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2023-27 VTS Access Arrangement: Revised proposal

July 15, 2022

Load and Demand 2022 GSOO/VGPR Update

Contents

1 Introduction

This document serves as an update of the load and demand forecast provided to the AER in response to question 11 of the VTS Access Arrangement Regulatory Information Notice (**RIN**).

Each year, the Australian Energy Market Operator (**AEMO**) is required to publish its *Gas Statement of Opportunities* (**GSOO**) in accordance with section 91DA of the National Gas Law (**NGL**) and Part 15D of the National Gas Rules (**NGR**). The 2022 GSOO forecasts the adequacy of gas supplies, based on information from gas industry participants, to meet consumers' changing gas needs from now until 2041 in Australian jurisdictions other than Western Australia and the Northern Territory.

In addition, as part of its role as operator of the Declared Transmission System (**DTS**), AEMO publishes the *Victorian Gas Planning Report* (**VGPR**) or *Update* in accordance with rule 323 of the NGR. The 2022 *VGPR Update* provides information about the supply and demand balance over the next five years (2022-26, called the outlook period) in Victoria, and the Victorian DTS. The 2022 VGPR *Update* complements AEMO's 2022 GSOO, which assesses the wider gas supply adequacy in eastern and south-eastern Australia.

AEMO released the 2022 GSOO and 2022 VGPR Update on 29 March 2022.

APA VTS relies heavily on AEMO, as operator of the Declared Wholesale Gas Market (DWGM) and VTS, in developing load and demand forecasts for the VTS access arrangement.

The load and demand forecast lodged with the AER as part of the VTS access arrangement proposal was based on the March 2021 GSOO and VGPR. Following the release of AEMO's 2021 forecasting information, there were several announcements that in our view were likely to affect the forecasts. These included Phase I of APA's planned expansion of the East Coast Grid, Origin's contemporaneous supply contract with APLNG, and Esso and Qenos curtailing consumption in Altona. The 2022 GSOO and VGPR include these announcements in their analysis.

1.1 Stakeholder engagement

Following the release of the 2022 GSOO and VGPR, APA VTS hosted AEMO's presentation to the stakeholder consultation group on 13 April 2022. This presentation was very well attended and generated a number of questions and discussion. We also met separately with the Consumer Challenge Panel.

On 22 April 2022, the AER issued an information request asking APA VTS to update its load and demand forecasts for the 2022 GSOO and VGPR.

This document has been prepared in response to that information request, and to support the revised access arrangement proposal.

We further engaged with the stakeholder consultation group in preparing this load and demand forecast update, notably at a round table session on May 25, 2022.

At this point we have not had the opportunity to review load and demand forecasts utilised by the Victorian Gas Distribution businesses in their respective 2023-28 Access Arrangements Revisions (published by AER on 13 July 2022).

1.2 Choice of scenario

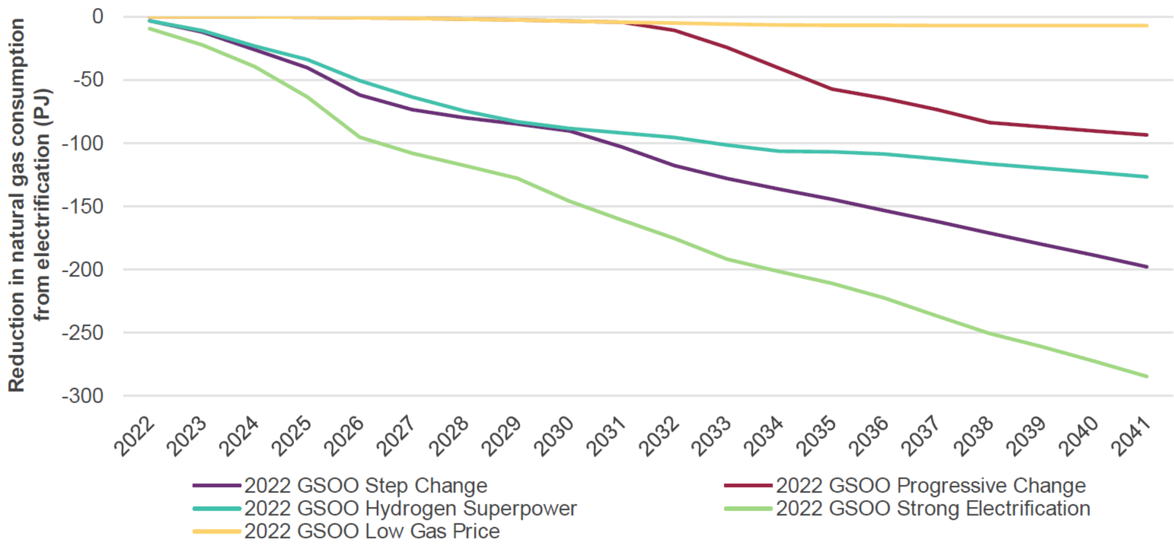
AEMO's GSOO and VGPR forecast gas consumption and demand based on a range of scenarios. As stated in AEMO's GSOO, section 1.2:

> For the 2022 GSOO, AEMO modelled the next 20 years using scenarios from the Draft 2022 Integrated System Plan (ISP) that are most relevant to the gas sector – Progressive Change, Step Change and Hydrogen Superpower. To complement the scenarios, AEMO also explored two key sensitivities – Strong Electrification and Low Gas Price – to assess the impacts of changes to specific scenario assumptions.
>
> These scenarios and sensitivities are described in detail in AEMO's 2021 Inputs, Assumptions and Scenarios Report (**IASR**). In summary:
>
> - **Step Change** is a future with a rapid transition towards net zero emissions economy wide. This includes significant levels of electrification (consumers shifting from gas to electricity) early on, as the electricity sector decarbonises with increasing renewable energy penetration and retiring coal generation.
> - **Progressive Change** also targets net zero emissions, but the trajectory to achieve it is quite different from Step Change. The scenario reflects slower action across the economy, allowing time for technologies to develop, but relies on very strong transformation efforts later to get to net zero by 2050.
> - **Hydrogen Superpower** describes a future with very strong environmental objectives globally, where Australia leverages its low-cost renewable resources to become a major exporter of hydrogen to countries that rely on imported energy. The scenario assumes higher growth in population and the economy overall as a result. Hydrogen is also used domestically to offset gas consumption, with reduced focus on electrification.
> - **Strong Electrification** reflects a similar high-growth future to Hydrogen Superpower, retaining the higher economic and population growth assumptions, but with minimal hydrogen adoption. Instead, a very high level of electrification is assumed.
> - **Low Gas Price** is a sensitivity that examines a likely upper bound to gas demand, with lower gas prices and no coordinated action for the gas sector to contribute to Australia's net zero commitment.
>
>   The scenarios have been defined based on specific assumptions, refined through extensive consultation with stakeholders. These include assumptions about the degree of electrification of existing gas demand, uptake of energy efficiency measures, hydrogen demand, and the technology used to produce hydrogen.

The various scenarios differ in terms of the forecast rate of change of electrification-driven reduction in gas consumption over the coming years:

Figure 1.1

Figure 9 Forecast reduction in gas consumption from electrification by scenario, 2022-41 (PJ)



For the purposes of this load and demand forecast, APA VTS has focused on the *Step Change* and *Progressive Change* scenarios. In deciding between these scenarios, APA VTS notes AEMO's comments in the GSOO (p6):

> Key emerging drivers that may impact future gas consumption levels include:
>
> - Public policy and private investment in energy efficiency and electrification, which would reduce gas consumption. The extent to, and speed at, which business and household consumers switch from gas to electricity is uncertain. While governments are moving to increase electrification and improve the energy efficiency of gas appliances (for example, Victoria's Gas Substitution Roadmap and Victorian Energy Upgrades program), *such action would need to speed up to rapidly reduce gas consumption*. [emphasis added]
> - The potential growth of hydrogen as an alternative fuel for transport, industry and households. The pace and impact of hydrogen deployment will rely on technology improvement and consumer uptake. Adding further uncertainty, hydrogen could be produced through steam methane reforming (**SMR**), which uses natural gas, or through other technologies that do not use gas. AEMO has assumed some level of gas consumption for SMR hydrogen in all scenarios and sensitivities apart from the Low Gas Price sensitivity. [DN – there is 30PJ of gas forecast for SMR in 2025-2027 – if H2 testing is not approved, the demand forecast should be reduced accordingly]

