South Australian Productivity Commission

Final Report

Inquiry into South Australia's renewable energy competitiveness

10 August 2022

Government of South Australia

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An appropriate citation for this publication is:

South Australian Productivity Commission, *Inquiry into South Australia's renewable energy competitiveness*, Final report, August (2022).

Transmittal letter

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Document Ref: B1306560

9 August 2022

The Hon Peter Malinauskas MP
Premier of South Australia
State Administration Centre
200 Victoria Square
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Dear Premier

SAPC Inquiry into South Australia's Renewable Energy Competitiveness

In accordance with the terms of reference received by the Commission on 16 November 2021, I am now pleased to submit the South Australian Productivity Commission's Final Report on our inquiry into South Australia's Renewable Energy Competitiveness.

The Commission's central purpose is to provide you with independent evidence based economic advice on how to improve our State's economic growth and in turn, South Australian household incomes.

The key conclusions of our report are as follows:

- our State has a legitimate economic claim to potential competitive advantage in the renewable energy and some associated sectors;
- we therefore endorse the State's prioritisation and focus on these markets as a potential source of economic growth;
- however, realising that economic dividend will be challenging;
- global and national competition for direct and indirect renewable energy investment is fierce and will only become more fierce; and
- we can do it, but we will need to be world class in all respects. We will need to skillfully build on our strengths but also fix our weaknesses. On top of that, we will probably also need a little luck.

Our report sets out 40 findings and 15 recommendations that we believe can collectively provide our State with a realistic pathway to success. That pathway is not easy or risk free but, on balance, we believe it is worthy of your careful consideration.

I take this opportunity to thank my colleague Mr Steve Whetton and our inquiry team for their high quality assistance on this assignment.

Yours faithfully

Adrian Tembel
CHAIRMAN

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Key messages

A significant transformation of global energy systems is required to avert catastrophic climate change

Atmospheric concentrations of greenhouse gases (GHG)[1] have increased significantly as the industrial revolution and subsequent economic development led to the burning of fossil fuels such as coal, petrol and natural gas. These increased concentrations of greenhouse gases have been the major driver of warming global temperatures. Climate change is responsible for a series of damaging flow-on effects, including rising sea levels, significant changes in rainfall patterns, extreme heatwaves and environmental degradation. Increased atmospheric concentrations of CO_2 also result in ocean acidification, with potentially dire consequences for marine eco-systems.

Developed countries need to achieve significant reductions in greenhouse gas emissions by 2030, and reach net zero emission by 2050

The Paris Agreement commits the parties to reduce emissions sufficiently to limit global warming to below 2 ºC (and preferably below 1.5 ºC) compared to pre-industrial levels. To meet this goal, countries aim to reach global peaking of greenhouse gas emissions as soon as possible to achieve net zero carbon emissions by 2050.

Countries also set shorter-term targets at the 2021 United Nations Climate Change Conference of the Parties (COP) 26 meeting in Glasgow, with most developed countries pledging to achieve emissions reductions of 50 per cent or more from 2005 levels by 2030.[2] The recently elected Albanese Government is seeking to legislate a target of 43 per cent reduction in GHG emissions below 2005 levels by 2030. South Australia, along with several other states is targeting a reduction of 50 per cent by 2030.

The need to reach net-zero emissions by 2050 requires not just a fundamental transformation of the global energy system away from hydrocarbons to non-GHG emitting electricity (hydroelectric, solar, wind, nuclear) but also transformation of a range of industrial and agricultural processes to reduce or avert emissions. To meet its targets Australia is likely to require an almost complete decarbonisation of the electricity sector by the early to mid-2030s.

The global energy transition is also going to have an impact on the pattern of economic activity, potentially changing relative regional competitiveness

Regions currently dependent on hydrocarbon exports (or cheap electricity from local coal or gas) will see a reduction in their competitive advantage, and regions with abundant and easy to access renewable energy (hydroelectric, solar and wind) will see their competitive advantage increase. Some of this potential advantage comes from the fact that regions with abundant renewable energy close to transmission lines have the potential to have lower green energy costs, and part of the relative advantage is that they will no longer need to import hydrocarbons from other regions.

[1] Most significantly carbon dioxide (CO_2), but also methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6) and a number of other types of hydro fluorocarbons and perfluorocarbons

[2] Nationally determined contributions to the Paris Agreement targets are compiled by the United Nations Framework Convention on Climate Change <https://www4.unfccc.int/sites/NDCStaging/Pages/All.aspx>

Renewable energy, particularly solar PV, is likely to get much cheaper

The cost of solar, grid-scale batteries and, to a lesser extent, wind is falling significantly, and so whilst at the moment their firmed cost of electricity is in line with existing coal and gas generation, within five to ten years renewables are likely to become substantially cheaper. This provides a future advantage to those regions with good endowments of wind and solar.

South Australia has the potential to benefit from renewable energy

South Australia has good endowments of both solar and wind, in relative proximity to our main electricity loads. This combination of availability over much of the year, and reasonable proximity to transmission networks gives South Australia:

- competitive levelised cost of electricity (LCOE) from wind; and
- amongst the lowest LCOE from solar.

South Australia also has a relatively low reliance on hydrocarbon production, with no coal mining and a relatively small natural gas sector, and therefore will not lose substantial exports or economic activity from the shift away from hydrocarbons.

Solar photovoltaic (PV), and to a lesser extent wind power, costs are projected to fall substantially over the next few decades. Estimates calculated using learning models suggest that the LCOE of solar PV power could fall as low as $US10-15/MWh by 2050, with wind power projected to drop to around US$20/MWh.

The main competitive advantage for South Australia is regions with world-class combined solar and wind resources

South Australia has several regions in which the ***combined*** solar and wind endowments are amongst the best in the world. This is a competitive advantage in green hydrogen production as the combined resource means that the (very capital intensive) electrolyser can produce hydrogen for more hours per year, reducing the capital cost per unit of hydrogen. The combined resource also tends to reduce the amount of firming (such as with batteries) required for the electricity network.

There are potential downstream benefits for South Australia from increased demand for minerals needed for the global energy transition and from increased downstream processing of South Australian minerals, which would otherwise be exported as ores, to produce metals such as copper or iron.

However, there are a number of barriers that could stop South Australia from realising its potential economic benefits from renewable energy…

… barriers in the electricity market

The favourable endowments of solar and wind do not guarantee that South Australia will be able to secure an economic advantage from the global energy transition.

The illiquid and highly concentrated market for 'on-demand' electricity in South Australia means that it is expensive to hedge spot market prices, creating a much larger wedge between the (generally low) spot market prices and the wholesale price passed through to electricity consumers. For example, in 2020-21 demand-weighted spot prices averaged $55.4/MWh in South Australia, 24 per cent cheaper than the average spot price in New South Wales. However, the wholesale price passed through to South Australian consumers

averaged more than twice this at $113.1/MWh and was significantly higher than the wholesale price in New South Wales ($94.1/MWh).

The South Australian Government's Hydrogen Jobs Plan is targeted at addressing some of the limitations in the South Australian region of the National Electricity Market (NEM), particularly the market concentration in on-demand electricity, and the at times the very low daytime demand for electricity.

As renewable electricity continues to increase its market share in South Australia, and continues to become cheaper to install, this will put downward pressure on prices. However, other Australian states will also see falling prices due to the expansion of renewables. Modelling undertaken for the Commission suggests that because of the factors in the local market pushing wholesale prices up above sport market prices, whilst the gap between South Australian and interstate prices is likely to shrink, South Australian power prices are likely to remain higher than interstate. Unless this can be addressed renewable energy will not generate competitive advantages for most electricity users.

… and recent adverse policy choices which make it more difficult to install renewables in South Australia.

There have also been a number of adverse policy changes made by South Australian Government agencies that make meeting the Government's targets around renewable energy (and the associated electricity price decreases) harder to achieve.

The state's major project approval processes are regarded by stakeholders as being cumbersome, error prone, and difficult to navigate. They are seen as being well behind best practice models interstate.

The changes to the Planning Development Code (PDC) for rural areas, which came into effect on 31 July 2020, also represent a significant barrier to renewable developments. This code amendment introduced setbacks for solar farms for the first time and setbacks for wind farms were significantly increased (more than doubled for high turbines).

As a result of the increases to setbacks, the land available for renewable projects in South Australia has shrunk, as previously viable locations no longer had sufficient area within which wind or solar farms could be approved. With the setbacks required for wind farms being dependent on wind turbine tip heights, the impact of the new setbacks will increase as blade heights are increasing with technological improvements.

There is another policy-related barrier to the connection of renewable projects to the South Australian grid. In 2017, following the black system event, the South Australian Office of the Technical Regulator introduced a requirement that new renewables projects must also install a synchronous condenser or a battery delivering fast frequency response services.

Whilst this may have had merit as an emergency measure, it has not been removed despite a number of stability measures having been introduced by the Australian Energy Market Regulator (AEMO). It has also significantly increased the cost of undertaking a renewable energy project in South Australia; modelling by the Commission suggests a cost increase of 8 to 20 per cent.

Green hydrogen is a potentially significant opportunity arising from the global energy transition for Australia and South Australia

As the world moves to decarbonise, green hydrogen potentially has a broad role as both an energy carrier and as an industrial feedstock. The speed with which the cost of green hydrogen production and storage falls will determine the scale of hydrogen's use, and the speed with which some industrial processes can decarbonise.

Estimates prepared for the Australian Renewable Energy Agency (ARENA), which assume a moderate amount of green hydrogen production by current energy importers, are that total hydrogen exports from Australia are likely to range from 0.6 Mt to 3.1 Mt by 2040, depending on the scale of global climate policy ambition. Whilst other more optimistic projections cannot be ruled out, the Commission's view is that the estimates prepared for ARENA are a more prudent basis on which to plan policy.

… South Australia's renewable energy endowments are a potential competitive advantage for green hydrogen

South Australia, along with Western Australia, has a number of regions with world class co-location of solar and wind resources close to existing transmission lines or industrial areas.

For South Australia, given its relatively smaller industrial base, green hydrogen opportunities will lie primarily in the export sector.

… and the potential impacts are large

Should the state secure hydrogen export production, the potential impacts could be significant. Computable general equilibrium (CGE) modelling of the impacts of a plant with a 1,500 MW electrolyser, producing 0.13 Mt of hydrogen a year suggest that it would increase Growth State Product (GSP) by 1.4 per cent or $1.9 billion (equivalent to a year's average GSP growth), increase exports by $0.9 billion and create 4,600 jobs. This employment impact would be equivalent to 40 per cent of the current total employment in Whyalla.

... however the state also has potential local barriers to the development of a green hydrogen sector

While South Australia's world-class co-located wind and solar endowments are a competitive advantage in attracting large scale investment in green hydrogen, there are a number of other local factors that act as a competitive disadvantage relative to other Australian states or international competitors.

South Australia, unlike Queensland and Western Australia, does not have a commercially managed port suitable for exporting hydrogen.

Access to water is also very constrained in South Australia.

And the barriers to renewable energy development identified in this report make it harder for South Australia to take advantage of the competitive advantage from its wind and solar endowments.

… and there are also some potentially significant external barriers to a local industry

Hydrogen as a potential industrial and export sector is being targeted by all states and territories in Australia, and in many jurisdictions internationally. The Commonwealth Scientific and Industrial Research Organisation's (CSIRO) database of potential hydrogen projects suggests that as at July 2022 there are currently 92 unique hydrogen projects

proposed in Australia. South Australia has five projects listed, the smallest number of any of the states. The greatest numbers of projects listed are in Western Australia and Queensland which each have 28 projects.

The Upper Spencer Gulf is also significantly further from potential markets that potential competitor export sites such as Darwin, Port Hedland and Gladstone.

And because of their existing gas export sectors, Western Australia and Queensland have a much stronger track record of successfully delivering large scale resources projects, and established links to many of the key potential hydrogen investors.

South Australia does not currently have a large-scale gas extraction workforce (most of the Cooper Basin gas projects are supported out of Queensland) creating a potential lack of readily available skilled workers to support any hydrogen projects.

Other states also have greater budgetary capacity than South Australia to support the development of an export hydrogen sector due to their higher income from their own taxation revenue, stronger underlying budgetary position, and historically higher GSP growth rates which give greater scope to pay down debt through growth.

Whilst there is significant potential in green hydrogen, the scale of international trade is highly uncertain

Green hydrogen is no certainty as a major source of international trade, as there is considerable uncertainty about the international demand for trade in green hydrogen. Also, hydrogen is more difficult to transport than natural gas, requiring cooling to much lower temperatures to liquify it (−253 °C compared to −160 °C for natural gas), which comes at a high energy cost.

Production location will be driven by the combination of local cost of production (with local green energy costs being the main variation) and the cost of getting green hydrogen from producers to users. This means that if current energy importers such as Japan and South Korea can drive down their clean energy costs, it may be more cost effective for them to produce their own green hydrogen rather than importing it.

The scale of the potential market will be driven by a combination of the decarbonisation pathways chosen by major energy importers (and therefore the overall demand for green hydrogen) and how cost effectively those current energy importers could generate sufficient clean electricity to make hydrogen within their own country.

Engaging with key potential trading partners such as Japan and South Korea around their decarbonisation strategies and opportunities for South Australia to contribute to those strategies will be required to manage this risk.

'Green minerals' are also a potential renewable energy opportunity for South Australia

The global transition to a net zero economy, and the electrification of many systems that currently rely on fossil fuels, is likely to substantially increase demand for a number of base metals, some of which are relatively abundant in South Australia. Potential opportunities exist around:

- Copper (South Australia has around 67 per cent of Australia's economic demonstrated resource (EDR));

- Magnetite (a form of iron ore regarded as more suitable for green steel production, South Australia has 44 per cent of Australia's EDR; and
- Critical minerals.

There is also the possibility of South Australia extending the value chain to undertake additional processing of minerals ores produced in the state. This would only occur if the transition to 'green' minerals shifts the relative costs such that South Australia's potential green minerals advantages, in terms of abundant green energy resources close to potential mineral processing locations, are large enough to outweigh the benefits of economies of scale in existing minerals processing hubs.

Enhancing competitive advantages from renewables and enabling economic development

Despite the range of barriers identified in this inquiry, it remains the case that renewable energy has the *potential* to deliver competitive advantages for South Australia. Actions to realise potential competitive advantage should be sequenced.

… addressing barriers to renewable energy – a short-term priority

A necessary precondition for realising any of these potential benefits is addressing the factors that are delaying the large-scale expansion of wind and solar power in South Australia and getting in the way of consumers realising the gains from falling spot market electricity prices. This makes the renewables sector itself the short-term priority for Government action.

If these policy barriers to renewable energy can be addressed, then other potential opportunities may emerge.

… facilitating green hydrogen opportunities – a medium-term priority

Given its potential scale, and its role as a facilitator of green minerals opportunities, green hydrogen is the medium-term priority for the state.

However, given the scale of national and international competition for green hydrogen opportunities, the barriers identified in this report, and the risk that a global trade in green hydrogen will not emerge, support for green hydrogen involves risk.

If a decision was made to pursue the opportunities in green hydrogen, it is likely that they would only be secured if the state gets everything right – a world-class plan, world-class people (management and delivery), with the right delegated authority to deliver the right project(s). And the state would also need some luck; that enough international demand for green hydrogen trade emerges.

… green minerals – a longer-term priority

The potential opportunities for the state around green minerals will be dependent on both low cost and abundant renewable energy, and the availability of competitively priced green hydrogen. This means that seeking to facilitate green minerals opportunities is a potential longer-term priority as it will only be feasible if both barriers to renewables are addressed, and a local green hydrogen sector emerges.

Summary of Recommendations

Recommendation 1: The South Australian Government removes all non-noise-related setbacks for renewable energy projects from the planning code.

Recommendation 2: The South Australian Government reform the major project approvals processes to increase transparency, and proponent certainty, whilst still retaining appropriate controls to ensure that regulation of projects meets community expectations. To ensure separation from existing models we recommend that the Chief Executive of the Department of the Premier and Cabinet be given a mandate to design a new process that better meets the state's needs.

Recommendation 3: The Commission recommends that the South Australian Government amends the *Pastoral Land Management and Conservation Act 1989* or develops an alternative legislative framework that extends the provisions that enable wind farm exploration and development on pastoral lease land to other forms of renewable energy.

Recommendation 4: As part of the South Australian Government's proposed work on developing a cross-government framework for the assessment of wind-farm exploration applications on pastoral lease land, the Commission recommends that the Department for Environment and Water (DEW) develops and implements policy and processes that set out:

- how the relevant government agency(s) will deal with:
  - competing applications to access and use the same pastoral land; and
  - applications seeking exclusive access (and use of) part of the land under a pastoral lease;
- options that can provide for third-party access where appropriate; and
- ways to extend the scope of this work to applications for other forms of renewable energy apart from wind farms.

Recommendation 5: The Commission recommends that the South Australian Government amend the *Pastoral Land Management and Conservation Act 1989* (or enacts alternative legislation) to require that the information and data obtained by persons undertaking exploration activities as a result of their exclusive access approved under section 49J be provided to the State Government and made publicly available, similar to reporting provisions required for other activities undertaken on Crown land.

Recommendation 6: The Commission recommends that DEW commissions scenario modelling from the Office of the Valuer-General on the potential impacts of renewable energy projects on pastoral leases and associated liabilities arising from the application of land-use codes.

Recommendation 7: The South Australian Government engages with the Australian Energy Market Operator's (AEMO) review of their connection processes and the integration with Transmission Network Service Provider (TNSP) connection processes, and reduces new connection timeframes to increase the efficiency of the grid connection process and remove any South Australian specific inefficiencies.

Recommendation 8: The Office of the Technical Regulator (OTR) and AEMO establish a process to reconcile their different assessments of the amount of inertia required to ensure the stable functioning of a decarbonised electricity grid in South Australia.

Recommendation 9: The OTR generator connection standards be abolished and all grid stability services required procured efficiently at a whole region level.

Recommendation 10: Planning for the Northern Water Supply project considers the most cost-effective capacity to meet potential future water needs of green hydrogen and green minerals sectors.

Recommendation 11: The South Australian Government planning for common use infrastructure corridors includes possible future uses, such as green hydrogen and green minerals projects in addition to the requirements of current industry.

Recommendation 12: The State Government supports research and development relevant to the green minerals sector around optimising leachate processing approaches and exploring the opportunities to extract critical minerals from existing base metals deposits.

Recommendation 13: The State Government sequence its activities around the opportunities from renewable energy, with an initial focus on addressing the barriers to renewable energy development.

Recommendation 14 The State Government undertakes planning now for what would be required by a hydrogen export sector (such as commercial management of Port Bonython, infrastructure development at Port Bonython, and access to infrastructure corridors). Decisions on whether such works are more appropriately funded by the State Government or private investors can be made when appropriate.

Recommendation 15: The Commission recommends that the Chief Executive of the Department of the Premier and Cabinet be tasked with assessing whether the state public sector has the right skill sets and the right structures to secure green hydrogen opportunities in the face of national and global competition. Western Australia and Queensland are expected to have a competitive advantage relative to South Australia because of their greater experience in facilitating large-scale resource projects.

Summary of findings

Finding 1: The cost of electricity generated by solar photovoltaic (PV) is likely to fall significantly over the next thirty years, with wind power also expected to become cheaper.

Finding 2: For most industry sectors electricity prices only account for a small share of their production costs, and therefore a reduction in power prices is unlikely to materially affect the competitiveness of South Australian businesses outside of a small number of energy intensive industries such as green hydrogen, green minerals and data centres.

Finding 3: Increased renewable energy supply has significantly reduced relative spot electricity prices in South Australia; however, this has not led to lower wholesale prices for electricity consumers.

Finding 4: The South Australian region of the national electricity market (NEM) has insufficient commercial and industrial load to absorb the solar generation on sunny spring and summer days. This poses a risk to system stability and increases electricity costs to consumers.

Finding 5: South Australia has insufficient competition in the on-demand generation market, resulting in a low liquidity, high cost, hedging market, increasing wholesale power prices.

Finding 6: The Hydrogen Jobs Plan directly targets two current limitations of the South Australian electricity market: the at times excess daytime electricity supply from rooftop solar, and the illiquid on-demand power market. However, it is a very substantial investment and ensuring that risks (including construction costs) are well controlled, and that its operating model meets best practice (including maximising its positive impacts on power prices) will be critical to ensure it is a worthwhile investment.

Finding 7: Current NEM regulations and pricing mechanisms are not fit for purpose, delivering neither lowest cost for consumers nor inducing sufficient investment in storage to support the renewable energy transition.

Finding 8: Meeting the State's greenhouse gas reduction targets will require a largely decarbonised electricity sector, and as a result a substantial increase in renewable energy with wind and solar at least doubling from their current levels over the next decade. The backward-looking approach to managing system stability to date raises questions about whether the current grid management systems will be able to adapt fast enough to this change in supply.

Finding 9: Forecasting suggests that whilst expansion of renewable generation in South Australia will reduce spot market electricity prices significantly, this is unlikely to lead to South Australia having lower retail electricity costs than interstate unless the larger gap between spot and wholesale prices in South Australia can be addressed.

Finding 10: The power purchase agreement (PPA) system means there is currently little incentive for firms to relocate to South Australia to take advantage of its low carbon intensity electricity market as they can remain where they are and purchase PPAs to claim they are using green power.

Finding 11: No evidence has emerged during the inquiry to suggest that firms may relocate to South Australia for environmental, social and governance goal reasons alone.

Finding 12: The current elements of the Planning and Design Code related to setbacks for renewable energy projects near townships and settlements in rural areas are inconsistent with the South Australian Government's renewable energy policies and commitments. If the Government wishes to achieve its targets, then it will need to make trade-offs in terms of potentially reducing visual amenity.

Finding 13: Administrative errors and slow processes in the major project approvals process are causing delays in those projects receiving final South Australian Government and Ministerial approval.

Finding 14: The planning system is now acting at a relative competitive disadvantage for investment in South Australian renewables. The reasons for this include: the impact of increased setbacks; frequent processing errors and delays within the bureaucracy; and an approval process ill-suited for major or complex projects.

Finding 15: The regulatory landscape for development approvals of renewable energy projects is confusing. Even experienced professionals struggle to identify appropriate contacts and sequencing of activities.

Finding 16: The South Australian Government should not seek to institutionalise Renewable Energy Zones either through the planning and design code or through using them as a key factor in infrastructure planning decisions.

Finding 17: Current provisions for wind farms in the *Pastoral Land Management and Conservation Act 1989* do not extend to other forms of renewable energy. Consequently, the existing regulatory obligations and approval processes to access and use pastoral land effectively limits opportunities for green energy – particularly given South Australia's comparative advantage for the co-location of wind and solar.

Finding 18: There are currently gaps in the policies and procedures used to manage renewable energy developers' applications to undertake exploration activity on, or develop projects on, pastoral lands.

Finding 19: Unlike other cases where governments grant temporary exclusivity to intellectual property (such as through minerals exploration licenses or patents) there is currently no requirement on developers undertaking wind farm related exploration on pastoral lands to share the resulting data with the government and broader community.

Finding 20: Stakeholders have expressed concern that there is uncertainty about the potential implications for pastoral lease fees, and potential liability for other taxes and charges such as land tax and the Emergency Services Levy if a renewable energy development takes place on pastoral lands. It would be good practice for the actual implications to be clear to pastoralists before they agree to grant access to developers.

Finding 21: AEMO's current processes for connecting new renewable generation to the electricity grid are inefficient and causing unnecessary delays. AEMO is reviewing these

processes to improve them, ensure better integration with ElectraNet's processes and allow more work in parallel to reduce future connection timeframes.

Finding 22: The Office of the Technical Regulator requirements impose a significant cost burden on new renewables projects without achieving any obvious benefits in terms of system strength due to the reduction in new renewables construction. They are incompatible with the South Australian Government target on decarbonisation.

Finding 23: The projected scale of Australian green hydrogen exports is likely to be between 0.6 million tonnes and 3.1 million tonnes depending on the extent of global climate policy ambition. Government planning around the potential sector should be mindful of the range of plausible outcomes and not be based on the upper bound or lower bound outcomes.

Finding 24: South Australia has potential competitive advantages in the development of a green hydrogen sector arising from it having:

- regions with world-class combined wind and solar resources located close to areas suitable for green hydrogen production, reducing the cost of green hydrogen production; and
- a high frequency of very low spot electricity prices in the grid.

Finding 25: An export-scale green hydrogen plant (1,500 MW electrolyser) would increase GSP by $1.9 billion and create an additional 4,600 jobs conditional on market prices for hydrogen being high enough to make its production financially viable.

Finding 26: Development of a large-scale green hydrogen sector in South Australia will be dependent upon key potential markets, particularly in East Asia and Europe if these regions choose decarbonisation approaches that require substantial supplies of green hydrogen.

Finding 27: The lack of a commercial port is a constraint on the development of a large-scale green hydrogen export sector.

Finding 28: Lack of high quality water in the most prospective regions is a potential barrier to a green hydrogen sector developing in South Australia.

Finding 29: Difficulties in establishing infrastructure corridors are as important for green hydrogen and renewable energy as they are for mining, and the location and design of any state sponsored corridors should enable their use for green energy projects.

Finding 30: The potential green hydrogen export sector is highly competitive, with a significant focus from both governments and international investors on opportunities across Australian states and territories. Currently South Australia has the smallest number of identified hydrogen projects of the states. This means that realising green hydrogen opportunities will require world class performance and competitive costs to deliver hydrogen to clients.

Finding 31: South Australia's poor budgetary position, and the poor historical (and current) economic growth performance constrains the extent to which the State Government can support the development of a local green hydrogen sector. Some other jurisdictions are offering substantial financial support to developers.

Finding 32: Green hydrogen is not tied to specific areas of the globe, and in theory any country could produce it. This means that the extent of international trade in hydrogen will be determined by whether imported green hydrogen is cheaper than domestically produced green hydrogen.

Finding 33: An international trade in green hydrogen may not actually develop, and therefore the scale of potential opportunities in green hydrogen is very uncertain, and effective engagement with key trading partners is important.

Finding 34: As global demand for critical minerals increases, a number of deposits which are currently uneconomic may move into production. If South Australian deposits can be extracted at a competitive cost the State may see a substantial increase in mining output over the next 30 years.

Finding 35: There is a potential opportunity from increased minerals processing, but it will depend on the cost of shipping and on reducing wholesale power costs in South Australia.

Finding 36: Green iron developments would require very significant amounts of renewable energy, and this could not be delivered without addressing current barriers in the approvals systems. It is also likely to require very substantial increases in transmission infrastructure in the state.

Finding 37: As is the case with the potential green hydrogen export opportunity, the relative lack of suitable export ports is a barrier to green minerals development.

Finding 38: Lack of availability of suitable quality water is likely to be a barrier for potential new green minerals developments.

Finding 39: Activities to help realise competitive advantages from renewables have a logical sequence. A prudent approach to managing risks would involve an initial focus on facilitating the roll out of renewables, then to green hydrogen, and finally only moving on to green minerals if the renewables and green hydrogen are successful.

Finding 40: Any infrastructure required to address barriers to hydrogen development may need to be delivered in a short timeframe to secure investment. Sophisticated planning and preparation are ways of accelerating the delivery time without undertaking substantial financial commitments.

About the South Australian Productivity Commission

The Commission's central purpose is to provide the Premier with independent evidence-based economic advice on how to improve our State's economic growth and in turn, South Australian household incomes.

Premier and Cabinet Circular, *The South Australian Productivity Commission* (PC046) sets out the objectives and functions of the Commission; how inquiries are referred to the Commission, undertaken and reported on; and how the Commission and public sector agencies work together.

The Commission is supported by the Office of the South Australian Productivity Commission which is an attached office of the Department of the Premier and Cabinet.

Commission's approach

The Commission is required to take a broad perspective in developing advice for the South Australian Government. It must consider the interests of industry, business, consumers and the community, regional South Australia, social-economic implications and ecological sustainability.

The Commission conducts its own independent quantitative and qualitative analysis. It also draws on the experience, evidence and views of all inquiry stakeholders.

Confidentiality

Transparency is an important part of the Commission's independent process for gathering evidence and other elements of the inquiry process. The Commission will publish the submissions that it receives on its website unless the author clearly indicates that the submission is confidential or the Commission considers the material to be offensive, potentially defamatory, beyond the scope of the inquiry's terms of reference, or an abuse of process.

Disclosure

The Commissioners have declared to the South Australian Government all personal interests that could have a bearing on current and future work. The Commissioners confirm their belief that they have no personal conflicts in regard to this inquiry.

More information

For more information on the Commission, including circular PC046, how to communicate with the Commission and details on the Commission's approach to handling confidential material visit our website at www.sapc.sa.gov.au, email to sapc@sa.gov.au or call 08 8226 7828.

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Acknowledgements

The South Australian Productivity Commission would like to acknowledge the assistance of all of those who contributed to the development of this report. The Commission has drawn on a range of data and stakeholder consultations in preparing this report and is grateful for all of the contributions made.

The Commission would like to thank the South Australian Department for Energy and Mining, for providing a number of briefings on the South Australian energy sector. We also acknowledge the assistance of the Australian Energy Market Commission in supplying pricing and demand data for the national electricity market.

