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Appendix: Pipeline demand and contracting scenarios

Higher gas prices and unwanted supply in the pipeline from Beetaloo

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Appendix: Pipeline demand and contracting scenarios

APA Group's proposed Beetaloo pipeline is estimated to be expensive, with capital expenditure possibly exceeding AU$7 billion. The scale of the required investment raises questions not only about APA's ability to finance the project, but also about whether it will be able to secure sufficient contractual commitments to underpin the investment.

APA's history suggests it is most likely to require firm transmission agreements to underpin the investment.[1] Given the magnitude of investment required to bring the North to East Australia (NEA) pipeline online, it is reasonable to assume APA is likely to sanction the proposed pipeline only if it is able to sign foundation transport agreements to cover its entire capacity. This, in turn, raises questions about sources of demand that could underpin such agreements.

There are two obvious sources of new demand for gas from the Beetaloo: Santos's Gladstone LNG plant (GLNG), and the east Australian gas market (which faces the prospect of supply shortages).

This section of the report discusses potential sources of demand and outlines hypothetical demand scenarios that underpin IEEFA's assessment of the financial case for the pipeline.

Santos Gladstone LNG likely the largest source of new demand

Since it commenced operations in 2015, Santos's GLNG has operated well below its nameplate capacity due to insufficient reserves.[2] Because of this, GLNG purchased more than 1000 petajoules (PJ) of gas from the domestic market from 2017 to 2024 to meet export commitments, a strategy that has become increasingly untenable in the face of industry and government scrutiny.[3]

For this reason, Santos CEO Kevin Gallagher has stated that gas from the Beetaloo sub-basin is an option for backfilling the GLNG project.[4] Augmenting its existing 2P (proven and probable) reserves and 2C (contingent) resources in Queensland would allow GLNG to support existing contracting arrangements and export larger volumes of LNG for a longer period into the future.

In practice, GLNG could either seek to enter into new firm LNG sales and purchase agreements (SPAs) or adopt an LNG "spot sale" strategy as part of backfilling the GLNG plant via a new Beetaloo pipeline. However, this will rely either on GLNG being able to find LNG buyers willing to sign long-term contracts starting after 2036, or on GLNG joint venture partners being sufficiently confident that LNG spot prices will remain sufficient high for long enough to provide a sufficiently high return.

[1] Australian Financial Review (AFR). APA Group to spend half its capex on WA pipeline. November 2020.
[2] IEEFA. Australian Gas and LNG Tracker. June 2025.
[3] Australian Competition and Consumer Commission (ACCC). Gas Inquiry 2017-30 June 2025 interim report. June 2025. Page 68.
[4] Argus Media. Australia's NT releases Beetaloo shale gas acreage. February 2026.

Kogas and Petronas are both possible counterparties for future LNG SPAs given the expiry of their existing 3.5 million tonnes a year (MTPA) contracts from 2031 to 2036 and their ownership stakes in GLNG.

Kogas contract renewal

South Korea's future domestic gas demand, and therefore future LNG contracting requirements, remains uncertain. Korean government planning documents present a mixed picture for future demand growth, underscoring the uncertainty.

South Korea's 11th Basic Plan for Electricity Supply and Demand, released in early 2025, detailed targets for gas generation to fall to 10.6% of the electricity mix, down from 28% in 2024.[5] Relative to 2023, the plan envisaged LNG power generation falling from 158 terawatt hours (TWh) to 74TWh in 2038, a fall of about 53%.[6] Given the majority of South Korea's gas consumption is in the electricity sector, this implies a fall in LNG demand.

The nation's 16th Long-term Natural Gas Outlook, published in mid-2026, presented two baseline demand scenarios of 41MTPA and 47.7MTPA by 2038, relative to 45.9MTPA and 47.6MTPA respectively in 2026.[7] The lower baseline accounts for greater nuclear and renewable generation, as well as coal phase-outs. The higher baseline accounts for the same factors but recognises the potential for higher gas demand for generation due to delays in new baseload power generation and transmission network construction. It also accounts for higher electricity demand arising from the rollout of data centres and an expansion in semiconductor production. The demand scenarios in the Natural Gas Outlook represent a more optimistic view of demand than in the 11th electricity plan.

The 12th Basic Plan for Electricity Supply and Demand, which will be finalised in late 2026, is likely to suggest an increase in gas power generation. While some of this new demand will be met with renewables given the recent announcement to accelerate the deployment of 100 gigawatts (GW) of renewable generation capacity by 2030, South Korea's Minister of Climate, Energy and Environment noted that "gas generation will inevitably increase to some extent".[8]

In summary, South Korea's gas demand is forecast to either fall to 41MTPA (a decline of about 11%) or remain broadly unchanged at 48MTPA by 2038.

