APA VTS

RIN s11 – Load and demand

December 1, 2021

Contents

1. Introduction

NETWORK INFORMATION REPORTING

11. DEMAND

11.1 Provide in the materials submitted to the *AER*:

(a) an explanation of any trends in demand and volumes over the *current access arrangement period* and the *next access arrangement period*;

(b) details of the key drivers behind the demand forecasts provided in response to *Workbook 1 – Reset (forecast) data, regulatory template* N1. Demand;

(c) any methodology and models that have been used to develop the demand forecasts;

(d) any data sets used as inputs into the models;

(e) any key inputs and assumptions that have been used in the models (including in relation to economic growth, *user* numbers and policy changes) and any associated models or data relevant to justifying these inputs and assumptions and how demand for *pipeline services* is differentiated;

(f) an explanation of any weather normalisation models used by *VTS* and how weather data has been used, as well as an explanation as to how *VTSs'* approach to weather normalisation has changed over time;

(g) how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load); and

(h) an explanation of how the demand forecasts have been used to develop *VTSs' capital expenditure* and *operating expenditure* forecasts.

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.

Following the release of AEMO's forecasting information, there were several announcements that in our view were likely to affect the forecasts. These included APA's planned expansion of the East Coast Grid, Origin's contemporaneous supply contract with APLNG, and Esso and Qenos curtailing consumption in Altona. APA wanted to better understand proposed supply projects to bring gas into

Victoria from the west of Melbourne and questioned AEMO's flat longer term demand forecast. (That is flat, rather than what we would have expected to be falling - considering Victoria's Net Zero 2050 ambition). A more detailed understanding was required to help us better understand the quickly changing demand and supply dynamics.

1.1. Stakeholder engagement

APA proposed a study to explore the key issues affecting supply and demand in more detail and take on board stakeholders' thoughts on these issues. Stakeholders asked to be involved in reviewing the terms of reference for the study. APA consulted with the stakeholder engagement group and the terms of reference for the study. APA engaged Oakley Greenwood to investigate factors that are likely to affect the demand and supply in the Victorian gas market and the potential implications for the VTS. Oakley Greenwood provided regular updates and sought feedback during stakeholder engagement.

On the demand side, stakeholders sought to understand the potential impacts of a net zero policy on demand forecasts. It was noted that the proposed electrification of Victorian residential heating loads could have a significant impact on future gas demand; many customers can simply switch from gas to air conditioning. The Victorian Government is providing incentives to switch. The potential for demand side management was raised.

Oakley Greenwood's final report took on board comments from stakeholders and looked further into the shift to electrification of heating. Oakley Greenwood noted that there was a case for policymakers to consider introducing a market mechanism that would allow demand side participation in the peak of winter to assist in managing the risks of small excess peak demand excursions.

On the supply side, there was a view from some stakeholders that storage facilities and proposed LNG import terminals could be potential sources of supply to alleviate gas shortages forecast by AEMO. Oakley Greenwood noted that its scope was to use publicly available information and placed more weight on projects that had reached Final Investment Decision (FID).

It was noted that the 2020 GSOO did not envisage the closure of Yallourn Power Station but that the implications for gas powered generation is difficult to assess.[1]

1.2. APA response and proposed approach

The demand forecast underpinning this access arrangement is one of the most uncertain aspects of the proposal package, but investment decisions hinge on them. For example, demand forecasts impact on whether to invest in the proposed expansion of the South West Pipeline.

[1] In the 2021 ESOO, AEMO said that since the 2020 ESOO, the planned retirement of Yallourn Power Station (Victoria) was brought forward. AEMO lists possible actions to improve reliability in Victoria include continued generation and storage investment and development of additional DSP resources. This includes the 350 MW, four-hour, large-scale Jeeralang Battery being developed by 2026.

The demand forecast will influence such decisions as the standard and remaining life of assets, the proposed approach to depreciation, and whether the expansion of the South West Pipeline is required to maintain security of supply.

1.3. 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; these differences are not material to this analysis.

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

RIN Schedule	2021-2025	2026-2027
N1.1	AEMO 2021 VGPR Table 10	AEMO 2021 VGPR Table 10
N1.2	AEMO 2021 VGPR Table 18	APA extrapolation
N1.3.1A	Not provided	Not provided
N1.3.1B	AEMO 2021 VGPR Table 20	APA extrapolation
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	Pro rata from 2020 actual	Pro rata from 2020 actual
N1.4.2	Pro rata from 2020 actual	Pro rata from 2020 actual

2. 2021 Demand conditions

AEMO's 2021 Gas Statement of Opportunities (GSOO) was published on 29 March 2021. In summary, relevant to the VTS access arrangement, the GSOO 2021 Central case forecast the following levels of demand:

	Industrial	Residential / Commercial	GPG	New Residential Connections	2021 GSOO Central
2020	66	125	18	0	210
2021	65	123	8	2	198
2022	65	120	5	3	193
2023	64	117	5	4	190
2024	63	114	5	6	187
2025	62	112	3	7	183
2026	61	111	2	9	183
2027	60	111	2	11	184
2028	60	110	3	13	186
2029	60	110	4	14	188
2030	59	110	6	16	191

Source: AEMO 2021 Gas Statement of Opportunities report figures and data, Figure 34

There were several announcements after the publication of the GSOO which could impact the GSOO forecasts, notably:

- Esso Altona converting its refinery to an import terminal[2]
- Qenos Altona announcing that it would reduce its production by approximately 50%,[3] and
- APA announcing that it had reached Final Investment Decision on expansions to the East Coast Grid, to bring more gas into southern markets.[4]