Acronyms and Definitions

AEMC	**Australian Energy Market Commission** – responsible for making and revising the energy rules. AEMC is guided by the three legislated National Energy Objectives (electricity, gas and energy retail).
AEMO	**Australian Energy Market Operator** – responsible for operating Australia's largest gas and electricity power systems. AEMO also provides critical planning, forecasting and power systems information.
AER	**Australian Energy Regulator** – responsible for regulating wholesale and retail energy markets, and energy networks, under national energy legislation and rules.
AGN	**Australian Gas Networks** (formerly Envestra Limited) – responsible for operating natural gas transmission and distribution pipelines across Australia.
ARENA	**Australian Renewable Energy Agency** – responsible for managing Australia's renewable energy programs, with the objective of increasing supply and competitiveness of Australian renewable energy resources to support the global transition to net zero emissions.
Capacity factor	The share of actual electricity generated by an energy plant as a proportion of its maximum generation capability. For example, an energy plant with a 500 MW maximum generation capacity that generates an average of 250 MW has a capacity factor of 50%.
CGE	Computable general equilibrium (modelling)
CLM Act	*Crown Land Management Act 2009*
COAG	Council of Australian Governments
COP	refers to the United Nations Climate Change **Conference of the Parties**
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEM	Department for Energy and Mining
DER	**Distributed Energy Resources** – consumer-owned devices that, as individual units can generate or store electricity or have the 'smarts' to actively manager energy demand, for example, roof top solar photovoltaic (PV) connected at houses and businesses, working to send power back to the network.
DEW	Department for Environment and Water
DTF	Department of Treasury and Finance
EDR	**Economic demonstrated resource** – A resource for which profitable extraction or production under defined investment assumptions is possible.
ESCOSA	Essential Services Commission of South Australia

ESG	**Environmental, social and governance** – Non-financial factors used to measure and evaluate an investment or company's sustainability and ethical impacts.
FCAS	**Frequency Control Ancillary Services** – used by AEMO to maintain the frequency of the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards.
FFR	**Fast frequency response** – The delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency.
Firmed energy	A supply of energy that can start, stop and change supply quickly, reliably and on-demand, for a committed period of time, to maintain grid stability when there are sudden changes to energy demand or supply.
GHG	**Greenhouse gases** refer to gases which act to trap heat in the atmosphere, if atmospheric concentrations increase global average temperatures will increase, if concentration decrease average temperatures will fall. Carbon dioxide (CO_2) is the most significant greenhouse gas, but greenhouse gases also include methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6) and a number of other gases including hydrofluorocarbons and perfluorocarbons
GHI	Global Horizontal Irradiance
GSP	Growth State Product
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISP	**Integrated System Plan** – a whole-of-system plan developed by AEMO that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond. Its primary objective is to maximise value to end-consumers by designing the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory, determined by policy makers, at an acceptable level of risk.
LCOE	**Levelised cost of electricity** – depends on the lifetime costs of generating the electricity (including capital expenditure) and the lifetime output of electricity.
LNG	Liquified natural gas
NEM	**National Electricity Market** – the wholesale exchange (market) operated and administered by AEMO for electricity supply the Australian Capital Territory, Queensland, New South Wales, Victoria, Tasmania and South Australia.
NER	**National Electricity Rules** (rules) – govern the operation of the NEM. The rules:

	• govern the operation of the wholesale electricity market, i.e. the market arrangements for the commercial exchange of electricity from the electricity producers through to electricity retailers; • govern the economic regulation of services provide by monopoly transmission and distribution networks; and • govern the way in which AEMO manages power system security.
OTR	**Office of the Technical Regulator** – responsible for electrical, gas and plumbing safety and technical regulation in South Australia.
OVG	Office of the Valuer General
PDC	**Planning and Design Code** – the single source of planning policy in South Australia. It implements the requirements of Section 66 of the *Planning, Development and Infrastructure Act 2016,* setting out a comprehensive set of policies, rules and classifications which may be selected and applied in the various parts of the State, for the purposes of development assessment and related matters within the State.
PDI Act	*Planning, Development and Infrastructure Act 2016*
PIRSA	Department of Primary Industries and Regions SA
PLMC Act	*Pastoral Land Management and Conservation Act 1989*
PLUS	**Planning and Land Use Services** – Responsible for managing the planning and land use system for South Australia.
PPA	**Power Purchase Agreement** – a contract between two parties, one which generates electricity (the seller) and one which is looking to purchase electricity (the buyer). The PPA defines all of the commercial terms for the sale of electricity between the two parties.
PV	Photovoltaic
R&D	Research and development
REZ	**Renewable Energy Zone** – high-quality resource area where clusters of large-scale renewable energy projects can be developed using economies of scale.
SCAP	**State Commission Assessment Panel** – The panel, which is established under the PDI Act, independently assess and determine certain development applications in South Australia, as delegated by the State Planning Commission.
SEB	Significant environmental benefit (obligations)
TNSP	**Transmission network service provide**r – State-based network service providers that service the various jurisdictions in the NEM. ElectraNet is the TNSP responsible for the South Australian electricity grid.
WPD	Wind power density

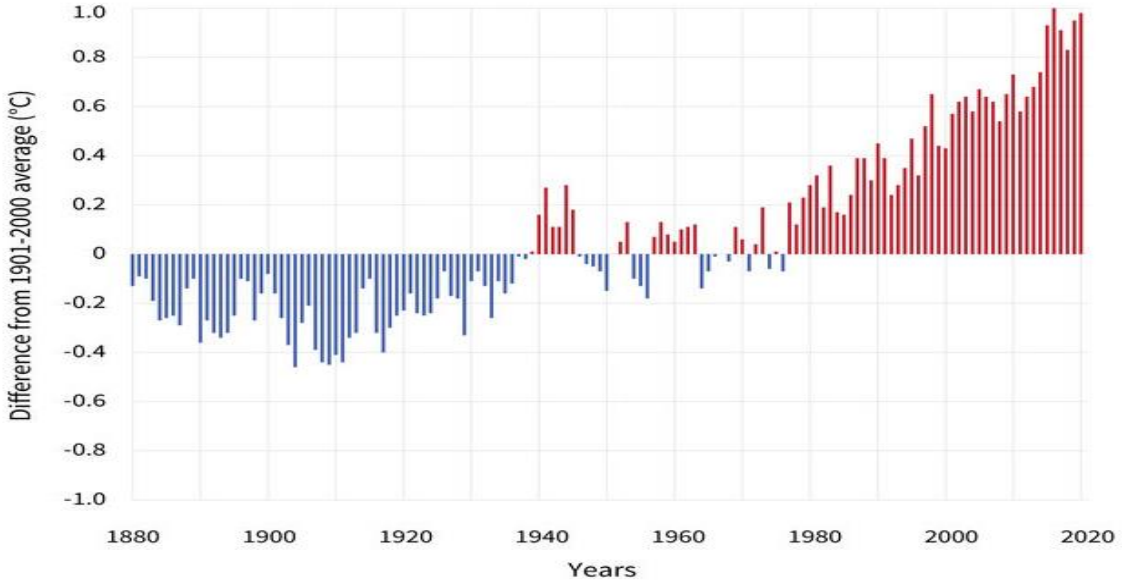
1. Background

1.1 Global energy transition

The climate change emergency and trajectories to zero carbon

Atmospheric concentrations of greenhouse gases[3] have increased significantly as the industrial revolution and subsequent economic development led to the burning of fossil fuels such as coal, petrol and natural gas. These increased concentrations of greenhouse gases have been the major driver of warming global temperatures (refer Figure 1.1). Climate change is responsible for a series of damaging flow-on effects, including rising sea levels, significant changes in rainfall patterns, extreme heatwaves and environmental degradation. Increased atmospheric concentrations of CO_2 also result in ocean acidification, with potentially dire consequences for marine eco-systems.

Figure 1.1 Global average temperatures



Source: National Oceanic and Atmospheric Association < https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature>*(2021)*

In the *State of Climate 2020 Report*, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) predicts Australia will experience continued warming, with more extremely hot days and fewer extremely cool days, a decrease in cool season rainfall, ongoing sea level rise and a longer and more dangerous fire season.[4]

Locally, South Australia's mean annual temperature, averaged across the state, is now approximately one degree Celsius warmer than it was in the 1970s.[5] The Murray–Darling Basin has experienced severe declines in streamflow [6] and the State encountered severe bushfires in January 2020 in significant areas of Kangaroo Island and the Adelaide Hills.

[3] Most significantly carbon dioxide (CO_2), but also methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6) and a number of other gases including hydrofluorocarbons and perfluorocarbons
[4] CSIRO and Bureau of Meteorology (2020), *State of the Climate*, 22
[5] Department for Environment and Water (2020), *Tracking Changes in South Australia's Environment*, 12
[6] CSIRO and Bureau of Meteorology (2020), *State of the Climate*, 9

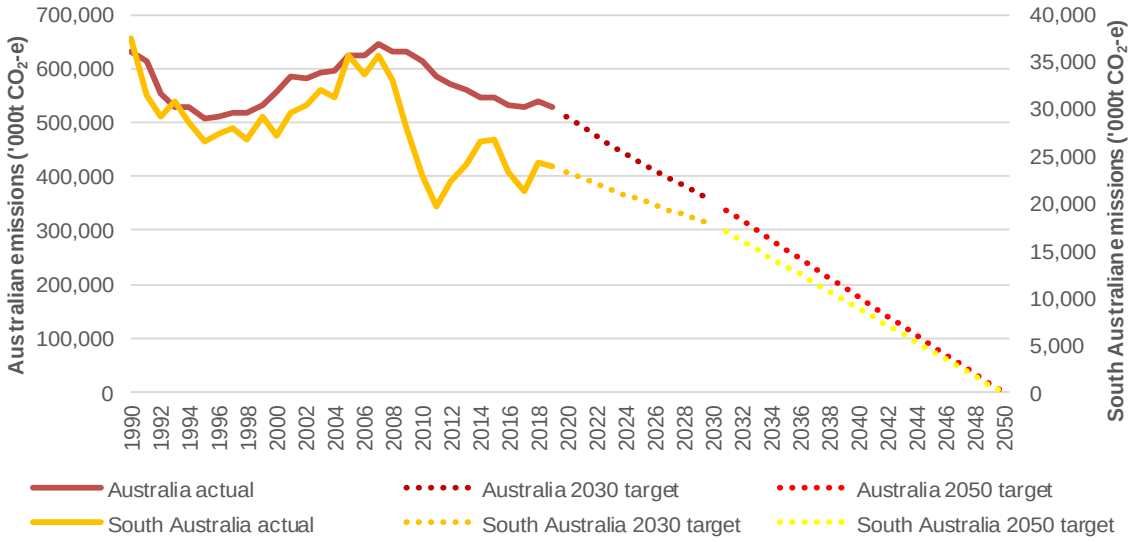
In response to the climate challenge, international governments have pledged to adopt and achieve a 'net zero' strategy to tackle climate change. Net zero would be achieved when most activities are shifted away from carbon-emitting processes and any remaining greenhouse gas emissions produced are offset by the removal of equivalent amounts of atmospheric greenhouse gases.

The global trajectory to net zero was most notably launched by the Paris Agreement, a legally binding international treaty adopted by 197 parties (including Australia) on 12 December 2015. At the core of the agreement was a commitment by parties to reduce emissions sufficiently to limit global warming to below 2 ºC (and preferably 1.5 ºC) compared to pre-industrial levels. To meet this goal, countries aim to reach global peaking of greenhouse gas emissions as soon as possible to achieve a climate-neutral world by mid-century (2050).

Countries also set shorter-term targets at the United Nations Climate Change Conference of the Parties (COP) 26 meeting in Glasgow, with most developed countries pledging to achieve emissions reductions of 50 per cent or more from 2005 levels by 2030.[7] The recently elected Albanese Government is currently seeking to legislate a 2030 target of 43% below 2005 levels, an increase from the previous government's target of a 26 to 28 per cent reduction.

Figure 1.2 shows Australia's and South Australia's annual greenhouse gas (GHG) emissions by year, together with projected trajectories to the relevant 2030 and 2050 targets for net emissions.

Figure 1.2: Australia's net greenhouse gas emissions by year, actual to 2019, projected to 2030, and trajectory from 2030 required to meet net zero emissions by 2050



Source: Australian Greenhouse Emissions Information System, Department of Industry, Science, Energy and Resources for actual emissions*; trajectory to 2030 and 2050 calculated by SAPC.*

Many state and territory governments have set more ambitious targets for decarbonisation. All states and territories have also established their own climate change strategies. These state and territory strategies and the 2030 emissions targets are listed in Table 1.1.

[7] Nationally determined contributions to the Paris Agreement targets are compiled by the United Nations Framework Convention on Climate Change <https://www4.unfccc.int/sites/NDCStaging/Pages/All.aspx>

At present neither the Australian Government nor most of the states and territories have established mechanisms to produce the changes needed to get to the 2030 or 2050 targets.

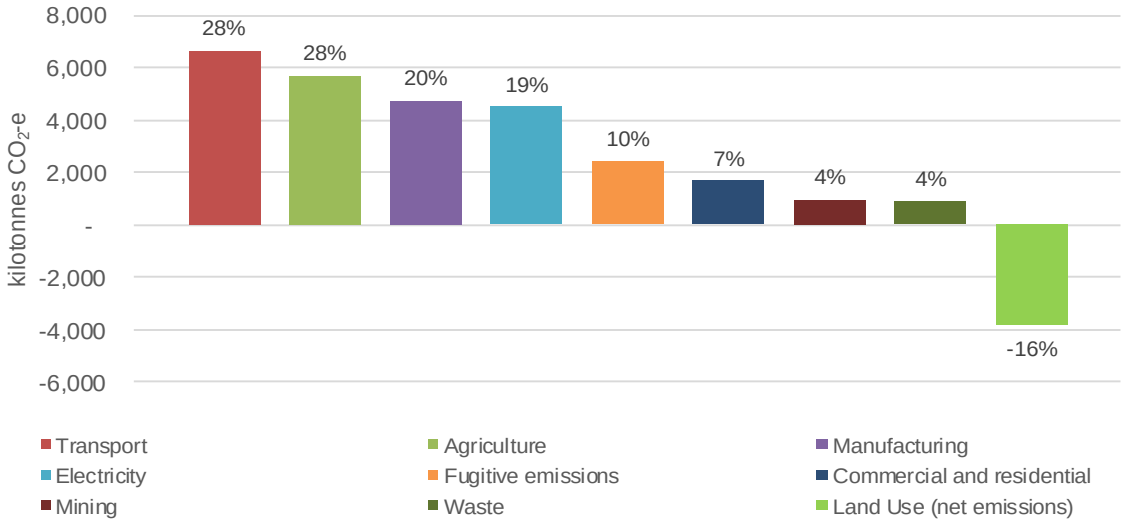
Table 1.1: States and territories interim emissions reductions targets and climate change strategies.

State/territory government	Interim targets	Climate change strategy
New South Wales	50% reduction on 2005 levels by 2030.	Net Zero Plan Stage 1 2020-2030
Victoria	Legislated 28–33% reduction on 2005 levels by 2025 and 45-50% reduction on 2005 levels by 2030 (legislated)	Victorian Climate Change Strategy
Queensland	At least 30% reduction on 2005 levels by 2030, 'contingent on continued national and global action'	Climate Action Plan 2030
Western Australia	None. Western Australia supports Federal Government target of reducing emissions by 26-28% by 2030.	Western Australian Climate Change Policy
South Australia	At least 50% reduction on 2005 levels by 2030.	South Australian Climate Change Action Plan 2021-2025.
Northern Territory	Intends to set interim targets by mid-2022, as at August 2022 an interim target has not yet been set.	Northern Territory Climate Change Response: Towards 2050
Tasmania	Committed to net zero by 2030. This was achieved in 2015.	Tasmanian Climate Change Action Plan 2017-2021
Australian Capital Territory	Legislated 50-60% reduction on 1990 levels by 2025, 65-75% reduction by 2030, and 90-95% reduction by 2040.	Australian Capital Territory Climate Change Strategy 2019-25

Greenhouse gas emissions are generated by a range of activities. Figure 1.3 shows South Australia's greenhouse gas emissions in the 2019 financial year across key economic sectors.

This shows the scale of the challenge in achieving the agreed net zero target for South Australia. Delivering enough zero carbon energy to completely decarbonise the electricity sector (which would involve roughly doubling current wind and solar generation in South Australia) would only address 19 per cent of gross emissions. Substantial additional zero carbon electricity would need to be added to the South Australia network to allow emissions in transport, manufacturing, mining, and commercial and residential sectors to be averted, either through electrification or through replacement of hydrocarbons with green hydrogen. Other sectors such as some types of manufacturing will require technological change to replace current emitting processes with net zero processes, or in the case of fugitive emissions from gas and coal extraction, a cessation of the existing activity.

Figure 1.3: South Australia's Greenhouse Gas Emissions in 2018-19 by economic sector, kilotonnes of emissions CO_2-equivalent, and share of state total



Source: Australian Greenhouse Emissions Information System, Department of Industry, Science, Energy and Resources, data extracted June 2022

1.2. South Australian electricity generation

Table 1.2 from the Australian Energy Market Operator (AEMO) shows the sources of electricity generated in South Australia. Approximately 62 per cent of South Australia's electricity for the 2020-21 financial year was generated through various renewable sources.

Table 1.2: South Australian registered capacity and local generation by energy source in 2020-21

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,681	34	5,226	37
Wind	2,141	27	5,738	41
Diesel & other non-scheduled generation	598	8	78	0.6
Rooftop solar photovoltaic (PV)[a]	1,651	21	1,925	14
Photovoltaic non-scheduled generation (PVNSG)[b]	151	1.9	248	1.8
Large-scale solar PV	411	5	673	5
Storage – Battery	212	2.7	85	0.6
Total[c]	**7,845**	**100**	**13,973**	**100**

Note: a This includes residential (≤10 kW) and small commercial (10 kW to 100 kW) solar power systems
b This is larger commercial systems (100 kW to 10 MW) which are below the threshold to be regulated by AEMO as a grid scale generator.
*c The total generation output recorded adds up to more than the annual **consumption** of electricity as storage is included as a source of generation and some of the generation is used to charge that storage.*

Source: 2021 South Australian Electricity Report (AEMO)

South Australia has made significant and rapid progress in decarbonising its electricity generation (using solar and wind) and is second only to Tasmania, with its large-scale hydroelectric generation, in terms of low emission intensity of electricity generation.

South Australia's energy mix, focused on wind and solar energy, is driven by local endowments. Hydroelectric energy is not feasible (except as energy storage) in South Australia due to the state's dry climate; nuclear energy is currently prohibited in Australia (and is estimated to be very costly[8]); other technologies such as wave power and tidal power are not yet proven at commercial scale.

Wind

Wind power is generated through wind turbines, which capture energy within the area swept by their blades. The spinning blades drive an electrical generator that produces electricity for export to the grid. Advances in technology have contributed to wind turbines now being larger, increasingly efficient, and making use of more intelligent technology. Rotor diameters and hub heights have increased to capture more energy per turbine. This means fewer turbines are needed to produce the same energy, and wind farms have increasingly sophisticated ability to adjust to local wind directions and variations in wind speed to maximise output.[9]

The key benefits of wind power are its relatively low cost and its ability to generate electricity in the evening and in overcast conditions. Turbines are cost-effective once installed, and when grouped together into 'wind farms', energy is collected and sent to the electrical grid.

South Australia is currently the biggest producer of wind energy in Australia. Table 1.2 shows there was 5,738 gigawatt hours of electricity generated by wind farms in 2020-21. South Australia currently has 22 wind farms in operation.[10]

Solar

Solar power is generated through two main technologies:

- solar PV panels that convert sunlight directly into electricity. The conversion takes place in cells of specially fabricated semiconductor crystals; and
- concentrated solar thermal (CST), which concentrates sunlight through lenses and reflectors, heating a storage medium such as salt or oil, which is then used to produce steam to drive a turbine.

In the AEMO data on electricity generation, solar PV is split between rooftop Solar PV (small-scale rooftop systems on homes and businesses), reported in AEMO data as Rooftop Solar PV); PVNSG which are medium scale systems of between 100kW and 10 MW; and large-scale solar PV (the solar farms that are regulated by AEMO as generators).

[8] The CSIRO estimates that by 2030 the LCOE for electricity generated from a small modular nuclear reactor (SMR), the type of generation IV reactor that is believed to have the best prospects to reduce costs through scale economies and learning, will be between $136/MWh and $326/MWh, with the lower bound only achievable if there is large scale international adoption of nuclear SMR to generate economies of scale in production. By way of contrast the LCOE for solar PV in 2030 is estimated by the CSIRO as between $27/MWh and $56/MWh, and the costs of a grid supplied with 90 per cent of its power by a combination of wind and solar, including the grid integration costs of being at 90 per cent renewables, is estimated at $61/MWh to $82/MWh. Graham, P., J. Hayward, J. Foster J. and L. Havas (2022), *GenCost 2021-22: Final report*, CSIRO, Australia.

[9] '*Wind Energy Facts',* Clean Energy Council <https://www.cleanenergycouncil.org.au/resources/technologies/wind>

[10] '*Wind Farm*s in South Australia' <https://www.renewablessa.sa.gov.au/large-scale-generation-and-storage/wind-farms-in-south-australia>

A key benefit of rooftop solar PV is that it generates electricity at the point of demand (i.e. homes and offices). There is therefore no requirement to transmit energy over long distances using expensive electrical infrastructure.[11] The key disadvantage of small-scale rooftop PV in the grid is that as a very disaggregated power source it is much more difficult for the network operator to control, which can negatively impact grid stability. A valuable benefit of CST is its storage capabilities, which allows the energy to be stored for long periods of time and dispatched as required. Globally, most CST plants used for electricity production incorporate three to 15 hours of thermal energy storage.[12]

Due to South Australia's high penetration of solar PV installations, according to AEMO it is the 'first large-scale power system in the world to approach zero net operational energy demand – even for very short time periods – due to high proportions of demand being met by solar'.[13]

A key limitation of both solar and wind is their intermittency/variability, which means that availability is not always well matched with demand. Therefore, energy storage (discussed in further detail below) is essential for providing stability to the grid.

Energy storage

Energy storage is critical to managing the variable output of renewable technologies, providing increased reliability and stability to the system. It also provides consumers with greater control over their energy use and allows households to maximise the solar energy they generate.

There are a range of energy storage technologies, including pumped hydroelectric, grid-scale batteries, green hydrogen and compressed air storage.

Trends in generation

South Australia's, and indeed the rest of the country's, energy generation mix is expected to change substantially over the next few decades. The exact form that change will take is still unknown as it depends on what types of incentive structures are established for grid decarbonisation, and for firming of variable renewables in the grid.

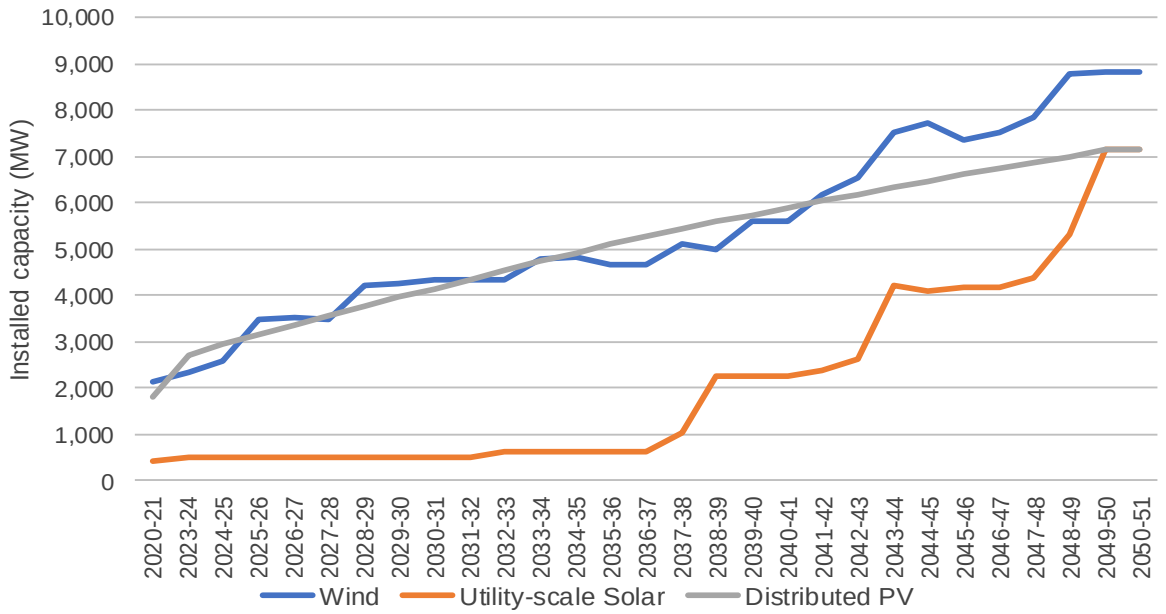
AEMO, the market operator for the National Energy Market (NEM), undertakes regular forecasting exercises, called the Integrated System Plan (ISP), to map out how the future grid may look under different scenarios. In both the 2021 and 2022 ISPs, stakeholder feedback was that the 'step change' scenario is the most realistic transition path for the NEM and this section summarises what that would mean for renewable power capacity in the South Australian grid.

Step change scenario

Figure 1.4 indicates that, under the step change scenario, it is estimated that the level of installed capacity for wind and distributed PV in South Australia will increase steadily over the next few decades. This compares to the expected growth in utility-scale solar which will remain relatively constant until the late 2030s (because much of the market it would serve is already being supplied by rooftop solar PV) when it sharply increases.

[11] *'Solar',* Clean Energy Council <https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy>
[12] 'Concentrated Solar Thermal', Australian Renewable Energy Agency (ARENA) <https://arena.gov.au/renewable-energy/concentrated-solar-thermal/>
[13] AEMO (2020), *Managing South Australia's Energy Transition*, 2

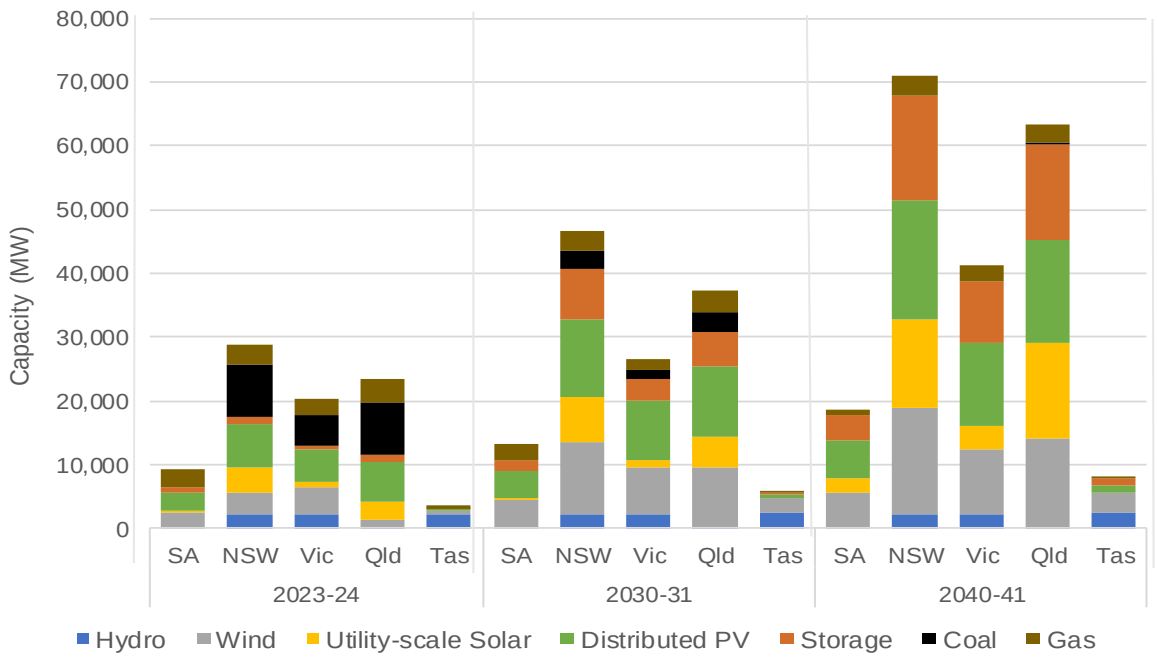
Figure 1.4: Projected trends in installed renewables capacity in South Australia, AEMO step change scenario, MW



Source: Australian Energy Market Operator, 2022 Integrated System Plan

The data in Figure 1.5 provides a comparison of the different dispatchable capacity for each fuel type for each NEM state at specified time periods.

Figure 1.5: Dispatchable capacity in the NEM by state and fuel type, AEMO step change scenario, MW

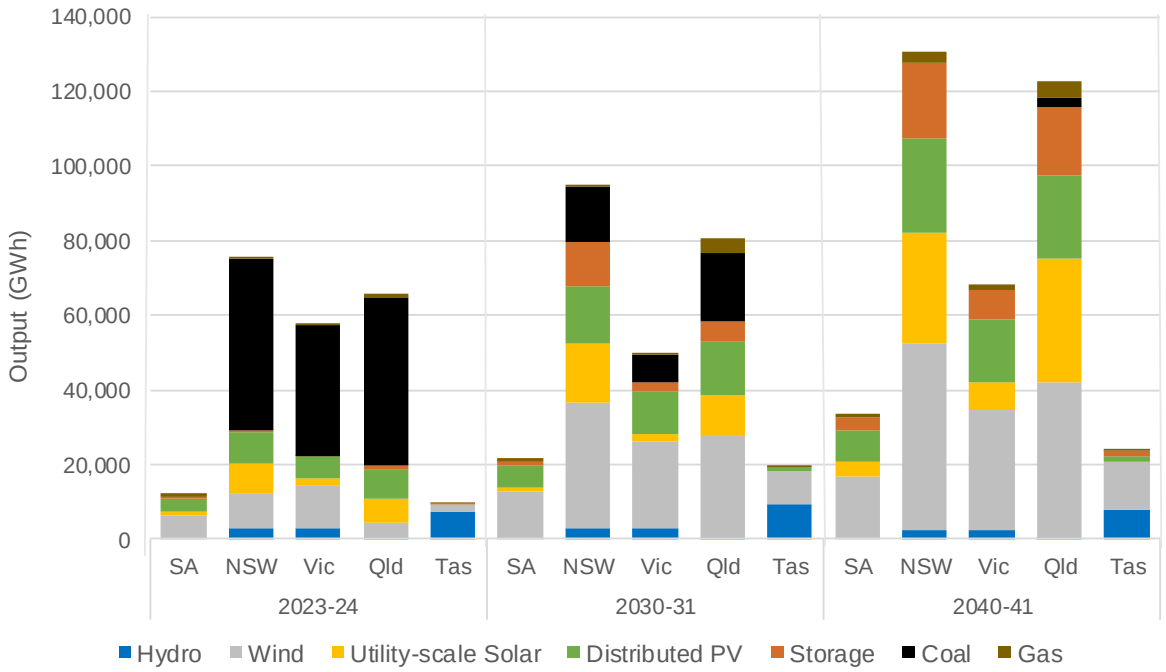


Source: Australian Energy Market Operator, 2022 Integrated System Plan

Figure 1.6 provides a similar comparison, although for expected electricity generated, or output by each type of fuel. Both are estimates under the step change scenario. Compared

to other states, the data indicates that the change in the volume and mix of fuel in South Australia over time will be less dramatic – particularly compared to NSW and Queensland.

Figure 1.6: Expected electricity generation in the NEM by state and fuel type, AEMO step change scenario, GWh



*Note: The total generation output recorded in the ISP adds up to more than the expected annual **consumption** of electricity as storage is included as a source of generation and some of the primary generation (such as wind and solar) would be used to charge that storage.*

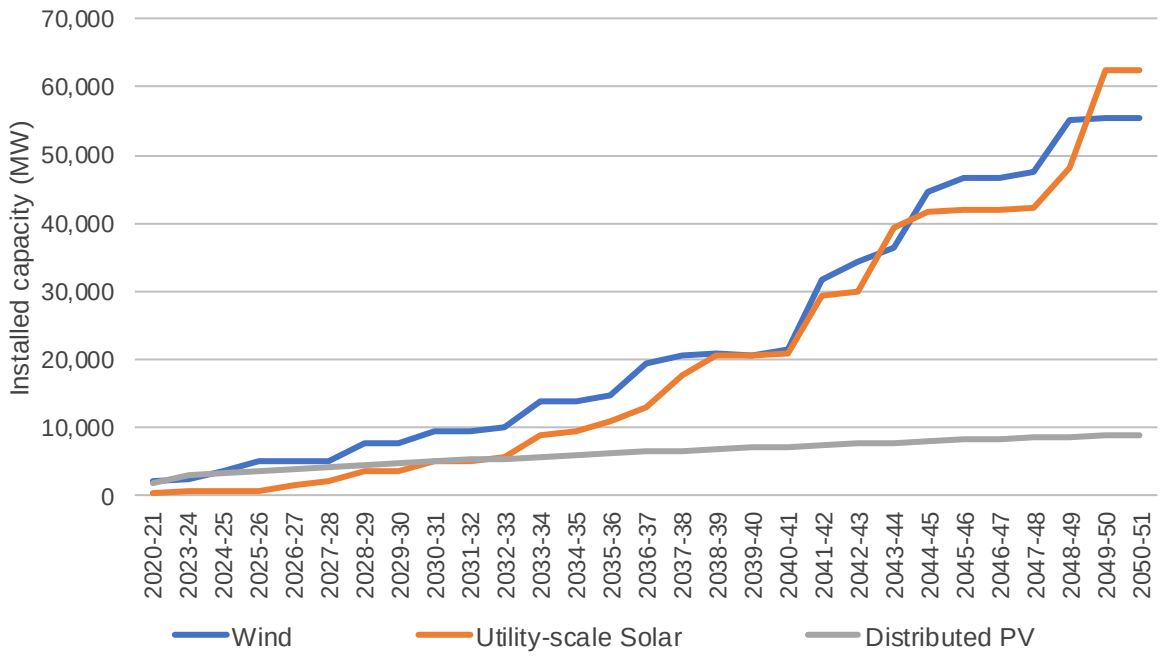
Source: Australian Energy Market Operator, 2022 Integrated System Plan

Hydrogen superpower scenario

AEMO also explores a scenario where green hydrogen production, for both export and local industrial use, has become an important part of the energy transition. Figures 1.7 to 1.9 summarise what that 'hydrogen superpower' scenario might look like in terms of required generation capacity.

Figure 1.7 indicates that, under the hydrogen superpower scenario, distributed PV plays a much smaller role and utility-scale solar plays a much larger role than estimated for the step change scenario indicated in Figure 1.4. As expected, the level of installed capacity required is significantly larger than in the step change scenario. By 2050-51 AEMO projects that the South Australian grid would require 126.7GW of renewable energy generation capacity, more than five times the 23.1 GW of renewable energy capacity projected under the step change scenario.

