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Higher gas prices and unwanted supply in the pipeline from Beetaloo

APA lays out expensive pipe plan to eastern Australia amid declining domestic gas demand and a looming LNG glut

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Contents

Key Findings 4
Executive summary 5
Introduction 7
APA's proposed Beetaloo pipeline will be expensive 8
Demand scenarios 8
Capital and operating costs 9
Breakeven tariffs 10
Beetaloo gas to Gladstone would sink LNG exports 11
Costs materially exceed expected revenue 11
Global LNG markets face oversupply and low prices 12
Beetaloo gas may be surplus or inflationary on east coast 15
Domestic gas demand forecast to fall in coming decades 17
Beetaloo production uncertainty poses risk to pipeline 18
The pipeline may create financial strain for APA 19
Debt could worsen its highly leveraged balance sheet 19
Pipeline could affect shareholder distributions 21
Higher profits or valuation not necessarily in the pipeline 21
Other investment opportunities may be missed 22
Conclusion 23
About IEEFA 25
About the Authors 25

Figures and tables

Figure 1: Beetaloo gas much more costly than export and domestic alternatives 6
Figure 2: APA's gas pipeline network in the Northern Territory, including the NEA pipeline 8
Figure 3: Beetaloo gas uncompetitive to Gladstone and exported from Gladstone 12
Figure 4: Global LNG capacity additions, MTPA 13
Figure 5: Beetaloo gas delivered to Melbourne uncompetitive with Queensland gas, AU$/GJ 16
Figure 6: AEMO demand forecasts have fallen in recent years, PJ 17
Table 1: Demand scenarios for cost and tariff estimates 9
Table 2: Estimated capital costs for the NEA pipeline 9
Table 3: Estimated breakeven gas tariffs for the NEA pipeline 10

Key Findings

APA has stated the Beetaloo is largely intended as an "export play", but using Beetaloo gas to backfill Queensland LNG plants is unlikely to be financially viable.

Demand for Beetaloo gas is highly uncertain given falling gas demand in eastern Australia, uncertain demand growth in LNG markets and a looming LNG supply glut.

Financing the pipeline project will materially increase APA's already high debt, potentially affecting the company's credit rating and shareholder distributions if it stretches APA's finances too far.

Investing in new gas infrastructure will affect APA's ability to invest in electricity transmission and generation assets at a time when electricity demand is forecast to boom.



Executive summary

The Beetaloo sub-basin has been promoted as Australia's next major gas producing province, and a solution to emerging gas shortfalls in eastern Australia in the early 2030s.

However, the Beetaloo, part of the McArthur Basin in the Northern Territory, is remote, far from gas users, and existing gas transmission networks linking the NT and eastern Australia have limited capacity. APA Group, Australia's largest gas pipeline operator, plans to build the 1,561km North to East Australia (NEA) pipeline to supply Beetaloo gas for both domestic use and for LNG exports from Gladstone in Queensland.

IEEFA's analysis raises substantial questions about the financial case for the pipeline, due to its high costs, and uncertain future demand in both domestic and LNG markets.

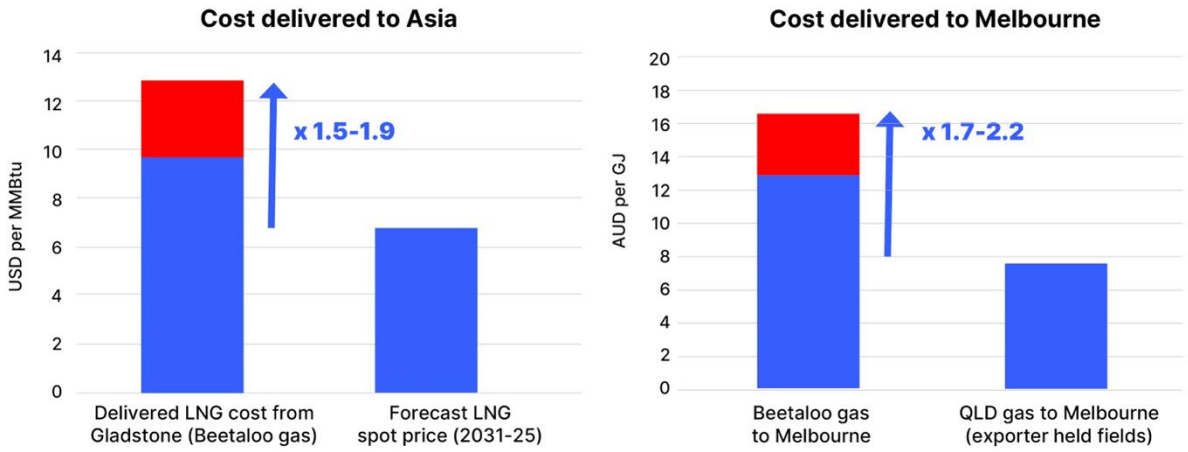
The most prospective source of demand for the pipeline is the Gladstone LNG (GLNG) project, which may need to source new gas to meet both its upcoming domestic requirements and any renewed LNG export commitments. Other potential customers are likely to have much more cost-effective options to choose from, particularly with a new reservation policy likely to increase gas supply from Queensland. However, GLNG's demand for gas to feed LNG exports is uncertain in light of a looming global supply glut and highly uncertain future demand in Asian markets, which were expected to absorb the large increase in global supply. GLNG also has more than 6000 petajoules (PJ) of gas reserves and resources in the Surat Basin it could develop before seeking gas from the Beetaloo.

Based on a range of potential demand scenarios, IEEFA estimates capital costs for the NEA pipeline of AU$5.3–7.1 billion, and costs could be even higher given APA is seeking regulatory approval for a pipeline of up to 48 inches, which IEEFA conservatively estimates would cost AU$8.3bn.

High capital costs will likely translate into high tariffs. Assuming APA sets tariffs to fully recover its costs through foundation gas transportation agreements (GTAs), IEEFA estimates breakeven effective tariffs of AU$2.01–3.76 per gigajoule (GJ) for modelled demand scenarios (see Appendix for more information). This is in addition to Beetaloo gas production costs, which are already estimated to be relatively expensive, from AU$7.00–9.15/GJ.

APA has stated the Beetaloo is largely intended as an "export play", and GLNG Joint Venture partner Santos has stated that Beetaloo gas is dependent on LNG exports. However, using Beetaloo gas to backfill Queensland LNG plants is unlikely to be financially viable. IEEFA estimates delivered LNG costs of US$9.8–12.7 per million British thermal units (MMBtu), significantly higher than both the IEA's recent forecast of US$6.80/MMBtu in 2035, and Goldman Sachs' forecast Asian LNG spot price of US$6.75/MMBtu from 2031–35. These results suggest gas supplied by the pipeline would be too expensive to make financial sense for GLNG (and other exporters), undermining the financial case for the project.

Figure 1: Beetaloo gas much more costly than export and domestic alternatives



Source: IEEFA.

In the domestic market, IEEFA estimates Beetaloo gas at AU$11.10–14.80/GJ delivered to Wallumbilla in Central Queensland or AU$12.8–16.4/GJ to Melbourne. This compares with average prices in July–October 2026 of AU$10/GJ. The lower end of the range corresponds to the pipeline serving large volumes of both domestic and export markets, while the higher end corresponds to the pipeline meeting a smaller amount of demand.

This has two possible implications: GLNG could develop its own reserves for a much lower cost than purchasing gas from the Beetaloo, meaning the pipeline may not be needed or; if Beetaloo gas is used to supply the domestic market, it will push up prices materially.