South Korean companies historically contracted for 65–68% of LNG demand, which would translate into LNG contracting requirements by 2038 of about 28MTPA to 32MTPA. IEEFA analysis in 2025

[5] S&P Global. South Korea to sharply cut LNG's share in power mix to 10.6% by 2038. 21 February 2025.
[6] International Trade Administration (US). Energy: Power Generation Mix, LNG and Commercial Nuclear Power. 26 June 2026.
[7] Energy News. 16th Long-term Natural Gas Outlook… 'Demand Increased' Compared to 15th. 27 July 2026.
[8] FN news. Surge in Electricity Demand Driven by Mega-projects… Will the 12th Basic Plan for Electricity include an Expansion of LNG Power Generation? 19 August 2026.

estimated contract volumes could fall to below 10MTPA by 2038, indicating there could be a need for additional contracting (specifically from 2029).[9]

Based on this, it seems possible South Korean companies will seek new LNG contracts.

LNG buyer Kogas has signed a number of LNG SPAs in recent years, indicating a willingness to take firm supply positions. However, recent contracting behaviour suggests a fundamental shift away from project LNG to more flexible LNG supplies, both in terms of price and destination flexibility, which could possibly affect Kogas's appetite for new contracts with specific suppliers. Namely:

- Kogas has shifted to shorter-term contracts, with all recent contracts (from 2024) having terms of 10–11 years.[10,11,12,13,14]
- Contracts have been with portfolio traders (noting Woodside's contracts permits delivery from its global portfolio), rather than from specific projects, which might suggest Kogas is turning to traders because it is seeking shorter-term deals.
- Pricing indexes have been diversified (to include Henry Hub pricing in particular).

A looming LNG supply glut will flood LNG markets with uncontracted gas from existing and new projects, but also from portfolio traders.[15] IEEFA estimates US projects under construction have close to 40Mt of uncontracted capacity, and expiry of Qatari contracts will increase volumes of uncontracted LNG from the Middle East. In the absence of new LNG contracts, IEEFA estimates Qatar could have as much as 75Mt uncontracted by 2035 (not including uncontracted volumes lifted from the US). Availability of uncontracted LNG volumes from existing producers will present a natural source of competition for any new LNG contract between GLNG and Kogas.

The glut is also likely to depress LNG spot prices, which could induce buyers to rely more heavily on the spot markets than on contract volumes.

Nonetheless, given the likely need for new LNG contracts, and Kogas's 15% ownership stake in GLNG, IEEFA considers Kogas may be willing to sign a new long-term LNG contract to start in 2037 (provided the contract price is sufficiently competitive at a time when LNG markets are likely to be well supplied). However, given the pivot to shorter-term contracts, and Korea's emissions reduction targets (net zero by 2050), we consider it unlikely Kogas would sign a 20-year extension starting in 2037.

[9] IEEFA. U.S. tariff deal could undermine South Korea's climate goals. August 2025.
[10] Hydrocarbon Engineering. BP and KOGAS sign long-term LNG SPA. 30 April 2024.
[11] LNG Prime. BP, Kogas sign new long-term LNG supply deal. 22 May 2026.
[12] Total Energies. South Korea: TotalEnergies to supply 1 million tons per year of LNG to KOGAS for 10 years. 9 September 2029.
[13] Trafigura. Trafigura signs long-term LNG supply agreement with KOGAS. 25 August 2025.
[14] Energy Connects. Woodside and KOGAS sign agreement for long-term LNG supply. 28 February 2024.
[15] Gas Strategies. How portfolio players may be fuelling LNG's boom and bust. September 2025. Page 5.

For the purposes of assessing the financial case for the NEA pipeline, IEEFA has modelled a scenario in which Kogas does not sign a new LNG SPA, and two scenarios where it signs a new 10-year LNG SPA commencing in 2037:

Scenario	Assumption	Demand
Low demand	Kogas does not sign a new LNG SPA	0PJ
Central demand	Kogas signs a new 10-year LNG SPA commencing in 2037	220PJ for 10 years
High demand		220PJ for 10 years

Petronas contract renewal

Malaysia, one of the largest LNG suppliers to Asia, is forecast to switch from being a net exporter to a net importer in coming decades as domestic gas production and pipeline gas imports (to Peninsular Malaysia) decline. Wood Mackenzie, for example, forecasts Malaysia will switch from being a net LNG exporter to a net importer in the early 2040s.[16]