2 https://www.argusmedia.com/en/news/2185554-exxonmobil-australia-to-shut-90000-bd-altona-refinery

3 http://qenos.com/internet/home.nsf/0/6C29EE4529E9F9BBCA2586DA0005EF13/$file/Qenos%20Media%20Release_Qenos%20Reconfigures%20Altona%20Manufacturing%20Facilities.pdf

4 https://www.apa.com.au/globalassets/asx-releases/2021/apa-commences-25-expansion-of-east-coast-grid.pdf

In response to these announcements, we engaged Oakley Greenwood to:

Conduct a survey of:

- The current gas supply and demand dynamics in eastern Australia, and in Victoria in particular, with commentary on whether and how they have been reflected in the GSOO and Victorian Gas Planning Report (VGPR), and the extent the consultant believes AEMO has adequately and reasonably reflected them
- Items announced post the publication of the GSOO and VGPR (e.g., APA – APLNG – Qenos Altona – Esso Altona), and the expected impact on the supply and demand dynamics
- Victoria's decarbonisation and electrification legislation and other policy statements.

and, with a time horizon of 2040 (to align with AEMO longer term forecasts), and a particular focus on the period up to 2030, advise:

- How we might expect this legislation and policy to affect the demand for gas in Victoria going forward – for residential, commercial, industrial, gas powered generation and exports (including from Longford up the Eastern Gas Pipeline)
- The extent to which this legislation and policy has been reflected in the GSOO and VGPR load and demand forecasts
- The extent to which the GSOO and VGPR load and demand forecasts should be adjusted to reasonably reflect this legislation and policy framework

and,

- Considering all those things, develop a load and demand forecast suitable for inclusion in the VTS access arrangement for the purposes of capital expenditure planning and tariff development.

Oakley Greenwood's report found that the Esso and Qenos closures would not have a significant impact on either annual production or peak day demand.

However, the situation surrounding the Victorian decarbonisation legislation was less clear. During the conduct of the Oakley Greenwood engagement, AEMO released its draft 2021 Inputs Assumptions and Scenarios Report (IASR) which forecast, in its Net Zero 2050 scenario, that:

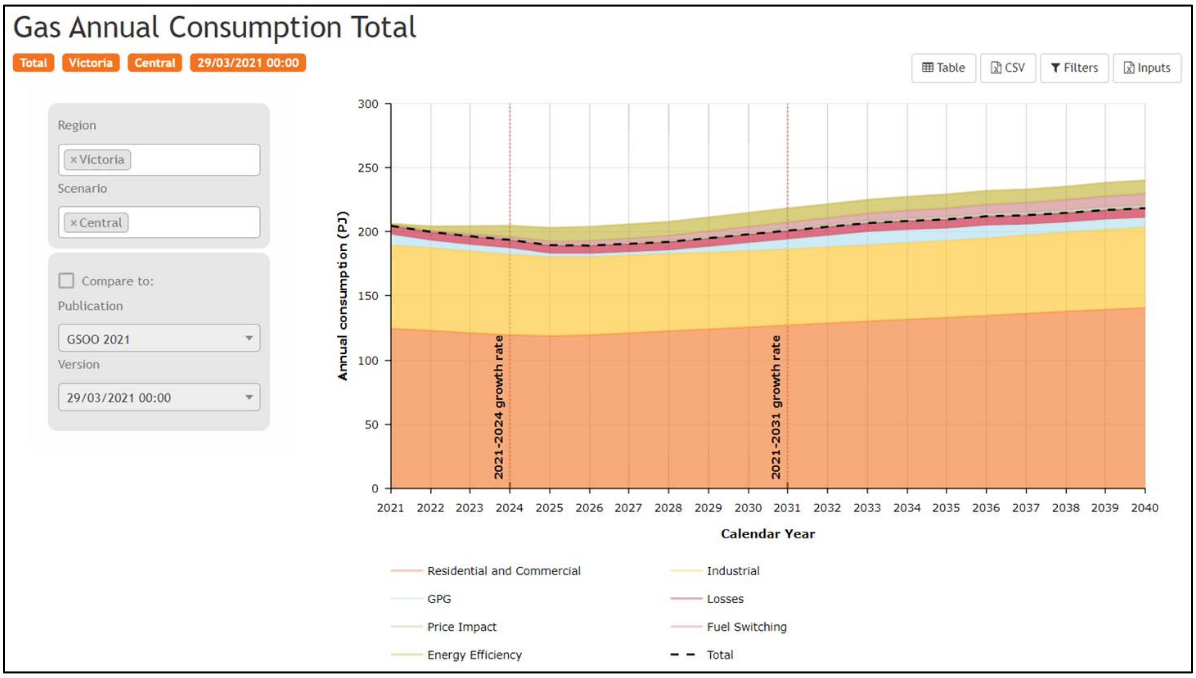
> *Consumers are (sic) initially continue to heat their homes in the same manner they do today, but by the mid-2030s nearly half the current gas heating has been electrified, and in the final years of the horizon nearly all residential heating is electrified.*

Assuming we pick up only half of AEMO's forecast decline (that is, a 25% reduction in gas home heating by mid-2030) and based on AEMO's supply forecasts, Oakley Greenwood found that there was not a need to augment the South West Pipeline to meet peak day demands.

As the 2020 IASR was published after the 2021 GSOO, the IASR assumptions, notably surrounding electrification of the home heating load, were not reflected in the 2021 GSOO. It is expected that these assumptions will be reflected in the 2022 GSOO, which is expected be released before the AER's draft decision on the VTS access arrangement.

