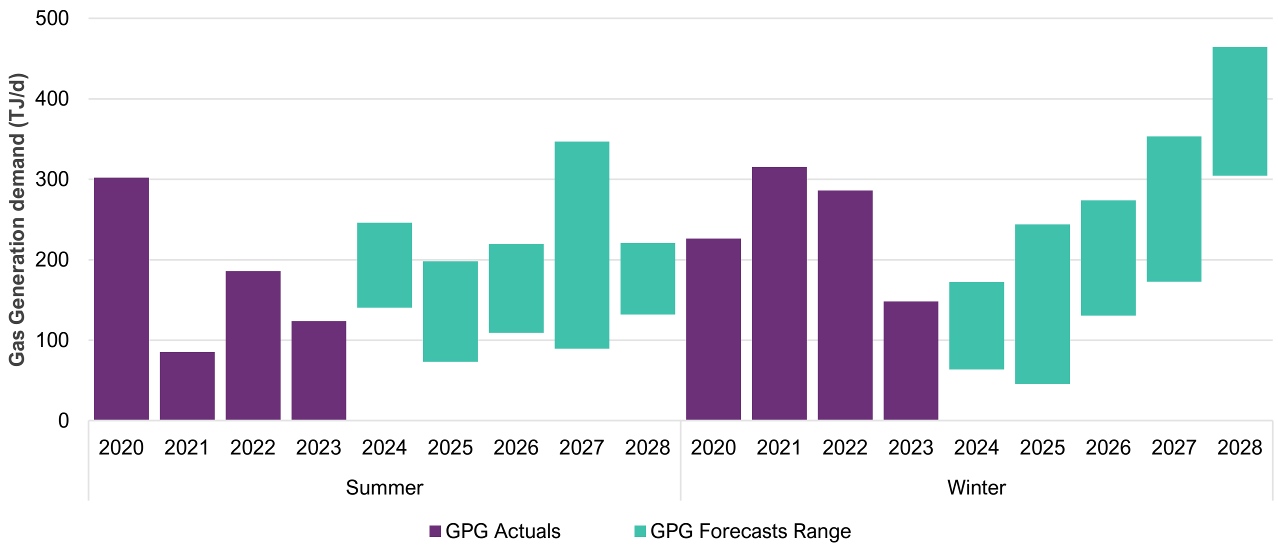
2.4.3 Seasonal peak GPG demand forecast

Peak GPG demand in winter is predicted to increase by approximately 170% over the outlook period, from a forecast maximum of 172 TJ/d in 2024 to 464 TJ/d in 2028. If winter system demand in 2028 is above approximately 900 TJ, which is less than the 1-in-2 peak day system demand forecast, total demand would exceed the current DTS total demand record of 1,308 TJ/d set on 9 August 2019.

Annual increases in peak GPG demand forecast vary between 12% and 42%. The largest increases are forecast to be 45% in 2025 and 31% in 2028. This increase in forecast winter GPG demand (and consumption) corresponds to the planned retirement of Eraring and Yallourn coal power stations during the outlook period, as well as the expected electrification of winter heating loads resulting in increased winter electricity demand.

GPG demand during summer is forecast to decrease by 10% in the outlook period, from a forecast maximum of 246 TJ/d in 2024 to 221 TJ/d in 2028. This decrease is projected as a step down from the second year of the VGPR outlook in 2025, with a significant increase in 2027 due to the Draft 2024 ISP modelling a Victorian coal generation unit closure in 2027, then reducing again in 2028. This declining summer GPG peak demand trend is expected to result in peak GPG demand in winter being higher than summer GPG peak demand from 2025, as shown in **Figure 19**.

Figure 19 Actual (2020-23) and forecast (2024-28) seasonal maximum and minimum Victorian GPG demand in summer and winter (TJ/d)



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

The 2024 GSOO projects that the GPG consumption profile will have higher demand peaks, particularly during winter months by 2040 (beyond this VGPR Update outlook period), and forecasts that during extreme demand periods, a month's worth of GPG consumption may be used in a few days. On these days, the value of the capacity provided by GPG is important for electricity consumers. If there is insufficient gas supply capacity available, the use of alternative resources – including alternative secondary generation fuels (generally diesel), deep electrical storages, and electricity demand response – will be needed to maintain power system reliability.

Flexible solutions to supply the increased gas quantities required under these challenging conditions will be essential. These could include increased utilisation of the linepack within high-pressure pipelines, local gas storages, higher liquid fuel storage inventories, and some large gas users agreeing to interruptible supply contracts.

High GPG demand during the winter period may create operational challenges for the DTS that result in a threat to system security. This risk is increased if GPG demand is not forecast accurately from the beginning of the gas day, or if it is higher than available gas supply.

3 Gas supply adequacy

Key findings

- **Victoria's production outlook has decreased since the 2023 VGPR**, with less supply available from 2024 through to 2026. The total available gas supply is forecast to reduce by 48% over the outlook period**,** from 297 PJ in 2024 to 154 PJ in 2028.
  - The stepped reduction in forecast production capacity is caused by a reduction in offshore field production capacity, driven by the decline of the large legacy fields. GBJV has advised planned retirement of gas processing plants at the Longford Gas Plant, starting with Gas Plant 1 in July 2024 and followed by Gas Plant 3 later in the decade.
- Victoria's annual gas production is forecast to exceed its annual gas consumption up to 2027, however, the 2024 GSOO forecasts indicate a risk in southern regions of **peak day shortfalls under extreme conditions from 2025** and the potential for **small seasonal supply gaps from 2026**, one year earlier than projected in the 2023 GSOO.
- Forecast Victorian winter production capacity will reduce in line with reduced annual production.
  - Gippsland region peak winter production capacity will reduce from 767 TJ/d in 2024 to 325 TJ/d in 2028, **a 58% reduction**, primarily due to the Longford plant retirements.
  - Port Campbell region production and Iona UGS capacity is forecast to experience a lower reduction in peak winter capacity, from 781 TJ/d in 2024 to 708 TJ/d in 2028 (a 9% reduction). Port Campbell supply into the DTS is forecast to remain at 530 TJ/d due to the capacity of the South West Pipeline (SWP).
- The 1-in-20 peak day shortfall for winter 2027 that was forecast in the 2023 VGPR remains and is now little more than three years away. In winter 2028, forecast system demand exceeds expected supply on both a 1-in-2 and 1-in-20 peak day.
  - This is despite a **forecast 11% reduction in Victorian peak day system demand** across the outlook period.
  - The 2024 GSOO highlights the **risk of peak day shortfalls from 2025 in the event of high coincident system and GPG demand across the southern states**.
- This VGPR Update outlook period is limited to 2024 to 2028, but lead times for production and infrastructure projects now often extend beyond five years. It is clear **more supply for Victoria is required**, however projects face the same challenges identified in the 2023 VGPR and investment uncertainty remains high.
- The decline of the large legacy fields and the subsequent retirement of infrastructure at Longford Gas Plant reduces redundancy and supply flexibility, which increases the probability of outages. The tight peak day supply balance leaves a **small margin for even brief supply issues**, where plant trips or equipment outages in winter in Victoria may result in a gas load curtailment event.

Background

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

AEMO assesses adequacy over three time periods in the VGPR:

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

Gas supply classification

Table 13 defines gas supply classifications used in this 2024 VGPR Update, with notes on the differences between these classifications in the 2024 GSOO and the Petroleum Resources Management System (PRMS)[72].

Table 13 Gas supply classifications

VGPR	2024 VGPR Update description	PRMS	GSOO
Existing supply	Comprises existing gas reserves and projects currently in operation.	Reserves: On Production	Existing supply
Committed supply	Encompasses committed new gas supply projects, including developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement and construction (EPC) phase, but are not currently operational.	Reserves: Approved for Development	Committed supply
Available supply	Incorporates both existing supply and committed supply.	Reserves: On Production, Approved for Development	Existing and committed supply
Anticipated supply	Considers gas supply from undeveloped reserves or contingent[73] resources that producers forecast to be available as part of their best production estimates provided to AEMO. It includes projects or developments which have not reached FID but are considered likely to proceed during the outlook period (often using existing infrastructure).	Reserves: Justified for Development	Anticipated supply

[72] 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.

[73] Quantities estimated to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable due to one or more contingencies.

VGPR	2024 VGPR Update description	PRMS	GSOO
Potential projects	Uncommitted gas supply projects that have not reached FID, which could potentially proceed during the outlook period. These projects have not been included in the anticipated supply forecast. They are considered less likely to proceed than the anticipated supply projects during the outlook period, due to: • The discovered gas fields being classified as contingent resources (not proven reserves) where commercial recovery is dependent on the development of new technology or where evaluation of the gas resource is still at an early stage; or • Insufficient gathering pipeline or appropriate gas processing capacity being available; or • The project requiring new infrastructure that currently does not have approved planning permits or environmental approvals.	Contingent Resources: Development Pending, Development on Hold, Development Unclarified	Uncertain supply
Exploration projects	These projects are associated with undiscovered gas resources that are usually mapped using seismic data. These have not been physically proven with exploration wells, so commercial quantities of hydrocarbons may not actually be present. Neighbouring wells and seismic data are used to estimate the 'gas in place', with the reported prospective resource volumes usually representing the estimated recoverable volume of hydrocarbons. These are not included in any of the supply forecasts but are discussed in the 2024 GSOO.	Prospective resources: Prospect/Leads/Plays	

3.1 Changes impacting the supply demand balance

This section highlights updates to key projects that have impacted the supply demand balance since the publication of the 2023 VGPR.

3.1.1 Updates reducing available supply

Thylacine and Enterprise

Beach Energy's connection of the two new offshore Thylacine North wells to Otway Gas Plant was successfully completed in May 2023, however the connection of the two Thylacine West wells was delayed due to an issue with the flowline. The connection of these remaining wells has been delayed until the second half of 2024.

The connection of the nearshore Enterprise-1 well to Otway Gas Plant has been delayed from early 2024 to mid-2024 as Beach Energy work through the final regulatory approvals.

The result of these delayed connections is a reduction in Otway Gas Plant forecast production for 2024 compared to the 2023 VGPR. The plant is forecast to return to its nameplate capacity of 205 TJ/d once the Thylacine West and Enterprise-1 connections are completed.

3.1.2 Updates increasing available supply

Winchelsea Compressor 2 and WORM

APA commissioned a second compressor unit on the SWP at the Winchelsea Compressor Station (CS) in August 2023 and completed the Western Outer Ring Main (WORM) project in February 2024. The completion of these two projects increased the injection capacity of the SWP from 447 TJ/d during early winter 2023 to 530 TJ/d for 2024, increasing the peak day supply available from Port Campbell, including from Iona UGS.

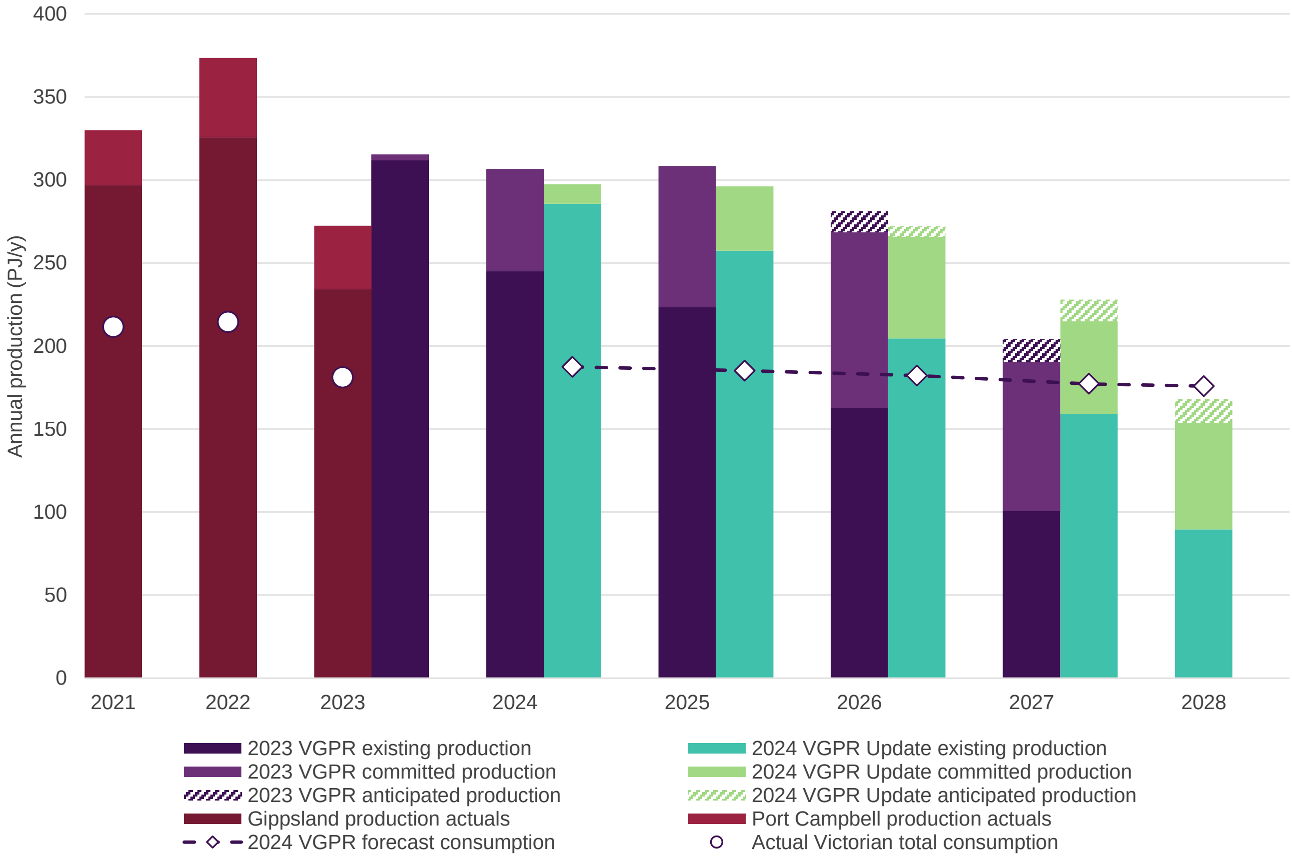
3.2 Annual supply adequacy

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

3.2.1 Annual production forecasts

Figure 20 shows the Victorian annual production forecasts for the outlook period and compares these to the forecasts published in the 2023 VGPR.

Figure 20 Actual and forecast supply and total consumption, compared to the 2023 VGPR, 2021-28 (PJ/y)



Gippsland[74]

Total Gippsland production is forecast to remain flat between 2024 and 2025, with production reducing by 3% from 243 PJ in 2024 to 235 PJ in 2025. This is comparable to the 234 PJ produced in 2023; however, as discussed in Section 1.2.1, low Gippsland production in 2023 can be attributed to overall low consumption and market participant behaviour rather than reflecting the available production capacity.