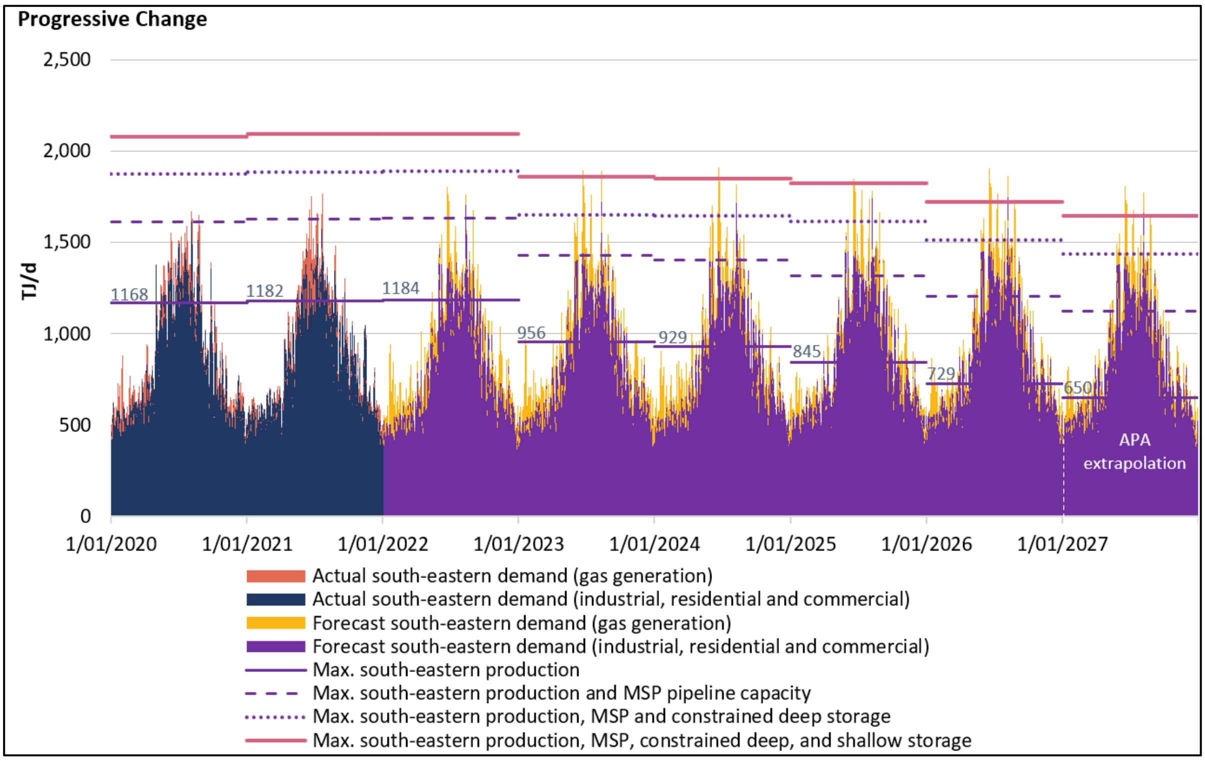
Considering this information has caused APA VTS to focus on the *Progressive Change* scenario for load and demand forecasting purposes in the 2023-27 access arrangement.

The published 2022 GSOO and VGPR documents forecast gas production and demand out to 2026 – however, for the VTS access arrangement, we require forecasts out to 2027. This data has been obtained from AEMO's forecasting portal.

For system adequacy illustrative purposes, APA VTS has extrapolated the GSOO data presented in GSOO Figures 4 and 34 by assuming:

- Max South-eastern production continues its forecast decline, to 650 TJ/day in 2027. This is consistent with AEMO's views expressed in the 2022 Winter Readiness Plan presentation;
- Residential, commercial and industrial demand falls by 5% relative to AEMO's 2026 forecast; and
- GPG demand falls by 5% relative to AEMO's 2026 forecast.

Figure 1.2



Source: AEMO 2022 GSOO report figures and data, Tables 4 & 34 as extrapolated by APA for 2027.

1.3 Events subsequent to the publication of the 2022 GSOO

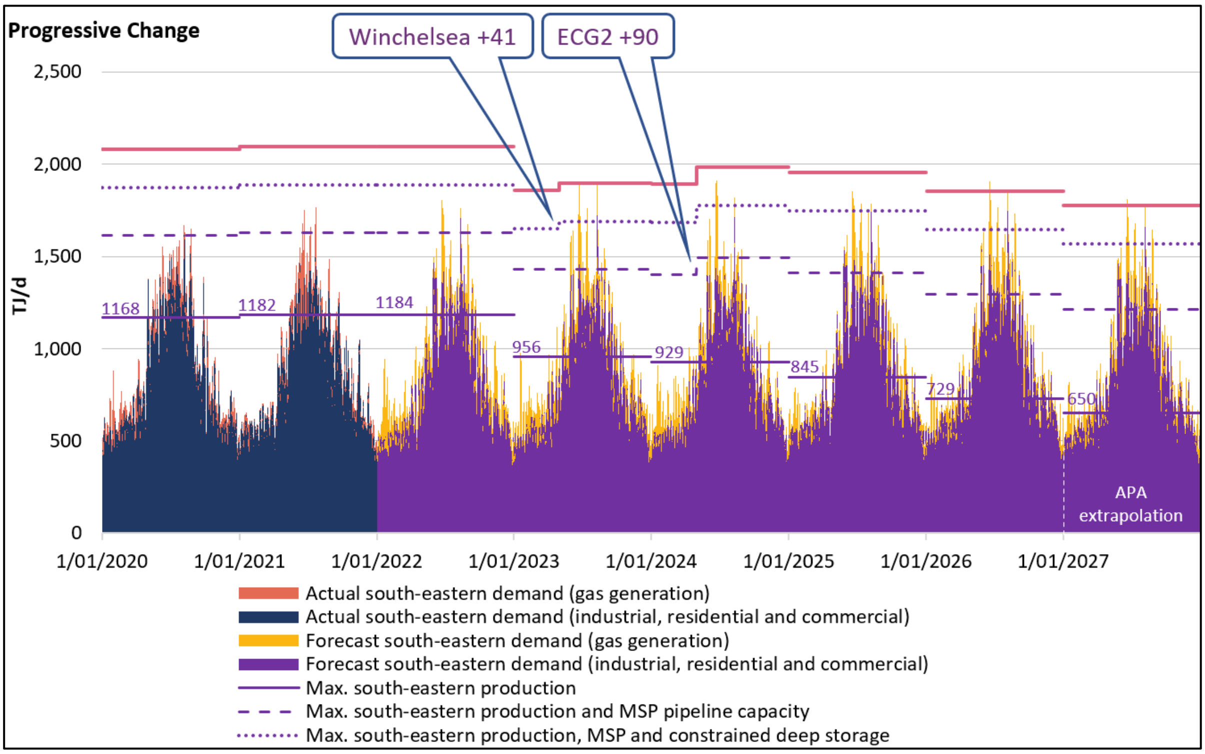
On 21 April 2022, APA announced[1] that it would increase the capacity of the South West Pipeline (**SWP**) through additional compression at Winchelsea. As the Winchelsea site was originally constructed to accommodate two compressor units, adding an additional unit at Winchelsea would be faster than building a greenfields site - this additional 41TJ/day of capacity is expected to be in place for winter 2023.

On 26 May 2022, APA announced[2] that it had reached Final Investment Decision (**FID**) on Phase 2 of its East Coast Grid expansion project. This expansion investment, all outside Victoria, will provide for capacity to bring an additional 90TJ/day to southern markets.

[1] APA announces additional capacity in Victoria ahead of forecast gas shortfalls
[2] APA commences stage two of east coast gas grid expansion

With these announcements, the GSOO extrapolated supply and demand balance chart could reasonably be recast as follows:

Figure 1.3



1.4 Weather and temperature sensitivity

Victorian gas demand, particularly for the Tariff V space heating load, is sensitive to temperature and weather patterns. In this respect, it is important to understand the forecast of temperature and weather on which the load and demand forecasts are based.

Temperature sensitivity is often measured by Heating Degree Days (**HDD**), a global standard measure used to forecast the extent to which heat-sensitive load will use space heating equipment. More specifically, one Heating Degree Day is recorded for each degree Celsius that the average of the daily high and low temperatures falls below 18°C.

