Draft Decision

Roma to Brisbane Pipeline
Access Arrangement 2022 to 2027

Attachment 12
Demand

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Note

This attachment forms part of the AER's draft decision on the access arrangement that will apply to APT Petroleum Pipelines Pty Limited's (APTPPL) Roma to Brisbane Pipeline (RBP) for the 2022–2027 access arrangement period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency carryover mechanism

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12 Demand

This attachment sets out our assessment of the demand forecasts for APT Petroleum Pipelines Pty Limited's (APTPPL) Roma to Brisbane Pipeline (RBP) for the 2022–27 access arrangement period (2022–27 period). Under price cap regulation, demand is an important input into the derivation of APTPPL's reference tariffs.[1] In simple terms, tariff prices are determined by cost divided by total demand (TJ/day), such that an increase in forecast demand has the effect of reducing the tariff price and vice versa. It also affects operating expenditure (opex) and capital expenditure (capex), which are linked to network growth via new connections.[2]

12.1 Draft decision

We are not satisfied that APTPPL's proposed demand forecasts comply with rule 74(2) of the National Gas Rules (NGR). Based on all the information before us, we do not consider that APTPPL's total average demand forecast of 206.7TJ/day[3] for the long-term firm service for the 2022–27 period is the best estimate in the circumstances. Our alternative forecast is an average of 260.7TJ/day, which is a 26 per cent increase relative to APTPPL's forecast.

While we are satisfied with APTPPL's demand forecast for retail and major industrial users, we are not satisfied that the forecasts for gas-fire powered generation (GPG) users and the westbound service were arrived at on a reasonable basis and represent the best forecast possible in the circumstances. The reasons for our decision are discussed below.

Our draft decision does not include the impact of Incitec Pivot's recent announcement of its intention to shut down its fertiliser plant.[4] This development was not included in APTPPL's initial RBP proposal. In this regard, our draft decision is a placeholder and we invite APTPPL to have regard to this change and any other new information in its revised proposal.

12.2 APTPPL's proposal

APTPPL's RBP proposal includes two reference tariffs corresponding to two reference services; the eastbound long term firm service (LTFS), and the westbound LTFS. The

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1 Appendix A discusses the differences between price cap regulation and revenue cap regulation in more detail and sets out our considerations around the current form of price regulation applied to regulated gas transmission and distribution pipelines

2 Our draft decisions on APTPPL's capex and opex are respectively at Attachments 5 and 6.

3 APTPPL originally proposed a total average demand forecast of 206.1TJ/day. In response to information request AER IR006, APTPPL revised its forecast demand upwards for retail users by 0.6TJ/day as it inadvertently omitted a user in the load and demand forecast. APTPPL, Response to information request AER IR009, 9 September 2021, p. 8.

4 Incitec Pivot, *Gibson Island manufacturing operations to cease at end of 2022*, 8 November 2021 (media release): available at https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022.

LTFS are services for the receipt, transportation, and delivery of gas to a delivery point along the RBP for a term of one year or more.[5] [6] Importantly, the reference tariffs are based on the amount of capacity reserved each day, rather than the amount used each day.

APTPPL submitted separate demand forecasts for the RBP eastbound and westbound services. Its forecast demand has been derived by splitting the market into four user groups: the eastbound retail (residential, commercial, and small industrial) load; the eastbound major industrial load; the eastbound GPG load; and the westbound load.[7] Table 1 below outlines the forecast demand for each user group.

Table 1 Summary of APTPPL's demand forecast for the RBP (TJ/day)

User group	2022–23	2023–24	2024–25	2025–26	2026–27	Average
Retail	75.0	75.0	75.0	75.0	75.0	75.0
Major Industrial	56.6	54.0	52.5	52.5	52.5	53.6
GPG	6.2	4.1	3.5	4.8	6.8	5.1
Total Eastbound	137.8	133.1	131.0	132.3	134.3	133.7
Westbound	85.0	80.0	70.0	65.0	65.0	73.0
Total	222.8	213.1	201.0	197.3	199.3	206.7

Source: APTPPL, AER analysis
Note: APTPPL revised its forecast demand upwards for retail users by 0.6TJ/day to 75TJ/day

APTPPL forecasts a total bi-directional average demand of 206.7TJ/day for each year over the 2022–27 period for the RBP. APTPPL's approach to forecasting differs between user groups:[8]

- For retail users, the forecast demand is determined primarily through reviewing existing contracts and the probability of contract renewal.
- For major industrial users, the forecast demand was undertaken at an individual customer level, as well as an assessment of the customer's operations and the market for the customer's product.
- For GPG users, APTPPL submits that demand is driven more by conditions in the electricity market than by the price of gas or gas transportation. It has relied on its consultant, ACIL Allen, to estimate a demand based on forecasts of electricity

[5] APTPPL, *Roma to Brisbane Pipeline 2022–27 Proposed revised access arrangement, 1 July 2022–30 June 2027* (Clean), July 2021, p. 7.

