Institute for Energy Economics and Financial Analysis

Briefing Note

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Simon Nicholas || Lead Analyst, Global Steel

South Australia: Long-term reliance on gas for iron and steelmaking faces significant risks

- *Any long-term reliance by South Australia on gas for iron and steel production would entail significant cost and supply risks. South Australia should instead seize the opportunity presented by green hydrogen.*
- *Australia cannot compete in gas-based direct reduced iron (DRI) with the Middle East, which already plans to produce DRI for export to Asia. Although lower-emissions than coal, gas-based iron and steelmaking is emissions-intensive. Carbon capture and storage will not play a significant role in decarbonising iron and steel.*
- *Gas is not cheap in Australia's east coast market – especially in southern states – where gas-based iron and steelmaking would exacerbate looming supply shortfalls. A key way to prevent gas shortages is reducing household and industrial demand, but gas-based DRI would be a shift in the opposite direction.*
- *While green hydrogen remains expensive, it is becoming clear we will need less of it for fewer sectors, one of which is steel. With its world-leading green iron and steel potential, South Australia should prioritise rapid adoption of green hydrogen-based DRI, as it is the only way to fulfill the state government's Green Iron and Steel Strategy. You can't make green iron and steel with gas.*

Introduction

The South Australian government's Green Iron and Steel Strategy is targeting a switch to green steel production at the Whyalla steelworks and green iron exports from a new direct reduced iron (DRI) plant in the state. This will require green hydrogen, as green iron and steel cannot be made using gas or coal.

In recent months it has become clearer that the cost of green hydrogen production is not falling as fast as had previously been forecast. This was always likely to happen – green hydrogen has been over-hyped for years. Many of the proposed uses for green hydrogen always looked extremely far-fetched, while exports of green hydrogen appear structurally expensive. A reality check was always on the cards. Some green hydrogen projects around Australia are now in question.

There is a silver lining to this. The bursting of the hydrogen bubble is helping to remove the more unlikely applications from the table. What remains is a shorter list of practical uses for green hydrogen, including the iron and steel sector. Overall, less green hydrogen will be needed than previously forecast. There is now an opportunity to refocus green hydrogen plans on domestic use in fewer sectors such as iron and steelmaking.

Meanwhile, the federal government's green hydrogen production tax credits have passed through parliament, providing a subsidy that could kickstart production in Australia if projects are focused on domestic use and realistic off-takers. The government has also announced a AU$1 billion Green Iron Investment Fund. These initiatives are important because Australia faces growing competition from overseas in the emerging green iron space, leaving the country's biggest export – iron ore – exposed.

In northern Sweden, Stegra aims to begin commercial-scale production next year of truly green iron and steel – produced using green hydrogen-based DRI technology. This is no longer just theoretical or at the pilot stage. In addition to northern Sweden, other locations that have both high-grade iron ore reserves and power grids that are already dominated by clean energy have the opportunity to be early movers in truly green iron and steel. Such locations include Canada, Brazil and South Australia.

Unfortunately, the South Australian government's planned green hydrogen plant has been shelved with funding transferred to plans to prop up Whyalla, originally an intended off-taker of the hydrogen produced. Any DRI plant developed at Whyalla looks increasingly likely to run on gas, at least initially. In addition, the expressions of interest (EoI) process for another proposed DRI development in South Australia also highlights the use of gas as a reductant until green hydrogen gets cheaper.

However, there are significant risks involved in any long-term reliance on gas for iron and steel production in South Australia via DRI.

Supply risks

There is currently no available supply of green hydrogen for iron and steelmaking in Australia, but the availability of gas for future DRI operations is itself uncertain.

A DRI plant uses a lot of gas. BlueScope has noted the issue of both supply and cost stating: "Operating a DRI production facility with output similar to Port Kembla Steelworks would require 30 to 40 petajoules (PJ) of natural gas per year, equivalent to seven per cent of natural gas demand on the Australian east coast in 2024 and 40 times Port Kembla's current gas use. Obtaining this amount of natural gas (at a competitive price) is challenging due to high export demand and limited domestic supply."