3. Withdrawal volumes

At the highest level, AEMO is forecasting relatively flat volumes going forward out to 2040, notwithstanding the impacts of the Victorian Net Zero 2050 initiatives. We note that the AEMO Inputs, Assumptions and Scenarios Report (IASR), which featured an assumption that approximately half the Victorian home heating load would be electrified by the mid-2030s, was published after the GSOO was released.



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

In this AA forecast, we have relied heavily on the AEMO data. This will allow us to update on a consistent basis for the 2022 GSOO, which will form the foundation of the updated load and demand forecast in the revised proposal.

3.1. Tariff V and Tariff D

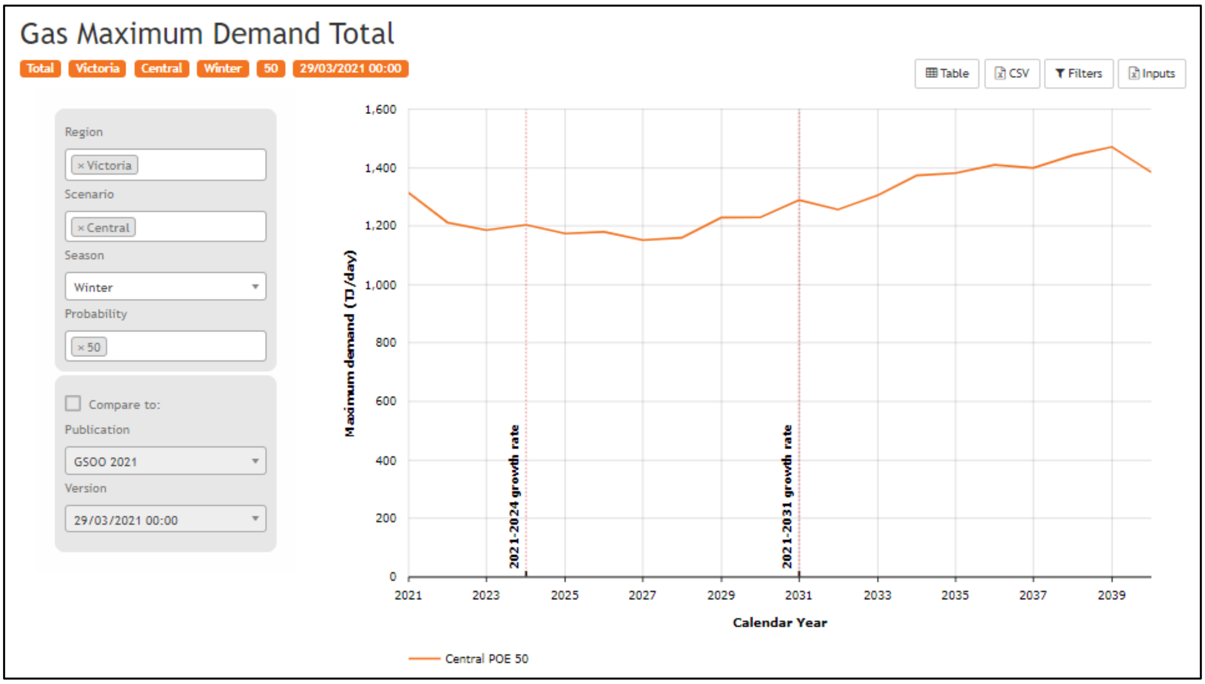
The Tariff V and Tariff D forecasts have been extrapolated from the 2021 VGPR Table 18, extrapolated such that the total Tariff V and Tariff D forecast for 2026 and 2027 aligns to the 2021 GSOO forecasts:

Table 18 Annual system consumption by SWZ (Tariff V and D split) (PJ/y)

SWZ		2021	2022	2023	2024	2025	APA Extrapolated 2026	APA Extrapolated 2027
Ballarat	Tariff V	8.9	9.0	9.0	9.0	9.2	8.5	8.6
	Tariff D	1.7	1.6	1.6	1.6	1.6	1.6	1.6
	SWZ total	**10.6**	**10.6**	**10.6**	**10.6**	**10.7**	**10.0**	**10.1**
Geelong	Tariff V	11.5	11.6	11.6	11.6	11.7	10.9	11.0
	Tariff D	9.1	9.1	8.9	8.8	8.6	8.7	8.7
	SWZ total	**20.6**	**20.6**	**20.4**	**20.3**	**20.3**	**19.6**	**19.7**
Gippsland	Tariff V	5.9	5.9	5.9	6.0	6.0	5.6	5.6
	Tariff D	8.1	7.9	7.7	7.4	7.1	7.5	7.5
	SWZ total	**14.0**	**13.8**	**13.6**	**13.4**	**13.2**	**13.1**	**13.1**
Melbourne	Tariff V	92.2	90.5	88.5	86.7	85.6	83.1	84.2
	Tariff D	35.5	35.3	34.9	34.5	33.9	34.2	34.1
	SWZ total	**127.7**	**125.8**	**123.4**	**121.2**	**119.5**	**117.3**	**118.2**
Northern	Tariff V	1.3	1.3	1.3	1.3	1.3	1.2	1.2
	Tariff D	2.7	2.7	2.7	2.7	2.7	2.7	2.6
	SWZ total	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**3.9**	**3.9**
Western	Tariff V	11.3	11.3	11.3	11.3	11.4	10.6	10.7
	Tariff D	8.6	8.7	8.7	8.6	8.5	8.5	8.4
	SWZ total	**20.0**	**20.1**	**20.0**	**19.9**	**19.8**	**19.1**	**19.2**
	Total Tariff V	131.1	129.6	127.6	125.9	125.2	119.8	121.3
	Total Tariff D	65.7	65.3	64.5	63.6	62.4	63.1	62.9
	Total	**196.9**	**194.9**	**192**	**189.4**	**187.5**	**183.0**	**184.3**