[6] APTPPL, *Roma to Brisbane Pipeline 2022–27 Proposed revised access arrangement, 1 July 2022–30 June 2027* (Clean), July 2021, p. 12.

[7] APTPPL, *Roma to Brisbane Pipeline 2022–27 Access arrangement, Overview*, July 2021, p. 31.

[8] APTPPL, *Roma to Brisbane Pipeline, Access arrangement submission - Load and demand forecast*, June 2021, pp. 3–4.

demand and analysis of the National Electricity Market. ACIL Allen's methodology is discussed in more detail in section 12.4.3.

- For westbound users, APTPPL submits that demand is driven by gas trading opportunities across the entire east coast gas market. It has relied on its consultant, ACIL Allen, to estimate a demand by an assessment of the broader east coast gas market. ACIL Allen's methodology is discussed in more detail in section 12.4.2.

12.3 Assessment approach

The NGR requires access arrangement information for a full access arrangement proposal for transmission pipeline to include:

- Usage of the pipeline over the earlier access arrangement period showing minimum, maximum and average demand for each receipt and delivery point; and user numbers for each receipt and delivery point.[9]
- To the extent that it is practicable to forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period, a forecast of pipeline capacity and utilisation of pipeline capacity over that period and the basis on which the forecast has been derived.[10]

The NGR also require that forecasts and estimates: [11]

- are arrived at on a reasonable basis
- represent the best forecast or estimate possible in the circumstances.

We consider that there are two important considerations in assessing whether demand forecasts are arrived at on a reasonable basis and whether they represent the best forecasts possible in the circumstances. [12] These are:

- the appropriateness of the forecast methodology – this involves consideration of how the demand forecast has been developed; and
- whether or not relevant factors have been taken into account in developing the demand forecasts.

To determine whether APTPPL's proposed demand forecasts for the RBP are arrived at on a reasonable basis and are the best possible forecasts in the circumstances, we reviewed the data inputs used to implement the forecasting methodology.

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9 NGR, r. 72(1)(a)(iii).

10 NGR, r. 72(1)(d).

11 NGL, s. 28(2)(a); NGR, r. 74(2). The revenue and pricing principles of particular relevance to our assessment of demand are those specified at NGL, ss. 24(2), 24(3), 24(6) and 24(7).

12 NGR, r. 74(2).

In making our draft decision, we relied on:

- information provided by APTPPL as part of its proposed RBP access arrangement
- information provided in response to the Regulatory Information Notice (RIN)
- responses to information requests
- stakeholder submissions
- Australian Energy Market Operator's (AEMO) 2021 Gas Statement of Opportunities (GSOO) report[13]
- Projected assessment of system adequacy (PASA) information[14]
- The National Gas Infrastructure Plan – 2021 Interim Report.[15]

12.3.1 Interrelationships

Tariff prices depend on estimates on forecast total demand (TJ/day). To set transmission tariffs, the demand forecast is expressed in terms of the capacity reserved by the user (maximum daily quantity). Changes in these forecasts will translate into changed tariff prices. In simple terms, tariff prices are determined by cost divided by total demand (TJ/day), such that an increase in forecast demand has the effect of reducing the tariff price and vice versa. Attachment 9 sets out our draft decision on the reference tariff.

Demand forecasts also affect capital and operating expenditure linked to increased network capacity. APTPPL submits that the role of the load and demand forecast in its current proposal is limited to supporting the calculation of the reference tariff as no augmentation expenditure is proposed.[16]

The demand forecast may also have a relationship where a business proposes a prudent discount. Attachment 9 sets out our draft decision on the prudent discount.

12.3.2 Minimum, maximum and average demand

Under the NGR, APTPPL's access arrangement must include minimum, maximum and average demand for each receipt or delivery point for the earlier access arrangement

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13 Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2021.