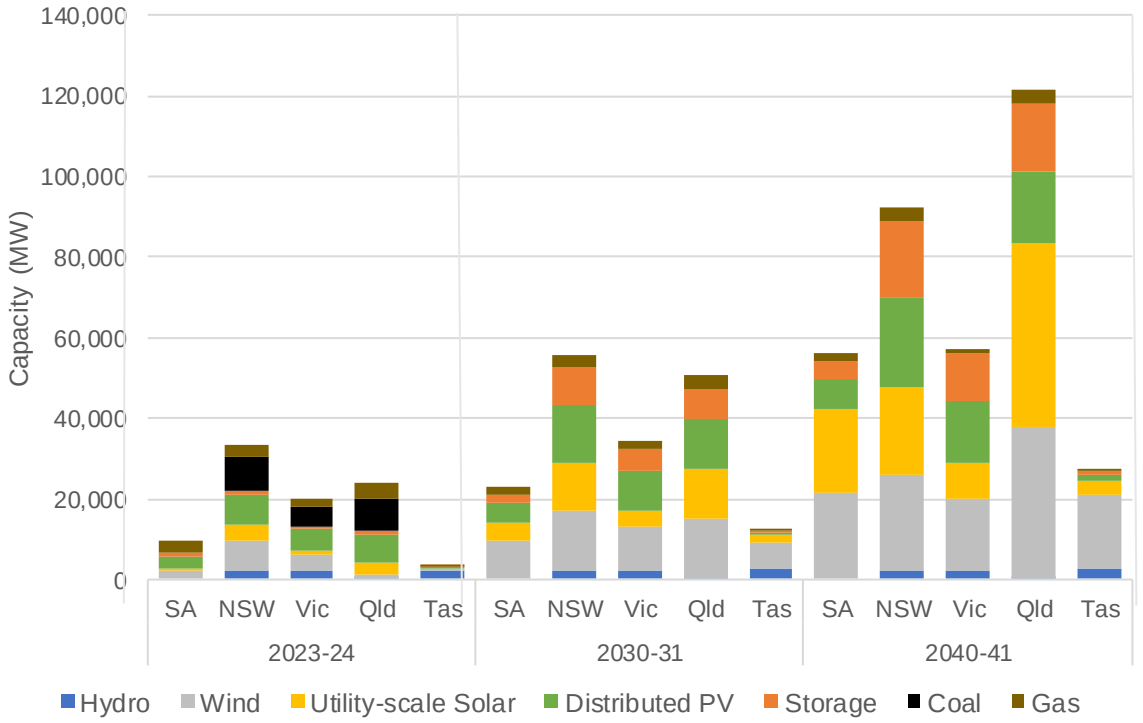
Figure 1.7: Projected trends in installed renewables capacity in South Australia, AEMO hydrogen superpower scenario, MW



Source: Australian Energy Market Operator, 2022 Integrated System Plan

The data in Figure 1.8 provides a comparison of the different dispatchable capacity for each fuel type for each NEM state at specified time periods.

Figure 1.8: Dispatchable capacity in the NEM by state and fuel type, AEMO hydrogen superpower scenario, MW

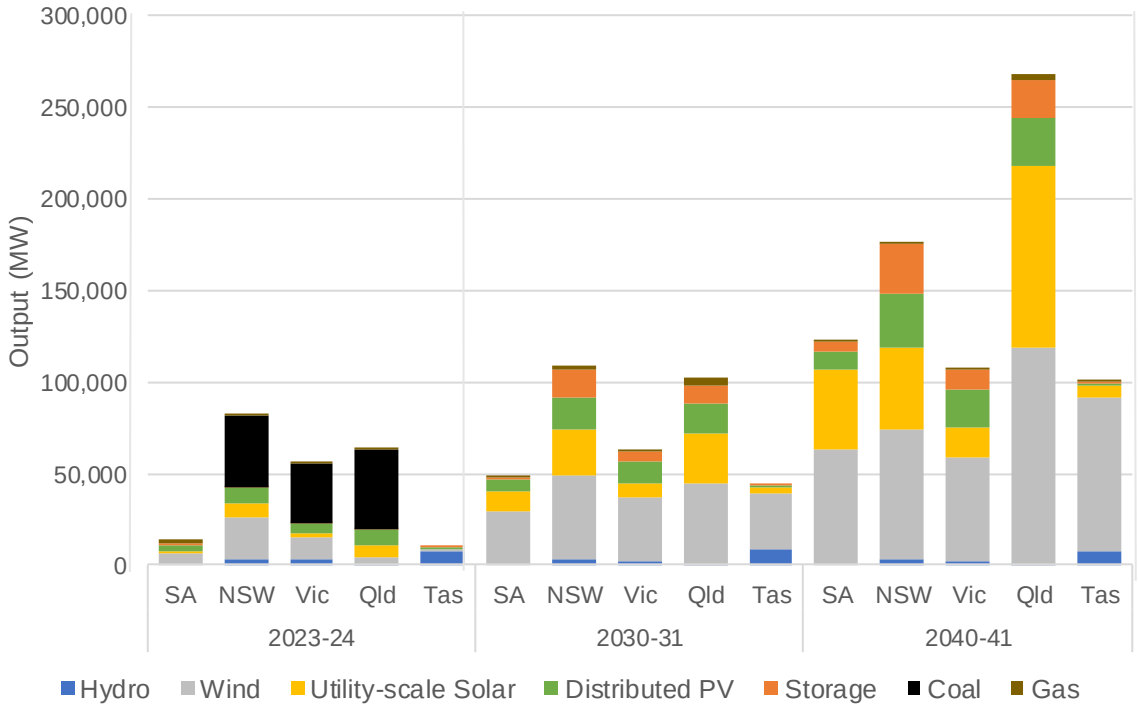


Source: Australian Energy Market Operator, 2022 Integrated System Plan

Figure 1.9 provides a similar comparison, although for expected electricity generated. Both are estimates based on the hydrogen superpower scenario, and as expected, they show that coal and gas are phased out very quickly and storage plays a more significant role in dispatched capacity and output generated.

Estimates indicate that South Australia's growth in total dispatched capacity is more in line with Victoria under the hydrogen superpower scenario compared to the step change scenario. The different scenarios see Queensland and NSW swapping the lead position based on their estimated total volume of dispatched capacity by 2040-41. Similar observations can be made for estimated total electricity generation for each state under the different scenarios.

Figure 1.9: Expected electricity generation in the NEM by state and fuel type, AEMO hydrogen superpower scenario, GWh



*Note: The total generation output recorded in the ISP adds up to more than the expected annual **consumption** of electricity as storage is included as a source of generation and some of the primary generation (such as wind and solar) would be used to charge that storage.*

Source: Australian Energy Market Operator, 2022 Integrated System Plan

1.3 Evidence of competitive advantage in renewable energy

Discussions of potential competitive advantages for South Australia from renewable energy are typically based on assessments of potential cost advantages in producing renewable energy in South Australia.

The cost of producing electricity is not just a matter of how much it costs to build and run the power plant, but rather the combination of the costs of building, running and financing with the amount of power it can produce. Formally this is typically expressed as the levelised cost of electricity (see Appendix 3 for details).

For renewable energy, cost of production is driven by:

- the cost of obtaining planning permission, including the cost of any appeals process;
- the cost of construction and equipment;
- the cost of connecting to the transmission network;
- the marginal loss factor (how much of the power generated is lost in the transmission system) which is determined by the distance of the renewable project from the network reference node and the level of congestion in the transmission network; and
- the capacity factor (the ratio of energy generated over a time period (typically a year) divided by the installed capacity). This is related to how much time in the year the wind is blowing, or the sun is shining, as these determine how much electricity the fixed construction costs are spread between.

The cost of construction and of purchasing the necessary equipment tends to be broadly similar across Australia, and so the relative competitiveness of regions is determined by the other factors.

Evidence collected by this inquiry suggests that South Australia has favourable endowments (both in terms of capacity factors and distance of good energy resources from the network reference node) and had a low-cost planning system, giving it an advantage in securing renewable energy developments over the 2000s and early 2010s.

South Australia's endowments

South Australia is seen as having favourable renewable endowments in solar and wind. This section examines South Australia's resource potential for wind and solar, compared to the rest of Australia. Figure 1.10 presents the average daily solar exposure and average wind speed at a height of 100 metres for Australia.

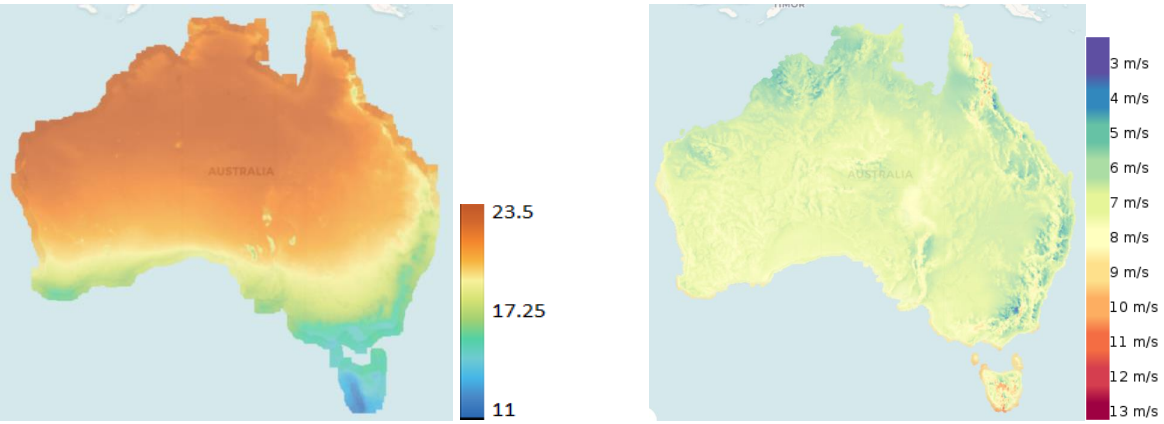
South Australia's solar resources, especially in the state's north are among the best in Australia and are close to major loads or population centres, with only Brisbane, Perth and Darwin having a higher average daily solar exposure.[14] South Australia also has some of the most consistent solar, especially in summer.

South Australia has relatively high wind speeds but also has a high variation of wind power. This pattern is characteristic of much of Australia's high-wind resource areas. In terms of unavailability, South Australia and Western Australia have some of the most reliable winds outside of the Great Dividing Range (where the terrain is generally poorly suited to wind farms), see Figure 1.10 and similarly have some of the longest mean continuous wind availability lengths. However, South Australia's wind resources are also largely coincident, which indicates that aggregating wind resources across large areas of the state is unlikely to mitigate the effects of low wind speeds so other technologies or storage will be required.

The presence of high-quality resources of both wind and solar in the same regions of South Australia, and in areas with existing connections into the electricity grid, presents a potential competitive advantage as it reduces the amount of storage required to have consistent power availability compared to regions with only one main resource. Coastal areas of Western Australia (from Port Hedland south to just north of Perth) and remote areas in the central desert in South Australia, Western Australia, Queensland and the Northern Territory are the only other Australian regions with comparable endowments.

[14] A detailed discussion of wind and solar variability is provided in Appendix 3.

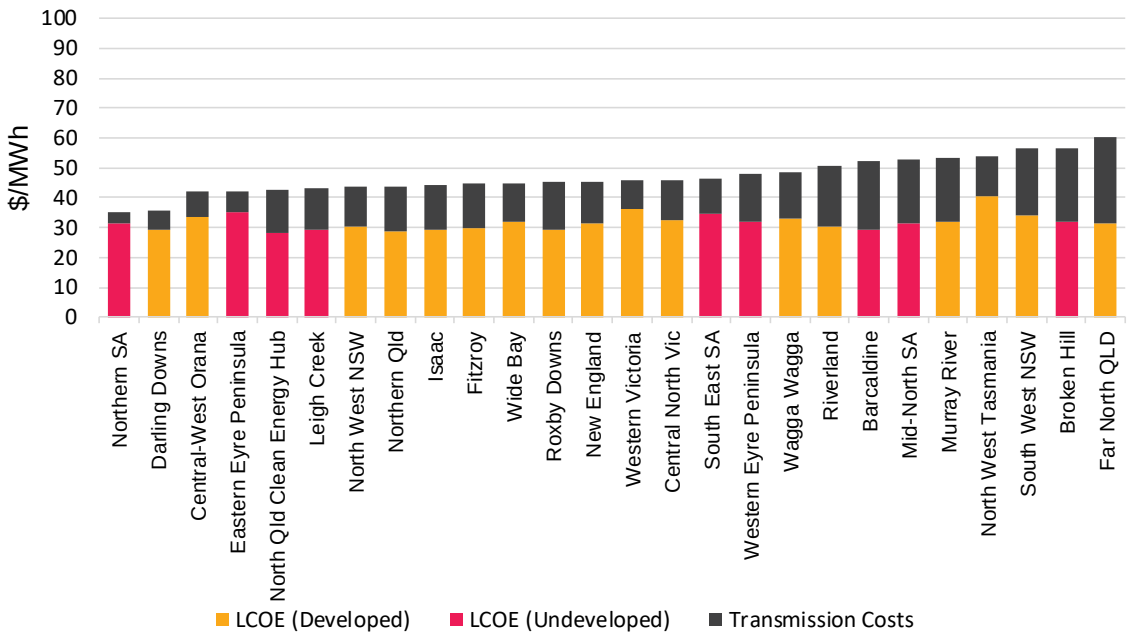
Figure 1.10: Mean daily global horizontal irradiance exposure (left) and average wind speed at 100m (right)



Note: these maps include littoral areas with renewable potential and so some coastal waters are also shaded.
Source: https://www.nationalmap.gov.au/

Data from AEMO indicate that northern South Australia has relatively low levelised cost of electricity (LCOE) compared to other Renewable Energy Zones (REZ)s for solar. The same data indicate that while southeast South Australia also has relatively low LCOE for wind, the costs in Tasmania and in far-north Queensland are lower. (Figures 1.11 and 1.12).[15]

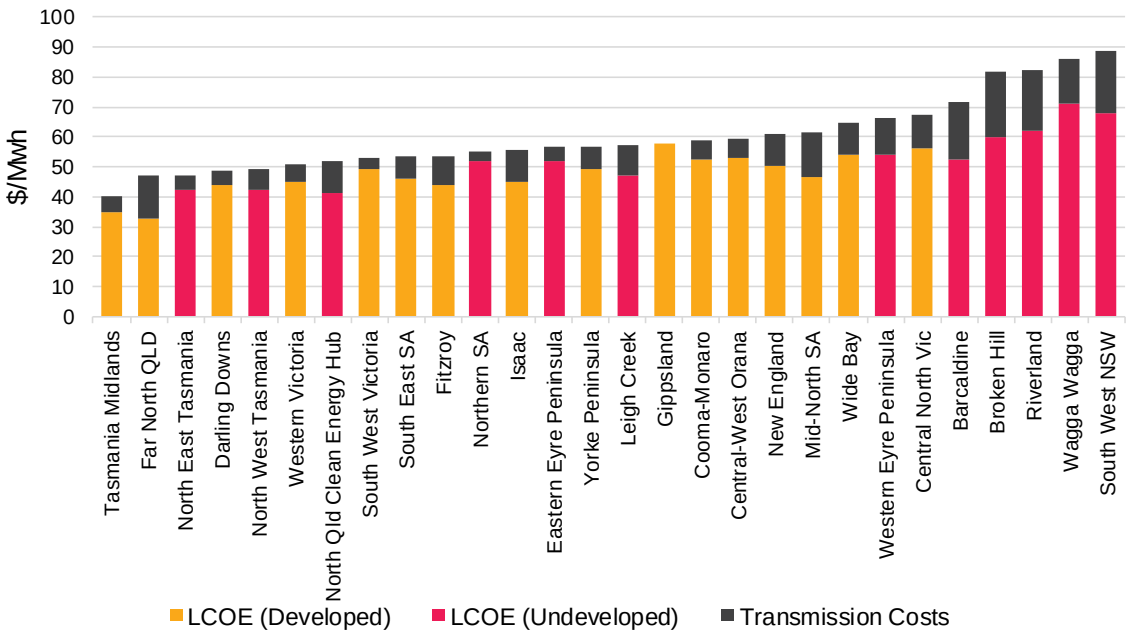
Figure 1.11: Levelised costs of electricity, by Renewable Energy Zone, solar PV



Source: AEMO, Integrated System Plan, (2020)

[15] AEMO (2020), 2020 *Integrated System Plan*, 46

Figure 1.12: Levelised costs of electricity, by Renewable Energy Zone, wind



Source: AEMO 2020 Integrated System Plan

Advantages in the planning system

But competitive advantages in renewable energy do not just arise from favourable endowments. South Australia's competitive advantages in renewable energy compared to other Australian jurisdictions in the 2000s and 2010s, arose as much from the favourable planning system in place at the time. The competitive advantages of this planning system were the result of several factors, including:

- good planning approval processes;
- absence of planning related barriers for renewables projects at both state and local government level[16]; and
- appropriately resourced administrative support.

The structure of the South Australian power sector at the time was also beneficial, with the phasing out of the relatively lower-cost coal-fired power stations in favour of more expensive gas-fired power stations, creating supply-side opportunities for renewable energy projects.

The combination of these factors gave potential investors greater certainty that their renewable energy projects would be approved and constructed in a timely manner and would be less likely to face expensive appeals. This helped increase the attractiveness of undertaking their projects in South Australia over other Australian jurisdictions.

[16] An important element in this State Government support was the potential for developers to use the Crown development pathway approval process. Projects under this approval process were approved by the Minister for Planning and Local Government and were not subject to third-party appeals. While this process could be more complex and time consuming, it gave proponents greater certainty that their project would be able to proceed once approved.

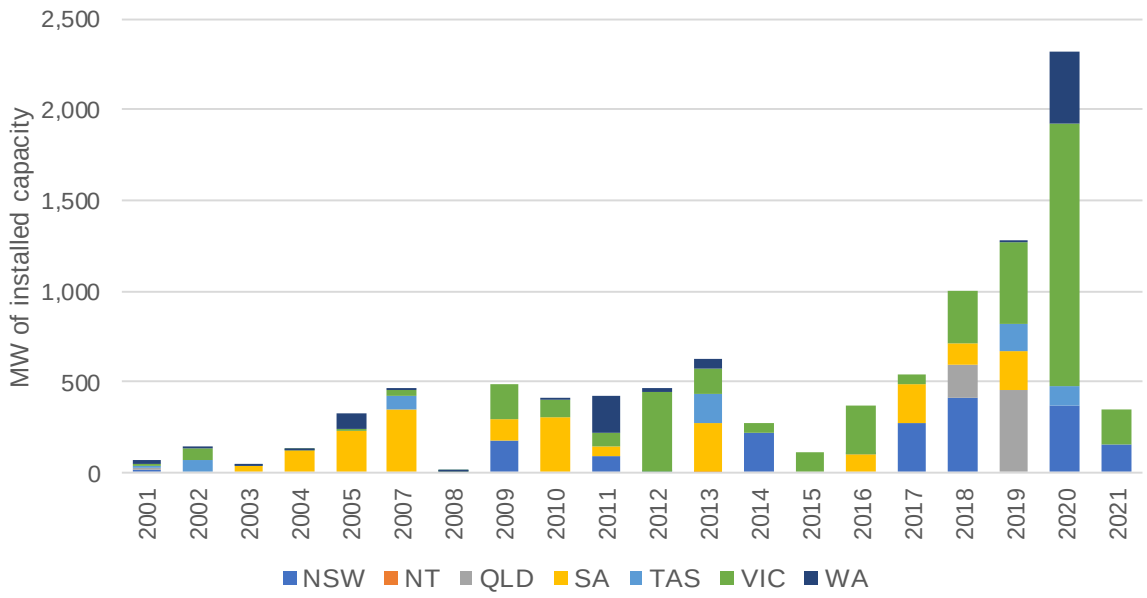
Evidence of regional relative competitiveness from the location of green energy developments

The scale of any competitive advantage enjoyed by South Australia in renewable energy generation cannot be directly observed without access to detailed commercial data from potential developers. However, it is possible to impute the degree of relative advantage from the location of generation installed.

Installation of grid-scale variable renewable power generation was spurred by the introduction of the large-scale renewable energy target (then known as the Mandatory Renewable Energy Target) in 2001, and its significant expansion in 2008. New generators could create credits based on the amount of power they supply into the grid. The scheme required wholesale purchasers of electricity such as power retailers to purchase credits for renewable power generation equal to a certain share of their power use.[17]

The incentives created by the scheme did not include any geographic constraints. This meant that the location of generation supported through the scheme provides a guide as to the relative comparative advantage of different jurisdictions in renewable energy, and in connecting it to the grid.

Figure 1.13: Installation of wind farm capacity approved for inclusion in the large-scale generation certificates registry, from 2001 to 2021



Note: this data excludes combined generation (e.g. wind and solar plants).
Source: Clean Energy Regulator, REC dataset.[18]

The installed wind generation capacity in each state by year is shown in Figure 1.13. From the connection of the first wind farm in South Australia in 2003 South Australia appears to have been a preferred location for wind farm development through the 2000s and into the early 2010s. Over the period 2003 to 2013, 44 per cent of the wind farm capacity installed in Australia was located in South Australia, with Victoria at 29 per cent and Western Australia

[17] <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/>
[18] <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data/large-scale-renewable-energy-target-supply-data/historical-large-scale-renewable-energy-target-supply-data#2001--2021-accredited-power-stations-data>

at 11 per cent the next most preferred. This suggests that South Australia enjoyed tangible advantages in the competitiveness of installing wind generation.

This relative advantage appears to have disappeared more recently. Over the period 2014 to 2021, 46 per cent of the wind generation installed was located in Victoria and 23 per cent was located in New South Wales. South Australia only accounted for 10 per cent of installed capacity over this period, roughly the same share as Queensland.

This pattern of installations reflects feedback received from industry stakeholders that South Australia had shifted from being seen as having the most favourable and lowest cost planning environment, to having a planning environment that is seen as a relative disadvantage. Market conditions are also seen as having worsened for renewable energy investment due to constraints of interconnector capacity into the eastern states, and the prevalence of negative price intervals in the South Australian region of the NEM.

1.4 How could renewable energy impact South Australian competitiveness

South Australia's renewable energy endowments prompted the former Premier to ask the South Australian Productivity Commission (the Commission) to undertake a robust and independent assessment of South Australia's current, or potential, competitive advantage from renewable energy, which would in turn provide an economic platform for future Government policy decisions and actions. (See Appendix 1 for the full referral).

The inquiry's terms of reference are to:

1. Assess SA's actual or potential renewable energy competitive advantage (both within Australia and globally) in terms of renewable energy cost, location, quantity, reliability and/or emissions levels.
2. Recommend any further actions the SA Government could take to create or enhance the actual or potential competitive advantage.
3. If a competitive advantage exists or is attainable, recommend what areas of potential economic development warrant further thorough investigation by the SA Government.

Discussions of potential renewable energy competitiveness typically start from the contention that South Australia has natural endowments in variable renewable energy. However, that, in and of itself, does not necessarily represent a competitive advantage for the state. In order to assess the potential for a competitive advantage to emerge it is necessary to identify the ways that favourable renewable energy endowments could translate to broader economic advantages.

South Australia's renewable energy endowments could potentially increase South Australia's broader economic competitiveness if it can do one or more of the following:

a. lower the cost of electricity to users; and/or
b. supply renewable power that is more consistently available than in other jurisdictions creating advantages for uses that require power that is both decarbonised and available consistently (such as green hydrogen); and/or
c. deliver the transition to a net zero economy energy system faster or at lower cost than in other jurisdictions; and/or
d. indirectly, take advantage of opportunities for increased minerals extraction or minerals processing due to demand arising from the global transition to net zero.

Lowering the cost of electricity to users

Many of the costs of renewable energy are broadly consistent across locations within a country, with the cost of the capital equipment, on-site construction costs, and operating costs all fairly consistent. Instead, what drives variations in the cost of renewable energy between locations within a country are the costs of connecting to the grid (including approvals and any additional transmission infrastructure) and the amount of energy the project can produce (which is determined by capacity factors).

More consistent renewable energy availability

Some potential uses of renewable energy require consistent supplies of electricity, either because prolonged interruptions to electricity supply can damage equipment (for example mineral smelting) or because the process has very high capital costs requiring production through as much of the day and year as possible. For these uses, locations have an advantage if they have access to renewable energy that either has consistent capacity factors through the day (such as hydroelectric power) or has access to renewable energy where the capacity factors are complementary, e.g. solar power with good daytime generation potential and wind speeds that pick up in the late afternoon/evening.

Faster transition to net zero

In addition to immediate cost advantages, many companies and financiers are choosing to switch towards less carbon intensive production activities as part of risk mitigation strategies. Investors who are concerned about assets depending on carbon intensive production technologies becoming economically unviable as the world decarbonises are willing to pay a premium for assets that have a lower carbon intensity (or alternatively will require a discount for carbon exposed assets). This creates an advantage for firms operating in jurisdictions that are further along the path of decarbonisation than their peers.

Increased opportunities from the global transition to net zero

Beyond the opportunities arising directly from renewable energy there are also possible opportunities that may arise as result of either global demand for minerals needed to support the transition to net zero, or from investor pressure around minimising scope 3 emissions (emissions that are not a direct result of an organisation's actions but which are within its value chain, for example the emissions generated in refining Australian copper ore in another country are scope 3 emissions for the copper miner).

South Australia does have good endowments of a number of the minerals that will be needed to support the global electrification required to meet greenhouse gas reduction targets, including substantial resources of copper and ultra-pure graphite. South Australian iron ore is predominantly magnetite, which is better suited to green steel production than the more common haematite ores. As global demand for these resources increases deposits which are currently uneconomic may be able to move into production.

There is also the possibility that structural changes in global supply chains may lead to onshore mineral refining activities for South Australian ores. If this does happen it is likely to be either because of investor pressure on mining companies to minimise the scope 3 emissions from refining the mineral ores they produce, or because a combination of increasing international shipping costs and local cost advantages in decarbonisation outweigh the economies of scale that see most Australian minerals refined offshore.

Chapter 2 of this report assesses whether there is evidence that South Australia enjoys any competitive advantage directly as a result of increased renewable electricity. Chapter 3 explores the scale of the potential economic opportunity for the state from green hydrogen and the barriers to realising that opportunity. Chapter 4 assess the extent to which South Australia's favourable endowment of renewable energy creates potential opportunities in 'green' minerals, and the barriers to realising those opportunities. Chapter 5 assesses South Australian Government activities that could increase the chance of the state realising opportunities from renewable energy, and the potential risks of intervention.

2. Potential competitive advantages from electricity decarbonisation

Box 2.1: 2022 Energy Crisis

It is important to acknowledge that at the time of producing this report, the world is experiencing a global energy crisis. Coal and gas prices have risen sharply as a result of Russia's invasion of Ukraine, and global supply chains are suffering due to a combination of increased demand for goods, input cost increases, and ongoing disruptions to global logistics systems from the COVID-19 pandemic.

In Australia, wholesale electricity prices have risen significantly, with Australian Energy Market Operator (AEMO) reporting that wholesale prices in the National Energy Market (NEM) averaged $87 per megawatt-hour (MWh) for the first quarter of 2022, up 141 per cent from quarter 1 in 2021. This was due to increased demand, ongoing outages of coal generators and higher fuel costs.[19] Conditions continued to worsen into May and June, with supply constraints increasing and spot market prices climbing sharply, with the coal dependent states worst affected. In the first two weeks of June, spot market prices averaged $537/MWh in Queensland and $476/MWh in New South Wales. South Australia and Victoria fared a little better given the higher shares of wind in their grids, with average prices of $343/MWh and $327/MWh, but these prices were still substantially above the norm.

In response to the price increases and the increasing difficulty in coordinating dispatch across the network given price ceilings had been reached, AEMO suspended the NEM wholesale market on 16 June and imposed a price cap of $300/MWh. The wholesale market suspension was lifted on 24 June, as availability of generators improved, but wholesale prices have remained high.

The short-term impacts of this energy crisis do not change any of the fundamental drivers of pricing within the NEM and the broader energy transition discussed in this report, but they do highlight the difficulties of managing the NEM to optimise consumer outcomes under the current rules and operating settings.

2.1 Potential for lower electricity prices from renewables

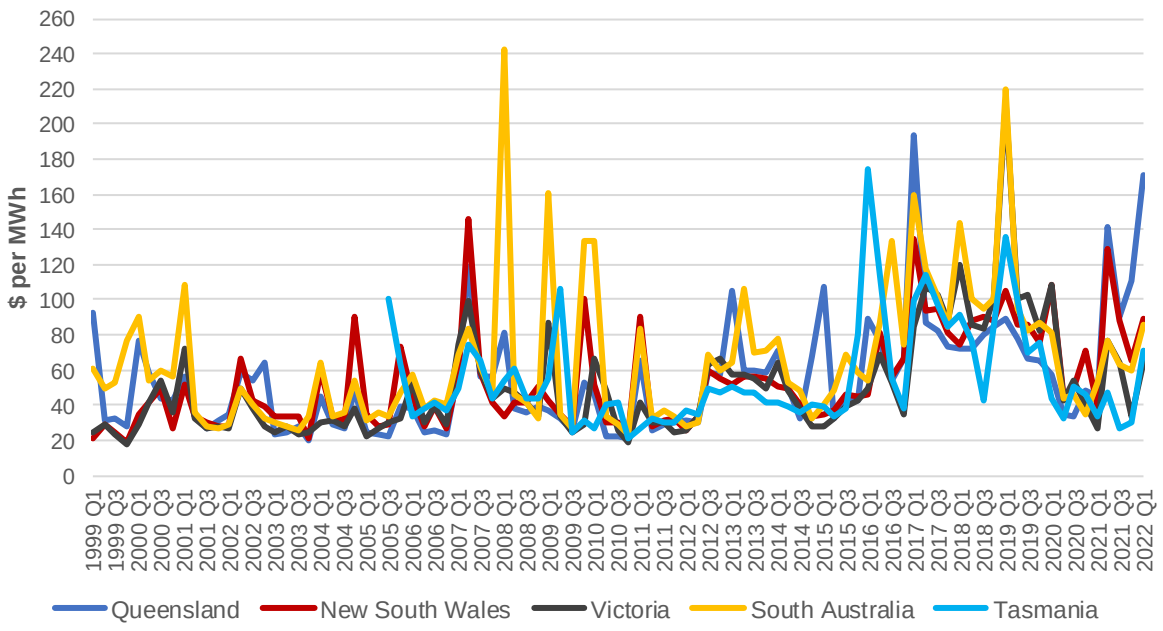
Over the last 20 years, there has been a significant shift in the way electricity is generated in South Australia, most notably due to the increased penetration of renewables into South Australia's grid. This has been driven by significant falls in the cost of renewable electricity generation from initially being much more expensive than coal or gas, to being cheaper than new-build coal or gas. This has influenced wholesale and retail electricity prices in the State. Of particular interest is that variable renewable energy, particularly solar, but also wind, has much lower variable operational costs as they do not need to purchase fuel, allowing them to bid into the market at lower prices than is the case for coal or gas.

South Australia has experienced a steady decline in the average wholesale spot price of electricity since mid-2019 (see Figure 2.1), with the state's average spot price falling from amongst the highest (a pattern that had been seen since the start of the NEM in 1999) to

[19] AEMO (2022), *'Electricity prices driven by outages and higher generation costs in volatile March quarter'* <https://aemo.com.au/newsroom/media-release/electricity-prices-driven-by-outages-and-higher-generation-costs-in-volatile-march-quarter>

amongst the lowest in the NEM.[20] At the same time, the percentage of total electricity generation from renewable sources has also increased. In 2020-21, South Australia had the lowest time-weighted average price for electricity among NEM regions for the first time, and more frequent negative prices than previously observed in any NEM region.[21]

Figure 2.1: Average quarterly volume weighted spot price by NEM region



Source: Australian Energy Regulator (AER), Quarterly volume weighted average spot prices, by regions (2022)

However, the favourable position in average spot prices has not flowed through to South Australian retail customers, who continue to face the highest electricity prices across the NEM. This constraint on the state's ability to realise the potential competitive benefits from its renewable energy endowments is explored in section 2.2.

In addition to immediate benefits from the scale of its renewable energy sector, it is possible that South Australia could reduce the cost of decarbonising its economy. In order to meet the decarbonisation goals set out in the Paris Agreement, electricity systems around the world will need to be rapidly decarbonised, shutting down coal, natural gas, oil and diesel generation and replacing them with zero carbon sources such as wind, solar photovoltaic (PV), solar thermal, hydroelectric and nuclear power. Indeed, as many other sources of carbon emissions such as transportation will also need to be decarbonised, economies will need to not only decarbonise their electricity generation but also expand electricity generation substantially.

For developed economies seeking to achieve net zero greenhouse gas emissions by 2050, electricity networks will need to be almost entirely decarbonised by the early 2030s.