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

Over the outlook period, Gippsland region production is forecast to reduce by 55%, from 243 PJ in 2024 to 109 PJ in 2028. This includes the committed Kipper compression project which is expected to provide additional supply from October 2024. The anticipated Kipper Stage 1B Project, comprising an additional infield production well, could lessen the reduction in Gippsland production from 2026. More information on this project is provided in Section 4.2 of the 2023 VGPR.

The reduction in Gippsland region supply over the outlook period is mainly due to the forecast decrease in production associated with the depletion of the Gippsland Basin Joint Venture (GBJV) large legacy fields that supply the Longford Gas Plant. Large reductions in Gippsland region production reported in the 2023 VGPR are still forecast to occur in 2024 and 2027, with an additional reduction in 2028.

The forecast available production in 2027 has increased from 130 PJ in the 2023 VGPR to 154 PJ with additional gas forecast to be available from the Longford Gas Plant.

Potential Gippsland region projects that could increase the production forecast include the Turrum Phase 3[75] and Late Life Optimisation projects at the Longford Gas Plant, development of the Trefoil field to supply the Lang Lang Gas Plant, the Manta field for the Orbost Gas Plant, and the Golden Beach production and storage facility. Project updates for this 2024 VGPR Update are discussed in Section 4.1.

Port Campbell[76]

Port Campbell production is forecast to increase from the 38 PJ produced in 2023 to 55 PJ in 2024 with the connection of the Thylacine West wells and the Enterprise-1 well to Otway Gas Plant during the second half of 2024. Completion of these projects will return the Otway Gas Plant to nameplate capacity of 205 TJ/d. The connection of these wells has been delayed, reducing forecast Port Campbell production for 2024 from the 73 PJ reported in the 2023 VGPR. Port Campbell production also includes the Athena Gas Plant, which processes gas from the Casino, Henry, and Netherby gas fields.

Production from the Port Campbell region is forecast to increase again to 70 PJ in 2026 before declining, with 2028 production forecast to be 18% lower than in 2024. Additional investment will be required to reduce this production decline. Potential projects include Cooper Energy's Otway Phase 3 Development Project and Beach Energy's Artisan field development. Both projects are discussed in Section 4.3 of the 2023 VGPR.

Cooper and Beach, along with the ConocoPhillips and 3D Oil joint venture, have formed a consortium to secure a drilling rig for planned drilling campaigns in the Otway Basin from 2025.

3.2.2 Annual supply adequacy

Table 14 shows the annual supply adequacy forecast over the outlook period. The annual supply adequacy assessment indicates:

- Forecast available supply exceeds forecast consumption for most of the outlook period, with surplus Victorian production, ranging between 110 PJ in 2024 and 38 PJ in 2027, being available to supply New South Wales, South Australia, and Tasmania.

[75] Referred to as Turrum and North Turrum in the 2023 VGPR.

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

- The 2024 GSOO identifies the risk of small seasonal supply gaps from 2026 (one year earlier than reported in the 2023 GSOO), due to increased GPG consumption forecasts in the southern states. This indicates that there are risks of seasonal shortfalls occurring during winter from 2026 onwards in the southern states, including Victoria.
- Victorian consumption is forecast to exceed available supply in 2028, one year later than reported in the 2023 VGPR. Completion of anticipated supply projects would increase supply by 14 PJ, reducing but not eliminating the projected supply imbalance in 2028.
- There is an improvement in forecast supply adequacy for all years compared to the 2023 VGPR, despite lower available production in 2024 to 2026. This is due to the lower consumption forecast for the *Step Change* scenario; for example, forecast total consumption for 2024 is 187 PJ, 13% lower than the 206 PJ forecast for 2024 in the 2023 VGPR. In 2027, an additional 25 PJ of committed production is also available compared to the 190 PJ forecast in the 2023 VGPR.
- As discussed in Section 2.2.1, the VGPR consumption forecast includes electrification of gas demand, mostly Tariff V demand. If this electrification is delayed beyond the outlook period, then the projected annual shortfall in 2028 increases from 22 PJ to 46 PJ.

Table 14 Victorian annual available supply and anticipated supply balance, 2024-28 (PJ/y)

Supply source		2024	2025	2026	2027	2028
Gippsland [A]	Existing	**243**	**215**	**156**	**118**	**62**
	Committed	0	20	40	36	47
	Total available	**243**	**235**	**196**	**154**	**109**
	Anticipated	0	0	6	13	14
	Total available plus anticipated	243	235	202	167	123
Port Campbell [B]	Existing	**43**	**42**	**48**	**41**	**28**
	Committed	12	18	22	20	17
	Total available	**55**	**61**	**70**	**61**	**45**
	Anticipated	0	0	0	0	0
	Total available plus anticipated	55	61	70	61	45
Total Victorian production	Existing	**286**	**257**	**205**	**159**	**90**
	Committed	12	39	61	56	64
	Total available	**297**	**296**	**266**	**215**	**154**
	Anticipated	0	0	6	13	14
	Total available plus anticipated	297	296	272	228	168
Total Victorian consumption [C]		187	185	182	177	176
Surplus quantity with Victorian available supply		**110**	**111**	**84**	**38**	**-22**

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

Seasonality and interconnection with other jurisdictions

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

- During the summer months, Victorian production is higher than Victorian consumption with the excess gas used to refill Iona UGS and supply other jurisdictions.
- Victorian consumption exceeds production during the winter months and Iona UGS is used to support increased Victorian gas usage, with supply also continuing to other jurisdictions during winter.

Historically Victoria has supplied other jurisdictions and acted as a net exporter of gas throughout the year:

- The amount of gas exported from Victoria is expected to decrease as forecast Victorian production declines. The forecast reduction in Victorian production, even with the completion of anticipated projects, is projected to result in limited gas being available to supply other jurisdictions from 2027.
- From winter 2028, Victoria is forecast to become a net importer of gas as Victorian consumption exceeds Victorian production and available storage inventory (unless potential Victorian supply and storage projects are developed).

The 2024 GSOO projects small seasonal supply gaps in 2026 and 2027 for the southern states, driven by GPG demand, followed by a consistent and larger supply gap from 2028. The risk of supply gaps is highest during the winter months, when consumption in the southern states is highest and could exceed combined southern production, storage inventory and the pipeline capacity from Queensland. The shortfall could impact any of the southern states, including Victoria.

The risk of shortfalls outside of winter is small, however low summer production including extended maintenance outages could impact southern storage refilling which increases the risks of winter seasonal shortfalls.

The 2024 GSOO explores east coast supply adequacy in further detail.

3.3 Peak day supply adequacy

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

3.3.1 Forecast Victorian peak day supply capacity

The forecast maximum daily Victorian supply capacity by SWZ, including capacity from the Iona UGS and Dandenong LNG storage facilities, is shown in **Table 15**. The actual supply available to the DTS from each zone is lower, due to DTS capacity constraints and gas flows from Gippsland to other jurisdictions that can only be supplied from Victoria (see Section 3.3.2).

Based on information from gas producers and storage providers, the available Victorian peak day supply capacity is forecast to decline by 34% over the outlook period:

- Gippsland producers have advised that maximum peak day production capacity will reduce by 58%, from 767 TJ/d in 2024 to 325 TJ/d in 2028. Actual Gippsland region production capacity during winter 2023 varied with the Longford Gas Plant continuing maintenance into early June, and fluctuating capacities for the Orbost and Lang Lang gas plants. Capacity ranged from less than 900 TJ/d to 945 TJ/d in late winter compared to forecast available capacity of 915 TJ/d published in the 2023 VGPR, which was 10% lower than the 1,018 TJ/d available during winter 2022. The highest actual Gippsland region daily production during winter 2023 was 872 TJ.

- The stepped reduction in forecast peak day production capacity is caused by a reduction in offshore field production capacity, driven by the decline of the large legacy fields. GBJV has advised AEMO of planned retirement of gas processing plants at the Longford Gas Plant, starting with Gas Plant 1 in July 2024 and followed by Gas Plant 3 later in the decade, to match onshore production capacity with the reduced offshore field production capacity as the large legacy fields decline.
- AEMO has assessed peak day supply adequacy for 2024 using the production capacity following the closure of Gas Plant 1. Prior to the closure of Gas Plant 1, planned for July, up to 810 TJ/d of peak day capacity will be available from Longford in winter 2024[77].
- Available Gippsland production includes supply from the committed Kipper compression project, with supply from this project expected from October 2024.
- The anticipated Kipper Phase 1B project could partly offset the forecast decline in Gippsland region production from 2026, but production capacity is still forecast to decline by 52% over the outlook period. Investment in the Kipper Phase 1B project remains subject to Kipper Unit Joint Venture (KUJV) investment decisions.

- Port Campbell producers and the Iona UGS operator have advised that maximum daily supply capacity will remain relatively stable over the outlook period, decreasing by 9%, from 781 TJ/d in 2024 to 708 TJ/d in 2028:
  - Production capacity is projected to increase from the actual maximum production of 199 TJ/d in 2023 to 211 TJ/d in 2024 and then to 222 TJ/d in 2025, mainly due to supply from the committed connection of the Thylacine West and Enterprise-1 wells which will return the Otway Gas Plant to its nameplate capacity of 205 TJ/d from late 2024.
  - Lochard Energy increased the Iona UGS supply capacity from 558 TJ/d to 570 TJ/d in June 2023, earlier than reported in the 2023 VGPR.
  - No anticipated Port Campbell production or Iona UGS expansion projects are forecast for the outlook period.
- Port Campbell peak day supply capacity into the DTS is forecast to remain at 530 TJ/d due to the capacity of the SWP, which has increased following the addition of the second Winchelsea compressor and the construction of the WORM pipeline. Available Port Campbell capacity is combined supply to the DTS, South Australia and Mortlake Power Station.

[77] Forecast capacities for winter 2024 are available in the Medium Term Capacity Outlook on the Gas Bulletin Board, at https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb.

Table 15 Peak day maximum daily quantity (MDQ) by System Withdrawal Zone, 2024-28 (TJ/d)

SWZ	Supply source	2024	2025	2026	2027	2028
Gippsland [A]	Available	767[B]	772	620	475	325
	Anticipated	0	0	30	52	45
	Total available plus anticipated	767	772	650	527	369
Port Campbell (Geelong) [C]	Available	781	792	775	745	708
	Anticipated	0	0	0	0	0
	Total available plus anticipated	781	792	775	745	708
Melbourne	Available	87	87	87	87	87
Total Victorian Supply	Total Victorian available	1,635	1,651	1,483	1,307	1,119
	Total Victorian anticipated	0	0	30	52	45
	Total Victorian available plus anticipated	1,635	1,651	1,513	1,359	1,164

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP so all of this capacity cannot be supplied to the DTS because of EGP and TGP demand.
B. The operator of Longford Gas Plant has published higher daily capacities for earlier in winter 2024 on the Gas Bulletin Board, prior to the closure of Gas Plant 1, however AEMO is using the post-closure capacity of Longford to undertake the peak day supply adequacy assessment. Up to 810 TJ/d of peak day capacity will be available from Longford in winter prior to the closure of Gas Plant 1, planned for July 2024.
C. Port Campbell zone includes the Otway and Athena production facilities and Iona UGS. The combined supply is available to the DTS, South Australia and Mortlake Power Station. All of this supply cannot be supplied into the DTS due to the SWP capacity.

3.3.2 Peak day supply adequacy

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

The forecasts shown in **Figure 21** and **Table 16** used the following data and assumptions:

- Forecast annual 1-in-2 and 1-in-20 year peak day system demands, discussed in Section 2.3.
- The full capacity of the Iona UGS and Dandenong LNG storage facilities were assumed to be available, and not restricted due to low storage inventories.
- Demand from GPG is not considered. 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 assessment only considers firm sources of gas supply. Imports from Culcairn via the VNI have not been included in the peak day supply capacity. Culcairn supply depends on operational and market conditions in the New South Wales transmission system, including demand in southern New South Wales and the operation of the Uranquinty Power Station. Short-term pipeline linepack, including from the Tasmanian Gas Pipeline (TGP) supplied via the TasHub facility, is also not considered.

The figure and table highlight the following key points:

- Peak day supply adequacy for years 2024, 2025 and 2027 has improved slightly compared to the outlook presented in the 2023 VGPR. This is mostly due to a reduction in the peak day demand forecasts under the updated *Step Change* scenario.

- There is sufficient peak day supply to meet demand until 2027. Peak day adequacy is tight in 2026, with Dandenong LNG injections required to support a 1-in-20 system demand day. There is likely to be insufficient supply capacity to support even moderate levels of GPG on a peak day during winter 2026.
- System demand exceeds available supply on a 1-in-20 system demand day in 2027, and on both a 1-in-2 and 1-in-20 system demand day in 2028:
  - The forecast peak day shortfall is now four years into the outlook period, instead of five years in the 2023 VGPR (that was published one year ago). This leaves little more than three years for projects to be developed and commissioned to resolve these forecast peak day shortfalls.
  - Anticipated projects improve peak day adequacy from 2026, but these projects cannot resolve any of the forecast supply adequacy gaps identified from 2027.
  - The development of the potential gas production project Turrum Phase 3, which uses existing infrastructure at Longford Gas Plant, would address the forecast peak day supply shortfall in winter 2027. GBJV participants have each been granted a conditional Ministerial exemption from the price rules provisions of the Federal Government's Gas Market Code[78], as announced in January 2024[79]. Investment in the Turrum Phase 3 project remains subject to GBJV investment decisions.
  - Alternative projects that could address the 2027 peak day supply adequacy gap include production from the Golden Beach gas field, or an LNG import facility such as the Port Kembla Energy Terminal or the Viva Energy Gas Terminal Project. Analysis of DTS capability with the connection of an LNG import facility to the SWP at Geelong is discussed further in Section 4.2.
  - The 2027 gas shortfall (and the tight capacity during 2026) may also be mitigated by non-firm sources including non-firm Dandenong LNG injections, importing gas from New South Wales via Culcairn (if there is sufficient supply in that state), or utilising pipeline linepack from interconnected pipelines.
  - A large amount of new supply capacity is required from 2028 to offset large forecast reduction in production capacity, mainly due to the step down in Longford Gas Plant capacity, and additional supply capacity is also required to support the large forecast increase in GPG demand following the closure of the Yallourn Power Station.
  - Development of potential supply projects, storage projects or an LNG import facility is forecast to be required to avert shortfalls on peak system demand days in 2028. There are no proposed pipeline expansions that would address the peak day shortfall in Victoria for 2028.

