Industrial and manufacturing gas user analysis

Executive summary

__Large East Australia gas users (industrial/manufacturers) in 2025:__

- ***Total estimated revenue, ~A$23.7 billion***
- ***Total estimated cost, ~A$19.9 billion***
- ***Total gas cost, ~A$ 0.9 billion***
- ***Total estimated margin ~A$3.8 billion***

__Reducing the wholesale gas price from A$12/GJ to A$10/GJ would:__

- ***Lower annual operating costs by ~A$93.9 million. This compares with total annual operating costs of almost A$20 billion.***
- ***Deliver a ~0.4% average improvement in profit margin***

The Australian government has released its draft design framework for the proposed Domestic Supply Obligation (DSO), requiring LNG projects to supply gas equivalent to 20% of their export volumes to the domestic market from July 2027. The policy aims to consolidate a fragmented set of existing east coast gas regulations into a single, definitive framework. One of the goals of the 20% DSO is to reduce the cost of gas to end users.

Australian Energy Producers (AEP) is seeking analysis to understand the current impact of gas prices on large gas users. This includes gas volumes used, relative cost of gas as part of the operating costs of their businesses, other cost factors that affect these operations and relative profitability including exposure to international pricing/competition in the domestic markets.

The large industrial and manufacturing gas users have diverse operations, and their cost impacts vary across buyers and their industry sectors. The amount of gas used, how the gas is utilised (feedstock and heating processes), the location of the operations (distance from the source – transmission and/or distribution cost and sometimes retail margin) are some of the influencing factors on the cost structure of these gas users. There are additional factors, such as labour and electricity costs, that also impact on the cost base of these businesses. The extent of a gas buyer being able to benefit from higher revenues will depend on the industry they are in, the level of competition they face and their ability to pass through their increased costs through their customer contracts.

Industrial and manufacturing gas use

Total gas demand for large industrial and manufacturing facilities in Eastern Australia was estimated to be approximately 161 PJ/a in 2025, spanning feedstock, process and heating operations (~129 PJ/a) and captive power generation for remote mining operations (~32 PJ/a). Eastern Australia's industrial gas demand spans a diversified pool of sectors and facilities. Whilst alumina and fertilisers, ammonia & derivatives dominate industrial gas demand use, with ~29.9% and 22.1% share respectively, other sectors reliant on gas use include pulp, paper, glass & packaging (~12.3%); oil refineries & chemicals (~10.4%); construction products (~11.0%); steel (~9.4%) and others (~5.8%).

East Australian industrial gas demand is concentrated in a small number of large operators. Three operators account for ~50% of the large industrial demand in East Australia (excluding captive power). Rio Tinto is the largest industrial gas user in Eastern Australia with an aggregated gas demand of ~39.3 PJ in 2025 across its operated alumina refineries. Orica (~16.4 PJ/a) and Mayfair Corp (Phosphate Hill ~9.1 PJ/a) are the next largest gas demand operators. Beyond this group, there are eight large industrial operators that accounted for gas demand of between 3.5 and 9 PJ each in 2025, with the remaining operators utilising <3.5 PJ/a.

Summary of large East Australia gas users (industrial/manufacturers) in 2025:

- Total estimated revenue ~A$23.7 billion
- Total estimated cost ~A$19.9 billion
- Total gas cost ~A$ 0.9 billion
- Total estimated margin ~A$3.8 billion

The two East Australia alumina refineries (Yarwun and QAL) are in the lowest third of the global alumina refineries cash cost curve. Rio Tinto (operator of the alumina refineries) entered into two long-term gas contracts with Origin Energy and APLNG for its Yarwun and QAL refineries. These gas supply contracts extend to 2031 and 2041 respectively and cover the full demand expected for these operations. As these contracts were signed a number of years ago, the price is substantially below the current market price for East Australia gas under new contracts (companies with long term gas supply contracts would be unaffected by a reduction in wholesale gas price, for the amounts and period they have these contracts).

Other long-term gas supply contracts with large industrial gas users include:

- Bluescope-Senex. 20 PJ of natural gas over 10 years from January 2026 (expiring December 2035). This represents ~55% of BlueScopes current demand requirements at Port Kembla.
- Brickworks-Santos. 35 PJ of natural gas over 11 years from 2025 (expiring 2036). This represents ~100% of Brickworks current demand requirements at Horsley Park.
- CSR-Santos. 17 PJ of natural gas over 10 years from 2025 (expiring 2034). This represents ~100% of CSR's Queensland current demand requirements and ~28% of its estimated total East Australia portfolio demand.
- I-O (Visy Glass)-Senex. 20 PJ of natural gas over 10 years from January 2026 (expiring December 2035).
- Orora-Senex. 14 PJ of natural gas over 10 years from January 2026 (expiring December 2035).
- Adbri-Senex. 11 PJ of natural gas over 7 years from January 2023 (expiring December 2029).
- South Australian Government-Santos 200 PJ over 20 years from 1 March 2030 (Binding Term Sheet). The SA government intends to utilize this gas to support Whyalla Steelworks deploy direct iron reduction technology.

Industrial and manufacturer's gas cost and impact of gas prices

Our gas price analysis assumed a base case wholesale price of A$12/GJ for East Australia. We then assessed the impact of A$2/GJ reduction in gas price (assumed gas price A$10/GJ). A further impact assessed a A$4/GJ reduction for East Australia (i.e. gas price of A$8/GJ). Across all gas price scenarios, we assume a A$1/GJ average transport cost to derive a delivered price at each facility (the A$1/GJ transportation assumption is a simplified, high-level estimate and may not capture the full variability in pipeline tariffs across Eastern Australia that may impact of delivered costs for some of the industrial/manufacturing buyers analysed in this report).

The gas price reduction is most material for gas-intensive fertiliser, ammonia & derivatives and for Whyalla Steel, where gas is either a feedstock or the principal process energy input. Phosphate Hill has the largest gas cost saving A$18.2m (under a A$2/GJ gas price reduction) and A$36.3m (under a A$4/GJ gas price reduction). QNP's estimated margin improves 3.4% (under a A$2/GJ gas price reduction) and 6.8% (under a A$4/GJ gas price reduction). By contrast, the impact is generally marginal for steelmakers and oil refineries, where gas is only a small share of total cost. Port Kembla's margin is essentially unchanged (30.4% to 30.6% under a A$2/GJ gas price reduction) and Whyalla remains deeply loss-making (margin changes from −26.7% to −23.7% under a A$2/GJ gas price reduction), while the Geelong and Lytton refineries margin barely move. For these facilities, cost position and profitability are driven by iron ore price, scale and refining margins rather than the gas price.

Summary of large East Australia gas users impact of wholesale gas prices:

- Reducing the wholesale gas price from $12/GJ to $10/GJ would lower annual operating costs by ~A$94 million or by ~A$188 million if reduced from $12/GJ to $8/GJ. This compares with total annual operating costs of almost A$$20 billion.
- 0.4% average improvement in profit margin with A$10/GJ (reducing from A$12/GJ) gas prices or ~0.8% with A$8/GJ gas price.

Implications of DSO policy on large industrial and manufacture gas users

The DSO policy framework, when applied to Queensland LNG exporters as currently designed, would result in the East Coast gas market (ECGM) experiencing a sustained, structural and large oversupply from 2027 to 2035 as compelled LNG exporter DSO volumes significantly exceed domestic market demand. While this period would see suppressed domestic gas prices, the analysis in this report finds that natural gas accounts for, on average, around 5% of total operating costs across the large East Coast industrial and manufacturing gas users assessed. This reflects average outcomes, noting that gas costs represent a materially higher share of total costs in some sectors, such as fertiliser, ammonia and derivatives. This finding is broadly consistent with the Grattan Institute's analysis, which found that gas generally represents less than 5% of total cash costs for smaller industrial and manufacturing gas users (consuming less than 2 PJ per annum). For these businesses, changes in gas price have a low impact on cash cost margins. Other input costs, including raw materials and labour costs, are far more significant to these industrial/manufacturer's cash cost margins.

This excessive structural oversupply would remove any price signals in the ECGM that would have underpinned investment in future gas supply, transportation infrastructure to bring this new supply to market and demand moderating programs that would reduce gas usage. Essentially, the ECGM would become so oversupplied that prices would collapse to below the marginal cost of domestic-only producers and any future investment in gas supply would become uneconomic. As a result, it is likely that no new supply would be brought to market during this period.

The challenge in the medium-to-long-term is that the market flips from being structurally oversupplied to structurally undersupplied as existing Queensland LNG exporter reserves are exhausted. The loss of investment signals in the market, and the risk premium applied to investments under a DSO regime, mean that there would be a reduction or complete loss of the continued investment required to maintain production over the longer term. The result would potentially be a near-complete reliance on LNG imports to meet ECGM demand, stranded gas pipeline infrastructure with no supply of gas and domestic gas prices set by international LNG markets directly (spot or contract LNG supply delivered into the ECGM, plus regasification costs) at import-parity prices of potentially A$17/GJ to A$19/GJ.

The long-term cost of suppressing prices at uneconomic levels through the end of this decade and into the early 2030s, is a lack of investment in new or incremental supply. This would manifest as an accelerated decline in production from northern domestic gas producers and southern market producers. Rising prices would signal the need for more gas and greater investment to discover, develop and bring new supply to market, as well as underwriting the economics of new developments. However, the loss of domestic gas production due to the oversupply and collapse of prices over the decade to 2036 would result in a lack of risk capital available to fund these developments.

In the event that LNG import terminal(s) enter the market, the southern domestic gas market will become strongly linked to LNG pricing. Marginal price-setting supply in peak winter months will be linked to LNG import parity, which presents structurally different contracting options to the existing fixed-price agreements available to domestic gas buyers currently.

Introduction

The Australian government has released its draft design framework for the proposed Domestic Supply Obligation (DSO), requiring LNG projects to supply gas equivalent to 20% of their export volumes to the domestic market from July 2027. The policy aims to consolidate a fragmented set of existing east coast gas regulations into a single, definitive framework. One of the goals of the 20% DSO is to reduce the cost of gas to end users.

Australian Energy Producers (AEP) is seeking supporting analysis to understand the current impact of gas prices on large gas users. This includes gas volumes used, relative cost of gas as part of the operating costs of their businesses, other cost factors that affect these operations and relative profitability including exposure to international pricing/competition in the domestic markets.

The large industrial and manufacturing gas users have diverse operations, and their cost impacts vary across buyers and their industry sectors. The amount of gas used, how the gas is utilised (feedstock and heating processes), the location of the operations (distance from the source – transmission and/or distribution cost and sometimes retail margin) are some of the influencing factors on the cost structure of these gas users. There are additional factors, such as labour and electricity costs, that also impact on the cost base of these businesses. The extent of a gas buyer being able to benefit from higher revenues will depend on the industry they are in, the level of competition they face and their ability to pass through their increased costs through their customer contracts.

The key components of this study include:

- An overview of large gas users in Eastern Australia – key sectors and facilities, operator gas demand, how gas is used and ranking of facility and user gas demand.
- Characterisation of the cost of gas for large gas users in Eastern Australia – relative cost components of gas as a proportion of the estimated operating costs (and ranking) and revenue. Assessment of the relative impact that an assumed A$2/GJ and $4/GJ reduction in wholesale gas price from the assumed A$12/GJ base price (i.e. A$10/GJ and A$8/GJ wholesale prices).
- Deeper analysis of seven selected large gas users and their operations to better understand the role of gas in their facilities and the potential impact on their business of changes in gas availability and pricing, including an understanding of profitability and the impact of changes in gas prices on the businesses.

Methodology and limitations

This report draws on Wood Mackenzie asset-level cost models, AEMO data and public company reports. Facility-level gas volumes, costs, margins and gas-cost shares are Wood Mackenzie estimates, not company-disclosed facility financials. They are derived from asset models or, where unavailable, from each facility's production share of the relevant business unit's reported cost of sales.

Three cost bases were used and are not fully comparable across facilities (see Cost components of gas section). Gas-price impact of applying a uniform A$2/GJ and A$4/GJ wholesale reduction, with both the base case and impact applying a uniform additional A$1/GJ for gas transportation. The A$1/GJ transportation assumption is a simplified, high-level estimate and may not capture the full variability in pipeline tariffs across Eastern Australia. For large gas users in Queensland, this figure is broadly reasonable given the proximity of demand centres to major supply basins (Surat/Bowen) and the shorter haulage distances involved. However, for southern buyers (Victoria, South Australia and NSW), this assumption likely understates delivered costs, as gas purchased from northern supply sources will need to be transported via additional pipeline routes (e.g. South West Queensland Pipeline plus Moomba-Adelaide, Moomba-Sydney, and/or NSW-Vic interconnect routes), especially as southern conventional supply continues to decline. We have not captured distribution tariff costs which tend to apply to smaller (<2PJ/a) industrial/manufacturing gas users located within the major cities (Brisbane, Sydney, Melbourne and Adelaide) distribution networks. Larger industrial gas users tend to be connected directly to transmission pipeline systems.

Comparisons of BF-BOF and DRI-EAF steel production methodologies are illustrative technology scenarios, not forecasts. Figures reflect 2025 estimates and may move with production, contract and market conditions. Verification against primary sources is recommended before reliance.

Impact of the Domestic Supply Obligation on the ECGM

The DSO policy framework, when applied to Queensland LNG exporters as currently designed, would result in the ECGM experiencing a sustained, structural and large oversupply from 2027 to 2035 as compelled LNG exporter DSO volumes significantly exceed domestic market demand. This excessive structural oversupply would remove any price signals in the ECGM that would have underpinned investment in future gas supply, transportation infrastructure to bring this new supply to market and demand moderating programs that would reduce gas usage. Essentially, the ECGM would become so oversupplied that prices would collapse to below the marginal cost of domestic-only producers and any future investment in gas supply would become uneconomic. As a result, it is likely that no new supply would be brought to market during this period.

The challenge in the medium to long-term is that the market flips from being structurally oversupplied to structurally undersupplied as existing Queensland LNG exporter reserves are exhausted, no new supply has been invested in, southern market supply has fallen to less than 20 PJ/a, and southern market demand remains above 200 PJ/a. The loss of investment signals in the market, and the risk premium applied to investments under a DSO regime, mean that there would be a reduction or complete loss of the continued investment required to maintain production over the longer term.The implications from the lack of investment in new supply would take a decade or more to rectify given the long-lead-time nature of gas developments.