For a day, the number of Heating Degree Days is calculated as:

MAX(18 – Average(Daily high temperature, Daily low temperature),0)

For example:

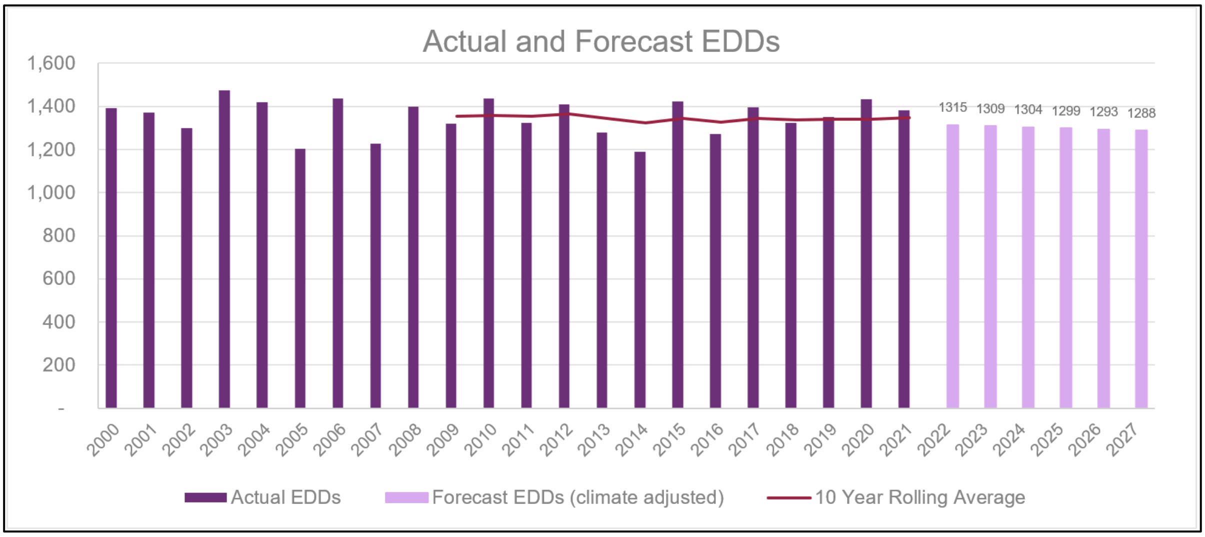
Table 1.1

High temperature	Low temperature	Average of high and low temperature	HDD
30	20	25	0
20	10	15	3
10	0	5	13

In forecasting load and demand, AEMO uses a measure of Effective Degree Days (**EDD**). This measure starts with the standard HDD measure and adjusts it for a combination of other factors such as wind chill, solar insolation and seasonal factors.[3] EDDs are accumulated over the year (recognising that, for much of the year we will record zero EDD).

AEMO publishes the historical EDD values, and these are important to be able to normalise historical demand and to understand the amount of "coldness" that has been forecast to underpin the load and demand forecasts. AEMO has supplied the following information regarding the forecast EDD values supporting the GSOO/VGPR load and demand forecasts:

Figure 1.4



Source: Data provided by AEMO. Climate adjustment is discussed in section A2.3 of AEMO's GSOO Gas Demand Methodology document.

The EDD forecast (along with a measure of temperature sensitivity, discussed below) is used in the Price Control Model to normalise demand, which is then used to adjust the revenue targets in the VTS revenue yield approach to ensure that APA VTS does not benefit from (is not penalised by) normal variations in weather.

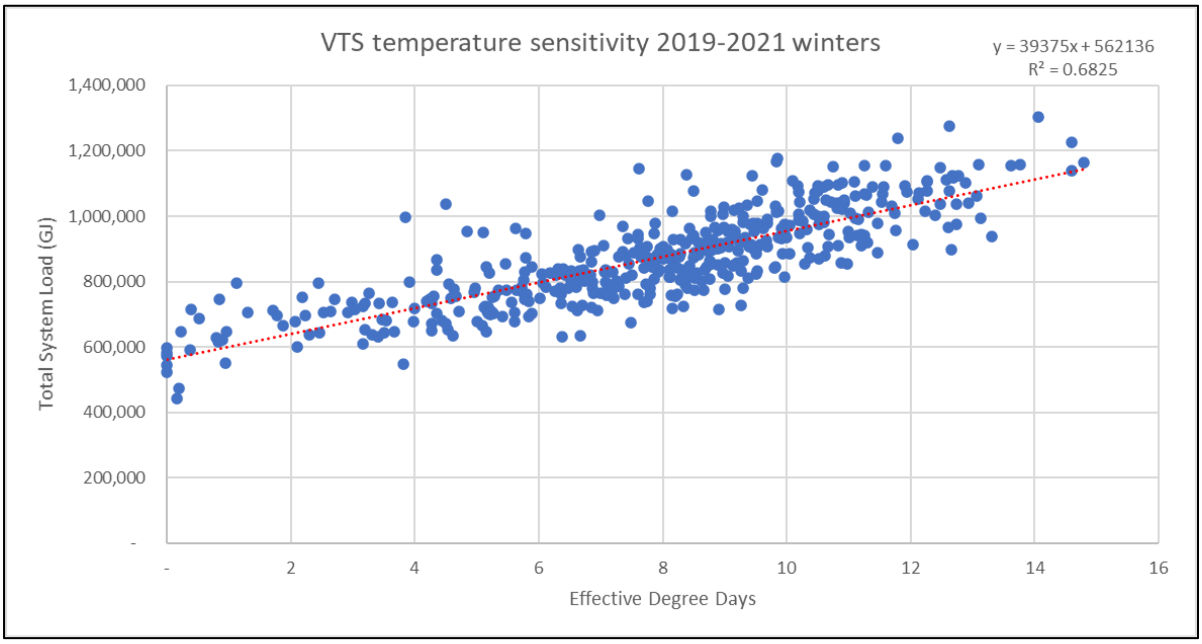
[3] More information on the calculation of Effective Degree Days can be found in section A2.2 of AEMO's GSOO Gas Demand Methodology document.

Temperature sensitivity

The regulatory framework applying to the VTS allows APA VTS to recover its allowed revenue over "normal" temperature levels. In order to do this, the Price Control Model adjusts actual volumes for the difference between the forecast and observed EDDs. In order to make this adjustment, we need to know the extent to which load varies by EDD levels.

APA VTS plotted the daily EDD measures against the daily VTS load. As temperature sensitivity is most observable over the colder winter months, we have observed 15 months' of daily data – for the five winter months of each of 2019, 2020 and 2021:[4]

Figure 1.5



While the correlation coefficient (R^2) in the regression analysis indicates that load and EDD are not perfectly correlated, the data over the three winters analysed indicates that, for each change in EDD from forecast, we can expect a change in load of 39.375TJ.

Table 4.6 of the Access Arrangement Information for use in the Price Control Model over the course of the access arrangement period, will therefore report as follows:

[4] Using winter-only data removes the large amount of variable "base load" data at which EDD=0.

Figure 1.6

4.6
Effective Degree Days (EDD) and weather sensitivity for the pipeline over the access arrangement period

	2023	2024	2025	2026	2027
Effective Degree Days (EDD)	1309	1304	1299	1293	1288
Weather Sensitivity (TJ/EDD)	39.375	39.375	39.375	39.375	39.375

1.5 RIN Templates – sources of information

There are a number of data sources available, which present data through different lenses and at different levels of granularity. For example, the VGPR reports demand data by System Withdrawal Zone (**SWZ**) whereas the GSOO data is for Victoria only. Moreover, the VTS tariff model requires this information to be translated to a further granular level, by tariff zone. APA VTS was unable to source an integrated set of historical and forecast data from AEMO, and as a result has had to undertake some extrapolation and allocation of the available information. In some cases this results in minor differences between sources;[5] these differences are not material to this analysis.

The key sources of data are the AEMO March 2021 and March 2022 Gas Statements of Opportunities (**GSOO**) and accompanying 2021 and 2022 Gas Statement of Opportunities report figures and data, the AEMO forecasting data portal, which presents the detailed information behind the GSOO, and the March 2021 and March 2022 AEMO Victorian Gas Planning Reports (**VGPR**).