As discussed in Section 2.3.1, the VGPR forecast includes an assumption that there is an increasing amount of electrification of mostly Tariff V demand in the outlook period. If this electrification is delayed beyond the outlook period:

- The 13 TJ/d surplus supply capacity during winter 2027 on a 1-in-2 peak system demand day switches to a 90 TJ/d shortfall, and the 65 TJ/d shortfall on a 1-in-20 peak demand day increases to 173 TJ/d.

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[78] More information is at https://www.accc.gov.au/business/industry-codes/gas-market-code#:~:text=The%20Gas%20Market%20Code%20is,prices%20and%20on%20reasonable%20terms.

[79] Minister for Resources and Minister for Northern Australia media release, "Gas market code secures supply for domestic market", 22 January 2024, at https://www.minister.industry.gov.au/ministers/king/media-releases/gas-market-code-secures-supply-domestic-market.

- In 2028, the shortfall is increased from 94 TJ/d to 248 TJ/d and from 165 TJ/d to 334 TJ/d on a 1-in-2 and 1-in-20 peak demand day respectively.
- The first year with a peak day shortfall comes forward from 2027 to 2026. The 46 TJ/d surplus on a 1-in-20 peak day demand day in 2026 becomes a 17 TJ/d shortfall.

The 2024 GSOO highlights the risk of peak day shortfalls in the southern states from 2025 on winter days when the extremally cold weather that results in a high system demand for heating coincides with high demand for GPG. The projected frequency of these high demand days increases later in the outlook period, after the planned closure of Eraring coal power station in August 2025. GPG is excluded from **Figure 21** and **Table 16**, but any GPG demand occurring on peak system demand days would increase the risk of insufficient gas supply. See the 2024 GSOO for more on east coast gas supply adequacy.

Figure 21 Forecast peak day supply and DTS adequacy, 2024-28 (TJ/d)

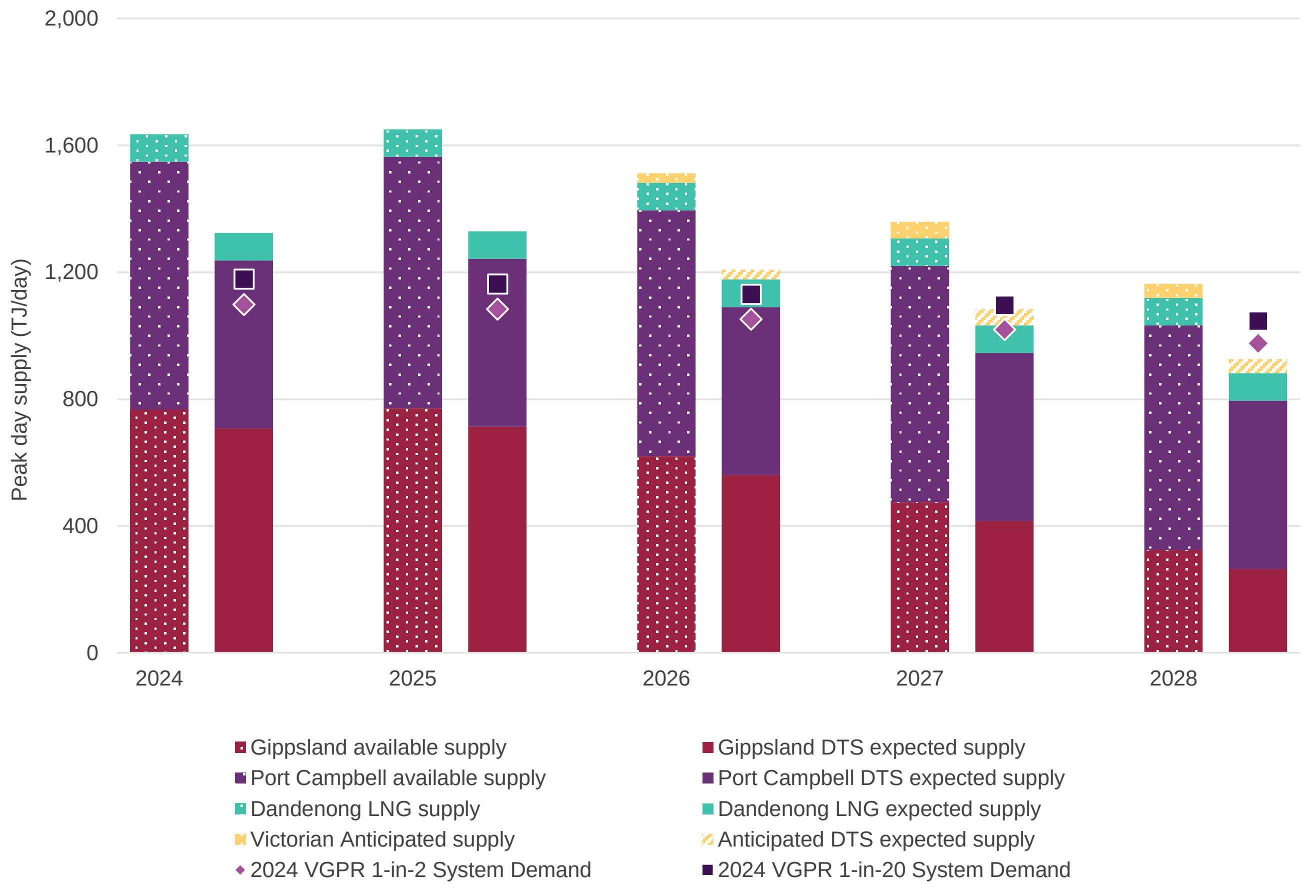


Table 16 Forecast peak day supply adequacy, 2024-28 (TJ/d)

Supply source		2024	2025	2026	2027	2028
Gippsland [A]	Expected [B]	707[C]	712	561	416	265
	Anticipated	0	0	30	52	45
	Total available plus anticipated	707	712	591	467	309
Port Campbell (Geelong) [D]	Expected [E]	530	530	530	530	530
	Anticipated	0	0	0	0	0
	Total available plus anticipated	530	530	530	530	530
Melbourne	Expected	87	87	87	87	87
Total Victorian supply	Total Victorian expected	1,324	1,329	1,178	1,033	882
	Total Victorian anticipated	0	0	30	52	45
	Total Victorian expected plus anticipated	1,324	1,329	1,208	1,084	926
1-in-2 system demand		1,098	1,084	1,052	1,020	976
1-in-20 system demand		1,179	1,164	1,131	1,097	1,047
1-in-2 day surplus quantity with Victorian expected supply		226	245	125	13	-94
1-in-20 day surplus quantity with Victorian expected supply		145	165	46	-65	-165

Note: totals may not add up due to rounding.
A. Gippsland zone includes Longford, Orbost and Lang Lang production facilities. Combined production is gas available to the DTS, EGP and TGP.
B. Expected Gippsland zone supply excludes the portion of available Gippsland supply that is needed to supply Tasmanian demand and demand along the EGP, including in south-east New South Wales, that cannot be supplied from any other source.
C. The operator of Longford Gas Plant has published higher daily capacities for earlier in winter 2024 on the Gas Bulletin Board, prior to the closure of Gas Plant 1, however AEMO used the post-closure capacity of Longford for the peak day supply adequacy assessment. Up to 810 TJ/d of peak day capacity will be available from Longford in winter prior to the closure of Gas Plant 1, planned for July 2024.
D. 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.
E. Expected Port Campbell supply is limited by the capacity of the SWP.

3.4 Longer-term supply adequacy

Under the NGR, the VGPR outlook period is five years; this requires the 2024 VGPR Update to consider the period from 2024 to 2028. Lead times for production and infrastructure projects now often extend beyond five years from project initiation to completion and commissioning.

This increasing lead time increases the risk of insufficient or inadequate supply options being available to address the supply adequacy shortfalls forecast during the five year VGPR Update outlook period. This report demonstrates that more supply is required. The forecast decline in production is faster than the forecast decline in gas consumption, and the announced closure of coal generation along with the electrification of gas demand will increase the requirement for GPG during winter when VRE generation output is low. The adequacy assessment for the southern states in the 2024 GSOO reaches the same conclusion.

Figure 22 illustrates one of the key components of Victorian production decline by showing a 10-year capacity outlook for the Longford Gas Plant, which is currently the largest gas production facility in the southern states with a nameplate capacity of over 1,100 TJ/d. Longford capacity is limited by supply from the offshore gas wells due to the decline of the large legacy fields, with the current winter capacity limited to 810 TJ/d. From July 2024 this capacity is forecast to further reduce to 700 TJ/d following the retirement of Gas Plant 1.

This chart includes supply from all committed, anticipated, and potential projects and includes production from contingent resources. Potential projects at Longford include Turrum Phase 3 and the Late Life Optimisation project, both discussed in Section 4.1.1. Investment in the Turrum Phase 3 and the Late Life Optimisation projects remains subject to GBJV investment decisions.

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

Future supply options for Victoria are discussed in Chapter 4, and options to address supply challenges across the broader east coast are discussed in Chapter 5 of the 2024 GSOO.

Figure 22 Forecast Longford Gas Plant winter capacity, 2024-33 (TJ/d)

Updates to project risks and uncertainties

AEMO recognises that the current investment environment for projects remains challenging and highly uncertain. Many of the potential projects identified in the 2023 VGPR have not materially progressed and face the same challenges identified in Section 4.6 of that report. **Table 17** discusses updates, if any, to each of the uncertainties.

Table 17 Gas project uncertainties updates

Factor	2023 VGPR description	2024 update
Global conflict	The Russian invasion of Ukraine in February 2022 caused shocks in the global energy markets because Russia is a major oil and gas producer.	Status update: continued uncertainty. While gas prices have stabilised following the initial Russian invasion of Ukraine, the conflict continues. The Israel-Palestinian conflict that commenced in October 2023 has increased instability in the Middle East.
Inflation	Higher inflation in Australia and overseas combined with rising interest rates to combat inflation.	Status update: stabilised. Inflation remained high through 2023, interest rates continued to rise. The rate of inflation has eased by remains high and interest rate increases have slowed, with the possibility of interest rates cuts later in 2024.
Financing	Natural gas is becoming unpalatable for some investors who are screening investments on environment, social and governance (ESG) grounds to limit exposure to fossil fuels.	Status update: no change. ESG concerns for all fossil fuels, including natural gas, remain a priority for some investors.
COVID-19	Ongoing impacts of the COVID-19 pandemic include global supply chain disruptions, limited resources and a backlog of projects.	Status update: reduced uncertainty, but not resolved. Global supply chains are experiencing a slow recovery, however some industries are likely to have been permanently affected.
Regulatory approvals	Environmental approvals for gas projects are becoming increasingly stringent. Court challenges have increased uncertainty. Approval requirements depend on which jurisdiction the project falls within.	Status update: no change. Offshore gas projects continue to experience additional National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) approval requirements and court challenges. The environmental and planning approvals for the WORM Pipeline took approximately three years, which is discussed in Section 4.2.4.
Market uncertainty	From 23 December 2022, the Australian Federal Government imposed a $12/GJ price cap to new domestic wholesale gas contracts for 12 months. The government has also introduced a mandatory code of conduct for the gas industry.	Status update: reduced uncertainty. The Gas Market Code, which commenced July 2023, retains the $12/GJ price cap but provides an exemption framework for domestic supply allowing producers to negotiate exemptions to the pricing provisions.
Competing investment interests for renewable gases	Policy and investment into renewable gases in other jurisdictions has been significant particularly in the United States and in the European Union.	Status update: reduced uncertainty but not resolved. The Federal Government announced the $2 billion Hydrogen Headstart program in May 2023, however overall funding and policy support for renewable gas, particularly biomethane, remains uncertain as discussed in Section 4.3.5.
Offshore rig availability	Declining offshore exploration and drilling activity in Australia, combined with very high rig demand globally, is resulting in few rigs remaining in Australia	Status update: reduced uncertainty but not resolved. The offshore exploration outlook includes more drilling activity but remains low compared to historical levels.

3.5 Changes impacting operational resilience

This section highlights updates to the system that materially impact operational resilience since the publication of the 2023 VGPR.

3.5.1 Updates reducing operational resilience

Longford Gas Plant – onshore infrastructure

The decrease in available Gippsland production discussed in Section 3.2.1 has implications for managing the real-time operational system security of the DTS as well as impacting supply adequacy.

GBJV is forecasting a reduction in offshore field production capacity and is undertaking a program to retire onshore and offshore gas production assets, driven by the need to match processing capacity with reduced offshore production. In 2024, GBJV will be reducing the number of operating offshore wells and pipelines as well as decommissioning a gas processing plant (Longford Gas Plant 1).

Gas Plant 1 is expected to operate until July 2024, then cease operation. This will leave two remaining onshore gas plants at Longford, with both required to achieve the 2024 peak day capacity of 700 TJ/d. This reduction in redundancy increases the risk to supply adequacy; if either of the two remaining plants are unavailable, the total production capacity of Longford Gas Plant could be reduced by up to 350 TJ/d. Even short-term outages can threaten peak day supply adequacy due to the small margins in the supply demand balance (see Section 3.3.2).

GBJV will also decommission one of the two fractionation trains at the Long Island Point Fractionation Plant, reducing the redundancy of this facility. While the Long Island Point plant does not directly produce natural gas, it is linked to gas production at Longford Gas Plant as it processes the natural gas liquids extracted along with natural gas.

GBJV will continue to review the required infrastructure to match production as additional legacy fields decline and cease production in the future.

Longford Gas Plant – offshore infrastructure

The three large, water-driven legacy fields in the Gippsland Basin – Snapper, Marlin, and Barracouta – have historically allowed GBJV to scale production up and down on a seasonal basis, and to ramp up to respond to issues with other fields or platforms. As the production capacity of these legacy fields continues to decline, the Longford Gas Plant will have reduced ability to maintain production by ramping up these fields to cover a reduction in capacity from other fields. Snapper's production capacity is expected to reduce significantly in the next 12 months.

It is also anticipated that available Gippsland production will flatten on a seasonal basis, instead of producing less in summer and more in winter. Flat production throughout the year is typical of gas production facilities, except for planned maintenance with large outages undertaken outside the winter peak demand period.

The uncertain decline in the GBJV legacy fields is characteristic of aquifer-driven reservoirs at the end of their field life. The large size and age of these fields also creates uncertainty. Once the fields approach final depletion, the reduction in production can be rapid.

3.5.2 Updates increasing resilience

Winchelsea Compressor 2 and WORM

As well as increasing Port Campbell supply by increasing the SWP capacity, the Winchelsea Compressor 2 and WORM projects improve the resilience of the DTS.