14 PASA is the principal method of forecasting the adequacy of the power system to stay within the reliability standard. Each week participants must submit forecasts of availability to AEMO for the next 36 months. These forecasts form the basis of the medium term PASA that will be produced the following week.

15 Department of Industry, Science, Energy and Resources, *National Gas Infrastructure Plan – Interim Report*, May 2021.

16 APTPPL, *Roma to Brisbane Pipeline, Access arrangement submission - Load and demand forecast*, June 2021, p. 2.

period.[17] APTPPL's access arrangement information did not provide this information, however its annual RINs satisfy these requirements.[18]

12.3.3 Forecast pipeline capacity and utilisation

The NGR require that to the extent practicable, the access arrangement information should include forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period.[19]

APTPPL's access arrangement information did not provide this information, but it has since provided forecast pipeline capacity. APTPPL explained that it did not provide utilisation information as it does not possess the forecast of gas throughput required to calculate utilisation.[20]

The information APTPPL provided satisfies the requirement of rule 72(1)(d) of the NGR. We have formed this view on the basis that the capacity forecast has taken into account aggregated contracted demand on the pipeline.

12.4 Reasons for draft decision

Based on all the information before us, we are not satisfied that APTPPL's demand forecast of an average of 206.7TJ/day for the long-term firm service for the RBP for the 2022–27 period was arrived at on a reasonable basis and represents the best forecast possible in the circumstances.

While we are satisfied with APTPPL's demand forecast for the RBP's retail and major industrial users, we are not satisfied that the forecasts for GPG users and the westbound service were arrived at on a reasonable basis and represent the best forecast possible in the circumstances. The reasons for our decision are discussed below.

12.4.1 Retail and major industrial users

We are satisfied that APTPPL's demand forecast for the RBP's retail users of an average of 75TJ/day is the best estimate in the circumstances.

APTPPL assumes that retail demand in the forecast period will remain similar to historic levels. We agree that retail historical contracted capacity is a reasonable indicator of forecast demand because:

- AEMO's 2021 GSOO report makes a similar observation. AEMO forecasts a flat trend over the access arrangement period in its demand forecast for eastern

17 NGR r. 72(1)(a)(iii)(A).

18 APTPPL, Response to information request AER IR013, 29 September 2021, p. 3.

19 NGR, r. 72(1)(d).

20 APTPPL, Response to information request AER IR013, 29 September 2021, p. 3.

Australia retail users as well as Queensland retail users in its 2021 GSOO report[21][22]

- a review of historical metering data indicates that retail demand along the RBP is generally stable over multiple years, suggesting a steady trend in future periods[23]
- we would not expect a great deal of variance in the forecast period relative to historical booked capacity as retail demand is generally inelastic.

We are also satisfied that APTPPL's demand forecast for the RBP's major industrial users of an average of 53.6TJ/day is the best estimate in the circumstances. In forecasting industrial demand, APTPPL appears to have had regard to historical booked capacity for each of its industrial users and then made adjustments based on its view of the viability of its users' operations and market for the user's product.

APTPPL's historical booked capacity for major industrial users was generally stable from 2016–17 to 2019–20 at approximately 81TJ/day on average before declining in 2020–21 and 2021–22 by 33 per cent.[24] APTPPL forecasts demand to remain steady in the 2022–27 period.

We consider that APTPPL's forecast for industrial users is reasonable because APTPPL's forecast of a decreasing and subsequently flattening trend is consistent with the general trend in AEMO's demand forecast for eastern Australia as well as Queensland industrial users over the 2022–27 period.[25] Further, we consider APTPPL's forecasting approach of having regard to each of its users' operations and the market for its users' product in forecasting overall industrial demand is reasonable. This is because gas transportation and delivery are necessary cost inputs for these users, such that changes in the market the industrial user operates in will have a flow-on effect on its demand for booked capacity on the RBP.

We note that since APTPPL submitted its RBP proposal, Incitec Pivot announced its intention to shut down its fertiliser plant in December 2022.[26] Our position to accept APTPPL's forecast for industrial users does not take account of this development. We invite APTPPL to have regard to this change and any other new information in its revised proposal.

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[21] Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2021, p. 27. The GSOO was used as a sense check as the forecast estimates annual gas consumption, whereas APTPPL's forecast estimates annual contracted capacity.