South Australia is also part of the east coast gas market, which is characterised by declining supply and high prices, with these issues heightened in the southern states. Southern shortfalls need to be met by gas transported from Queensland, but gas pipelines on those routes have limited spare capacity.

The Australian Energy Market Operator's (AEMO) 2025 Gas Statement of Opportunities (GSOO) for the east coast gas market forecasts "risks of peak day shortfalls from 2028, and structural supply gaps emerging from 2029 in southern Australia".

From 2028, AEMO sees the potential for seasonal supply gaps in southern Australia in the event of high gas usage, even given the development of committed and anticipated new supply. From

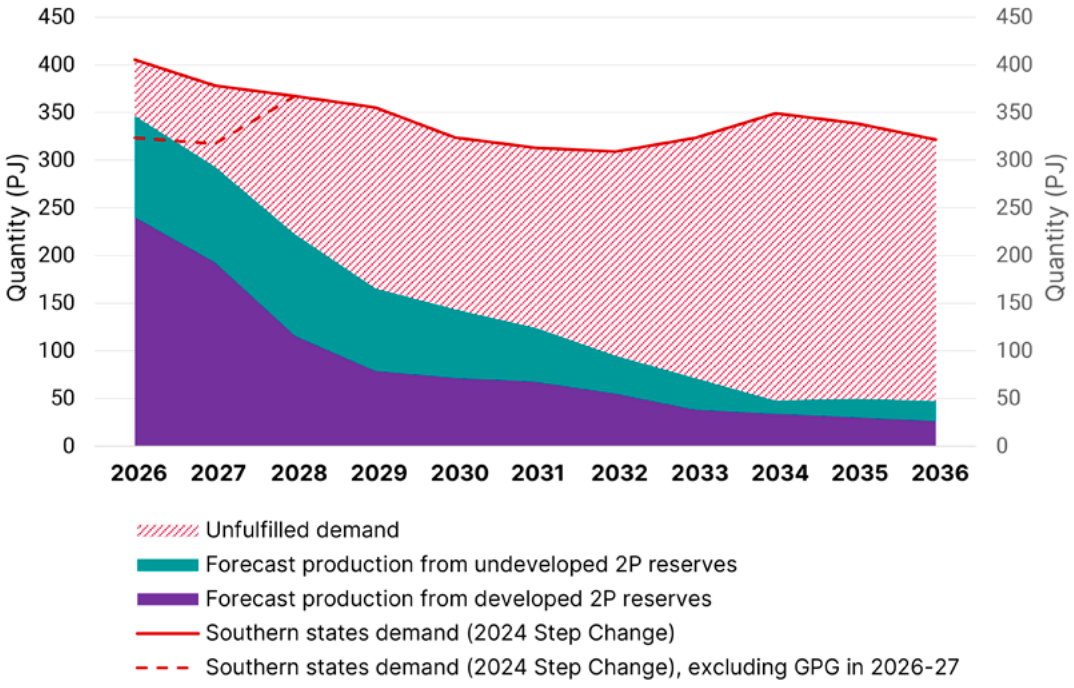
2029, annual supply gaps become structural as southern gas production continues its decline, requiring new gas supply in response.

Under its central, Step Change scenario, AEMO forecasts that industrial gas consumption in the east coast market will decline from over 230PJ in 2026 to below 220PJ in 2040 due to production changes, electrification and fuel-switching. This forecast has been revised down since the 2024 GSOO. The 2024 GSOO also included a sensitivity to this forecast in the case that Australian ironmaking switches from coal-based blast furnaces to gas-based DRI (this was not included in the 2025 GSOO). In this case, industrial gas usage would peak about 80PJ higher in the early 2030s. This extra demand from gas-based DRI would put further pressure on a gas market already facing major supply issues, exacerbating shortfalls. The 2024 GSOO forecast higher annual gas supply gaps in the event of a switch to gas-based DRI.

However, this additional demand comes from replacing current Australian ironmaking capacity with gas-based DRI. The long-term opportunity for Australia – as recognised by South Australia's Green Iron and Steel Strategy – is to produce far more iron than its domestic steel industry needs for export to global steelmakers seeking to meet their emissions reduction targets. Attempting to realise this opportunity with gas-based DRI seems highly likely to place more demand on the gas market than it could possibly meet.