The completion of the WORM Pipeline improves resilience by:

- Providing more supply reliability and flexibility by reducing dependence on Longford Gas Plant injections, which enables the DTS to better support reduced supply from Gippsland throughout the year and a Longford plant outage during low demand periods.

- Increasing the available system linepack and adding the ability to transfer linepack between pipelines that were previously disconnected. Additional system linepack increases the DTS's ability to support large swings in demand including unforecast GPG and issues at production facilities.
- Providing additional compression options and flow paths, reducing the reliance on the Brooklyn CS.

The second unit at Winchelsea CS provides redundancy to what was previously a single-unit station, and greatly decreases the impact to operations and pipeline capacity if a single unit is unavailable.

Longford to Melbourne pipeline operations

Longford Gas Plant 1 does not have the same compression capability as the other Longford gas processing plants, so high pressure in the LMP can impact Longford production. Following the retirement of Gas Plant 1, the two remaining gas plants will be more capable of maintaining injections into the DTS when there is higher pressure in the LMP. This will increase the available linepack in the LMP and increase operational flexibility, increasing the capability of the DTS to respond to plant and equipment trips as well as increases in demand without materially impacting Longford operations.

Ethane constraint

The Longford production system produces an ethane product stream that is processed at Long Island Point then used by a downstream customer. Operational changes at Longford during 2022 reduced the impact of insufficient ethane customer offtake on Longford production capacity, and this constraint did not impact supply during 2023. A risk to Longford plant operations remains if the customer does not accept the ethane.

GBJV is constructing an ethane power generation facility at Hastings adjacent to the Long Island Point facility that can consume this ethane stream. Subject to regulatory approvals, the facility is expected to be operational from September 2024.

3.5.3 Other updates

Dandenong LNG

The Dandenong LNG storage facility inventory will remain maximised for winter 2024 with AEMO continuing to contract the remainder of the facility's capacity, in accordance with the DWGM interim LNG storage measures rule change[80] which is effective until the end 2025.

The East Coast Gas System stage 2 functions[81] are expected to replace the DWGM interim LNG storage measures rules before the end of 2025. The timing of these stage 2 reforms is uncertain and there is a potential gap between the existing rules expiring and new rules commencing, which may require the DWGM interim LNG storage measures to be temporarily extended.

[80] Australian Energy Market Commission (AEMC), "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

[81] Consultation on stage 2 of the reliability and supply adequacy framework, at https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas

3.6 Operational resilience risks for 2024

This section highlights the key system operational risks for winter 2024 and discusses the operational impact of each risk materialising.

3.6.1 Peak day risks

The key resilience risks identified for peak day operational system security ahead of winter 2024 are:

- **Production facility outages.** As discussed in Section 3.5.1, the closure of Longford Gas Plant 1 and the reduced production capacity of the large legacy fields increases the risk of an unplanned outage or reduction in supply from the Longford Gas Plant. Other production, storage and transmission facilities in Victoria are aging and unplanned outages may occur more frequently.
- **Unforecast system or GPG demand.** System demand is highly dependent on weather conditions – in winter 2019 and 2020, Victoria experienced several cold snaps and total demand for gas peaked at above 1,200 TJ/d, but the past three winters have seen milder weather during winter and lower system demand. Prolonged outages at coal-fired generators can lead to increased gas generation. Extended coal generation outages occurred during 2019, 2021 and 2022. Section 2.4.3 explores forecast winter GPG demand increases that may coincide with high system demand.

The eventuation of either risk may result in a threat to system security, as demand would exceed supply.

Impact of an unplanned Longford outage in winter

Figure 23 shows the results of indicative modelling performed by AEMO to demonstrate the amount of time until the first distribution system connection point pressure breach occurs in the event of an unplanned Longford production outage during winter 2024, after Gas Plant 1 is decommissioned. The modelling used 1-in-2 peak day system demand and typical GPG demand and assumed that AEMO undertakes an operational response including injecting firm-rate LNG at Dandenong.

If an unplanned outage of one of the two remaining Longford gas plants occurred at 2.00 pm on such a day, the first pressure breach would occur within six hours. This time would be shorter if the trip occurred closer to the evening peak, or longer if the trip occurred overnight when demand is lower.

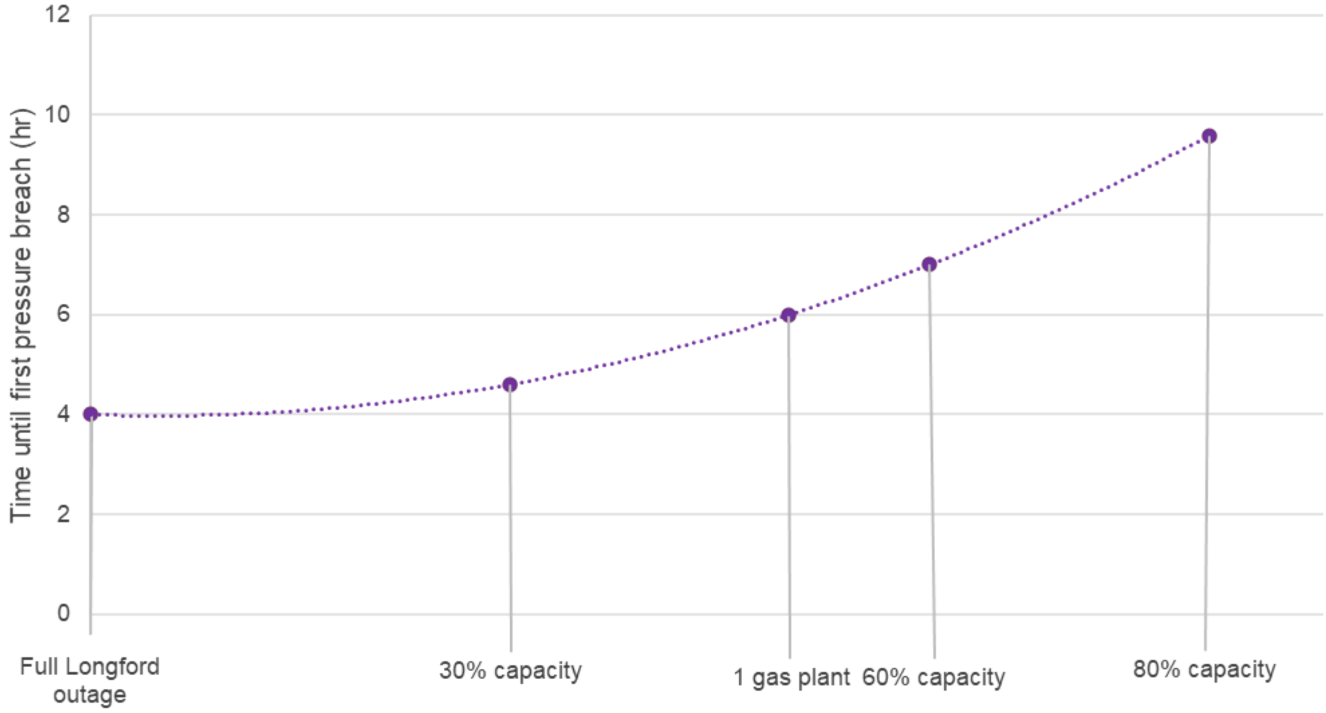
This analysis demonstrates the impact of short-term outages on a high demand day following the retirement of Gas Plant 1.

Further actions AEMO could take to extend the time before the first pressure breach include:

- Issue a system wide notice seeking a market response.
- Request Dandenong LNG to inject at non-firm rates.
- Seek non-firm gas from other facilities.

If these responses are not sufficient, AEMO would commence the initial steps of gas load curtailment which includes limiting gas use for electricity generation, voluntary appeals to reduce gas use, and the curtailment of high consuming (Tariff D) customers that will likely have a negligible to low impact to health, the environment or community financial sustainability. For further information refer to AEMO's *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*[82].

Figure 23 Projected time until the first pressure breach in the event of a Longford Gas Plant trip at 2.00 pm on a 1-in-2 system demand day (hr)



3.6.2 Seasonal risks

The three key resilience risks identified for seasonal adequacy ahead of winter 2024 are:

- **Reduction in Queensland gas made available to 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. Volumes made available during winter 2024 may be reduced due to lower production, including continued limited or no supply from the Northern Territory to Mt Isa in Queensland (which reduces the quantity of gas that the SWQP can deliver into the Moomba hub), higher demand, or favourable international LNG conditions.
  - Modelling for the 2024 GSOO indicates that international market conditions are unlikely to cause a supply adequacy issue unless all uncontracted gas is exported and time-swap arrangements are not utilised.
  - GSOO modelling also indicates that quantities forecast to be transported to the southern states from Queensland for winter 2024 range between 13 PJ and 24 PJ, less than the 28 PJ transported to the southern states during winter 2023.
- **Prolonged gas production outage or production project delay.** The Longford Gas Plant experienced an almost three week outage of Gas Plant 3 during winter 2021 with the Iona UGS facility also undertaking a short unplanned outage. The connection of the Enterprise-1 well to the Otway Gas Plant is expected to be in

[82] AEMO Victorian emergency management role, at https://www.aemo.com.au/energy-systems/gas/emergency-management/victorian-role.

mid-2024. The other committed production projects – the Otway Thylacine North wells and the Longford Kipper Compression Project – are not forecast to be commissioned until after winter 2024. This additional production is expected to assist with Iona UGS refilling prior to winter 2025.

- **Prolonged outages at coal-fired generators.** As discussed in Section 2.4.1, prolonged coal outages can lead to increased GPG demand. Extended coal generation outages occurred during 2019, 2021 and 2022.

A reduction in available supply or an increase in GPG consumption across the winter months would result in a tightening of seasonal supply adequacy through winter 2024. If additional Queensland gas is not made available to the southern states in response to supply tightening, the reliance on Iona UGS would increase and result in an elevated storage depletion risk. The Iona UGS supply capacity reduces when the storage inventory is low.

4 Future supply sources

Key findings

- **Many of the potential projects identified in the 2023 VGPR have not materially progressed and face the same challenges identified in that report.**
  - Golden Beach has completed the drilling of an appraisal well and commenced a post-drilling evaluation program.
  - GBJV has proposed optimisation options for the Turrum and North Turrum fields to maximise production later in the decade, referred to as the Longford Late Life Optimisation project. Investment in these projects remains subject to GBJV investment decisions.
- **AEMO has conducted modelling of the DTS to determine the transportation capacity adequacy for potential supply projects and options to increase capacity where the capacity is not adequate.** (This modelling presents the potential supply options and does not represent the lowest cost supply or consider the economics of potential options.)
  - There are minimal options to materially increase the transportation capacity of the SWP from Port Campbell to Melbourne. AEMO has identified one small option which could expand the capacity by approximately 20 TJ/d. Beyond this, modelling shows multiple significant bottlenecks limiting options to increase capacity without substantial investment.
  - There are several options to expand the capacity of the SWP from Geelong to Melbourne if an LNG import terminal is developed near Geelong. The augmentations assessed which provide the largest supply capacity increase with the least extensive augmentation options are:
    - Geelong LNG import terminal plus a Wyndham Vale compressor (846 TJ/d).
    - Geelong LNG import terminal plus 44 km of pipeline looping from Lara to Rockbank (933 TJ/d).
    - Geelong LNG import terminal plus the above 44 km of looping and a compressor (1,070 TJ/d).
- AEMO recognises that **the current investment environment for projects is challenging and uncertain**. The 2024 VGPR Update contains few committed and anticipated supply projects. Many projects do not have firm timelines, making the analysis of system adequacy in Chapter 3 difficult. All projects currently underway or proposed in the VGPR Update outlook period face a range of challenges to maintain schedules and reach completion.
- The **transition to biomethane and hydrogen** is expected to play an important role in the decarbonisation of Australia's energy sector, but these distributed supply sources are not expected to produce significant volumes within the outlook period, as they still face a variety of barriers preventing their entry into the market.

4.1 Project updates

The following projects have had some changes or updates since the publication of the 2023 VGPR. For information on other potential projects, refer to the 2023 VGPR.

4.1.1 Potential supply projects

Golden Beach

The Golden Beach Energy Storage Project involves the production and development of the Golden Beach gas field in the Gippsland Basin, with a forecast supply of up to 35 PJ over two years from mid-2026 (delayed from 2025), and an initial delivery capacity of up to 125 TJ/d for winter 2026.

GB Energy drilled the appraisal well known as the Golden Beach-2 (GB-2) on 17 July 2023. The post-drilling evaluation program to determine the design and operation of future production infrastructure and storage wells has been completed[83]. This includes the drafting of the field development plan, with GB Energy currently preparing an application for a production licence. Design of the gas processing and compression facilities is largely complete.

Final investment decision (FID) is expected during the third quarter of 2024, with the project proposed to be online prior to winter 2027.

Turrum Phase 3 and Longford Late Life Optimisation

GBJV is evaluating expansion and optimisation options for the Turrum and North Turrum fields, referred to as the Turrum Phase 3 project. This potential project would provide additional gas to be processed at the Longford Gas Plant from 2026. Investment in the Turrum Phase 3 project remains subject to GBJV investment decisions.

In addition to Turrum Phase 3, GBJV is considering the Longford Late Life Optimisation project which aims to maximise production from depleting reserves later in the decade. GBJV has advised AEMO that this project is dependent upon the progression of Turrum Phase 3 project.

GBJV participants have each been granted a conditional Ministerial exemption from the price rules provisions of the Federal Government's Gas Market Code[84], as announced in January 2024[85].

4.1.2 Other supply projects

APA East Coast Grid Expansion project[86]

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

[83] GB energy upcoming operations, operational progress updates, at https://gbenergy.com.au/upcomingoperations.

[84] More information is at https://www.accc.gov.au/business/industry-codes/gas-market-code#:~:text=The%20Gas%20Market%20Code%20is,prices%20and%20on%20reasonable%20terms.

[85] Minister for Resources and Minister for Northern Australia media release, "Gas market code secures supply for domestic market", 22 January 2024, at https://www.minister.industry.gov.au/ministers/king/media-releases/gas-market-code-secures-supply-domestic-market.

