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Queensland LNG exports: A decade of high domestic prices, falling local demand

- *The reality of Queensland's LNG export industry has failed to live up to the hype, plagued by cost blowouts and billions in asset write-downs.*
- *The LNG revenue bonanza promised the Queensland government has failed to materialise, with gas royalties a drop in the ocean compared with international levels.*
- *As LNG export contracts expire, the industry faces a global supply glut, declining prices and demand, and stiff competition from cheaper overseas producers.*
- *Exporting LNG has shackled eastern Australia's gas supply to volatile global markets, driving up gas prices, constraining local supply and forcing manufacturers to close.*

Queensland marked 10 years as an LNG exporter in January 2025, and has emerged as a key supplier of LNG, primarily to China. Besides boosting Australia's energy trade with Asia's largest economy, the industry has left a legacy of higher domestic gas prices, weaker domestic gas demand, lower than expected state royalty payments and poor financial returns for investors.

In the decade since Queensland started exporting LNG, domestic gas prices have tripled due to the stronger linkage between LNG export prices and domestic gas prices. According to the RBA, prices are likely to remain higher than pre-2015 levels for decades to come.

Correspondingly, gas demand in eastern Australia has dropped to a 25-year low, with large reductions in demand from the electricity and manufacturing sectors, which tend to be more price sensitive. There are indications gas demand may fall further in manufacturing, electricity and the residential market due to high gas prices, more competitive energy alternatives and government policy incentives.

Queensland's three LNG projects – Queensland Curtis (QCLNG), Gladstone (GLNG) and Australian Pacific (APLNG) – have also soaked up gas reserves earmarked for domestic customers, contributing substantially to expected domestic gas supply gaps.

Royalties from the gas production for LNG exports have been largely below expectations for most of the past decade, amounting to 2.3% of the total LNG export revenue for the industry. But this share may increase after state royalties were amended in late 2020, although the impact of this change coincided with the surge in oil and gas prices due to Russia's expanded invasion of Ukraine. Queensland's petroleum royalties could, however, have been much higher had the state revised the gas royalty scheme to the same rate as the state's coal royalties.

The three LNG projects at Gladstone have financially underperformed due to cost and schedule blowouts. This has led to asset write-downs by the operators, with the projects failing to deliver financial value to their shareholders. They now face significant financial risks as the global LNG industry enters a period of oversupply that is likely to push prices down materially. Future LNG demand from China is uncertain, with potential for significant gas over-contracting by 2030 putting in question contract renewals (once the existing LNG contracts expire).

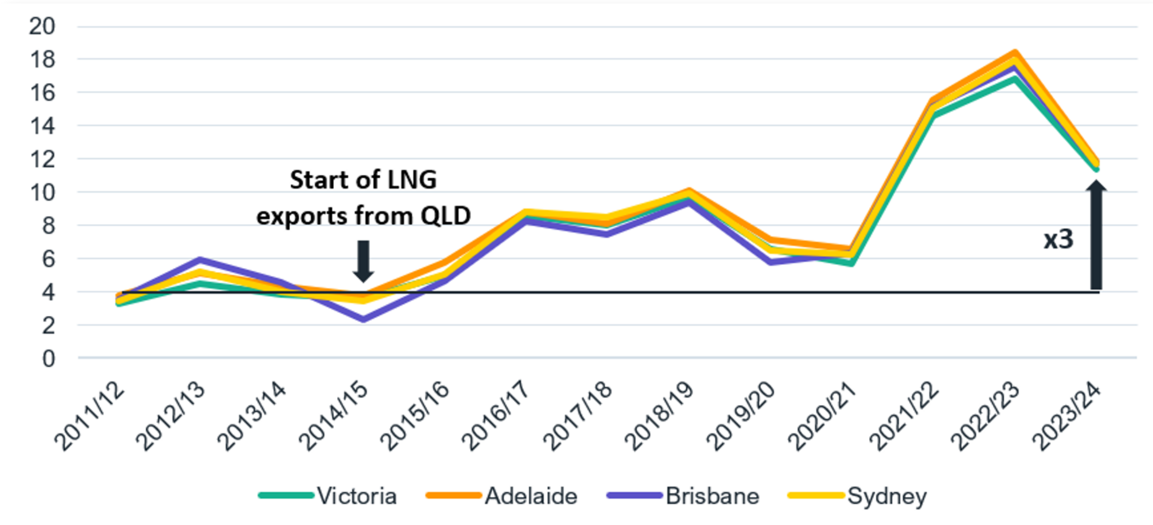
In this context, it will be hard for the Queensland LNG industry to justify continuing to take gas away from a tight domestic market to supply its international consumers.