[22] The GSOO shows the aggregate retail demand for eastern Australia, but the data for Queensland retail consumption can be found on AEMO's website: http://forecasting.aemo.com.au/Gas/MaximumDemand/Total.

[23] APTPPL, Response to information request AER IR001, 30 July 2021.

[24] Ibid.

[25] Australian Energy Market Operator, *Gas Statement of Opportunities*, March 2021, p. 28. The GSOO report shows the aggregate industrial demand for eastern Australia, but the data for Queensland industrial consumption can be found on AEMO's website: http://forecasting.aemo.com.au/Gas/MaximumDemand/Total.

[26] Incitec Pivot, *Gibson Island manufacturing operations to cease at end of 2022*, 8 November 2021 (media release): available at https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022.

12.4.2 Westbound users

We are not satisfied that APTPPL's demand forecast for the RBP's westbound users of an average of 73TJ/day is the best estimate in the circumstances. Our alternative forecast is an average of 114.3TJ/day, which is a 57 per cent increase relative to APTPPL's demand forecast and in line with historical westbound demand.

Forecasting approach

APTPPL relied on its consultant, ACIL Allen, to estimate westbound demand for the RBP for the 2022–27 period. ACIL Allen forecasts demand in two ways:[27]

1. Modelling gas throughput for the 2022–27 period – ACIL Allen uses its GasMark model to understand the market factors driving western haul services to estimate westbound gas flows. The modelling does not take into account non-market factors related to security of supply/operational flexibility and some short-term trading opportunities.
2. Firm-capacity bookings – ACIL Allen estimates how much firm capacity is likely to be booked for western haul services under three scenarios: Low, Base and High. ACIL Allen states that these estimates take into account the modelled flows, but also other drivers.[28]

Table 2 sets out ACIL Allen's forecasts for the westbound service across its three scenarios. ACIL Allen recommends the Base case as the appropriate forecast for the westbound service for the 2022–27 period. The High case assumes booked capacity will trend similar to levels seen in the past couple of years and its Low case assumes significant supply developments and greater competition from other pipelines.[29]

Table 2 ACIL Allen's RBP westbound demand forecast scenarios (TJ/day)

Scenario	2022–23	2023–24	2024–25	2025–26	2026–27	Average
High	100	100	100	100	100	100
Base	85	80	70	65	65	73
Low	65	65	50	45	45	54

Source: ACIL Allen, AER analysis.

The Base case assumes that booked capacity falls compared to historical contracted capacity over 2018–19 and 2019–20. ACIL Allen states the fall is in line with the

27 ACIL Allen, *Roma to Brisbane Pipeline demand forecasts GPG and western-haul demand*, June 2021, pp. 45–46.

28 We understand other drivers to mean development of the Wallumbilla hub, increased demand from southern states for Queensland produced gas, Security of supply and operational flexibility, and short-term trading opportunities.

29 ACIL Allen, *Roma to Brisbane Pipeline demand forecasts GPG and western-haul demand*, June 2021, p. 53.

modelling results and the main reason for the decline is Port Kembla and Narrabri increasing gas supply in southern Australia.[30]

Our assessment

We are not satisfied that ACIL Allen's approach to derive the westbound demand forecast in particular, the base case forecast, has been arrived at on reasonable basis and is the best estimate in the circumstances. While subsequent communications with ACIL Allen provided some clarity around its forecasting approach,[31] material information gaps remain. We have the following remaining concerns:

- ACIL Allen does not explain why it made specific year-on-year downward adjustments to the High case to derive the Base case forecasts. When we asked for an explanation, ACIL Allen provided a qualitative response similar to its explanation in its report.[32] We are concerned that its downward adjustments from recent booked capacity levels have no quantitative basis. For example, there appears to be no reasoning why adjustment has been made from 100 to 85TJ/day in 2023, and not to, for instance, 90 or 60TJ/day.
- Similar to the point above, ACIL Allen does not explain why it made year-on-year adjustments from the Base to the Low case. The lack of explanation further reduces our confidence in its forecasting approach.
- ACIL Allen did not undertake any sensitivity testing around the key assumption of the additional supply coming online in southern states.[33] This is the critical variable in its Base case scenario, and any delays in Port Kembla and Narrabri is likely to have a material impact in its forecast.
- The GasMark model did not undergo sensitivity testing. That is, ACIL Allen did not test how modelling results would change in response to changes in the inputs and assumptions.[34]
- While ACIL Allen indicates that its demand forecast was based on both the GasMark model as well as a review of historical booked capacity, it has not provided quantitative evidence as to how the two approaches were brought together to derive the forecast.
- The lack of clarity around the forecast was also highlighted by Shell Australia's submission, which noted that there would be benefit in making the model and underlying assumptions available to stakeholders to understand why APTPPL believes there will be subsequent declines in western haul usage.[35]

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30 Ibid., pp. 51–52.