Source: AEMO 2021 VGPR, AEMO forecasting portal, APA VTS analysis

AEMO's forecasting portal also provides the 2021 GSOO forecasts of the 1-in-2 (P50) peak day:



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

The 1-in-2 peak day volumes reported in the AEMO gas forecasting portal reports:

Year	Period	Scenario	Probability	Maximum demand (TJ/day)
2021	Winter	Central	50	1,313.6
2022	Winter	Central	50	1,212.2
2023	Winter	Central	50	1,186.7
2024	Winter	Central	50	1,204.2
2025	Winter	Central	50	1,174.8
2026	Winter	Central	50	1,180.3
2027	Winter	Central	50	1,152.6

APA VTS has extrapolated the VGPR 1-in-2 peak demands pro-rata based on the Gas Forecasting Portal 2026 and 2027 totals.

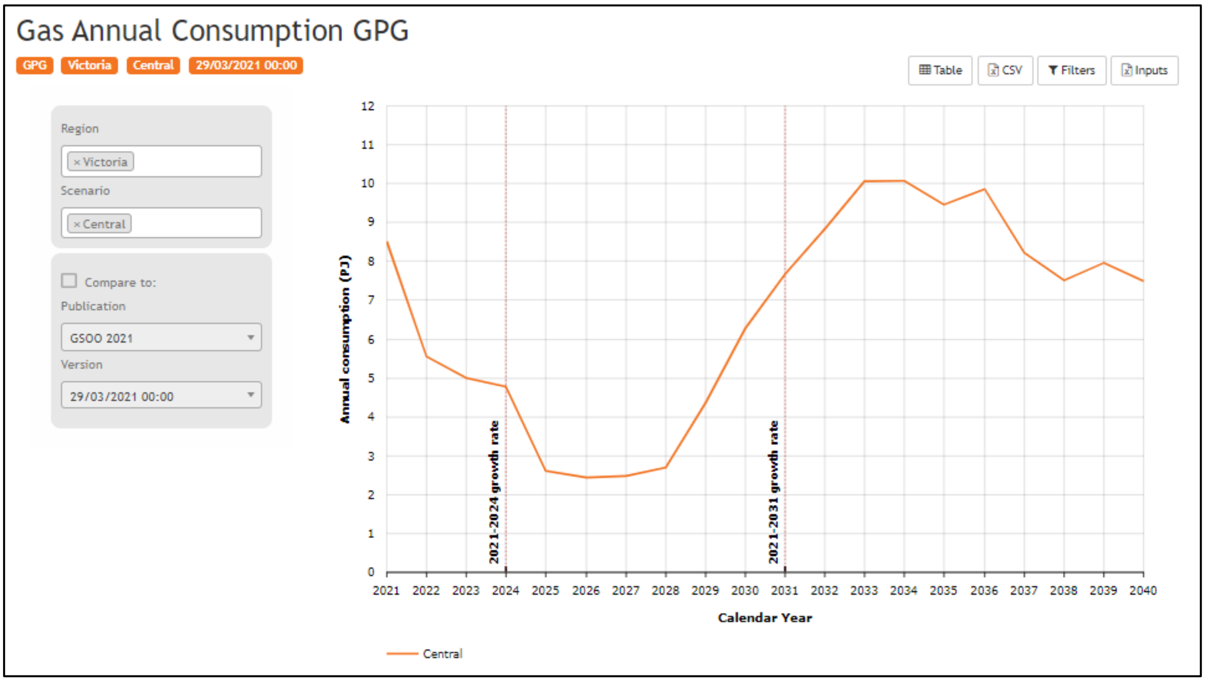
Table 19 Annual 1-in-2 peak daily demand by SWZ (TJ/d)

							APA Extrapolated	
SWZ		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Ballarat	Tariff V	59.0	59.5	59.5	59.9	60.8	62.6	61.1
	Tariff D	5.6	5.3	5.3	5.2	5.2	5.6	5.4
	SWZ total	**64.6**	**64.8**	**64.8**	**65.1**	**66.0**	**68.2**	**66.6**
Geelong	Tariff V	78.1	78.6	78.4	78.6	79.4	82.4	80.4
	Tariff D	37.5	37.6	36.6	36.5	36.3	38.7	37.7
	SWZ total	**115.7**	**116.2**	**115.0**	**115.0**	**115.7**	**121.0**	**118.2**
Gippsland	Tariff V	41.0	41.4	41.4	41.6	42.2	43.5	42.5
	Tariff D	27.4	26.7	25.9	25.1	24.4	27.1	26.5
	SWZ total	**68.4**	**68.1**	**67.3**	**66.8**	**66.6**	**70.6**	**69.0**
Melbourne	Tariff V	664.7	653.6	637.3	624.8	617.3	670.0	654.2
	Tariff D	122.2	121.3	119.8	118.9	118.2	125.8	122.8
	SWZ total	**787.0**	**775.0**	**757.1**	**743.7**	**735.4**	**795.8**	**777.1**
Northern	Tariff V	72.9	73.1	72.6	72.6	73.1	76.3	74.5
	Tariff D	28.9	29.2	29.2	29.0	28.8	30.4	29.7
	SWZ total	**101.8**	**102.3**	**101.8**	**101.6**	**101.9**	**106.7**	**104.2**
Western	Tariff V	8.5	8.5	8.4	8.3	8.4	8.8	8.6
	Tariff D	8.7	8.8	8.8	8.9	8.9	9.2	9.0
	SWZ total	**17.1**	**17.2**	**17.2**	**17.2**	**17.2**	**18.0**	**17.6**
	Total Tariff V	924.2	914.7	897.6	885.8	881.2	943.6	921.4
	Total Tariff D	230.3	228.9	225.6	223.6	221.8	236.8	231.2
	Total	**1154.6**	**1143.6**	**1123.2**	**1109.4**	**1102.8**	1180.3	1152.6