Exports drive tripling of eastern Australia gas prices

In the 10 years since Queensland started exporting LNG using the state's vast coal-seam gas (CSG) reserves as feedstock, domestic gas prices have tripled due to the stronger linkage between LNG export prices and domestic gas prices, as well as higher production costs for CSG compared with conventional gas production.

On an annual average basis, prices across the short-term trading markets (STTM), declared wholesale gas market (DWGM) in Victoria and gas supply hub (GSH) at Wallumbilla in Queensland have all increased significantly (Figure 1).

Figure 1: Eastern Australia gas prices (A$/GJ)



Source: Australian Energy Regulator, Gas Market Prices

Gas prices likely to remain high for decades

The Reserve Bank of Australia (RBA) warned in 2021 that eastern Australia's domestic gas prices would remain higher than pre-2015 levels for decades due to the dominance of LNG exports. "Wholesale gas prices on the east coast have become linked to LNG export prices since 2015. This is because local gas producers can now sell into international markets through the 3 Queensland LNG export terminals. Wholesale prices will continue to be influenced by LNG export prices as long as this option is available." It added that, "gas prices are likely to remain structurally higher than their pre-2015 levels over coming decades, reflecting higher marginal costs of domestic production".

Manufacturing gas use at 31-year low as plants close

Higher gas prices have coincided with large reductions in gas demand from the electricity and manufacturing sectors, which tend to be more price-sensitive.

Gas demand in the manufacturing sector fell by 24% between FY2012-13 and FY2022-23, with demand in FY2022-23 at its lowest level since FY1991-92. This reflects the closure of petroleum refineries, the loss of minerals and chemicals processing capacity, and the impact of worsened economic conditions, including higher gas prices, on smaller manufacturers, which have forced some plants to close.

In 2024, Australia's largest plastics manufacturer, Qenos, closed its plants in Melbourne and Sydney, which caused the shutdown of chemical suppliers such as Indorama in Sydney.

The Australian Competition and Consumer Commission (ACCC) reported industry concerns about further closures of manufacturing facilities should high prices persist. "We are seeing the hollowing out of manufacturing capability in Australia, with the recent closure of two domestic manufacturers, including Qenos. As a result of failures in the east coast gas market and the market power of producers, Qenos were in the position where they had to go into voluntary receivership. The failure of the east coast gas market is not the sole cause; but it's a significant driver."

Gas use in eastern Australia's National Electricity Market (NEM) dropped almost 60% between FY2012-13 and FY2023-24 as more renewables connected to the grid.

Gas-fired power generation in eastern Australia is expected to decline further following large investments in grid-scale battery capacity. In November 2024, the Australian government revised upwards its national battery installation forecast by more than 53% to 40 gigawatts (GW) by 2035, from 26GW a year earlier. Much of this capacity is expected to be in the NEM given it is the dominant power system in Australia.

Gas demand in households, particularly in Victoria, which accounts for about two-thirds of household demand in eastern Australia, has also declined in recent years.

Overall, gas demand in eastern Australia has dropped to a 25-year low. There are indications gas demand may fall further in manufacturing, electricity and the residential market due to high gas prices, more competitive energy alternatives and government policy incentives.

Warnings of impact on domestic gas prices ignored

There were warnings at the outset that an LNG export industry in Queensland could have a negative impact on domestic gas prices and demand. Gas demand in the residential, commercial and industrial sectors, and gas for power generation, were all forecast to fall between 2016 and 2021.

A Queensland government paper on the state's potential as an LNG exporter also warned that the availability of gas in the ground may not translate into gas supplied to the domestic market. "Right now we can observe that despite the known availability of gas resources, it is difficult for domestic gas-fired electricity generators to secure long-term gas contracts."

A paper co-authored by Paul Simshauser, now chief executive of Queensland's state-controlled electricity transmission network, PowerLink, also warned of lower domestic gas demand, and higher gas prices. "As reserves of commercially extractable CSG increased, resource developers realised that the east coast gas market was not large enough to enable the monetisation of reserves in suitable timeframes and at the scale necessary to maximise profit. The logical way in which these new resources could be developed was through a substantial increase in aggregate demand via the development of an LNG export industry. One consequence of this profit-maximising behaviour was that the east coast gas market would have a 'link' with the global gas market for the first time."

"It is worth noting that 80 per cent of existing 2P [proven and probable] east coast reserves are notionally allocated for LNG exports as they are owned by market participants with financial obligations to supply LNG overseas. This has implications for the domestic market … This will in turn create scarcity pricing events with an unusually long tail by energy market standards."