With limited new supply expected in the southern states, shortfalls are expected to worsen. The Australian Competition and Consumer Commission's (ACCC) December 2024 gas inquiry report expects the annual gas shortfall to rise to around 300PJ by the mid-2030s (Figure 1).

Figure 1: Southern states gas supply and demand outlook, 2026-2036



Source: ACCC analysis of data obtained from gas producers as of January 2024 and domestic demand from AEMO's 2024 GSOO.
Note: Chart includes forecast production from developed and undeveloped 2P [proven and probable] reserves in the Gippsland, Bass, Otway, Sydney, Gunnedah and Cooper basins. Southern states demand for gas under AEMO's Step Change scenario has not been adjusted to account for the potential impact of a delayed retirement of Eraring Power Station, which is likely to lower overall GPG [gas-powered generation] consumption. The dashed line represents southern states' demand for gas excluding the total amount of GPG projected to be consumed in 2026 and 2027, which is presently estimated at 142PJ over two years.

The ACCC has also warned that the three Queensland liquefied natural gas (LNG) exporters are expected to source 10 times more gas from the east coast market in 2035 to meet export commitments than they will this year. According to ACCC figures, the three LNG exporters will supply 156PJ of gas to the east coast market in 2025 but will buy 178PJ – a net draw from the domestic market of 22PJ. In 2035, the ACCC forecasts this net draw will reach 209PJ, adding to concerns over long-term supply adequacy in the east coast market.

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Given the state of gas supply in the east coast market, supplying enough gas for even one DRI plant looks difficult. Of the 30-40PJ required to switch its Port Kembla operations to gas, Anna Matysek, head of climate change at BlueScope, has stated: "It is hard to see where we would get those sorts of volumes of gas from if there are potentially no new developments, I don't know if that will happen, but if there are no new developments then we should be looking at a domestic reservation."

Effective domestic gas reservation in the east coast market has long faced fierce resistance from the gas industry, which insists that increasing supply should be the priority. Commonwealth Bank of Australia (CBA) has noted that "the pathway to successfully implement a gas reservation policy will likely be volatile, long and uncertain."

However, fast-tracking federal approvals of new gas projects looks unlikely to add significant volumes into the east coast market. Despite the ACCC calling for new gas supply since at least 2017, the east coast market remains at significant risk of gas shortages. One of the key approaches that can reduce the risk of such shortages is to reduce household and industrial gas demand – however a move into gas-based DRI is a shift in the opposite direction.

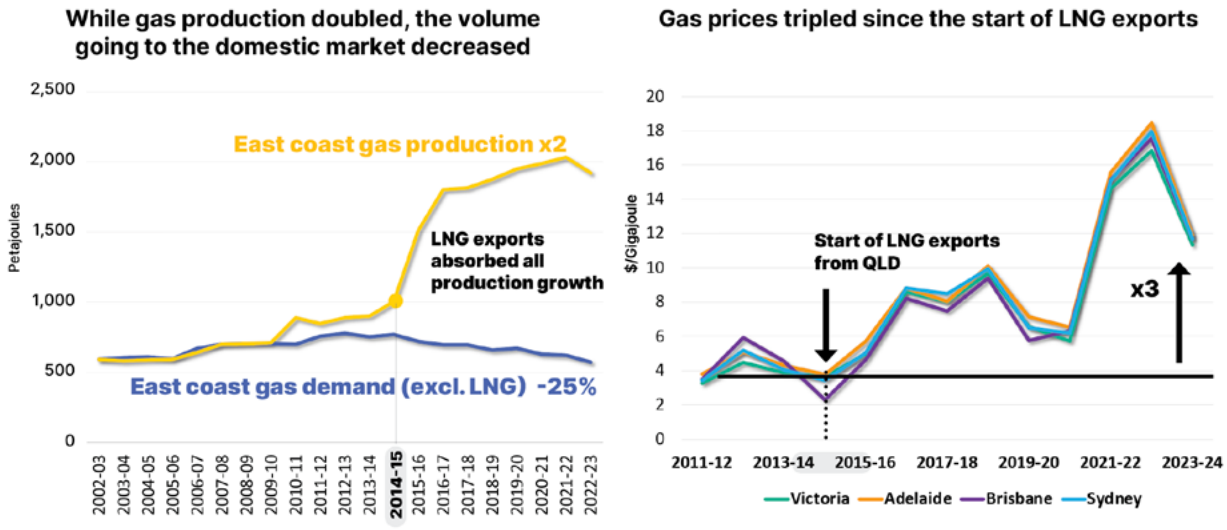
As a result of these supply problems, one of the world's largest LNG exporters is now in the absurd situation of planning LNG imports into the southern states to address supply concerns. The ACCC has stated that, in the near term, "the most realistic new supply and infrastructure prospect are the proposed LNG import terminals". There are four proposed LNG import terminals, all of which are in the gas supply-constrained southern states of the east coast market – two in Victoria, one in New South Wales, and one in South Australia.