Source: AEMO 2021 VGPR, AEMO forecasting portal, APA VTS analysis

3.2. Gas-fired Power Generation

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



Source: AEMO gas forecasting portal http://forecasting.aemo.com.au/Gas/MaximumDemand/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 2025. 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 2023-2025. For 2026-27, APA VTS has 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:

$$\text{DTS-connected GPG load 2026} = \text{AEMO forecast Victoria GPG load 2026} \times \frac{\text{Total DTS-connected GPG load 2021-2025}}{\text{Total Victorian GPG load 2021-2025}}$$

Table 10 GPG consumption forecast, 2021-25 (PJ/y)						APA Extrapolated	
	2021	2022	2023	2024	2025	2026	2027
DTS GPG consumption	3.19	2.19	1.90	1.77	0.92	0.92	0.93
Non-DTS GPG consumption	5.38	3.36	3.13	2.99	1.69	1.52	1.55
Victorian GPG Consumption	8.57	5.55	5.03	4.76	2.61	2.44	2.48
% DTS-connected GPG	37%	39%	38%	37%	35%	38%	38%

Source: AEMO 2021 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 DTS-connected GPG percentages above to forecast the DTS-connected GPG peak demand:

	2021	2022	2023	2024	2025	2026	2027
Vic GPG peak day	262.31	221.76	156.69	168.76	114.27	127.20	153.33
DTS-connected GPG as a % of total	37%	39%	38%	37%	35%	38%	38%
DTS-connected GPG Peak day	97.64	87.51	59.19	62.75	40.28	47.82	57.64

3.3. Export volumes and demand

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.

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.

	2018A	2019A	2020A	2021E	2022F
Export volumes (TJ)	15,768	11,291	12,129	18,934	11,359

This data presents an average annual export flow of 13,896 TJ per year. In the absence of a more rigorous forecast, APA VTS has assumed that this average level of NSW exports will continue over the 2023-27 access arrangement period.

The peak export volumes are also relevant for tariff determination purposes. We assume that this gas is delivered entirely over the four summer months – December, January, February, and March. That is, we assume no northbound gas in the Victorian winter – June – September, and no northbound gas in the 2-month shoulder seasons either side of the Victorian winter (April/May, October/November). This provides a 1-in-2 peak demand estimate of 114.3 TJ/day.

4. 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.

4.1. 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 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:

Withdrawals (TJ)	2023	2024	2025	2026	2027
Tariff V	127,600	125,900	125,200	119,831	121,339
Tariff D	64,500	63,600	62,400	63,135	62,926
GPG	1,900	1,770	920	916	932
Exports	13,896	13,896	13,896	13,896	13,896
Total Withdrawals	**207,896**	**205,166**	**202,416**	**197,778**	**199,093**

Using Gas Bulletin Board data[5] from October 2018 through October 2021, APA VTS calculated the proportion of gas sourced from each injection point across the period:

[5] Gas Bulletin Board Data:
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2019.zip
http://nemweb.com.au/Reports/Current/GBB/GBB_PIPELINE_CONNECTION_FLOW/GASBB_PIPELINE_CONNECTION_FLOW_2020.zip

Proportion of gas injected at:	2018 Oct-Dec	2019	2020	2021 Jan-Oct	Average
Longford CPP	86.4%	80.6%	83.8%	86.8%	**84.4%**
Iona Hub	5.7%	8.7%	5.1%	9.0%	**7.1%**
Culcairn Injection	0.3%	6.1%	6.2%	1.4%	**3.5%**
BassGas Injection	7.0%	4.2%	4.5%	2.7%	**4.6%**
LNG Injection	0.5%	0.3%	0.4%	0.2%	**0.3%**
	100%	100%	100%	100%	**100%**

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

Volume of gas injected at:	2023	2024	2025	2026	2027
Longford CPP	175,477	173,172	170,851	166,936	168,046
Iona Hub	14,794	14,599	14,404	14,074	14,167
Culcairn Injection	7,311	7,215	7,119	6,955	7,002
BassGas Injection	9,616	9,489	9,362	9,148	9,208
LNG Injection	699	690	680	665	669
Total	**207,896**	**205,166**	**202,416**	**197,778**	**199,093**

4.2. 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:

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

Year	Period	Scenario	Probability	Maximum demand (TJ/day)
2023	Winter	Central	50	1,186.7
2024	Winter	Central	50	1,204.2
2025	Winter	Central	50	1,174.8
2026	Winter	Central	50	1,180.3
2027	Winter	Central	50	1,152.6

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

We then referred back to the Bulletin Board data to ascertain the volumes of gas injected from each injection point over the four month winter period (June, July, August, September):

Proportion of winter gas injected at:	2019 Winter	2020 Winter	2021 Winter	Average
Longford CPP	75.6%	79.9%	83.3%	79.6%
Iona Hub	12.9%	5.5%	12.5%	10.3%
Culcairn Injection	8.9%	10.8%	2.2%	7.3%
M138 BassGas Injection	2.4%	3.2%	1.9%	2.5%
M108 LNG Injection	0.2%	0.6%	0.1%	0.3%
	100%	**100%**	**100%**	**100%**

We then applied 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:[6]

[6] As the Victorian peak day occurs in the winter, and exports to NSW are assumed to be provided only in summer, NSW export volumes do not affect the Injection peak demand.