Availability of gas to fill the pipeline also presents another risk. The Beetaloo sub-basin is still in the appraisal phase and has not yet been proven as commercially viable. In practice, the timing and volumes of any future gas production remain uncertain, creating a risk around the availability of gas.

Financing the pipeline may also present challenges given APA's high debt levels, with any increase in debt possibly affecting the ratio of funds from operations (FFO) to debt (a key metric used to determine APA's credit rating). Major rating agency S&P indicated APA would need to maintain an FFO to net debt ratio threshold of at least 8.5%, which IEEFA estimates leaves a maximum "headroom" of about AU$4bn, with actual headroom likely to be lower due to committed capital expansions. This is much lower than estimated pipeline capital costs of AU$5.3–72bn, which IEEFA notes may require additional debt before operations, and therefore revenue.

Additional debt obligations could limit the ability of APA Group to invest in electricity infrastructure at a time when growing electricity demand is increasing the need for investment.

More details on the parameters and assumptions underpinning this report's findings can be found in a separate Appendix and Technical Appendix.

Introduction

The Beetaloo sub-basin has largely been promoted by a small band of explorers, backed by the Northern Territory government and US shale gas investors.[1,2] It was first identified as a prospective oil and gas basin in the 1980s, but its shale gas potential only gained attention in the 2000s.[3,4]

Despite decades of exploration, the Beetaloo is only now in the early stages of commercial development. Tamboran Resources' Shenandoah South pilot project, one of the two pilot projects in the basin, only commenced sale gas flows in September 2026.[5,6] This pilot project could be significant in determining the economics of large-scale gas production from the region.

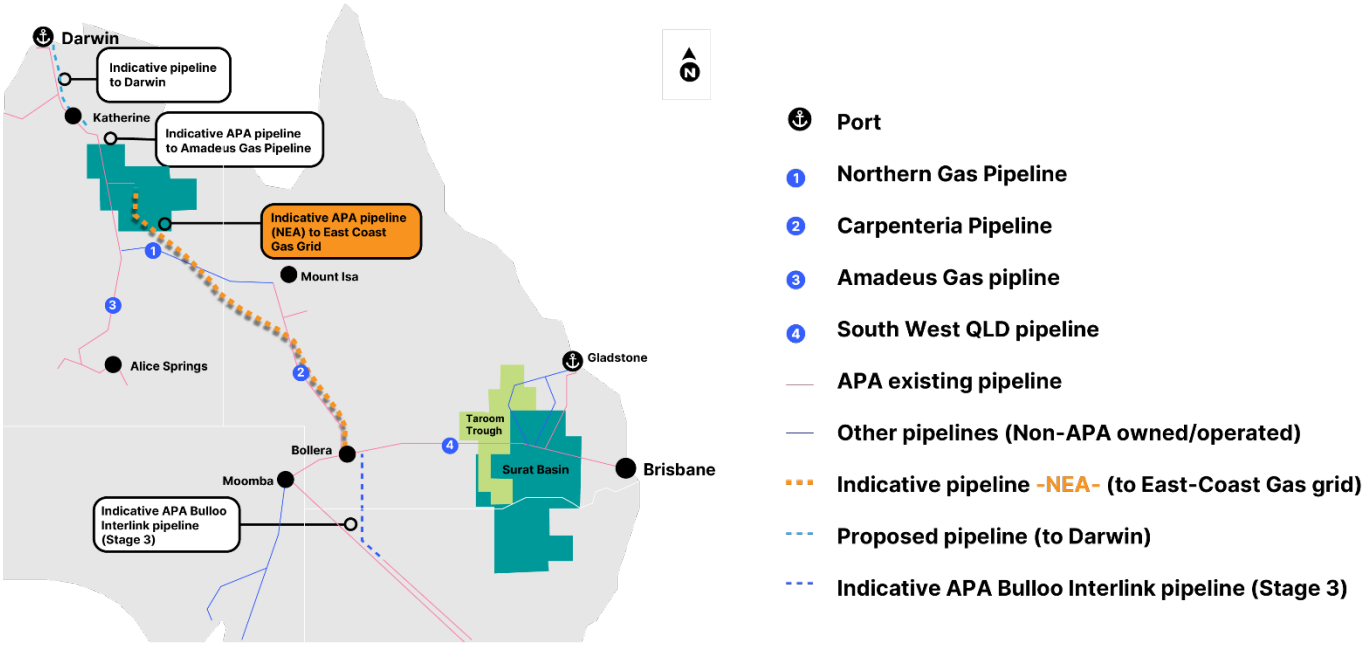
The remoteness of the basin means significant new transmission infrastructure is required for large-scale development of the resource.

APA Group announced a Beetaloo pipeline plan in 2021, first working with Australian gas producer Empire Energy (now called Beetaloo Energy) and then with Tamboran Resources; in late 2025, APA revised plans into the NEA pipeline without involving any gas producer (Figure 2).[7]

If built, the NEA pipeline would link the Beetaloo sub-basin via a proposed 1,561km pipeline to the South West Queensland Pipeline (SWQP) pipeline at Ballera in southern Queensland.[8] This would allow the gas to then flow to other demand centres, including Gladstone, Melbourne and Sydney. With APA seeking approval for a pipeline with a diameter of up to 48 inches (which could have a capacity of 2,000 terajoules/TJ a day), there may may also be a need for additional investment to expand capacity at APA's SWQP (which has a capacity of 340–512TJ/day).[9,10]

[1] The Northern Territory government. Beetaloo Sub-basin. Accessed 24 July 2026.
[2] The Australian. Tamboran CEO Joel Riddle exits as US investors tighten grip on Beetaloo gas developer. 28 July 2025.
[3] Australian government. Department of Industry Science and Resources (DISR). Beetaloo Strategic Basin Plan. Gas industry activity.
[4] AGES 2017 Proceedings. NT Geological Survey. Proterozoic shale gas plays in the Beetaloo Basin and the Amungee NW-1H discovery. *Close, D. et al*. Page 92.
[5] Tamboran Resources. Tamboran Delivers First Gas Sales from the Beetaloo Basin. 8 September 2026.
[6] Beetaloo Energy. Beetaloo Operations Update. 1 July 2026. Page 4.
[7] APA. APA granted permit to survey potential North to East Australia Pipeline route. 17 December 2025.
[8] APA. North to East Australia Pipeline Project. Accessed 24 July 2026.
[9] APA. APA NEA Pipeline Stage 2 Project: Initial Advice Statement. July 2026. Page 12.
[10] Australian Energy Market Commission. QLD: South West Queensland Pipeline.

Figure 2: APA's gas pipeline network in the Northern Territory, including the NEA pipeline



Source: APA Group.[11]

The NEA pipeline is still in the scoping phase, and APA has not confirmed pipeline capacity or cost. It has indicated the planning phase will take two years, and the construction phase a further three years. APA expects it to start operating between 2032 and 2034.[12,13]

APA guidance suggests it is targeting final investment decision from 2028, but this will be contingent on Santos and other explorers proving sufficient gas reserves in the Beetaloo. This creates uncertainty about timing given the unpredictability associated with exploration and appraisal campaigns.