Table 1.2

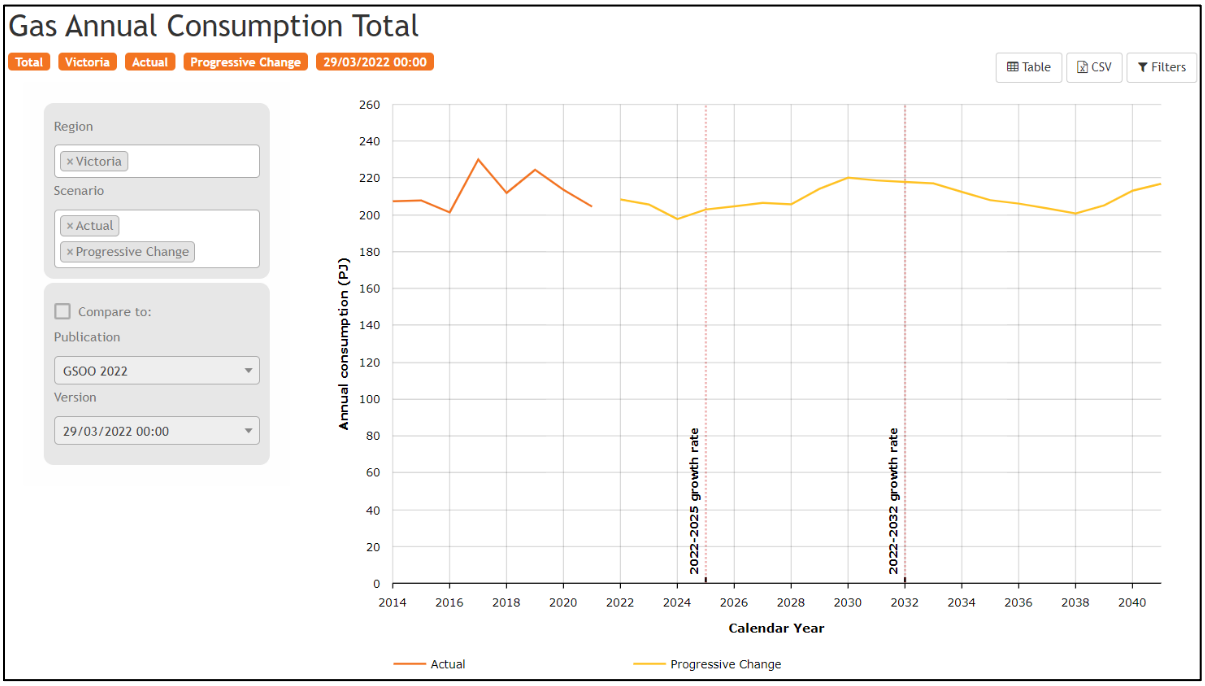
RIN Schedule	2022-2026	2027
N1.1	AEMO 2022 VGPR Table 14	APA extrapolation
N1.2	AEMO 2022 VGPR Table6 & 8	APA extrapolation
N1.3.1A	Not provided	Not provided
N1.3.1B	AEMO 2022 VGPR Table 11	AEMO GSOO data file
N1.3.1C	Calculated from Table N1.2	Calculated from Table N1.2
N1.3.2	Refers to Table N1.2	Refers to Table N1.2
N1.4.1A	Not provided	Not provided
N1.4.1B	Pro rata from 2020 actual	Pro rata from 2020 actual
N1.4.1C	Refers to Table N1.4.2	Refers to Table N1.4.2
N1.4.2	Pro rata from 2021 actual	Pro rata from 2021 actual

[5] For example, the VGPR helpfully separates the GPG forecast between DTS-connected and non-DTS connected GPG load, but only forecasts the expected GPG load to 2026. However, the GSOO reports only Victorian GPG load; it does not distinguish between DTS- and non-DTS-connected GPG load.

2 Withdrawals

At the highest level, AEMO's GSOO *Progressive Change* scenario is forecasting relatively flat volumes going forward out to 2040, notwithstanding the impacts of the Victorian Net Zero 2050 initiatives.

Figure 2.1



Source: AEMO gas forecasting portal http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total Note that Actual volumes have not been EDD-normalised.

AEMO's 2022 Victorian Gas Planning Report - Update (**VGPR**) was published on 29 March 2022. In summary, relevant to the VTS access arrangement, the GSOO 2022 Progressive Change scenario forecasts the following levels of demand[6]:

[6] The GSOO glossary defines system demand as "Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas generation demand, exports, and gas withdrawn at Iona."

Figure 2.2

Table 2 Victorian gas consumption forecast, *Progressive Change* (PJ)

	2022	2023	2024	2025	2026	Change over outlook
System consumption	193.1	192.0	189.9	196.4	196.4	1.7%
DTS gas generation consumption	7.8	7.1	4.0	3.5	4.4	-43.0%
Total DTS consumption	200.9	199.1	193.8	200.0	200.9	0.0%
Non-DTS system consumption	1.4	1.4	1.4	1.3	1.2	-19.5%
Non-DTS gas generation consumption	9.7	8.6	5.7	5.0	6.0	-37.7%
Total Victorian consumption	212.0	209.1	200.9	206.2	208.0	-1.9%

2.1 Tariff V and Tariff D

The Tariff V and Tariff D 2022-2026 forecasts by SWZ have been sourced from the 2022 VGPR Tables 8 and 9. For the 2027 forecast we have pro-rated the GSOO 2027 Tariff V and Tariff D forecasts to SWZ based on the VGPR's 2022-2026 data. That is:

$$\text{Tariff V load by SWZ 2027} = \text{AEMO forecast Tariff V load 2027} \times \frac{\text{Total Tariff V load by SWZ 2021-2026}}{\text{Total Tariff V load 2021-2026}}$$

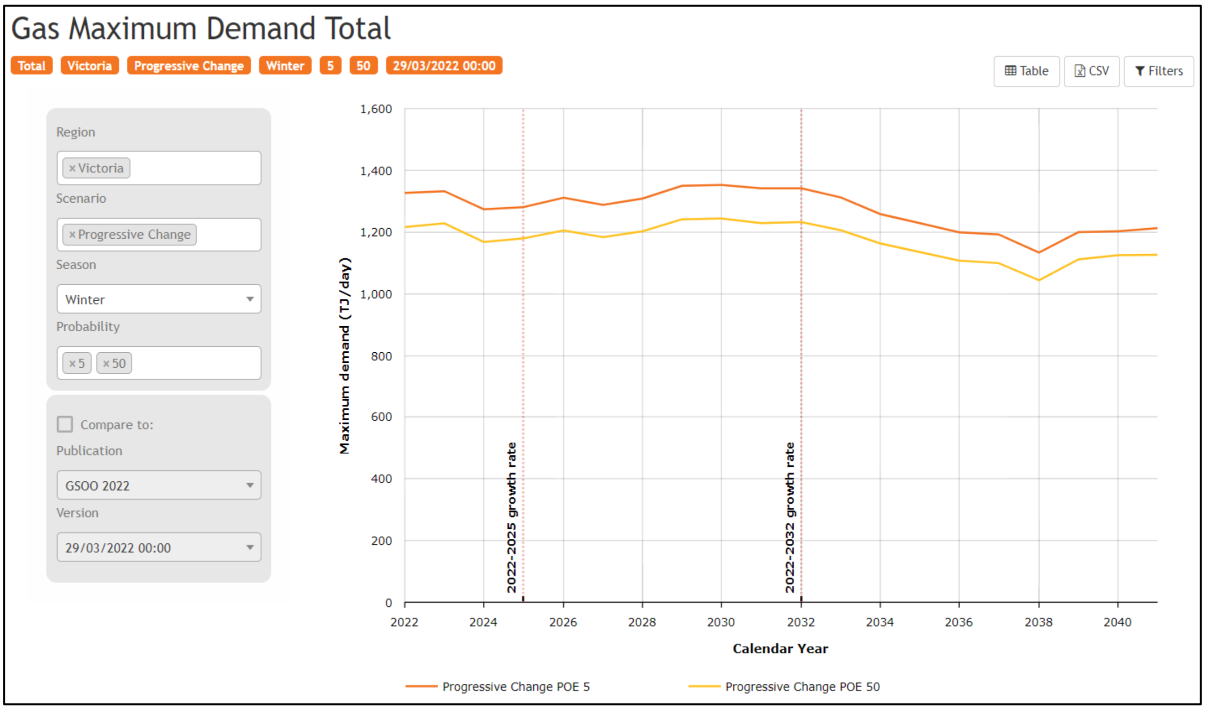
Table 2.1

		AEMO Data					APA Extrapolated
SWZ		**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Ballarat	Tariff V	9.0	9.1	9.2	9.2	9.4	8.4
	Tariff D	1.4	1.3	1.3	1.9	1.9	1.7
	SWZ_total	**10.3**	**10.5**	**10.5**	**11.1**	**11.3**	**10.1**
Geelong	Tariff V	11.4	11.6	11.7	11.7	12.0	10.7
	Tariff D	9.7	9.7	9.7	13.7	13.4	11.3
	SWZ_total	**21.1**	**21.3**	**21.3**	**25.4**	**25.3**	**22.0**
Gippsland	Tariff V	6.1	6.3	6.4	6.5	6.7	5.8
	Tariff D	8.9	8.3	8.2	7.0	5.5	8.8
	SWZ_total	**15.0**	**14.6**	**14.6**	**13.5**	**12.2**	**14.6**
Melbourne	Tariff V	89.4	88.5	86.4	84.3	83.9	81.7
	Tariff D	34.2	34.0	34.1	39.0	40.3	38.5
	SWZ_total	**123.6**	**122.6**	**120.4**	**123.3**	**124.2**	**120.2**
Northern	Tariff V	10.7	10.7	10.6	10.5	10.6	10.0
	Tariff D	8.4	8.4	8.4	8.5	8.6	9.2
	SWZ_total	**19.0**	**19.1**	**19.0**	**18.9**	**19.2**	**19.2**
Western	Tariff V	1.3	1.3	1.2	1.2	1.2	1.2
	Tariff D	2.8	2.8	2.7	3.0	3.1	3.0
	SWZ_total	**4.0**	**4.0**	**4.0**	**4.2**	**4.3**	**4.2**
Total	**Tariff V**	**127.9**	**127.6**	**125.4**	**123.4**	**123.8**	**117.8**
Total	**Tariff D**	**65.2**	**64.4**	**64.5**	**73.1**	**72.7**	**72.5**
Total		**193.1**	**192.0**	**189.9**	**196.4**	**196.4**	**190.3**