Proportion of 1-in-2 peak day gas injected at:	2023	2024	2025	2026	2027
Longford CPP	910.2	893.9	882.9	877.7	939.4
Iona Hub	118.2	116.0	114.6	113.9	122.0
Culcairn Injection	83.5	82.1	81.0	80.6	86.2
BassGas Injection	28.2	27.7	27.4	27.2	29.1
LNG Injection	3.5	3.4	3.4	3.4	3.6
	1,143.6	**1,123.2**	**1,109.4**	**1,102.8**	**1,180.3**

4.3. 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 top ten peak days in prior years, from the 2022 price control model[7]:

Top ten day gas injected at: (TJ)	**2018** Actual (Final)	**2019** Actual (Final)	**2020** Actual (Final)	**2021** Actual (Final)	
Longford CPP	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%**

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

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:

Top ten day gas injected at: (%)	**2018**	**2019**	**2020**	**2021**	**Average**
Longford CPP	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:

Top ten day gas injected at: (%)	**2023**	**2024**	**2025**	**2026**	**2027**
Total injections	207,896	205,166	202,416	197,778	199,093
% made up by top ten days	5.00%	5.00%	5.00%	5.00%	5.00%
Forecast top ten injection volumes	**10,405**	**10,268**	**10,131**	**9,899**	**9,965**

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:

Forecast top ten day injection volumes (TJ)	**2023**	**2024**	**2025**	**2026**	**2027**
Longford CPP	6,650	6,563	6,475	6,327	6,369
Iona Hub	2,433	2,401	2,368	2,314	2,329
M126 Culcairn Injection	1,002	989	976	954	960
M138 BassGas Injection	320	316	311	304	306
Total	**10,405**	**10,268**	**10,131**	**9,899**	**9,965**

5. Longer term supply

On the supply side, production declines in southern fields, particularly the Bass Strait, are well documented. AEMO has consistently noted that it will be necessary to bring more gas into Victoria to offset these known production declines.

A key feature of AEMO's 2021 GSOO was that the Australian Industrial Energy Port Kembla LNG import terminal[8] was considered to be a "committed project", notwithstanding that it had not, and still has not at time of writing, announced that it has reached Final Investment Decision.

The GSOO is clear that supply adequacy depends heavily on the Port Kembla Gas Terminal (PKGT) (p5):

> *The timely commissioning of committed developments, including the PKGT, is critically important given the forecast reduction in maximum daily capacity from southern fields. If delivered to schedule, domestic supply shortfalls during winter peak demand periods are not forecast until at least 2026.* ***If these committed projects are not delivered to schedule, greater reliance would be placed on storages, and gas shortfalls of up to 100 TJ per day may eventuate in winter 2023 under extreme conditions.*** *(emphasis added)*

The fact that the PKGT has not reached FID (notwithstanding that construction is understood to be continuing) is a factor we have taken into consideration.

In August 2021, Lochard Energy, owner of the Iona Gas Storage facility, announced that it had reached FID on expansions to the Iona Gas Storage facility to enable withdrawals of up to 570 TJ/day. Having been announced after publication of the GSOO, the Iona expansion did not feature in the AEMO supply and demand modelling.

However, it is unclear how much of Iona capacity will directed to the Victorian market on a given day – this will depend on shipper contracting and DWGM bidding behaviour. The post-WORM eastbound capacity of the South West Pipeline will be 468 TJ/day - less than the expanded Iona deliverability.

The expansion of the APA East Coast Grid will allow northern supply to serve southern markets, particularly in Sydney. Oakley Greenwood noted (p.8):

> *The estimated impact of this augmentation is that it will allow up to an extra 100TJ/day to flow into Sydney on peak demand days, with a consequent impact on flows to Melbourne, subject to transmission pipeline capacity being available. This is based on the 25% increase in current capacity of ~ 400TJ/day.*

Expansion of the East Coast Grid involves the expansion of the Moomba Sydney Pipeline (MSP) which is to be conducted in two stages:

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[8] See https://ausindenergy.com/our-project/

- increment of 29 TJ/day from current capacity. Estimated commissioning date: 1 April 2023;
- increment of 119 TJ/day from current capacity (that is, an additional 90 TJ/day). Estimated commissioning date: 1 April 2024

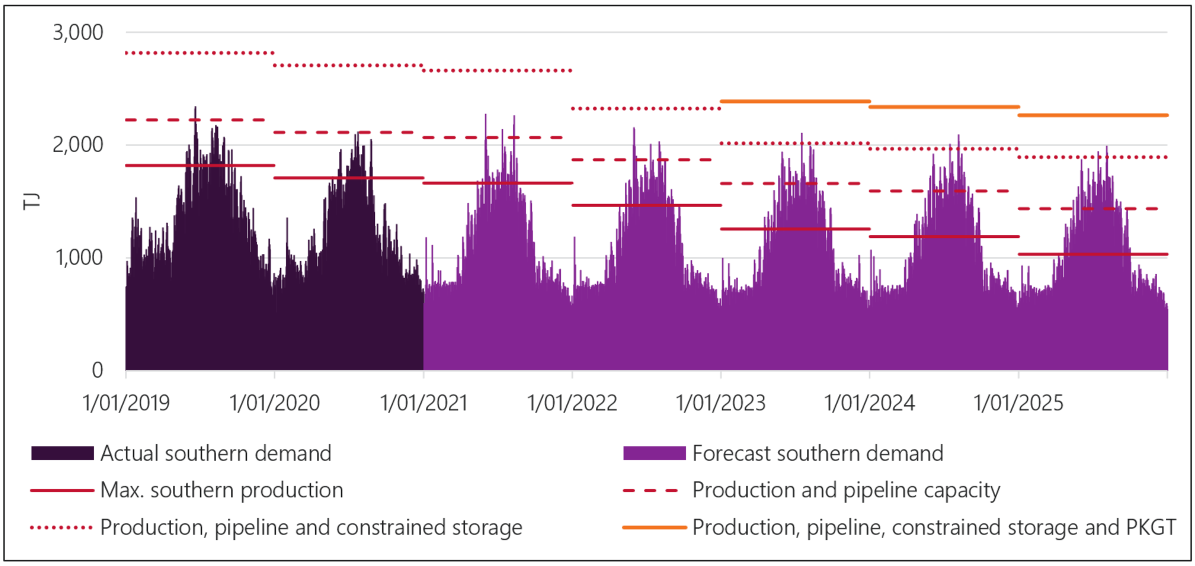
To the extent that the expansion of the East Coast Grid will enable 119 TJ/day of additional gas to meet Sydney demand, this could displace demand currently being met from Longford production travelling northbound to Sydney on the Eastern Gas Pipeline. This would allow an additional 119 TJ/day of Longford production to be redirected to Victorian needs.