Wood Mackenzie also forecasts Malaysia's gas demand to grow to the late 2030s, before remaining flat to 2050. Growing electricity consumption, in part due to data centre growth, and coal generation exits are key drivers of the forecast LNG demand growth in Malaysia.[17]

Malaysia's Natural Gas Roadmap, due to be released in late 2026, specifically forecasts gas will increase from 43% of the energy mix in 2020 to 56% by 2050, and notes that LNG imports will need to increase in Peninsular Malaysia and Sabah as legacy fields decline.[18]

To improve incentives for both domestic gas production and LNG imports, the Malaysian government has flagged an intent to consider liberalising the gas market (following earlier reforms) by potentially removing or reforming price controls.[19] While this is intended to encourage supply by allowing for pass-through of higher LNG costs, it might also affect the competitiveness of LNG in the power sector, particularly if renewable energy costs continue to fall.

Meanwhile, the Malaysian government is targeting a renewable share of electricity generation of 70% by 2050, up from 17% in 2021, which may in part explain why Wood Mackenzie is forecast flatlining growth from 2040.[20]

Petronas also seems likely to seek LNG supply as part of a strategy to supply Southeast Asia, with it expecting LNG demand to double by 2035.[21] In addition to continuing to develop domestic gas fields,

[16] Wood Mackenzie. Gas on the move: Malaysia's energy crossroads. 4 September 2025.
[17] Ibid.
[18] The Edge Malaysia. Cover Story 2: National Gas Roadmap to overhaul gas policy amid tightening supply, coal phase-out by 2044. 11 February 2026.
[19] Ibid.
[20] Enerdata. Malaysia sets new target to reach 70% of renewables in the power mix by 2050. 12 May 2023.
[21] Bangkok Post. Petronas LNG targets transformation into energy solutions partner. 21 September 2026.

Petronas noted it will use an "asset-light" approach, whereby LNG is secured without any infrastructure investment.[22]

Given forecasts of rising domestic and Southeast Asian demand, it seems highly likely that Malaysia's LNG imports will continue to grow, and that Petronas might be willing to sign new long-term LNG contracts that start as late as 2037. In 2025, Petronas announced plans to boost international upstream growth by 60% to 2035 to meet domestic and LNG demand, with the latter reflecting Petronas adopting a "portfolio player" model.[23]

Recent contracting also indicates Petronas is more willing than Kogas to take on longer-term contracts, with recent SPA terms generally being up to 20 years. With some not slated to begin supply until the late 2020s, this means Petronas has already taken long-term supply positions to the late 2040s.

In IEEFA's view, it seems possible Petronas would be willing to renew its 3.5MTPA contract with GLNG on expiry, potentially for an additional term of 20 years given growth expectations. That said, uncertainty about future data centre demand and the rollout of renewables, and gas exploration in the Gulf of Thailand, could prompt Petronas to contract for shorter periods. For the purposes of assessing the financial case for the NEA pipeline, IEEFA has modelled scenarios in which Petronas signs 10-year, 15-year and 20-year LNG SPAs commencing in 2037 (Table 1).

Table 1: Projected LNG demand from Petronas under varying SPA terms

Scenario	Assumption	Demand
Low demand	Petronas signs a new 10-year LNG SPA commencing in 2037	220PJ for 10 years
Central demand	Petronas signs a new 15-year LNG SPA commencing in 2037	220PJ for 15 years
High demand	Petronas signs a new 20-year LNG SPA commencing in 2037	220PJ for 20 years

Other new contracts

Alternatively, GLNG could seek to sign SPAs with other LNG buyers. Industry forecasts, including from Shell and BP, suggest LNG demand in the Asia-Pacific region will continue to show strong growth in coming decades. If this growth were to occur, there may be other LNG buyers willing to sign long-term contracts.

Supply disruptions in the Middle East may also have implications for Australia. With the war affecting LNG supplies through the Strait of Hormuz, LNG buyers may be more willing to enter into new LNG contracts with suppliers that have unimpeded access to Asian markets, such as those in Australia and Canada. Middle East LNG suppliers may also be willing to sign contracts for supply in other regions to maintain their market share and provide a natural hedge against bottlenecks to their

[22] Petronas. Shaping the Next Era of Energy: Integrated Report 2025. February 2026. Page 59.
[23] Malay Mail. Petronas to boost international upstream growth by 60pc over next 10 years. 27 February 2026.

customers. For instance, Qatar Energy recently signed new LNG offtake deals with US LNG producers.[24]

Whether recent events drive new contracting for Australian LNG projects remains to be seen, and IEEFA notes that surging LNG supply and uncertain demand could have implications.