However, the prospect of becoming reliant on LNG imports to meet supply requirements raises another key risk of relying on gas for iron and steelmaking – the cost of supply.

Cost risks

Gas prices in the east coast market have already been significantly impacted by the LNG trade. The stronger link between domestic and international LNG prices that resulted from the start of LNG exports out of Queensland in 2015 has seen domestic prices triple as producers have the discretion to sell uncontracted gas either into the domestic market or the LNG spot market (Figure 2).

Figure 2: East coast LNG exports have resulted in domestic gas prices tripling



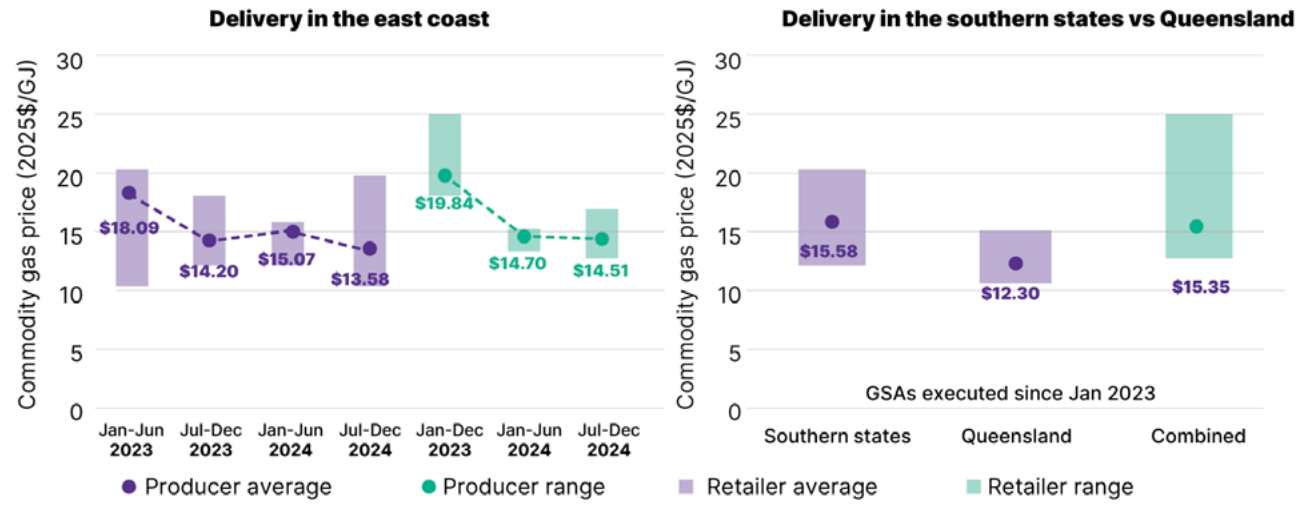
Source: IEEFA

The average price agreed under gas supply agreements (GSAs) in the second half of 2024 for 2025 supply was AU$13.58 per gigajoule (GJ) for producers and AU$14.51/GJ for retailers. However, gas prices are higher in the southern states than in Queensland, due to declining supply in the south and the cost of transporting gas from Queensland. The average price agreed for 2025 supply under GSAs for southern states was AU$15.58 (Figure 3).

The prospect of the east coast market becoming reliant on LNG imports will only increase the link between international LNG markets and domestic gas prices. As the ACCC has put it, "Domestic gas prices will therefore become increasingly driven by international oil and gas prices and the cost of transporting gas over large distances across the east coast."