The result would potentially be a near-complete reliance on LNG imports to meet ECGM demand, stranded gas pipeline infrastructure with no supply of gas and domestic gas prices set by international LNG markets directly (spot or contract LNG supply delivered into the ECGM, plus regasification costs) at import-parity prices of potentially A$17/GJ to A$19/GJ.

Potential effects on Australian manufacturing and industry

In 2030, the DSO would result in an oversupply of 240 PJ compared to ECGM demand. In order to balance the market, all northern gas supply other than LNG exporter volumes would be displaced (given their higher marginal cost of supply). Additionally, another 74 PJ of southern production would need to be displaced – reducing southern market supply by 38% and potentially exacerbating peak-day shortfall risks.

While this period would see suppressed domestic gas prices, the analysis in this report finds that natural gas accounts for, on average, around 5% of total operating costs across the large East Coast industrial and manufacturing gas users assessed. This reflects average outcomes, noting that gas costs represent a materially higher share of total costs in some sectors, such as fertiliser, ammonia and derivatives. This finding is broadly consistent with the Grattan Institute's[1] analysis, which found that gas generally represents less than 5% of total cash costs for smaller industrial and manufacturing gas users (consuming less than 2 PJ per annum). For these businesses, changes in gas price have a low impact on cash cost margins. Other input costs, including raw materials and labour costs, are far more significant to these industrial/manufacturer's cash cost margins.

Additionally, the DSO framework operates on an annual cycle: the DSO for the forward twelve months is set at 20% of export volumes, year-ahead variations are adjudicated against a 'high assessment threshold', the 'release valve' mechanism (RVM) operates in-year, and unmet DSO volumes are carried forward. The visibility of available gas supply therefore resets each year. A supplier whose deliverable volume is set annually by Ministerial decision cannot readily offer firm long-dated volumes, pushing domestic gas users into short-term and spot contracting, which then reduces the bankability of their own capital investment and increases their exposure to price volatility.

The long-term cost of suppressing prices at uneconomic levels through the end of this decade and into the early 2030s, is a lack of investment in new or incremental supply. This would manifest as an accelerated decline in production from northern domestic gas producers and southern market producers. Rising prices would signal the need for more gas and greater investment to discover, develop and bring new supply to market, as well as underwriting the economics of new developments. However, the loss of domestic gas production due to the oversupply and collapse of prices over the decade to 2036 would result in a lack of risk capital available to fund these developments.

In the event that LNG import terminal(s) enter the market, the southern domestic gas market will become strongly linked to LNG pricing. Marginal price-setting supply in peak winter months will be linked to LNG import parity, which presents structurally different contracting options to the existing fixed-price agreements available to domestic gas buyers currently.

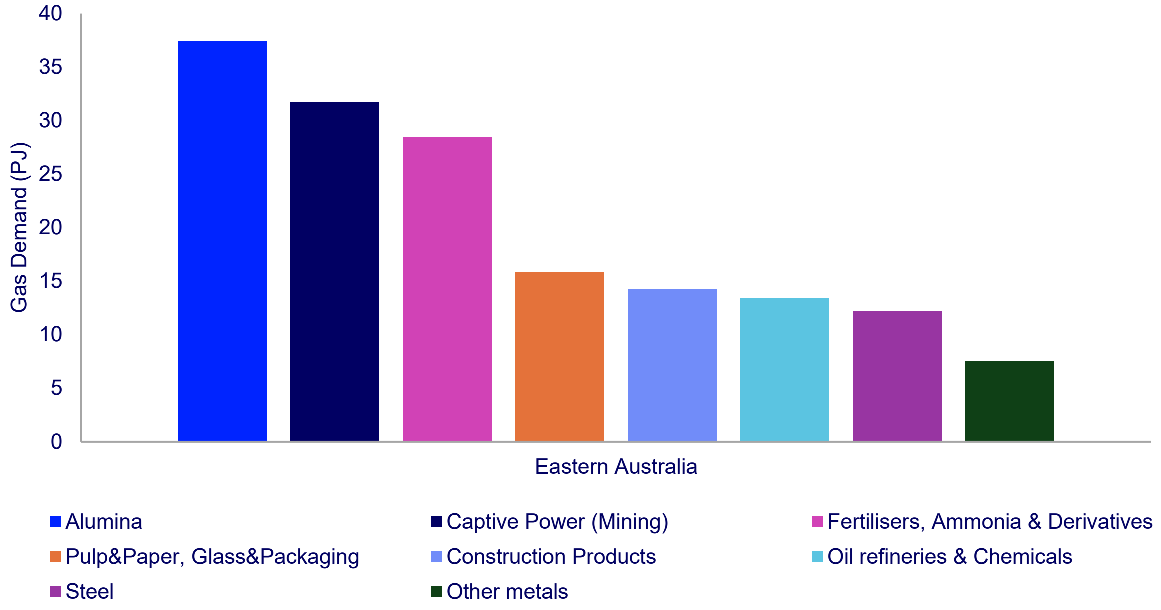
[1] *https://grattan.edu.au/report/flame-out-the-future-of-natural-gas/ Gattan "Flame out the future of natural gas" report - Appendix C: Moderately gas-intensive companies.*

Characterising Eastern Australian large gas users

Summary of industrial gas use

Total gas demand for large industrial and manufacturing facilities in Eastern Australia was estimated to be approximately 161 PJ/a in 2025, spanning feedstock, process and heating operations (~129 PJ/a) and captive power generation for remote mining operations (~32 PJ/a).

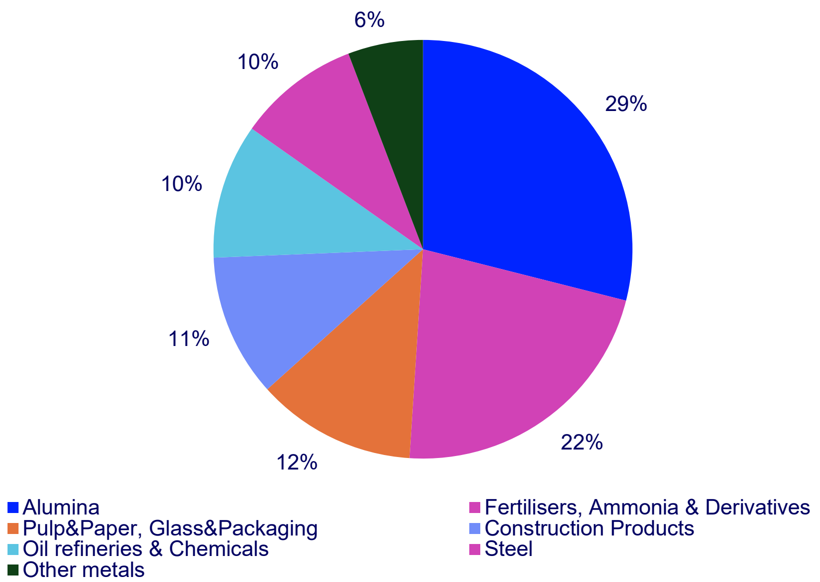
Figure 1 – Gas demand by industry type across Eastern Australia (2025), PJ



Source: Wood Mackenzie, AEMO, Company Annual Reports

The following analysis excludes captive power generation for remote mining operations from our large industrial demand and instead focusses on industries that utilise gas for feedstock, heat processes and cogeneration. The alumina and fertilisers, ammonia & derivatives sectors are the dominant demand sectors in the East Australia gas market, accounting for ~51% of large industrial demand.

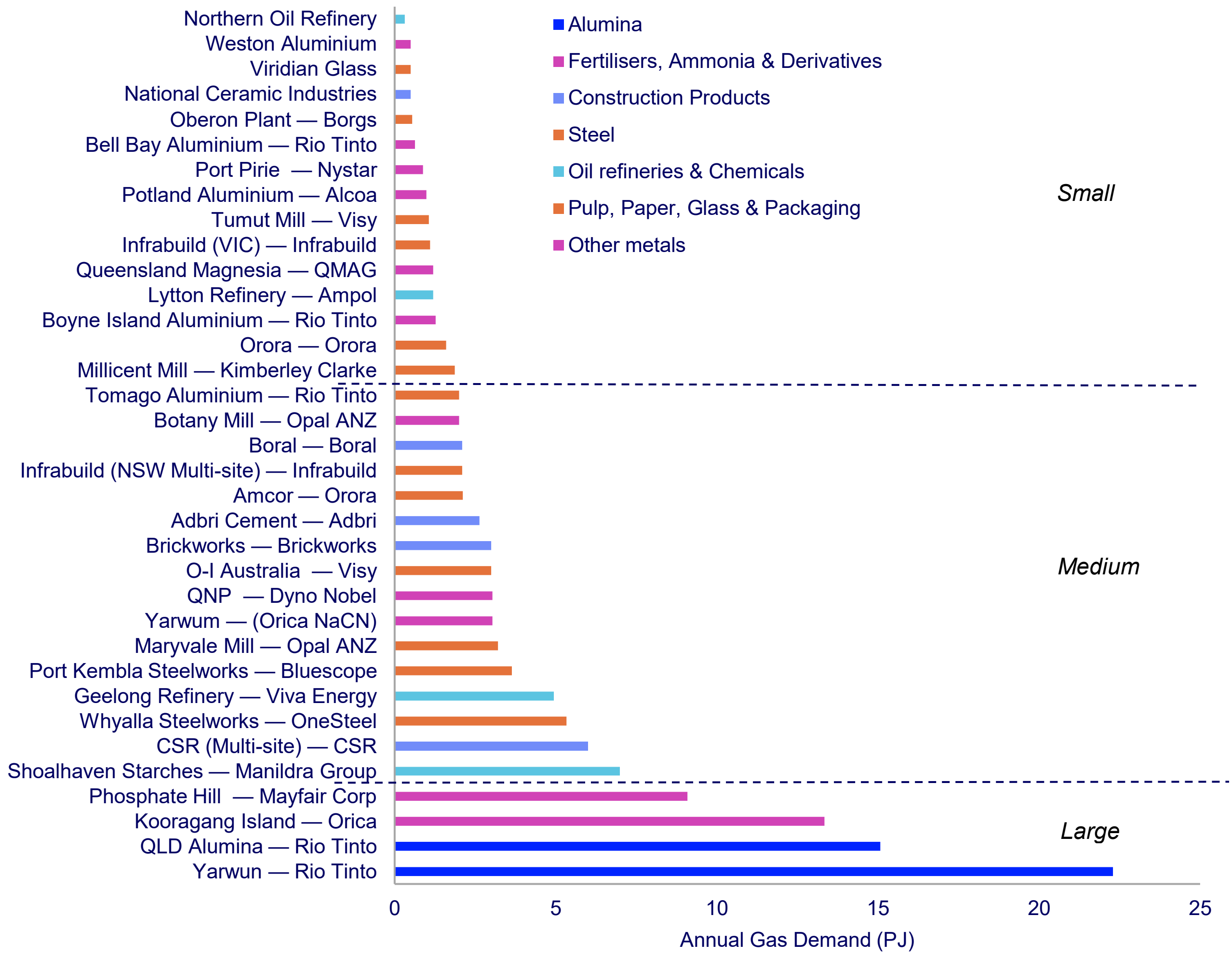
Figure 2 – Eastern Australia gas demand by Industry type (excluding captive power) (2025), %



Source: Wood Mackenzie, AEMO, Company Annual Reports

Eastern Australia's industrial gas demand spans a diversified pool of sectors and facilities. Whilst alumina and fertilisers, ammonia & derivatives dominate industrial gas demand use, with ~29.9% and 22.1% share respectively, other sectors reliant on gas use include pulp, paper, glass & packaging (~12.3%); oil refineries & chemicals (~10.4%); construction products (~11.0%); steel (~9.4%) and others (~5.8%).

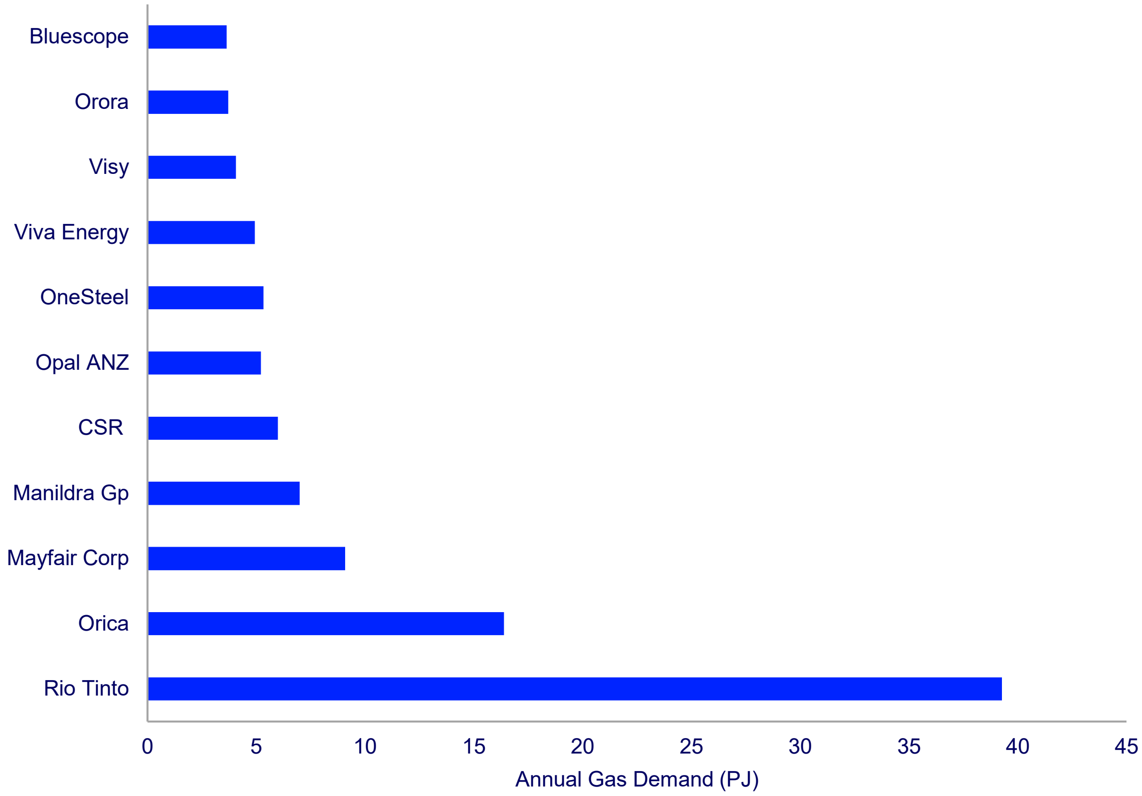
Figure 3 – Eastern Australia industrial gas demand by facility (excluding captive power) (2025), PJ



Source: Wood Mackenzie, AEMO, Company Annual Reports

At the company level, East Australian industrial gas demand is concentrated in a small number of large operators. Three operators account for ~50% of the large industrial demand in East Australia (excluding captive power). Rio Tinto is the largest industrial gas user in Eastern Australia with an aggregated gas demand of ~39.3 PJ in 2025 across its operated alumina refineries. Orica (~16.4 PJ/a) and Mayfair Corp (Phosphate Hill ~9.1 PJ/a) are the next largest gas demand operators. Beyond this group, there are eight large industrial operators that accounted for gas demand of between 3.5 and 9 PJ each in 2025, with the remaining operators utilising <3.5 PJ/a.