5.1. Analysis

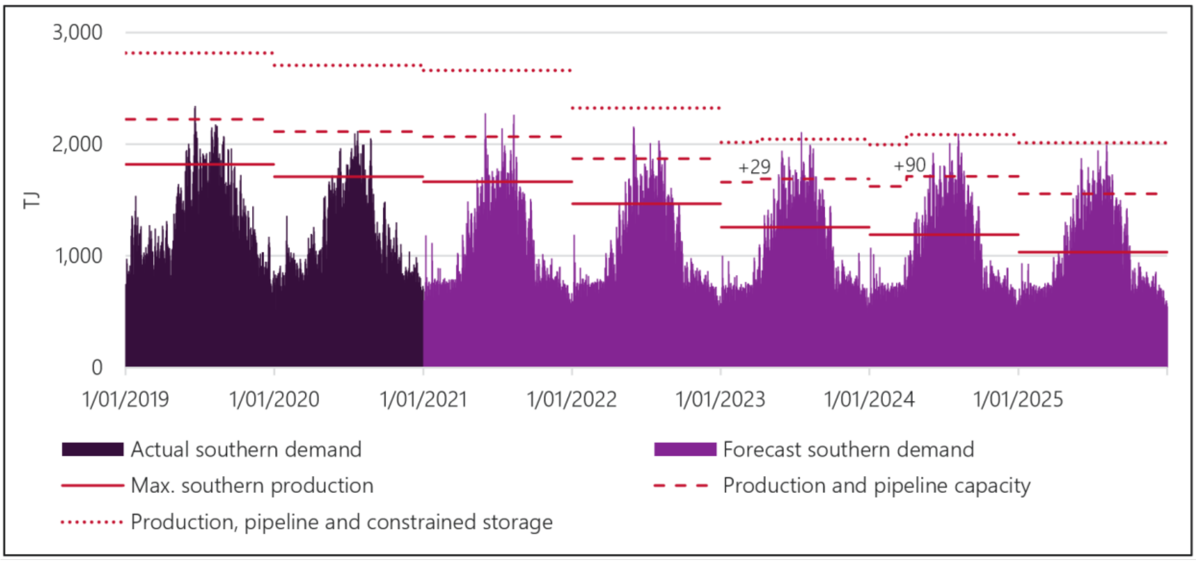
The AEMO GSOO was clear that, if the PKGT is delivered to schedule, domestic supply shortfalls during winter peak demand periods are not forecast until at least 2026. To ascertain the expected impact of the deferral of the PKGT and the increased capacity of the APA East Coast Grid, APA VTS has adjusted the AEMO GSOO forecasts to:

- Remove the additional supply made available by the PKGT; and
- Increase the available pipeline supply by 119 TJ/day.

Where the GSOO originally reported:



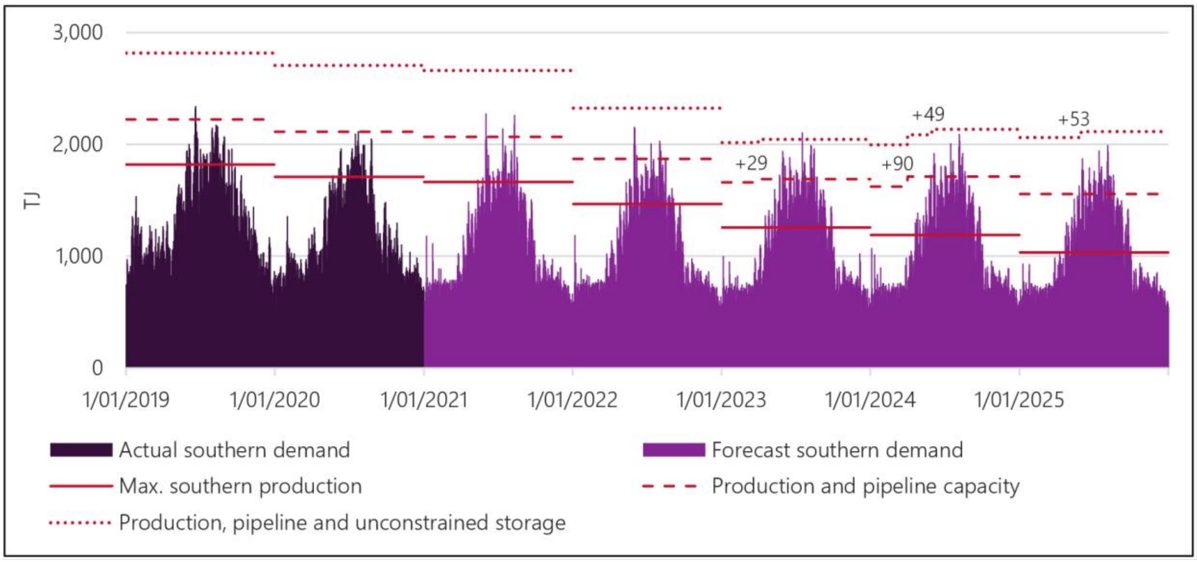
The (above stated) adjustments change the picture somewhat:



Allowing approximately 100 TJ/day of Longford production to be redirected from Sydney to Melbourne provides for an adequate, albeit tight, supply and demand balance to be maintained to 2025. With continued declining Longford production, the supply and demand balance may result in shortfalls in the outer years of the access arrangement period.