[86] APA, *east coast grid expansion*, at: https://www.apa.com.au/about-apa/our-projects/east-coast-grid-expansion/

- **Stage 1 –** APA completed this stage, which consisted of an additional compressor between Moomba and Young, and an additional compressor on the SWQP, ahead of winter 2023. Stage 1 increased the nominal capacity of the SWQP by 49 TJ/d (404 TJ/d to 453 TJ/d) and the MSP by 29 TJ/d (446 TJ/d to 475 TJ/d).
- **Stage 2 –** currently under construction and on track for completion prior to winter 2024, Stage 2 consists of a second additional compressor on both the SWQP and MSP. This will increase the nominal capacity of the SWQP by another 59 TJ/d to 512 TJ/d and the MSP by another 90 TJ/d to 565 TJ/d.
- **Stage 3 –** Stage 3 has been split into two parts: Stage 3a and Stage 3b. Stage 3a consists of an additional compressor on the MSP between Moomba and Young, and will increase the nominal capacity of the MSP by 34 TJ/d to 599 TJ/d. Stage 3b consists of an additional compressor between Young and Culcairn, to provide a capacity increase of 41 TJ/d to Culcairn and further 5 TJ/d for the mainline MSP. Both Stage 3a and Stage 3b are currently in design phases.
- **Stage 4 –** APA is considering an additional stage which would increase the MSP capacity to 657 TJ/d.

LNG import terminal projects

- **Viva Energy Gas Terminal Project** – Viva Energy is continuing to progress with the supplementary data request for the Environment Effects Statement (EES) required from the Victorian Planning Minister to assist in its decision[87]. The terminal is forecast to supply up to 140 PJ/y, have a capacity of 620 TJ/d, and potentially be operational and available to the market as early as 2027. Section 4.2 explores DTS augmentation options if an LNG import facility connects in Victoria.
- **Vopak Victoria LNG** – in August 2023, Victoria's Minister of Planning published a decision on Vopak's referral submission requiring an EES be completed for the project[88]. The terminal is planned to have a supply capacity of up to 778 TJ/d, supply around 270 PJ/y, and be operational in 2028.
- **Port Kembla Energy Terminal** – Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023. Squadron Energy continues to progress the physical construction at the LNG Terminal, with more than three-quarters completed. The facility is on track for physical mechanical completion within 12 months, with a forecast supply capacity of 500 TJ/d to become available from 2026. Jemena has proposed an upgrade to the Eastern Gas Pipeline (EGP) to become bi-directional. If the project is developed, it will initially deliver the capacity to deliver 200 TJ/d in reverse flows south to Victoria and could be upgraded to 325 TJ/d.
- **Outer Harbor LNG Project –** Venice Energy has completed Stage 1 Enabling Works for site preparation works and as of February 2024[89] has entered a new commercial agreement that guarantees the project will receive a floating storage regasification unit (FSRU). Negotiation is continuing for Origin Energy to reach an exclusivity agreement with Venice Energy, initially signed in October 2023, for the exclusive use of the Outer Harbor LNG import terminal at Port Adelaide for 10 years. The terminal is advised to have a supply capacity of up to 446 TJ/d or 110 PJ/y. SEA Gas pipeline reversal would allow flow from Adelaide to Port Campbell in Victoria,

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

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

[89] Venice Energy, "Chairman's Update", at https://veniceenergy.com/2024/02/15/chairmans-update/.

although flows through to the DTS would be limited by the SWP capacity, as discussed in Section 4.2. Venice Energy is targeting FID in late 2024 with first gas targeted for pre-winter 2026. If the Outer Harbor LNG Project does not proceed as proposed, it may be feasible in the interim to install a compressor at the Adelaide end of the SEA Gas pipeline to enable reverse flow of gas received from the Moomba to Adelaide Pipeline System (MAPS) to support Iona UGS inventory conservation and refilling during times when the MAPS is not flowing at capacity to support Adelaide demand.

4.2 Potential supply project options to increase DTS capacity

As reported in the 2024 GSOO, many potential new supply options to resolve the forecast supply gaps in the southern states for the VGPR Update outlook period have been identified, including LNG import terminals, increased north to south transportation capacity, and the development of contingent resources in the southern states.

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

These future supply projects can be grouped by connection location to the DTS, then the impact to the DTS can be assessed on a transmission pipeline basis as summarised in **Table 18**:

- For potential projects that add supply into the DTS from the Gippsland region via the Longford to Melbourne pipeline (LMP), the LMP is considered adequate to support additional supply capacity from any of the potential supply projects. This includes the Golden Beach production and storage project, and the Port Kembla Energy Terminal.
- Similarly, the additional injection capacity that APA's East Coast Grid Expansion project provides via Culcairn can be supplied by the existing VNI pipeline capacity.
- In contrast, if supply capacity was to be expanded in the Port Campbell region – from projects including a further Iona UGS expansion or connection of new Otway Basin fields, particularly projects that increase the production capacity of the Athena Gas Plant – further expansion of the SWP would be required to transport this increased supply capacity to Melbourne.
  - The SWP was recently expanded through the construction of an additional compressor at the existing Winchelsea CS that was commissioned during winter 2023 and through the completion of the WORM pipeline that was commissioned in February 2024. The combination of both these projects increased the SWP capacity from 447 TJ/d to 530 TJ/d.
  - The available Port Campbell peak day supply for 2024 is forecast at 781 TJ/d. This capacity is utilised to supply DTS demand, the Mortlake Power Station and South Australia (which is mainly GPG demand). Options for further SWP expansion from Port Campbell are discussed in the next section.
  - A potential LNG import terminal project connecting to the SWP near Geelong would also increase DTS supply capacity. This additional capacity is only achieved when the LNG import terminal is injecting at maximum rates. This limits the simultaneous supply from facilities in Port Campbell as they are backed out

of the SWP by the higher supply pressure of an LNG import terminal connected closer to Melbourne. Options to expand the SWP, including limiting the impact on simultaneous Port Campbell supply capacity into the SWP, are discussed in the next section.

Table 18 Future potential supply projects and DTS expansion summary

Future supply sources	Projects	Supply expansion location (relative to the DTS)	Impacted DTS pipeline	Potential future DTS pipeline capacity expansion required
Potential supply projects	• Golden Beach • Trefoil and White Ibis • Turrum • Manta • Longtom • Wombat	Gippsland	Longford to Melbourne	No
	• Athena plant capacity increase • Iona UGS expansion	Port Campbell	South West Pipeline	Yes
Potential LNG import terminal projects	• Viva • Vopak	Geelong	South West Pipeline	Yes
	• Outer Harbor (Venice) & SEA Gas Pipeline bi-directional flow	Port Campbell	South West Pipeline	Yes
	• Port Kembla & EGP bi-directional flow	Gippsland	Longford to Melbourne	No
APA East Coast Grid Expansion project	• Stage 2 and 3b	Culcairn	Victorian Northern Interconnect	No

From the potential supply projects above, AEMO's modelling has explored two different scenarios for potential additional supply connecting at Port Campbell or at Geelong, and how the DTS can support additional SWP supply capacity.

In this analysis:

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

4.2.1 Scenario A – Port Campbell supply expansion

This scenario identifies augmentation options for a future where there is no Geelong LNG import terminal, the Iona CPP remains the sole source of supply to the DTS from the west of Melbourne, and available supply capacity is increased from Port Campbell either through an Iona UGS expansion, additional Port Campbell production capacity, or from Venice Energy's LNG terminal project via a reversal of the SEA Gas Pipeline as shown in **Figure 24**.

The SWP transportation capacity could be materially increased through pipeline looping from Port Campbell to Melbourne and the installation of new compressor units near Lara, with possible incremental construction options shown in **Table 19**. AEMO's modelling and analysis demonstrates that expansion options beyond Option 1 will require substantial investment to increase the capacity of the SWP further.

Figure 24 Diagram of the DTS showing key locations

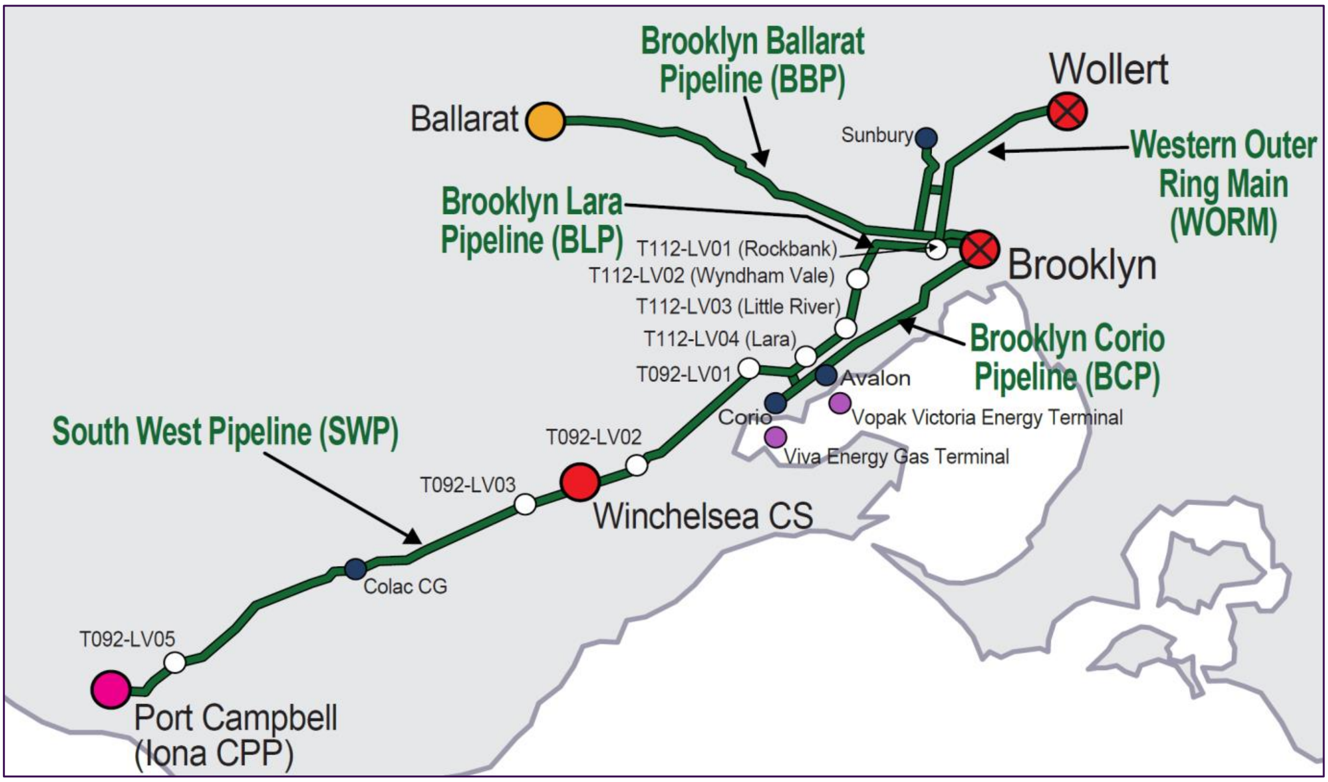


Table 19 Potential options for Scenario A augmentations

	Option	Augmentation description	SWP Capacity (TJ/d)	SWP Capacity increase from existing (TJ/d)
Existing SWP	-	No network augmentation	530	-
Port Campbell to Melbourne augmentation options with no Geelong LNG import terminal	1	Looping of the existing 18 km SWP from Colac to Winchelsea	550	20
	2	Option 1 plus: • Looping of the existing 90km SWP from Iona UGS to Lara and Winchelsea • Winchelsea Compressor modifications for parallel operation	660	130
	3	Option 2 plus: • 29 km of BLP looping from Lara to Wyndham Vale	700	170
	4	Option 3 plus: • Two compressor units at Lara	720	190

4.2.2 Scenario B – New supply connecting at Geelong

With a potential LNG import terminal connecting to the DTS near Geelong (as shown above in **Figure 24**), the resulting SWP capacity increase is modelled to be substantial, with approximately 240 TJ/d of additional injection capacity. However, this capacity increase can only be achieved by backing off Iona CPP supply and maximising Geelong LNG injections. This would introduce market complexities, because the connected LNG import terminal and Iona CPP would be competing for capacity on the SWP. Therefore, AEMO has identified additional augmentation options to further increase the SWP capacity, reducing the impact on injection capacity at the Iona CPP.

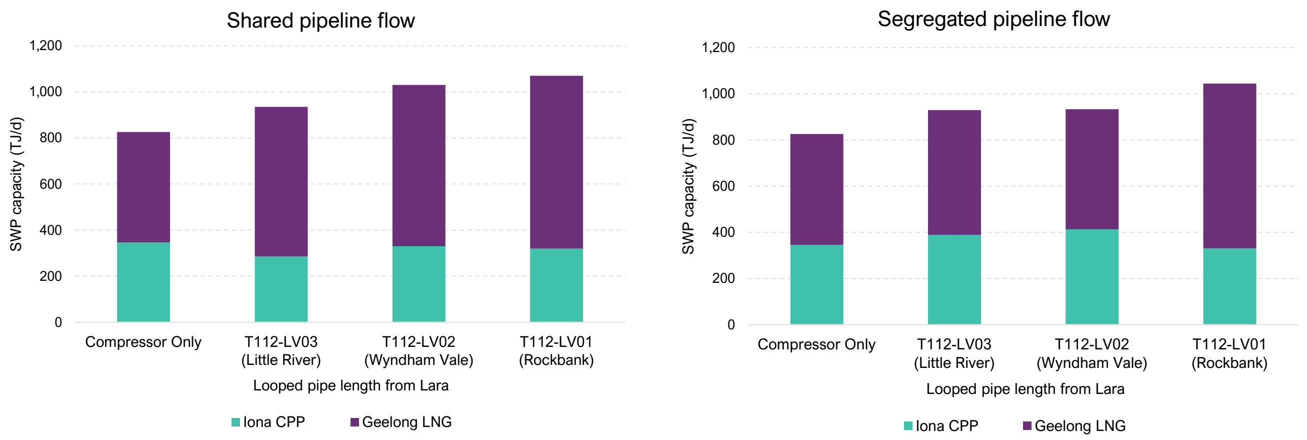
Similar to Scenario A, the augmentation options with a Geelong LNG import terminal involve construction of pipeline looping and/or the installation of new compressor units as shown in **Table 20**. The pipeline looping and new compressor units to further increase SWP capacity are most beneficial downstream of Lara (or Avalon) from the LNG import terminal connection into the SWP. Additionally, analysis shows an upgrade to the new WORM pressure reduction station (PRS) at Wollert to be advantageous in enabling more transportation capacity towards Melbourne.

Table 20 Potential options for Scenario B augmentations

	Option	Augmentation description	SWP capacity (TJ/d) with LNG delivery prioritised	SWP capacity increase from existing (TJ/d)
Existing SWP	-	No network augmentation	530	0
Port Campbell to Melbourne augmentation options with Geelong LNG import terminal	1	Import terminal connects to current system	770	240
	2	Option 1 plus: • WORM PRS upgrade	790	260
	3	Option 2 plus: • 44 km of BLP looping from Lara to Rockbank • Bi-directional regulator installation at Lara to enable segregated pipeline operation	933	403
	4	Option 2 plus: • Two compressor units near Wyndham Vale	846	316
	5	Option 2 + Option 3 + Option 4	1,070	540

To minimise the effects of backing off the Port Campbell supply and impacting the market, the SWP expansion analysis also identified an option to install a bi-directional regulator facility at Lara to enable flow segregation of the Iona CPP and Geelong LNG terminal supply flows. Preliminary capacity analysis shows that by segregating the flow between Iona CPP and Geelong LNG terminal flow, the maximum Iona CPP injection capacity can be maintained when compared to the shared flow path, as **Figure 25** shows.