Figure 4 – Annual industrial gas demand by top eleven operator companies in East Australia (excluding captive power) (2025), PJ



Source: Wood Mackenzie, AEMO, Company Annual Reports

Overview of gas use – Alumina sector

The alumina sector is the largest industrial sector for gas demand in East Australia. There are two active alumina refineries in East Australia. Gas is utilised in steam production (digestive stage steam and sometimes integrated with cogeneration) and calcining – a high-temperature (>1,000 degrees Celsius) molecular drying process. Gas demand at these refineries ranges from 15 PJ/a up to 22 PJ/a, with variability due to some operations utilising coal in steam and power generation.

These key alumina refineries in Australia include:

- **Yarwun Alumina Refinery**, Gladstone, QLD.
    - ~2.9 Mtpa alumina production in 2025.
    - Rio Tinto is operator and has a 100% interest.
    - ~22.3 PJ of gas consumed in 2025.
- **Queensland Alumina Refinery**, Gladstone, QLD.
    - ~3.6 Mtpa alumina production in 2025.
    - Rio Tinto is operator and has an 80% interest, Rusal UC 20% interest.
    - ~15.1 PJ of gas consumed in 2025.

These alumina refineries are in the lowest third of global alumina refineries cash cost curve. Key operating cost components of Alumina refineries include bauxite, caustic soda, gas/coal (energy), and labour costs. Gas costs range from ~8% to 15% of the total alumina refinery operating cost. This variability in the gas cost component is due to the level at which coal is utilised in the operation (displacing gas in steam production) as well as the price paid for gas (contracted gas price).

Rio Tinto entered into two long-term gas contracts with Origin Energy and APLNG for its Yarwun and QAL refineries respectively. These gas supply contracts extend to 2031 and 2041 respectively. The gas price is fixed plus CPI escalation and as they were signed a number of years ago, the price is substantially below the current market price for East Australia gas under new contracts.

Overview of gas use – Fertilisers, ammonia & derivatives

The fertilisers, ammonia & derivatives sector is the second largest industrial gas-consuming sector in East Australia.

The fertilisers, ammonia & derivatives sector uses natural gas primarily as a feedstock, using it as the primary hydrogen source for ammonia synthesis via Steam Methane Reforming (SMR). Operations also use gas for electricity generation / cogeneration (electricity and steam). This creates structurally higher gas cost exposure with a lack of viable fuel-switching substitutes for the fertilisers, ammonia & derivatives sector.

Ammonia plants may be integrated with other processes to produce different end use products. These products include urea, ammonium phosphate fertilisers (Diammonium Phosphate – DAP. and Monoammonium Phosphate – MAP), ammonia nitrate (fertilisers and explosives) and sodium cyanide. Gas demand in Australian fertilisers, ammonia & derivatives sector facilities range from ~3 PJ/a (QNP and Yarwun) to ~11.6 PJ/a (Orica, Kooragang Island), with variability driven by plant scale and end-product type.

The key fertilisers, ammonia & derivatives facilities in Australia are:

- **Kooragang Island (Orica)**, Newcastle, NSW.
    - ~360 ktpa ammonia; ~550 ktpa ammonium nitrate (750 ktpa approved capacity).
    - Orica is operator, and Orica Limited has a 100% interest.
    - ~13.3 PJ of gas consumed in 2025.
- **Phosphate Hill**, Mt Isa region, QLD.
    - ~400 ktpa DAP, ~200 ktpa MAP; integrated mine and fertiliser complex with on-site ammonia production.
    - Mayfair Australia Corporation is operator and has a 100% interest (transferred from Dyno Nobel).
    - ~9.1 PJ of gas consumed in 2025.
- **Queensland Nitrates (QNP)**, Moura, Central QLD.
    - ~235 ktpa explosive-grade ammonium nitrate; partial on-site ammonia production.
    - Dyno Nobel Asia Pacific is operator and has a 50% interest (formerly Incitec Pivot), 50% CSBP (Wesfarmers).
    - ~3.0 PJ of gas consumed in 2025.
- **Yarwun (Orica, NaCN)**, Gladstone, QLD.
    - Sodium cyanide (100+ ktpa).
    - Orica is operator and has a 100% interest.
    - ~3.0 PJ of gas consumed in 2025.

Key operating cost components for ammonia producers include natural gas (feedstock), electricity, labour, and maintenance. Gas costs represent approximately 60% to 80% of total ammonia production costs – the highest gas cost exposure of any industrial sector in Australia – though this number drops to ~33% to 50% for the integrated downstream operations (ammonia nitrate, ammonia phosphate) and to ~20% for Yarwun (Orica NaCN, sodium cyanide).

Variability in gas demand for integrated ammonia plants can be due to the level of over production (export of ammonia – e.g. Orica, Kooragang Island) or under-production (importation of ammonia – e.g. QNP) into the facility's operations.

Overview of gas use – Other metals sector

Excluding alumina refining, the other metals sector comprises seven active gas-consuming facilities across Eastern Australia, spanning primary aluminium smelting, secondary aluminium recycling, magnesia processing and lead/zinc smelting.

Gas demand in these facilities is ~2 PJ/a or less. Gas plays a secondary role for primary aluminium smelters, which are overwhelmingly electricity-intensive (Hall-Héroult electrolysis), serving cast house operations and auxiliary process heat only.

Multiple facilities carry material operational risk driven by power cost and commodity markets, most acutely at Tomago and Bell Bay aluminium, and Port Pirie poly-metals.

The key facilities are:

- **Tomago Aluminium**, Tomago (Newcastle), NSW.
    - Up to ~590 ktpa aluminium. Australia's largest aluminium smelter.
    - Rio Tinto is operator and has a 51.55% interest, Gove Aluminium Finance Ltd (CSR) 36.05%, Norsk Hydro 12.40%.
    - ~2.0 PJ of gas consumed in 2025.
- **Boyne Smelters (Boyne Island Aluminium)**, Gladstone, QLD.
    - ~550 ktpa aluminium.
    - Rio Tinto is operator and has a 73.5% interest, YKK Aluminium 9.50%, UACJ Australia 9.29%, Southern Cross Aluminium 7.71%.
    - ~1.3 PJ of gas consumed in 2025.

- **QMAG**, Parkhurst (Gladstone), QLD.
    - Up to ~270 ktpa magnesia product.
    - Refratechnik Group is operator and has a 100% interest.
    - ~1.2 PJ of gas consumed in 2025.
- **Portland Aluminium**, Portland, VIC.
    - ~358 ktpa aluminium.
    - Alcoa is operator and has a 55% interest, CITIC 22.5%, Marubeni 22.5%.
    - ~1.0 PJ of gas consumed in 2025.
- **Port Pirie**, Port Pirie, SA.
    - ~160 ktpa lead; polymetallic smelter also producing zinc fume, silver, copper matte, sulphuric acid, and antimony (pilot plant commissioned November 2025).
    - Nyrstar is operator. Trafigura has a 100% interest.
    - ~0.9 PJ of gas consumed in 2025.
- **Bell Bay Aluminium**, Bell Bay, TAS.
    - ~190 ktpa aluminium; first aluminium smelter in the Southern Hemisphere (est. 1955).
    - Rio Tinto is operator and has a 100% interest.
    - ~0.6 PJ of gas consumed in 2025.
- **Weston Aluminium**, Kurri Kurri (Hunter Valley), NSW.
    - Secondary aluminium recycling; processes aluminium dross and scrap to produce aluminium de-oxidant for steelmaking.
    - Owned by Weston Group (private).
    - <0.5 PJ of gas consumed in 2025.

Key operating cost components for primary aluminium smelters are electricity (~30% to 40% of opex), alumina (35% to 40% of opex), labour, and anode materials (20% to 30% of opex), with gas being a minor input (~1% of opex).

Overview of gas use – Pulp, paper, glass & packaging

Gas demand in these facilities is generally less than ~3.5 PJ/a (although some companies have multiple sites with aggregate demand above this level). Gas is used in furnace melting of glass and steam and heat processes for pulp, paper and packaging. The key companies in East Australia in this sector include Opal ANZ, Kimberley-Clarke, Orora, and Visy. Key longer-term gas contracts include:

- I-O (Visy Glass)-Senex. 20 PJ of natural gas over 10 years from January 2026 (expiring December 2035).
- Orora-Senex. 14 PJ of natural gas over 10 years from January 2026 (expiring December 2035).

Overview of gas use – Construction products

Gas demand in these facilities is generally less than ~3.5 PJ/a (although some companies have multiple sites with aggregate demand above this level). Gas is used in kilns and other heat processes. The key companies in East Australia in this sector include CSR, Boral, Brickworks, and Adbri. Key longer-term gas contracts include:

- Brickworks-Santos. 35 PJ of natural gas over 11 years from 2025 (expiring 2036). This represents ~100% of Brickworks demand requirements at Horsley Park.
- CSR-Senex. 17 PJ of natural gas over 10 years from 2025 (expiring 2034). This represents ~100% of CSR’s Queensland demand requirements and ~28% of its estimated total East Australia portfolio demand.
- Adbri-Senex. 11 PJ of natural gas over 7 years from January 2023 (expiring December 2029).

Overview of gas use – Steel

Onsteel and Bluescope and have gas demand of 5.3 PJ/a and 3.6 PJ/a (2025). Gas is used in high-heat processes and DRI. Key longer-term gas contracts include:

- Bluescope-Senex. 20 PJ of natural gas over 10 years from January 2026 (expiring December 2035). This represents ~55% of BlueScopes current demand requirements at Port Kembla.
- South Australian Government-Santos 200 PJ over 20 years from 1 March 2030 (Binding Term Sheet). The SA government intends to utilize this gas to support Whyalla Steelworks deploy direct iron reduction technology.

Summary

Table 1 – Gas use in industry – summary

Industrial sub-sector	Primary gas function(s)	Gas use in operations (generalised)	Feedstock or fuel
Alumina	Steam generation + high-temp calcination	Gas-fired boilers produce large volumes of steam for Bayer process digestion of bauxite; separate gas-fired calciners (~1,000°C) convert bauxite to alumina product. Demand is continuous and high intensity across the refinery cycle.	Fuel
Captive Power (Mining)	Off-grid electricity generation	Gas-fired turbines and reciprocating engines generate electricity behind the meter for remote mine sites (Pilbara, Goldfields, far-north QLD). Delivered via pipeline gas or trucked LNG/CNG where grid and pipeline access is absent.	Fuel
Fertilisers, Ammonia & Derivatives	Feedstock (hydrogen source) + reformer process heat	Methane is steam-reformed (SMR) to produce hydrogen; hydrogen is then combined with nitrogen via Haber-Bosch to synthesise ammonia. The reformer furnace itself is also gas-fired. Ammonia downstream is converted to urea, ammonium nitrate (fertiliser and explosives grade), DAP/MAP, and other nitrogen compounds. Ammonia chemical feedstock dependence on gas — feedstock typically represents 60%–80% of variable production cost.	Both (feedstock-dominant)
Pulp & Paper, Glass & Packaging	High-temp glass melting + steam and process drying	Continuous gas-fired furnaces melt raw batch materials at ~1,500°C for container and packaging glass; furnace campaigns cannot be interrupted without significant damage to the refractory lining. Steam and direct-fired heat dry pulp, paper, and board.	Fuel
Construction Products	High-temp kiln firing + process drying	Gas fires rotary or vertical kilns for cement clinker (~1,450°C) and lime calcination; kiln tunnel furnaces for bricks and ceramics; lower temperature drying lines for plasterboard and fibre cement board.	Fuel
Steel	Process heat + chemical reductant (DRI)	Gas fires reheat and annealing furnaces in hot and cold rolling mills and finishing operations. In direct reduced iron (DRI), reformed gas (primarily H_2 and CO) strips oxygen from iron ore pellets, substituting for metallurgical coke. BlueScope (Port Kembla) and Whyalla Steelworks are both assessed for DRI transition, which would substantially increase per-tonne gas intensity. Conventional blast furnace–BOF steelmaking (current primary route) uses coal/coke with gas as auxiliary process heat.	Fuel (chemical reductant in DRI)
Oil Refineries & Chemicals	Process heat + on-site hydrogen production	Gas fires process heaters, steam reboilers, and boilers across distillation, hydrotreating, and catalytic reforming units; also used as refinery fuel gas blended with off-gas streams. Hydrogen for hydrotreating (sulphur removal) and hydrocracking is produced on-site via SMR using natural gas as feedstock. Note: Australia has only two operating refineries — Viva Energy Geelong (VIC) and Ampol Lytton (QLD), both retained under government subsidy to 2030. Qenos (ethylene/polyethylene) closed its Botany and Altona operations — ending bulk petrochemicals production in Australia.	Both (fuel-dominant; SMR hydrogen is feedstock use)
Other Metals (aluminium, magnesia, lead/zinc, mineral sands)	High-temp smelting, roasting, calcining, moderate-temp. process heat	Gas used for: (1) Magnesia and Mineral sands — gas fires calcination and roasting kilns; (2) Aluminium — cast house operations and auxiliary process heat; (3) Lead/zinc smelting — gas fires furnaces (e.g., Nyrstar Port Pirie).	Fuel

Cost of gas for large gas users in Eastern Australia

Gas share of costs

This section provides analysis of the relative importance of gas costs across major industrial gas consumers and key industrial subsectors. Gas expenditure is assessed both as a percentage of estimated operating costs and as a percentage of revenue, indicating the importance of gas within each sector's cost structure and overall economics.