Source: AEMO 2022 VGPR, AEMO forecasting portal, APA VTS analysis

AEMO's forecasting portal also provides the 2022 GSOO forecasts of the 1-in-2 (P50) and 1-in-20 (P5) peak day:

Figure 2.3



Source: AEMO gas forecasting portal http://forecasting.aemo.com.au/Gas/MaximumDemand/Total

The *Progressive Change* 1-in-2 peak day for system demand is forecast as follows:

Table 2.2

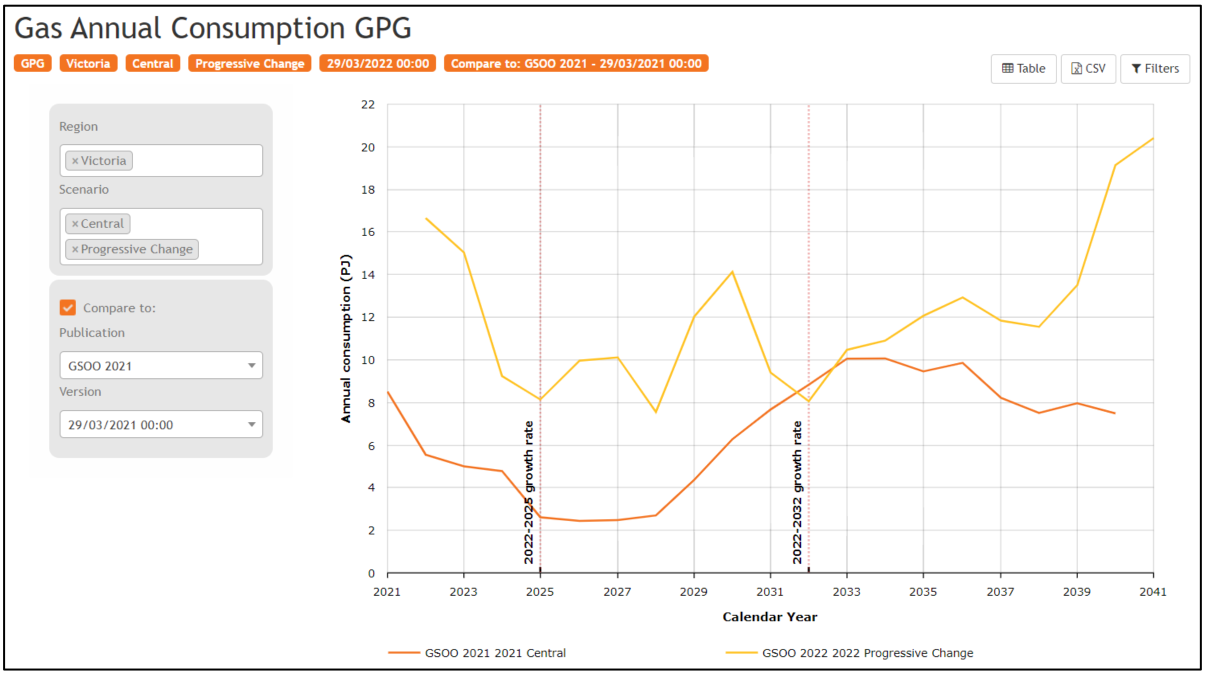
	2022	2023	2024	2025	2026	2027
Tariff V	919.9	915.7	900.3	888.1	887.5	853.9
Tariff D	227.4	226.5	227.3	253.9	256.3	254.1
System total	1147.2	1142.2	1127.5	1142.0	1143.7	1108.0

APA VTS has applied these GSOO values as the 1-in-2 system peak demand. The level of peak demand for Tariff V and Tariff D by SWZ has been calculated using the same approach as discussed above for total annual load.

2.2 Gas-fired Power Generation

AEMO's forecasting portal includes forecasts for Victorian GPG consumption:

Figure 2.4



Source: AEMO gas forecasting portal http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total

Some Victorian GPG units are connected to the VTS and others (Mortlake) are not. The VGPR helpfully separates this forecast between DTS-connected and non-DTS connected GPG load, but only forecasts the expected load to 2026. However, the GSOO reports only Victorian GPG load; it does not distinguish between DTS- and non-DTS-connected GPG load.

APA VTS has adopted the VGPR forecast of DTS-connected GPG for 2023-2026. For 2027, APA VTS has adopted the GSOO total Victorian GPG forecast, and multiplied it by the average proportion of Victorian GPG forecast load over the period show in the AEMO VGPR. For example:

$$\begin{array}{c}\text{DTS-connected GPG load}\\ \text{2027}\end{array} = \begin{array}{c}\text{AEMO forecast Victoria GPG load}\\ \text{2027}\end{array} \times \frac{\text{Total DTS-connected GPG load 2021-2026}}{\text{Total Victorian GPG load 2021-2026}}$$

Figure 2.5

Table 14 Gas generation consumption forecast, 2022-26 (PJ/y)

	2022	2023	2024	2025	2026	Extrapolated 2027
DTS gas generation consumption	7.8	7.1	4.0	3.5	4.4	4.7
Non-DTS gas generation consumption	9.7	8.6	5.7	5.0	6.0	5.45
Victorian gas generation Consumption	17.4	15.7	9.7	8.5	10.4	10.11

Source: AEMO 2022 VGPR, AEMO gas forecasting portal, APA VTS analysis

The AEMO gas forecasting portal also forecasts peak GPG demand for Victoria. APA VTS has applied the 2021-2026 percentages of DTS-connected GPG relative to total Victorian GPG to forecast the DTS-connected GPG peak demand:

Table 2.3

	2023	2024	2025	2026	2027
Vic GPG peak day	81.95	37.77	34.34	60.51	32.83
DTS-connected GPG as a % of total	45%	41%	41%	42%	46%
DTS-connected GPG Peak day	37.06	15.58	14.14	25.60	15.13

2.3 Export

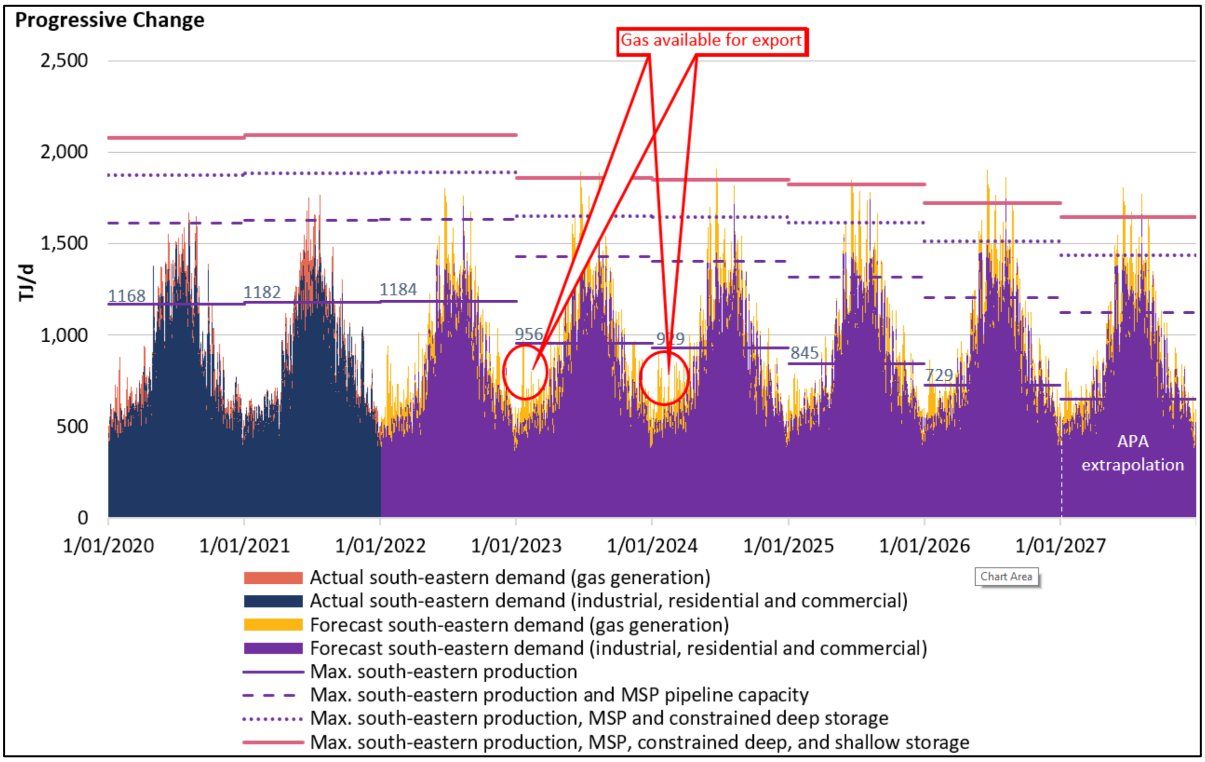
AEMO does not forecast gas volumes exported from Victoria. However, these volumes are important for VTS cost allocation and tariff derivation purposes. Also relevant for tariff derivation purposes is the peak volumes to be exported each year.