This will involve substantial investment, with the scale of the investment required being greater for jurisdictions that currently have higher carbon intensity of their electricity

[20] Specifically, in the period from the establishment of the NEM to mid-2019, South Australia had the highest or equal highest average quarterly volume weighted spot prices in 43 of the 82 quarters, including recording the two highest average quarterly prices seen in the NEM, $243/MWh in the March quarter of 2008 (whilst South Australia was still largely supplied by coal fired power stations in Port Augusta) and in the March quarter of 2019. In the 11 quarters since mid-2019, South Australia has had the highest quarterly average sport price twice.
[21] AEMO (2021), *South Australian Electricity Report,* 3

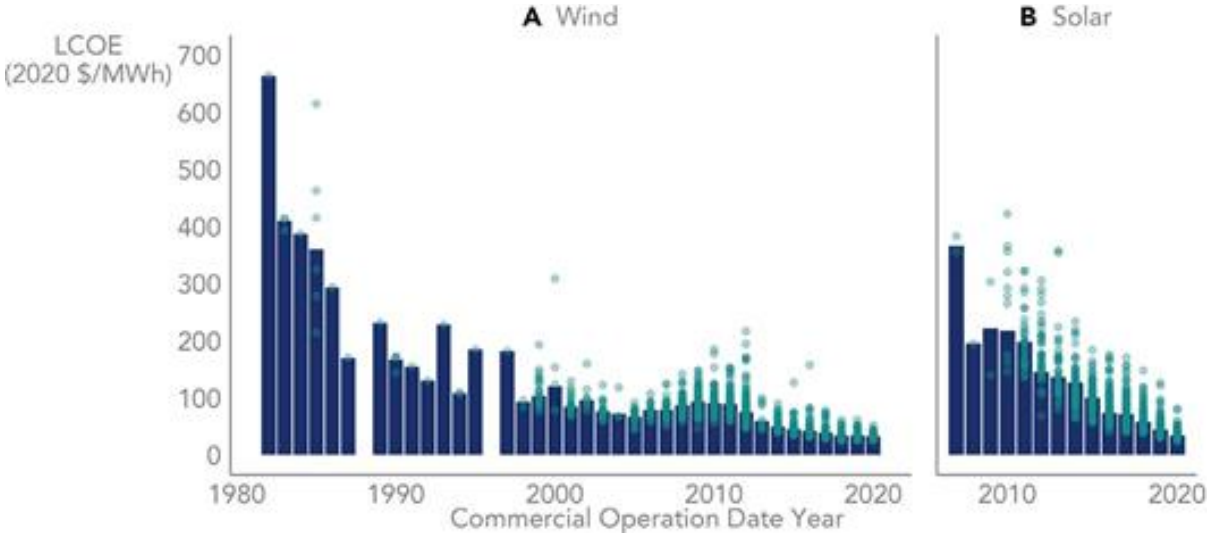
generation sector. To the extent that the existing NEM processes have provided South Australia with the transmission and distribution infrastructure needed to support renewable energy developments then this could provide some cost advantage for the state.

Longer-term impacts on electricity prices

The potential benefits of renewable energy for power prices are not primarily due to the *current* costs, which have levelised costs of electricity (LCOE) for unfirmed renewables that are only moderately below the cost of hydrocarbons. Rather, the optimism about its potential impacts are based on the fact that, as renewable technologies are still being scaled up, there remain considerable opportunities to further reduce costs. This is often referred to as a 'learning curve' effect.

Learning curve effects arise where increased deployment of the technology, and associated research and development (R&D) and improvements in production systems and effectiveness of deployment see costs fall with the scale of production. Many technologies do not display sustained learning curve effects once they reach a commercial scale of production; however, renewable energy and battery storage are amongst those that do.[22]

Figure 2.2: Historic (non-normalised) levelised cost of electricity for US wind and solar developments



Note: Columns report average LCOE for all plants commissioned in that year in the US, dots indicate the LCOE of individual plants.
Source: Bolinger, Wiser and O'Shaughnessy (2022)

The scale of cost reduction for renewables to date is shown in Figure 2.2. which presents estimated LCOE for individual new-build grid-scale wind and solar PV plants in the US.[23]

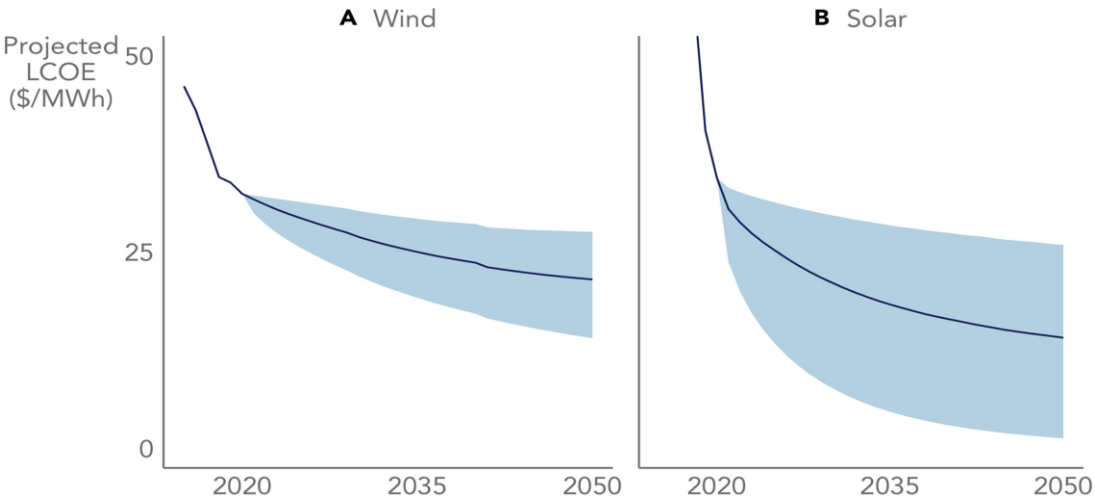
[22] Koh H., and C.L. Magee (2006), 'A functional approach for studying technological progress: Application to information technology', *Technological Forecasting and Social Change*, 73:9, 1061–1083, quoted in Way, R., M. Ives, P. Mealy and J. Doyne Farmer (2022), 'Empirically grounded technology forecasts and the energy transition', Institute of New Economic Thinking, Oxford, Working Paper No. 2021-01.
[23] Bolinger, M., R. Wiser and E. O'Shaughnessy (2002), 'Levelized cost-based learning analysis of utility-scale wind and solar in the United States', *iScience*, 25:6, <https://doi.org/10.1016/j.isci.2022.104378> The authors note that these LCOE estimates are not normalised for interest rates or short-term shocks to input prices, and so part of the fall in the LCOE from the early 1980s to the mid-2000s will reflect the long-term downward trend in borrowing costs over that period.

Since 2010, the International Renewable Energy Agency (IRENA)[24] estimates that globally, a cumulative total of 644 GW of renewable power generation capacity has been added, with estimated costs that have been lower than the cheapest fossil fuel-fired option in each respective year. In emerging economies, the 534 GW added at costs lower than fossil fuels, was expected to reduce electricity generation costs by up to USD$32 billion in 2021.

New solar and wind electricity generation projects are increasingly undercutting even the cheapest and least sustainable of existing coal-fired power plants. IRENA analysis suggests 800 GW of existing coal-fired capacity has operating costs higher than new utility-scale solar PV and onshore wind, including USD$0.005/kWh for integration costs.

Learning curve-based estimates suggest that cost reductions for wind and solar (and the cost of firming them through battery storage or hydrogen production) are likely to continue with increasing international deployment.

Figure 2.3: Historic (non-normalised) levelised cost of electricity for US wind and solar developments (US$/MWh)



Source: Bolinger, Wiser and O'Shaughnessy (2022)

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) projects that the average levelised cost of electricity (LCOE) for new build solar PV will be between $27/MWh and $56/MWh in Australia by 2030[25], with wind between $40/MWh and $59/MWh in that year. Costs are expected to continue to fall, reaching around $29-$30/MWh for solar PV and $34-58 for wind by 2050. Similarly, Bolinger, Wiser and O'Shaughnessy (2022) project the average LCOE for new-build wind in the US falling to around US$28/MWh by 2030, with the average LCOE for solar PV reaching US$25 in that year; see Figure 2.3.[26] Costs are expected to continue to fall, reaching around US$20/MWh for wind and $US15/MWh for solar by 2050.

Estimates from Way, Ives and colleagues (2022) are even more optimistic about the potential cost reductions in solar if the world continues on its current decarbonisation trajectory, projecting a LCOE of around US$20/MWh by 2030 and US$10/MWh by 2050.[27]

[24] IRENA (2021), *Renewable Power Generation Costs in 2020*, International Renewable Energy Agency, Abu Dhabi
[25] Graham, P., J. Hayward, J. Foster J. and L. Havas (2022), *GenCost 2021-22: Final report*, CSIRO, Australia
[26] Bollinger et al. (2022), *Op Cit*
[27] Way, R., M. Ives, P. Mealy and J. Doyne Farmer (2022), '*Empirically grounded technology forecasts and the energy transition*', Institute of New Economic Thinking, Oxford, Working Paper No. 2021-01

For a region like South Australia with very good wind and solar resources (along with much of the rest of Australia) these expected reductions in wind and solar costs suggest that the spot price for electricity could fall considerably, benefiting households and industry broadly, and particularly those which are energy intensive.

Finding 1: The cost of electricity generated by solar is likely to fall significantly over the next thirty years, with wind power also expected to become cheaper.

Similarly, steep reductions in cost are likely to be seen for green hydrogen manufactured using wind and solar. Not only are the costs of electricity (one of the main cost factors for green hydrogen) likely to fall steeply where there are good wind and solar resources, but hydrogen electrolysers are also likely to see their capital cost fall significantly due to their own learning curve. Way, Ives and colleagues (2022) project that in a high adoption scenario the capital cost of electrolysers could fall from around US$1,000 per kW currently to around US$100/kW by 2050.[28]

Potential benefits of lower power prices

At the household level, reductions in power prices will reduce household living cost pressures. The extent of any benefit will depend on how much households spend on electricity. Unfortunately, the available data on spending patterns is very dated, but back in 2015-16 (the last available data) 2.1 per cent of the weekly expenditure of the average Australian household was spent on electricity. For lower income households (those in the bottom 20 per cent) that increases to 3.3 per cent of spending.[29]

At the industry level, electricity is an input to production and reductions in electricity prices will reduce the cost of production making South Australian producers more competitive. The size of the effect will depend on the extent to which electricity costs contribute to production costs. For the economy as a whole electricity (including transmission, distribution and retail costs) accounts for around 1.5 per cent of the cost of inputs to production.[30] A 20 per cent fall in electricity costs would on average reduce production costs by 0.3 per cent which is unlikely to make any difference to competitiveness.

Certain manufacturing sectors, such as 'Pulp, paper and paperboard manufacturing' (7.6 per cent of production costs) and 'Forged iron and steel product manufacturing' (4.1 per cent)[31] have higher shares of electricity in their production costs but even in these cases the impacts of a reduction in electricity costs are unlikely to be material. The only cases where electricity costs are likely to materially affect competitiveness is in a small number of niche industries (not included in ABS data) where electricity costs are particularly important such as green hydrogen, green minerals and data centre operations.

Finding 2: For most industry sectors electricity prices only account for a small share of their production costs, and therefore a reduction in power prices is unlikely to materially affect the competitiveness of South Australian businesses outside of a small number of energy intensive industries such as green hydrogen, green minerals and data centres.

[28] *Ibid*
[29] Australian Bureau of Statistics (2017), Household Expenditure Survey, Australia: Summary of Results 2015–16
[30] Australian Bureau of Statistics (2022), Australian National Accounts: Input-Output Tables 2019-20
[31] *Ibid*

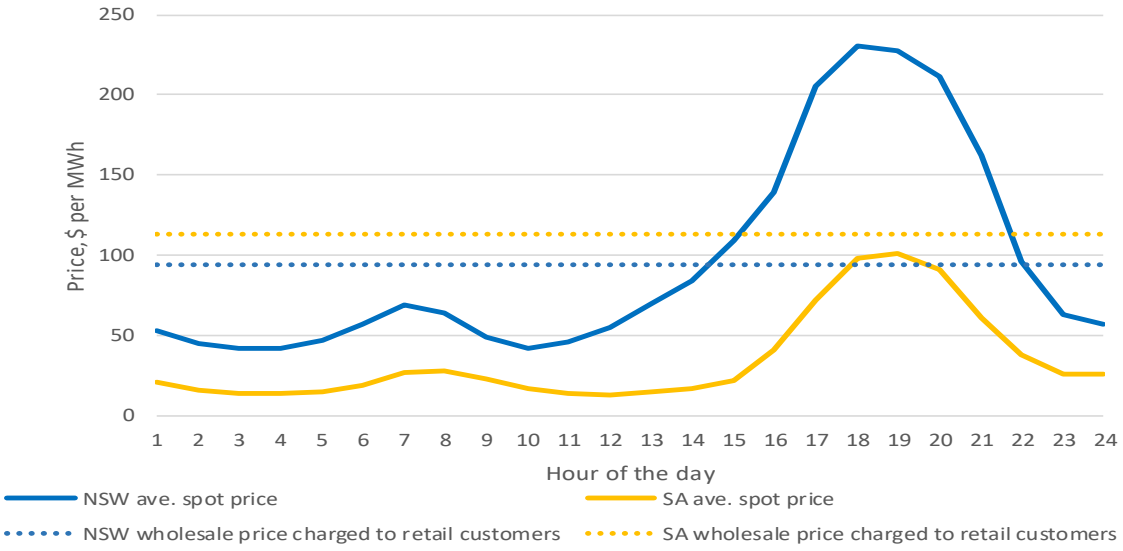
2.2 Electricity market barriers to securing advantages from green energy

High wholesale prices in South Australia

South Australia has seen its spot market electricity costs fall to amongst the lowest in the NEM over the past few years; however, these benefits are not flowing through to the prices paid by electricity users in South Australia.

For example, despite having had the second lowest average wholesale spot price (hereafter referred to as the spot price) in the NEM in 2020-21 (the most recent full year of data at the time of writing), analysis by the Australian Energy Market Commission (AEMC) shows that South Australian electricity consumers had the highest average wholesale price component of their electricity charges.

Figure 2.4: Average spot electricity prices by hour of the day and wholesale price charged to consumer – SA and NSW (2020-21)



Source: AEMC Residential Electricity Price Trends Report (2021)

Weighting spot prices by the amount of electricity consumed in the pricing period, South Australian demand weighted spot prices averaged $55.4/MWh in 2020-21. In that year the wholesale price passed through to retail customers as part of their electricity bill was $113.1/MWh (the yellow dotted line in Figure 2.4). Over the same period, the demand weighted spot price was $72.8 /MWh in New South Wales, 31 per cent higher than in South Australia, but the wholesale price passed through to consumers was $94.1/MWh (**17 per cent lower than in South Australia**).

The difference in wholesale prices passed through to retail customers between South Australia and the other states and territories does not arise from variances in patterns of costs through the day. Average spot electricity prices in 2020-21 for both South Australia and New South Wales by time of day are also shown in Figure 2.4. The pattern of prices through the day is very similar, with prices low from 1am through to 11am, increasing steadily through the afternoon to a peak in late afternoon/early evening, and then falling back.

The only difference in time-of-day average prices between jurisdictions is that South Australia has substantially **lower** average wholesale spot prices at any given time of day.

For example, comparing South Australia to New South Wales, the price difference ranges from South Australia spot prices being 80 per cent lower than the New South Wales price in the early afternoon to around 55 per cent lower than prices in New South Wales in the early evening.

Finding 3: Increased renewable energy supply has significantly reduced relative spot electricity prices in South Australia; however, this has not led to lower wholesale prices for electricity consumers.

Higher wholesale prices in South Australia are not caused by the local spot market having a higher frequency of high price intervals. In 2020-21 New South Wales had 93 five-minute pricing intervals where the price was $10,000/MWh or higher, more than twice as many as South Australia which had 44 of these extremely high-priced five-minute price intervals.

It is the case, however, that the quantity of electricity demanded within the South Australian market is much more variable than that in New South Wales, with more frequent periods of very low demand (compared to the average) and more frequent periods of very high demand.

Each of these types of variation produce challenges for the grid. Periods of very high demand require significant investment in the grid to serve demand that is only present for around one per cent of the time. Very low demand creates potential risks to system stability as prices fall very low and generators cease producing making the state vulnerable to voltage fluctuations. AEMO has been particularly concerned about the potential impacts of very low demand in South Australia caused by the high rates of rooftop solar PV generation which acts to both reduce household and business demand for power (as they are meeting their own needs from rooftop solar) and to increase supply into the grid from surplus rooftop solar generation.[32]

Table 2.1 shows the number of 5-minute pricing intervals where demand was well above or well below average. In 2020-21 South Australia had almost twice as many five-minute intervals where demand was more than 125 per cent above the average, including 1,025 where demand was more than twice the average (New South Wales had no periods where demand was more than twice the average).

Illustrating AEMO's concern about low daytime demand, South Australia had over 17,000 five-minute periods where demand was 75 per cent of the average or less, including 58 where it was less than a quarter of the average. These low demand intervals were one tenth as frequent in New South Wales, and New South Wales had no periods where demand was less than 25 per cent of the average.

Table 2.1: Distribution of demand by five-minute pricing intervals relative to the average electricity demand for the state, 2020-21 (out of 105,120 pricing intervals in the year)

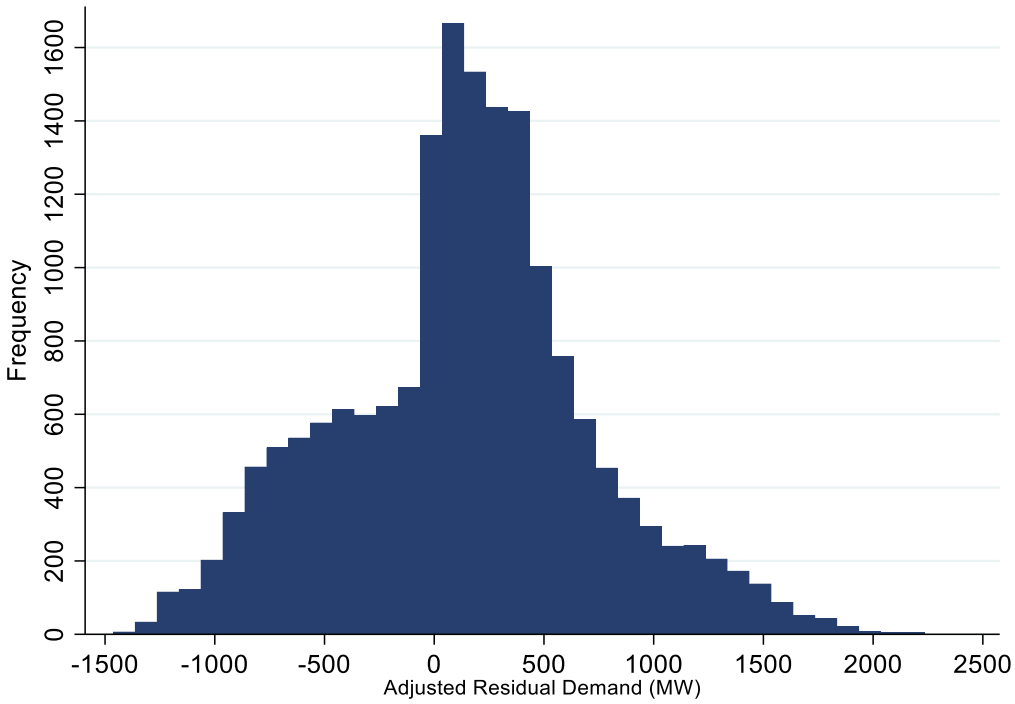
State	Number of intervals for different % proportions of average demand					
	25%	25-75%	75-100%	100-125%	125-200%	>200%
NSW	0	1,772	57,489	36,811	9,048	0
SA	58	17,277	37,235	33,092	16,433	1,025

Source: AER data supplied by AEMC.

[32] AEMO (2020), Minimum operational demand thresholds in South Australia, May 2020 Technical Report, Advice prepared for the Government of South Australia

Analysis commissioned by the Commission from Bruce Mountain and colleagues[33], highlights the substantial variation in South Australian demand that needs to be met from local 'on-demand' sources (e.g. after accounting for variable renewable generation, and imports and exports interstate through the interconnector). Figure 2.5 shows that there are many periods where this adjusted demand is negative, and power is therefore being 'spilled' with no demand available to use it. But there also a small number of periods where the residual demand is over 1,500 MW and even a small number of intervals when over 2,000MW of power are needed from local on-demand sources.

Figure 2.5: Distribution of 'adjusted residual demand' in South Australia, 2021, number of 30-minute pricing intervals at each level of demand



Source: Data from Carbon + Energy Markets (2022)[34]

This potential risk to the grid would be best addressed by increasing the overall load in the grid during the day, ideally through reductions in load that could be cost effectively curtailed if needed. New large power users such as data centres or green hydrogen producers would be an effective way of providing the additional load, as would increased storage in the grid, such as through grid-scale batteries. Some of this storage could be locally distributed to maximise its contribution to suburb-level system strength, and to reduce transmission losses from generation to storage.

Finding 4: The South Australian region of the NEM has insufficient commercial and industrial load to absorb the solar generation on sunny spring and summer days. This poses a risk to system stability and increases electricity costs to consumers.

[33] Carbon + Energy Markets (2022), 'Financial sustainability of renewable energy under National Electricity Market rules', <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-F-Financial-sustainability-of-renewable-energy-under-NEM-rules-Carbon-and-Energy-markets.pdf>

[34] *Ibid*

Feedback received from stakeholders, indicates that South Australia has a highly concentrated market for 'on-demand' power (e.g. power that can be brought into the market rapidly to adjust for shortfalls in supply of variable renewables, or spikes in demand), with supply not significantly exceeding peak demand, and much of the installed capacity owned by vertically integrated 'gentailers' who internally hedge their exposure to spikes in the demand for electricity, reducing the amount of capacity available in the hedging market for other users.

This relatively tight balance between peak demand and potential supply, together with the relatively concentrated ownership structure of on-demand generation in South Australia, is believed to contribute to the relatively illiquid hedging market for wholesale power prices in South Australia, where even relatively small increases in the demand for hedging contracts can result in large price increases. These increased hedging costs are then passed through to consumers (both retail, and commercial and industrial) and reported by stakeholders to be the most significant driver of the gap between spot prices and wholesale prices passed through to energy users.

Analysis undertaken by the University of Wollongong[35] for the Commission confirms that the gap between spot market prices and wholesale prices in the South Australia region of the NEM is both much larger than that seen in other regions, and has existed for a number of years resulting in wholesale power prices that are much higher relative to spot prices in South Australia compared to other regions of the NEM.

There are also impacts (albeit less significant) from pass-through of the costs of AEMO directing synchronous generation to feed into the grid in South Australia even when it is not the lowest cost supply (a measure undertaken to increase system stability) and feed-in tariffs paid by retailers to clients with rooftop solar which are frequently higher than the spot price at the time the solar power was produced.

Drawing on our analysis and stakeholder feedback, it appears that South Australia's grid would benefit from both an increased load during the day that can be readily curtailed, and increased competition in on-demand generation. Firmed green energy such as that obtained through the SA Government's Hydrogen Jobs Plan (see Box 2.2), which will comprise hydrogen electrolysers run during periods of excess power supply generating fuel for hydrogen powered turbines run during periods of high prices/high demand, is an innovative way of solving this problem. However, we have not yet had the opportunity to assess whether it is a cost-effective solution.

[35] Havyatt, D. G. Grozev, R. Nepal, T. Christopher and P. Perez (2022), 'Future wholesale and retail electricity prices in SA in 2030 and 2040 under select ISP scenarios', University of Wollongong <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-D-Wholesale-and-retail-price-projections-UoW.pdf>

Box 2.2: Hydrogen Jobs Plan

One of the election commitments of the South Australian Government was an intervention in the electricity market through the Hydrogen Jobs Plan. The Hydrogen Jobs Plan includes the construction of a hydrogen power station, electrolyser and storage facility in Whyalla. It includes a commitment to construct a:

- 250 MW of electrolysers;
- A 200 MW hydrogen-fuelled gas turbine power station (using green hydrogen produced by the electrolysers); and
- hydrogen storage for 3,600 tonnes of hydrogen, or the equivalent of two months of hydrogen consumption for power generation.[36]

The hydrogen jobs plan aims to lower electricity prices in South Australia. It can achieve this both through the addition of large flexible loads (electrolysers) to the grid and by providing firming services to renewable energy generators. The electrolysers serve to increase demand for renewable energy, while increasing the ability of the market operator to match demand and supply during periods of low renewable generation. It also aims to serve as a catalyst for renewable hydrogen exports by providing a demonstration plant and creating domestic demand for hydrogen.

Hydrogen Power South Australia, a new government enterprise will be set up to own and operate the hydrogen power plant. The Office of Hydrogen Power South Australia has been established as an interim body that will oversee the initial implementation process for delivering the Hydrogen Jobs Plan.

Market sounding, seeking proposals from industry on the technical system and commercial project approaches for the hydrogen facility, has been undertaken. This process received 60 submissions.[37]

The two-year construction period is expected to begin by the middle of 2023 with the plant operational by the end of 2025.

Finding 5: South Australia has insufficient competition in the on-demand generation market, resulting in a low liquidity, high cost, hedging market, increasing wholesale power prices.

Finding 6: The Hydrogen Jobs Plan directly targets two current limitations of the South Australian electricity market: the at times excess daytime electricity supply from rooftop solar, and the illiquid on-demand power market. However, it is a very substantial investment and ensuring that risks (including construction costs) are well controlled, and that its operating model meets best practice (including maximising its positive impacts on power prices) will be critical to ensure it is a worthwhile investment.

[36] Additional information available at: <https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-jobs-plan>
[37] Spence, A (2022), '*Hydrogen plan fuels global interest*', *InDaily*, 26 July, <https://indaily.com.au/news/2022/07/26/hydrogen-plan-fuels-global-interest/>

Broader limitations of the NEM

In addition to the specific issues related to the liquidity of the market for on-demand power in South Australia, in general the NEM does not appear to have served South Australia well through the energy transition:

- interventions to support system stability have been predominantly reactive and case by case rather than strategic;
- there have been very limited price signals available to induce those investments that would be most effective in providing system stability and on-demand low emissions power supply to the local network (for example by beginning to install the storage that AEMO's Integrated System Plan (ISP) studies have identified as necessary for a decarbonised grid in South Australia[38]); and
- there are few controls on strategic behaviours by generators.

These dysfunctional elements of the NEM systems came to a head in the first half of 2022 when the combination of unexpected outages of coal plants for maintenance, spikes in input costs for coal and natural gas, difficulties in coordinating when power plants with limited reserves of fuel should best be used, and bidding strategies adopted by some generators forced AEMO to temporarily suspend the national market and operate the grid through directions.

It is not clear that current market rules and regulations are consistent with a smooth transition to a largely decarbonised electricity grid, particularly given that to meet Australia's (and individual state's) targets around overall greenhouse gas emissions this grid transition will need to be largely complete by the early 2030s.

Finding 7: Current NEM regulations and pricing mechanisms are not fit for purpose, delivering neither lowest cost for consumers nor inducing sufficient investment in storage to support the renewable energy transition.

A number of underlying factors suggest that the scale of renewable generation in South Australia could continue to increase substantially. In AEMO's step change scenario by 2030 South Australia will generate 12,993 GWh of electricity from wind and 938 GWh from utility-scale solar. This would represent a more than doubling of wind output (5,738 GWh in 2020-21) and a 40 per cent increase in utility-scale solar (currently 673 GWh). Over the same time frame installed rooftop solar capacity is expected to increase from 1,651 MW to 4,152 MW.[39] By 2040 wind generation output is expected to be three times its 2020-21 level, at 17,760 GWh, with utility-solar six times its 2020-21 level at 4,650 GWh.[40]

Should a green hydrogen sector develop in South Australia the demand for additional renewable generation would be potentially large. A 1,500 MW electrolyser (reported by

[38] Bruce Mountain and colleagues note that "We also expect continued market-driven investment in storage, although we think it is unlikely that such market-driven investment will be sufficient to meet the requirement to fully decarbonise electricity supply." Carbon + Energy Markets (2022), 'Financial sustainability of renewable energy under National Electricity Market rules', < https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-F-Financial-sustainability-of-renewable-energy-under-NEM-rules-Carbon-and-Energy-markets.pdf>

[39] AEMO (2022), 2022 Integrated System Plan, Generation workbooks, step change scenario; AEMO (2021) 2020/21 generation and installed capacity, AEMO (2021) 2021 South Australian Electricity Report

[40] These increases in generation are larger than would be required to supply current electricity demand from renewable power as the scenario also assumes that passenger transport, and household energy use such as space heating and water heating will also be increasingly electrified.

several stakeholders as the efficient size for green hydrogen generation for the export market) would use 8,000 GWh of renewable electricity per year[41] (current total South Australian generation is just under 14,000 GWh per year).

Finding 8: Meeting the State's greenhouse gas reduction targets will require a largely decarbonised electricity sector, and as a result a substantial increase in renewable energy with wind and solar at least doubling from their current levels over the next decade. The backward-looking approach to managing system stability to date raises questions about whether the current grid management systems will be able to adapt fast enough to this change in supply.

Past experience suggests that further expansion of the South Australian renewable sector is likely to lower spot prices still further. There is, however, no guarantee that these additional price reductions will flow through to reductions in retail prices in the State.

To better understand the potential price dynamics of electricity sector decarbonisation in South Australia the Commission asked researchers at the University of Wollongong to undertake two studies examining pricing under AEMO's step change and hydrogen superpower scenarios from the 2021 ISP. The first study[42] focussed on the potential for changes in the frequency of very low (≤$0/MWh) and very high (>$1,000/MWh) spot market power prices, and the second study[43] looked at plausible trajectories for wholesale and retail prices under the scenarios.

The conclusions of the analysis were that increases in renewable generation would reduce power prices in South Australia, but that the impacts would be much more significant for spot prices than for retail prices.

The University of Wollongong modelling finds that the continued expansion of renewable power will reduce spot prices in both the South Australia and (to a lesser extent) the New South Wales regions of the NEM. For South Australia spot prices are expected to fall from their 2018-2021 average of $102/MWh to between $47-64 by 2030 and $48-68 in 2040 (see Table 2.2). New South Wales, which even by 2040 will have a less wind and solar intensive generation mix is expected to see average spot prices fall, but not as significantly.

However, as has been the case for the past few years, the modelling suggests that the significantly lower spot price is unlikely to result in a retail price advantage for South Australian electricity consumers relative to New South Wales due to a combination of the persistent gap between spot prices and wholesale prices in South Australia, and the higher unit costs of distribution and transmission (see below) and environmental costs passed through to power bills in South Australia.

After the expected values for the remaining items that contribute to the retail price are added, South Australian retail prices are likely to be between $0.296 and $0.316/kWh by

[41] Department for Energy and Mining (2022), 'Hydrogen Export Modelling Tool', <https://hydrogenexport.sa.gov.au/>

[42] Grozev, G., D. Havyatt, R. Nepal, T. Christopher and P. Perez (2022), 'Analysis of historical wholesale electricity spot price volatility in South Australia and their projections in 2030 and 2040' <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-C-Projections-of-spot-price-volatility-UoW.pdf>

[43] Havyatt, D. G. Grozev, R. Nepal, T. Christopher and P. Perez (2022), 'Future wholesale and retail electricity prices in SA in 2030 and 2040 under select ISP scenarios', https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-D-Wholesale-and-retail-price-projections-UoW.pdf.

2030 and between $0.310 and $0.333/kWh by 2040. Whilst this is lower than current retail prices (averaging around $0.326/kWh in 2020-21) it is still likely to be higher than NSW prices in the equivalent periods (see Table 2.2).

Table 2.2: Forecast electricity prices under AEMO's 2021 Step Change Scenario, South Australia and New South Wales, 2030 and 2040

Forecast spot electricity prices ($/MWh)				
	2030		2040	
	Lower bound	Upper bound	Lower bound	Upper bound
South Australia	46.52	64.36	47.67	67.93
New South Wales	60.50	100.31	53.39	80.33
Forecast retail electricity prices (c/kWh)				
	2030		2040	
	Lower bound	Upper bound	Lower bound	Upper bound
South Australia	29.59	31.55	31.04	33.27
New South Wales	27.93	32.31	27.38	30.34

Source: Havyatt, Grozev et al. (2022[44])

Finding 9: Forecasting suggests that whilst expansion of renewable generation in South Australia will reduce spot market electricity prices significantly, this is unlikely to lead to South Australia having lower retail electricity costs than interstate unless the larger gap between spot and wholesale prices in South Australia can be addressed.