APA's proposed Beetaloo pipeline will be expensive

Demand scenarios

IEEFA reviewed all the potential sources of demand for Beetaloo gas on Australia's east coast. The most prospective source of demand for the pipeline is the GLNG project, which needs to source new gas to meet both its upcoming domestic requirements and to supply its LNG exports. Other potential

[11] APA Group. Investor Presentation FY26 half-year results. 19 February 2026. Page 13.
[12] APA Group. North to East Australia Pipeline Project.
[13] APA Group. Annual Report 2026. 20 August 2026. Page 91.

customers are likely to have much more cost-effective options. Even the GLNG project's demand is uncertain, given the owners have undeveloped gas reserves in the Surat Basin they could use instead, and that LNG exports could decline materially in the context of a looming global supply glut and plateauing demand growth in Asian markets, which were expected to absorb the large increase in global supply.

Based on this analysis, IEEFA has developed several demand scenarios for the purpose of estimating capital, operating and decommissioning costs for the NEA pipeline (Table 1, see Appendix for further discussion).

Table 1: Demand scenarios for cost and tariff estimates

Scenario	Foundation GTAs for the NEA pipeline (capacity and term)
LNG exports	
Low demand	210PJ pa for 10 years, starting in 2037
Central demand	420PJ pa for 10 years, followed by 210PJ for 5 years, starting in 2037
High demand	420PJ pa for 10 years, followed by 210PJ 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

*Notes: *DSO = domestic supply obligation. Assumptions around foundation GTAs have a large influence on estimated costs. This is because higher demand is assumed to directly translate into larger pipeline capacity, which in turn requires a larger diameter. In practice, pipeline diameter is one of the key cost drivers. IEEFA implicitly assumes the pipeline would be sized to meet demand under GTAs.*

Capital and operating costs

Based on these scenarios, IEEFA estimates APA's proposed new pipeline will have a capital cost of AU$5.3–7.1bn, which would make it the most expensive gas pipeline ever built in Australia (Table 2). If APA were to proceed with a 48-inch pipeline, it would have an estimated capital cost of AU$8.3bn.

Table 2: Estimated capital costs for the NEA pipeline

Scenario	Pipeline capacity (TJ/day)	Pipeline capital costs (AU$bn)
Low demand	575	5.2
Central demand	1,151	6.7
High demand	1,332	7.1
Approval capacity	2,042	8.3

The majority of the NEA pipeline cost (for all pipeline sizes modelled) is the actual pipeline itself, which is estimated at AU$4.9–6.7bn. IEEFA notes, however, that we have used relatively

conservative pipeline cost estimates (of AU$104,000 per inch/km). Rystad, for instance, used an estimate of AU$130,000 per inch/km in its upper-bound cost estimate for the pipeline.[14] Adopting this cost parameter would escalate IEEFA's estimated total capital costs to AU$6.4–8.8 billion for the modelled scenarios, and AU$10.2 billion for a 48-inch pipeline.

Operating costs add further to the estimated costs of the project, with IEEFA estimating annual costs at AU$110–150 million in standard years, and as high as AU$180m every 10th year due to the need for sustaining investment. This does not include the costs of gas required to power compressors.

APA may face additional pipeline investment costs to upgrade capacity on the SWQP, but IEEFA has not explicitly modelled those costs. IEEFA notes, however, that existing capacity of about 340TJ/day is not sufficient to transport the volume of gas required under our low-demand scenario. IEEFA's high-demand scenario would require eastward capacity on the SWQP to increase several times over. In practice, this would require significant investment in new compression, looping and potential duplication of the pipeline. IEEFA notes that the use of swaps could address some of the limitations, but there would still be a need for large investments in high-demand scenarios.

Breakeven tariffs

Given the large cost of the pipeline, and APA's demonstrated approach of not reaching final investment decision without foundation GTAs that provide return on investment, it is likely APA will seek to fully recover pipeline costs from foundation shippers (through set tariff structures).[15,16]

IEEFA estimates "breakeven tariffs" for the NEA pipeline of AU$2.01–3.76/GJ depending on the volume and term of foundation GTAs (Table 3). While the estimated tariffs are not intended to provide a breakdown of specific tariff components (i.e. capacity vs throughput charges), they do provide an indication of the tariffs required to fund the NEA pipeline under our demand scenarios.

Table 3: Estimated breakeven gas tariffs for the NEA pipeline

Scenario	Pipeline capacity (TJ/day)	Pipeline diameter (inches)	Breakeven tariff (AU$/GJ)
Low demand	575	29.6	3.76
Central demand	1,151	38.6	2.01
High demand	1,332	40.9	2.03

Crucially, the high tariffs will add to the already (relatively) high Beetaloo production costs, meaning Beetaloo gas delivered to eastern Australia will be expensive.

[14] Rystad Energy Advisory Asia Pacific. LNG Import Competitiveness. Final Report (Short version). Page 12.
[15] APA Group. Annual Report 2026. 20 August 2026. Page 95.
[16] Australian Financial Review (AFR). APA Group to spend half its capex on WA pipeline. 25 November 2020.

Beetaloo gas to Gladstone would sink LNG exports

Costs materially exceed expected revenue

Beetaloo production costs are likely to be high, with estimates ranging from AU$6.84/GJ in the now dated 2024 Future Gas Strategy to AU$9.15/GJ in the Australian Energy Market Operator (AEMO)'s 2026 Gas Statement of Opportunities (GSOO) (based on costs for the two pilot production projects).[17,18] APA's latest guidance suggests a production cost of AU$7.24/GJ once the basin reaches scale (but it is not clear if this includes development costs).[19]

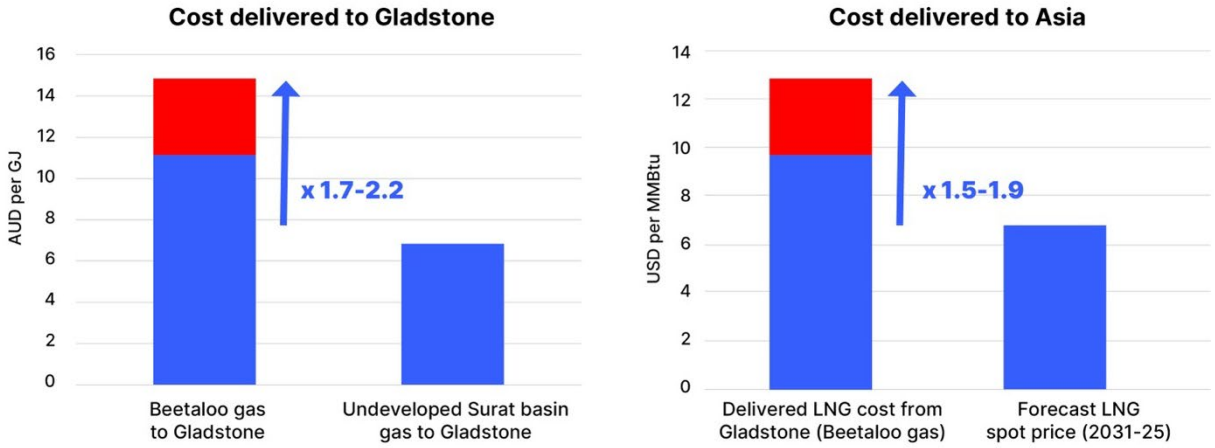
The added cost of transporting Beetaloo gas more than 2,800km to provide feedgas at a Gladstone LNG plant would make it more expensive than Queensland gas. Based on a Beetaloo production cost range of AU$7.24–9.15/GJ, and a tariff range of AU$2.01–3.76/GJ, IEEFA estimates Beetaloo gas would cost AU$11.10–14.80/GJ to be delivered to Gladstone (Figure 3, left).

Adding in LNG production and shipping costs, IEEFA estimates Beetaloo gas exported from Queensland to North Asia would have a landed cost of US$9.8–12.7/MMBtu (Figure 3, right). While this is lower than 2026 market pricing, it is well above long-term LNG supply costs and price forecasts in light of surging new global LNG supply.