To forecast exports, APA VTS first assumed that southern production would first be dedicated to southern consumption – that is, that no gas would be exported if southern demand exceeded southern production. This limits the periods in which gas would be exported to the summer, and to a lesser extent spring and autumn, seasons.

APA VTS then accessed, from AEMO's Gas Statement of Opportunities – report figures and data, the detailed information underlying Figures 4 and 34 of the 2022 GSOO, and calculated the amount of gas notionally available for export on each forecast day. This was calculated as the excess of "Max. South-eastern Production" in excess of the combination of :

- Actual or forecast south-eastern demand (industrial, residential and commercial); and
- Actual or forecast south-eastern demand (gas generation):

Figure 2.6



In practice, the level of "Max. South-eastern production" is unlikely to be available year round. The lower demand shoulder and summer months are generally used for plant maintenance shutdowns, such that the amount of available production is unlikely to be at its maximum level during the period when export is possible.

As a result, basing the export forecast on the difference between AEMO's reported Max. South-eastern Production and demand is likely to overstate export volumes. This is most apparent in 2026 and projected 2027, when available off-season production appears to be very low indeed.

The next step in the forecast process is to ascertain the amount of gas exported in recent years relative to actual Max. South-eastern production.

As a starting point, APA VTS reports the 2018-19 actual, 2020 estimated, and 2021 forecast volumes of Culcairn gas exports as reported to the AER in the Price Control Model supporting the 2022 VTS tariff variation.

Table 2.4

	2018A	2019A	2020A	2021E
VTS Export volumes (TJ)	15,768	11,291	12,129	18,934

Sourcing data from the 2021 (for 2019 actual) and 2022 (for 2020 and beyond) Gas Statement of Opportunities – report figures and data files, we calculate the following proportions of exports relative to gas available for export:

Table 2.5

(PJ)	2019A	2020A	2021E	2022F	Average
Southern Production available for export	186.8	115.2	114.7	111.8	
Export volumes	11.3	12.1	18.9	11.4	
As a % of available production	6.0%	10.5%	16.5%	10.2%	11.0%

Applying the average ratio of 11.0%, we forecast the following amounts of gas to be exported for 2023-2027:

Table 2.6

(PJ)	2023F	2024F	2025F	2026F	2027F
Forecast Southern Production available for export	57.3	52.6	36.9	16.2	9.8
Exports as a % of available production	11.0%	11.0%	11.0%	11.0%	11.0%
Forecast export volumes	6.3	5.8	4.1	1.8	1.0

3 Injections

In contrast to other Australian pipelines, the VTS is a very complex system. Where many pipelines connect a single source to a single market, the VTS has five injection points (Longford Hub, Pakenham, Culcairn, Iona Hub, and Dandenong LNG) and 23 withdrawal zones.

3.1 Annual injection volumes

The VTS tariff model calculates a flow path from each injection point to each withdrawal point, and allocated costs to each withdrawal zone on the basis of the optimised replacement cost of assets along each flow path and the relative amounts of gas forecast to be transported from each injection point to each withdrawal point over the course of the year. It is therefore important to forecast both the amount of gas to be injected into the VTS from each injection point as well as the amount of gas to be withdrawn at each withdrawal point.

As a starting point, APA VTS has assumed that total injection volumes will equal total withdrawal volumes (calculated above) plus exports:

Table 3.1

Withdrawals (TJ)	2023	2024	2025	2026	2027
Tariff V	127,567	125,416	123,357	123,777	117,762
Tariff D	64,410	64,451	73,070	72,658	72,536
GPG	7,100	4,000	3,500	4,400	4,657
Exports	6,294	5,778	4,051	1,778	1,072
Total Withdrawals	**205,371**	**199,645**	**203,978**	**202,613**	**196,027**

Using Gas Bulletin Board data[7] for 2020 and 2021, APA VTS observed the annual total volumes injected into the VTS from each injection point:[8]

Table 3.2

Proportion of gas injected at:	2020 (TJ)	2020 (%)	2021 (TJ)	2021 (%)
Longford Hub	197,728	79%	211,295	82%
Iona Hub	22,582	9%	32,062	12%
Culcairn Injection	18,751	7%	7,339	3%
BassGas Injection	11,473	5%	7,072	3%
LNG Injection	602	0%	241	0%
	251,135	100%	258,009	100%

Having regard to the need to recognise declining production volumes at Longford over the forecast period, and the expectation that more peak day gas will be sourced from Iona gas storage, APA VTS has used the 2021 proportions to forecast peak injection volumes from each delivery point over the forecast period.

[7] Gas Bulletin Board Data:
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2020.zip
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2021.zip
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/PipelineConnectionFlow_History.csv

[8] There is a significant margin between these injection and withdrawal volumes. This suggests that the Gas Bulletin Board data, which reports gas flows, is reporting gas that has been delivered into the VTS (say, at Longford) for delivery into Iona Gas Storage, which is later being reported as an injection to the VTS from Iona. This results in a “double-counting” of Iona Gas Storage volumes.

We then applied the 2021 percentages to the total withdrawals to determine the annual injection quantities from each injection point:

Table 3.3

Volume of gas injected at (PJ):	2023	2024	2025	2026	2027
Longford Hub	178,256	173,286	177,047	175,862	170,146
Iona Hub	18,767	18,243	18,639	18,515	17,913
Culcairn Injection	2,776	2,686	2,611	2,668	2,650
BassGas Injection	5,460	5,283	5,135	5,247	5,212
LNG Injection	392	380	369	377	375
Total	**205,371**	**199,645**	**203,978**	**202,613**	**196,027**

Regarding the declining supply at Longford, we note that the forecast annual Longford injections above are lower than the Gippsland Available Supply in the order of 200PJ/year as reported in Table 16 of the 2022 VGPR.

3.2 Peak day injection volumes

The 1-in-2 peak day injection volume is also important for tariff determination purposes.

To calculate the 1-in-2 peak day injection volumes, we referred to the AEMO Gas Forecasting portal to ascertain the 1-in-2 system peak as identified above:

Table 3.4

Year	Period	Scenario	Probability	Maximum demand (TJ/day)
2023	Winter	Progressive Change	50	1,142.2
2024	Winter	Progressive Change	50	1,127.5
2025	Winter	Progressive Change	50	1,142.0
2026	Winter	Progressive Change	50	1,143.7
2027	Winter	Progressive Change	50	1,108.0

The Gas Forecasting Portal was also able to identify that the system peak day was forecast to a winter peak over the forecast period.

Using Gas Bulletin Board data[9] for 2020 and 2021, APA VTS observed the (non-coincident) peak day volumes injected into the VTS from each injection point:

Table 3.5

Proportion of gas injected at:	2020 (TJ)	2020 (%)	2021 (TJ)	2021 (%)
Longford Hub	941,245	59%	970,281	60%
Iona Hub	369,180	23%	465,542	29%
Culcairn Injection	157,964	10%	123,918	8%
BassGas Injection	45,843	3%	30,983	2%
LNG Injection	69,583	4%	15,631	1%
	1,583,815	100%	1,606,355	100%

Having regard to the need to recognise declining production volumes at Longford over the forecast period, and the expectation that more peak day gas will be sourced from Iona gas storage, APA VTS started by using the 2021 proportions to forecast peak injection volumes from each delivery point over the forecast period.

If we then apply these winter injection proportions to the peak day data to forecast the proportion of gas to be injected from each injection point on the 1-in-2 peak day:

Table 3.6

Forecast of 1-in-2 peak day gas injected at:	2023	2024	2025	2026	2027
Longford Hub	951.2	939.0	951.0	952.5	922.7
Iona Hub	143.2	141.4	143.2	143.4	139.0
Culcairn Injection	25.6	25.2	25.5	25.6	24.8
BassGas Injection	21.4	21.1	21.4	21.4	20.7
LNG Injection	0.8	0.8	0.8	0.8	0.8
	1,142.2	**1,127.5**	**1,142.0**	**1,143.7**	**1,108.0**

However, the forecast Longford Hub injection volumes resulting from this approach is greater than the total south-eastern production as forecast by AEMO's 2022 GSOO, as shown in the figures in sections 1.2 and 1.3 above.