High retail prices in South Australia

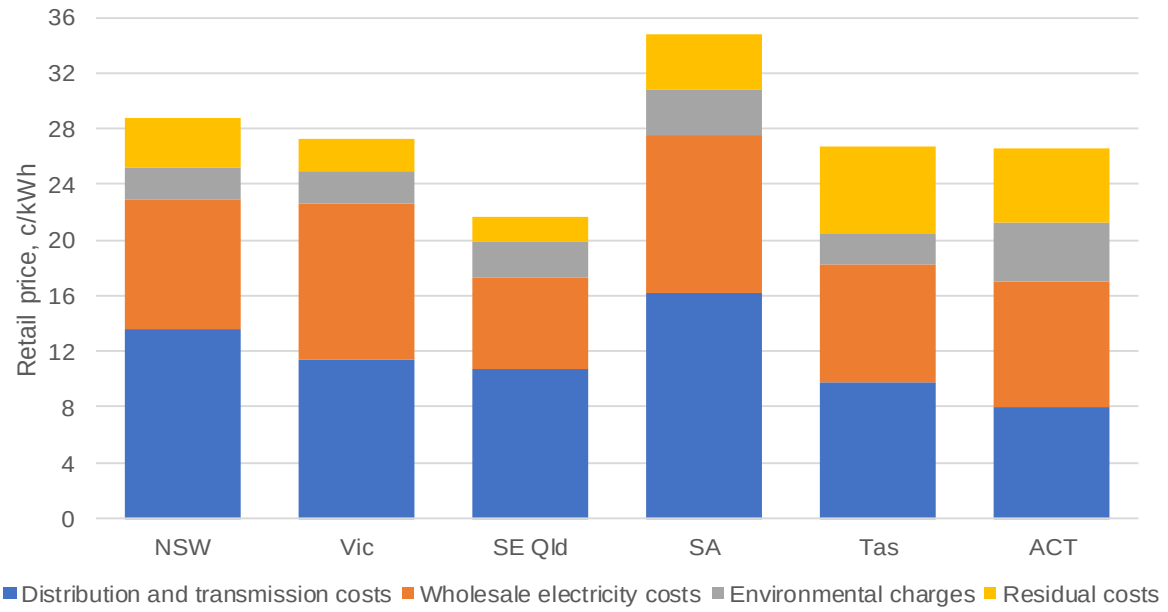
High wholesale power prices are not the only factor contributing to high retail electricity prices. Figure 2.6 shows the estimated components of average retail electricity prices for each of the NEM regions.

In addition to the high wholesale power prices, South Australian consumers also face substantially higher distribution and transmission costs because of lower population density, a large geographic area covered by transmission infrastructure, and lower industrial demand (which essentially spreads out the cost across fewer users). South Australian costs are also higher due to a larger gap between average demand and peak demand in South Australia compared to other regions in the NEM, which means that both the transmission and distribution infrastructure has to be large enough to handle significant peaks which only occur a few days per year. In 2020-21 an average South Australian consumer paid 16.18 c/kWh in distribution and transmission costs, well above the 11.38 c/kWh paid in Victoria, or the 13.54 c/kWh paid in New South Wales.

For South Australia to have retail price parity with New South Wales given these other cost factors, wholesale power costs facing consumers would need to be 45 per cent lower. In combination with the higher wholesale cost component, these effects result in higher electricity prices in South Australia compared to other states.

[44] *Ibid*

Figure 2.6: Components of retail electricity prices (excluding supply charges) 2020-21



Source: AEMC Residential Electricity Price Trends Report (2021)

2.3 Capturing the value of the local grid decarbonisation

If firms have clients or financiers who are willing to pay a premium for operations using green power, South Australia (along with Tasmania) has a potential advantage due the low carbon intensity of its power. Depending on how much they value green power, this may attract firms to locate operations here.

However, even if firms are willing to pay for green power that does not actually mean they are more likely to locate in South Australia.

The reason for this is the Power Purchase Agreement (PPA) market. A firm located in New South Wales or Queensland can use a PPA to purchase renewable power at an agreed price, and then surrender the Renewable Energy Credits generated by a South Australian project allowing them to claim that the power they are using is 100 per cent renewable, even if the actual electricity they are using comes from a coal power station.

Over the past few years, in the absence of a carbon price or other strong government incentive towards decarbonisation, PPAs have been one of the most effective mechanisms for increasing the total amount of renewable generation in the NEM.

An example of this are the sets of agreements struck by the Australian Capital Territory Government with renewable energy developers in South Australia, Victoria, New South Wales and the Australian Capital Territory to induce sufficient renewable energy supply into the NEM to offset the electricity use in the Australian Capital Territory. These involved significant purchases of electricity from South Australia and Victoria that, given the nature of electricity flows in the NEM, would never have actually reached the Australian Capital Territory. In the second quarter of 2021-22, 249 GWh of electricity generated by the Hornsby wind farm in the mid-North of South Australia was contracted to the Australian Capital Territory government via PPAs (this was 52 per cent of the ACT's electricity requirements).

Without the funding provided by the PPAs, many of the renewable projects in South Australia and elsewhere which contract a PPA would not have been able to proceed, and so the country as a whole has benefited from the PPA market. However, this means that any reputational or market benefits of green power can be enjoyed by firms located interstate, whilst the adjustment costs of moving to a largely renewable powered grid are borne by South Australian electricity consumers.

South Australia would likely benefit from certification approaches to carbon intensity which reflect the *actual* carbon intensity of the grid, providing local firms with an advantage from the low carbon intensity of the South Australian grid. However, if a switch to certification based on actual grid carbon intensity rather than PPAs occurred, it is likely that PPAs would be less valuable to corporate clients, reducing the extent to which they could be used by renewable energy developers to fund projects.

Discussions of the potential benefits for South Australia of its renewable energy intensity sometimes suggest that even without a cost advantage in electricity, perceptual issues may result in firms moving activities to South Australia to meet environmental, social and governance (ESG) goals. In our consultations we have found no evidence of this having occurred or of it being seriously considered by firms.

Finding 10: The PPA system means there is currently little incentive for firms to relocate to South Australia to take advantage of its low carbon intensity electricity market as they can remain where they are and purchase PPAs to claim they are using green power.

Finding 11: No evidence has emerged during the inquiry to suggest that firms may relocate to South Australia for environmental, social and governance goal reasons alone.

2.4 Planning system barriers to energy system decarbonisation

As discussed in Chapter 1, South Australia's favourable planning system for renewable energy projects in the 2000s and early-2010s contributed to South Australia's competitive advantages over other Australian jurisdictions in renewable energy. This may no longer be the case.

Complex planning system framework

Over time, South Australia's planning system framework has grown longer and more complex. It now totals almost 5,000 pages in length, making it more difficult for potential investors to work through.

Feedback from stakeholders was that the online planning system was not designed with major projects, such as renewable energy projects, in mind. That, combined with the sheer length of the planning system framework, has made using the online planning system extremely difficult. Unless a proponent knows exactly what sections of the framework they need to use and where those sections are located, it can be difficult to find them using the online planning system.

Stakeholders suggested that the online planning system could be made significantly easier for proponents by having a separate online planning process specifically for major projects. Concerns about the effectiveness of South Australia's major projects process have also been raised with the Commission previously, most recently during the 2021 Review into

Development Referrals. Another, lower cost, solution could be to create a planning system framework document specifically tailored to renewable energy projects that only included the relevant sections of the planning system framework.

Setbacks

Under the recent changes to the Planning and Design Code (PDC) for rural areas, which came into effect on 31 July 2020, setbacks for solar farms have been introduced for the first time and setbacks for wind farms have increased. Under the previous PDC, wind farms were required to be set back 2 km from townships and settlements and 1 km from non-involved dwellings.

Under the new PDC, in rural areas wind turbines with a tip height of 150 m or less are not deemed to satisfy the performance criteria of the planning and design code unless they are set back:

- at least 2 km from townships and settlements;
- at least 1.5 km from non-involved dwellings; and
- wind turbines with a tip height above 150 m must have an additional 10 m of setback from settlements per additional metre of tip height (e.g. a wind turbine with a tip height of 200 m would require a setback of 2.5 km from the nearest township and 2 km from the nearest non-involved dwelling).

While there was a consultation process as part of the changes to the PDC, stakeholders noted that the consultation was around the draft proposal to increase setbacks for wind farms from non-involved dwellings to 1.2 kilometres. It appears that no specific stakeholder consultation took place on the increase in setbacks in the final code, and no rationale or feedback given as to why that setback was increased from the consultation draft.

Setbacks for solar farms vary depending on the size of the array and generation capacity (see Table 2.3) but must be set back up to 30 metres from the adjoining land boundary, set back 500 metres from conservation areas and set back up to two kilometres from townships and settlements.

Table 2.3: Setbacks required for grid-scale solar photovoltaic projects under the revised planning code

Generation capacity	Approximate size of array	Setback from adjoining land boundary	Setback from conservation areas	Setback from township, rural settlement, rural neighbourhood and rural living zones
> 50MW	> 80 ha	30 m	500 m	2 km
10 MW to 50 MW	16 ha to 80 ha	25 m	500 m	1.5 km
5 MW to 10 MW	8 ha to 16 ha	20 m	500 m	1 km
1 MW to 5 MW	1.6 ha to 8 ha	15 m	500 m	500 m
100 kW to 1 MW	0.5ha to 1.6 ha	10 m	500 m	100 m
<100 kW	< 0.5 ha	5 m	500 m	25 m

Source: South Australian Planning and Design Code, Version 2022.6, p. 4539

While it is not mandatory for the various setback distances to be met under the revised PDC for a project to be approved (e.g. projects that are not 'deemed to satisfy' performance criteria can still potentially be approved), in practice stakeholder feedback suggests that approval processes have treated the setbacks as though they were mandatory.

Stakeholders also questioned the policy rationale for some of these setbacks. For example, under the current PDC, renewable energy projects must be set back 500 m from conservation areas, with the impact on visual amenities often cited as the reason for the setback. However, stakeholders noted that conservation areas were often uninhabited, making it unclear to them what purpose the setback served.

Similarly, stakeholders cited examples where undulating topography meant that it was not uncommon for a wind farm to be located less than 2 km from a township or settlement without being seen or heard, yet a 2 km setback was still required for a project to be approved.

As a result of the increases to setbacks, the land available for renewable projects in South Australia has shrunk. Stakeholders stated that the increased setbacks made previously viable locations no longer viable, as the legally available space in which a wind or solar farms could be built was no longer large enough.

With the setbacks required for wind farms being dependent on wind turbine tip heights, the new setbacks will have an increasing impact on wind farms as the height of wind turbines continues to increase with technological improvements. This will further shrink the available space in which those wind turbines can be placed.

Stakeholders agreed that the current setbacks that related to noise levels for renewable energy projects were appropriate and should not be changed. Stakeholders also agreed that renewable energy projects had the potential to cause issues, such as overshadowing and 'strobing', to nearby areas. However, they argued those issues are best dealt with through existing elements of the PDC which regulate overshadowing, rather than through arbitrary distance-based setbacks.

Stakeholders also told the Commission that the flow-on effect of increased setbacks for wind and solar farms is that renewable energy proponents have been pushed further north to consider projects on pastoral lands. Not only are such locations less economically viable, due to the increased distance from existing power transmission, but there are also additional issues and complexities when building renewable energy projects on land under pastoral lease. These issues are discussed in greater detail later in this chapter.

To meet the South Australian Government's renewable energy commitments, South Australia's wind generation capacity will need to increase significantly in the next decade. For example, AEMO's step change scenario sees wind generation doubling its output by 2030 and tripling it by 2050. Those renewable energy commitments are unlikely to be able to be achieved with the current setback restrictions in place.

Finding 12: The current elements of the Planning and Design Code related to setbacks for renewable energy projects near townships and settlements in rural areas are inconsistent with the South Australian Government's renewable energy policies and commitments. If the Government wishes to achieve its targets, then it will need to make trade-offs in terms of potentially reducing visual amenity.

Recommendation 1

The South Australian Government remove all non-noise-related setbacks for renewable energy projects from the planning and design code.

Planning approval delays and errors

Some stakeholders stated that they had encountered avoidable and otherwise unnecessary delays in receiving planning approval for their projects. Feedback from stakeholders indicated that, while they were happy with the level of expertise encountered across the South Australian Government, state government major projects processes were now seen as frequently subject to errors and excessive delays.

Errors noted included documentation being sent out by Planning and Land Use Services (PLUS) containing incorrect details, or processes being incorrectly followed, resulting in the documentation or those processes needing to be redone. Stakeholders also noted that renewable energy projects were taking longer than they felt was necessary to be approved, and to get on the State Commission Assessment Panel agenda.

Broadly similar concerns were raised by stakeholders in consultations on the Commission's 2021 Review into Development Referrals:

> *The feedback received by the Commission from major project proponents and their agents spoke commonly to a lack of trust in the process and a lack of understanding by the relevant authority and referral bodies of the economic impacts of the assessment process on proponents.*[45]

Finding 13: Administrative errors and slow processes in the major project approvals process are causing delays in those projects receiving final South Australian Government and Ministerial approval.

Other issues in the current system identified by stakeholders included: the impact of increased setbacks (discussed above); unclear areas within the legislation, regulations, and policies; and difficulties in identifying the relevant person or area within the South Australian Government to contact.

In comparison, stakeholders reported that other Australian jurisdictions have improved their project approval processes and timeframes for renewable energy projects over recent years. Several stakeholders identified Queensland as the leading Australian jurisdiction in terms of having the most efficient and clear processes for renewable energy project approvals, with projects in Queensland frequently receiving government approval in under six months.

Finding 14: The planning system is now acting at a relative competitive disadvantage for investment in South Australian renewables. The reasons for this include: the impact of increased setbacks; frequent processing errors and delays within the bureaucracy; and an approval process ill-suited for major or complex projects.

[45] South Australian Productivity Commission (2021), Development referrals regulatory review, final report, 10 <https://www.sapc.sa.gov.au/reviews/reviews/development-referrals/documents/Development-Referrals-Review-Final-Report.pdf>

Recommendation 2

The South Australian Government reform the major project approvals processes to increase transparency, and proponent certainty, whilst still retaining appropriate controls to ensure that regulation of projects meets community expectations. To ensure separation from existing models we recommend that the Chief Executive of the Department of the Premier and Cabinet be given a mandate to design a new process that better meets the state's needs.

Stakeholders stated that even when it is clear what processes they needed to undertake to receive planning approval for their project and which South Australian Government departments they needed to contact, finding the contact details for the relevant person or area within that department to discuss their project could be challenging.

With several different departments being responsible for various parts of the project approval process for renewable energy projects, difficulties in finding the relevant contact person or area can be repeatedly encountered by proponents during the project approval process.

Finding 15: The regulatory landscape for development approvals of renewable energy projects is confusing. Even experienced professionals struggle to identify appropriate contacts and sequencing of activities.

The Department for Energy and Mining (DEM) operates a unit to assist proponents through the government approvals process, essentially providing them with 'one window' to government. The feedback received by the Commission in relation to the mining unit in DEM has been positive with the unit having secured several good outcomes for both mining proponents and South Australia. If South Australia is to achieve its policy goals and renewable energy targets, a unit within the South Australian Government with similar strategic oversight and consideration of South Australia's overall renewable energy generation needs could offer similar significant benefits to the renewable energy sector. The design of any such unit would need to ensure non-duplication with existing government functions and activities.

Improvements to the planning system

As highlighted above, renewable energy proponents have encountered several challenges within the South Australian planning system in the past decade that have made the approval process more difficult.

However, not all changes made to the South Australian planning system for renewable energy projects in the last decade have made the approval process more difficult or have been negatively received by renewable energy proponents. Several changes have benefited renewable energy projects and improved the overall approval process.

Anecdotally, the centralisation of the planning assessment process, with projects assessed by an independent expert assessment panel with a consistent set of assessment criteria, was seen by proponents as providing a clear and measurable set of requirements that their projects must satisfy to get planning approval. The Commission has heard that the previous process, where projects were assessed by the local council in which the project was being built, resulted in significant variance in the expertise of those assessing the project and an inconsistent set of assessment criteria applied.

Box 2.1: 'One window to government' for mining companies

A unit within the Department for Energy and Mining (DEM) assists mining proponents through the various project approval processes required to proceed with their project. This serves several purposes.

Firstly, they provide a single-point-of-contact 'concierge' service to help guide and assist mining proponents through the South Australian Government project approval processes. This allows proponents to better understand the various approval pathways available to them, as well as the legislative, regulatory and policy requirements related to each pathway.

Secondly, the single-point-of-contact allows this unit to establish and develop a relationship and rapport with the mining proponent. By developing this relationship and building trust over time, this leads to proponents exhibiting a greater level of transparency and disclosure.

Thirdly, by working closely with the mining proponent, the unit within DEM can better identify the key risks that a specific mining project may have from a South Australian Government perspective, allowing them to work with the proponent in a mutually beneficial way to manage and mitigate those risks before they become a major problem for either party.

An additional benefit of having a specific unit for new mining projects is that it allows DEM to better consider any new mining projects from a holistic and strategic perspective as part of South Australia's overall mining strategy, rather than each project being considered in isolation.

Another recent change that has made it easier for renewable energy projects to be approved was the removal of third-party appeal rights for projects approved under the private project pathway, provided certain requirements are met. This change was seen by proponents as a significant improvement. Previously the Crown development approval pathway was used by many proponents as projects approved via that pathway were not subject to third-party appeal. The removal of third-party appeal rights under the private project pathway has given proponents more options in the approval pathway they can choose, improving investor certainty.

However, on balance, stakeholders indicated that the current approval processes for renewable energy projects in South Australia are no longer as simple to navigate as they were when South Australia was leading the NEM in new renewables installation. In addition, project applications are not processed in as timely a fashion as they previously were, especially when compared to the improved approval processes used in other Australian jurisdictions.

Renewable Energy Zones

As part of the consultation process on the inquiry draft report, feedback was sought from stakeholders regarding the benefits of Renewable Energy Zones (REZ)) in South Australia being formally recognised by the South Australian Government from a policy and legislative perspective.

REZs are geographic areas identified by AEMO as representing high-priority potential areas for the development of renewable energy projects to deliver renewable energy in line with AEMO scenario planning. AEMO has identified 33 potential REZs across Australia, including 9 in South Australia.

In recent years, other Australian jurisdictions have taken steps to formally incorporate REZs into their energy policies and strategies, either providing regulatory advantages for projects locating in REZ's or supporting the development of additional transmission infrastructure.

Stakeholder feedback on the benefits of formally recognising and legislating REZs in South Australia was mixed. Whilst welcoming any changes to South Australian policy, legislation and/or regulation that would make building new renewable energy projects easier, there was concern that by specifically identifying areas of South Australia as REZs, it could create a perception that renewable energy projects should only be built within designated REZs. This could have the unintended consequence of making it more difficult for renewable energy projects to be built outside of a REZ in South Australia, or for planned projects to secure investment.

Stakeholders suggested that the South Australian Government should not try to 'pick winners' by expending resources trying to enact REZs in local planning systems. A better, and simpler, solution would be for the South Australian Government to make legislative and policy changes that made it easier for renewable energy projects to be built in any non-urban areas across South Australia.

Finding 16: The South Australian Government should not seek to institutionalise Renewable Energy Zones either through the planning and design code or through using them as a key factor in infrastructure planning decisions.

2.5 Barriers to accessing pastoral lands

Investors and proponents of utility-scale renewable energy projects seek to access large tracts of land in locations offering the best conditions for wind and solar generation. The type of tenure over that land influences the regulatory obligations and processes that govern access to, and use of, that land. In South Australia:

- Crown land is managed by the Department for Environment and Water (DEW) in accordance with the *Crown Lands Management Act 2009* (CLM Act); and
- Crown land under a pastoral lease is managed by the Pastoral Unit within DEW (with oversight by the Pastoral Board) in accordance with the *Pastoral Land Management and Conservation Act 1989* (PLMC Act).

A pastoral lease enables the owner of the lease (the lessee) to occupy and use that Crown land for pastoral and other approved purposes in accordance with the PLMC Act. Additional legislation, including the CLM Act regulates activities that seek to access, change or use pastoral lease land. Following the recent transfer of the Pastoral Unit to DEW, the responsible Minister for both the PLMC Act and the CLM Act is the Minister for Climate, Environment and Water.

The PLMC Act states that it is an '*Act to make provision for the management and conservation of pastoral land*'[46] and consequently, applications seeking to access or use pastoral lease land for non-pastoral purposes are be assessed by the Pastoral Unit and Pastoral Board and require Ministerial approval. Applications are assessed according to their potential impact on the ongoing viability of pastoral activities, and their alignment with the objects of the PLMC Act. Particular considerations for renewable energy projects include:

[46] SA Government, Pastoral Land Management and Conservation Act 1989, 1

- whether activities may preclude the primary purpose of pastoralism or can co-exist with pastoralist activities;
- the term and size of the proposed activity and potential impact on the primary pastoral purpose; and
- additional land requirements to acquit significant environmental benefit (SEB) obligations (if acquitted onsite).

Appendix 4 provides an overview of the current regulatory environment and the associated processes and governance arrangements that apply to renewable energy projects and pastoral lease land in South Australia.

Demand to access and use pastoral lease land for renewable energy purposes is anticipated to continue to grow due to:

- the level of anticipated renewable energy generation required to achieve net zero emission targets[47];
- the impacts of climate change on the viability and nature of pastoral activities and opportunities to diversify and reduce risk; and
- regulatory impacts that have pushed land suitable for renewable energy purposes further north in the state (including requirements relating to setbacks as discussed in section 2.4).

The Commission heard that:

- there is increasing interest from investors who are investigating viable opportunities for renewable energy projects in South Australia; and
- DEW is dealing with an increasing number of inquiries and applications from renewable energy proponents seeking exclusive access to Crown land (including pastoral lease land).

Opportunities for pastoralists and investors to benefit from increasing demand for potential renewable energy projects depends, in part, on the legislative framework and associated approval processes that govern and manage access and use of pastoral lease land. Investors in utility-scale renewable energy projects in Australia warn that excessive risk caused by policy uncertainty or poor regulatory design and implementation can increase the cost of capital and impede investment.[48] Inconsistent and unclear regulation reduces investor and landholder confidence in security of land tenure and impedes investment in highly geared large-scale renewable energy generation;[49] it can also deter pastoralists from considering opportunities to diversify land use.

Additional regulatory obligations to access and use Crown land can be warranted given Crown land is to be managed and used for the benefit of all South Australians. The Commission's research and consultation indicates that renewable energy projects, particularly those for solar and hydrogen, can face inconsistent and ambiguous regulatory obligations and processes when seeking to access and use pastoral lease land. These

[47] AEMO estimates that the most likely transition scenario will see renewables share of total annual generation rise from around 28% in 2020-21 to 83% in 2030-21, to 96% by 2040, and 98% by 2050. AEMO (2022) Integrated System Plan, June, 38

[48] The Clean Energy Investor Group estimates the risk premium from policy and regulatory uncertainty as around 10% of the total value of the renewable energy project pipeline required, or around $10 billion AUD. CEIG (2021), 'Unlocking low-cost capital for clean energy investment, Clean Energy Investor Principles, August < https://ceig.org.au/wp-content/uploads/2021/08/CEIG_Clean-Energy-Investor-Principles.pdf>

[49] Atholia, T., G. Flannigan and S. Lai, (2020), Renewable energy investment in Australia, Bulletin – March, <https://www.rba.gov.au/publications/bulletin/2020/mar/renewable-energy-investment-in-australia.html>

issues are compounded by increasing competition to access and use land for renewable energy – a relatively recent and rapidly evolving sector that was not a consideration when the regulatory framework was developed.

Inconsistent and fragmented regulatory framework

Regulatory obligations and processes to access and use pastoral lease land vary depending on the:

- industry sector (e.g. pastoral, mining, energy);
- type of renewable energy generation (e.g. wind, solar, solar thermal); and
- renewable energy activity (e.g. generation, transmission, storage).

Non-wind farm renewable energy

Under the PLMC Act, all land uses apart from pastoralism and ancillary activities, mining, and wind farms are treated as 'non-pastoral' purposes or alternative land uses. The PLMC Act provisions in Division 4 enables access, exploration, and use of pastoral lease land for wind farms. These provisions do not extend to other forms of renewable energy generation including solar or solar thermal and proponents are required to seek approval to amend the conditions of a pastoral lease. Given this, the Commission is informed that most proponents will seek to access and use pastoral lease land using the unsolicited proposals pathway managed by DEW or the Department of Treasury and Finance (DTF). This can involve a complicated process requiring Ministerial approval to surrender part or all of the pastoral lease land (thereby excising the land), changes to the tenure of the excised land, and issuance of a Crown licence to use that land (for limited purposes and time period).

DEW proposes that the complexities and delays associated with this process may be reduced by reforming the State's unsolicited proposals pathway as it applies to renewable energy and Crown land.

Hydrogen generation and production

Applications to access and use pastoral lease land for hydrogen production under existing legislation would be treated as a non-pastoral purposes application and would therefore likely involve excising the required land, changing the tenure and issuing of Crown licence(s) to facilitate land access and use. If the application was for a wind farm (to generate energy to produce green hydrogen), then the current provisions under Division 4 of the PLMC Act would apply. The ability to access and use sufficient land to generate the renewable energy required to produce green hydrogen is a crucial element of any green hydrogen proposal.

At the time of preparing this final report the scope of the proposed new South Australian Hydrogen Generation Act was not yet formally finalised. The Commission was informed that there is uncertainty over whether the proposed legislation will extend to provisions for the land required for renewable energy generation to generate green hydrogen. It is also not clear whether the proposed new act will be included in s62 of the PLMC Act, along with the other mining legislation listed (and which could provide some benefit for resource tenement holders consistent with other s62 mining legislation as discussed below).

Mining and renewable energy generation

DEW advises the Commission that the current approach to s62 of the PLMC Act is to ensure that approvals granted under the *Mining Act 1971*, *Opal Mining Act 1995* and *Petroleum and Geothermal Energy Act 2000* can operate without interference and further approval

requirements under the PLMC Act. For example, the responsible Minister cannot grant a wind farm licence (nor enable other forms of renewable energy activity) if a resource tenement (as defined in the listed mining legislation at s62) exists on the pastoral lease land in question – unless certain statutory requirements are met.

Stakeholder feedback indicates that there is uncertainty over how s62 may be applied in practice – particularly where a renewable energy project is linked to a mining project/tenement. As demand to access and use pastoral lease land for non-pastoral purposes intensifies, inconsistencies in the regulatory treatment of different projects becomes increasingly important and relevant.

DEW has advised the Commission that the potential implications of s62 can be included in work on a policy framework for the operation of wind farms under the PLMC Act. The Commission notes that under the existing regulatory framework, this work will be limited to implications for wind farms only.

Regulatory reform for non-wind farm renewable energy

Government stakeholders have acknowledged the regulatory issues regarding pastoral leases and renewable energy outlined in the inquiry draft report. Consultation indicates that government stakeholders support reform proposals aimed at addressing the issues raised. Many of the issues result from the development of a regulatory framework at a time when land requirements for renewable energy purposes were not an issue. It is important to state that any proposed reforms to the PLMC Act should not detract from nor diminish the Act's existing stated purpose – '*to make provision for the management and conservation of pastoral land'*.[50]

Finding 17: Current provisions for wind farms in the *Pastoral Land Management and Conservation Act 1989* do not extend to other forms of renewable energy. Consequently, the existing regulatory obligations and approval processes to access and use pastoral land effectively limits opportunities for green energy – particularly given South Australia's comparative advantage for the co-location of wind and solar.

Recommendation 3
The Commission recommends that the South Australian Government amends the *Pastoral Land Management and Conservation Act 1989* or develops an alternative legislative framework that extends the provisions that enable wind farm exploration and development on pastoral lease land to other forms of renewable energy.

Easements

Renewable energy proponents must obtain easements on land over which the renewable energy is to be transmitted. Easements over Crown land (including pastoral lease land) are granted under the CLM Act. DEW requires certain conditions to be met before an easement application can be lodged and then granted, as discussed in Appendix 4.

Given most energy transmission routes are long and linear, multiple easements will be required over multiple land areas and involve numerous landowners/holders and various forms of tenure.

[50] SA Government, Pastoral Land Management and Conservation Act 1989, 1

Stakeholder feedback indicates that:

- due to the complex regulatory environment, most proponents seek to change the land tenure rather than try and obtain easement(s) over pastoral lease land; and
- delays in obtaining the relevant electricity licence(s) and lodgement of survey plans can often mean an interim Crown licence has to be granted to enable a project to commence.

Industry stakeholders have told the Commission they spend a disproportionate amount of time and resources dealing with easement issues when progressing renewable energy projects. Interim Crown licenses may help progress projects; however, they are generally limited in their application, time and scope. Government stakeholders have also told the Commission that the regulatory obligations and processes relating to easements and transmission infrastructure require review to develop an approach that simplifies processes and reduces unnecessary red tape. The Commission considers that work to reform regulatory obligations and processes for easements on Crown land may form part of the government's response to recommendation 2, and to recommendation 11 (common use infrastructure corridors).

Competing demand to access and use pastoral lease land for non-pastoral purposes

Demand to access and use pastoral lease land is anticipated to increase – particularly if South Australia becomes a key player in the green hydrogen sector. The Commission has heard that the supply of suitable pastoral lease land is being adversely impacted by pastoralists who can be reluctant to relinquish part or all of their land for a renewable energy facility due to uncertainty over whether they will be able to reacquire that land once it is no longer needed for the facility.

Until recently there had been no applications to explore the possibility of establishing wind farms on pastoral land. Recent advances in the renewable energy sector have created competition with more traditional land use interests and within the sector itself. The Commission has heard that stakeholders are uncertain on how the State Government deals with competing demands for pastoral lease land (whole or part), and that this is adversely impacting on their ability to effectively plan and make decisions on long-term investments in renewable energy projects and pastoral lease land management.

The Commission considers that the uncertainty is partly due to the lack of clear, consistent policy and guidance on competing demands, particularly within the context of the PLMC Act. Although the Pastoral Board has published a guideline, 'Use of Pastoral Land for Non-Pastoral Purposes', this guideline appears to be dated and provides fairly generic advice, particularly when compared to the guidance and policy material that is available on mining regulation (exploration and licensing) via DEM.

DEW has advised the Commission that it will be working with a range of State Government agencies to expedite a cross-government framework for assessment of wind-farm exploration applications on pastoral lands (under s49J of the PLMC Act). The Commission notes that this work is limited to wind farm exploration applications. Other jurisdictions are facing similar issues; for example, the NSW Government[51] is currently developing strategies to mitigate the risk of conflict around access to land and improve land outcomes.

[51] NSW Department of Primary Industries taskforce established in March 2022 to review issues and opportunities from the forecast growth in renewable energy and agricultural land, and develop strategies to mitigate the risk of

Finding 18: There are currently gaps in the policies and procedures used to manage renewable energy developers' applications to undertake exploration activity on, or develop projects on, pastoral lands.

Recommendation 4

As part of the South Australian Government's proposed work on developing a cross-government framework for the assessment of wind farm exploration applications on pastoral lease land, the Commission recommends that the Department for Environment and Water (DEW) develops and implements policy and processes that set out:

- **how the relevant government agency(s) will deal with:**
  - **competing applications to access and use the same pastoral land; and**
  - **applications seeking exclusive access (and use of) part of the land under a pastoral lease;**
- **options that can provide for third-party access where appropriate; and**
- **ways to extend the scope of this work to applications for other forms of renewable energy apart from wind farms.**

Reporting obligations and access to explore

Section 49J of the PLMC Act provides that a person who is intending to apply for a wind farm licence on pastoral land can apply to the Minister for approval to enter and occupy the pastoral land for a period of up to 2.5 years to conduct tests and investigations (plus an option to extend for a further 3 years). Clause (4) of that section prescribes that no other person can apply for a s49J approval to access pastoral land where the Minister has already granted a s49J approval to another person over that land. Furthermore, clause (6) of s49J provides that '*nothing in this section requires a person granted an approval under this section to disclose to the Minister or any other person any information collected pursuant to the approval*'.