The Simshauser report also forecast domestic gas demand to contract by more than 20% due to a significant scaling back of gas-fired power generation, and warned of higher gas prices. "Wholesale gas prices will rise by a factor of 2-3 from the historic A$3-A$4 per gigajoule (GJ) to A$6-A$9/GJ in the long run, punctuated by spikes above $10/GJ in the short run". It added, "for industrial gas users who currently pay wholesale prices plus a small gas transmission pipeline charge, the price increases … will be material".

Queensland's lacklustre gas royalties get a belated boost

Despite industry promises, royalties from Queensland's LNG industry were well below expectations in the first seven years of exports. In response, the Queensland government amended the royalty scheme in October 2020. The new scheme started in FY2021-22, which coincided with the surge in oil and gas prices following Russia's expanded invasion of Ukraine. This combined impact boosted royalty revenues, but how much of the rise is attributable to the change in royalty calculations and to higher prices is debatable.

The Queensland government collected A$6.83 billion in petroleum (gas) royalty revenue between FY2014-15 and FY2023-24, which covers the period LNG exports began from Gladstone on 6 January 2015.

More than three-quarters of these royalties were collected in the past three fiscal years, from FY2021-22 to FY2023-24, when the new scheme started and oil and gas prices were elevated. These combined effects helped push up the average annual royalty income to A$1.75 billion in this period, or a total of about A$5.25 billion.

In the first seven years of exports, average annual royalty income was A$227 million, well below original expectations. This equates to about 2.27% of LNG export revenue in that period. Since the royalty regime changes and higher gas prices, the royalty take has more than doubled to almost 5% of LNG export revenue of A$137.19 billion from January 2015 to September 2024.

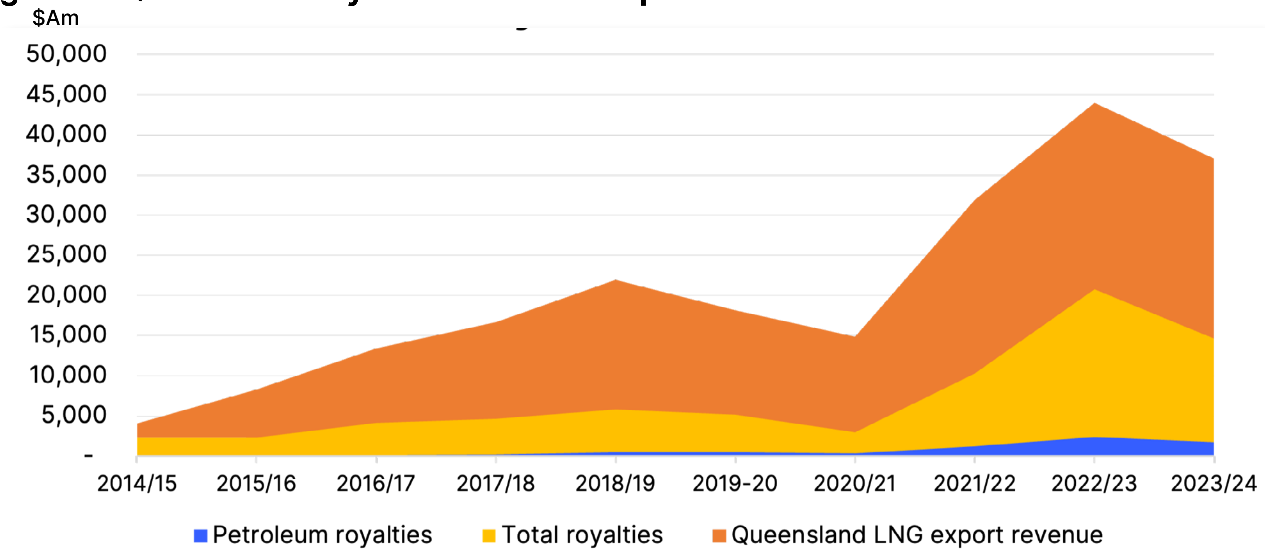
However, Queensland's petroleum (gas) royalties could have been much higher had the state revised the scheme to the same rate it did for the state's coal royalties. As noted in a previous IEEFA study, "The gas industry has experienced similar windfall profits to the coal industry. However, the Queensland government hasn't reformed its royalty structure accordingly to take account of windfall profits in the gas and liquefied natural gas (LNG) industries."

While there is no breakdown of the corporate taxation paid by the partners in the three LNG consortiums in Queensland, the low level of royalty payments means government income from the development and export of Queensland's gas reserves is likely to be relatively low. A study by the International Energy Agency (IEA) showed that since 2018, about half of the US$3.5 trillion average annual revenue generated by the oil and gas industry has gone to governments.