Imported gas will incur additional costs not currently experienced by east coast gas consumers, including the cost of LNG shipping, liquefaction and regassification as well as premiums to cover financial, foreign exchange and insurance risks, according to the ACCC. Imported LNG is likely to result in even higher gas prices for consumers.

Figure 3: Gas commodity prices in the east coast gas market for 2025 supply



Source: ACCC analysis of GSA information provided by suppliers.
Note: Volume-weighted average prices are displayed next to the point. All GSAs are for quantities of at least 0.5PJ per annum and a contract term of at least 12 months. Prices are based on assumptions as of 17 February 2025. Retailer GSAs in the January-December 2023 period have been aggregated to maintain confidentiality for these parties.

LNG prices are also prone to volatility. The major LNG price spike following the invasion of Ukraine in February 2022 saw some east coast gas consumers exposed to the spot market, facing prices as high as AU$40-50/GJ. But this was not the only LNG price spike experienced in recent years; two major price spikes were also experienced in 2021.

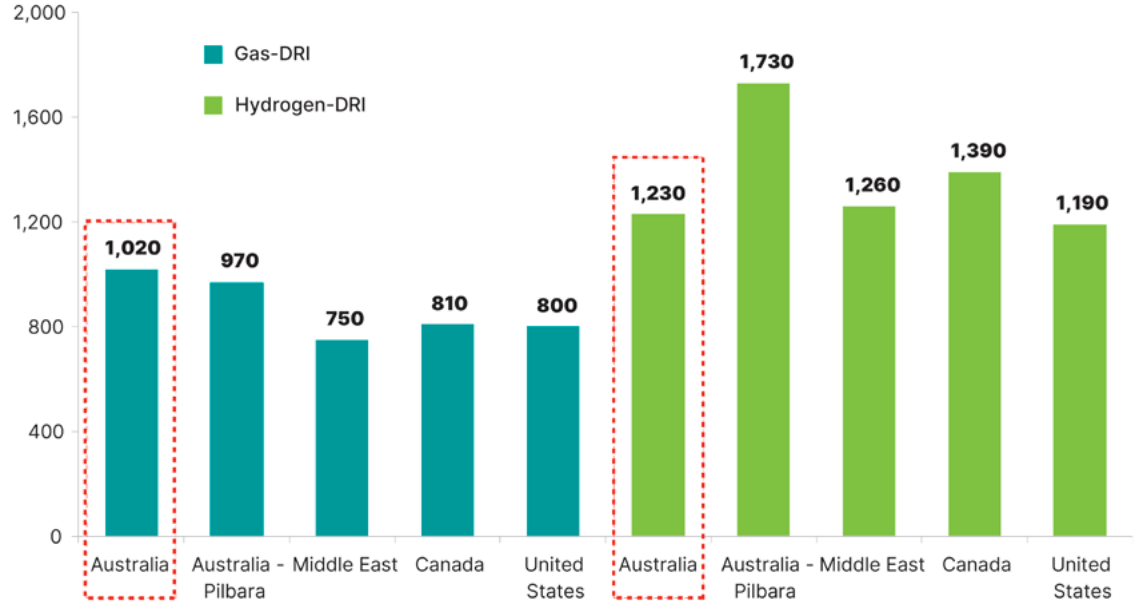
Gas infrastructure company APA has warned about the impact of LNG imports on gas prices, highlighting an average Asian LNG spot price of AU$21.58/GJ during the 2024 Australian summer. APA stated: "Relying on imported LNG means burdening the domestic economy with significantly higher energy costs, impacting the competitiveness of our export industries and driving energy prices higher for small business and consumers."

CBA estimates that the cost of LNG imports would be AU$14-20/GJ (delivered into Melbourne) with the risk skewed towards the upside. CBA has stated, "It is challenging to see how east-coast gas prices can shift materially lower over the next five years."