31 Including a meeting on August 11 and three information requests.

32 APTPPL, Response to information request AER IR009, 9 September 2021.

33 APTPPL, ACIL Allen Response to information request AER IR009, September 2021, pp. 1–2.

34 Ibid.

35 Shell Australia, *Roma (Wallumbilla) to Brisbane Pipeline – Proposed access arrangement 2022 to 2027*, August 2021.

In its revised proposal, we encourage APTPPL to address the remaining concerns on ACIL Allen's approach to forecasting the RBP's westbound service.

Alternative forecast

Our alternative forecast for the westbound service is 114.3TJ/day, on average, over the 2022–27 period and is 57 per cent higher than APTPPL's. We consider our forecast is the best estimate in the circumstances. Our forecast is based on four years of historical booked capacity for the westbound service. We consider historical demand is a reasonable predictor of the forecast for the westbound service as contracted capacity appears to have remained steady at reasonably similar levels over the current access arrangement period. Further, there is an expectation that westbound demand is likely to remain buoyant especially with the Wallumbilla hub continuing as a major transit point between Queensland and other gas markets in the East Coast.

We note that APTPPL submits that when reviewing the historical series, 35TJ/day should be excluded over 2019 and 2021.[36] It states that the reserved capacity is not contracted on the RBP but related to services on another pipeline, the South West Queensland Pipeline (SWQP).[37]

Based on the information before us, we are not satisfied that the 35TJ/day reservation capacity should be excluded between the 2019–2021 period. At this stage, it appears that the reserved capacity is similar to the current booked transportation service offered on the RBP. That is, APTPPL cannot access or sell the reserved capacity without permission. Excluding the reserved capacity would allow APTPPL to recover more than its efficient costs, which is inconsistent with ss24(2) of the National Gas Law (NGL).

We encourage APTPPL in its revised proposal to provide information to support its reasons to make these adjustments to its historical series.

12.4.3 Gas Powered Generation forecast

We are not satisfied that APTPPL's demand forecast for the RBP's GPG of an average of 5.1TJ/day is the best estimate in the circumstances. Our alternative forecast is an average of 17.8TJ/day, which is in line with recent historical GPG demand.

Forecasting approach

APTPPL has relied on its consultant, ACIL Allen, to estimate the RBP's GPG demand for the 2022–27 period. ACIL Allen forecasts future dispatch at three power stations along the RBP: Oakey, Braemar[38] and Swanbank E.[39]

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36 APTPPL, Response to information request AER IR009, 9 September 2021, pp. 10–11.

37 The SWQP is owned by APTPPL.

38 Braemar power station consists of two separate power stations: Braemar 1 and Braemar 2. ACIL Allen combines the forecasts for the two Braemar power stations.

39 ACIL Allen, *Roma to Brisbane Pipeline demand forecasts GPG and western-haul demand*, June 2021, p. 29.

ACIL Allen uses its PowerMark model to model the electricity market and estimate a generator's future dispatch based on a set of "Reference Case Assumptions".[40] In modelling future dispatch, ACIL Allen also models short run marginal costs (SRMC) and assumes that a station dispatches only when it is able to cover its SRMC.[41] ACIL Allen notes its model does not include out-of-merit dispatch which has been seen over historical periods.[42]

Table 3 shows ACIL Allen's forecast average daily throughput for each generator. ACIL Allen forecasts Oakey and Braemar to operate at a capacity of generally below 2 per cent.[43] It forecasts Swanbank E to operate at a capacity of 5 to 10 per cent due to lower electricity prices and increased renewables leading to less opportunities for GPG.[44]

Table 3 Forecast average daily throughput (TJ/day)

	2023	2024	2025	2026	2027	Average
Oakey	0.3	0.2	0.1	0.1	0.2	0.2
Swanbank E	5.9	3.9	3.5	4.6	6.6	4.9
Braemar	0.033	0.022	0.007	0.018	0.026	0.021
Total	6.2	4.1	3.5	4.8	6.8	5.1

Source: ACIL Allen, AER analysis.