In November 2026, the International Energy Agency (IEA) forecast a gas import price in Japan (Australia's largest buyer) of US$6.80/MMBtu in 2035 (under its Stated Policies scenario or STEPS), and Goldman Sachs recently forecast spot prices to fall to US$6.75/MMBtu in 2031–35 (with prices possibly even lower).[20,21]

[17] DISR. Future Gas Strategy Analytical Report. May 2024. Page 90.
[18] AEMO. 2026 GSOO supply data. Reserves Costs assumptions. Production Costs. March 2026.
[19] APA. Investor Presentation: FY26 Full-year results. August 2026. Page 44.
[20] International Energy Agency (IEA). World Energy Outlook 2026. November 2026. Page 118.
[21] Gas Outlook. The looming LNG bust. 11 November 2026.

Figure 3: Beetaloo gas uncompetitive to Gladstone and exported from Gladstone



Sources: IEEFA estimates; Gas Outlook. The Looming LNG bust. November 2026; DISR. Future Gas Strategy Analytical Report. May 2024. Page 90. Note: IEEFA assumes zero marginal costs for transporting gas from Wallumbilla/Surat Basin to Gladstone. While there may be marginal transport costs, IEEFA notes these are likely to be negligible and would apply to Beetaloo and Surat gas alike.

The costs of Beetaloo LNG are also potentially above the price levels that will be required to drive sufficient new demand to absorb locked-in LNG supply growth (see next section). For example, the chief executive of Petronet (India's largest LNG buyer) noted that prices around US$6–7/MMBtu, "will be a comfortable price range to improve LNG consumption in India" (South Asia is considered one of the key growth opportunities for the sector).[22,23] In 2025, the IEA also noted LNG prices of US$5/MMBtu would be needed to trigger material coal-to-gas switching.[24]

Finally, IEEFA notes our cost estimates are conservative as they do not account for any potential costs associated with expanding eastward capacity on the SWQP, which would likely be required to transport sufficient volumes to meet LNG demand (under IEEFA's demand scenarios). The SWQP has eastward capacity of 340TJ/day (enough to produce 2.24 million tonnes/Mt of LNG), below the 525TJ/day capacity required under IEEFA's low-demand scenario.[25]

Global LNG markets face oversupply and low prices

The global LNG market outlook remains uncertain amid surging new supply and questions about structural growth in demand, both of which could mean there is no market for LNG produced using Beetaloo gas. With respect to the NEA pipeline, the potential for lower LNG prices (due to oversupply and weak demand) creates financial risks for shippers intending to export Beetaloo gas via Gladstone.

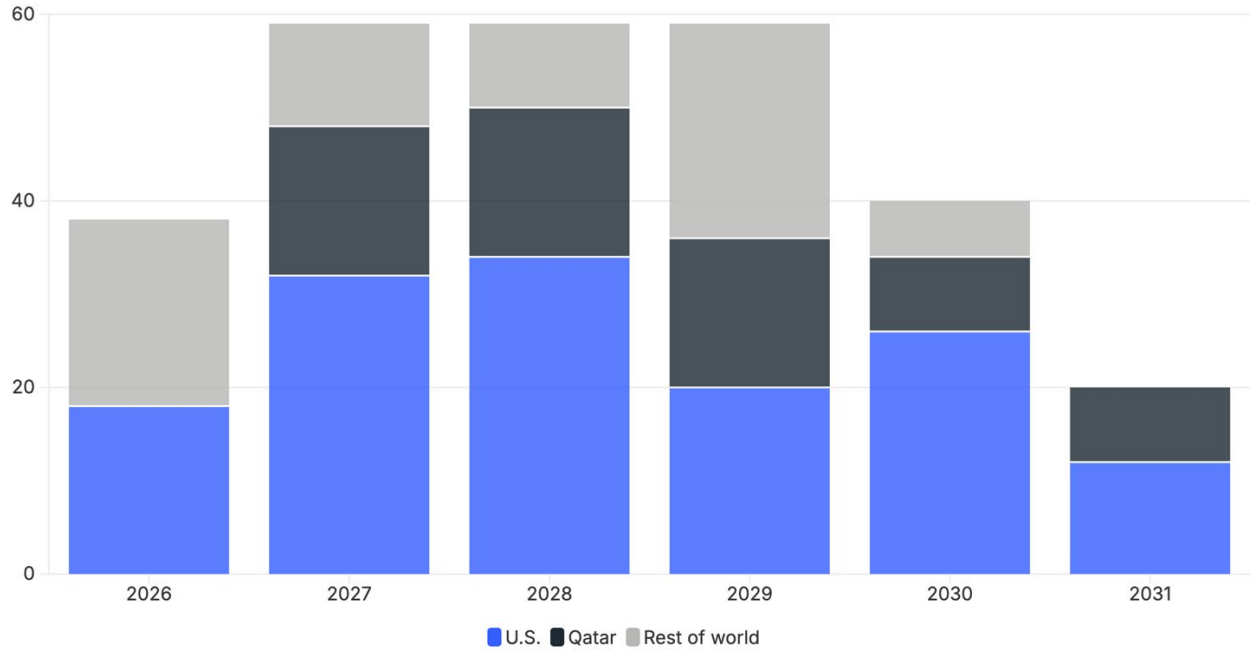
[22] Gas Processing & LNG. India's LNG demand set to grow across industries-if prices cooperate. January 2026.
[23] Shell. Shell LNG Outlook 2026. June 2026. Pages 4 and 25.
[24] IEA. World Energy Outlook 2025. November 2025. Page 73.
[25] APA. South West Queensland Pipeline (SWQP).

IEEFA estimates that from 2025 to 2031, global LNG supply capacity will expand by about 274Mt, or more than 13,000PJ (Figure 4), based on projects that are effectively locked in. This marks an unprecedented increase of about 52% in global capacity compared with the end of 2025 (524.5Mt).[26]

The risks of oversupply have been noted by the International Gas Union, the peak body for the global gas industry. It stated that the massive ramp-up in capacity would be sufficient to meet LNG demand until at least 2035, and that the sector faces downside risks due to two crises in less than five years.[27,28]

There have already been examples of anticipated LNG demand disappearing due to events in the Middle East. In China, Sinopec has cancelled a planned LNG import terminal expansion, with these funds being reallocated to a domestic gas supply project.[29] China's imports have effectively flatlined.

Figure 4: Global LNG capacity additions, MTPA



Source: IEEFA estimates.

South Korea has flagged it intends to restart shuttered nuclear facilities and fast track renewable energy projects, which IEEFA estimates could replace up to 6Mt of LNG imports each year.[30] South Korea's president noted the need for an urgent pivot to renewable energy due to the inherent risks of

[26] International Gas Union (IGU). 2026 World LNG Report. July 2026. Page 11.
[27] Ibid. Page 17.
[28] Ibid. Page 59.
[29] Chemnet. China Petroleum & Chemical Corporation Terminates Two Major Projects, Adjusting Over 8 billion Yuan in Fundraising. 30 March 2026.
[30] IEEFA. The Iran conflict is cutting the long-term role of LNG in Asia. April 2024.

fossil fuel reliance, stating, “Our future will be at serious risk if we continue to rely on fossil fuels.”[31] South Korea has been Australia’s third-largest LNG export market over the past decade.[32]

Other countries in Asia are looking to increase nuclear generation, including Bangladesh, Taiwan and Japan.[33] Taiwan is particularly illustrative as it had not long shuttered its remaining nuclear plants before the Iran conflict prompted an abrupt about-face.