CBA highlights that sustained east coast gas prices in the AU$15-20/GJ range are forcing commercial and industrial (C&I) users to consider exiting the market, with some C&I consumers already curtailing some or all of their operations. It notes that "the price anchoring to LNG spot and oil prices is fundamentally driving the economic pain for C&I users in east-coast Australia." If the supply shortfalls that AEMO and the ACCC are predicting come to pass, gas prices – already too high for many C&I users – are likely to be pushed even higher. CBA expects C&I gas users to feel the pressure of high gas prices "for at least the next 5 years and potentially even longer".

As the global steel sector shifts from coal-based blast furnaces to DRI, the high cost of gas in Australia puts it at a disadvantage internationally, according to a new report from Deloitte and WWF Australia. Regions such as North America and the Middle East are already home to DRI-based iron and steelmaking at commercial scale, and their lower gas prices will allow them to outcompete Australia on cost (Figure 4).

Figure 4: Comparison of cost of steel production via gas-based DRI and green hydrogen-based DRI in 2030 (A$/tonne)



Source: Deloitte Green Value Chain Explorer - Iron and Steel, 2024.
Note: Cost of steel production comparing gas-DRI and green hydrogen-DRI in Australia (Pilbara), Australia (outside Pilbara, for example South Australia), Canada, the USA and the Middle East. Includes raw material and energy inputs, transport, and electric arc furnace (EAF)-based steel production.

With no metallurgical coal reserves and plentiful gas, the Middle East & North Africa (MENA) region has established its steel industry based on DRI. Now, countries in the region are targeting a significant expansion in DRI-based iron and steelmaking to capture growing demand for lower-emissions steel in both Europe and Asia. MENA-based projects are already developing DRI projects with Japanese steelmakers and trading houses, targeting the export of iron made via gas-DRI to Japan. The region has a significant head start over Australia when it comes to gas-based DRI for iron exports.

The UAE steelmaker Emsteel – which is developing one such project with JFE Steel and Itochu of Japan – is now also piloting green hydrogen-based DRI.

Other risks

South Australia has a target to reduce greenhouse gas emissions by 60% by 2030 from a 2005 baseline, before progressing to net zero emissions by 2050. The state had achieved a 57% emissions reduction by 2021-22, with most of the reductions coming from the power sector and land use. Some other sectors, including manufacturing, have seen emissions rise since 2005.

One of the policy priorities in the state's Net Zero Strategy relates to manufacturing and resources: "Assist existing industries to transition, and grow green, low emissions industries that leverage South Australia's comparative advantages". Under this policy priority, actions to be taken include delivering South Australia's Green Iron and Steel Strategy to support the state in becoming "a leading green iron and green steel producer, using hydrogen-based iron-making processes". South Australia published its Green Iron and Steel Strategy in 2024.

However, if DRI plants are run on gas instead of green hydrogen, they will significantly increase South Australia's emissions. Gas-based DRI has lower emissions than the blast furnace route, but it is still emissions-intensive with around 1.4 tonnes of carbon dioxide (CO_2) emitted for every tonne of crude steel produced on average. Emissions from any new DRI plant in the state focused on iron exports and running on gas will likely cancel out any emissions reduction achieved by transitioning the Whyalla steel plant from coal-based blast furnace to gas-based DRI. Any further DRI plants built in the future to take advantage of South Australia's world-leading iron export opportunity will add further to the state's emissions if they run on gas.

Another policy priority in the state's Net Zero Strategy is Priority 6 – to "Sustainably develop viable carbon capture and storage capability" with an action to "Aim for 3 million tonnes of carbon capture in South Australia by 2030". However, the long track record of failure and underperformance that carbon capture and storage (CCS) has strongly suggests that South Australia has little chance to meet that target. Furthermore, any attempt to use CCS to decarbonise gas-based DRI will end in disappointment.

Prior to Whyalla being forced into administration, the steelworks signed a Memorandum of Understanding (MoU) with Santos for gas supply to the proposed DRI plant. The MoU included a "joint pre-feasibility study of CCS opportunities aimed at abating emissions from the Whyalla iron and steel works" aimed at storing captured carbon at Santos's Moomba CCS project. The Moomba CCS project has been championed by Santos as an emissions solution, but the reality is that it has captured a minute fraction of Australia's total emissions. In addition to a poor global track record, the experience of CCS implementation in Australia is one of significant underperformance at great expense.