Our assessment

Based on the information before us, we are satisfied that ACIL Allen's forecast demand for Oakey and Braemar power stations is the best estimate for the 2022–27 period. However, we are not satisfied that ACIL Allen's demand forecast for Swanbank E is the best estimate. We consider that its forecast average demand of 4.9TJ/day is materially understated especially when compared to Swanbank E's historical consumption of 17.6TJ/day over 2018 to 2021.[45]

40 Ibid., p. 29.

41 Ibid., p. 32 and 35.

42 Ibid., p. 32 and 35.

43 Ibid., p. 32 and 36.

44 Ibid., pp. 32–35.

45 APTPPL, Response to information request AER IR001, 30 July 2021.

We consider that ACIL Allen does not consider critical relevant factors in deriving its demand forecast; namely that:

- Swanbank E has operated at a historical capacity of 33 per cent on average since its inclusion in the CleanCo portfolio.[46] Evidence to date suggests that it will continue to operate at similar levels in future periods
- information from the PASA indicates no change from Swanbank E's historical capacity levels.[47]

Each of these points are discussed below.

Swanbank E has operated at a historical capacity of 33 per cent on average since its inclusion in the CleanCo portfolio

Swanbank E is a combined cycle gas turbine and is one of the more efficient gas generators. This means it is a better position than other GPGs to capitalise on more opportunities such as when there are unplanned outages. For instance, in late May 2021, Swanbank E was ramped up after the Callide power station was shut down.

Since its inclusion in the CleanCo portfolio in September 2017, Swanbank E has materially increased its operations. Metering data provided by APTPPL indicated that Swanbank E's operating capacity was between 27 to 41 per cent from 2018 to 2021, averaging at 33 per cent.[48] This corresponds to a gas consumption of 13 to 24TJ/day from 2018 to 2021, averaging at 17.6TJ/day.

Swanbank E's high historical operating capacity levels is inconsistent with ACIL Allen's prediction that Swanbank E is likely to operate at 5 to 10 per cent capacity levels. When we queried APTPPL about ACIL Allen's considerably lower capacity level assumption, it submitted that Swanbank E was operating more regularly to make up for the shortfall caused by Callide. Further: [49]

> "Now that the Callide site has been cleaned up to the point that Callide…can resume operations, we expect to see Swanbank E return to infrequent operations as Queensland relies on reinstated Callide C generators supported by Wivenhoe pumped hydro."

However, our analysis of metering data provided by APTPPL indicates that from September 2017 to May 2021 (prior to Callide C's outage), Swanbank E was operating at a capacity of 33 per cent.[50] That is, the Callide C outage did not materially impact

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[46] APTPPL, Response to information request AER IR001, 30 July 2021. Operating capacity is calculated by dividing average throughput by maximum throughput over each financial year.

[47] The data can be downloaded from the AEMO website, under Medium Term DUID availability. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data/projected-assessment-of-system-adequacy-pasa.

[48] APTPPL, Response to information request AER IR001, 30 July 2021. Operating capacity is calculated by dividing average throughput by maximum throughput over each financial year.

[49] APTPPL, Response to information request AER IR006, 13 August 2021, p. 6.

[50] APTPPL, Response to information request AER IR001, 30 July 2021.

Swanbank E's operating capacity. Further, APTPPL's assumption that Swanbank E will return to 'infrequent operations' is inconsistent with our review of the metering data, which indicates Swanbank E's operating frequency increased from 41 per cent in 2018–19 to 50 per cent in 2019–20 to 75 per cent in 2020–21.[51]

As mentioned, ACIL Allen assumes Swanbank E will operate only when it can cover its SRMC and does not dispatch "out of merit".[52] However, this is inconsistent with commentary in its report that its forecasts are likely to be conservative (understated) given how the generator has sometimes run "out of merit" since it has returned to service:[53]

> "CleanCo now runs Swanbank E and its generation has likely been increased beyond what is achievable economically (or in other words, Swanbank E has been run 'out of merit' order for certain periods). It could be the case that Swanbank E is run more and achieve higher levels of generation than what our model has forecast. Therefore, it is likely that our forecasts could be conservative given how the generator has been run since it has returned to service."