We have therefore returned to the AEMO 20222 GSOO Graphs 4 and 34 data to back-calculate the forecast Longford production capacity. In reviewing the 2022 GSOO, we understand that the amount shown as "Max south-eastern production" is the combined total of Longford, Pakenham and Port

[9] Gas Bulletin Board Data:
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2020.zip
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2021.zip
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/PipelineConnectionFlow_History.csv

Campbell production – however, neither the GSOO nor VGPR separate these sources. However, we do know that:

- The post-WORM (pre-Winchelsea 2) capacity of the SWP is 468 TJ/day;
- Port Campbell production needs to travel along the SWP to get to market, and therefore takes up some of that capacity;
- The GSOO reports the scope to deliver gas from deep storage as being constrained by the available capacity on the SWP – that is, the remaining capacity after Port Campbell production has been accommodated.
- We can then determine, through subtraction, the amount of SWP capacity determined to be dedicated to Port Campbell production, and
- We can then determine, through subtraction from the Max south-eastern production, the amount of production considered to be available from Longford.

Using 2023 data as an example:

Table 3.7

Longford volumes curtailed to GSOO Max south-eastern production less Port Campbell production:			**2023**
Max south-eastern production per 2022 GSOO			956
Less: Port Campbell production:			
Capacity of SWP		468	
Less: GSOO reported available SWP capacity:			
Max. south-eastern production MSP and constrained deep storage per 2022 GSOO	1,650		
Max. south-eastern production and MSP pipeline capacity per 2022 GSOO	-1,431		
SWP capacity available for Iona injection	219	-219	
SWP capacity attributed to Port Campbell production		249	-249
Eastern Victoria production			707
Less: Pakenham injections			-21
Max Longford production			686

It should be noted that production from Longford is divided between northbound shipments to NSW on the Eastern Gas Pipeline and production directed to the Victorian market.

Applying this calculation to each year of the access arrangement period gives us the maximum peak day Longford injection volumes:

Table 3.8

Longford volumes curtailed to GSOO Max south -eastern production less Port Campbell & Pakenham production:					
	2023	**2024**	**2025**	**2026**	**2027**
Max south-eastern production	956	929	845	729	650
Less: Port Campbell production:					
Capacity of SWP	468	468	468	468	468
Less: GSOO reported capacity:					
Max. south-eastern production MSP and constrained deep storage	1,650	1,685	1,658	1,557	1,519
Max. south-eastern production and MSP pipeline capacity	1,431	1,404	1,320	1,204	1,125
SWP capacity available for Iona injection	219	282	338	352	394
SWP capacity attributed to Port Campbell production	249	186	130	116	74
Eastern Victoria production	707	742	715	614	576
Less: Pakenham injections	21	21	21	21	21
Max Longford production	686	721	694	592	556

We have therefore capped the Longford peak day injection volumes at the level of the forecast maximum south-east production, and applied the difference to Iona Hub injections:

Table 3.9

Adjusted Forecast of 1-in-2 peak day gas injected at:	2023	2024	2025	2026	2027
Longford Hub	685.5	721.0	693.7	592.3	555.6
Iona Hub	408.9	359.3	400.6	503.6	506.1
Culcairn Injection	25.6	25.2	25.5	25.6	24.8
BassGas Injection	21.4	21.1	21.4	21.4	20.7
LNG Injection	0.8	0.8	0.8	0.8	0.8
	1,142.2	**1,127.5**	**1,142.0**	**1,143.7**	**1,108.0**

3.3 Top ten day injection volumes

The VTS tariff model charges injections across the top ten peak days, rather than over the full year.

To forecast the volumes expected to be injected from each injection point over the top ten peak days each year, we first ascertained the actual volumes that had been injected over the (non-coincident) top ten peak days in prior years, from the 2022 price control model[10]:

Table 3.10

Top ten day gas injected at: (TJ)	2018 Actual (Final)	2019 Actual (Final)	2020 Actual (Final)	2021 Actual (Final)	
Longford Hub	7,002	8,097	8,419	8,763	
Iona Hub	3,152	3,107	2,091	3,452	
Culcairn Injection	1,006	1,449	1,454	942	
BassGas Injection	523	399	373	233	
Top ten day volumes	**11,684**	**13,052**	**12,337**	**13,390**	
Total volumes per price control model	245,158	259,079	249,699	253,826	
Top ten days as a proportion of total volumes	4.77%	5.04%	4.94%	5.28%	**Average 5.00%**

We then use this volumetric data to calculate the relative proportions of gas injected at those points over the top ten days, and calculate an average:

[10] Dandenong LNG, located at the Dandenong City Gate, is not charged an injection tariff, so no forecast of top ten injection volumes is required.

Table 3.11

Top ten day gas injected at: (%)	2018	2019	2020	2021	Average
Longford Hub	59.9%	62.0%	68.2%	65.4%	**63.9%**
Iona Hub	27.0%	23.8%	16.9%	25.8%	**23.4%**
Culcairn Injection	8.6%	11.1%	11.8%	7.0%	**9.6%**
BassGas Injection	4.5%	3.1%	3.0%	1.7%	**3.1%**
	100.0%	100.0%	100.0%	100.0%	**100.0%**

Applying the proportion of top ten peak day volumes relative to total forecast volumes provides the forecast top ten injection volumes:

Table 3.12

Top ten day gas injected	2023	2024	2025	2026	2027
Total injections	205,371	199,645	203,978	202,613	196,027
% made up by top ten days	5.00%	5.00%	5.00%	5.00%	5.00%
Forecast top ten injection volumes	10,279	9,992	10,209	10,141	9,811

We can then apply the relative top ten injection percentages to the forecast top ten injection day volumes to derive the top ten injection day volumes:

Table 3.13

Forecast top ten day injection volumes (TJ)	2023	2024	2025	2026	2027
Longford Hub	6,570	6,386	6,525	6,481	6,271
Iona Hub	2,403	2,336	2,387	2,371	2,294
M126 Culcairn Injection	990	963	984	977	945
M138 BassGas Injection	316	307	314	312	302
Total	**10,279**	**9,992**	**10,209**	**10,141**	**9,811**

Again we see that the forecast, based on historical actuals, exceeds the total amount of gas available to be injected at Longford per day.

We have therefore adjusted the forecast to cap the Longford forecast top ten day injection volumes at ten times the daily maximum, assigning the balance to Iona Hub:

Table 3.14

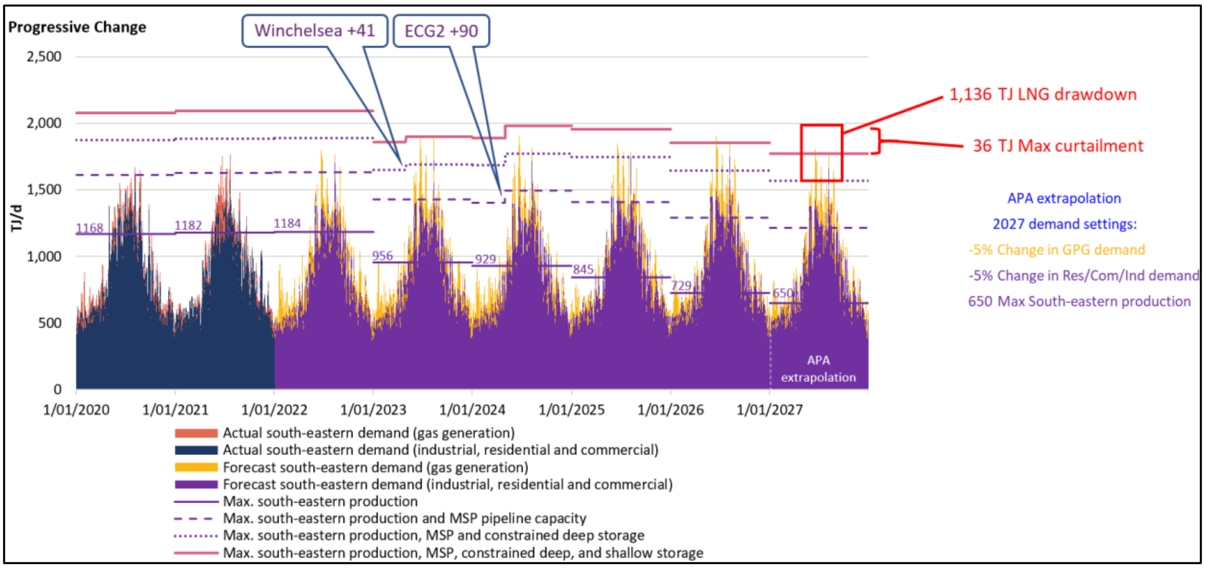
Adjusted forecast top ten day injection volumes (TJ)	2023	2024	2025	2026	2027
Longford Hub	6,570	6,386	6,525	6,137	5,763
Iona Hub	2,403	2,336	2,387	2,715	2,801
M126 Culcairn Injection	990	963	984	977	945
M138 BassGas Injection	316	307	314	312	302
Total	**10,279**	**9,992**	**10,209**	**10,141**	**9,811**

We see in these totals that one tenth of the Iona top ten peak day injection volumes (that is, an approximation of the peak day), about 280 TJ/day, is significantly less than the post-WORM capacity of the South West Pipeline, 468 TJ/day, and the post-Winchelsea capacity of the SWP, 517 TJ/day.