While industry forecasters point to expected demand growth, they also recognise inherent uncertainty, which is why both Shell and BP publish forecasts based on a range of scenarios. BP, for example, forecasts LNG demand will decline through the 2030s and 2040s in a "fast transition" (below 2°C warming) scenario, which would result in LNG exports in 2050 being 25% lower than in 2023.[25] Similarly, Shell's outlook clearly shows supply under construction could be sufficient to meet LNG demand in 2035, with supply potentially larger if demand falls towards the bottom of the estimated range.[26] Both outlooks also point to emerging markets, particularly in South and Southeast Asia, as being the key source of future demand growth.

The International Energy Agency (IEA) similarly forecasts LNG capacity under construction would be sufficient to meet demand in 2035 if countries implement policies to meet their stated emissions targets (STEPS scenario), with growth in emerging markets a driver. Under a Net Zero Emissions by 2050 scenario (aligned with 1.7°C warming), some of the under construction capacity will not be needed, and LNG projects will collectively be underutilised.[27]

LNG demand growth in Asia has stagnated, with imports in the first half of 2026 the lowest in six years, and 2026 imports expected to fall for the second year running.[28,29] This, in part, reflects the impact of high prices due to the wars in Ukraine and Iran, meaning demand may rebound to some extent as prices fall in future.

There have already been numerous examples of structural (future) demand destruction following the Iran war (as discussed in the report), which raise questions about optimistic industry forecasts. Further, as noted in the report, LNG markets will be awash with uncontracted LNG in coming years, in part due to a looming supply glut.

In light of this, it remains highly uncertain whether other LNG buyers would be willing to sign new LNG contracts with GLNG starting from 2037. LNG buyers wishing to sign new contracts with Australian suppliers may be able to recontract prior to 2037 as existing LNG SPAs expire.[30] Further, the high cost of Beetaloo gas exported via Gladstone (discussed further below) mean that, to the extent this is demand for new Australian LNG contracts, buyers are likely to prioritise other LNG projects. IEEFA notes, for instance, that Australia Pacific LNG (APLNG) and Queensland Curtis LNG

[24] Gas World. Qatar becomes largest buyer of US LNG after back-to-back deals. 30 October 2026.
[25] BP. BP Energy Outlook 2025. September 2025. Page 43.
[26] Shell. Shell LNG Outlook 2026. June 2026. Page 16.
[27] International Energy Agency. World Energy Outlook 2025. October 2025. Page 70.
[28] IEEFA. Australian Gas and LNG Tracker. September 2026.
[29] Reuters. Asian LNG demand set to fall for second year as war shrinks supply. 17 September 2026.
[30] IEEFA. Australian Gas and LNG Tracker. June 2025.

(QCLNG), the two other exporters in Gladstone, are likely to have access to cheaper feedgas than that from the Beetaloo.

For that reason, in assessing the financial case for the NEA pipeline, IEEFA has modelled scenarios in which LNG buyers (other than Kogas and Petronas) do not sign new LNG SPAs with GLNG (Table 2).

Table 2: Projected LNG demand from other LNG buyers without SPAs

Scenario	Assumption	Demand
Low demand	No LNG SPAs with non-JV partners	0PJ
Central demand		0PJ
High demand		0PJ

Additional spot sales

In the absence of firm new LNG contracts, GLNG could adopt a "spot sale" strategy, under which it would commit to acquiring Beetaloo gas over a longer period to sell LNG into spot markets. Such a strategy would potentially allow GLNG to achieve higher utilisation of its LNG plant for longer, but it would expose GLNG to price and volume risks beyond those under long-term, oil-linked contracts.

To adopt such a strategy, GLNG would likely need to be confident that long-term LNG spot prices would remain high enough to cover the long-run marginal cost of incremental Beetaloo gas supply and transport to Gladstone, plus the short-run marginal operating cost of its existing LNG facility.

In the IEA's 2026 World Energy Outlook STEPS scenario, weighted-average LNG import prices for emerging markets in Asia are forecast to be around US$6.80 per million British thermal units (MMBtu) in 2035 and US$9.90/MMBtu in 2050.[31] Goldman Sachs recently forecast LNG spot prices at US$6.75/MMBtu (or lower) from 2031 to 2035.[32]

At this price point, LNG spot sales from GLNG are unlikely to be financially viable even if the costs of transporting gas via the NEA pipeline are very low. This is because the costs of purchasing, transporting, liquefying and shipping Beetaloo gas to end users in Asia are likely to be high (Table 3).

[31] IEA. World Energy Outlook 2026. November 2025. Page 118.
[32] Gas Outlook. The looming LNG bust. 11 November 2026.