China, South Korea, Japan and Taiwan are all key markets for Australian LNG exports.[34]

Thailand, the largest importer in Southeast Asia, has implemented measures to increase solar generation.[35] Its Energy Minister noted, “the ongoing conflict in the Middle East demonstrates that we must urgently reduce imports of LNG and other fuels. We need to build a cleaner and more self-reliant power system.”

While industry forecasts often still suggest strong LNG demand growth in response to new supply additions, it is notable forecasts have nonetheless fallen from those in previous years. For example, Shell’s 2026 LNG Outlook forecast was lower than the 2024 Outlook, and industry consultancy Rystad has also reduced Asian LNG demand forecasts due to a lack of investment in infrastructure and the rollout of renewable energy.[36]

Sharp price falls in solar photovoltaic cells and grid-scale batteries have driven, at least in part, a rise in renewable energy projects in the Asia-Pacific region that will provide more competition to gas-fired power generation.[37]

In addition, a global gas turbine shortage is adding to gas generation project timelines and costs, and therefore providing challenges to LNG power project proponents.[38] IEEFA has reported that wait times for closed-cycle gas turbines (which are mainly used for baseload power given their relative efficiency) had pushed out to eight years.[39] In contrast, timelines for solar and wind projects can be as short as one year, meaning any delays in procuring gas turbines may create opportunities for greater adoption of renewables.[40] Falling battery costs may also affect the rollout of peaker gas plants, with Wood Mackenzie finding that four-hour battery storage costs less than open-cycle gas generation (i.e. peakers) in 43 markets modelled.[41]

[31] Asia News Network. South Korean President Lee calls for gas renewable pinot, says energy crisis keeps him up at night. 31 March 2026.
[32] IEEFA. Australian Gas and LNG Tracker. December 2025.
[33] IEEFA. The Iran conflict is cutting the long-term role of LNG in Asia. April 2024.
[34] DISR. Future Gas Strategy. Remaining a reliable trading partner for LNG and low-emissions gases.
[35] Bloomberg. Thailand to Shift From LNG Toward Renewables in Wake of Iran War. August 2026.
[36] Shell. Shell LNG Outlook 2026. June 2026. Page 4.
[37] IEEFA. Renewables are now the clear solution to Asia’s energy trilemma. July 2026.
[38] IEEFA. Global gas turbine shortages add to LNG challenges in Vietnam and the Philippines. October 2025. Page 4.
[39] Ibid.
[40] Ibid. Page 19.
[41] Wood Mackenzie. Four-hour battery storage now beats gas peaking on cost globally. 8 October 2026

In reality, structural LNG demand growth faces headwinds given the geopolitical supply interruptions and the increasing rollout of lower-cost renewables and battery storage. This has implications for shippers intending to contract for capacity in the NEA pipeline to support exports from Gladstone. Without a large, sustained growth in structural LNG demand that absorbs looming supply additions and supports high prices, Beetaloo gas via Gladstone is simply not competitive with other LNG supply sources.

Beetaloo gas may be surplus or inflationary on east coast

The cost of transporting Beetaloo gas to eastern Australia will make it more costly than alternative sources of gas from Queensland, meaning it will either not be competitive (in a well-supplied market) or will be the marginal supply source and therefore push up wholesale gas prices.

With estimated gas production costs of AU$7.24–9.15/GJ, the costs of Beetaloo gas delivered to remote south-west Queensland could be as high as AU$9.3–12.9/GJ. This compares with estimated costs of AU$6.7/GJ for undeveloped Surat Basin fields, and much lower costs for producing fields. Santos reports production costs of US$7.04 per barrel of oil equivalent (boe) or (AU$1.73/GJ),[42] while the Australia Pacific LNG (APLNG) Project off Gladstone reported total LNG production cost (including gas and liquefaction costs) of just AU$4.23/GJ (in FY2025–26).[43]

Transporting Beetaloo gas to domestic gas consumers, particularly in southern states, will add further costs. IEEFA estimates the cost of Beetaloo gas delivered to Sydney at AU$11.8–15.5/GJ, and to Melbourne at AU$12.8–16.4/GJ (Figure 5). The lower end of the range corresponds to the pipeline serving large volumes of both domestic and export markets, while the higher end corresponds to the pipeline meeting a smaller amount of demand.

Our low-demand scenario does not account for any domestic demand. In practice, if GLNG were to use Beetaloo gas for its export plan, some would likely flow to the domestic market (with GLNG using some of its lower-cost production from the Surat Basin to “top up” feedgas to its export plant). This means Beetaloo gas costs could set or influence domestic prices even if the pipeline is sized purely to meet an export commitment.

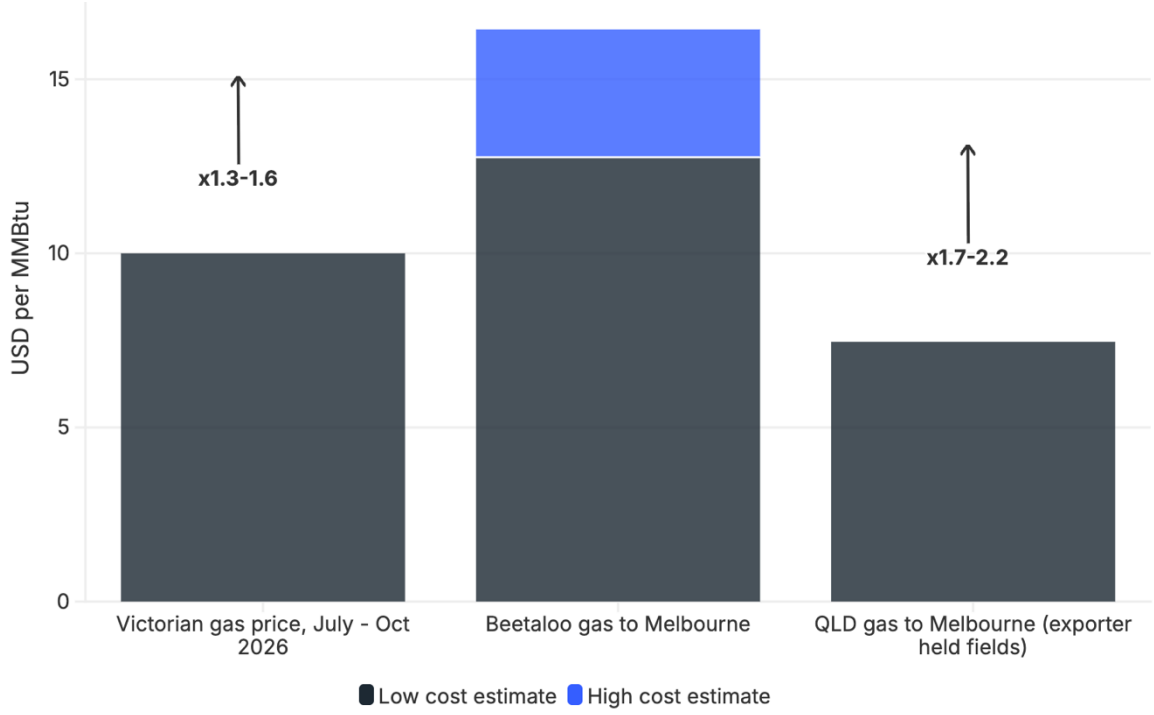
The cost delivered to Melbourne would be materially higher than prices in Victoria’s declared wholesale gas market from July to September 2026, which were about AU$10/GJ.[44]

Adding transport costs, Queensland gas from fields held by exporters delivered to Melbourne is estimated to cost AU$7.45/GJ (based on AU$4/GJ cost for fields held by exporters and transport

[42] Santos. 2025 Full-Year Results. 18 February 2026. Page 21.
[43] Origin Energy. Full year results 2026. Presentation to investors and analysts. 13 August 2026. Page 34.
[44] Australian Energy Regulator. Gas market prices. Accessed 17 November 2026.

costs), or 42–55% below the cost of supply from the Beetaloo.[45,46] Undeveloped Queensland gas is also less costly, at AU$11.35/GJ (based on AU$6.70/GJ cost for undeveloped Surat gas), or 20–38% less costly.