Where applicable, Wood Mackenzie cost breakdowns are used to estimate gas costs. For metals, C1 cash cost of products for minerals and products are indicated. C1 cash cost includes all direct operating costs (e.g. raw materials, labour, gas, O&M, other consumables, royalties), but excludes depreciation, financing costs and other corporate overheads (SG&A).

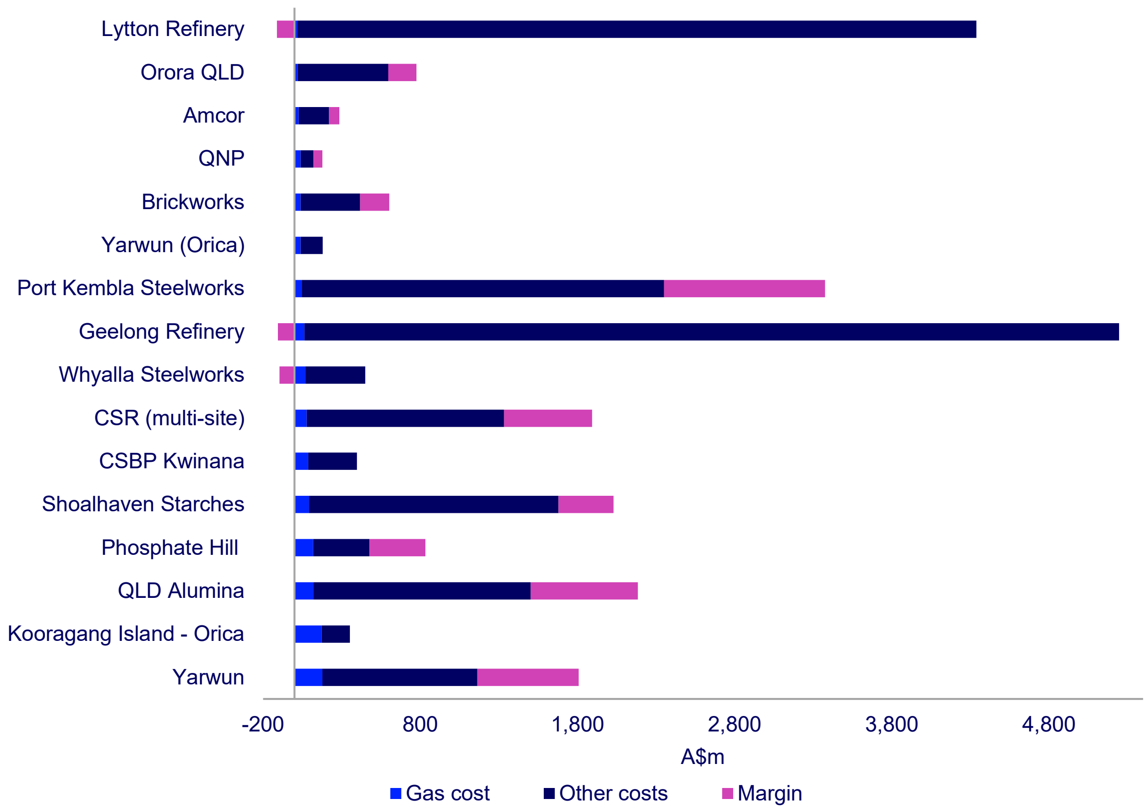
Where Wood Mackenzie cost breakdowns are not available, costs reflect cost of sales as reported in financial statements, which includes direct operating costs plus associated depreciation, but excludes freight and marketing costs. Cost data at facility level is estimated via derivation from the facility's production share of capacity within the relevant business units/geography.

Gas use across industries varies significantly depending on whether it is a feedstock, used for heating, or used for steam generation. Correspondingly, the share of cost across large industrial users ranges anywhere from 1% to 63%.

Summary

The chart below summarises some of the larger East Australia gas users, ranked by total gas cost, together with their operating costs, and cash cost margins.

Figure 5 – Large East Australia gas users by gas cost / other costs / cash cost margin, A$m



Source: Wood Mackenzie, Company Annual Reports

Note – No Margin has been calculated for Orica (Yarwun, NaCN) or Orica Kooragang Island as these are integrated operational facilities without transparent asset-level attributions of operations revenue or earnings.

Table 2 – Large East Australia gas users by revenue, gas cost, total costs and cash cost margin, A$m and %

Facility	Total Revenue (A$m)	Total cost (A$m)	Total gas cost[4] (A$m)	Total est. margin (A$m)	Total Est. margin (%)	Gas cost as share of Revenue (%)	Gas cost as share of Total Cost (%)	Gas cost as share of Margin (%)
Yarwun Alumina[1,3]	1,808.6	1,162.3	178.3	646.3	35.7%	9.9%	15.3%	27.6%
QLD Alumina[1,3]	2,184.0	1,503.1	120.6	680.9	31.2%	5.5%	8.0%	17.7%
Phosphate Hill	833.4	475.8	118.1	357.6	42.9%	14.2%	24.8%	33.0%
Shoalhaven Starches[2]	2,030.0	1,680.0	90.9	350.0	17.2%	4.5%	5.4%	26.0%
CSR (multi-site)[2]	1,893.7	1,332.9	78.0	560.8	29.6%	4.1%	5.9%	13.9%
Whyalla Steelworks[1]	354.7	449.4	69.3	-94.7	-26.7%	19.5%	15.4%	-73.2%
Geelong Refinery[1]	5,142.3	5,247.3	64.2	-105.3	-2.0%	1.2%	1.2%	-61.1%
Port Kembla Steelworks[1]	3,377.0	2,351.7	47.3	1025.3	30.4%	1.4%	2.0%	4.6%
Brickworks[2]	603.0	418.6	39.0	184.4	30.6%	6.5%	9.3%	21.1%
QNP	178.4	120.4	39.4	58.0	32.5%	22.1%	32.7%	67.9%
Amcor[2]	285.4	219.5	27.5	65.9	23.1%	9.6%	12.5%	41.7%
Orora QLD[2]	776.9	597.5	21.5	179.4	23.1%	2.8%	3.6%	12.0%
Lytton Refinery[1]	4,228.0	4,340.0	15.6	-112.0	-2.6%	0.4%	0.4%	-13.9%
Total	**23,695**	**19,889**	**910**	**3,797**				

Source: Wood Mackenzie, AEMO, Company Annual Reports

Notes:

1) Via WM cash cost methodology.

2) Via cost of sales methodology.

3) Contracted delivered gas price of A$8/GJ applied as default to Yarwun (Rio Tinto, alumina) and QLD Alumina (QAL), and therefore not assessed for change in wholesale gas prices.

4) Gas cost represents the wholesale gas price A$12/GJ plus A$1/GJ for delivered cost.

Orica Kooragang Island and Yarwun (Orica NaCN) – were excluded from the above analysis as these are integrated operational facilities without transparent asset-level attributions of operations revenue or earnings.

Kooragang Island – Orica. Estimated total cost = A$352.0m, Gas cost A$172.9m, Gas cost as share of Total Cost = 49.1%

Yarwun (NaCN Orica). Estimated total cost = A$180.2m, Gas cost A$39.5m, Gas cost as share of Total Cost = 21.9%

Summary of large East Australia gas users (industrial/manufacturers) in 2025:

- Total estimated revenue ~A$23.7 billion
- Total estimated cost ~A$19.9 billion
- Total gas cost ~A$ 0.9 billion
- Total estimated margin ~A$3.8 billion

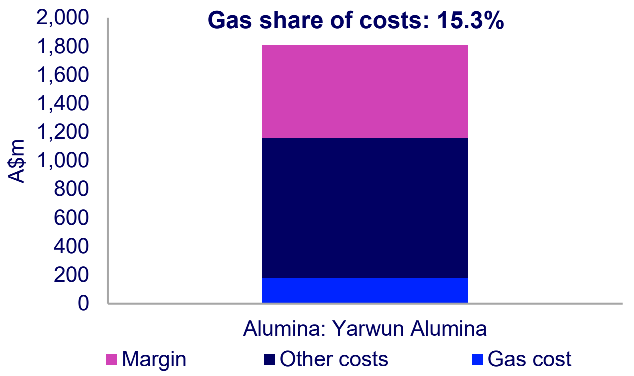
Alumina

Gas is a large variable cost in an alumina refinery; gas consumption responds to process technology choices and efficiency investments, making it a primary focus of capex and operational improvement programs.

The alumina sector sells products intra and inter-state in Australia and also exports overseas, mostly under long-term supply contracts to aluminium smelters. Alumina product is priced off international spot price indices and short-term fixed prices. Domestic consumers of alumina are the aluminium smelters (Portland VIC, Bell Bay TAS, Tomago NSW, Boyne Island QLD). The three major alumina players in Australia – Alcoa, Rio Tinto, South32 – are vertically integrated and globally oriented.

For large gas users in this sector, such as Yarwun Alumina (Rio Tinto), gas costs are 9.9% of total revenue and represents 15.3% of total costs.

Figure 6 – Gas share of costs – Alumina (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

Fertilisers, ammonia & derivatives

Fertilisers

In fertiliser manufacturing, natural gas serves a dual role – firstly as primary feedstock (for ammonia synthesis via the Haber-Bosch process) and secondly as the main energy source. Natural gas is a critical input in fertiliser production, and alternatives to its use in the Haber–Bosch process remain limited and generally uneconomic at scale.

Australia's fertiliser market heavily relies on imports. In 2024, Australia consumed 8.7 Mt of fertiliser with imports accounted for 7.9 Mt (91%)[2]. Local producers such as Mayfair Corporation (Phosphate Hill) compete against imported product. Product prices are therefore strongly linked to international fertiliser and ammonia prices.

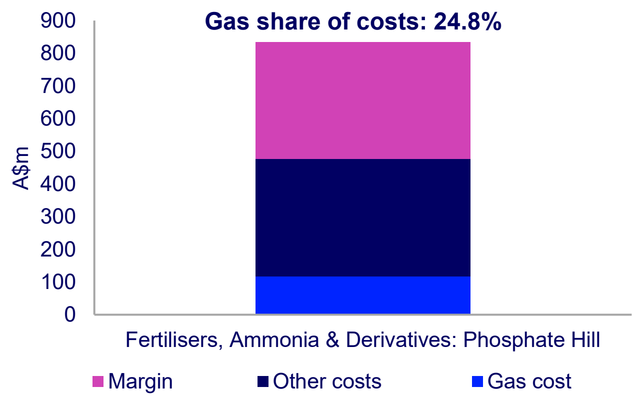
Phosphate Hill (integrated mining and processing operation) gas costs are equivalent to 14.2% of total revenue and represents 24.8% of total costs.

Ammonia Nitrate

Ammonia Nitrate (a derivative of ammonia) is a key component of explosives used in the mining industry. Ammonia Nitrate for the Australian mining industry is largely manufactured in Australia, with only a small volume of imported product due to strict safe handling/regulatory requirements.

For integrated Ammonia/Ammonia Nitrate producers (such as QNP – DynoNobel / CSBP JV), gas cost represents an equivalent of 22.1% of total revenue and representing 32.7% of total costs. Ammonia Nitrate producers have the ability to pass through some of their cost structures linked to ammonia import prices or local gas costs.

Figure 7 – Gas share of costs – Fertilisers and ammonia (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

---

[2] Grain Central, 2026

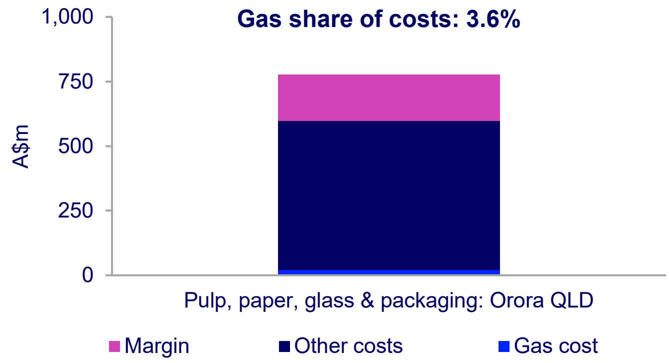
Pulp, paper, glass and packaging

Gas exposure varies across the pulp, paper, glass and packaging sectors. In container glass manufacturing, gas is the predominant fuel source and a critical input to furnace operations. In corrugated fibre / paper packaging, gas remains an important energy input, primarily for steam generation (cylinder dryers on paper machines), process heating, and on-site power generation.

Orora's glass operations in Gawler, SA, has estimated gas costs equivalent to 9.6% of total revenue and representing 12.5% of total costs. Manufacture of aluminium cans requires electricity for presses and coatings, with gas used for annealing/coating cure ovens. Orora's QLD can manufacturing gas costs are equivalent to 2.8% of total revenue and represent 3.6% of total costs[3].

The sector is primarily domestic market focused and exports are minimal. Australian packaging (corrugated fibre, glass, cans, flexible plastics) serve the domestic food, beverage, pharmaceutical and consumer goods sectors.

Figure 8 – Gas share of costs – Pulp, Paper, Glass & Packaging (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

Oil refineries and chemicals

Refineries use gas for hydrogen production via steam-methane reforming, process furnace heating and steam generation. For oil refineries, gas is important as an operating input but costs are minimal compared to crude oil acquisition costs. Refinery economics are driven primarily by the refining margin, not gas prices. For the chemicals sector, gas serves as both feedstock and fuel and therefore is a more material input cost.

At Geelong Refinery, gas costs represent 1.2% of both total revenue and total costs, while at Shoalhaven Starches, gas cost is equivalent to 4.5% of total revenue and represents 5.4% of total costs.

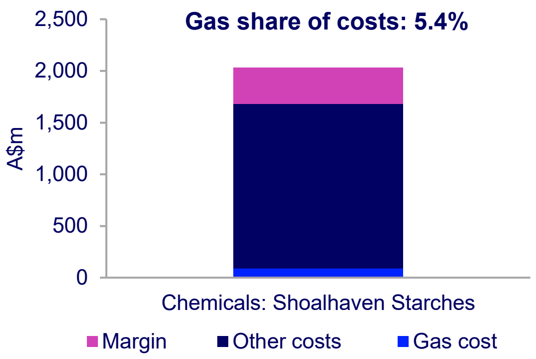
The Australian domestic fuel market is heavily reliant on imports. Australia has only two active fuel refineries, Viva Energy's Geelong and Ampol's Lytton refineries. Their capacities can only meet around 20% of Australia's fuel demand. Therefore, the country strongly relies on imports of gasoline, diesel, and other petroleum products. The two Australian refineries rely on Government support (Fuel Security Service Payment[4] – until at least 30 June 2027 with the option to extend to 30 June 2030) with a minimum margin threshold to protect them during unprofitable periods.