Table 3: Beetaloo gas to LNG cost components

Component	Cost	Rationale
Wholesale gas costs	AU$7.24–9.15/GJ	Various forecasts of Beetaloo gas production costs between AU$6–9.15/GJ.
Transport – NEA pipeline	AU$2.01–3.76/GJ	IEEFA's estimated minimum pipeline tariff (under a high demand scenario).
Transport – South West Queensland Pipeline	AU$1.82/GJ	APA's published single pipeline tariff.
Transport – GLNG Wallumbilla to Gladstone pipeline	Marginal costs, likely negligible	GLNG owns the pipeline, and operating costs are small.
Gas liquefaction cost	7.5% of the wholesale cost (AU$0.45–0.68/GJ)	This is based on LNG plant own gas use of 7.5% of feedgas.
LNG shipping costs	AU$1.40/GJ	Assumption informed by forecast LNG freight rates from Gladstone to Asia over the next 5 years (assumed as a proxy for longer-term rates).[33]
Total cost (delivered to Asia)	AU$13.30–17.30/GJ (US$9.80–12.70/MMBtu)	

Even without accounting for the costs of transporting gas via the NEA pipeline, using Beetaloo gas to supply LNG to customers in Asia via GLNG is estimated to cost US$8.20–9.80/MMBtu, well above the IEA's 2035 long-term price forecast under the STEPS scenario. Even under the Current Policies scenario, which the IEA considers unrealistic, LNG prices (into Japan) will be equivalent to just over US$10.90/MMBtu by 2035. This indicates that a "spot sale" strategy would rely on Beetaloo production costs being towards the bottom of the estimated range and emerging markets in Asia not implementing any new climate policies that affect LNG demand.[34]

Given the high cost of Beetaloo gas, we consider it unlikely GLNG adopts a spot sale strategy (Table 4).

Table 4: Demand projections for Gladstone LNG spot sales

Scenario	Assumption	Demand
Low demand	GLNG demand limited to LNG SPAs and meeting domestic supply obligations (DSOs) — no additional Beetaloo volumes for spot sales	0PJ
Central demand		0PJ
High demand		0PJ

Alternative feedgas sources

GLNG will also have the option to develop its own 2P reserves and 2C resources in eastern Australia, which could either delay or reduce GLNG's need for gas from the Beetaloo.

[33] FTI Consulting. LNG Freight Rate Estimates – Results. December 2025. Page 28.
[34] IEA. World Energy Outlook 2026. November 2025. Page 118.

Based on Australian Competition and Consumer Commission (ACCC) reporting, and accounting for planned third-party gas purchases, IEEFA estimates GLNG holds 3300PJ of reserves and resources beyond those required to meet existing commitments.[35] Assuming this could all be developed, it would more than sufficient to meet a 10-year extension of either the Kogas or Petronas 3.5MTPA contracts. A 20-year extension, however, would require GLNG to source new gas supply.

The costs of developing these reserves and resources are likely to be lower than sourcing gas from the Beetaloo. Specifically, the Australian Energy Market Operator (AEMO) estimates production costs from the Bowen and Surat basins at AU$3.65/GJ for 2P reserves and AU$6.65/GJ for 2C resources.[36]

Further, GLNG announced in late 2025 it intends to invest more than AU$1bn a year to develop its reserves in Queensland as part of a strategy to cease domestic gas purchases.[37] This could allow it to meet a larger share of its exports with its own reserves.

However, GLNG may also face additional refurbishment costs to extend the life of its liquefaction plant. As part of the Barossa backfill to Darwin LNG project, Santos has invested about US$600m (AU$915m) on plant refurbishment and pipeline tie-in projects.[38]

GLNG will also need to secure government export licences to continue producing LNG beyond the expiry of current contracts. Given GLNG's historic reliance on domestic gas to meet its exports, it may only receive approval for part of its LNG capacity (i.e. for only one LNG train).

While additional costs and the need for export licences could affect future demand scenarios for Beetaloo gas (by GLNG), for simplicity, IEEFA has assumed neither of these factors has a material impact. We modelled two scenarios in which GLNG uses its own gas and third-party purchases to meet its domestic supply obligation (DSO) (Table 5).

Table 5: Demand projections for Gladstone LNG meeting its DSO

Scenario	Assumption	Demand
Low demand	GLNG develops all of its own 2P reserves and 2C resources, and purchases third-party gas to meet DSO.	0PJ
Central demand	GLNG develops all of its own 2P reserves and 2C resources, and purchases third-party gas to meet DSO.	0PJ
High demand	Beetaloo gas supplies GLNG's total DSO (see next section).	Peaks at 86PJ in 2033–2035 before steadily falling to 0PJ by 2057.