Figure 25 SWP capacity with shared or segregated pipeline flows (TJ/d)



4.2.3 Comparison of Scenario A and Scenario B augmentation options

There are limited low capital cost options available to increase the total SWP capacity with Iona CPP as the single supply location. The first augmentation option identified could expand the capacity by 20 TJ/d, but to increase SWP capacity beyond this option, major augmentations would be required.

The augmentation options for a Geelong LNG import terminal assessed that provide the highest supply capacity increase with least extensive augmentation options are:

- Geelong LNG import terminal plus Wyndham Vale compressors (846 TJ/d).
- Geelong LNG import terminal plus 44 km of pipeline looping from Lara to Rockbank (933 TJ/d).
- Geelong LNG import terminal plus above 44 km of looping and compressors (1,070 TJ/d).

The installation of additional compressors near Wyndham Vale coinciding with the development of a Geelong LNG terminal would increase overall system capacity by 56 TJ/d and provide future operational flexibility benefits. Depending on other factors, including approval timelines, supply chain availability and other project dependencies, a compression project may be a faster initial option than pipeline looping. Installation of compressors near Wyndham Vale prior to completing looping (Option 3) adds a step-up in capacity but at a lower efficiency than looping first (Option B). Adding both compression and looping (Option 4) significantly increases the capacity to 1,070 TJ/d.

4.2.4 Project uncertainties

Easement and land access

AEMO's assessment of SWP looping options assumed that the existing 20-metre-wide pipeline easement is adequate for the new pipeline routes to be constructed. For sections where the existing easement is fully utilised with current parallel pipelines, new easement acquisitions would be required.

While some sections along the SWP and BLP have existing easements, any proposed pipeline route would still be subjected to property, environmental and heritage approvals, and landowner engagements.

The proposed locations for the compressor unit options are indicative only and represent theoretical locations along the SWP that are modelled to provide the maximum increase in transportation capacity. Therefore, these locations would be subject to land availability and social license analysis to identify the most suitable locations required for each compressor option.

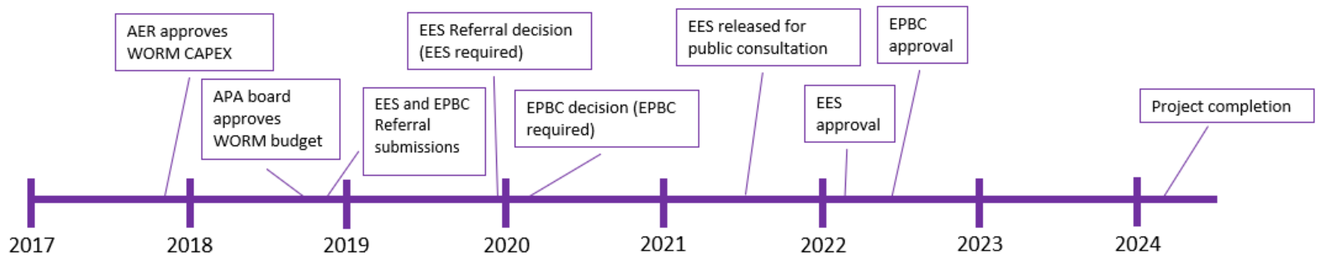
Further preliminary and detailed property assessment would be required to determine detailed cultural heritage study and property approval as part of the initial design phase.

Project timeline

The project timeline for all major augmentation options could be in the order of five to six years from financial approval.

The timeline from the WORM project, shown in **Figure 26**, is a recent demonstration of the extended project timeline required across five years from financial approval to completion.

Figure 26 WORM construction timeline



Note:

- The AER approved capital expenditure (CAPEX) for the WORM as part of APA's 2023-27 Access Arrangement.
- The EES process is an assessment of potential environmental effects under the *Environmental Effects Act 1978* in Victoria. The Victorian Minister for Planning determines if an EES is required following a referral.
- The Environment Protection and Biodiversity Conservation Act 1999 (EPBC) is an environmental assessment at the federal level. The Federal Minister for Environment and Water determines if an EPBC assessment is required following a referral.

4.3 Renewable gas

4.3.1 Renewable gas production and their use cases

Renewable gases and their use cases are increasingly of interest to governments and industry due to their potential use in decarbonising energy systems and addressing hard-to-abate industrial emissions. The renewable gases in scope of this analysis are biomethane and renewable hydrogen, because these gases and their blends are being integrated into the NGL and NGR[90,91].

Renewable hydrogen is produced via electrolysis of water using renewable energy sources, including wind and solar energy generation, to produce low emissions hydrogen. Renewable hydrogen is typically associated with its use in decarbonising heavy road freight transportation, mitigating curtailment of renewable energy production by utilising surplus energy supply, and its ability to act as a long-term energy storage medium.

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[90] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/extending-national-gas-regulatory-framework-hydrogen-and-renewable-gases.

[91] See https://www.aemc.gov.au/market-reviews-advice/review-extending-regulatory-frameworks-hydrogen-and-renewable-gases.

Displacement of natural gas within pipeline networks, as an input into specific production processes including fertiliser production, and as an energy firming source in compatible GPG units, could also be achieved with hydrogen or blended hydrogen depending on the specific application. As identified in the 2019 National Hydrogen Strategy[92], renewable hydrogen may also have a use in energy exports, akin to the current LNG exports from Australia.

Biomethane is produced by the anaerobic decomposition of organic matter and can be produced from multiple feedstocks, including agricultural and municipal waste streams, wastewater treatment facilities and forestry residues. The gas products from the organic waste streams may need to be treated to separate the biomethane from the other by-products including carbon dioxide and solid particulates. Biomethane, unlike hydrogen, is chemically comparable to natural gas, which is primarily methane, and can therefore typically be used in many of the applications natural gas is used in. Biomethane and its blends must still meet the applicable gas quality specifications and the specific requirements of the use-case of interest.

Both renewable hydrogen and biomethane are alternative energy supply sources to natural gas which could assist governments and industry in reaching their decarbonisation objectives and provide energy consumers an option to decarbonise their personal energy use. However, based on the information submitted to AEMO, the supply outlook of these renewable gases is limited and there are distinct challenges impeding future development of the renewable gas industry within Victoria.

4.3.2 Policy and regulatory framework related to renewable gases

Legislation at both the federal and state level may impact the future development of the renewable gas industry within Victoria.

Federal Government policy initiatives

The Federal Government has legislated, in the *Climate Change Act 2022*, a 43% emissions reduction target on 2005 levels by 2030, and net zero emissions by 2050[93].

There are three relevant policy tools which may help to facilitate the legislated emissions reductions targets which are related to renewable gases:

1. The National Hydrogen Strategy 2019[94], which was under review and consultation in 2023. The strategy identified 15 measures of success for the hydrogen industry in Australia, including being clean, safe, used domestically and for export to the Asian market.
2. The Guarantee of Origin Scheme, administered by the Clean Energy Regulator[95,96]. The scheme tracks and verifies the emissions associated with renewable electricity and hydrogen production, allowing for the reduced emissions intensity of renewable hydrogen compared to natural gas to be verified.

[92] See https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf.

[93] See https://www.dcceew.gov.au/climate-change/emissions-reduction/net-zero.

[94] See https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf.

[95] See https://www.dcceew.gov.au/energy/renewable/guarantee-of-origin-scheme.

[96] See https://www.cleanenergyregulator.gov.au/Infohub/Markets/guarantee-of-origin.

3. The Safeguard Mechanism, administered by the Clean Energy Regulator and reformed in 2023[97,98]. The Safeguard Mechanism applies to facilities that emit more than 100,000 tonnes carbon dioxide equivalent per year, and from 1 July 2024 these facilities will need to reduce their baseline emissions each year in line with Australia's federal emission reduction targets.

Victorian Government policy initiatives

The Victorian Government has, through the *Climate Change Act 2017*, committed to a 28-33% emissions reduction target on 2005 levels by 2025, 45-50% by 2030, 75-80% by 2035 and net zero emissions by 2045[99], which is a more rapid decarbonisation target than is federally legislated. These targets apply Victoria-wide to all industries, including the energy industry. To assist in these emissions reduction targets, Victoria's Gas Substitution Roadmap[100] is the primary state-based policy tool which is related to renewable gases and the decarbonisation of Victoria's natural gas use.

An aim of the roadmap is to enable small businesses and households to electrify their existing natural gas use and therefore reduce supply pressures on industrial users while alternative decarbonisation methods mature in the market. This aim may be achieved in three distinct ways in the roadmap:

1. The reduction of existing natural gas use within small businesses and households, mostly through electrification and energy efficiency measures in the VEU program.
2. Minimising future demand for natural gas by phasing out new connections to the gas network for new dwellings, apartment buildings, and residential subdivisions which require planning permits and requiring 7 Star energy efficiency ratings for new homes.
3. Investigating potential decarbonisation options for hard to abate emission sources. Examples include a $10 million investment[101] to begin establishing hydrogen refuelling infrastructure along east coast transit corridors and Victoria's Renewable Gas Consultation Paper[102] which addresses potential renewable gas use by hard to abate industrial users within Victoria.

Both federally and within Victoria, there are several legislated emission reduction targets and policy tools which may lead to the potential displacement of natural gas, particularly in households and small businesses, via electrification. Natural gas use which cannot be readily electrified may be displaced through renewable gas use, and emerging policies and initiatives may encourage renewable hydrogen and biomethane production and use in Victoria. It is uncertain, however, to what extent and within what timeframe this natural gas displacement may occur within hard-to-abate industries and users.

4.3.3 Victorian renewable gas projects

Several projects are proposed in Victoria to supply either biomethane or hydrogen blended with natural gas to end-use gas customers. This section discusses Victorian projects that have progressed since the 2023 VGPR.

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[97] See https://www.cleanenergyregulator.gov.au/NGER/The-Safeguard-Mechanism.

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

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

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

[101] The New South Wales Government has also contributed $10 million to the investment.

[102] See https://engage.vic.gov.au/victorias-renewable-gas-consultation-paper.

Hydrogen Park Murray Valley

Hydrogen Park Murray Valley is a committed project from the Australian Gas Infrastructure Group (AGIG). The project consists of the construction of a 10 megawatt (MW) electrolyser to produce hydrogen and blend this with natural gas into the Albury-Wodonga gas distribution network. The project attained FID on 26 June 2023[103];construction is planned to begin in Q2 2024[104] with production expected to commence in mid-2025[105].

Ararat Bioenergy

Ararat Bioenergy is one of the projects currently proposed in Victoria that aims to inject biomethane into the east coast gas grid. This circular economy project, led by Valorify and Bioenergy Australia, is proposed to be developed in Ararat, in western Victoria. Using cereal straw and other agricultural waste leftovers as feedstock, the project aims to produce biomethane and other renewable products[106].

4.3.4 Potential renewable gas use by large industrial users and safeguard facilities

The Safeguard Mechanism, initiated by the Federal Government in 2016 and reformed in 2023, is applied to industrial facilities that emit more than 100,000 tonnes of carbon dioxide equivalent (CO_2-e) annually. It imposes legislated greenhouse gas emission limits, known as baselines, on major industrial facilities. These baselines, determined by the Clean Energy Regulator, decrease by 4.9% annually from 1 July 2024 through to 2030 with the aim to ensure emissions targets are met[107]. To comply with the scheme, facilities must implement emission reduction actions such as switching to renewable gas use, improving energy efficiency, carbon capturing, electrification, offset certificates or shutting down.

According to 2021-22 Safeguard facility information, there are 19 facilities in Victoria covered by the mechanism[108]. These facilities can be grouped into four general categories by their relationship to natural gas. **Table 21** below highlights some decarbonisation initiatives and projects that have been identified for each category.

Table 21 Examples of decarbonisation initiatives/projects by safeguard facility category

Category	Example safeguard facility[A]	Project/initiative	Project owner	Description
Gas producers	Longford Gas Plant and Gippsland Basin processing	CO_2 processing facility	BOC	CO_2 captured from the Longford gas conditioning plant will be the supply source. The facility is expected to commence operation in 2024[B].
		SEA CCS Project	GBJV	The project is currently undergoing pre-FEED studies. It has the potential to capture up to two million metric tonnes of CO_2 and construction is expected to commence between 2024 to 2025 after approval[C].

[103] See https://www.hydrogeninsight.com/production/australian-green-hydrogen-blending-project-takes-fid-after-government-foots-almost-all-36m-in-costs/2-1-1474841.

[104] See https://gasmatters.agig.com.au/hydrogen-park-murray-valley.

[105] See https://www.agig.com.au/hydrogen-park-murray-valley-a-key-step-forward-for-renewable-hydrogen.

[106] See https://araratbio.com.au/.

[107] See https://www.dcceew.gov.au/sites/default/files/documents/safeguard-mechanism-reforms-factsheet-2023.pdf.

[108] See https://www.cleanenergyregulator.gov.au/NGER/The-Safeguard-Mechanism/safeguard-data/safeguard-facility-reported-emissions/safeguard-facility-reported-emissions-2021-22.

Category	Example safeguard facility[A]	Project/initiative	Project owner	Description
Gas consumers	Opal Australian Paper Maryvale Mill	Energy from waste (EfW) project	Opal Australian Paper	The Maryvale paper mill's energy mix consists of 36% of natural gas which would be lowered by the electricity and steam generated by the EfW plant[D]. The project is currently undergoing studies for full design and construction costings[E].
Gas transporters	Distribution networks	Distribution pipelines replacement	AusNet	Replacement of ageing distribution pipelines with modern polyethylene pipelines to reduce methane leaks and to be ready for hydrogen blend[F].
		Hydrogen blending	AGIG	Hydrogen blend into Albury and Wodonga distribution network from HyP Murray Valley's production[G].
Potential biomethane producers[H]	Sewerage West and Sewerage East treatment plants	Bioenergy generation	Melbourne Water	Biogas captured at Western Treatment Plant and Eastern Treatment Plant. The collected biogas is currently combusted at on-site power stations to convert into electricity which is then provided back to the treatment plants[I].