Figure 5: Beetaloo gas delivered to Melbourne uncompetitive with Queensland gas, AU$/GJ



Sources: IEEFA estimates; DISR. Future Gas Strategy Analytical Report. May 2024. Page 90; AEMO. DWGM data dashboard. Accessed 13 November 2026.

GLNG using Beetaloo gas to meet its domestic supply obligation (DSO) would have two implications:

- Domestic prices will increase materially if GLNG is the marginal price setter (as would likely be the case), which could lead to significant domestic backlash and/or trigger domestic demand destruction.
- If prices do not increase above contemporary levels, GLNG will be unable to recover the high costs of Beetaloo gas and will incur a loss on domestic sales. If GLNG anticipates prices not rising enough or export earnings not being sufficiently high to cross subsidise domestic supply, it might be better placed to develop and utilise its remaining reserves in the Surat Basin.

[45] DISR. Future Gas Strategy Analytical Report. May 2024. Page 80.
[46] IEEFA. Without reservation, Beetaloo gas could increase domestic prices by 50%. November 2026.

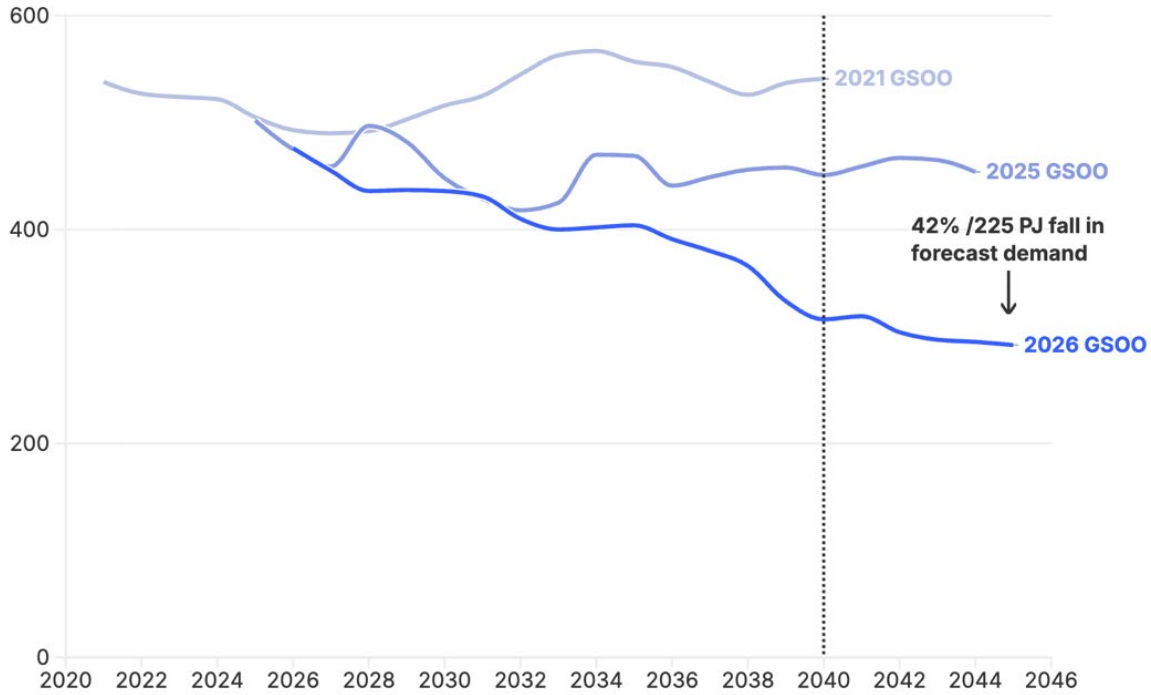
Domestic gas demand forecast to fall in coming decades

Declining gas demand in eastern Australia presents a key financial risk for the pipeline and potential shippers. Given its high cost, Beetaloo gas is likely to be the first source of gas displaced if domestic demand falls quickly. This translates to a direct financial risk for shippers in the pipeline, which will need to pay tariffs even when not using or underutilising the pipeline.

Gas demand is in structural decline in eastern Australia, dropping 30% between FY2012–13 and FY2024–25, and is projected to drop by further 41% by 2045.[47,48] This reflects, in part, renewables scaling up both at household and commercial level, and electrification of gas load.

Crucially, there is uncertainty about future demand levels, and AEMO has revised down its forecasts in recent years (Figure 6), underscoring the risks of demand falling faster than anticipated. For example, AEMO's Gas Statement of Opportunities reduced its 20-year eastern Australia gas demand forecast by 1,594PJ from the 2025 to 2026 reports. This equates to about three years of eastern Australia gas demand in FY2023–24.[49]

Figure 6: AEMO demand forecasts have fallen in recent years, PJ



Sources: AEMO GSOOs 2021, 2025 and 2026.

[47] Department of Climate Change, Energy, the Environment and Water (DCCEEW). Australian Energy Update 2026. Table F.
[48] AEMO. 2026.GSOO - report figures and data. Figure 10.
[49] Ibid.

The decline in projected gas demand in eastern Australia by AEMO may still be conservative. The 2026 GSOO forecasts industrial gas demand to drop by 24% by 2045, which would mark a slowdown in the rate of demand destruction in eastern Australia.[50] Manufacturing gas demand fell 34% between FY2012–13 and FY2024–25.[51]

The newly implemented gas reservation scheme also has implications for the financial case for the NEA pipeline. Because it will increase supply of Queensland gas to the domestic market, it will inherently reduce the amount of domestic demand that otherwise could have been met with Beetaloo gas.[52]

Finally, the potential for higher than forecast gas production in eastern Australia presents another risk, as higher production would reduce the need for Beetaloo gas. Several gas companies have ramped up exploration in the Otway Basin offshore Victoria and South Australia, and several companies are exploring Queensland's Taroom Trough, which is estimated to hold at least 4.97 trillion cubic feet (5,243PJ) of gas contingent resources, which is the pre-commercial stage.[53,54] APA clearly recognises the trough's potential, and is conducting a feasibility study on infrastructure to connect it to the Wallumbilla gas hub, which sits on the trough.[55]

Beetaloo production uncertainty poses risk to pipeline

The timing and utilisation of the NEA pipeline will also depend on the Beetaloo gas producers and explorers booking and converting significant commercial gas reserves into production to fill the pipeline. Exploration and development of gas resources in the Beetaloo sub-basin are in the early stages, with few companies active in the area; larger scale development will rely on exploration activities demonstrating commerciality.

Santos, the largest company active in the Beetaloo, indicated it does not plan to sanction any gas development there for at least two years.[56] It has flagged a 500TJ/day development concept if its 2027 exploration and appraisal drilling campaign is successful (possibly expanding to 3,000TJ/day).[57]

Tamboran Resources is the only company actively producing sales gas in the Beetaloo, with production from its Shenandoah South pilot project commencing in September 2026. It will ramp up to 40TJ/day in early 2027, with this gas already contracted to the Northern Territory government.