Information from the PASA indicates no change from Swanbank E's historical capacity levels

PASA is the principal method of forecasting the adequacy of the power system to stay within the reliability standard. Each week participants must submit forecasts of availability to AEMO for the next 36 months. These forecasts form the basis of the medium term PASA that will be produced the following week.[54]

The medium term PASA data indicates that over the next three years Swanbank E has committed a continuous capacity of approximately 355MW a day.[55] This is consistent with its historical dispatch data and indicates that Swanbank E is not expecting material interruptions or to wind back its capacity.

Alternative forecast

Our alternative forecast of 17.8TJ/day, on average, for total GPG demand for the 2022–27 period includes an alternative forecast of 17.6TJ/day for Swanbank E. Our forecast is based on Swanbank E's historical gas usage from September 2017 to May 2021.[56] Our alternative forecast for Swanbank E is consistent with its historical

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51 APTPPL, Response to information request AER IR001, 30 July 2021. Operating frequency was calculated by dividing the number of days Swanbank E operated by 365 days.

52 ACIL Allen, *Roma to Brisbane Pipeline demand forecasts GPG and western-haul demand*, June 2021, p. 32 and 35.

53 Ibid., p. 35.

54 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/projected-assessment-of-system-adequacy.

55 The data can be downloaded from the AEMO website, under Medium Term DUID availability. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data/projected-assessment-of-system-adequacy-pasa.

56 APTPPL, Response to information request AER IR001, 30 July 2021.

gas demand since its inclusion in the CleanCo portfolio. Further, it is supported by the PASA availability data which suggests that Swanbank E's available electricity generation capacity over the next three years remains consistent with historical capacity.

A. Shortened forms

Shortened form	Extended form
AEMO	Australian Energy Market operator
AER	Australian Energy Regulator
APTPPL	APT Petroleum Pipelines Pty Limited
Capex	Capital expenditure
GPG	Gas-fire powered generation
GSOO	Gas Statement of Opportunities
LTFS	Long term firm service
MW	Mega watt
NGL	National Gas Law
NGR	National Gas Rules
Opex	Operating expenditure
PASA	Projected assessment of system adequacy
RIN	Regulatory Information Notice
SRMC	Short run marginal cost
SWQP	South West Queensland Pipeline
TJ	Terra joule

Appendix A The form of price regulation

The relationship between demand forecasts and reference tariffs is influenced by the form of price regulation applied to the pipeline in question. This appendix sets out our considerations around the current form of price regulation applied to regulated gas transmission and distribution pipelines.

Price cap regulation

The RBP, consistent with most fully regulated (covered) pipelines in Australia, is subject to price cap regulation.[57]

Under price cap regulation we determine maximum prices that may be charged by network service providers for the services we determine to be reference services. That is, reference services must be available to pipeline users at no more than the reference tariffs we set.

Incentives created by price cap regulation

The AER has consistently applied price cap regulation to gas pipelines because of the incentives created by this form of control. Price caps assign demand (or volume) risk to network service providers. Should actual demand be lower than forecast, the network service provider will earn less revenue than expected. This incentivises network service providers to promote use of gas from their networks. In turn, this promotes lower reference tariffs for all pipeline users because tariffs are the result of target revenue divided by demand. The higher demand, the lower the tariffs.

In the broader context of declining per customer gas consumption, we have considered price cap regulation to be in the long term interest of pipeline users.

Price caps and demand forecasting uncertainty

Recently however, we have observed that pipeline demand forecasts are associated with increasing uncertainty. Growing uncertainty risks assigning volume risk to gas pipeline users rather than to network service providers. This is because, where actual volumes are higher than forecast, pipeline users are subject to higher than necessary reference tariffs.

Material assignment of volume risk to customers breaches a principle of economic regulation, which is that risk should predominantly be assigned to the party with greatest ability to mitigate that risk. Network service providers are more able to mitigate volume risk than pipeline users.

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57 This is an average price cap. This approach is consistent with APTPPL's RBP current period access arrangement. See Attachment 10 for more information: AER, *Draft decision, Roma to Brisbane Pipeline 2022–27, Attachment 10 – Reference tariff variation mechanism*, November 2021.

Price caps and jurisdictional environmental policies

We are also seeing Australian state and territory governments committing to net zero carbon equivalent emissions targets. Jurisdictional environmental targets are being supported by a range of jurisdictional policy interventions which, while each intervention has its specific policy objective, collectively contribute to achieving those net zero targets. Under net zero targets, pipelines carrying large volumes of fossil fuel natural gas are unlikely to be viable.