For the steel sector specifically, the track record for CCS is almost non-existent. There is only one commercial-scale CCS project for steelmaking anywhere in the world – the Al Reyadah project in the UAE, which captures emissions from an Emsteel DRI-based steel plant. This CCS project captures only around 25% of the plants Scope 1 and 2 emissions, so in no way can the resulting steel be described as decarbonised or "green". Furthermore, the captured carbon is used for enhanced oil recovery (EOR), enabling the emission of more CO_2. Without the EOR element to the project, the CCS facility probably would not have been built at all. Tellingly, this CCS plant became operational nine years ago and no other commercial-scale facility for steelmaking has become operational anywhere since then.

The project pipeline of commercial-scale CCS projects for steel is also unimpressive. According to the Global CCS Institute (GCCSI), there are six commercial-scale CCS projects for iron and steelmaking in the development pipeline but the lack of available detail casts doubts over their status. In all cases the GCCSI is unable to confirm important details of the projects. In each case the GCCSI lists at least one category of "operational year", "capture capacity" and "storage type" as "under evaluation". Two of the three projects supposedly in "advanced development" don't have a known date when they are expected to become operational. No information about carbon storage or usage is disclosed for any of them, and the CO_2 capture capacity is unknown in half of the projects under development.

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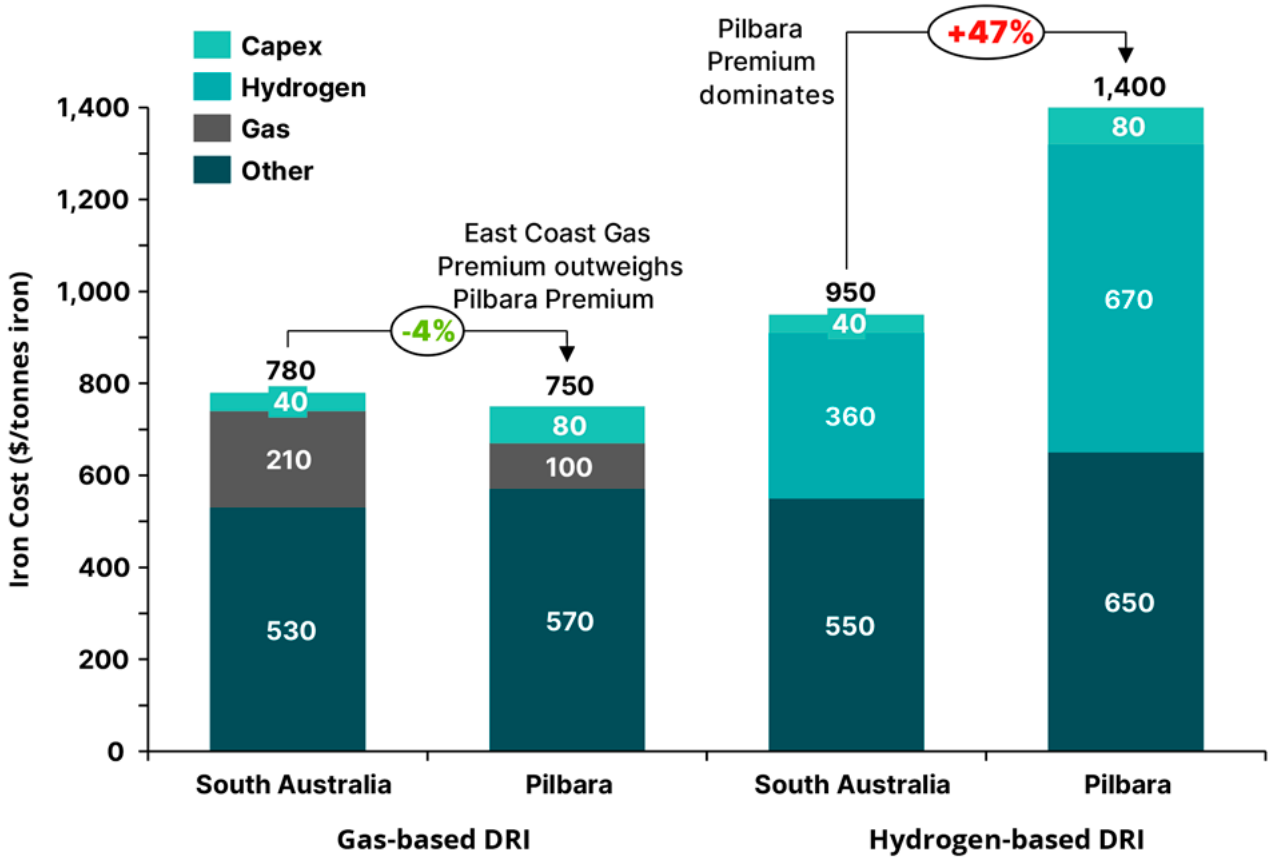
Target early opportunities for green hydrogen use in iron and steel