Expectations of a royalty windfall were built up when the LNG export industry was being developed in Queensland. Catherine Tanna, then chief executive of BG Group, developer of the 8.5 million tonne per annum (Mtpa) QCLNG project now owned by Shell, stated in October 2010: "We also expect to pay about $1 billion a year in federal taxes and a further $300 million or so each year in royalties to the Queensland government."

The Queensland government was banking on a royalty bonanza. The 2014-15 state budget forecast petroleum (gas) royalties to rise from A$68 million in 2013-2014 to A$660 million by 2016-2017 due to the boom in coal-seam gas extraction. The actual royalties paid that year, however, were a fraction of that, at A$98 million. While royalty revenue had increased significantly to A$298 million by FY2020-21, it was still less than half the budget estimate of A$620 million in the 2019-20 budget papers.

Figure 2: Queensland royalties and LNG export revenue



Source: Queensland Treasury, State Budget Papers, 2014-15 to 2024-25.

Initial royalty expectations were also boosted by overly optimistic industry growth forecasts. The day the first LNG shipment left Gladstone in 2015, the Australian Petroleum Producers and Exploration Association (APPEA) said a further six LNG projects – worth more than A$180 billion – were in development. At one stage, eight LNG projects were proposed for Queensland, but the Arrow LNG project was folded into the QCLNG venture, and the other four were abandoned.

The state government shared the industry's initial optimism. The 2009 Blueprint for Queensland's LNG Industry estimated the eight LNG projects, worth more than A$40 billion, would ship 50Mtpa of LNG if they went ahead. Even at their peak, LNG exports have failed to reach half this estimate.

Despite the proclamations of a "golden age for gas" in Queensland, not everyone was convinced. In 2019, industry consultants EnergyQuest warned in a report that one-third of the state's LNG export industry could close by 2025, partly due to the need to divert gas supplies to domestic users.

LNG exports from Queensland have tightened domestic gas supply

Back in July 2007, Santos announced it would develop a one-train LNG project at Gladstone with an export capacity of 3-4Mtpa. These plans changed in September 2010 when Santos signed an agreement with French energy group Total to supply 1.5Mtpa of LNG from Gladstone, as well as a revised non-binding agreement for 3.5Mtpa with Malaysia's state-controlled energy group, Petronas. To meet the combined total of 5Mtpa, GLNG was expanded to a two-train project.

A month later, Santos signed an agreement to supply 750 petajoules of gas to GLNG from the onshore Cooper Basin in northern South Australia. Until then all gas production in the Cooper Basin was supplied to the domestic market; this agreement meant gas earmarked for Australian customers would now flow overseas. Santos chief executive David Knox said at the time that, “the agreement delivers significant value to Santos’ Cooper Basin position by opening an export channel for Cooper gas and accelerating its monetisation.” By December 2010, Santos had signed export contracts for a total of 7Mtpa from GLNG. However, the plant has never been able to fulfil this export volume, with production peaking at 6.3Mtpa in 2021.

GLNG has been partly reliant on third-party gas for feedstock as the gas reserves owned under the venture were insufficient.

QCLNG also buys some of its gas from third parties to provide feedstock for its two trains. This gas would otherwise be destined for the domestic market. This in turn has put pressure on local gas supplies.

The Australian Competition and Consumer Commission (ACCC) acknowledged that third-party purchases by GLNG and QCLNG were a “substantial contributor to expected east coast gas shortfalls”.

Investors in Queensland LNG projects count costs of write-downs

Previous analysis by IEEFA estimated that the three lead companies in the consortium that owns the three Gladstone LNG plants wrote off A$24 billion in value from 2014 to 2020. In particular: Santos wrote off A$7 billion on its east coast CSG and LNG assets. Origin Energy, upstream operator of the 9Mtpa APLNG venture, wrote off A$4.7 billion. BG Group and its QCLNG operations were taken over by Shell in 2015. Prior to this, BG Group wrote down the value of its QCLNG assets by US$6.8 billion (A$8.8 billion). In May 2017, Shell wrote off a further $A1.2 billion following poor drilling results. In June 2020, Shell announced up to US$22 billion in global write-downs, including US$8-9 billion primarily on its Australian assets, QCLNG and the Prelude floating LNG venture off Western Australia. IEEFA estimates the total write-offs taken on QCLNG by Shell (and BG Group) were A$11.8 billion.