It should be noted that production from Longford is divided between northbound shipments to NSW on the Eastern Gas Pipeline and production directed to the Victorian market. The VTS injection volumes assumed for the Longford Hub are set equal to the maximum Longford production capability. If, in 2027, 237 TJ/day is transported northbound from Longford to serve Eastern Victoria and NSW loads, the expanded capacity of the SWP will again form the constraint to delivering enough gas from the Iona Hub to meet the Victorian peak day.

4 Supply and demand balance

In assessing the forecast supply and demand balance over the access arrangement period, APA VTS started with the graph in the 2022 GSOO, and adjusted the maximum deliverability for the increased capacity caused by the Winchelsea expansion and the East Coast Grid expansion:



Source: AEMO 2022 Gas Statement of Opportunities report figures and data, APA analysis

This analysis indicates:

- we expect to have sufficient capacity to meet peak demands for 2023-2025.
- a minor degree of curtailment in winter 2026 (55 TJ/day).
- the maximum curtailment would be 36 TJ/day in winter 2027
- the amount of gas forecast to be required to be delivered from shallow storage (Newcastle and Dandenong) in 2027 is less than the combined capacity of those two facilities.[11]

Providing the rate of decline of the Bass Strait legacy gas fields is not faster than forecast by AEMO, there does not appear to be a clear need for further expansion of the South West Pipeline in the 2023-27 access arrangement period.

5 Longer term outlook

The longer term outlook for both supply and demand remain highly uncertain, and will be impacted by:

Supply	Demand
Bass Strait production capability	Gas substitution policy framework and implementation
Port Kembla Gas Import Terminal	Scope for, and rate of electrification of residential and commercial loads
LNG import terminals at Geelong, Avalon, and Adelaide	Scope for introduction of hydrogen and other renewable gases
	Ongoing need for GPG

[11] Noting that sufficient capacity will need to be contracted, and sufficient gas liquefied, in order for this capacity to be available.

On 30 June 2022, AEMO released its Integrated System Plan (**ISP**) While this plan primarily relates to the electricity market, its inter-relationship with substituting gas demand for electricity, and the future role of gas powered generation are important elements.

AEMO invested considerable effort in seeking agreement among energy industry experts as to the most likely energy transition scenario, and concluded that the Step Change scenario was the most likely:[12]

> Step Change is considered by energy industry stakeholders to be the most likely scenario to play out, ahead of the Progressive Change scenario. This was the conclusion of a careful process in 2021 through which AEMO twice convened a panel of Australian energy market experts representing all stakeholder groups, with an intervening round of public consultation. The events of 2022 have been more aligned with Step Change than any other scenario. ...

AEMO convened two expert panels as part of the ISP. In the first forum, held on 5 October 2021, "Step Change and Progressive Change each earned over one-third of participant votes, with Hydrogen Superpower and Steady Progress splitting most of the remainder, and very few votes expecting Slow Change to play out." AEMO then held a public forum on 22 October 2021, following which:

> *The same experts from the first panel were invited back to repeat the Delphi process on 16 November 2021, following COP26. In this second sitting, the panel considered that the Steady Progress scenario (with its failure to meet net zero ambitions) was no longer appropriate, and that the ISP focus its modelling on the remaining four scenarios. In considering those four, the panel concluded that the Step Change scenario was the clear 'most likely' scenario, securing approximately half of all votes, followed by Progressive Change and then Hydrogen Superpower. Again, Slow Change received very few votes.*

This is not to say that the Step Change scenario is certain – there remains significant diversity of views among industry experts.. AEMO articulated its concern of the actual realisation of this scenario in the 2022 GSOO:[13]

> Key emerging drivers that may impact future gas consumption levels include:
>
> • Public policy and private investment in energy efficiency and electrification, which would reduce gas consumption. The extent to, and speed at, which business and household consumers switch from gas to electricity is uncertain. While governments are moving to increase electrification and improve the energy efficiency of gas appliances (for example, Victoria's Gas Substitution Roadmap and Victorian Energy Upgrades program), such action would need to speed up to rapidly reduce gas consumption.

AEMO's point on the speed of policy action is relevant. Considering the time required to adopt policy, legislate, create incentives and allow consumers to respond to those incentives, there is a question as to whether the Step Change scenario, if it happens, is likely to happen in the upcoming five year term of the 2023-27 APA VTS access arrangement.

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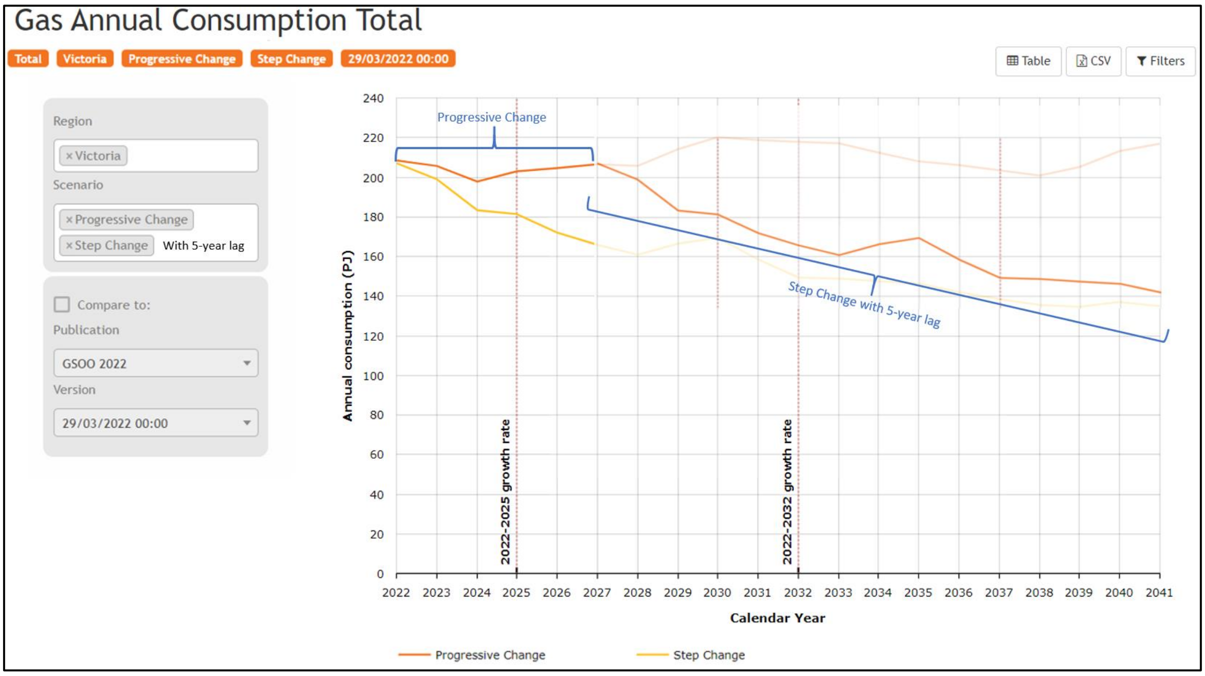
[12] AEMO, ISP p33.
[13] AEMO 2022 GSOO, p6.

The ISP was also clear on the key role for gas powered generation over the entire outlook period:[14]

> Without coal-fired generation, the ISP modelling suggests that the NEM will require by 2050 the firming capacity set out below. However, the investment schedule will vary between types, and evolving economics will determine the actual level of investment in each of these technologies. ...
>
> 10 GW of gas-fired generation for peak loads and firming. Gas-fired generation will play a crucial role as coal-fired generation retires. It will complement battery and pumped hydro generation in periods of peak demand, particularly during long 'dark and still' weather periods. It will help cover for planned maintenance of existing generation and transmission. And it will provide essential power system services to maintain grid security and stability, particularly following unexpected outages or earlier than expected generation withdrawal.
>
> This critical need for peaking gas-fired generation will remain through the ISP time horizon to 2050, and older and less efficient peaking plants may need to be replaced. Additional and earlier peaking gas-fired generation would add resilience against potential shortfalls in VRE, storage, DER or transmission. Over time, gas-fired generation emissions will need to be offset elsewhere if the economy is to reach net zero emissions, and natural gas may be replaced by net zero carbon fuels such as green hydrogen or biogas.

The key message is that we continue to face an uncertain and evolving future.

On balance, for the purposes of modelling in this access arrangement proposal, APA VTS has applied a hybrid scenario which adopts AEMO's Progressive Change scenario in the near term, and shifts to AEMO's Step Change scenario after a 5-year "policy lag".



Source: AEMO forecasting portal as modified by APA VTS

[14] AEMO, ISP p11.