It is unclear the extent to which price cap regulation can co-exist with jurisdictional policies which, in the absence of re-purposing gas pipelines to carry alternative fuels such as green hydrogen, are likely to see gas pipelines close. There may be a conflict between jurisdictional policies working to close gas pipelines and forms of price regulation which incentivise gas demand.

Revenue cap regulation

Both because of increasing demand forecasting uncertainty and jurisdictional policies for net carbon zero, it may be appropriate for the gas pipeline sector, its stakeholders and the AER to reconsider the appropriateness of price cap regulation.

The alternative form of price regulation, revenue cap regulation, would alleviate volume risk for gas pipeline users. Revenue caps do this by allowing network service providers to earn the target revenue that we determine, regardless of actual demand. Under or over revenue recoveries in a given year, driven by lower or higher actual demand compared to forecasts used to calculate reference tariffs, are carried forward into future years. In this way, over a period of time, network service providers earn no more and no less revenue than we determine.

Under revenue cap regulation, network service providers would no longer face an incentive to grow the volume of gas carried by their pipelines. This would be more consistent with jurisdictional zero carbon policies but may expose pipeline users to higher reference tariffs due to lower demand.

Revenue cap regulation is currently applied to all National Electricity Market regulated distribution and transmission electricity networks. Revenue caps are applied to electricity networks specifically because they do not incentivise network service providers to grow volumes. In the electricity context this is important because peak demand growth has driven significant network investment and therefore costs which are ultimately incurred by electricity customers.

While the drivers of any gas pipeline sector future switch from price caps to revenue caps would be very different to the current drivers of revenue cap regulation for electricity networks, the revenue and incentive outcomes would be the same.

Switching to revenue caps could drive changes to gas network tariff structures

In the short term, revenue cap regulation applied to gas networks could be expected to influence reference tariffs proposed by gas network service providers. This is particularly the case for gas distribution networks. Currently, gas distribution networks typically offer declining block tariffs, whereby per unit prices decline as pipeline users consume increasing volumes of gas. Under revenue cap regulation, we would expect network service providers to reconsider declining block tariffs and perhaps instead propose flat tariffs or inclining block tariffs.

Gas transmission pipelines and revenue caps

We note that gas transmission pipelines currently see much of their capacity transacted by negotiation between network service providers and pipeline users. These negotiations relate to both the details of the service provided and to tariffs. The result is that much, or most, transmission pipeline capacity is transacted for services and tariffs that are similar to, but not the same as, the reference services and reference tariffs we determine. That is, reference services and reference tariffs are the starting point for negotiations between network service providers and pipeline users.

In the context of gas transmission pipelines, imposition of revenue caps may suppress negotiations between network service providers and pipeline users. That is, the scope for effective negotiation between parties may be smaller than under price cap regulation. There may even be no scope for such negotiations under revenue cap regulation. We consider this would be a major change to the way the gas transmission pipeline sector currently operates and may not be supported by pipeline users.

Gas distribution pipelines and revenue caps

In the context of gas distribution networks, application of revenue caps would be less disruptive to current practices. This is because gas distribution pipeline capacity is transacted differently to gas transmission pipelines. Gas distribution network service providers typically see almost all of their potential services directly regulated as reference services. Gas distribution reference services are offered to pipeline users, at reference tariffs, in a take-it-or-leave-it manner. There is no negotiation between the parties. In this way, gas distribution capacity transactions are more consistent with the electricity distribution and transmission sectors where, as noted above, revenue cap regulation is currently applied uniformly. In the electricity network sector, network capacity is transacted in a take-it-or-leave-it manner.

No change proposed for RBP but we are raising this an issue for sector consideration going forward

As a gas transmission pipeline, changing the RBP's form of price regulation from a price cap to a revenue cap may be more disruptive than in the context of distribution pipelines, as described above. Also, changing the form of price regulation would, in our view, require notification to the network service provider, pipeline users and other stakeholders well in advance of an access arrangement variation process. This is because such a change would have potentially significant consequences, including for tariff structures. It is not appropriate, in our view, to impose such a change within an access arrangement variation process without prior notification and appropriate engagement.

We take this opportunity to raise this issue with the gas pipeline sector and its stakeholders to prompt consideration and to flag it as an issue for further engagement in the context of future gas pipeline access arrangement variation processes.