Green hydrogen remains expensive for now. CCS is also expensive but has the clear disadvantage in that it is unable to decarbonise iron and steel in the way green hydrogen can. Despite the global slowdown in development globally, green hydrogen remains the key to unlocking South Australia's green iron potential. South Australia needs to target earliest-possible adoption of green hydrogen-based DRI – the only production route that can truly fulfill the state government's Green Iron and Steel Strategy. You cannot make green iron and steel with gas.

According to Deloitte's modelling, summarised in Figure 4, steel made in Australia using green hydrogen (outside the Pilbara) will have a 20% higher cost of production in 2030 than steel made using gas. For iron production and export, Deloitte finds that green hydrogen-based DRI production in South Australia will cost 22% more than gas-based DRI in 2030 (Figure 5).

However, in Sweden, Stegra has signed a number of steel offtake agreements for its future green steel production using green hydrogen at a 20-30% premium, which have underpinned its financing. Some of these off-takers are car-makers – the limited amount that steel adds to the overall cost of a car means paying a 20-30% premium for green steel barely impacts its final selling price. Similar early-offtake opportunities are likely to exist in Asia, the world's largest car-making region.

Figure 5: Comparison of gas-based and hydrogen-based DRI between South Australia and the Pilbara, 2030



Source: Deloitte – Mined the gap: Australia's place in the emerging green iron value chain

Figure 5 also highlights that South Australia has a cost disadvantage compared with the Pilbara due to the premium on gas in the east coast market. However, it has a major cost advantage over the Pilbara in green hydrogen-based DRI due to the "Pilbara premium" – the additional costs of constructing infrastructure in a remote region, including higher wages.

South Australia should exploit the major advantages it has over other regions – both inside and outside Australia – to become a pioneer of truly green iron and steel. Given green steel can't be made using gas, this requires seizing early opportunities to use green hydrogen.

Numerous forms of support are now available from the federal government that can help accelerate green iron and steel production in Australia, including the Green Iron Infrastructure Fund, the Hydrogen Headstart program and the Hydrogen Production Tax Incentive. Most recently, the Australian government announced AU$750 million in grants to support the development of new technologies to produce green metals.

The development of new technologies will be crucial in Western Australia to allow the use of its lower-grade ores in DRI-based iron and steelmaking. But South Australia does not need to wait for such new technologies. It can use its high-grade magnetite reserves in mature, commercial-scale DRI facilities that are already in use overseas. The key providers of DRI technology have already made clear that their equipment is hydrogen-ready.

South Australia also has the significant advantage of having a power grid that will reach net 100% renewables by 2027. Although the state government's green hydrogen project has disappointingly been shelved, there still ought to be an early opportunity to produce some

green hydrogen using renewable grid power in the middle of the day that would otherwise be wasted. Early green hydrogen production in the state can be blended into the DRI reduction mix to reduce reliance on gas, and then gradually ramped up to 100% green hydrogen as the cost of production continues to decline.

Furthermore, the shipping of green hydrogen and green ammonia increasingly looks structurally expensive. The global slowdown in project development should be an opportunity to re-focus on domestic use rather than export, and on key sectors where green hydrogen will have a viable use – such as iron and steel that are truly green.

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About the Author

Simon Nicholas

Simon Nicholas is IEEFA's Lead Analyst for the global steel sector. Simon's focus is on the long-term outlook for steel production, as well as on the implications for the global iron ore and metallurgical coal markets. snicholas@ieefa.org