[35] ACCC. Charts and data from the gas inquiry June 2026 interim report. July 2025. Chart 2.7.
[36] AEMO. 2026 Gas Statement of Opportunities supply data. March 2026.
[37] Pipeline and Gas Journal. Santos' GLNG to End Domestic Gas Purchases for Exports by 2027. 21 October 2025.
[38] Santos. Santos announces FID on the Barossa gas project for Darwin LNG. 30 March 2021.

Beetaloo developers eye domestic gas demand

Eastern Australia's gas market is the other possible source of demand that could possibly (partly) underpin the NEA pipeline investment. With shortfalls predicted by the early 2030s, it is unsurprising Beetaloo proponents have proposed its gas as a potential solution.

Beetaloo gas could be used to avert eastern Australia shortfalls

AEMO's 2026 Gas Statement of Opportunities (GSOO) forecasts growing annual shortfalls in eastern Australia, including demand for gas to supply LNG exports.[39] In the absence of new supply, eastern Australia is likely to need Beetaloo gas to meet demand.

Looming shortfalls thus present a possible demand scenario for Beetaloo gas.

However, the implementation of the reservation policy is likely to limit how much demand in eastern Australia could be met with Beetaloo gas. The two largest Queensland exporters, APLNG and QCLNG, have access to large reserves that are likely to be more than sufficient to meet their export domestic supply requirements well into the future (noting QCLNG also has access to Arrow Energy reserves under a long-term GSA).[40,41] Neither is likely to require Beetaloo gas either for exports or to meet their DSOs under the reservation scheme.

For this reason, IEEFA's view is that Beetaloo gas is unlikely to meet eastern Australia gas demand, with the exception of GLNG using it to meet its DSO.

GLNG may look to Beetaloo gas to meet its DSO

In IEEFA's view, GLNG is more likely than other Queensland exporters to look to Beetaloo gas to help it meet its domestic supply requirements (in addition to providing feedgas for LNG exports). This reflects both GLNG's smaller reserves in Queensland and that GLNG joint-venture partner Santos has Beetaloo interests.

Using AEMO GSOO data, IEEFA estimates that GLNG's annual DSO would be, at most, 87PJ from 2032 to 2036 (assuming individual exporter DSOs are determining by pro-rating nameplate plant capacity), before falling to 44PJ in 2045 (due to falling gas supply in eastern Australia). In practice, this is likely to provide an upper bound for the level of domestic demand in eastern Australia that could be met with gas from the Beetaloo.

However, GLNG will have other options to meet its DSO, such as entering into commercial arrangements with smaller gas producers that result in "additional gas" coming to market in eastern

[39] AEMO. 2026 Gas Statement of Opportunities – report figures and data. March 2026. Figure 45.
[40] ACCC. Charts and data from the gas inquiry June 2026 interim report. July 2025. Chart 2.7.
[41] Arrow Energy. Arrow Energy agrees deal for Surat Basin reserves. April 2018.

Australia, or purchasing gas from APLNG or QCLNG. Given the other Queensland exporters have access to relatively low-cost reserves, this would be a more cost-effective approach than underpinning the NEA pipeline and relying on Beetaloo gas (due to its high cost, discussed earlier).

Nonetheless, IEEFA assumes GLNG will use Beetaloo gas to supplement its Queensland production, as needed, to meet its DSO under a high-demand scenario, and that its DSO will be allocated on a pro-rata basis based on nameplate capacity. In practice, this is likely to represent an upper bound of domestic demand (Table 6).

Table 6: Demand projections for Gladstone LNG meeting its DSO with/without Beetaloo gas

Scenario	Assumption	Demand
Low demand	GLNG does not use Beetaloo gas to meet DSO.	0PJ
Central demand	GLNG does not use Beetaloo gas to meet DSO.	0PJ
High demand	GLNG uses Beetaloo gas to supplement domestic supply to meet DSOs (as well as LNG SPAs).	Peaks at 86PJ in 2033–2035 before steadily falling to 0PJ by 2057.

Others may look to the NEA pipeline to meet eastern Australia demand

LNG exporters aside, Northern Territory (NT) gas producers may also be willing to take long-term positions in the NEA pipeline if it provides a financially viable option to help increase the scale of their Beetaloo developments.