---

[3] Orora FY 2025 Annual Report. Revenue and costs are based on the Orora Cans business segment, as facility-level revenue and cost disclosures are not publicly available.

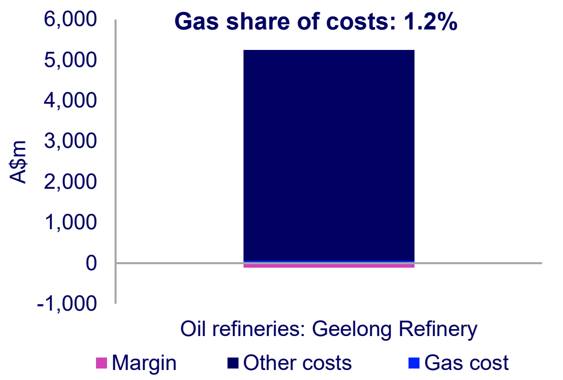
[4] https://www.dcceew.gov.au/energy/security/australias-fuel-security/fuel-security-services-payment

Figure 99 – Gas share of costs – Chemicals (%)



Source: Wood Mackenzie, AEMO, Grain Central

Figure 10 – Gas share of costs – Oil refineries (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

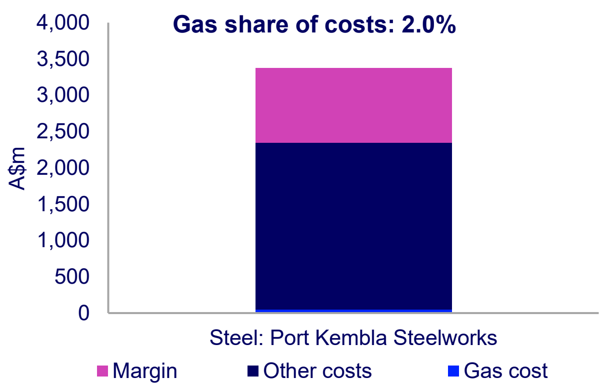
Steel

Steel uses gas as supplementary fuel in heat treatment and downstream processing (BF-BOF process[5]). In the future, gas is being evaluated as the key fuel input for operations by OneSteel (Whyalla) and BlueScope (Port Kembla) as they transition from coal-based blast furnaces toward DRI-EAF[3] technology to reduce emissions.

Australia is a net importer of steel products. Domestic producers include BlueScope Steel (Port Kembla), Whyalla Steelworks, and InfraBuild (Laverton VIC, Rooty Hill NSW). BlueScope is a major global exporter, manufacturing and supplying flat steel, metallic-coated products, and branded roofing materials to over thirty countries worldwide.

Whyalla steelworks uses more gas in its operations than Port Kembla. This is due to the operations at Whyalla utilising magnetite (compared to hematite), but lower scrap steel compared to Port Kembla. Whyalla Steelworks gas costs represent 19.5% of total revenue and 15.4% of total costs. Whyalla Steelworks has had technical and financial difficulties that have resulted in it being placed into administration. Port Kembla Steelworks gas costs represent 1.4% of total revenue and 2.0% of total costs.

Figure 11 – Gas share of costs – Steel (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

Construction Products

In Australia, gas and coal are both used as kiln fuel. For bricks, cement and especially lime, gas is a large cost item and critically important to economics. Lime kilns are the most gas-intensive, closely followed by cement clinkers. The processes require sustained very high temperatures (900–1,500°C) that currently cannot be economically electrified, making gas effectively irreplaceable in the short to medium term.

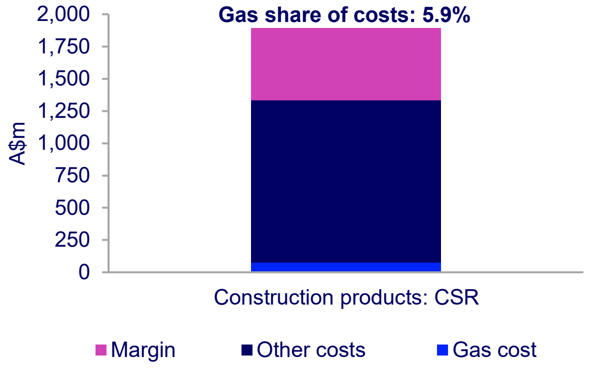
Construction sub-sectors vary enormously. Products such as cement, concrete, bricks, plasterboard and roof tiles are bulky/heavy and generally relatively expensive to import at scale. And whilst this provides a degree of natural geographic protection from overseas competition, imports and alternative building products do provide competition to local products

[5] Blast furnace (BF), Basic Oxygen Furnace (BOF), Direct Iron Reduction (DRI), Electric Arc Furnace (EAF)

with high costs in this sector. The construction sector is driven by Australian housing completions, infrastructure projects and commercial construction.

For larger gas users in this sector, such as Brickworks, gas costs are 6.5% of total revenue and represents 9.3% of total costs. Other gas users in this sector have different cost profiles. For example, CSR's gas cost is 4.1% of total revenue and represents 5.9% of total costs.

Figure 12 – Gas share of costs – Construction products (%)



Source: Wood Mackenzie, AEMO, Company Annual Reports

Product price curves and gas price impact

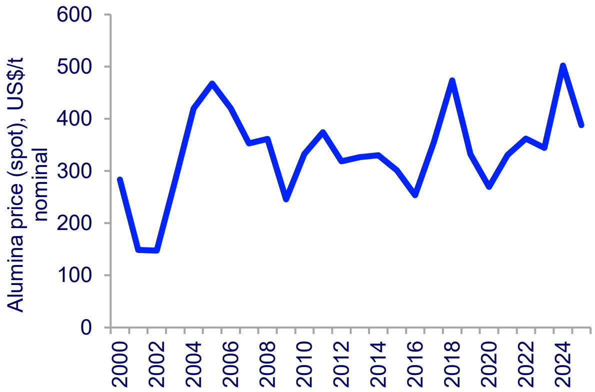
The price curves of end products across the key sub-sectors have evolved over time, reflecting shifts in market dynamics, technology, and industry development. The below analysis illustrates these changes and highlights the varying pricing trends among some of the key commodities related to the large energy users in this report.

Alumina

The alumina market surplus that emerged last year is set to persist and widen through 2026. Softened demand driven by production curtailments at Middle Eastern smelters amid the ongoing conflict has coincided with an accelerating wave of new Chinese refining capacity, with 6 Mtpa expected to be commissioned in 2026 alone. This is forecast to push the global alumina surplus to 3.6 Mt this year, keeping prices depressed and inventories elevated. Against this backdrop, alumina prices are forecast to average around US$305/t in 2026.

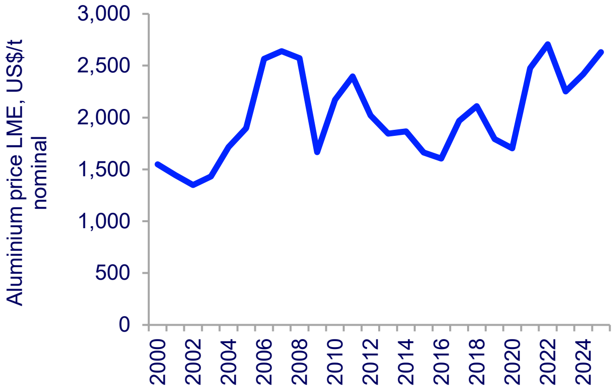
Historically, aluminium prices have shown a strong correlation with the 90th percentile of the global C1 cost curve. Cyclical supply, demand and stock changes are the main influences on forecast medium-term prices. Aluminium supply/demand is expected to continue its tightening trend through 2026, with price expected to average US$3,511/t.

Figure 13 – Historical Alumina price (Spot), US$/t nominal



Source: Wood Mackenzie

Figure 14 – Historical Aluminium LME price, US$/t nominal



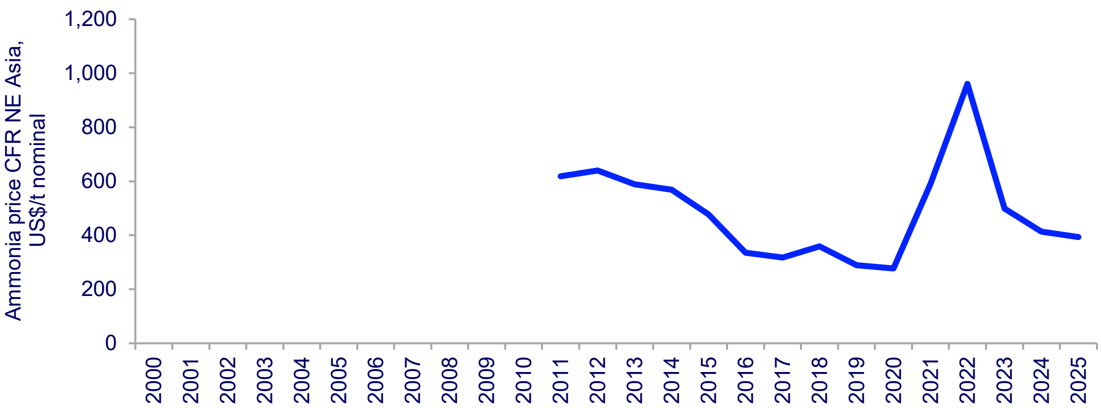
Source: Wood Mackenzie

Ammonia

Ammonia plant outages in Saudi Arabia and gas supply issues in Trinidad have periodically tightened markets over the last two years. With 25% of the internationally traded ammonia and 37% of urea exported through the Strait of Hormuz, the current Middle East crisis has resulted in a spike in prices in H1 2026.

Ammonia prices have a major and direct impact on the production cost of fertilisers and therefore ammonia prices dictate fertilisers wholesale pricing. Fertilisers transactions are traditionally dominated by spot market trading. Longer-term contracts may have pricing that is linked to gas price or ammonia price benchmark. Australian fertlisers manufacturers compete with imports that are linked to international spot prices, and therefore manufacturers are limited in their ability to pass through their gas cost to customers.

Figure 15 – Historical Ammonia price CFR NE Asia, US$/t nominal



Source: Wood Mackenzie

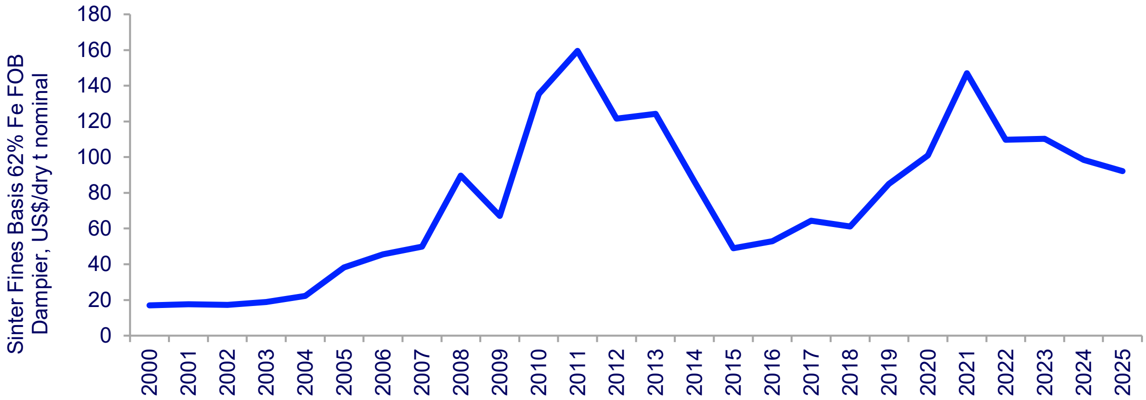
Ammonia nitrate pricing is influenced by international ammonia prices. Whilst local manufacturers need to be competitive with imports, safety and security regulations limits the amount of ammonia nitrate that can be imported to displace locally produced product. Local manufacturers of ammonia nitrate therefore can link their customer prices to their input costs (such as ammonia import purchases and domestic gas pricing) to pass through changes in local costs relative to imported product.

Iron Ore

Iron ore proved resilient through 2025, averaging roughly US$100/t. So far in 2026, cost-push support has helped underpin prices, though the benchmark has drifted back toward the psychologically important US$100/t mark, and the balance of risks now points to prices settling around that level. Ample supply, softening Chinese demand, and trade-policy uncertainty (US tariffs, the EU Carbon Border Adjustment Mechanism (CBAM), and China's steel export licensing) all point to sustained downward pressure.

Iron Ore is the key input component to steel making and its price is an influence (together with other inputs such as coal, limestone and electricity) on steel pricing. However, it generally isn't a direct pass-through cost from steel makers to customers.

Figure 16 – Historical Iron Ore price, sinter fines basis 62% Fe FOB Dampier, US$/dry t nominal

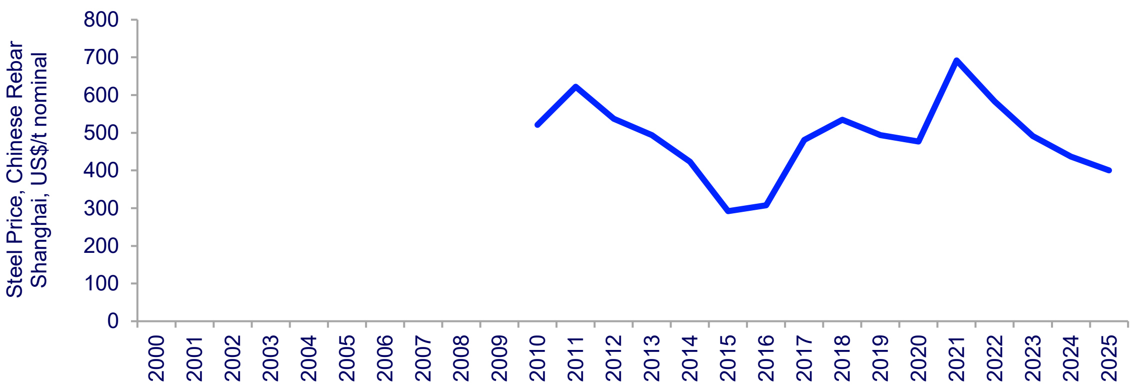


Source: Wood Mackenzie

Steel

Steel prices were range-bound in 2025, with Chinese prices falling nearly 9% on weak domestic demand, EU prices broadly flat, and US prices rising 11.5% supported by a 50% blanket import tariff under the Trump administration. Prices across regions are expected to trend higher in 2026 amid elevated raw material and energy costs. Scrap prices rose recently due to Middle East conflict tensions but are expected to stabilise as that premium fades, with longer-term divergence between regions. The EU market stands to benefit from accelerating EAF adoption driving demand against constrained domestic supply, while China faces medium-term headwinds from limited EAF capacity, though its decarbonisation push will ultimately support sustained scrap demand growth.