A. See https://www.cleanenergyregulator.gov.au/NGER/The-Safeguard-Mechanism/safeguard-data/safeguard-facility-reported-emissions/safeguard-facility-reported-emissions-2021-22.
B. See https://www.boc-limited.com.au/en/news_and_media/press_releases/20220829-gippsland-basin-joint-venture-agreement.html.
C. See https://www.exxonmobil.com.au/-/media/Australia/Files/Energy-and-environment/Upstream-operations/SEA-CCS-Pipeline-Fact-Sheet--About-the-Project.pdf.
D. See https://drive.google.com/file/d/1EI5nVykIyyFk61UA7lZVOW-FEPW58OxA/view.
E. See https://opalanz.com/news/major-milestone-for-600-million-maryvale-energy-from-waste-project/.
F. See https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/sustainability/ausnet-climate-change-position-statement.pdf?rev=5e5941ed56ab4a3d8ddd3ef4e642cde7&hash=001E49AAE365F5703676150FF152C118.
G. See https://www.hydrogeninsight.com/production/australian-green-hydrogen-blending-project-takes-fid-after-government-foots-almost-all-36m-in-costs/2-1-1474841.
H. Facilities that produce potential feedstock for biomethane production.
I. See https://www.melbournewater.com.au/water-and-environment/energy/biogas.

4.3.5 Risks and barriers to the renewable gas industry within Victoria

AEMO has consolidated the risks and barriers commonly identified in public consultations and papers regarding renewable gases and their potential use and incentivisation. The primary risks and barriers identified are summarised in **Table 22** and represent the input of multiple government bodies, professional organisations, producers, and end users.

Additional risks and barriers raised are presented below, but did appear to have the same level of concern or discussion as the primary risks identified.

High level risks and barriers to renewable gas projects include:

- The risk of connecting to existing gas pipelines which may become subject to escalating transportation costs in the future if existing gas users disconnect (electrify) and the cost burden becomes spread over a reduced customer base.
- Potentially limited and varied scalability and economics of renewable gas production facilities, particularly biomethane which can be produced from a variety of feedstocks and locations.
- Potential competition of renewable hydrogen production and other users for water, particularly in drought prone or water scare regions.
- Renewable hydrogen compatibility considerations with existing infrastructure and desired use cases.

Table 22 Summary of primary barriers potentially preventing increased production and use of renewable gas

Barrier	Description
Lack of a unified approach or wholistic strategy for renewable gases.	Australia's carbon accounting framework, including the NGER measurement determination, carbon certificate trading (ACCUs) and the safeguard mechanism are enforced through federal legislation and the associated government bodies. Market incentivisation of renewable gases, however, differ between federal and state governments. For example, renewable hydrogen has federal government support through the $2 billion Hydrogen Headstart program, but there is no analogous biomethane equivalent. Similarly, while state governments including New South Wales, South Australian and Victoria have all committed to net zero emission targets, they have differing levels of maturity, ambition and commitment to renewable gas in their policies. Renewable gas industry proponents argue this arrangement does not adequately recognise that the gas market across the east coast is highly interconnected, both physically and financially, and creates uncertainty in which states/markets are the most favourable for renewable gas investment.
Lack of carbon abatement recognition of renewable gas compared to natural gas.	Renewable gas producers currently lack ability to assign a price premium to renewable gases as their potential carbon abatement is not federally recognised when used in place of natural gas, particularly for large industrial users and safeguard facilities. Industry proponents suggest that the federal Guarantee of Origin scheme should be promptly expanded to include biomethane, and the emission intensity reduction compared to natural gas be included in the NGER measurement determination to assist.
Lack of timely, appropriate, and delineated targets for renewable hydrogen and biomethane.	Clear, appropriate targets for renewable gases which identify the different use cases for renewable hydrogen and biomethane help provide the market with appropriate certainty and investment confidence. Renewable gas producers argue that appropriate targets help to provide confidence to producers that they will be able to recover their capital costs over the lifecycle of their assets as a long-term customer base will develop.
Financial risk and uncertainty relating to market entry.	Renewable gas is currently more expensive per GJ than natural gas, limiting potential customers[109]. There is also additional complexity for renewable gases to be injected into existing markets compared to natural gas. Within Victoria the DWGM provides a structured framework for renewable gas participants to follow[110], which will continue to be developed as the penetration of renewable gases becomes more certain. If renewable gas proponents seek to utilise non-declared pipelines within Victoria however, additional contractual and operational complexity will need to be managed. STTMs also offer a familiar, structured market entry point for renewable gas proponents. For example, the Malabar production facility allows for renewable gas to enter the Sydney STTM market[111]. Outside of the markets operated by AEMO, there can be significant contractual and operational complexity for renewable gas proponents to navigate to produce and transport renewable gases to the end user or market hub. As the federal and state governments work to harmonise policy frameworks and market settings regarding renewable gases, some of these contractual and operational complexities may reduce with timePolicy and regulatory framework related to renewable gases.

[109] See https://www.aph.gov.au/DocumentStore.ashx?id=a8dc5df8-d71b-48e4-858a-54e753d0f15f&subId=726509.

[110] See https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-victorian-declared-wholesale-gas-market-and-retail-market-1-may-2024-release.

[111] See https://aemo.com.au/en/consultations/current-and-closed-consultations/sttm-procedures-new-malabar-custody-transfer-point.

A1. System capability modelling

A1.1 Monthly peak demand for 2024-2028

Table 23 shows forecast peak day system demand for each month from 2024 to 2028. Forecast peak day system demand will be used to inform the amount of capacity certificates for any month and capacity certificate type[112].

Table 23 Forecast monthly 1-in-20 peak day demand from 2024 to 2028 (TJ/d)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2024	426	451	549	767	1,018	1,137	1,169	1,140	958	806	712	506
2025	425	445	544	760	1,001	1,118	1,153	1,129	948	796	696	501
2026	410	430	520	736	967	1,085	1,116	1,099	921	767	671	487
2027	402	425	512	716	941	1,051	1,083	1,059	890	748	655	479
2028	389	410	500	684	905	1,011	1,038	1,013	858	723	632	457

A1.2 Capacity certificate zones

There is no change to the capacity certificate zones that AEMO determined and published in the 2023 VGPR. **Table 24** shows the capacity certificates zone and the system points allocated to the capacity certificates zone.

Table 24 Capacity certificate zones and equivalent VGPR pipeline capacity

Capacity certificate zone	System points	VGPR pipeline capacity
Gippsland entry zone	Longford injection point VicHub injection point TasHub injection point BassGas injection point	Longford Melbourne Pipeline to Melbourne (**Figure 27**)
Gippsland exit zone	VicHub withdrawal point TasHub withdrawal point	Longford Melbourne Pipeline to Longford (**Table 26**)
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	South West Pipeline to Melbourne (including WTS demand) (**Figure 28**)
South west exit zone	Iona withdrawal point SEA Gas withdrawal point Otway withdrawal point	South West Pipeline to Port Campbell (**Figure 29**)
Northern entry zone	Culcairn injection point	Victorian Northern Interconnect to Melbourne (**Figure 30**)
Northern exit zone	Culcairn withdrawal point	Victorian Northern Interconnect to New South Wales via Culcairn (**Figure 31**)

112 Capacity certificate type means each combination of exit capacity certificate or entry capacity certificate and capacity certificates zone.

A1.3 DTS pipeline and system points capacity charts

The capacity modelling assumptions used for the system capability modelling are the same as the assumptions used in the 2023 VGPR except for the changes outlined in **Table 25**. For assumptions in the 2023 VGPR, refer to Appendix A6.

Table 25 Changes to Victorian gas planning approach from the 2023 VGPR

Location	Previous setting	Current setting	Reason for change
Winchelsea Compressor Station	Minimum inlet pressure 4,000 kPa in both directions.	Minimum inlet pressure 4,500 kPa when compressing from Melbourne to Port Campbell. No change when compressing from Port Campbell to Melbourne.	Updated operational settings at the completion of the Winchelsea Compressor 2 project.

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

A1.3.1 Longford to Melbourne Pipeline

Figure 27 LMP injection capacity to Melbourne (TJ/d)

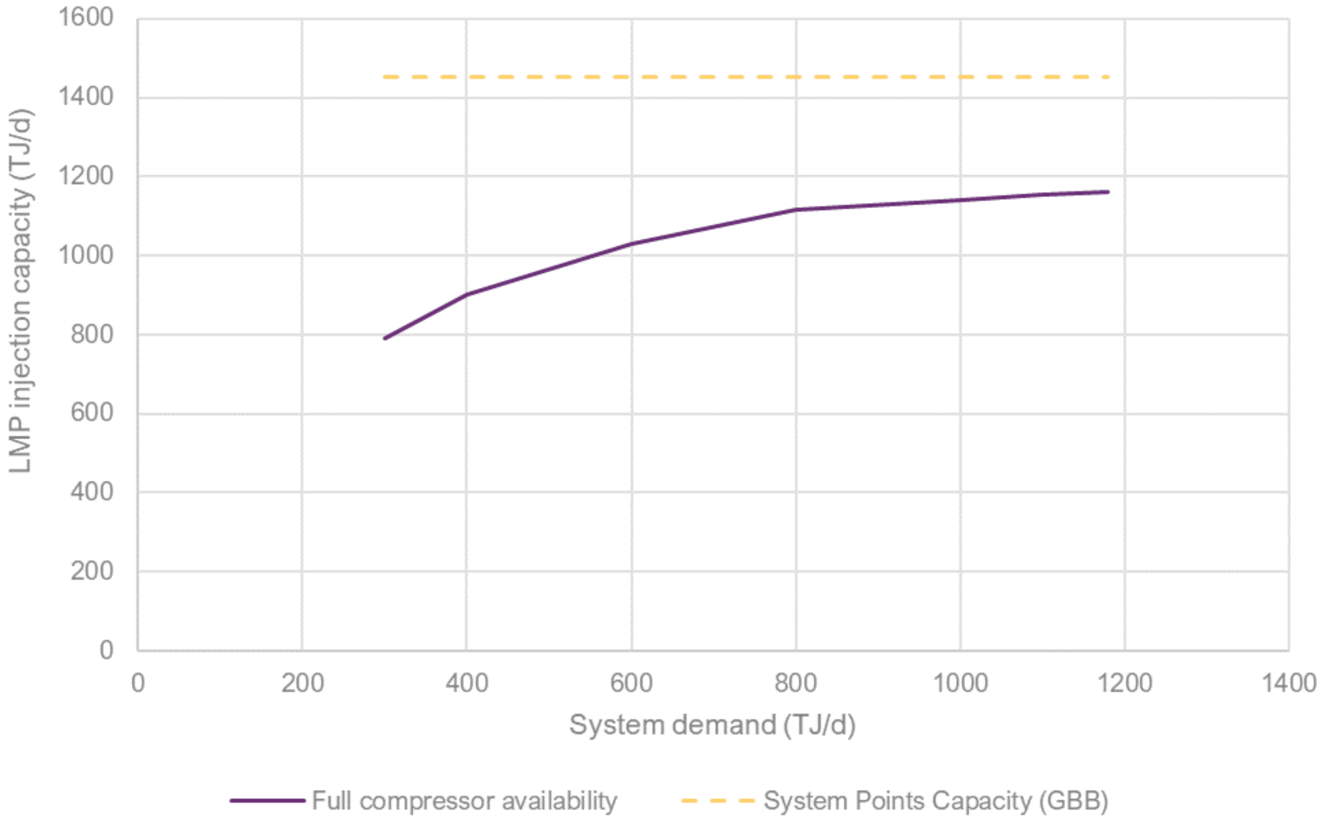


Table 26 Longford to Melbourne Pipeline to Longford capacity

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

A1.3.2 Melbourne entry zone

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

Table 27 Melbourne entry zone capacity

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

A1.3.3 South West Pipeline

Figure 28 SWP injection capacity to Melbourne (TJ/d)