IEEFA notes, however, that they would need to satisfy APA Group's strict creditworthiness requirements. Beetaloo proponents, with the exception of Santos, are likely to have relatively limited revenue without materially scaling up production in the sub-basin, which might affect how much capacity they are able (or willing) to contract. That said, APA may be willing to enter into gas transportation agreements with smaller producers if they have corresponding gas supply agreements with credit-worthy counterparties. For instance, APA recently built a new pipeline to Tamboran Resources' pilot project, which will help the latter supply gas to the NT government under a long-term agreement.[42]

NT producers will also have the competing option of targeting export facilities and other demand sources in Darwin. For example, Beetaloo Energy recently signed a non-binding memorandum of understanding with Australian Gas Infrastructure Group to build a new pipeline from the Beetaloo sub-basin to Darwin.[43]

Gas retailers and gentailers in eastern Australia represent another potential source of firm GTAs for APA. Relative to NT gas producers, retailers may be more willing to commit to long-term GTAs given the inherent flexibility and optionality created by their diverse gas portfolios. In addition to supplying

[42] Tamboran Resources. Tamboran enters binding agreements with APA to deliver the Sturt Plateau Pipeline. 16 December 2024.
[43] Australian Securities Exchange. Announcement: Beetaloo Energy Builds Momentum for Beetaloo Digital With AGIG Memorandum of Understanding. August 2026. Page 1.

major gas users, retailers also have the option to sell to relatively price-insensitive households, with gentailers also having the option to direct gas to their electricity generation assets.

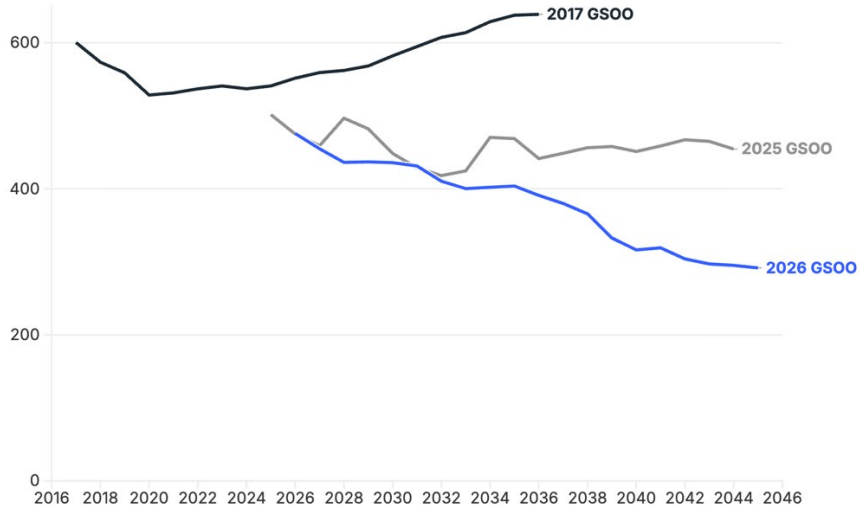
However, potential NEA pipeline shippers will likely consider not only the impact of any reservation policy on demand for Beetaloo gas, but also the potential for continued demand destruction and lower than forecast actual demand in the eastern gas market (discussed in detail in the report).

In the 2026 GSOO Central Steps scenario, AEMO forecast gas demand to fall by almost 40% from 2026 to 2045 (Figure 1), underscoring the very clear downward trend in gas demand.

Further, AEMO's 2026 forecast represented a marked shift from previous forecasts, some of which suggested either growing demand, relatively flat demand or more moderate declines. For example, AEMO's forecast demand in 2044 fell by 35% from the 2025 GSOO to the 2026 GSOO under the STEPS scenario.[44] The 2026 forecast is much lower than some earlier forecasts. The 2017 GSOO forecast gas demand of 639PJ in 2036 (the last year of the forecast period) was more than 60% higher than the 2026 forecast for that same year, of 391PJ.

In practice, the potential for further demand downgrades remains a key risk for potential NEA pipeline shippers.

Figure 1: AEMO forecasts of eastern Australia's gas demand (Central Steps scenario), PJ