This has some potentially significant implications:

- The extent to which land is effectively quarantined from any access for some years under s49J depends, in part, on how clause (4) is interpreted and applied, with stakeholders expressing concern that it is being interpreted broadly.
- It is not clear if 'pastoral land' referred to in s49J applies to the whole pastoral lease or part thereof.
- A person granted s49J access is not required to provide or report on any data or information they collect via their exclusive access.

The Commission notes that South Australia has a comprehensive mining regulatory framework that governs access to land (including pastoral lease land) to explore mineral opportunities. This includes obligations requiring mineral explorers to report data and information to DEM and other responsible State Government authorities who are authorised to use the information for regulatory compliance, and strategic policy development, as well as making it publicly available to inform other potential users of the land.

conflict where agricultural land may be required for large-scale renewable energy facility projects, <www.dpi.nsw.gov.au >

The Commission acknowledges there may be concerns around the sharing of commercially sensitive information or data – particularly that which results from exploratory activities. Additionally, there can be significant differences in the potential impact on the landscape from mineral versus renewable energy exploration activities. However, the Commission considers that such concerns do not justify the significantly different statutory obligations on persons seeking exclusive access to investigate pastoral lease land based on whether the approval was granted under the PLMC Act or the *Mining Act 1971*. The Commission considers that the exclusive exploration rights provided to approved potential wind farm proponents under s49J of the PLMC Act provides a significant advantage to them.

Finding 19: Unlike other cases where governments grant temporary exclusivity to intellectual property (such as through minerals exploration licenses or patents) there is currently no requirement on developers undertaking wind farm related exploration on pastoral lands to share the resulting data with the government and broader community.

Recommendation 5

The Commission recommends that the South Australian Government amend the *Pastoral Land Management and Conservation Act 1989* (or enact alternative legislation) to require that the information and data obtained by persons undertaking exploration activities as a result of their exclusive access approved under section 49J be provided to the State Government and made publicly available, similar to reporting provisions required for other activities undertaken on Crown land.

Land value and taxes and rates

The inquiry draft report sought feedback from stakeholders on the potential implications for land value and resulting tax/rate liabilities arising from increasing demand for Crown land (pastoral lease land) and changes to the use and occupation of pastoral land for renewable energy purposes. The Office of the Valuer General (OVG) advised that they had recently completed an assessment of pastoral lease land, as required under Section 23 (4) of the PLMC Act. The OVG advised the inquiry team that land-use codes are currently not legislated in South Australia and the introduction of suitable legislation would be a significant undertaking. The inquiry team were advised that:

- There is little consistency in how each rating authority (SA Water, Revenue SA, local government authorities) applies land-use codes when administering their rating and taxing statutes.
- So far, changes to pastoral land use and occupancy for renewable energy purposes are relatively new and rare, so the consequences and implications are still being worked out.
- Due to the different rate/tax applications using land-use codes and the wide range of different circumstances and scenarios involving pastoral land and renewable energy, it would be difficult to develop an overarching policy on Crown land, renewable energy and land value and rating.

The OVG advised the inquiry team that they undertook scenario planning with relevant stakeholders as part of a reform project for independent retirement developments. The Commission considers that, given the existing complex regulatory environment and potential

future demand for pastoral lease land for renewable energy purposes, scenario planning would provide key stakeholders with:

- an early and clear understanding of the regulatory obligations and processes;
- potential land value and associated rate/tax implications (based on different scenarios); and
- help in planning and developing appropriate responses as required.

Finding 20: Stakeholders have expressed concern that there is uncertainty about the potential implications for pastoral lease fees, and potential liability for other taxes and charges such as land tax and the Emergency Services Levy if a renewable energy development takes place on pastoral lands. It would be good practice for the actual implications to be clear to pastoralists before they agree to grant access to developers.

Recommendation 6

The Commission recommends that the Department for Environment and Water commissions scenario modelling from the Office of the Valuer-General on the potential impacts of renewable energy projects on pastoral leases and associated liabilities arising from the application of land-use codes.

2.6 Regulatory barriers to connection of renewable energy to the grid

Access to the transmission network as a (large-scale) generator is very tightly regulated as it is important to ensure that any new connections comply with all of the operating requirements, and that their addition to the grid will not have any adverse impacts on system stability.

Grid connection approvals – ElectraNet and AEMO processes

Renewable energy proponents must overcome several regulatory barriers to get their new renewable energy projects built and connected to the South Australian electricity grid.

The South Australian electricity grid is part of the NEM. The NEM which is made up of electricity generators, transmission network service providers (TNSP)s, distribution network service providers, electricity retailers and end-users.

The NEM is operated by AEMO and regulated by the Australian Energy Regulator (AER). The Australian Energy Market Commission (AEMC) sets the rules to ensure the NEM delivers efficient, reliable, and safe energy to consumers. It also provides independent advice to policy makers across the various Australian jurisdictions.

TNSPs are state-based and service the various jurisdictions in the NEM. ElectraNet is the TNSP responsible for the South Australian electricity grid. TNSPs link electricity generators to the 13 major distribution networks that supply electricity to end-users, with cross-border interconnectors linking the electricity grid at state borders to allow electricity to flow from one state to another.

ElectraNet also serves as the jurisdictional transmission planning body for South Australia and is responsible for drawing upon AEMO's high-level (ISP) for the NEM to create Annual Planning Reports that detail more specific investment needs and drivers for the state, detail potential network investments and forecast loads for the next 10 years.

Connection of any new electricity generation, renewable or other source of electricity to the NEM in South Australia requires regulatory approval from both ElectraNet, as the TNSP, and AEMO, as the market operator.

This regulatory approval is achieved by the renewable energy project proponent providing ElectraNet and AEMO with modelling that demonstrates that, if approved, the connection of their new electricity generation to the NEM will not impact the NEM's grid stability or performance.

These regulatory approval processes are essential to the successful operation of the NEM. It is impossible for ElectraNet and AEMO to manage South Australia's and the NEM's grid stability without close regulation of large new electricity generation connections.

South Australia's regulatory approval processes for new electricity generation to connect to the grid are in most respects no different to those in any other Australian jurisdiction, except for the additional grid stability requirements imposed by the Office of the Technical Regulator (OTR) (see below). However, the fact that South Australia has significantly less synchronous generation to provide firming to the electricity grid, makes the South Australian regulatory approval process for new electricity more challenging compared to other Australian jurisdictions.

In theory, primary responsibility for assessing new electricity generation connections should fall to ElectraNet in their role as South Australia's TNSP, with AEMO acting as a reviewer to check ElectraNet's processes.

However, as part of the consultation process, stakeholders indicated that AEMO's and ElectraNet's assessment processes were poorly integrated. As a result, AEMO frequently required renewable energy proponents to undertake additional studies or modelling, despite the project having been approved by ElectraNet based on the current information provided.

While these additional studies and modelling added to the financial costs of a project, stakeholders indicated that the time delays caused by AEMO's requests for additional information were the more significant problem. As a result of these frequent time delays, stakeholders indicated that it was taking more than 12 months to have their new electricity generation connections approved by ElectraNet and AEMO, which they felt was unreasonably long.

In addition to the time needed to undertake the requested studies and modelling, due to the lack of advance notification of AEMO's requests proponents often found it difficult to find available consultants in Australia with the necessary expertise due to the specialised nature of the required work. This meant that projects were often further delayed while the proponent waited for a consultant to find time in their schedule to carry out the additional work.

Stakeholders indicated that they were already experiencing capacity constraints in the regulatory approvals system due to the shortage of suitably skilled staff. As the transition to renewable energy generation accelerates over the next few years, it is likely that these skill shortages will increase, adding another barrier to the regulatory approval process.

Feedback received by the Commission also suggested that the lack of integration, and the need for additional studies and modelling required by AEMO at the very last stage of the regulatory approval process, could be largely avoided if AEMO engaged in discussions with the renewable energy proponent and ElectraNet at the beginning of the regulatory approval process.

This would allow AEMO to identify the factors they required to be addressed at the beginning of the process. The renewable energy proponent could then ensure that any factors of interest to AEMO were included in any initial modelling they undertook, rather than needing to undertake additional modelling at the end of the process.

Other options suggested by stakeholders to improve the speed with which the regulatory approvals process was completed in South Australia included allowing AEMO to defer more responsibility to ElectraNet; and for AEMO to undertake more work in parallel with ElectraNet, rather than AEMO waiting until ElectraNet had completed all their regulatory approval processes before starting their own processes.

AEMO indicated to the Commission that they were aware of all of the above issues raised by stakeholders and agreed that their current processes could be improved to allow new renewable energy projects to connect to the national electricity grid in a more timely manner. AEMO is undertaking reviews of its processes to ensure the issues identified by stakeholders are addressed moving forward.

The potential 'batching' of applications accessing related transmission infrastructure, or of giving applicants a set of hypothetical additional local generators to include in the modelling reflecting plausible medium-term demands on the transmission infrastructure could make the assessment process more transparent and less reactive.

Another regulatory barrier faced by renewable energy proponents is that any grid stability measures required of projects by the TNSP or by AEMO (e.g. synchronous condensers or batteries allocated to fast frequency response services) are considered on a project by project basis. This can result in measures being built in an inefficient and costly manner. In many cases it would be more effective and cheaper to procure one larger grid stability asset to address the impacts of several projects, rather than several individual smaller ones.

Finding 21: AEMO's current processes for connecting new renewable generation to the electricity grid are inefficient and causing unnecessary delays. AEMO is reviewing these processes to improve them, ensure better integration with ElectraNet's processes and allow more work in parallel to reduce future connection timeframes.

Recommendation 7

The South Australian Government engages with AEMO's review of their connection processes and the integration with TNSP connection processes, and reduces new connection timeframes to increase the efficiency of the grid connection process and remove any South Australian specific inefficiencies.

Office of the Technical Regulator (OTR) generator connection standards

After the state-wide outage in South Australia, AEMO implemented a number of national changes to generator standards to ensure, amongst other things, that it had visibility of the protection settings of all connected generators, and that they were set in a way that was consistent with AEMOs management approach to the NEM.[52] These changes are part of the current TNSP and AEMO approvals process for new generation discussed above.

[52] AEMC (2018), National Electricity Amendment (Generator Technical Performance Standards) Rule 2018)

Box 2.2: State-wide power outage in 2016

On 28 September 2016, strong winds in the mid-north of South Australia brought down several high voltage transmission lines. The change in the system voltage caused by these fallen lines (and the associated loss of power from the region) activated protection settings (not known to AEMO, the system manager) on several windfarms causing them to disconnect from the grid further reducing electricity supply in South Australia. In the absence of a rapid demand-response capability, the system tried to balance by increasing the power drawn through the interconnector with Victoria, overloading it and causing it to trip. The further loss of supply meant that there was a catastrophic undersupply of electricity in the now isolated South Australian grid, and the entire network went down (also known as a black system).[53]

Following the state-wide outage, AEMO, as the national electricity market operator, introduced a set of reforms to address deficiencies in the NEM operations in South Australia. The key deficiencies identified from the AEMO review of the state-wide outage event were:

- incorrectly set protection settings on a number of wind farms (if the wind farms had had the correct protection settings, they would have been able to ride through the voltage disturbance);
- excess load on the interconnector in normal operations meaning there was insufficient capacity to deal with the system disturbance; and
- barriers to rapid load shedding in the South Australia subregion of the NEM.

The re-start following the state-wide outage was also slowed as several of the firms contracted to provide system restart services were unable to meet their contracted requirements.[54]

In addition to these national measures, AEMO determined that South Australia's high penetration of variable renewables required some additional controls and determined that South Australia needed:

- increases in inertia under some conditions;
- improvements in load shedding systems, and reduced interconnector flows in certain circumstances;
- increases in frequency control services; and
- sufficient system strength to control voltages including ensuring the correct operation of inverter-controlled systems.[55]

Since the state-wide outage in 2016, AEMO has also undertaken a number of (relatively costly) interventions to increase the amount of inertia in the South Australian grid, reducing the need for action by the OTR. These have included setting a minimum level of gas generation in the South Australian market (initially four generators and now two generators operating at all times) and requiring the installation of four synchronous condensers in South Australia.[56]

Energy regulation in Australia is technically a matter for the states, and the NEM and its regulators only operate because of state government legislation in those states participating in the NEM referring certain regulatory powers over electricity to the Commonwealth. South

[53] AEMO (2017a), Black System South Australia 28 September 2016 – Final Report
[54] *Ibid*
[55] *Ibid* (AEMO, 2017a)
[56] AEMO (2020), *Minimum operational demand thresholds in South Australia* – technical report, <https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/minimum-operational-demand-thresholds-in-south-australia-review.pdf?la=en>

Australia in referring these powers to the Commonwealth also retained a potential role for a state-based regulator, the OTR, in approving new grid connections.

Following the state-wide outage, the OTR concluded that South Australia no longer had enough inertia in its electricity grid. In addition to the actions being undertaken by AEMO, the OTR introduced its own requirement that any new grid-scale generation connected in South Australia would need to include either inertia (through conventional generation or the installation of a synchronous condenser) or a battery capable of delivering Fast Frequency Response Services (FFR).[57] These requirements significantly increase the cost of developing a new renewable energy project in South Australia. It is also not clear why the system strength modelling required by ElectraNet and AEMO before they will allow a grid connection from a new generator is insufficient to manage any potential risks to the state.

These requirements were prudent as an emergency response in the immediate aftermath of the state-wide outage in 2016 when it was unclear how the South Australia grid could safely integrate more renewables. However, it has now been over five years since the state-wide outage, and regulations should move on from emergency measures to more sustainable and system level actions around system security.

The scale of the provision of inertia or frequency control services required by the OTR is substantial. Modelling by the Commission of the cost of a battery of the required scale, and consultations with industry about the cost of installing synchronous condensers, suggests that OTR's connection requirement has increased the cost of developing a renewable power project in South Australia by around 8 to 20 per cent. This reduces the expected return on South Australian projects and makes investment in other states and territories relatively more attractive.

It is impossible to be certain what would have happened in terms of renewable energy developments in the absence of the OTR requirements as several other factors have also made South Australia a relatively less attractive destination for wind and solar developments since the mid-2010s. These include very low summer day-time prices, reduced levels of PPA deals, and constraints on interconnector capacity to the rest of the NEM. It may be that these other factors on their own would have been sufficient to deter wind and solar investment even if the OTR requirements had not been in place.

Nonetheless, it is notable that the only projects subject to these requirements that have been constructed have been SA Water managed projects to deliver green power to their pumping operations. No commercial grid-scale wind or solar projects subject to the OTR requirements have been constructed, despite a number having secured planning approval.

As projects subject to the requirements have not proceeded, not only have the generator standards held back commercial scale (and therefore easier to manage) renewable energy investment, but they have also not led to any meaningful increase in inertia in the South Australian grid – the actual objective of the requirements.

Nor have these requirements stopped new renewables from connecting to the grid without additional inertia being supplied, as over this period there has been a substantial increase in rooftop solar PV capacity and grid feed in.

[57] Department of Premier and Cabinet (2017), Generator Development Approval Procedure, reference no. D21012132

The OTR generator connection standards act as another South Australian policy setting that substantially reduces the state's ability to meet its goals around decarbonisation.

It is also notable that in recommending potential solutions to South Australia's grid stability risks to the Essential Services Commission of South Australia (ESCOSA) and the OTR, AEMO explicitly recommended against project level requirements for inertia:

> *AEMO does not recommend that ESCOSA introduce any generator license conditions associated with the provision of inertia.*
>
> *A static technical obligation to generators to provide inertia when operating would not:*
>
> - *Lend itself to co-optimisation of inertial requirements with other power operating system attributes such as system strength.*
> - *Lend itself to optimisation of locational distribution of inertia.*
> - *Necessarily deliver a secure power system.*[58]

Part of the difference between AEMO and OTR requirements on generators arises from a different assessment of the amount of inertia it is prudent to have in the South Australian grid to maintain system stability. The OTR's assessment of the preferred amount of inertia is roughly twice as high as AEMO's. The Commission is not in a position to assess which of the two levels of inertia represents the best balance between costs and risk reduction. Our concern with the OTR standards is they are an inefficient means of achieving a given level of inertia in the grid and have broader adverse impacts on the renewable energy transition in South Australia.

Finding 22: The OTR requirements impose a significant cost burden on new renewables projects without achieving any obvious benefits in terms of system strength due to the reduction in new renewables construction. They are incompatible with the South Australian Government target on decarbonisation.

An alternative, more efficient, approach would be to undertake system level modelling of the inertia and other system stability needs of the South Australia grid at various levels of decarbonisation, and centrally procure those services at a scale that matches the planned decarbonisation of the grid.

Recommendation 8

The Office of the Technical Regulator and AEMO establish a process to reconcile their different assessments of the amount of inertia required to ensure the stable functioning of a decarbonised electricity grid in South Australia.

Recommendation 9:

The OTR generator connection standards be abolished and all grid stability services required should be procured efficiently at a whole region level.

[58] AEMO (2017b), 'Recommended Technical Standards for Generator Licensing in South Australia: Advice to ESCOSA', 31 March

3. Green hydrogen – opportunities and challenges

3.1 Green hydrogen

Green hydrogen is widely regarded as a fuel of the future as its economic and renewable energy potential is significant. There are different types of hydrogen, categorised by colour based on its extraction method. For example:

- Brown hydrogen is produced using coal, releasing significant greenhouse gas emissions.
- Grey hydrogen is produced using natural gas, also resulting in significant greenhouse gas emissions.
- Blue hydrogen is produced using natural gas, but the emissions generated in splitting the hydrogen from the natural gas are (largely) captured during the production process and are either used in other industrial processes or geologically sequestered. Blue hydrogen still results in greenhouse gas emissions in the form of fugitive emissions when the natural gas is extracted from the ground, because the carbon capture process is only partially efficient, and because in many cases natural gas is burned to fuel the steam methane reformation that splits the hydrogen, and to fuel the carbon capture and storage process.[59]

Green hydrogen is the cleanest form of manufactured hydrogen as it is made without using fossil fuels by means of a method called electrolysis, whereby a strong electrical current is passed through water. This process splits the H_20 molecule into its two parts. If the electricity to power the electrolyser is generated from renewable sources (i.e., solar and wind) the production of hydrogen using this method does not generate greenhouse gases. The decreasing cost of solar and wind power makes hydrogen production increasingly attractive for South Australia.

Hydrogen is considered to be a versatile option for potential applications in energy storage, industrial uses and as a transport fuel. Currently the main use of hydrogen is as a raw material for industrial processes including petrochemical refining and fertiliser production.[60] If produced via electrolysis from renewable energy it presents an opportunity to decarbonise these processes which would be fully compatible with the net zero route, and provide further opportunities including the ability to store and export renewable energy. Future potential uses for green hydrogen as part of a broader decarbonisation of the global economy include[61]:

- Green hydrogen (either directly or through one of its by-products) can act as a store of energy for transport systems, allowing green energy to be used in transportation. The most prospective uses for green hydrogen in transport currently appear to be in substituting it for diesel in long-haul transport such as shipping and rail and for natural gas in forklifts. Opportunities for fuel cell electric vehicles in trucking and cars are also possible but will depend on the relative cost competitiveness of batteries.

[59] One recent study has even estimated that using a full life cycle analysis, blue hydrogen emits more greenhouse gases than just burning natural gas, and is only marginally lower in its emissions than grey hydrogen. Howarth, R.W. and M.Z. Jacobson (2022), 'How green is blue hydrogen?', *Energy Sci Eng*, 9,1676–1687. <https://doi.org/10.1002/ese3.956>
[60] ARENA (2022), *'Hydrogen Energy'* <https://arena.gov.au/renewable-energy/hydrogen/>
[61] International Energy Agency (IEA) (2019), *The Future of Hydrogen*, IEA: Paris <https://www.iea.org/reports/the-future-of-hydrogen>

- Green hydrogen can also act as a long-term store of variable renewable electricity to better match supply with demand, particularly for longer time periods where grid-scale batteries are less suitable. At present grid smoothing activity in Australia is undertaken by natural gas fuelled turbines and diesel generators, but hydrogen and pumped hydroelectric plants are zero carbon substitutes for these services.
- Green hydrogen is a potential substitute for natural gas in industrial processes where high levels of heat are required.
- Green hydrogen can also replace natural gas and coal as an industrial feedstock in many of their current uses, such as in steel, fertiliser and other chemicals production.

The key benefits of green hydrogen for energy storage include:

- versatility in supply and use as it can be converted to heat or electricity, and thus can be used for a wide array of functions for domestic and business use;
- (relative) ease of transportation as a gas by pipelines or in liquid forms by ships, similar to liquified natural gas (LNG);[62]
- providing additional flexibility to a constrained power system as hydrogen electrolysers can increase or decrease their production on a time scale of minutes or even seconds.[63] Electrolysers can also be strategically located to ease grid congestion and to transport hydrogen instead of electricity, which helps to avoid variability of supply; and
- addressing long-term seasonal flexibility to the power system through the production of hydrogen from renewable power in seasons with lower power requirements and storage of the hydrogen for later use.[64]

Currently, green hydrogen production is limited across the world. According to the International Energy Agency (IEA), less than 0.1% of hydrogen today is produced through electrolysis. However, more developed economies are establishing hydrogen strategies. Hydrogen faces the following key challenges and barriers in establishing and scaling up production:

- production, storage and transport costs of green hydrogen are high, preventing large scale deployment and reaching economies of scale. A price of $2/kg is widely regarded as being the cost at which green hydrogen is economically viable and cost competitive against other forms of hydrogen made with fossil fuels;
- uncertainty of demand given the current high production and transport costs, low level of technological maturity and lack of economies of scale. Without sufficient demand, investments remain risky for wide-scale production that could reduce costs; and
- significant energy losses in hydrogen production across each part of the value chain, including particularly, transport and conversion.[65] Reducing these losses is critical for the reduction of the hydrogen supply cost.

[62] International Energy Agency (2019), *The Future of Hydrogen*, International Energy Agency, p. 13 <https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf>
[63] IRENA (2019), *Hydrogen: A Renewable Energy Perspective, Abu Dhabi: International Renewable Energy Agency,* p. 24 <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf>
[64] Ibid, (2019), p. 25
[65] IRENA (2022), *Geopolitics of the Energy Transformation – The Hydrogen Factor*, Abu Dhabi: International Renewable Energy Agency, <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jan/IRENA_Geopolitics_Hydrogen_2022.pdf>

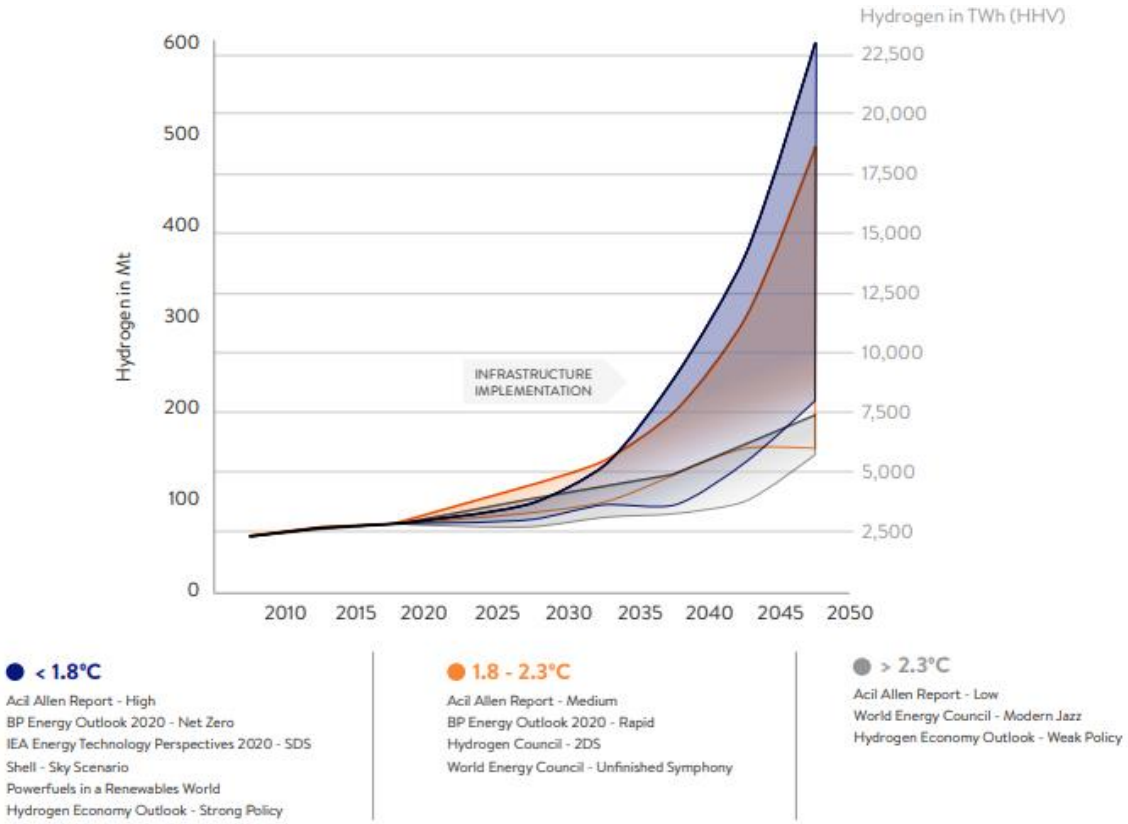
3.2 Economic opportunities from hydrogen

Green hydrogen is often put forward as a significant industrial opportunity arising from renewable energy. Hydrogen provides an opportunity to store and export South Australia's renewable energy but is also able to support the stability of an electricity grid that is completely based on renewables.

Global demand for hydrogen

Projections for hydrogen demand vary significantly based on the underlying assumptions. As such it is important to understand the different scenarios and data used in the projections. This also highlights the inherent uncertainties and risks of policies based on such projections.

Figure 3.1: Range of global hydrogen demand projections up to 2050, upper and lower bounds of demand for each of three scenarios, million tonnes (Mt) and Terra Watt hour of electricity equivalent



Source: World Energy Council[66]

Figure 3.1 illustrates the result of a study compiling hydrogen demand projections based on 13 scenarios from 8 different reports. The scenarios fell into three broad categories based on the scale of global policy ambition. The extent of policy ambition is important in determining the extent of hydrogen demand. The categories used were:[67]

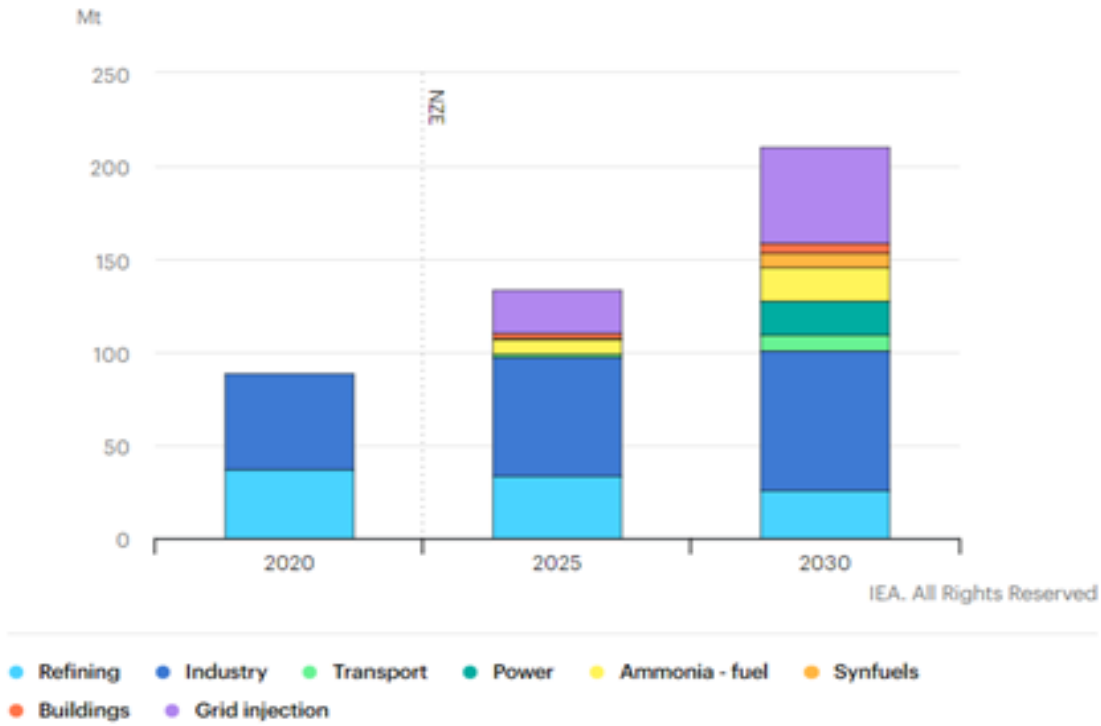
[66] <https://www.worldenergy.org/assets/downloads/Working_Paper_-_Hydrogen_Demand_And_Cost_Dynamics_-_September_2021.pdf>
[67] World Energy Council (2021), *Hydrogen Demand and Cost Dynamics*, Working paper <*https://www.worldenergy.org/assets/downloads/Working_Paper_-_Hydrogen_Demand_And_Cost_Dynamics_-_September_2021.pdf>*

- a low ambition trajectory where policy measures only moderately restrict greenhouse gas emissions and are consistent with temperature increases exceeding 2.3°C;
- a medium ambition trajectory where policy measures are sufficient to limit global warming to 1.8-2.3°C; and
- a high ambition trajectory, where policy measures are strong enough to come close to the aspirational goal of the Paris Agreement, and limit global temperature increases to <1.8°C.

Depending on the scenario, possible hydrogen demand in 2050 ranges from just over 100 Mt to over 600 Mt. The scenarios for higher ambition climate goals require higher hydrogen demand by 2050 (200 to 600 Mt). Medium ambition scenarios identify a range between 160 to 490 Mt by 2050, with an average growth of around 330 Mt. The less ambitious scenarios only see a small and almost linear growth in hydrogen demand (150 to 200 Mt in 2050).

Figure 3.2 presents hydrogen demand projections from the IEA in a net zero scenario for 2020-2030. Under this scenario, projected hydrogen demand goes from just under 100 Mt in 2020 to over 200 Mt in 2030.

Figure 3.2: IEA forecasts of global hydrogen demand by sector in the net zero scenario



Source: IEA (2022) 'Hydrogen' <https://www.iea.org/reports/hydrogen>

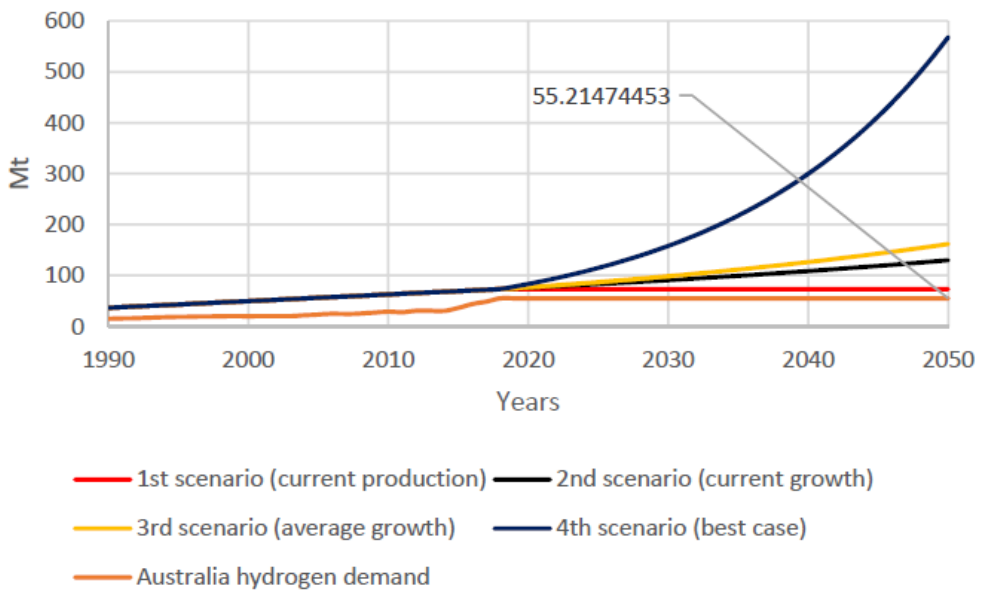
Potential Australian exports of hydrogen

Another study on Australian and global hydrogen demand projections based on four scenarios estimates that by 2050 the global demand will range from a low of 73 Mt (at current production rates) to a high of 568 Mt in the best-case scenario (e.g. towards the higher end of the high ambition scenarios reviewed by the World Energy Council in 2021), see Figure 3.3.[68] The four scenarios include: hydrogen demand remaining at 2019 levels;

[68] Yusaf, T., M. Laimon, W. Alrefae, K. Kadirgama, H.A. Dhahad, D. Ramasamy, M.K. Kamarulzaman, and B. Yousif (2022), 'Hydrogen Energy Demand Growth Prediction and Assessment (2021–2050) Using a System Thinking and System, Dynamics Approach', Appl. Sci., 12, 781.

growing by the average rate from 1990-2019 (1.8 per cent); growing by the average rate of the past 10 years (2.5 per cent); and a best-case scenario assuming that hydrogen becomes the fuel of choice for grid electrical supply as a back-up capacity, and for heavy and long distance transport, energy-intensive manufacturing and ammonia production.