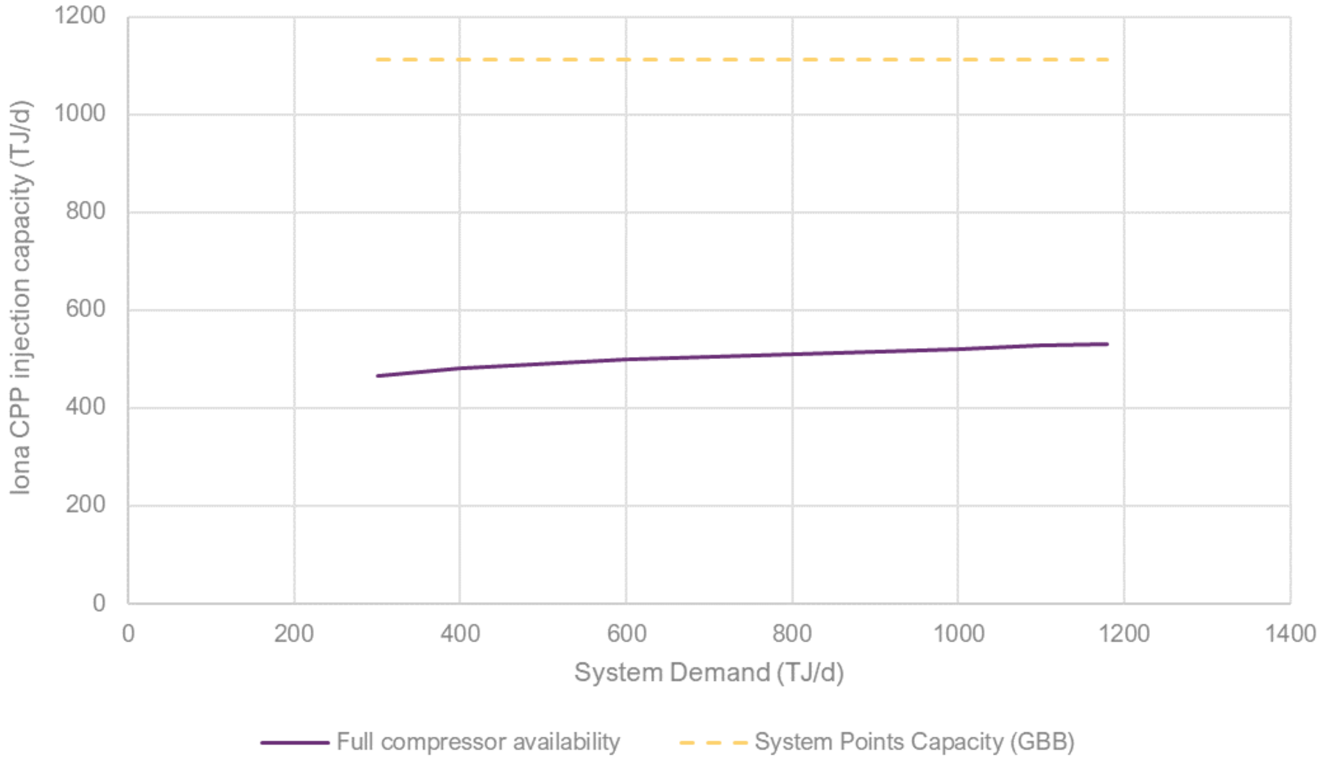
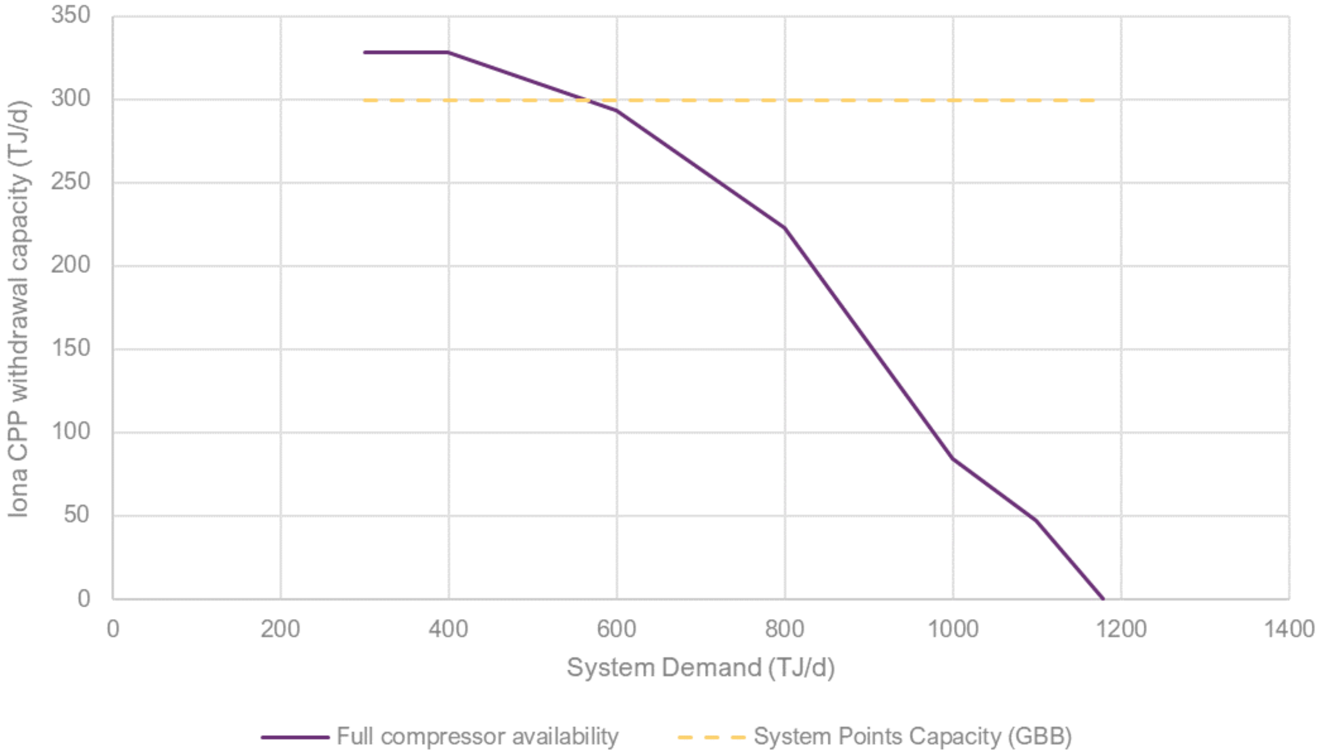


Figure 29 SWP withdrawal capacity to Port Campbell (TJ/d)



A1.3.4 Victorian Northern Interconnect

Figure 30 Victorian Northern Interconnect import capacity (TJ/d)

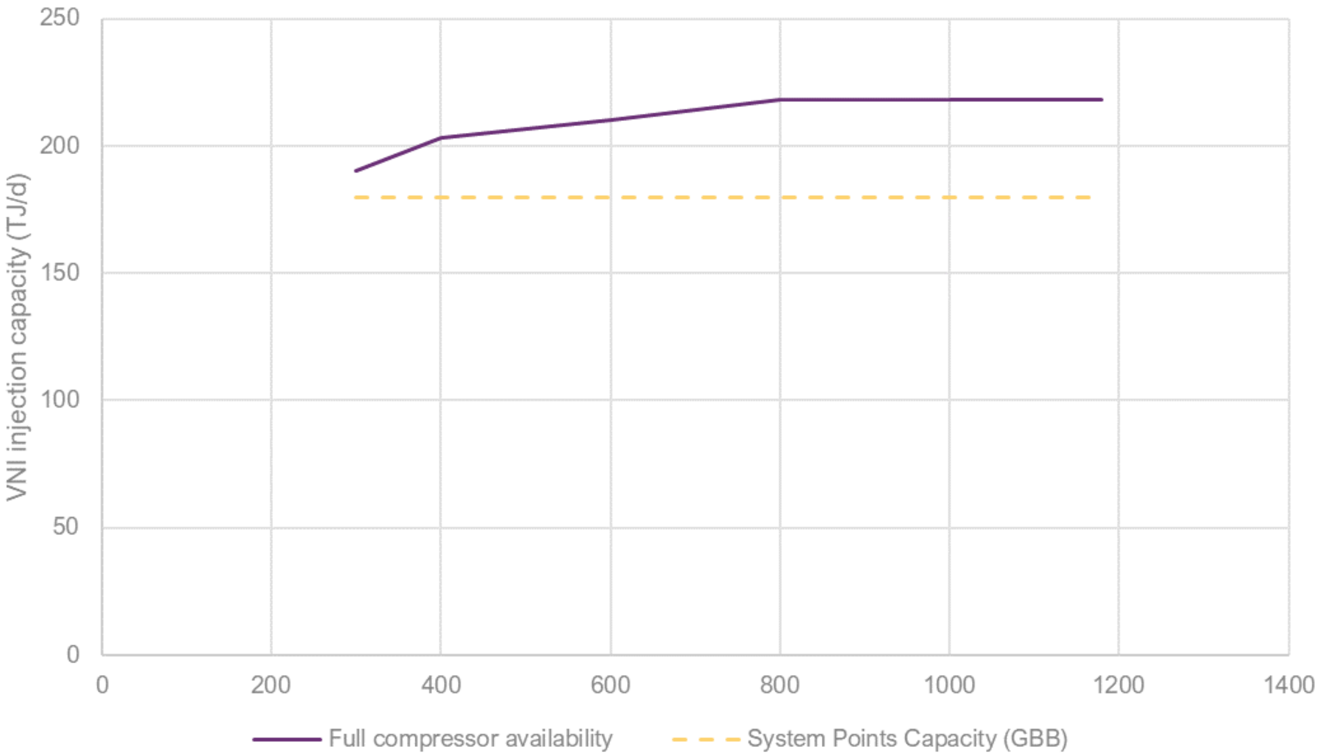
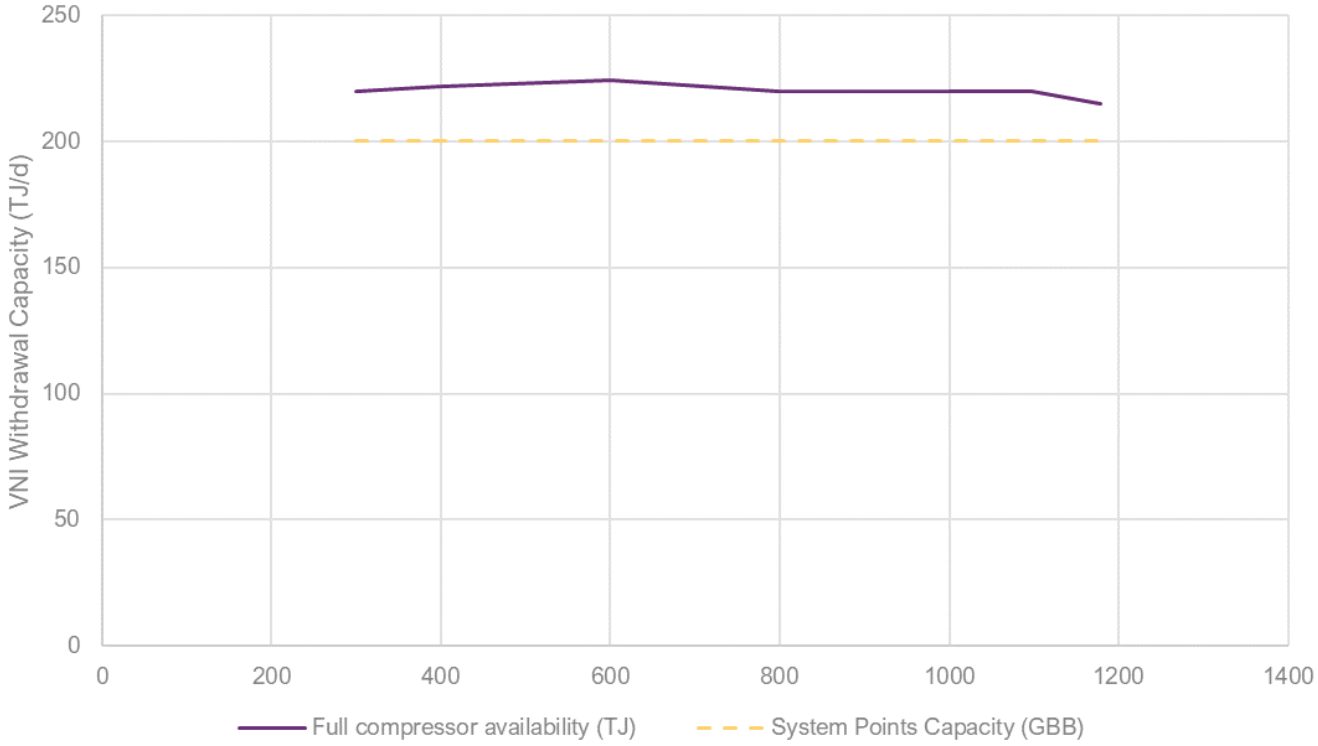


Figure 31 Victorian Northern Interconnect export capacity (TJ/d)



List of tables and figures

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Measures, abbreviations and glossary

Units of measure

Term	Definition
CO_2-e	carbon dioxide equivalent
EDD	effective degree days
GJ	gigajoules
kPa	kilopascals
mm	millimetre
MW	megawatts
PJ	petajoules
PJ/m	petajoules per month
PJ/y	petajoules per year
t/h	tonnes per hour
TJ	terajoules
TJ/d	terajoules per day
TJ/h	terajoules per hour
TJ/m	terajoules per month
TJ/y	terajoules per year

Abbreviations

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

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

Term	Definition
TGP	Tasmanian Gas Pipeline
UAFG	unaccounted for gas
UGS	Underground Gas Storage
VEU	Victorian Energy Upgrades
VGPR	*Victorian Gas Planning Report*
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
WORM	Western Outer Ring Main
WTS	Western Transmission System

Glossary

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

Term	Definition
1-in-2 peak day	The 1-in-2 peak day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (DTS) and injected at Pakenham.
biomethane	Methane captured from biological processes such as wastewater treatment, landfill or biodigesters (also known as biogas) and purified to meet gas quality standards. Biomethane can be used interchangeably with natural gas.
capacity certificate	A certificated right in respect of a specified capacity certificates zone that is allocated for the purposes of tie-breaking.
capacity certificate zone	A group of one or more system injection points or system withdrawal points in the DTS which comprise a capacity certificates zone, as determined by AEMO.
city gate	A facility which regulates gas pressure from a higher to a lower pressure.
connection point	A gas delivery point, transfer point, or receipt point.
Culcairn	The gas transmission network interconnection point between the DTS and the New South Wales transmission system (part of the MSP).
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
custody transfer meter	A meter installed at a connection point to measure gas withdrawn from or injected into a transmission system.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the DWGM) or may be registered as market participants in their own right.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the National Gas (Victoria) Act, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Wholesale Gas Market	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTs.
delivery point	The point on a pipeline that gas is withdrawn from for delivery to a customer or injection into a storage facility.

Term	Definition
distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
effective degree day	A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The EDD is used to model the daily relationship between weather and gas demand.
electrification	The conversion of technologies or systems to use electrical power. In the context of the VGPR, this most often refers to converting appliances or industrial processes from using natural gas to electricity.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas consumption	Gas consumption refers to total gas demand used over longer periods (months and years)
gas demand	Gas demand refers to short-term gas use (hours and days).
gas-powered generation	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
Gas Statement of Opportunities	Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia published annually by AEMO.
gas supply	The total volume of gas a facility is able to supply on an annual basis.
gas supply capacity	The maximum volume of gas a facility is able to supply in a single day.
gigajoule	An International System of Units (SI) unit. One GJ equals 1 x 10^9 joules.
injection	The physical injection of gas into the transmission system.
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is at Dandenong.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand.
maximum hourly quantity	Maximum hourly quantity (MHQ) of gas supply or demand.
metropolitan ring main	The 450 mm, distributor-owned pipeline from Dandenong to Keon Park to West Melbourne.
natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
peak day profile	The hourly profile of injection or demand occurring on a peak day.
peak flow rate	The highest hourly flow rate of gas or maximum hourly quantity (MHQ) passing a particular point in the system under normal conditions (as determined by AEMO) in the immediately preceding 12-month period or, if gas has passed a particular point in the system for a period of less than 12 months, the highest hourly flow rate that in AEMO's reasonable opinion is likely to occur in respect of that system point under normal conditions for the following 12-month period.
peak loads	Short duration peaks in gas demand.
peak shaving	Meeting a demand peak using injections of vaporised LNG.
petajoule	An International System of Units (SI) unit. One PJ equals 1 x 10^{15} joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
retailer	A seller of bundled energy service products to a customer.

Term	Definition
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the National Gas Rules (NGR), for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
shoulder season	The period between low (summer) and high (winter) gas demand. It includes the calendar months of March, April, October, and November.
southern states	New South Wales, South Australia, Victoria, the Australian Capital Territory, and Tasmania.
storage facility	A facility for storing gas, including the LNG storage facility and Iona UGS.
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors; accordingly, a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • Load distribution across the system. • Hourly load profiles throughout the day at each delivery point. • Heating values and the specific gravity of injected gas at each injection point. • Initial linepack and final linepack and its distribution throughout the system. • Ground and ambient air temperatures. • Minimum and maximum operating pressure limits at critical points throughout the system. • Compressor station power and efficiency.
system coincident peak day	The day of highest system demand (gas). See also system demand.
system constraint	A constraint applied in the DWGM.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes GPG demand, exports, and gas withdrawn at Iona.
system injection point	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas DTS connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
system withdrawal zone	Part of the gas DTS that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
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.