If we further allow for an additional 102 TJ/day to be delivered from Iona storage,[9] (shown here with the 2 proposed compressors installed from 1 June 2024 and 1 June 2025 respectively) the picture is clear that there would be adequate supply to serve the Victorian market:

[9] Increasing the capacity of the SWP from a post-WORM capacity of 468 TJ/day to 570 TJ/day.



5.2. APA VTS proposed position

For the purposes of the 2023-27 VTS access arrangement, APA has taken the following position:

- Having not reached FID, the PKGT cannot be assumed to be completed in a period sufficient to allow the VTS access arrangement to rely on its presence for security of supply;
- The expansion of the APA East Coast Grid is assumed to be able to supply more gas consumption in Sydney, some of which would otherwise have been supplied from Longford via northbound flows on the Eastern Gas Pipeline. The gas that would have flowed north to Sydney, particularly on the peak day, will be available for redirection to Melbourne needs;
- Even with 100 TJ/day being redirected from Sydney to Melbourne, the supply and demand balance in the outer years of the access arrangement period appears tight. Expansion of the SWP to 570 TJ/day to allow all committed Iona injection capacity to access the market will be sufficient to meet Victoria's peak day demand needs.

5.3. Long term supply adequacy

The analysis above surrounding the adjustments to the GSOO forecast and augmenting the SWP to accommodate Iona committed deliverability focuses on the ability of the VTS to meet peak day demand requirements.

However there remains a need, considering ongoing declines in Longford production, to get enough gas into Victoria to meet not only peak day needs but also annual supply requirements.

Iona gas storage does not currently have enough capacity to serve as seasonal storage.[10] Its limited storage volumes restrict its role to meeting peak day, rather than seasonal, requirements. There remains a need to source additional gas to meet Victoria's annual needs.

There are projects mooted to bring more gas into Victoria, which, for the purposes of this access arrangement proposal, fall into two general categories: those that require investment outside the VTS and those that require investment both outside and within the VTS. None of these projects has reached Final Investment Decision (FID). In the first category:

- The completion of the PKGT would require investment in the terminal itself, but also bi-directionality and compression on the Eastern Gas Pipeline. However, once that gas reaches Longford, the Longford-Melbourne Pipeline has sufficient capacity, considering the declines in Longford production, that the VTS would not require investment to accommodate this additional gas.
- Additional expansion of the APA East Coast Grid to allow further injections at Culcairn would require additional upstream compression to deliver more gas to Culcairn. However, once at Culcairn, the Victoria-NSW Interconnect would have sufficient southbound capacity to accept significant quantities of gas without further VTS investment.
- Further expansion of the APA East Coast Grid to deliver more gas to Wilton to then be shipped southbound on the Eastern Gas Pipeline would also require investment outside Victoria, but as with the PKGT, the Longford-Melbourne Pipeline has sufficient capacity to accommodate these additional flows without further investment in Victoria.

In the second category, there are three projects proposed to bring more gas into Victoria, which may require some investment in the VTS:

- An LNG import terminal at Geelong, proposed by VIVA Energy. This could provide seasonal injections in the order of 600 TJ/day over the course of the southern winter. Depending on the need to be able to maintain deliverability from Iona, this could require augmentation of the SWP, the Brooklyn-Lara Pipeline and the Brooklyn City Gate.
- An LNG import terminal in deep water off Avalon, proposed by Vopak. This could provide seasonal injections in the order of 600 TJ/day over the course of the southern winter. Depending on the need to be able to maintain deliverability from Iona, this could require augmentation of the SWP, the Brooklyn-Lara Pipeline and the Brooklyn City Gate.
- Further augmentations to the Iona Gas Storage facility proposed by Lochard Energy, which would increase both the amount of gas that could be stored, and also the daily deliverability rate. This project may require additional looping of the SWP, and also upgrades to the Brooklyn City Gate.

[10] The Iona Gas Storage facility holds approximately 16 PJ of useable gas, compared to an annual VTS load in the order of 200 PJ/year, weighted more heavily to winter than summer. With the completion of the WORM and bi-directionality of the proposed SWP compressors, there may be scope for Iona storage to cycle more frequently over the winter season.

While these three projects are the subject of public proposals, none have reached Final Investment Decision, and are not expected to do so before the VTS access arrangement proposal is required to be lodged with the AER on 1 December 2021.

The VTS is unique in that, under the market carriage model, there is no scope to enter into bilateral arrangement with shippers to support investment in pipeline capacity – all such investment must pass through the access arrangement process. This places these last three projects, all potentially requiring investment in the VTS, at a competitive disadvantage relative to those projects only requiring investment outside the VTS, which investment can be undertaken through commercial arrangements.

To maintain a level playing field, APA proposes to lodge an application under Rule 80 of the National Gas Rules (lodged under separate cover), seeking the pre-approval of the AER to consider these projects as conforming capital expenditure if they are built.