[50] AEMO. Gas annual consumption. Industrial 2026-2045. Accessed 20 August 2026.
[51] DCCEEW. Australian Energy Update 2026. September 2026. Table F.
[52] Minister for Climate Change and Energy. Joint media release: Landmark legislation to secure Australian gas for industry and households. 14 October 2026.
[53] Elixir Energy. Good Oil and Gas. Essential Energy Conference Presentation. 15 September 2026. Page 14.
[54] Omega Oil and Gas. Unlocking a New Basin-Scale Play. June 2026. Page 11.
[55] Proactive Investors. Elixir advances Taroom gas commercialisation with APA feasibility deal. 10 April 2026.
[56] Investing.com. Earnings call transcript: Santos lifts h1 2026 output as barossa, pikka ramp. 19 August 2026.
[57] Santos. 2026 Investor Briefing Day. 26 May 2026. Page 47.

Plans for further expansion from 2028 and delivery of gas in the 2030s will depend on the success of its pilot project (Tamboran has yet to provide any guidance).[58,59,60]

Beetaloo Energy is also developing a pilot project, which will supply the Northern Territory government.[61] The project remains in the appraisal phase, with reserves not yet proven.[62]

Beetaloo shale gas has been compared to some of the US shale-producing basins (which turned the US into the world's largest LNG exporter).[63,64] However, it has taken a long time for the US industry to become profitable given the significant investment required to scale its shale gas production. Around US$1.2 trillion was spent on the oil and gas sector in the US between 2010 and 2019[65], a period in which US shale gas and oil production rose significantly.[66] On the journey to profitability, the industry underwent consolidation.[67]

The lesson from the US suggests significant investment will be required, investment that may not arise as companies in the Beetaloo shale sector do not have the financial balance sheets to carry years of losses before reaching profitability.

Put simply, the financial case for the NEA pipeline rests on whether Beetaloo gas is commercially viable, which remains to be seen.

The pipeline may create financial strain for APA

Debt could worsen its highly leveraged balance sheet

The financing of the AU$5.3–7.1bn NEA pipeline is likely to require significant debt financing, adding considerably to APA's large existing debt. This, in turn, could cause rating agencies to reassess its credit rating, limiting its ability to maintain its relatively high investor distributions and affect its ability to invest in other energy opportunities.

The NEA pipeline, like other large energy infrastructure projects, is likely to be majority debt funded, in part because APA's cost of debt is likely to be lower than the cost of equity. Taking on material amounts of new debt would increase debt repayment obligations and could result in higher

[58] Tamboran Resources. 3Q FY26 Result Presentation. 13 May 2026.
[59] Tamboran Resources. Tamboran delivers first gas sales from the Beetaloo Basin. 7 September 2026.
[60] Tamboran Resources. 2Q FY26 Results Presentation. 12 February 2026. Pages 6–7.
[61] Beetaloo Energy. SEAAOC Conference 2026 Presentation. September 2026.
[62] Small Caps. Beetaloo Energy Granted Retention Licence for Carpentaria Shale Gas Fairway. November 2026.
[63] Tamboran Resources. Equity Raising to Unlock and Accelerate Development in the Beetaloo Basin. 8 April 2026. Page 9.
[64] US Energy Information Administration. In-brief analysis. Ten years after first Sabine Pass cargo, US LNG exports are still on the rise. 24 February 2026.
[65] Federal Reserve Bank of Dallas. Falling oil prices drag down U.S. business investment. 14 May 2020.
[66] US. Energy Information Administration (EIA). U.S. crude oil production grew 11% in 2019, surpassing 12 million barrels per day. 2 March 2020
[67] US EIA. M&A activity in 2023 furthers consolidation of U.S. crude oil and natural gas firms. 19 March 2024.

obligations relative to funds from operations (FFO) both during the construction phase and over the longer term.

APA's debt levels are already high, equivalent to more than five times its equity level of AU$2.7bn (as of June 2026).[68,69] All other things being equal, an additional AU$4bn in debt could push its debt-to-equity ratio to 6x. In general, higher leveraging increases financial risk (as changes to the cost of debt will have a larger impact on FFO to debt servicing obligation), and could lead investors to seek higher equity risk premiums.[70]

APA's debt levels are high relative to similar publicly listed gas infrastructure companies overseas. For example, European gas infrastructure companies Snam and Enagas have more conservative balance sheets and investor payouts, with debt-to-equity ratios no greater than 2.1x at the end of 2025.[71,72] In contrast to APA, Enagas and Snam funded shareholder dividends with earnings per share (i.e. net profit) rather than free cash flow, with their shareholders receiving between 75% and 82% of their respective earnings per share in 2025.[73,]

Based on APA's net debt of AU$14.23bn as of 30 June 2026 and FFO to net debt ratio of 11.2%, IEEFA estimates APA's FFO at $1.4bn.[74,75] This, in turn, implies a maximum net debt (based on current FFO and S&P's 8.5% FFO to net debt ratio threshold) of almost AU$16.5bn, meaning APA can only increase debt by about AU$4bn if it is to maintain its credit rating (all other things being equal). With APA anticipating material additional expenditures funded from its balance sheet, which will add to its debt levels, headroom will fall below AU$4bn.[76] This is well below IEEFA's estimated cost range for the pipeline of AU$5.3–7.1bn, and much lower than estimated AU$8.3bn costs for the 48-inch pipeline for which APA is seeking approval.

We note that further growth in revenue, to the extent it translates to FFO, could increase APA's allowable debt levels. In addition to revenue growth arising from escalation of inflation-linked tariffs, the NEA pipeline, if sanctioned, would generate estimated additional net cash flows of AU$675–700m under the low- and central-demand scenarios modelled by IEEFA. Under the high-demand scenario, additional net cash flow peaks at AU$830m by 2041. However, this additional cash flow will only arise once the pipeline starts operation, after debt is added to fund construction. It will also be partly or wholly offset by a fall in APA's tariff revenue from the Wallumbilla to Gladstone pipeline, which

[68] Future Business Journal. Role of debt to equity ratio in project valuation, assessing risk and return in capital markets. *Nukala, V. and Prasada Rao, S.* March 2021. Page 2.
[69] APA Group. Investor Presentation FY26 Full-year results. 20 August 2026. Page 27.
[70] Sage Open. The Impact of Financial Leverage on the Financial Performance of the Firms Listed on the Tokyo Stock Exchange. *Arhinful, R. and Radmehr, M*. October 2023. Page 1.
[71] Snam. Annual Report 2025. March 2026. Pages 69 and 83.
[72] Enagas. 2025 Annual Financial Statements. Page 301.
[73] Ibid. Pages 306 and 313.
[74] APA Group. Annual Report 2026. August 2026. Page 6.
[75] Ibid. Pages 57 and 184.
[76] APA Group. Annual Report 2026: Investor Briefing. August 2026. Page 20.

accounts for a third of earnings before interest, tax, depreciation and amortisation (EBITDA), with expected revenues set to fall by more than AU$700m in 2036.[77,78]

While IEEFA has not explicitly modelled the impact of the NEA pipeline on APA's FFO to debt ratios, we nonetheless note the need for it to maintain sufficiently high FFO to debt levels.[79]

APA is also pursuing other growth projects that will contribute to debt levels, with a spending program of up to AU$3.5bn (largely on gas infrastructure projects) between FY2026–27 and FY2028–29.[80] APA is scheduled to repay AU$3.38bn by the end of FY2028–29.[81] It had AU$1.64bn in cash on hand (at 30 June 2026).[82] APA will need to find additional funding to repay this debt, through either using free cash flow from its operations over the period to 2029, or it may roll over the debt.