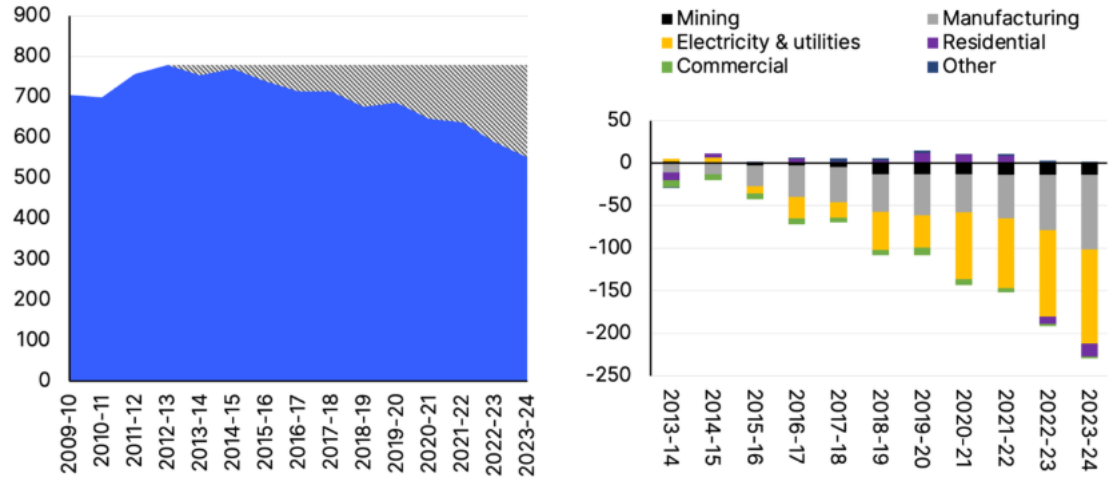


Sources: AEMO. 2026 GSOO – report figures and data. March 2026. Figure 10. AEMO. 2025 GSOO – report figures and data. March 2025. Figure 10. AEMO. 2017 GSOO supply-demand modelling output files (Neutral Scenario). 'Demand' tab.

[44] AEMO. 2026 Gas Statement of Opportunities – report figures and data. March 2026. Figure 10.

Recent trends highlight how quickly demand can fall. From FY2014–15 to FY2023–24, gas demand in eastern Australia fell by about 30%, equivalent to annualised falls of 3%, materially higher than the annualised falls forecast by AEMO (Figure 2).

Figure 2: Eastern Australia's gas demand falling across most sectors, petajoules (PJ)



Source: IEEFA. Slump in eastern Australia gas demand shows no signs of easing. September 2025.

Whether retailers and NT gas producers are willing to contract for capacity in the NEA Pipeline remains be seen in light of the potential for lower than forecast gas demand and the introduction of a reservation policy intended to slightly oversupply the domestic market. The latter also means retailers will very likely have access to sufficient gas supply from Queensland.

NT producers may be willing to contract for capacity if it provides a means for scaling up Beetaloo production, and because Beetaloo gas could potentially crowd out Queensland gas (additional gas from the NT would result in the Queensland exporters having lower domestic supply obligations under the reservation scheme). However, the high cost of Beetaloo gas, particularly once delivered to the southern states, could accelerate the rate of demand reduction, and expose NT producers to downside demand risks.

In order to contract NEA pipeline capacity on a long-term basis, potential shippers will likely need to believe that:

- The high cost of Beetaloo gas will not trigger demand reduction or greater electrification of gas demand.
- LNG produced in Queensland using Beetaloo gas will be competitive against other sources of LNG supply, meaning LNG demand will need to outstrip global LNG supply growth.

- Existing production in offshore Victoria will fall as expected and no new unanticipated supply projects are developed in eastern Australia, including offshore Victoria where several companies are progressing exploration and appraisal campaigns.

- Demand will not fall materially faster than forecast by AEMO in the period to 2045, including as a result of government policy. For instance, legislation to implement the reservation scheme sets out the potential for exporters to meet their DSOs by funding electrification of gas consumption in eastern Australia.

In IEEFA's view, it is much more likely that either Santos or GLNG contract capacity on the NEA pipeline to use Beetaloo gas to meet GLNG's domestic supply obligations (in addition to backfilling its Gladstone facility) (Table 7).

Table 7: Demand projections for Beetaloo gas if no NEA pipeline foundation contracts signed

Scenario	Assumption	Demand
Low demand	Other parties do not enter foundation contracts for the NEA pipeline.	0PJ
Central demand		0PJ
High demand		0PJ

Table 8 pulls together the sources of demand presented throughout this appendix and summarises IEEFA's demand scenarios.

Table 8: Foundation contract scenarios for estimating NEA pipeline costs and breakeven tariffs

Scenario	Foundation contracts for the NEA pipeline (capacity and term)
LNG exports	
Low demand	210PJpa for 10 years, starting in 2037
Central demand	420PJpa for 10 years, followed by 210 PJ for 5 years, starting in 2037
High demand	420PJpa for 10 years, followed by 210 PJ for 10 years, starting in 2037
Eastern Australia demand	
Low demand	0PJ
Central demand	0PJ
High demand	Forecast GLNG DSO to 2045, peaking at 86.5PJ from 2032–2035 before falling to 43.5PJ in 2045, 2% annual decline post–2045.