Figure 17 - Historical Steel price, Chinese rebar Shanghai (excl. VAT), US$/t nominal



Source: Wood Mackenzie

Gas price impact analysis

The starting point for our gas price impact analysis was a base case wholesale price of A$12/GJ for East Australia. We then assessed the impact of A$2/GJ reduction in gas price (assumed gas price A$10/GJ). A further impact assessed a A$4/GJ reduction for East Australia (i.e. gas price of A$8/GJ). Across all gas price scenarios, we assume a A$1/GJ average transport cost to derive a delivered price at each facility.

The only exception to this is facilities on long-dated legacy gas contracts priced materially below the current market price assumption of A$12/GJ (Yarwun Alumina and Queensland Alumina). These are analysed considering their contracted price only (assumed A$8/GJ). Whilst some other industrial/manufacturer companies may have also contracted supplies on a medium and longer-term basis, the contracted gas price is likely closer to the assumed wholesale price of A$12/GJ (as the contracts have been signed in recent years). The contracted volumes may not reflect their full demand requirements (i.e. part of a portfolio of gas supply contracts). We have therefore included the price impact analysis of these other companies, regardless of their contracted supply, to illustrate the indicative price impacts of the changes in wholesale gas price on their overall operations.

For steel manufacturers, we also consider the scenario where production technologies move from current BF-BOF to DRI-EAF steel production. These are illustrative technology scenarios and not price sensitivities, and are described as such in the following "Large gas user facilities deep dive" section of this report.

Table 3 – Indicative gas price impact analysis – summary

	Present gas cost assumption[4] (A$12/GJ)		Reduced gas cost assumption[4] (A$12/GJ down to A$10GJ)		Reduced gas cost assumption[4] (A$12/GJ down to A$8/GJ)	
Facility	**Total gas cost** (A$m)	**Est. margin** (%)	**Gas Cost Reduction** (A$m)	**Improved Margin** (%)	**Gas Cost Reduction** (A$m)	**Improved Margin** (%)
Yarwun Alumina[1,3]	178.3	35.7%	0	0.0%	0.0	0.0%
QLD Alumina[1,3]	120.6	31.2%	0	0.0%	0.0	0.0%
Phosphate Hill	118.1	42.9%	18.2	2.2%	36.3	4.4%
Shoalhaven Starches[2]	90.9	17.2%	13.9	0.7%	27.9	1.4%
CSR (multi-site)[2]	78	29.6%	12	0.6%	24.0	1.3%
Whyalla Steelworks[1]	69.3	-26.7%	10.7	3.0%	21.3	6.0%
Geelong Refinery[1]	64.2	-2.0%	9.9	0.2%	19.8	0.4%
Port Kembla Steelworks[1]	47.3	30.4%	7.3	0.2%	14.5	0.4%
Brickworks[2]	39	30.6%	6	1.0%	12.0	2.0%
QNP	39.4	32.5%	6.1	3.4%	12.1	6.8%
Amcor[2]	27.5	23.1%	4.3	1.5%	8.5	3.0%
Orora QLD[2]	21.5	23.1%	3.3	0.4%	6.7	0.8%
Lytton Refinery[1]	15.3	-2.6%	2.3	0.1%	4.7	0.1%
Total	**909.4**		**93.9**		**187.8**	

Source: Wood Mackenzie, AEMO, Company Annual Reports

Notes:

1) Via WM cash cost methodology.

2) Via cost of sales methodology.

3) Contracted delivered gas price of A$8/GJ applied as default to Yarwun (Rio Tinto, alumina) and QLD Alumina (QAL), and therefore not assessed for change in wholesale gas prices.

4) Gas price represents the wholesale gas price, A$1/GJ is added for delivered cost.

Orica Kooragang Island and Yarwun (Orica NaCN) – were excluded from the above analysis as these are integrated operational facilities without transparent asset-level attributions of operations revenue or earnings.

Kooragang Island – Orica. Estimated total cost = A$352.0m, Gas cost A$172.9m, Gas cost as share of Total Cost = 49.1%

Yarwun (NaCN Orica). Estimated total cost = A$180.2m, Gas cost A$39.5m, Gas cost as share of Total Cost = 21.9%

Summary of large East Australia gas users impact of wholesale gas prices:

- A reduction in the wholesale gas price from $12/GJ to $10/GJ would lower annual operating costs by ~A$94 million or by ~A$188 million if reduced from $12/GJ to $8/GJ. This compares with total annual operating costs of almost A$$20 billion.
- 0.4% average improvement in profit margin with A$10/GJ (reducing from A$12/GJ) gas prices or ~0.8% with A$8/GJ gas price.

The gas price reduction is most material for gas-intensive fertilizer, ammonia & derivatives and for Whyalla Steel, where gas is either a feedstock or the principal process energy input. Phosphate Hill has the largest gas cost saving A$18.2m (under a A$2/GJ gas price reduction) and A$36.3m (under a A$4/GJ gas price reduction). QNP's estimated margin improves 3.4% (under a A$2/GJ gas price reduction) and 6.8% (under a A$4/GJ gas price reduction).

By contrast, the impact is marginal for steelmakers and oil refineries, where gas is only a small share of total cost. Port Kembla's margin is essentially unchanged (30.4% to 30.6% under a A$2/GJ gas price reduction) and Whyalla remains deeply loss-making (margin changes from −26.7% to −23.7% under a A$2/GJ gas price reduction and -20.7% under a A$4/GJ gas price reduction), while the Geelong and Lytton oil refineries margin barely move. For these facilities, cost position and profitability are driven by iron ore price, scale and refining margins rather than the gas price.

Where Wood Mackenzie asset-level cost models are available, costs are on a C1/cash-cost basis (excluding depreciation, financing and SG&A). Where they are not, costs reflect company-reported cost of sales (which includes depreciation but excludes freight and marketing). Because the two bases treat depreciation differently, gas-cost shares and margins are strictly comparable only within a basis, not across it. Facilities are marked 1 (cash cost) and 2 (cost of sales) accordingly. Rankings by absolute gas cost are unaffected, however comparisons of gas-share-of-cost and margin between a cash-cost and cost-of-sales basis should be read as indicative only.

Margins and gas-cost shares for individual facilities are Wood Mackenzie estimates derived from asset-level modelling and, where company cost models are unavailable, from each facility's production share of the relevant business unit's reported cost of sales. They are not company-disclosed facility financials and may differ from figures the operator would report. This is particularly relevant for facilities shown in a loss position (notably Whyalla Steelworks and the Geelong and Lytton oil refineries), where the estimated margin depends on allocation assumptions that the operator has not confirmed.

Large gas user facilities deep dive

Yarwun (Rio Tinto, alumina)

Rio Tinto's Yarwun alumina refinery is located 10 km from Gladstone in central Queensland. It is Rio Tinto's first wholly owned and operated alumina refinery, with Gladstone (QAL) alumina refinery following later. Commissioned in 2004 and further expanded in 2012, Yarwun now has a smelter grade alumina (SGA) capacity of 3.2 Mtpa, with 2025 production reaching 2.9 Mt.

Alumina is refined from bauxite through the Bayer process, which involves digestion, precipitation, and calcination. Digestion and calcination are the most energy-intensive steps, and gas is the core energy input to both. At Yarwun, a 160 MW gas-fired cogeneration plant raises the high-pressure steam that dissolves alumina from bauxite in digestion and supplies electricity to the refinery, with surplus energy being exported to the Queensland electricity grid.

Separately, two gas-fired fluid-flash calciners handle the calcination duty, firing the kilns directly to drive off moisture at temperatures above 1,000°C to produce smelter grade alumina. The high-temperature calcination step in particular has no commercially viable substitute today, leaving the refinery structurally dependent on gas. In 2025, Yarwun's purchased gas volume is estimated at around 22.3 PJ, corresponding to a gas intensity of roughly 7.6 GJ/t alumina.

Wood Mackenzie estimates Yarwun's gas cost at around A$178.3 million at an assumed contract gas price of A$7/GJ (plus A$1/GJ transport costs). Rio Tinto has contracted gas supply from Origin Energy on a long-term basis (through to ~2031), accounting for approximately 15% of total cash costs. Raw materials involving bauxite, caustic soda and lime represent 43% of total cash costs.

Note: this table is the illustrative current-market-repricing scenario referenced in the executive summary, not the standard A$2/GJ sensitivity. It is presented to show the value of Yarwun's legacy contract, and is not comparable to the A$2/GJ deltas applied elsewhere.

Table 4 – Yarwun (Rio Tinto) 2025 cost breakdown (A$7/GJ contract vs A$12/GJ scenario)

Cash cost component	Cash Cost at A$7/GJ contract price[1] *(A$m)*	Cash Cost at A$12/GJ scenario[2] *(A$m)*
Gas	178.3	289.8
Raw materials[3]	501.1	501.1
Others[4]	482.9	482.9
Total Cash Cost	**1,162.3**	**1,273.7**

Source: Wood Mackenzie

Notes:

1) *A$7/GJ contract price represents the estimated price paid by Rio for gas supplied by Origin Energy under contract to ~2031. An additional A$1/GJ is added for delivered price.*
2) *A$12/GJ scenario represents the assumed current wholesale gas price. An additional A$1/GJ is added for delivered price.*
3) *Raw materials costs include bauxite (including freight cost), caustic soda and lime costs.*
4) *Others includes labour, coal, consumables and repair & maintenance etc.*

In 2010, Rio Tinto signed a 20-year contract with Origin Energy to feed into Yarwun's gas-fired cogeneration plant. Origin Energy will supply up to 22.8 PJ/a at full operation (actual consumption in 2025 was 22.3PJ/a). As this gas supply contract was signed in 2010 on a fixed plus CPI basis, Wood Mackenzie understands the gas price is substantially below today's domestic contract gas prices.

The low contracted gas price assists Yarwuns' position in the lowest quartile of the global alumina cash cost curve.

Port Kembla (BlueScope)

BlueScope's Port Kembla steelworks is an integrated steel making site, located in the Illawarra region of New South Wales. The plant is built around blast furnace-basic oxygen furnace (BF-BOF) operation, supported by coke ovens, a sinter plant, continuous casting and hot rolling mills. The site produces slab, hot rolled coil and plate for sale, with a portion of output transferred to further finishing at an adjacent line within Port Kembla and at BlueScope's Western Port (VIC) facility. Port Kembla has a crude steel capacity of around 3.2 Mtpa, with 2025 crude steel production reaching 3.07 Mtpa.

Under the BF-BOF route, coking coal and coke are the primary fuel inputs, whereas natural gas is a supplementary fuel in reheat furnaces, steam generation, ancillary heating and power generation. Alongside purchased fuel demand, energy is also generated within the integrated plant, benefitting from the cokemaking and ironmaking processes where by-product gases (coke oven gas, blast furnace gas and BOF gas) are recovered and reused internally. In 2025, purchased gas volume was estimated to be ~3.6 PJ, corresponding to a 1.2 GJ/t crude steel gas intensity.

Wood Mackenzie estimates Port Kembla's gas cost at A$15.4/t of crude steel in 2025, accounting for 2% of total cash costs at a wholesale gas price of A$12/GJ (plus an additional A$1/GJ assumption for delivered coast). Labour stands as the single largest cost component, affected by Australia's high wage environment. Raw materials, including iron ore, coal and scrap, follow closely and collectively accounted for 57% of total cash costs.

Table 5 – Port Kembla 2025 crude steel cash cost breakdown (BF-BOF vs DRI-EAF production) – A$12/GJ wholesale gas price.

Cash cost component	BF-BOF Cash Cost (A$ / t crude steel)	DRI-EAF Cash Cost (A$ / t crude steel)
Gas	15.4	157.3
Iron ore	176.7	238.9
Coal	140.6	0
Coke	0	0
Scrap	126.3	0
Electricity	5.2	120.9
Labour	186.9	186.9
Others	134.9	134.9
Credits	-19.9	-17.9
Total Cash Cost	**766.0**	**820.9**

Source: Wood Mackenzie

Notes: DRI-EAF figures are indicative, based on a full transition to 100% DRI feed at A$12/GJ wholesale gas

For the purposes of this analysis, Wood Mackenzie models an indicative Direct Reduction Iron - Electric Arc Furnace (DRI-EAF) scenario in which Port Kembla's current crude steel capacity of 3.2 Mt is fully replaced by a gas-based direct reduction operation using 100% DRI feed. In the DRI-EAF operation, natural gas is reformed into a hydrogen and carbon-monoxide-rich reducing gas, which is fed into a shaft furnace to strip oxygen from iron ore pellets and produce solid metallic iron (DRI). The DRI is then melted in an electric arc furnace (EAF) to produce crude steel. Natural gas thus serves as both the chemical reductant and the primary heat source, replacing coal and coke entirely. Because the ironmaking stage no longer generates by-product gases, the full gas requirement must be met by purchased supply.