Figure 3.3: Global and Australian hydrogen demand projections, million tonnes (Mt)



Source: Yusaf et al (2022)[69], p10.

The study reported in Figure 3.3 predicts that, under the best-case scenario, demand for Australian hydrogen could be around 55 Mt in 2050. This includes 21 Mt for domestic use, and international exports of 34 Mt by 2050 which implies both a relatively large international trade in green hydrogen, and Australia having secured a substantial share of that international trade.[70] In the Commission's view this estimate provides an upper limit to plausible Australian hydrogen demand as it assumes very little green hydrogen production in countries which are currently LNG importers. Estimates prepared for the Australian Renewable Energy Agency (ARENA), which assume a moderate amount of green hydrogen production in current energy importers, are that total hydrogen exports from Australia are likely to range from 0.6 Mt to 3.1 Mt by 2040, depending on the scale of global climate policy ambition.[71] Whilst the optimistic projections cannot be ruled out, the Commission's view is that the estimates prepared for ARENA are a more prudent basis on which to plan policy.

Finding 23: The projected scale of Australian green hydrogen exports is likely to be between 0.6 million tonnes and 3.1 million tonnes depending on the extent of global climate policy ambition. Government planning around the potential sector should be mindful of the range of plausible outcomes and not be based on the upper bound or lower bound outcomes.

[69] *Ibid.*
[70] This scenario predicts that hydrogen will be used for 100% of heavy and long-distance transport, 100% of energy-intensive manufacturing, 100% of mining, and 20% of grid electrical supply as a backup capacity.
[71] ACIL Allen (2018), 'Opportunities for Australia From Hydrogen Exports' <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>

Main export markets

Australian hydrogen exports will depend on various countries' decarbonisation strategies. The main applications of hydrogen in decarbonising an economy are to stabilise an electricity grid with a high reliance on renewable energy or replace fossil fuels such as natural gas and coal in their various uses including electricity production, household energy and industrial heat. Countries which can generate sufficient renewable energy from renewables to power their grid are likely to be able to produce enough hydrogen to stabilise their own grid, so Australian exports of hydrogen are likely to be directed to countries seeking to replace fossil fuels. The largest of these potential markets in our region are likely to be Japan, South Korea and possibly China. In Europe, Australia would face significant competition from both the US, the Middle East and parts of Europe itself due to the cost of transport.

Table 3.1: Australia's potential hydrogen exports by country, upper bound estimates, '000 tonnes and Petajoules (PJ)

Scenario	Country	2025		2030		2040	
		PJ	'000 tonnes	PJ	'000 tonnes	PJ	'000 tonnes
Low hydrogen scenario	Japan	2.1	17.3	21.9	182.2	47.1	392.1
	Korea	1.0	8.0	4.8	40.1	12.9	107.4
	Singapore	0.04	0.3	0.5	3.9	1.5	12.5
	China	0.1	0.5	1.4	11.6	10.7	88.9
	Rest of the world	0.05	0.4	0.5	4.3	2.4	20.3
	Total	**3.2**	**26.5**	**29.1**	**242.1**	**74.6**	**621.3**
Medium hydrogen scenario	Japan	12.7	106.1	44.2	368.1	102.3	852.2
	Korea	2.9	23.9	9.4	78.1	28.1	233.6
	Singapore	0.2	2.1	0.9	7.4	2.7	22.6
	China	0.3	2.6	4.5	37.6	23.7	197.3
	Rest of the world	0.2	1.8	1.3	11.0	5.4	44.8
	Total	**16.4**	**136.5**	**60.3**	**502.1**	**162.2**	**1,350.4**
High hydrogen scenario	Japan	33.0	275.0	96.4	803.0	237.7	1,978.8
	Korea	6.4	53.0	20.1	167.4	68.4	569.5
	Singapore	0.5	4.2	1.8	15.1	7.5	62.5
	China	0.9	7.9	9.5	79.3	55.7	463.9
	Rest of the world	0.6	4.8	2.8	23.5	12.7	105.6
	Total	**41.4**	**344.8**	**130.7**	**1,088.4**	**382.0**	**3,180.4**

Source: ACIL Allen (2018)[72]

[72] ACIL Allen (2018), 'Opportunities for Australia From Hydrogen Exports' <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>

Potential demand from Japan

Japan is one of the world's largest natural gas consumers, which, as it has minimal production, relies on imports to meet nearly all its demand.[73] Australia is the largest supplier of energy to Japan, with Japan purchasing one-third of Australia's LNG and coal exports in 2021.[74] However, as Japan seeks to decarbonise its economy, it is likely to seek to replace these imports with greener sources of energy. Hydrogen provides a potential alternative to LNG for energy use, and with constraints on its potential to generate green hydrogen from renewable energy, Japan could potentially import the majority of its green hydrogen demand.

The Japanese Government expects new fuels like hydrogen and ammonia to account for about one per cent of the electricity mix in 2030.[75] The government of Japan projects that hydrogen demand will be 3 million tons in 2030 and 20 million tons in 2050.[76]

ACIL Allen estimates that Australia could supply Japan with as much as 0.8 million tonnes of green hydrogen by 2030 and almost 2 million tonnes by 2040.[77]

Potential demand from South Korea

Like Japan, South Korea is a significant importer of energy which will shift to greener sources. The combined hydrogen production capacity in South Korea's three main petrochemical complexes is around 2 million tonnes. The government anticipates that the country's hydrogen demand will be 0.47 million tons in 2022, 1.94 million tons in 2030 and 5.26 million tons in 2040.[78] Currently identified hydrogen projects include:

- Daewoo Shipbuilding and Marine Engineering is studying the possibility of using ammonia as ship fuel.
- H2KOREA, a private-government body connecting central government and local government with private companies, has signed a memorandum with the Australian Hydrogen Council.
- KOGAS has signed an agreement with Australia's Woodside Petroleum to examine the feasibility of a green hydrogen pilot project. Almost all of South Korea's LNG imports are handled by KOGAS and the company aims to import 0.3 million tons of hydrogen by 2030 and 1.2 million tons by 2040.

By 2040, the Korean government aims to have 70 per cent of the country's hydrogen demand met by clean hydrogen (either produced from domestic renewable energy or imported from overseas).

ACIL Allen predict that Australia could export up to 0.2 million tonnes of green hydrogen to South Korea by 2030 and 0.6 million tonnes by 2040.[79]

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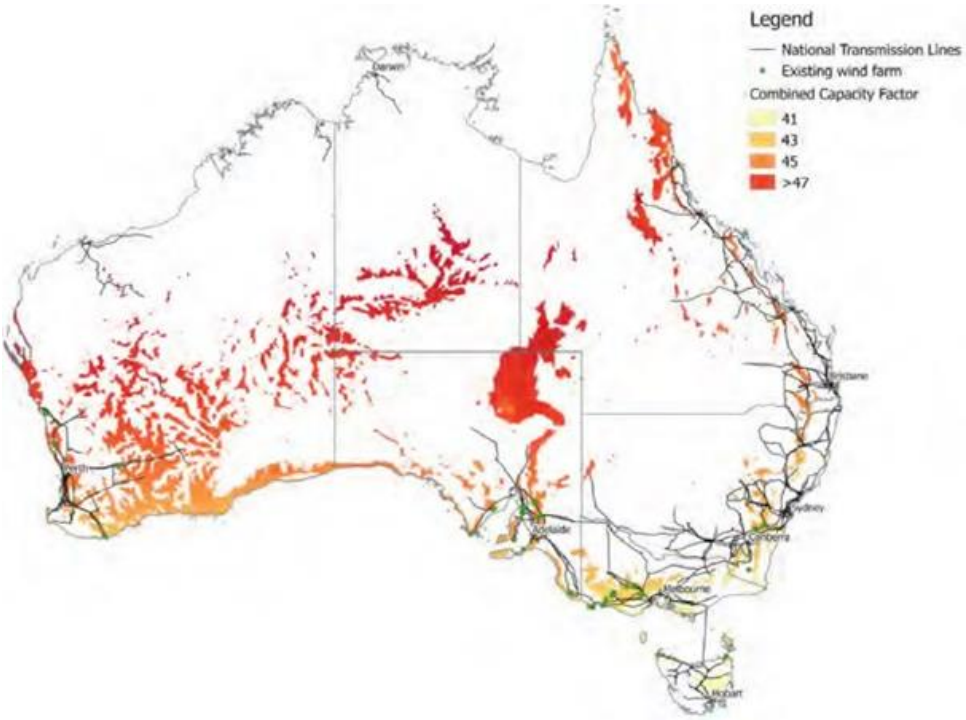
[73] <https://www.eia.gov/international/analysis/country/JPN>
[74] DFAT publication 'Composition of trade Australia'
[75] <https://www.reuters.com/business/energy/japan-boosts-renewable-energy-target-2030-energy-mix-2021-07-21/>
[76] <https://www.env.go.jp/seisaku/list/ondanka_saisei/lowcarbon-h2-sc/PDF/Summary_of_Japan's_Hydrogen_Strategy.pdf>
[77] ACIL Allen (2018), 'Opportunities for Australia From Hydrogen Exports' <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>
[78] <https://www.ifri.org/en/publications/editoriaux-de-lifri/edito-energie/south-koreas-hydrogen-strategy-and-industrial>
[79] ACIL Allen (2018), 'Opportunities for Australia From Hydrogen Exports' <https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf>

3.2 South Australia's advantages in green hydrogen

South Australia leads the nation in solar and wind energy penetration (see section 1.2), with renewables representing 62 per cent of energy consumed in South Australia in the 2020-21 financial year.[80] This high amount of renewable energy already being used in the grid may give South Australia a short-term advantage in attracting firms to locate their hydrogen production in South Australia.

More significantly, South Australia along with Western Australia has a number of regions with world-class co-location of solar and wind resources close to existing transmission lines or industrial areas, see Figure 3.4. Due to the high capital costs of hydrogen production, it is more efficient to be able to operate as close to 24 hours a day as possible. The co-location of wind and solar enables a hydrogen producer to produce more efficiently using solely renewable energy by giving them a higher effective capacity factor allowing them to produce for more hours per year.

Figure 3.4 Combined capacity factors of wind and solar resources.



Note: Combined capacity factor refers to the average capacity factor available from renewable energy if wind and solar are both deployed in a region
Source: AECOM (2016)[81]

The significant expected long-term downward trend in the cost of generating electricity using solar PV (and the moderate expected fall in wind costs) means that regions like South Australia where green energy is sourced from solar and wind are likely to have a significant medium-term cost advantage over regions whose green energy is sourced from hydroelectric, geothermal or nuclear power.

The Commission has also heard that South Australia's current electricity price dynamics (discussed in further detail in section 2.1) are advantageous for hydrogen producers.

[80] AEMO (2021), 2021 South Australian Electricity Report
[81] AECOM (2016), Co-location Investigation, prepared for ARENA, Sydney: AECOM, <https://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf>

Compared to other states, South Australia has a higher proportion of negative electricity prices during periods of high daytime solar production, but also a higher proportion of very high electricity prices. As a result, large scale hydrogen producers are capable of reducing the cost of electricity from the grid by operating during periods of low electricity costs but are also able to receive secondary revenues through Frequency Control Ancillary Services (FCAS) markets to shed their load during price spikes when their production may not be economic.

The Commission engaged the University of Wollongong to investigate whether these electricity price dynamics would continue following an expansion of hydrogen under the most expansive energy scenarios in the Australian Energy Market Operator's (AEMO)'s 'Draft 2022 Integrated System Plan for the NEM' – that is, both the step change and hydrogen superpower scenarios.

The analysis indicates that these favourable price dynamics are likely to continue under both scenarios. The frequency of negative spot prices is expected to increase slightly in comparison with recent market trends under both scenarios. The hydrogen superpower scenario would result in a more significant increase in the frequency of very low prices compared with the step change scenario.[82]

With significant new generation capacity expected over the next two decades in South Australia, it is also expected that market conditions for very high spot prices (more than $1,000/MWh) will occur less frequently in comparison with events recorded over the last two years, although the reduction is expected to be relatively small.

Finding 24: South Australia has potential competitive advantages in the development of a green hydrogen sector arising from it having:

- **regions with world-class combined wind and solar resources located close to areas suitable for green hydrogen production, reducing the cost of green hydrogen production; and**
- **a high frequency of very low spot electricity prices in the grid.**

South Australia has a history of favourable government policies for hydrogen, with strong bipartisan support for the expansion of renewable energy, and for hydrogen projects. For example, in 2019 the South Australian Government funded the development of the Hydrogen Export Modelling Tool and prospectus to promote South Australia as a location for hydrogen production and to inform potential proponents of indicative hydrogen export supply-chain configurations.

More recently, the South Australian Government's election commitment on the Hydrogen Jobs Plan 2022 involves the construction of a 200 MW hydrogen power plant in Whyalla, supplied by a 250 MW electrolyser and a 3,600 tonne hydrogen storage facility (see Box 3.1).[83]

[82] The full study is available on the SAPC website, Grozov, et. al. (2022) 'Analysis of historical wholesale electricity spot price volatility in South Australia and their projections in 2030 and 2040', University of Wollongong.
[83] South Australian Labor Party (2022), *Hydrogen Jobs Plan: Powering new jobs and industry for the future.* <https://uploads-ssl.webflow.com/612f07247ff286d66d81fe5c/61ea31da6864d0f9ebee539d_Final%20Style-Policy-Hydrogen%20Jobs%20Plan.pdf>

Box 3.1: South Australian Government actions on hydrogen

In September 2019, the South Australian government worked with industry to launch South Australia's Hydrogen Action Plan.[84] It builds on the government's Hydrogen Roadmap for South Australia, released in 2017[85] and has five objectives in scaling-up renewable hydrogen production for export and domestic consumption:

- Facilitate investments in hydrogen infrastructure
- Establish a world-class regulatory framework
- Deepen trade relationships and supply capabilities
- Foster innovation and workforce skills development
- Integrate hydrogen into our energy system

A key action of South Australia's Hydrogen Action Plan was the completion of a $1.25 million hydrogen export pre-feasibility study, online modelling tool and prospectus to support the establishment of an international-scale clean hydrogen export value chain. The prospectus outlines the results of a pre-feasibility export study and the tool provides an indicative view of the possible hydrogen export supply chain configurations and their production cost implications.

The proposed Hydrogen Production Act 2022 is intended to enable the licensing and regulation of hydrogen generation in South Australia, providing an equivalent licencing regime and one-window to government that is available to the petroleum industry under the existing *Petroleum and Geothermal Energy Act, 2000.*

The South Australian Government is also investing more than half a billion dollars to accelerate new hydrogen projects, shipping infrastructure and modelling tools for investors and developers.

Current government supported projects, include:

- Hydrogen Jobs Plan which includes the construction of a large-scale green hydrogen production facility and a hydrogen power station;
- AGIG's Hydrogen Park South Australia, a $14.5 million demonstration at the Tonsley Innovation District, the largest of its kind installed in Australia;
- Hydrogen Utility (H2U)'s development of the Eyre Peninsula Gateway Project at Cultana, providing a facility integrating more than 75 MW in water electrolysis to produce renewable hydrogen and renewable ammonia;
- Trafigura Group Pte Ltd's Green Hydrogen Project with Nyrstar, progressing plants to construct a commercial scale green hydrogen manufacturing facility in Port Pirie and
- Establishment of a Hydrogen Hub at Port Bonython to create a large-scale clean hydrogen production precinct for both export and domestic markets.

This support includes $17 million in grants and over $25 million in loans to three Megawatt-scale renewable hydrogen projects[86] and $593 million for the hydrogen jobs plan.
The Port Bonython Hydrogen Hub also received $70 million in federal funding and is expected to generate a further $40 million in private investment.[87] It has not yet been announced what the federal funding will be used for.

In 2021, the State Government short-listed seven potential projects at the hub involving the companies Santos, Fortescue Future Industries, Origin Energy, H2U, Neoen, Chiyoda, ENEOS Australia, Mitsubishi Australia and AMP Energy. At the time of writing the tender process to allocate industrial land in Port Bonython to some or all of the shortlisted projects is still ongoing.

The primary purpose of the Hydrogen Jobs Plan 2022 is to improve grid stability; however, it could also provide a boost to the establishment of a hydrogen industry in South Australia if it

[84] Department for Energy and Mining (2019), South Australia's Hydrogen Action Plan. Available at <https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-files/south-australias-hydrogen-action-plan-online.pdf>

acts as an early offtake market for private sector green hydrogen producers. The Commission understands that while market sounding is currently being undertaken, it is possible that a significant portion of the hydrogen required to run the power plant could be contracted from other projects, such as those potentially locating in the Port Bonython hydrogen hub. This presents an advantage for South Australia as a location for hydrogen businesses, as it will reduce the risk faced by prospective hydrogen companies by having some local offtake, also contributing to efforts to support greater economies of scale of production.

However South Australia is not alone in having government support for hydrogen. All of the other Australian states and territories have their own hydrogen plans, or actions under Australia's National Hydrogen Strategy.

3.3 Scale of potential opportunity in green hydrogen

As noted in section 3.1, the potential size of global demand for green hydrogen is a matter of great uncertainty. The scale of any potential industry in South Australia will depend on global demand for green hydrogen. However, there are several projects in South Australia that have either commenced or are currently being investigated.

Current projects

While details of proposed hydrogen projects are generally commercial in confidence, there are currently six publicly announced projects in South Australia. These are:

- The Hydrogen Jobs Plan 2022 proposed by the Government, involves the construction of a 200 MW hydrogen power plant in Whyalla, supplied by a 250 MW electrolyser and a 3,600 tonne hydrogen storage facility.[88]
- AGIG is running a demonstration project at Hydrogen Park South Australia comprising a 1.25 MW electrolyser at the Tonsley Innovation District, supplying hydrogen blended gas into the gas distribution network in Tonsley.[89]
- The Hydrogen Utility (H2U) – The proposed Eyre Peninsula Gateway Project would use an approximately 100 MW electrolyser to produce renewable hydrogen for use in green ammonia production on the Eyre Peninsula.
- Neoen Australia Hydrogen Superhub – Neoen Australia is investigating the possibility of constructing a green hydrogen production facility at its Crystal Brook Energy Park. It would be the largest co-located wind, solar, battery and hydrogen production facility in the world, capable of producing up to 25,000 kg of hydrogen per day.
- Trafigura Group – Port Pirie Green Hydrogen Project – is investigating plans to develop a $750 million hydrogen project to be integrated with the Nyrstar Port Pirie lead smelter. The project would be developed in stages, with the first phase producing 20 tonnes of hydrogen from an 85 MW electrolyser. At full capacity, it is

[85] Department for Energy and Mining (2017), *Hydrogen Roadmap for South Australia*. Available at: <https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-files/hydrogen-roadmap-11-sept-2017.pdf>
[86] South Australian Government Financing Authority (2022) *Hydrogen Action Plan.* <https://www.safa.sa.gov.au/environmental-s-governance/energy/hydrogen-action-plan>
[87] Spence, A (2022), 'Hydrogen plan fuels global interest', *InDaily*, 26 July, <https://indaily.com.au/news/2022/07/26/hydrogen-plan-fuels-global-interest/>
[88] South Australian Labor party (2022), *Hydrogen Jobs Plan: Powering new jobs and industry for the future*, <https://uploads-ssl.webflow.com/612f07247ff286d66d81fe5c/61ea31da6864d0f9ebee539d_Final%20Style-Policy-Hydrogen%20Jobs%20Plan.pdf>
[89] <https://www.agig.com.au/hydrogen-park-south-australia>

expected to produce 100 tonnes per day of green hydrogen from a 440 MW electrolyser.[90]

- AGL – Torrens Island green hydrogen hub – is leading a consortium to conduct a detailed feasibility study into the development of a green hydrogen production facility at its Torrens Island site.[91]

In addition, the South Australia Government is currently running a tender process for access to industrial land at Port Bonython, which will at least partially be zoned for hydrogen generation and processing.

Potential economic impacts

The Commission engaged The University of Adelaide to investigate the economic impact of the development of a new export-oriented green hydrogen facility in South Australia.[92] The study used a Computable General Equilibrium (CGE) modelling approach based on a scenario where a 1,500 MW hydrogen electrolyser was constructed at Port Bonython.[93] Under this scenario, the plant would produce 130,000 tonnes of hydrogen when fully operational, all of which would be exported. In the modelled scenario, the construction of the new green hydrogen plant and associated infrastructure would occur over the period 2023-24 to 2025-26, with the plant fully operational in 2026-27.

The study analysed the impact of such a green hydrogen plant with exports growing to $1,014 million by 2026-27 and continuing at that volume relative to a baseline with no green hydrogen production. Based on this analysis, the study found the following key macroeconomic net impacts in 2029-30 relative to the base case as follows:

- Gross state product is 1.4 per cent higher ($1.9 billion).
- Capital investment is 1.4 per cent higher ($380 million) after having, in the project development phase, reached a level 8.0 per cent higher in 2025-26.
- Overseas export volumes are 5.9 per cent higher ($900 million).
- Employment (employed persons basis) is 0.5 per cent higher (4,600 persons).
- Increase in employment is largely met from net migration to South Australia, so that population is 0.5 per cent higher – about 9,800 extra people in 2029-30.
- Real wages in South Australia are unchanged.

This modelling exercise compares a policy scenario in which there is both a substantial demand for green hydrogen from South Australia and a regulatory and planning environment that accommodates meeting that demand with one where the global trade in hydrogen does not eventuate.[94] The critical assumption is that demand conditions will be strong enough to deliver prices for green hydrogen high enough that a plant would be financially viable, but if that does some to pass the study indicates that green hydrogen production could deliver substantial benefits for the State.

[90] <https://www.renewablessa.sa.gov.au/hydrogen-in-south-australia/hydrogen-projects-in-south-australia>
[91] <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/june/agl-partners-with-industry-for-a-study-to-transform-torrens-isla>
[92] For additional information see, University of Adelaide (2022), 'Potential economic impact of transitioning South Australia's heavy industry and mineral sectors', <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-E-Potential-economic-impact-of-transitioning-South-Australias-heavy-industry-and-mineral-sectors.pdf>
[93] Department for Energy and Mining (2022), 'Hydrogen Export Modelling Tool', <https://hydrogenexport.sa.gov.au/>
[94] *Ibid* (University of Adelaide (2022))

Finding 25: An export-scale green hydrogen plant (1,500 MW electrolyser) would increase GSP by $1.9 billion and create an additional 4,600 jobs conditional on market prices for hydrogen being high enough to make its production financially viable.

3.4 South Australian barriers to a local hydrogen sector

Stakeholders noted a number of potential barriers to the establishment of a local green hydrogen sector. This section discusses potential barriers that are local, and section 3.5 outlines potential external factors that could act as a barrier to the development of a hydrogen export sector in South Australia. Local barriers included: offtake agreements; port infrastructure and management; land access; access to water; infrastructure corridors; and government approval processes.

Offtake

Currently, the merchant market for hydrogen in South Australia is negligible with virtually all hydrogen production closely linked with end-use. Viable long-term offtake schemes play an important role in validating hydrogen projects. As such, the uncertainty faced by firms in their ability to sell in the marketplace is a critical barrier in developing a green hydrogen sector. Estimates from the Commonwealth Scientific and Industrial Research Organisation (CSIRO) indicates that long-term 'take or pay' offtake agreements of 20 to 25 years with a flat demand profile will be the most favourable in the near-term to encourage investment.[95] The push and pull of supply and demand are a key source of uncertainty in the nascent green hydrogen sector and strategic planning is required to minimise risks.

From a South Australian perspective, given the smaller scale of heavy industry in the state, the low level of potential offtake demand is likely to be a disadvantage relative to states with a larger industrial base such as Western Australia, Queensland and New South Wales. Potential demand for large-scale green hydrogen from South Australia is likely to be in export markets in East Asia (and potentially Europe given current geopolitical tensions with Russia). As such the potential commercial viability and scale of green hydrogen in South Australia will depend on the decisions made in those markets around their decarbonisation pathways.

Finding 26: Development of a large-scale green hydrogen sector in South Australia will be dependent upon key potential markets, particularly in East Asia and Europe if these regions choose decarbonisation approaches that require substantial supplies of green hydrogen.

Management of ports

While South Australia's favourable wind and solar endowments are a key factor for large-scale investment in green hydrogen, the necessary infrastructure is not in place. In particular, the Commission has heard that the absence of a commercially managed port suitable for exporting hydrogen is a considerable barrier for developing a local green hydrogen sector.

If hydrogen exports are to eventuate from South Australia, the most likely source port would be Port Bonython in the Upper Spencer Gulf. The Commission notes that the South Australian government is in the process of developing a site plan for the establishment of a

[95] Bruce, S. et al. (2018) National Hydrogen Roadmap (CSIRO), 53

hydrogen production, conversion and export precinct in Port Bonython in collaboration with key private sector partners.[96]

However, at present Port Bonython is a small-scale hydrocarbon import/export port with a single jetty, very limited industrial facilities and effectively no central port management structures. Whilst small-scale hydrogen or ammonia exports may be able to be accommodated within the existing jetty infrastructure, large-scale hydrogen exports would likely require significant new infrastructure such as a new arm for the existing jetty or a new jetty.

Hydrogen exports, if they occur, will involve significant industrial activity at the port. At a minimum, if the hydrogen is produced elsewhere, this would require liquefaction of the hydrogen or its conversion to alternative compounds such as ammonia or metal hydrides for shipping. However, depending on the potential location of renewable energy, hydrogen production could occur at the port. This will require not only access to, and management, of land but will also require significant and complex infrastructure provision and management.

Although the recent expression of interest (EOI) process for development of projects in Port Bonython[97] has resolved concerns around access land, the ongoing complexity of designing and managing an industrial port remains unresolved. Once the EOI process is completed the government will need to rapidly set up a commercial management structure to oversee the various developments and manage the provision and operation of the infrastructure needed to support them.

A further constraint relates to conditions for access to the existing infrastructure. The Port Bonython Jetty was constructed by Santos and transferred to the State. At the time of the transfer, the State entered into an Indenture agreement with Santos under the *Stony Point (Liquid Project) Ratification Act 1981* which granted Santos full exclusive priority use of the jetty facility. The Commission understands that under the terms of the Indenture, Santos can effectively claim exclusive use of the jetty by providing 48 hours' notice. While this management system is appropriate under current demands for the jetty, where Santos is the primary user of the jetty, and which is used by under 40 vessels per year on average, this could provide a potential barrier to large-scale hydrogen exports from Port Bonython.

Finding 27: The lack of a commercial port is a constraint on the development of a large-scale green hydrogen export sector.

The Port of Gladstone Authority in Queensland has been identified by a number of stakeholders as a model for the management of a port with a significant industrial component. While this model would be costly and unnecessary for current demand at Port Bonython, there is value in the State Government preparing for options should a large-scale hydrogen export industry develop. Any commercial management of the port would need to address issues such as access to infrastructure within the port, prioritising access between potential users, identifying additional port infrastructure that may be needed and managing the construction of new infrastructure connections into the port and out of it.

Land access

Stakeholders raised access to land as another key barrier to developing green hydrogen projects in South Australia. The emergence of green hydrogen as a potential industry has

[96] <https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/port-bonython-export-hub>
[97] *Ibid*

transformed land that was earlier considered commercially unviable for renewables development to now be suitable for such use.

High marginal loss factors of transmitting power south may mean that hydrogen production is lower cost in the far north away from the NEM, in which case water would need to be piped up to the hydrogen production facility, and hydrogen piped back down to a port or local user. As a result, more renewable energy projects are considering northern areas of South Australia, where land access may involve pastoral leases, native title or crown land, adding another layer of complexity and uncertainty.

Developing multi-use infrastructure corridors is a key consideration, as hydrogen projects will require infrastructure to transport electricity, water and hydrogen. Issues relating to land access are discussed in detail in section 2.4 for freehold land and section 2.5 for issues relating to access to pastoral leases

Lack of water

Hydrogen production requires long-term reliable access to clean water, with approximately nine litres of water required to produce one kilogram of green hydrogen.[98] South Australia is the driest state in the world's driest inhabited continent. Given the scarcity of water in regions that are considered ideal for hydrogen production, but also for the state as a whole, securing water access is crucial for the development of a viable green hydrogen sector. Most hydrogen proponents have suggested that this can be addressed through desalination with the cost of desalination estimated at approximately five cents per kilogram of hydrogen produced.[99]

Finding 28: Lack of high-quality water in the most prospective regions is a potential barrier to a green hydrogen sector developing in South Australia.

The Commission notes that the Northern Water Supply project, which is considering a new coastal desalination plant and a new pipeline to transport water to the north of the state to support mining projects, could be equally important to hydrogen production.

Recommendation 10

Planning for the Northern Water Supply project considers the most cost-effective capacity to meet potential future water needs of green hydrogen and green minerals sectors.

Infrastructure corridors

Green hydrogen production requires large amounts of both electricity and water. Given this, producers can either locate close to demand centres (likely ports or industrial areas) and transmit electricity to the production site, or co-locate with renewable energy and establish pipelines to transport water to and hydrogen from the facility.

[98] *National Hydrogen Strategy* (p12) < https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy>; International Renewable Energy Agency (2020), *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goa*l, 26, 30), <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf>

[99] Government of South Australia (2020) '*South Australia's hydrogen export prospectus'* <https://www.renewablessa.sa.gov.au/documents/hydrogen-files/south-australia-hydrogen-export-prospectus.pdf>, 13

The development of infrastructure to support hydrogen production and transportation (such as water pipelines, electricity transmission lines and gas pipelines) is governed by the *Planning, Development and Infrastructure Act 2016* as well as specific regulations related to specific infrastructure. For example, the transportation of hydrogen is regulated under the *Petroleum and Geothermal Energy Act 2000* and the transmission of electricity is governed by the *Electricity Act 1996*.

The Commission has heard that these infrastructure corridors can be relatively simply established through the planning system using overlays. However, the permission of landowners is required and given the potentially large number of landowners that these infrastructure corridors can cross, plus in many cases traditional owners, this process can be difficult for many companies.

The South Australian Government recognised water and infrastructure corridors as an important enabler (particularly for mining activity) as part of the Growth State strategy. The Commission understands that the South Australian Government has been undertaking a program of work to investigate the creation of a number of shared-use infrastructure corridors, primarily for the mining sector, to make it easier for companies to obtain permissions and access to infrastructure. While such corridors have yet to be established, and processes and governance issues remain around the use of such corridors, they could be a key enabler of a hydrogen industry through either: transmission of renewable energy to new hydrogen facilities and/or pumping water to hydrogen facilities co-located with renewable resources; and transporting hydrogen back to ports or industry.

Finding 29: Difficulties in establishing infrastructure corridors are as important for green hydrogen and renewable energy as they are for mining, and the location and design of any state sponsored corridors should enable their use for green energy projects.

The first such common use infrastructure corridor being considered is for the Northern Water project, being led by Infrastructure SA. This seeks to create a new sustainable water supply for the far north and Upper Spencer Gulf, predominantly to meet the needs of the mining industry. However, this is an area with high-quality renewable resources suitable for hydrogen production. A business case is currently being developed and the Commission understands final options have not been settled. For this project to be an enabler for hydrogen development, it will need capacity beyond the current needs of the mining industry.

Recommendation 11

The South Australian Government planning for common use infrastructure corridors includes possible future uses, such as green hydrogen and green minerals projects in addition to the requirements of current industry.