Pipeline could affect shareholder distributions

APA's high debt could potentially affect its ability to pay distributions (i.e. dividends) to investors, which have consistently increased since 2014. In recent years, APA has spent a significant proportion of its free cash flow on distribution payments, with FY2025–26 payouts accounting for almost 64% of the AU84.4¢ free cash flow per security held by investors. More importantly, this is well above net profits per share of AU17.8¢ over that period. In practice, this means APA's high distribution payment rate has kept its debt levels higher as free cash flow is not being used to reduce debt, with growing distributions coinciding with a period of rising debt levels.[83]

Further, given the potential for higher interest rates to increase debt costs, additional debt could lead to higher debt servicing obligations, thereby reducing FFO and potentially affecting APA's ability to fund distributions in the future.

Higher profits or valuation not necessarily in the pipeline

APA's large investments in its businesses over the past decade have not translated into higher profits or a significant increase in its share market valuation.

[77] APA. Investor Presentation: FY26 Full-year results. August 2026. Page 29.
[78] Market Forces. APA Group investor briefing. September 2026. Page 9.
[79] APA. Moody's rating modification supports APA's capacity to fund future growth. 14 April 2026.
[80] APA. Investor Presentation FY26 Full-year results. 20 August 2026. Page 20.
[81] Ibid. Page 35.
[82] APA Group. Annual Report 2026. Page 158
[83] Ibid. Page 27.

APA's net profit (excluding significant items) of AU$234m in FY2025–26 was less than annual profits in each of the seven years from FY2016–17 to FY2022–23.[84,85,86] This is an important metric as it provides an indication of the profitability of APA's underlying business.

APA Group's share market valuation of about AU$15.1bn is above its total drawn debt levels, and the AU$13bn nominal value of the takeover offer for APA Group by CK Group in 2018.[87,88] Accounting for inflation, this would suggest that despite the growth strategies implemented by APA since 2018, the real value of APA has declined.[89] This may signal that equity investors have not fully rewarded APA's strategy that has been weighted more to gas than electricity assets.

IEEFA notes, however, that APA's enterprise value, which includes equity and debt, is higher in November 2026 at AU$28bn compared with an inflation-adjusted enterprise value of AU$26.5bn (based on the AU$20bn value at the time of the takeover offer in 2018).[90]

Other investment opportunities may be missed

APA's investment in the NEA pipeline, should it reach final investment decision, will affect its ability to finance investment in other major opportunities in Australia's energy markets. In particular, investment in new gas infrastructure will limit APA's ability to invest in new electricity assets.

Forecasts suggest demand in Australia's electricity markets is much more likely to grow in coming decades. Electricity consumption in the National Electricity Market (NEM), which accounts for about 80% of Australia's electricity generation, is forecast to almost double by 2050.[91] Demand in Australia's second-largest electricity market, Western Australia's South West Interconnected System (SWIS), is forecast to rise by 47% from FY2026–27 to FY2035–36.[92]

Rising electricity demand will require investment in transmission lines and power generation, with AEMO forecasting 6,000km of new power transmission lines will be required in Australia by 2050.[93]

AEMO's strong electricity demand growth forecasts contrast with its sliding domestic gas demand outlook. As noted earlier, gas demand is forecast to materially fall in eastern Australia.

This reflects the contrasting roles Australia's electricity and gas networks are playing in the country's energy transition.[94] The Australian Energy Regulator noted, "Investment in electricity network

[84] APA Group. Investor Presentation FY26 Full-year results. 20 August 2026. Page 27.
[85] APA Group. Annual Report 2021. August 2021. Page 43.
[86] APA Group. Annual Report 2023. August 2023. Page 78.
[87] ASX Markets. APA Group share price. Accessed 12 October 2026.
[88] AFR. APA Group's long-term future still in question after $13b takeover knockback. 25 November 2018.
[89] AFR. CKI's bid for APA Group officially rejected by Treasurer Josh Frydenberg. 21 November 2018.
[90] ASX. APA Group overview. Accessed 17 November 2026.
[91] AEMO. 2026 Integrated System Plan. 25 June 2026. Page 43.
[92] AEMO. 2026 Wholesale Electricity Market Electricity Statement of Opportunities. June 2026. Page 5.
[93] AEMO. 2026 Integrated System Plan. 25 June 2026. Page 93.
[94] Australian Energy Regulator (AER). State of the energy market. Network performance report 2026. 2 July 2026. Page 4.

capacity is needed for the growth in new solar, wind generation and battery storage … conversely, while residential customers electrify their household gas appliances, there will be a decline in the gas delivered by gas distributors and the number of customers connected."

Further investment in gas infrastructure would increase APA's already high exposure to the Australian gas sector as it already operates 70% of eastern Australia's gas transmission market.[95] Revenue from gas infrastructure accounts for about 83% of its underlying EBITDA in FY2025–26. The remaining 17% came from electricity assets.[96]

APA's gas power generation assets also face increased competition from grid-scale batteries, with batteries providing more electricity than gas plants in peak demand periods in 2026.[97] A pivot to non-gas electricity infrastructure could help to shield APA from competitive pressures created by the rollout of low-cost renewables.

Conclusion

APA's proposed Beetaloo pipeline is likely to be very expensive, representing the largest ever gas transmission investment in Australian history. High costs will, naturally, lead to high transmission tariffs, and undermine the competitiveness of gas delivered using the pipeline.

APA presents the Beetaloo as principally "an LNG export play".[98] IEEFA also finds that LNG exports present the largest potential source of demand for gas supplied by the pipeline. However, given relatively high Beetaloo gas production cost forecasts and high transport tariffs, it is highly unlikely Gladstone LNG exporters relying on Beetaloo gas feedstock could recover their costs in oversupplied global LNG markets.

There is also significant uncertainty about the amount of domestic demand for Beetaloo gas as eastern Australia's gas demand has been declining steeply, and the federal government has implemented a reservation policy to address upcoming supply gaps. Given its high cost, Beetaloo gas is likely to either have little demand or push up domestic gas prices.

These factors suggest there is no financial case for the pipeline. There are also additional risks associated with the project, such as:

- The lengthy pipeline will require considerable debt financing, which might stretch APA's balance sheet and affect its ability to fund shareholder distributions. If sufficiently stretched, t could also trigger rating agencies to reassess APA's credit rating.

[95] S&P Global. Research Update: APA Infrastructure Ltd. 'BBB' Ratings Affirmed; Outlook Stable. 7 December 2025.
[96] APA. Investor Presentation FY26 Full-year results. 20 August 2026. Page 29.
[97] AEMO. AEMO CEO Speech at 2026 AFR Energy and Climate Summit. 13 October 2026.
[98] Stock Analysis. APA Group Earnings Call: H1 2026. 18 February 2026.

- Further gas infrastructure investments could also affect APA's ability to invest in other energy assets, namely electricity transmission at a time when electricity demand is forecast to surge.
- The NEA pipeline will also depend on large-scale Beetaloo gas production, but the sub-basin's developments are still in the early phases. With the Beetaloo not yet proven to be commercially viable, the risk remains that supply needed to fill the pipeline will not actually materialise.

With high costs, and an uncertain demand outlook in both the LNG and domestic market, APA's NEA pipeline is likely to face too many risks to make financial sense.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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