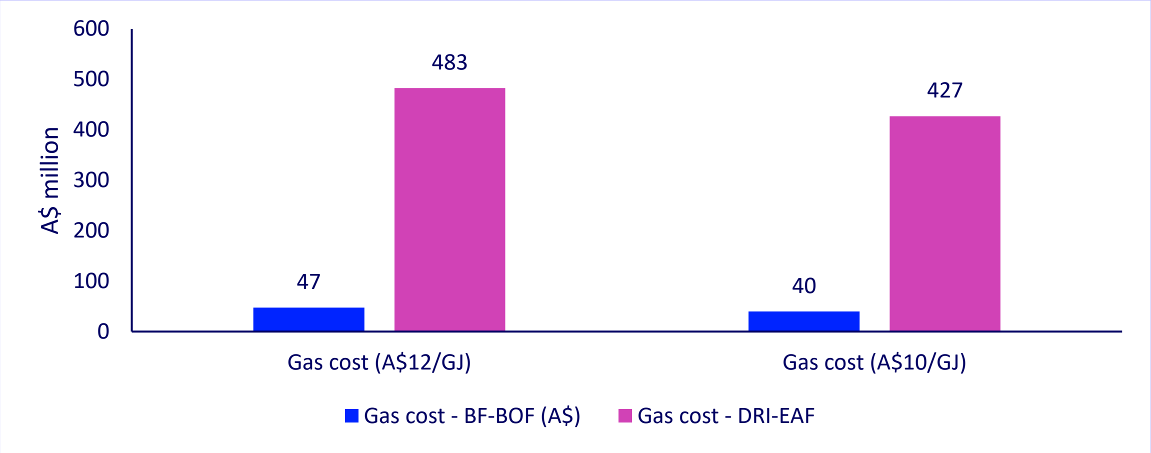
Gas consumption would rise from 3.6 PJ under BF-BOF to 37 PJ under DRI-EAF, with gas intensity rising from 1.2 GJ/t to 12.1 GJ/t of crude steel. Coal, coke and scrap are largely removed from the cost structure. Conversely, higher gas volumes, increased EAF electricity consumption and a premium on DR-grade pellets offset these savings and raise total cash cost from A$766/t to A$821/t. As a result, gas climbs from 2% to 19% of total operating costs.

Like other large industrial users, BlueScope procures gas directly from upstream producers rather than through a retailer. In 2023 it signed a 10-year gas contract with Senex Energy to supply Port Kembla with 2.0 PJ/a of gas from 2026, sourced from the Surat Basin in Queensland and delivered south to the Illawarra via long-haul transmission.

On the demand side, Port Kembla is Australia's largest flat-steel producer, supplying slab, hot rolled coil and plate into domestic markets. The majority of output is consumed internally by BlueScope's downstream coating lines to produce COLORBOND and ZINCALUME, which carry premium pricing and natural freight protection. The balance is sold as commodity flat products into the domestic market and faces direct competition from lower-cost imports, particularly from China and Southeast Asia.

BlueScope has set a target to reduce steelmaking emission intensity by 12% between 2018 and 2030, with a net-zero ambition by 2050. In 2024, Port Kembla reduced its intensity by 5%, from 2.18 t CO_2 per tonne of raw steel in FY2018 to 2.07 t CO_2 per tonne of raw steel, being placed in the top 15% BF-BOF performers globally, driven by increased scrap usage and operational efficiency. However, BF-BOF steelmaking remains one of Australia's most carbon-intensive industrial processes. It will require a DRI transition to achieve more than a 50% carbon emissions reduction.

Figure 18 – Gas price sensitivity analysis for Port Kembla steel works, A$ million



Source: Wood Mackenzie

As part of our analysis of the impact of gas prices on Australian industrial gas users, Wood Mackenzie assessed the relative impact of a potential A$2/GJ reduction in wholesale gas prices. For Eastern Australia, we assume a base case gas price at A$12/GJ and the alternative gas price at A$10/GJ. Under the current BF-BOF process, a A$2/GJ change in wholesale gas price moves total cash cost by only A$2.4/t. However, a potential transition to gas-based DRI-EAF scenario would lower cost by around A$24/t as a result of a A$2/GJ change in wholesale gas price, or roughly A$74 million total change in gas costs at 3.2 Mt capacity. As a decarbonisation pathway, a transition to gas-based DRI-EAF would be assessed against a broad range of commercial and policy factors, including Safeguard Mechanism obligations, rather than operating costs alone.

Table 6 – Gas price sensitivity analysis for Port Kembla

Wholesale gas price[1] *(A$/GJ)*	**BF-BOF operation**		**DRI-EAF operation**	
	Gas Cost *(A$/t crude steel)*	**Share of total cash cost** *(%)*	**Gas Cost** *(A$/t crude steel)*	**Share of total cash cost** *(%)*
A$8 / GJ	10.7	1.4%	108.9	14.1%
A$10 / GJ	13.0	1.7%	133.1	16.7%
A$12 / GJ (base)	15.4	2.0%	157.3	19.2%

Source: Wood Mackenzie

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

Overall, Port Kembla can be characterised as a low gas price-exposure facility today, with gas at just 2% of cash cost and competitiveness driven primarily by labour, raw materials and import competition. This changes fundamentally under a DRI transition: gas would rise to around 19% of cash cost.

Whyalla Steelworks (OneSteel)

The Whyalla Steelworks is an integrated operation with a nominal crude steel capacity of 1.2 Mtpa, producing long products including rail, structural sections and rod. Unlike conventional steelworks, the Whyalla plant runs a hybrid operation, which combines blast furnace-basic oxygen furnace (BF-BOF) operation with an on-site direct reduced iron (DRI) plant. Natural gas plays a larger role acting as both a process fuel and a reductant in the DRI plant.

As operational and financial distress caused the plant to be placed into administration in February 2025, crude steel production has fallen sharply, from 1.16 Mt in 2020 to 0.37 Mt in 2025. In the meantime, total gas consumption has not fallen proportionally with output – 2025 inlet gas was around 5.3 PJ against 0.37 Mt of steel produced. This reflects a combined impact of both progressive removal of coke oven capacity and the minimum gas consumption of the DRI plant despite its low utilisation rate.

Wood Mackenzie estimates Whyalla's gas cost at A$187.4/t crude steel at a wholesale gas price of A$12/GJ, representing approximately 15% of total cash costs, far higher than Port Kembla's 2%. The elevated gas cost is due to the combined impacts of the hybrid configuration, amplified by low production volumes in 2025 (0.37 Mt). Within total cash costs, labour is the dominant cost component at A$597.5/t, a high share due to the low production volumes spreading a largely fixed workforce over a very small output base. Raw materials including iron ore, coke and scrap together account for 41% of total cash cost.

Table 7 – Whyalla 2025 crude steel cash cost breakdown (BF-BOF vs DRI-EAF production)

Cash cost component	BF-BOF Cash Cost (A$ / t crude steel)	DRI-EAF Cash Cost (A$ / t crude steel)
Gas	187.4	157.3
Iron ore	215.7	194.5
Coal	0.0	0
Coke	164.4	0
Scrap	119.0	0
Electricity	26.3	120.9
Labour	597.5	597.5
Others	96.8	96.8
Credits	-192.5	-173.2
Total Cash Cost	**1,214.7**	**993.8**

Source: Wood Mackenzie

Note: DRI-EAF figures are indicative, based on a full transition to 100% DRI feed at A$12/GJ wholesale gas. BF-BOF figures reflect 2025's low production volume of 0.37 Mt; DRI-EAF assumes the planned 1.5 Mt capacity at 95% utilisation, with a full transition to 100% DRI feed at A$12/GJ wholesale gas.

Similarly, Wood Mackenzie models an indicative DRI-EAF scenario for Whyalla Steelworks, in which the steelworks will employ a 1.8 Mtpa direct reduction plant (DRP) and ramp crude steel capacity to 1.5 Mtpa by 2030, in line with OneSteel's plan.

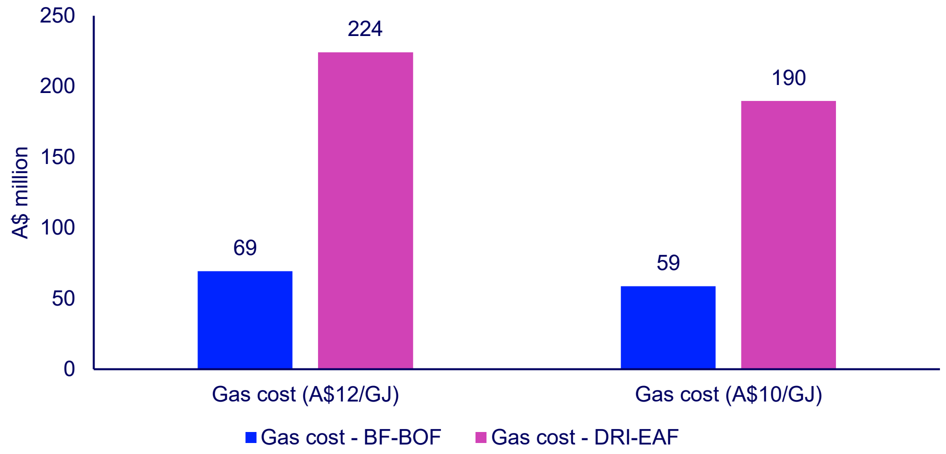
Gas consumption would rise from 5.3 PJ under current operations to approximately 17 PJ under DRI-EAF, with gas intensity at 12.1 GJ/t. Coke and scrap are eliminated from the cost structure, reducing total cash cost from A$1,214.7/t to A$993.8/t, a significant decrease of A$221/t. Gas cost per tonne also falls, from A$187.4/t to A$157.3/t, because the modelled DRI operation runs at high utilisation, spreading gas use across a significantly larger output base than the current depressed production. Gas remains around 16% of total cash costs, which indicates that gas-price sensitivity is a structural feature of this asset under both configurations.

In February 2026, the South Australian Government secured a binding 10-year agreement for the supply of 20 PJ per annum from 1 March 2030, delivered by Santos ex-Moomba via the Moomba-to-Adelaide Pipeline System (MAPS). The contracted volume exceeds modelled DRI demand of approximately 17 PJ, providing operational headroom but also potential take-or-pay exposure if production underperforms.

On the demand side, Whyalla produces long products for domestic construction, infrastructure and rail markets. Its niche provides some insulation from imports, but small scale and single-site concentration leave it sensitive to domestic demand cycles and government infrastructure spending.

Whyalla's decarbonisation pathway is more immediate than Port Kembla's. The gas-based DRI transition is targeted for commissioning around 2030, aligned with the Santos gas supply agreement, and would cut emissions by approximately 50% relative to the current BF-BOF route. A further shift toward hydrogen-based DRI was originally envisaged through a planned 250 MW electrolyser, but that project was formally cancelled in early 2025 following cost overruns and the site's financial collapse.

Figure 19 – Gas cost sensitivity analysis for Whyalla steel works, A$ million



Source: Wood Mackenzie

In the analysis of the impact of gas prices on Whyalla Steelworks, Wood Mackenzie models Whyalla at a wholesale gas price of A$12/GJ as a base case and a reduced gas price of A$10/GJ under both current operations and DRI-EAF operation. The A$2/GJ gas price reduction lowers BF-BOF cash cost by approximately A$28.8/t, which is around A$10.7 million per annum for 2025's reduced output of 0 .37 Mt. Under the modelled DRI-EAF scenario at 1.5 Mtpa capacity, the same A$2/GJ reduction lowers cost by approximately A$24.2/t, or around A$34.5 million per annum. In both cases, the gas price sensitivity impact is more material than at Port Kembla, but remains modest against Whyalla's elevated total cost, which is driven primarily by low utilisation and high fixed costs.

Table 8 – Gas price sensitivity analysis for Whyalla current BF-BOF operation

Wholesale gas price[1] *(A$/GJ)*	BF-BOF operation		DRI-EAF operation	
	Gas Cost *(A$/t crude steel)*	Share of total cash cost *(%)*	Gas Cost *(A$/t crude steel)*	Share of total cash cost *(%)*
A$8 / GJ	129.8	11.2%	108.9	11.5%
A$10 / GJ	158.6	13.4%	133.1	13.7%
A$12 / GJ (base)	187.4	15.4%	157.3	15.8%

Source: Wood Mackenzie

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

A lower gas price improves margin but does not, on its own, restore competitiveness. The decisive levers are restoring production volumes and completing the DRI transition. Whyalla's short to medium-term outlook depends more on returning utilisation toward design capacity than specific sensitivity to changes in gas price.

Horsley Park (Brickworks)

Brickworks Group has a diversified corporate structure consisting of three divisions: Building Products Australia, Building Products North America and Property. Building Products Australia is a manufacturer and distributor of building products across all Australian states. In total, Building Products Australia comprises 19 active manufacturing sites, and a vast network of company-owned design centers, studios and resellers across the country. Brickworks merged with Soul Patts in 2025.

The portfolio includes key brands such as Austral Bricks (Australia's largest clay brick manufacturer), Austral Masonry and Bristile Roofing. The portfolio also includes a 33% interest in the Southern Cross Cement joint venture, established to import and supply cement to the joint venture partners in Queensland.

Brickworks utilises gas as fuel for its brick kilns. Brickworks' Horsley Park operations has improved efficiency over the last few years, reducing its gas demand in operations. In 2025, Brickworks purchased gas volume was estimated to be ~3 PJ. Wood Mackenzie estimates Brickwork's gas cost at A$39m per year, accounting for ~9.3% of total cash costs at a wholesale gas price of A$12/GJ (delivered price of A$13/GJ including transport). A reduction of wholesale gas prices from A$12/GJ to A$10/GJ would reduce total costs by ~1.4%.

Table 9 – Gas price sensitivity analysis for Brickworks FY2024 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] (A$m)	Cash Cost at A$10/GJ scenario[1] (A$m)	Cash Cost at A$8/GJ scenario[1] (A$m)
Gas	39	33	27
Other cash costs	380	380	380
Total Cash Cost	**419**	**413**	**407**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

In November 2022, Santos announced it had signed a gas supply agreement with Brickworks for the supply of 35PJ of gas to be delivered over 11 years, beginning 2025 (with an option to extend). The gas price was a fixed plus CPI pricing structure. Whilst gas cost doesn't play a material role in Brickworks' overall costs, securing a long term gas supply contract provides gas cost predictability over the next decade for the operations.

QNP (DynoNobel)

Queensland Nitrates Pty Ltd (QNP) operates an integrated ammonium nitrate facility at Moura, in central Queensland's Bowen Basin, around 160 kilometers inland from the port of Gladstone. The site is a 50/50 joint venture between Wesfarmers Chemicals, Energy and Fertilisers (through CSBP) and Dyno Nobel Asia Pacific, and has operated since 2000. Built around an on-site ammonia plant, a nitric acid plant and an ammonium nitrate plant, QNP has a crude ammonium nitrate capacity of around 230 ktpa and supplies roughly a quarter of the explosives-grade ammonium nitrate consumed by the Queensland resources sector.