LNG projects suffer cost blowouts and delays

The three Queensland LNG projects were among seven LNG projects under development in the 2010s when cost blowouts became common in the Australian LNG sector. A report by the Australian Centre for Corporate Responsibility (ACCR) found that the average cost overrun at each LNG project that came online in Australia during the 2010s was about 35%. Each of the three Gladstone LNG projects started later than initial guidance at the time of final investment decision. Furthermore, the three Queensland LNG projects were all constructed at the same time in the same region and by the same lead contractor, Bechtel. “This created an unusual situation where the LNG companies were effectively competing with each other for contractor resources.”

As a result, the ACCR concluded that, “while Australia’s LNG growth wave is currently generating strong cash flows, it does not appear to have generated value for shareholders, since returns do not meet the cost of capital”. The ACCR data shows that the three Queensland LNG plants had the poorest return of the eight Australian LNG projects assessed in its report. Santos’s GLNG plant had the lowest internal rate of return (IRR) of 3.4%, followed by QCLNG with 5.8% and the ConocoPhillips and Origin Energy-operated APLNG plant, which boasts the highest IRR of the three at 7.7%. However, all are well below contemporary investment hurdle rates for European and US oil and gas companies of 11% to 30%.

Queensland LNG faces global supply glut as contracts lapse

Gladstone has become a key supplier of LNG to China, accounting for a significant proportion of Australia's total LNG shipments to Asia's largest economy. China has been the biggest buyer of LNG from the three Queensland-based LNG ventures over the past 10 years, comprising almost 61% of the near 200Mt shipped between January 2015 and December 2024.

Queensland's LNG exporters, together with the rest of the industry, face a wave of new LNG supplies in coming years, largely from North America and Qatar. "IEEFA anticipates that global LNG production capacity will grow by roughly 193Mtpa from 2024 through 2028, rising from approximately 474Mtpa of nameplate capacity at the beginning of this year to 666.5Mtpa by the end of 2028. This will be the fastest capacity growth in the global LNG industry's brief history, representing a 40% increase in just five years." Meanwhile, demand in mature markets is declining, and demand from emerging markets is uncertain. The IEA expects that if all the new supply is to be absorbed by the market, prices would need to drop significantly, possibly to about half of the cost of new supply, under its in its stated policies scenario (STEPS). This would also slow the transition to energy from lower emissions sources.

In the long term, large volumes of uncontracted LNG and increased competition mean Australian LNG exporters could find it more difficult to secure firm sales and purchase agreements (SPAs) to replace expiring contracts. The alternative is to sell LNG into spot markets, which are volatile and likely to be oversupplied. This is because not all the new supply is underpinned by long-term SPAs, and is likely to be sold into spot markets. Lower global LNG spot prices may increase spot trade as buyers seek to take advantage of low spot prices.

The ACCC said there was an opportunity for the Australian government to work with Queensland's LNG exporters before any possible decisions to renew any new long-term export contracts to ensure that long-term domestic gas needs are met.

Firm SPAs may not shield LNG exporters from lower prices, with most contracts linked to either global oil prices, which are also expected to experience significant decline by the end of the decade, or global LNG spot prices.

Declining LNG prices could also pose risks for Queensland LNG producers, which face higher costs than conventional gas producers in Australia. Queensland gas production costs are estimated to be higher given that the source CSG does not have oil as a byproduct like some conventional gas projects. "Unconventional deposits [including CSG] … account for 90 per cent of the east coast's known remaining gas reserves. The shift towards CSG production has therefore increased the marginal cost of production on the east coast. Analysis conducted for the Australian Competition and Consumer Commission (ACCC) indicates that the median cost of production from CSG deposits is around 35 per cent higher than remaining conventional deposits."

Queensland's high exposure to Chinese LNG demand could make it particularly sensitive to changes in China's energy markets. After a strong increase in LNG imports in previous decades, there is high uncertainty on future LNG demand from China. The government signalled a more orderly approach to growth in gas use, including with a "less indiscriminate gas-fired power build out". China already has large volumes of LNG contracted under firm SPAs. The IEA, under its 2023 Announced Pledges Scenario, anticipated that China could have up to 59Mtpa in surplus gas by 2030.

Conclusion

The warning in 2019 that one third of the Queensland LNG export industry could close by 2025 might not be realised. However, the sector still faces strong headwinds as politicians and large gas users look for ways to untether eastern Australia's gas prices from the volatile LNG export market, and to alleviate domestic gas market constrictions.

As the global LNG market enters a period of major oversupply, it will be hard for the Queensland LNG industry to justify continuing to take gas away from a tight domestic market to supply its over-contracted international customers, with a high risk of financial losses and poor returns on capital.

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