Natural gas is QNP's principal raw material and fuel. Ammonia is produced on site by steam methane reforming, in which gas is both the hydrogen feedstock and the process fuel. The ammonia is then converted to nitric acid and reacted to form ammonium nitrate. Because reforming sits at the front of the production chain, gas consumption per tonne of product is high relative to most other large industrial users. In 2025, purchased gas volume was estimated to be ~3.0 PJ. QNP also purchases around 20 ktpa of merchant ammonia to supplement on-site production, itself a gas-derived input that is effectively a pass-through of the prevailing gas price.

Wood Mackenzie estimates QNP's gas cost at A$601.4/t of ammonium nitrate, accounting for ~31.5% of the total cash costs at a wholesale gas price of A$12/GJ (delivered price of A$13/GJ including transport). Gas is the single largest cost component, and purchased merchant ammonia – itself a gas-derived input – adds further indirect exposure. The move from A$12/GJ to A$10/GJ lowers QNP's total cash cost by around 5.1%.

Table 10 – Gas price sensitivity analysis for QNP (Ammonia Nitrate) 2025 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] (A$m)	Cash Cost at A$10/GJ scenario[1] (A$m)	Cash Cost at A$8/GJ scenario1 (A$m)
Gas	39	33	27
Other cash costs	81	81	81
Total Cash Cost	**120**	**114**	**108**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

QNP's scope to reduce its gas exposure is limited. Its inland location makes wholesale substitution of merchant ammonia imports impractical, and a 2020 CSIRO/ARENA feasibility study found that an on-site green hydrogen-to-ammonia plant displacing only 20% of QNP's ammonia requirement would cost A$150–200 million in capital, with no commercial case at the time.

The strategy across Dyno Nobel's Australian operations is to deepen domestic gas security rather than to fully substitute imported ammonia. Wholesale ammonia imports would simply trade gas-price exposure for global ammonia-price exposure. In the near term, QNP's competitiveness therefore depends on securing domestic gas at workable prices rather than on switching feedstock.

On the demand side, QNP's output is effectively captive to mining activity in the Queensland resources sector, concentrating its revenue in a single region and commodity complex. Metallurgical coal, the dominant end-use, faces longer-dated demand than thermal coal given the slower decarbonisation path for steelmaking, but neither is immune to cyclical downturns, and a sustained pull-back in regional mining volumes would feed directly through to ammonium nitrate offtake.

QNP's joint venture income to Dyno Nobel Asia Pacific rose 71% to A$29 million in FY2025. Ammonium-nitrate producers generally have some capacity to pass-through gas costs through customer contracts, but this earnings step-up should not be read as direct evidence of that mechanism. It more likely reflects the ammonium-nitrate/explosives price cycle and strong mining-driven demand over the period. However, we would characterise QNP's gas price pass-through ability as plausible given contract structures in the sector.

QNP has a gas supply contract with the Greater Meridian Joint Venture (Westside and Mitsui E&P Australia Pty Ltd) that commenced on 1 January 2024. QNP will purchase up to 1.7PJ/a over four years with the potential for additional volumes to be supplied in the future.

QNP also signed a gas supply contract with APLNG in June 2021 for up to 7.75PJ. Wood Mackenzie believes this volume to be 1.55PJ/a over 5 years ending June 2026.

Kooragang and Yarwun (Orica)

Kooragang

Orica operates two integrated nitrogen-chemicals complexes on Australia's east coast: Kooragang Island at Newcastle in New South Wales, and Yarwun near Gladstone in Queensland. Kooragang Island comprises an ammonia plant, three nitric acid plants and two ammonium nitrate plants with a capacity of 360 ktpa of ammonia and around 500 ktpa of ammonium nitrate and employs roughly 210 staff. Yarwun runs three nitric acid plants, two ammonium nitrate plants, an emulsion plant and a sodium cyanide plant, importing ammonia rather than an on-site ammonia manufacturing plant. Between them the two sites supply ammonium nitrate and, at Yarwun, sodium cyanide to mining customers across the eastern states and for export.

Natural gas is central to Kooragang Island's cost base because the site is integrated upstream into ammonia production. Gas is used both as a hydrogen feedstock and as process fuel in the steam methane reforming route to ammonia, which is then oxidised into nitric acid and reacted into ammonium nitrate. This places Kooragang in the same broad cost-exposure category as other gas-based ammonia/ammonium nitrate producers, although Orica's broader east-coast manufacturing footprint gives it more optionality than a standalone inland producer. In practical terms, Kooragang's direct gas exposure sits at the front of the production chain: if delivered gas prices rise, the cost impact flows first into ammonia and then into downstream ammonium nitrate production.

Wood Mackenzie estimates Kooragang Island's gas cost at around A$550/t of ammonium nitrate, equivalent to roughly 55% of total cash costs at a wholesale gas price of A$12/GJ (delivered price of A$13/GJ including transport). The low gas price scenario assumes the commodity component falls to A$10/GJ, with transport cost still incurred separately. On this basis, gas is by far the largest cash-cost line at Kooragang, although the proportional sensitivity is somewhat lower than QNP because Orica's cost allocation, site configuration and broader operating model differ.

Table 11 – Gas price sensitivity analysis for Kooragang Island (Ammonia Nitrate) 2025 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] *(A$m)*	Cash Cost at A$10/GJ scenario[1] *(A$m)*	Cash Cost at A$8/GJ scenario[1] *(A$m)*
Gas	173	146	120
Other cash costs	179	179	179
Total Cash Cost	**352**	**325**	**299**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

The reduction in gas price from the base case A$12/GJ to the low-cost scenario of A$10/GJ reduces Kooragang Island's estimated total cash cost by around A$26.6 million, or about 7.6%. This is meaningful, but lower than QNP's sensitivity because the modelled Kooragang cost base reflects a different site configuration and product allocation. Kooragang operations provide export flexibility for some of the ammonia production to other Orica operations (mainly Yarwun in Gladstone). This excess ammonia capacity offers Orica flexibility to increase ammonia output and export when gas prices are more favourable compared to internationally priced ammonia.

Kooragang's gas strategy has historically centered on securing term supply rather than relying on short-dated procurement. Orica previously contracted up to 42 PJ over three years from 2017 from Esso/BHP, equivalent to 14 PJ/a, which it said would meet Kooragang Island's total gas requirement at the time.

Orica has more flexibility than QNP because Kooragang is port-connected and has ammonia import/export infrastructure.

The site completed ammonia-management upgrades in 2020, including replacement of the pipeline between Kooragang and Berth 2, and Orica has proposed a further 30 kt ammonia storage tank to supplement existing storage and support ship loading/unloading. This gives Orica a practical option to balance local ammonia production against imported ammonia when relative gas and ammonia economics justify it.

That flexibility reduces risk but does not eliminate gas exposure. Imported ammonia is still generally priced off gas-based production economics overseas, so substitution mainly shifts exposure from domestic gas prices to global ammonia prices, freight and storage costs. In practice, imports are likely to be most useful for outage cover, maintenance flexibility, temporary price dislocations or margin optimisation, rather than a full replacement for Kooragang's integrated ammonia plant.

Yarwun (NaCN)

Orica's Yarwun facility is located around 9 kilometers west of Gladstone, Queensland. Unlike Kooragang Island, Yarwun does not have an on-site ammonia manufacturing plant. The site operates three nitric acid plants, two ammonium nitrate plants, an ammonium nitrate emulsion phase plant and a sodium cyanide plant, with raw material import facilities at Fisherman's Landing supporting ammonia and caustic soda unloading, storage and delivery to the Reid Road manufacturing site. Yarwun supplies products to Queensland mining operations as well as national and international mining markets.

Natural gas is therefore important at Yarwun, but in a different way to Kooragang. The site consumes gas directly as a process input and fuel, particularly in sodium cyanide production, where hydrogen cyanide is produced by reacting ammonia, natural gas and process air before absorption into caustic soda to form sodium cyanide liquor. Nitric acid and ammonium nitrate production, however, rely primarily on purchased ammonia rather than on-site gas-based ammonia manufacture. As a result, Yarwun has lower direct exposure to Australian gas prices than Kooragang, but higher indirect exposure to merchant ammonia prices.

Table 12 – Gas price sensitivity analysis for Yarwun (NaCN, Gladstone) 2025 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] (A$m)	Cash Cost at A$10/GJ scenario[1] (A$m)	Cash Cost at A$8/GJ scenario[1] (A$m)
Gas	40	33	27
Other cash costs	141	141	141
Total Cash Cost	**180**	**174**	**168**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

Wood Mackenzie estimates Yarwun's (NaCN Gladstone) 2025 gas cost to be ~A$39.5 million, equal to roughly 22% of total cash costs. This is materially lower than Kooragang's gas share because Yarwun does not carry the full gas feedstock burden of ammonia production. On the modelled low-gas case, gas cost falls to A$33.4 million, while other cash costs remain unchanged at around A$140.9 million.

The reduction in gas price from the base case A$12/GJ to the lower-cost scenario of A$10/GJ reduces Yarwun's estimated total cash cost by around A$6.1 million, or approximately 3.4%. This is a much smaller impact than at Kooragang because gas is not the main feedstock for Yarwun's ammonium nitrate chain. Lower gas prices still help, especially for sodium cyanide and site utilities, but they are not the primary driver of competitiveness.

Yarwun's larger exposure is to ammonia procurement. Ammonia is consumed in nitric acid, ammonium nitrate and sodium cyanide (NaCN) production, meaning Orica's cost base is still indirectly linked to gas markets through global ammonia pricing. In this sense, Yarwun's configuration shifts exposure away from domestic east-coast gas and toward imported or merchant ammonia economics, including freight, storage, port logistics and global nitrogen-market volatility.

The site's Gladstone location gives it more import flexibility than an inland facility. Orica's Fisherman's Landing infrastructure includes ammonia unloading, storage and delivery systems, supporting the practical movement of imported ammonia into Yarwun's production chain. This gives Orica useful procurement optionality, but it does not fully insulate the site from energy-price cycles because ammonia prices are themselves typically driven by gas-based production costs in exporting regions.

Orora

Orora is a beverage packaging manufacturer headquartered at Hawthorn, Victoria, Australia. Orora has gone through a significant strategic transformation in recent years, narrowing from a diversified packaging conglomerate (paper, fibre, cartons, displays, plus glass and cans) down to a pure-play global beverage packaging company. It sold its fibre business in 2020, then acquired Saverglass, and most recently sold its North American packaging solutions operation in 2024.

Orora now operates through two segments: Global Glass and Orora Cans. The Global Glass segment, spanning Australasia, Europe, North America and the UAE, manufactures glass bottles ranging from premium/ultra-premium spirit and wine packaging to standard bottles. The Orora Cans segment, with manufacturing sites across Australia and New Zealand, supplies aluminium can solutions across the Asia-Pacific beverage sector, including custom printing and decoration.

Global Glass

Global Glass comprises Australian operations at Gawler and global premium glass business Saverglass. Gawler produces glass products for use in packaging of wine, beer and spirits to olive oil and juices. It is also a large-scale recycler, with an on-site beneficiation plant to process used glass. The Gawler production facility is located in Kingsford, South Australia.

In the Orora glass business, natural gas is the primary fuel for melting raw materials and recycled glass in furnaces. Gas is a key energy source for heating furnaces to mould glass bottles manufactured at the Gawler plant each year. Orora wine glass furnaces in Gawler is powered in part by oxyfuel technology drawn from their own onsite oxygen plant, aiming at lower total energy consumption[6].

Orora's Gawler site gas demand was estimated to be approximately 2.1 PJ in 2025 with annual gas costs of around A$27.5 million (~12.5% of total cash costs) at a wholesale gas price of A$12/GJ (delivered price of A$13/GJ including transport). Consequently, a reduction in wholesale gas prices from A$12/GJ to A$10/GJ would reduce total cash costs by ~1.9%. Orora secured a decade-long gas supply agreement with Senex Energy for Gawler facility in 2023[7].

Table 13 – Gas price sensitivity analysis for Orora Gawler (Glass) 2025 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] *(A$m)*	Cash Cost at A$10/GJ scenario[1] *(A$m)*	Cash Cost at A$8/GJ scenario[1] *(A$m)*
Gas	28	23	19
Other cash costs	192	192	192
Total Cash Cost	**219**	**215**	**211**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

Orora Cans

The Orora cans business produces aluminium cans with different shapes and sizes for customers across carbonated soft drinks, beer, cider and alcohol ready-to-drink. The Orora cans business continues to focus on growing its network capacity. The second line at Revesby was commissioned and delivery of the first digital printer occurred in 2025. Construction of the third line at Rocklea commenced and when this completes in 2026 the current growth capex cycle will be complete with no new capacity required until the next decade[8].

Key manufacturing sites for the cans business are located in Ballarat, Dandenong, Canning Vale, Revesby and Rocklea, plus a New Zealand can plant at Wiri, Auckland.

In cans manufacturing, the energy-intensive steps are electrical (melting and curing coatings) rather than gas-fired furnaces. The cans facilities do use gas, just at much smaller scale than glass. To further reduce greenhouse gas emissions, the cans business is also focusing on improving the efficiency of electricity and gas usage.

Orora Cans' gas consumption was estimated to be ~1.65 PJ in 2025. We estimate annual gas expenditure at A$21.5 million, equivalent to ~3.6% of total costs, at a wholesale gas price of A$12/GJ (delivered price of A$13/GJ including transport). Given the limited cost exposure to gas, a reduction in wholesale gas prices to A$10/GJ would reduce total cash costs by ~0.6%.

---

[6] Orora Beverages, 2025

[7] Senex Energy, 2023

[8] Orora Annual Report 2025

Table 14 – Gas price sensitivity analysis for Orora Aluminium Cans 2025 operations

Cash cost component	Cash Cost at A$12/GJ base case[1] (A$m)	Cash Cost at A$10/GJ scenario[1] (A$m)	Cash Cost at A$8/GJ scenario[1] (A$m)
Gas	21	18	15
Other cash costs	576	576	576
Total Cash Cost	**597**	**594**	**591**

Source: Wood Mackenzie and company reports

Notes: 1) Gas price represents the wholesale gas price, A$1/GJ is added for delivered price.

Wood Mackenzie

Disclaimer