The Commission has heard that there have been issues in the process of obtaining an easement for electricity production. The *Electricity Act 1996* allows for an easement to be established for the transmission of electricity. However, the transmission of electricity for a company's (for instance transmission from a wind farm to an off-grid green hydrogen facility owned by the same firm) is not automatically eligible for this type of easement and would have to separately apply to be eligible, which increases project timeframes.

Employee skills base

As South Australia currently has a relatively small mining and resource sector, it has a less-developed skill base than a number of the other states in terms of employees with relevant skills and expertise in managing gas sector production, processing and export, and in delivering large-scale resource sector capital works. For example, at the 2016 Census, 1,544 South Australians were employed in 'Oil and gas extraction' and a further 120 were employed in 'Petroleum and coal manufacturing'. In Western Australia, there were 8,906 persons employed in 'Oil and gas extraction' and 790 persons were employed in 'Petroleum and coal manufacturing'. In Queensland the equivalent employment was 5,677 persons employed in 'Oil and gas extraction' and 1,049 persons employed in 'Petroleum and coal manufacturing'.

Government approvals

Currently, the *Petroleum and Geothermal Energy Act 2000* only covers naturally occurring hydrogen (often referred to as gold hydrogen). This means that, while the production of other forms of hydrogen such as green hydrogen is able to be approved, developments face significant uncertainty regarding approval processes and requirements placed upon individual projects. The Government has already recognised this issue and has proposed a new licensing arrangement for the manufacturing of other forms of hydrogen, including blue, grey and green hydrogen.

The proposed Hydrogen Production Act 2022 is intended to enable the licensing and regulation of hydrogen generation in South Australia, providing the same land access/licensing regime and one-window to government regulation that is available to the petroleum industry under the existing *Petroleum and Geothermal Energy Act.* All forms of hydrogen, including blue and green hydrogen are included under the proposed Act.

Government approvals are also a significant barrier to the development of the renewable energy needed for a green hydrogen sector, see sections 2.4, 2.5 and 2.6.

3.5 Potential external barriers to a South Australian hydrogen export sector

Competition from other Australian jurisdictions

Hydrogen as a potential industrial and export sector is being targeted by all states and territories in Australia, and in many jurisdictions internationally.

Reviewing the CSIRO's database of potential hydrogen projects[100] suggests that there are 92 unique hydrogen projects currently proposed in Australia (see Table 3.2). South Australia has 5 projects listed, the smallest number of any of the states. The greatest number of projects listed are located in Western Australia and Queensland which each have 28 projects.

These projects differ markedly in scale and scope, including a number that are focussed on domestic transportation use such as seed funding for refuelling stations. It is also not possible to assess at this stage how many are likely to actually be developed. Nonetheless the number of projects provides a good indication of the scale of interest in the hydrogen economy in other states, particularly Western Australia and Queensland.

[100] <https://research.csiro.au/hyresource/projects/facilities/>, accessed 21 July 2022

Some of the proposed projects are very significant in their scale. For example, the proposed Asian Renewable Energy Hub in the Pilbara region of Western Australia, led by bp, would require 26 GW of installed wind and solar and produce 1.6 Mt of hydrogen annually if it proceeded. This would represent between 270 per cent and 50 per cent of ACIL Allen's estimated range of total Australian hydrogen exports for 2040. This raises the potential that there may end up being relatively few hydrogen facilities needed to meet Australia's export demand unless international demand reaches the upper bound of current estimates.

Table 3.2: Proposed hydrogen projects identified by the CSIRO, by jurisdiction

State	Number of projects[a]
Western Australia	28
Queensland	28
Victoria	12
Tasmania	8
New South Wales	7
South Australia	5
Australian Capital Territory	2
Northern Territory	2

Note: a Projects that were purely funding schemes or which were duplicative, have not been included.
b The SA Government's Hydrogen Jobs Plan is not yet included in the database.
Source: CSIRO hydrogen projects database, <https://research.csiro.au/hyresource/projects/facilities/> as at 21 July 2022

Finding 30: The potential green hydrogen export sector is highly competitive, with a significant focus from both governments and international investors on opportunities across Australian states and territories. Currently South Australia has the smallest number of identified hydrogen projects of the states. This means that realising green hydrogen opportunities will require world class performance and competitive costs to deliver hydrogen to clients.

The geographic and industrial diversity of Australia also means that potential competitive advantages in hydrogen are present in many locations. For example, South Australia's most significant potential advantage in hydrogen production is generally thought to be its world-class combined wind and solar resource. But this advantage is shared with a number of locations in Western Australia, including the areas around Geraldton and the Pilbara.

Other desirable criteria for green hydrogen development, identified in Arup's study undertaken for the COAG Energy Council[101], appear to be more prevalent in other regions of Australia. For example, Port Hedland and Gladstone have extensive existing gas export port facilities and gas industry workforces. Port Hedland, Geraldton and Gladstone have private sector workforces and government agencies with extensive track records of successfully developing major industrial and resource projects. And Darwin, Port Hedland and Gladstone are significantly closer to potential markets.

Other states also have greater budgetary capacity than South Australia (see box 3.2 for a summary of South Australia's current fiscal position) to support the development of an export

[101] Arup (2019), 'Australian Hydrogen Hubs Study - Technical Study', COAG Energy Council Hydrogen Working Group, Issue 2, November, pp. 8-9

hydrogen sector due to their higher income from own source taxation revenue, stronger underlying budgetary position, and historically higher GSP growth rates which give greater scope to pay down debt through growth.

Box 3.2: South Australia's current budget position

South Australia, like many other jurisdictions across Australia and the rest of the world, is currently in a difficult budgetary and fiscal position.

The South Australian Government has three key fiscal targets:

Target 1: Achieve a net operating surplus in the general government sector every year.

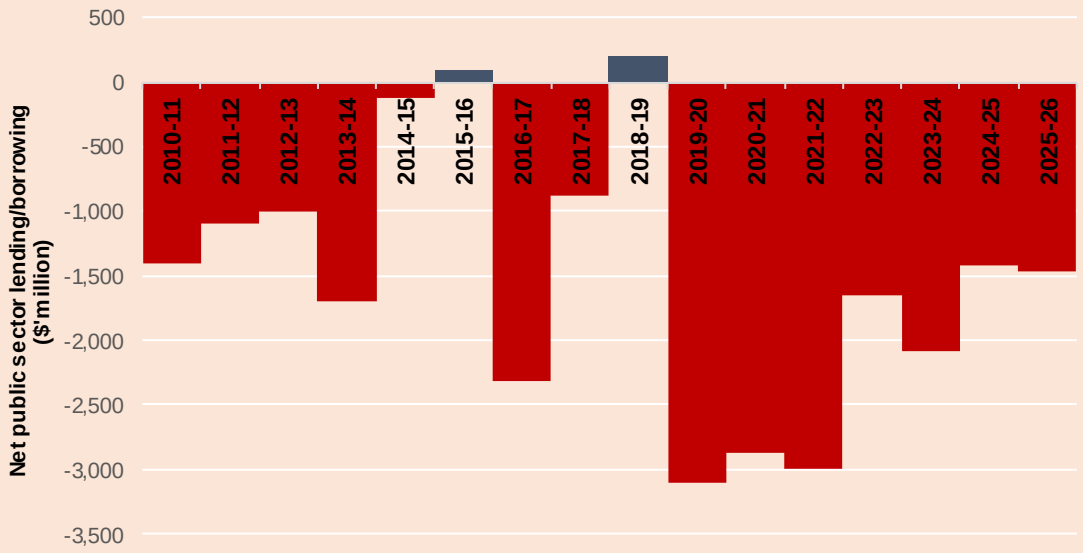
Target 2: Limit general government operating expenditure growth to trend growth in household income.

Target 3: Achieve a level of net debt that is sustainable over the forward estimates.

South Australia's budgetary position has weakened considerably since 2019, with general government revenue falling by 2.6 per cent in 2019-20 while expenses increased by 6.0 per cent over the same period. South Australia experienced budget deficits of $1.485 billion in 2019-20 and $0.563 billion in 2020-21.

Although operating expenditures are expected to return to a modest surplus from 2022-23, net public sector lending or borrowing indicates that overall expenditures will consistently exceed revenues over the forward estimates, driven by borrowing for capital spending (see Figure 3.5). Even once the Covid related impacts have washed out of the state budget by 2022-23, net borrowing will average more than $1.5 billion per year.

Figure 3.5: Net public sector lending or borrowing, South Australia, actual (up to 2020-21) and projected, $'million



Source: ABS[102] and South Australian State Budget, 2022-23

Target 2 limits the growth in the South Australian government operating expenditure to approximately 4 per cent per annum. South Australia's government operating expenditure is estimated to be $25.079 billion in 2021-22. It is budgeted to decrease to $23.554 billion in 2022-23, then increase over the forward estimates to $25.783 billion in 2025-26, a growth rate consistent with the target.

[102] Australian Bureau of Statistics (2002), Government Finance Statistics, Australia, 2020-21

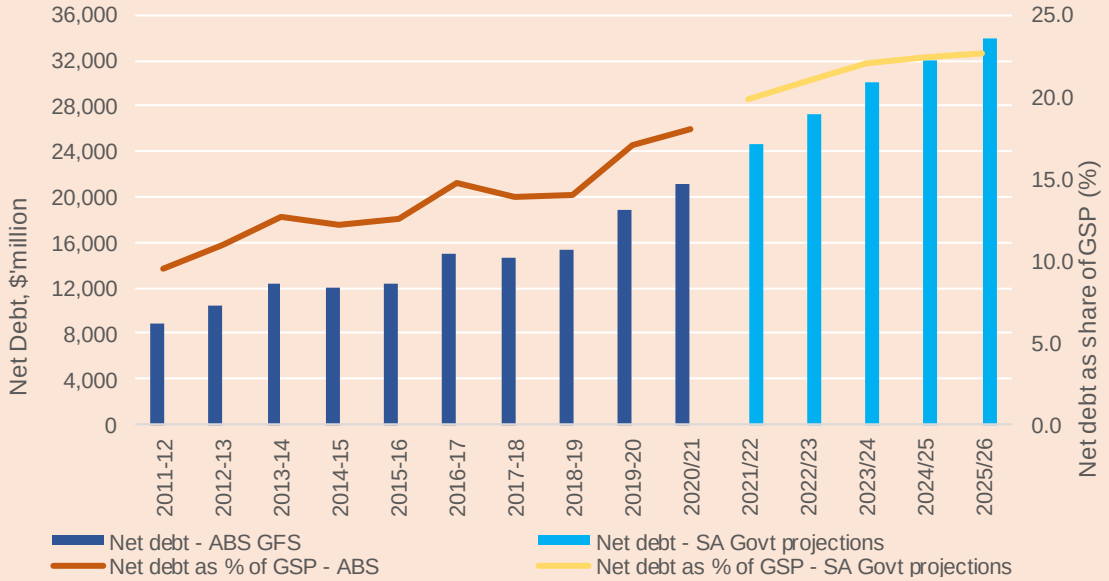
At the same time, the South Australian Government has detailed $2.1 billion in new operating expenditure initiatives in the general government sector over the next four years, in addition to $0.792 billion of new operating expenditure initiatives in 2021-22. These operating initiatives include significant new initiatives in health and wellbeing, education and child protection.

Target 3 requires the South Australian Government to maintain debt levels that allow for sustainable borrowings for investment in key infrastructure without placing undue burden on future generations.

Since 2019, South Australia's government net debt has grown considerably. Net debt in the non-financial public sector (NFPS) is also expected to grow over the forward estimates period, from $24.710 billion as at 30 June 2022, to an estimated $33.862 billion by 30 June 2026. This is largely due to the South Australian Government's infrastructure investment in the North-South Corridor, River Torrens to Darlington and the new Women's and Children's Hospital projects.

As a result of these infrastructure investments, the NFPS net debt to revenue ratio is forecast to increase from an estimated result of 100.6 per cent in 2021-22 to an estimated 122.4 per cent in 2025-26, Figure 3.6.

Figure 3.6: Non-financial public sector net debt, South Australia, actual and projected, $ million and% of GSP



Source: ABS[103] and South Australian State Budget, 2022-23

It is possible that some projects may end up located in regions that are in the second tier in terms of their suitability for hydrogen because of the cost advantages from direct subsidies, or from the provision of infrastructure. The significant New South Wales and Queensland government investment in green hydrogen and renewable energy opportunities are detailed in Boxes 3.3 and 3.4 below.

Finding 31: South Australia's poor budgetary position, and the poor historical (and current) economic growth performance constrains the extent to which the State Government can support the development of a local green hydrogen sector. Some other jurisdictions are offering substantial financial support to developers.

[103] *Ibid*.

Box 3.3 NSW Government support for hydrogen and renewables

NSW Hydrogen Strategy[104]

- This a framework to support the development of a commercial hydrogen industry in the state.
- The Strategy provides up to $3 billion of incentives to commercialise hydrogen supply chains and reduce the cost of green hydrogen by an estimated $5.80 per kg.
- It aims to produce 110,000 tonnes of green hydrogen per annum from 700 MW of electrolyser capacity for under $AU2.80 per kg by 2030.

To achieve these goals, the Strategy will:

- support industry to adopt green hydrogen;
- develop hydrogen hubs at major ports;
- build a hydrogen refuelling network for heavy vehicles along major highways;
- create a market-led framework to drive demand for green hydrogen; and
- waive a wide range of taxes and charges to reduce the cost of green hydrogen.

Net Zero Industry and Innovation Program:[105]

- This is to support industry to adopt green hydrogen. The program has $750 million available across three key focus areas of Clean Technology Innovation, New Low Carbon Industry Foundations and High Emitting Industries.

The Hydrogen Hub initiative:

- Up to $150 million in grant funding is available to support the development of hydrogen hubs at major ports in the Hunter and Illawarra regions. Hydrogen hubs are regions where various users of hydrogen across industrial, transport and energy markets are co-located to minimise the cost of infrastructure, and support economies of scale in producing and delivering hydrogen to customers.
- Funding is being prioritised for projects that can scale quickly and support increasing hydrogen demand, such as heavy transport deployment, and projects that support the creation of a distributed refuelling network.

Hydrogen Refuelling network:

- This is providing funding support for a hydrogen refuelling network along key strategic freight routes across NSW. As part of the east coast hydrogen refuelling network, the NSW Government has partnered with the Victorian Government to jointly fund a $20 million hydrogen refuelling initiative.

Green hydrogen and gas power plant:

- $78 million funding support has been allocated to create a foundational hydrogen offtake at the new gas/green hydrogen powered Tallawarra B power station in the Illawara.

2022-23 NSW Budget Measures[106] include:

- more than $2.5 billion allocated to the Climate Change Fund over 10 years to fund programs to reduce emissions and increase climate resilience;
- $300 million over 10 years in grants for new business activities related to low emissions materials,
- $1.2 billion net to accelerate the delivery of the new transmission projects required for Renewable Energy Zones (REZ)s (total gross investment, which is intended to be fully recouped, is $3.1 billion over the next 10 years);
- $250 million over five years for grants to businesses to competitively manufacture components for renewable energy infrastructure, electrolysers, electrification of plant, and electric vehicles; and
- $84 million over 10 years to accelerate the Electricity Infrastructure Roadmap to replace retiring power stations with new sources of clean, cheap and reliable generation.

[104] Department of Planning, Industry and Environment (October 2021), *NSW Hydrogen Strategy: Making NSW a global hydrogen superpower*. <https://www.energy.nsw.gov.au/sites/default/files/2021-10/govp1334-dpie-nsw-hydrogen-strategy-fa2_accessible_final.pdf>

[105] <https://www.energysaver.nsw.gov.au/reducing-emissions-nsw/net-zero-industry-and-innovation>

[106] <https://www.budget.nsw.gov.au/budget-papers/overview/building-brighter-future#Protecting-our-planet-and-growing-a-clean-economy>

Box 3.4 Queensland Government hydrogen programs

Hydrogen and Renewable Energy Jobs Fund[107]

- This is a $2 billion hydrogen and renewable energy jobs fund.
- The Queensland Jobs Fund includes a $350 million Industry Partnership Program and existing programs that support job-creating industries like renewable energy and hydrogen.

Training support includes:[108]

- $20 million towards a Queensland Apprenticeships Centre in renewable hydrogen; and
- $10.6 million towards a Hydrogen and Renewable Energy training facility.

Queensland Hydrogen Industry Development Fund (HIDF)[109]

$35 million has been committed by the Queensland Government for hydrogen industry development activities. Projects funded from Round One of the HIDF include:

- Australian Gas Networks Limited – up to $1.78 million to build a renewable hydrogen production facility and undertake a gas blending trial;
- Sun Metals Corporation – up to $5 million for integration of renewable hydrogen into potential applications including remote area power, transport and heavy industry; and
- Jilrift Pty Limited – up to $0.94 million to build a renewable hydrogen plant and demonstrate use of low-pressure hydride remote power systems at its eco-camps.

HIDF Round Two funding announcements include:

- SeaLink Marine and Tourism – $5 million contribution to a total project cost of $20.6 million to establish a hydrogen powered passenger ferry;
- Emerald Coaches – Up to $2.7 million in funding for Emerald Coaches to integrate two hydrogen fuel cell electric buses into its fleet; and
- Goondiwindi Regional Council – Up to $2 million HIDF funding support to integrate hydrogen production with wastewater treatment.

Other Hydrogen Expenditure includes:

- $15 million to support development of the Stanwell-Iwatani consortium's CQH2 hydrogen export facility in Gladstone;
- $600,000 in financial support over four years for the Future Energy Exports Cooperative Research Centre;
- $250,000 towards the QUT-led H2XPort renewable pilot plant hosted at the Queensland Government's Redlands Research Facility; and
- $100,000 to support the National Energy Resources Australia national hydrogen technology clusters program.

2022-23 Budget measures

There is funding of more than $2 billion in large-scale storage, renewable energy projects and generation and transmission investment.[110] This includes:

- $1.41 billion to improve electricity supply through Energy Queensland;
- $239.7 million investment in Powerlink to improve system reliability;
- $300.1 million investment in Stanwell including $85.1 million towards its $207 million Southern Queensland Renewable Energy Zone battery project;
- $47.3 million to build CleanCo's renewable and firming portfolio, including windfarm development and upgrades of pumped hydroelectric storage; and
- $10 million invested over two years as part of the Queensland Microgrid Pilot Fund.

[107] <https://www.epw.qld.gov.au/about/initiatives/hydrogen/investment-funding>
[108] < https://statements.qld.gov.au/statements/91080>
[109] <https://www.epw.qld.gov.au/about/initiatives/hydrogen/investment-funding>
[110] <https://statements.qld.gov.au/statements/95448#:~:text=The%20Palaszczuk%20Government%20has%20reaffirmed,and%20generation%20and%20transmission%20investment>.

Distance to international markets

South Australia is significantly more distant from potential key markets than potential locations for hydrogen production in the other states and territories, see Table 3.3. For example, Whyalla to Tokyo by ship is 5,959 nautical miles (nm)[111], but from Darwin the distance is only 3,376 nm, or 4,057 nm from Gladstone in Queensland. Similarly, Whyalla to Busan in South Korea is 6,197 nm compared to 3,048 nm from Darwin or 3,770 nm from Port Hedland.

Increased shipping distances increase costs of delivering hydrogen to international customers, both directly through fuel, crew cost and depreciation, and also potentially indirectly as when hydrogen is liquified for transport some of the hydrogen is lost to 'boil off' while the hydrogen is stored as a liquid. For example, Smith and colleagues (2022) estimate that plausible levels of boil off rate for liquid hydrogen shipping (assuming much higher insulation than an equivalent LNG carrier) are around 0.6 per cent per day,[112] so the addition 7 days travel time from Whyalla compared to Port Hedland would increase the cost of delivered hydrogen in Tokyo by around 5 per cent due to boil off alone.

Table 3.3: Distance to transport hydrogen to selected international ports from ports linked to potential Australian hydrogen hubs

Australian port	Distance to port of Tokyo (nautical miles)	Distance to port of Busan (nautical miles)
Port of Newcastle, New South Wales	4,648	5,140
Port Kembla, New South Wales	4,855	5,347
Port of Darwin, Northern Territory	3,376	3,048
Port of Gladstone, Queensland	4,057	4,550
Port of Whyalla, South Australia	5,959	6,197
Port of Bell Bay, Tasmania	5,253	5,745
Port of Hastings, Victoria	5,332	5,847
Port of Geraldton, Western Australia	5,108	4,669
Port Hedland, Western Australia	4,209	3,770

Source: http://www.shiptraffic.net/2001/05/sea-distances-calculator.html

International trade may not emerge (or only at a small scale).

There is considerable uncertainty about the international demand for trade in green hydrogen. Hydrogen is more difficult to transport than natural gas, requiring cooling to much lower temperatures to liquify it (−253 °C compared to −160 °C for natural gas). The cooling process significantly adds to the energy loss from the conversion of electricity into hydrogen.

The extent to which energy endowments are restricted to particular regions also changes with green hydrogen. In a hydrocarbon-based energy system, nations or regions either have an endowment of natural gas or they do not, and regions without those endowments need to import natural gas (or oil or coal). However, for green hydrogen the endowment needed is water and zero carbon electricity. This means that production location will be driven by the combination of local cost of production (with local green energy costs being the main

[111] All shipping distances calculated using <http://www.shiptraffic.net/2001/05/sea-distances-calculator.html>
[112] Smith J.R., S. Gkantonas E. Mastorakos (2022), '*Modelling of Boil-Off and Sloshing Relevant to Future Liquid Hydrogen Carriers*', *Energies*, 15:6, 2046, <https://doi.org/10.3390/en15062046>

variation) and the cost of getting green hydrogen from producers to users. For a current LNG importer such as Japan, green hydrogen imports will only occur if the cost of local production (using nuclear energy or offshore wind) is more expensive than the cost of producing green hydrogen elsewhere, liquifying it[113], and shipping it to Japan.

The other potential case in which an international hydrogen trade might develop is where the local green energy systems of existing natural gas users is only large enough to meet their domestic electricity demand and cannot readily expand to also enable green hydrogen production.

Finding 32: Green hydrogen is not tied to specific areas of the globe, and in theory any country could produce it. This means that the extent of international trade in hydrogen will be determined by whether imported green hydrogen is cheaper than domestically produced green hydrogen.

This means that for potential exporters the scale of the potential market will be driven by a combination of the decarbonisation pathways chosen by major energy importers (and therefore the overall demand for green hydrogen) and how cost effectively those current energy importers could generate sufficient non-greenhouse gas (GHG) electricity to make hydrogen within their own country.

It is possible that we could end up in a world where decarbonisation has been focussed on electrification, and hydrogen is only used as an industrial feedstock or source of high heat; and is made at the place of use with no domestic or international trade.

Alternatively, hydrogen could end up filling many of the uses that natural gas does currently, and be used in heavy transport, but the cost of international shipping of hydrogen could be so large that it is cheaper to produce it in-country, even for those countries with smaller renewable energy endowments. In this case whilst *demand* for green hydrogen may be high, *international trade* in it would be very low.

Finally, the world could end up with a decarbonisation pathway where hydrogen has a significant role in industry and transportation, and where either the cost of transporting hydrogen is low, or where the cost of green energy is sufficiently important in the costs of producing hydrogen that only regions with good renewable energy endowments produce substantial quantities of hydrogen. This latter case it the only one in which the full potential opportunities for green hydrogen exports considered in this chapter will be available.

The risks arising from uncertainty around international decarbonisation pathways can be managed through effective cooperation with trading partners. For example, a recent report[114] on the transition of the energy relationship between Australia and Japan has called for a bilateral dialogue to identify and respond to the risks involved. South Australia has an opportunity to engage with, learn from and contribute to that dialogue as it proceeds, demonstrating its advantages in the process. The agenda would draw on the experience of developing the LNG trade with Japan. It includes the matter of dealing with the risks of large-scale infrastructure investments, such as ports and processing facilities, which the market alone is unlikely to deliver.

[113] Or converting it to ammonia or other liquid hydrogen carriers such as metal hydrides and then re-converting it to hydrogen at the destination.
[114] Armstrong, Shiro (2021), *Reimaging the Japan Relationship: An agenda for Australia's Benchmark Partnership in Asia*, Australia-Japan Research Centre, Australian National University, Canberra.

Finding 33: An international trade in green hydrogen may not actually develop, and therefore the scale of potential opportunities in green hydrogen is very uncertain, and effective engagement with key trading partners is important.

3.6 Conclusion

The potential scale of the global industry and South Australia's renewable energy endowments make hydrogen a legitimate focus of government economic policy.

However, whilst the potential global and Australian opportunities from export-scale hydrogen production are large; they are subject to substantial uncertainty, resulting in significant and hard-to-manage risk. The most fundamental uncertainty relates to international demand for trade in green hydrogen, which is not a risk that can be directly mitigated through South Australian Government action.

Although South Australia has very favourable endowments of renewables due to world class combined solar and wind resources (and the benefits of these endowments is likely to increase over time as the cost of solar falls), this competitive advantage is shared with Western Australia. Queensland also has some areas of very good wind and solar resource, although those in areas in which it is feasible to build major renewables developments are not as good as the resources in South Australia and Western Australia.

South Australia also has a number of relative competitive disadvantages in establishing a large-scale green hydrogen export sector. As such, South Australia has a potential, but not a current, competitive advantage in green hydrogen. If enough of the competitive disadvantages were addressed, then it is possible that the state would gain a competitive advantage.

Different regions have different areas of relative advantage. Table 3.4 sets out an indicative, and partially subjective, assessment of Australia's potential hydrogen hubs against the criteria identified in Arup's study undertaken for the COAG Energy Council.[115] Gladstone in Queensland and Port Hedland in Western Australia are the regions which have more areas of apparent advantage.

Some of these aspects of relative disadvantage can be readily overcome by reversing SA Government policy choices that have adverse impacts on deployment of renewables. However other barriers are more fundamental and could require considerable resources to address. That does not mean that the state cannot secure opportunities in green hydrogen, but rather that it will require world-class planning and delivery, and a degree of luck.

[115] Arup (2019), 'Australian Hydrogen Hubs Study - Technical Study', COAG Energy Council Hydrogen Working Group, Issue 2, November, pp. 8-9

Table 3.4: Criteria for relative advantage as a hydrogen export hub, and subjective assessment of current apparent advantage

Criteria	Regions with an apparent advantage
Health and safety provisions	No information
Environmental considerations	No information
Economic and social considerations	No information
Water availability	Hunter, NSW Port Hastings, Vic., Bell Bay, Tas.
Land availability with appropriate zoning and buffer distances & ownership (new terminals, storage, solar PV, industries)	Geraldton, WA, **Port Bonython, SA** Port Darwin, NT
Availability of electricity grid connectivity, backup energy supply or co-location of renewables	Geraldton, WA, Port Hedland, WA, **Port Bonython, SA**
Road & rail infrastructure (site access)	Geraldton, WA Port Hedland, WA Gladstone, Qld Hunter, NSW,
Community and environmental concerns and weather. Social licence consideration	No information
Berths (berthing depth, ship storage, loading facilities, existing LNG and/ or petroleum infrastructure etc.)	Port Hedland, WA Gladstone, Qld Darwin, NT
Port potential (current capacity & occupancy, expandability & scalability)	Geraldton, WA Gladstone, Qld Darwin, NT
Availability of, or potential for, skilled workers (construction & operation)	Geraldton, WA Port Hedland, WA Gladstone, Qld
Availability of, or potential for, water (recycled & desalinated)	No information
Opportunity for co-location with industrial ammonia production and future industrial opportunities;	Geraldton, WA Port Hedland, WA Gladstone, Qld Hunter, NSW
Interest (projects, priority ports, state development areas, politics)	No information
Shipping distance to target market Japan South Korea	Darwin, NT Gladstone, Qld Darwin, NT Port Hedland, WA

Source: Arup[116]; assessment of hubs, SA Productivity Commission

[116] *Ibid*. (Arup (2019))

4. Green minerals – opportunities and challenges

4.1 South Australian minerals and opportunities from global energy transition

The global transition to a net zero economy will require a significant increase in green energy generation, electricity transmission and electricity storage as, in many cases, increased electrification will be the least-cost method of decarbonising economic activities.

This is likely to substantially increase demand for a number of base metals, some of which are relatively abundant in South Australia. Potential opportunities exist around:

- **Copper** Unpublished analysis by the Department of Energy and Mining (DEM) indicates that South Australia has around 67 per cent of Australia's economic demonstrated resource (EDR) of copper.
- **Magnetite** This is a form of iron ore which requires less energy-intensive beneficiation than the haematite that currently dominates global steel production, and is consequently regarded as more suitable for green steel production. DEM analysis indicates that South Australia has 44 per cent of the EDR for magnetite ore in Australia.
- **Critical minerals** South Australia already has deposits of zircon and graphite in commercial production. South Australia also has deposits of a number of critical minerals identified by Geosciences Australia as being required for the clean energy transition, including the Rare Earth Elements, gallium and indium, as well as graphite (65 per cent of Australia's DER uses graphite based on DEM analysis).
  Some of these critical mineral deposits are co-located with existing minerals and so there may be opportunities for processing of tailings dams of existing mines depending on the competitiveness of local production costs.[117]

Many of these deposits are not currently economic at prevailing market prices but as global demand increases, prices may also increase, expanding the scale of commercially viable mining in South Australia. The extent to which this occurs will depend on the supply response from the rest of the world and cannot be accurately predicted in advance.

In addition to the potential benefits to the State's mining output, a number of stakeholders have identified opportunities in additional processing of South Australian minerals. Currently most South Australian minerals (and, indeed, most Australian minerals) are exported as unrefined ores as the increased transport cost is more than outweighed by the economies of scale achieved by large international processors.

Investor, customer and government[118] concerns about scope 3 emissions (i.e. the emissions generated when Australian minerals are refined, usually overseas) may also create demand for refined metals that can be certified as low-carbon intensity or zero carbon. If this happens then opportunities are likely to arise for South Australian minerals producers to extend the value chain and refine the ores they are mining.

[117] Geosciences Australia (2013), *Critical commodities for a high-tech world: Australia's potential to supply global demand*, < https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/76526>
[118] The European Union's proposed carbon border adjustment mechanism is a good example of emerging government focus on scope 3 emissions.

Finding 34: As global demand for critical minerals increases, a number of deposits which are currently uneconomic may move into production. If South Australian deposits can be extracted at a competitive cost the State may see a substantial increase in mining output over the next 30 years.

If decarbonisation were to increase international shipping costs, and if South Australian power prices were to fall in the future relative to existing locations of mineral processing such as China, Japan and South Korea, then it may be more cost effective to refine minerals in South Australia rather than export ores. But for this to occur, the high prices faced by South Australian-based electricity users would first need to be reduced to competitive levels.

4.2 South Australia's competitive advantages in green minerals

To better understand the South Australian mineral sector's perspectives on the opportunities and challenges for the sector from the global energy transformation, the Commission engaged a team from The University of Adelaide's Institute for Sustainability, Energy and Resources to undertake extensive consultations with the sector and analyse the implications of the industry feedback. This section, and section 4.4 draw extensively on that report.[119]

Key potential competitive advantages for South Australia in the green minerals sectors identified though the consultations with industry include:

- large deposits of magnetite and copper ore (44 per cent and 67 per cent of the demonstrated resources in Australia);
- South Australia's world-class combined wind and solar resource, with excellent resources available close to the potential location of minerals refining, reducing the cost of 'firming' renewable energy (minerals processing needs a consistently available power supply) and reducing transmission costs;
- the ability to undertake minerals processing relatively close to the mine site due to the state's wind and solar energy resources, potentially reducing transport costs;
- low middle-of-the-day electricity prices due to the abundance of rooftop solar energy;
- Australia being seen as a reliable strategic partner by the US and other western governments, creating the potential to secure price premia for rare earth elements and other critical minerals; and
- the potential for green hydrogen, which is likely to be an essential component of many green minerals supply chains, to be relatively cheaper in South Australia given the favourable renewable energy endowments, particularly the co-location of wind and solar.

4.3 Scale of potential opportunity in green minerals

The Commission engaged The University of Adelaide to investigate the economic impact of the additional downstream minerals processing in South Australia.[120] As was the case for the modelling of the potential impact of green hydrogen, the study used a Computable General

[119] Wagner, L., A. Chinnici, C. Spandler, N. Cook, W. Saw, G. Nathan, and M. Goodsite (2022), 'Potential for SA in additional processing of SA's minerals deposits', report prepared for the South Australian Productivity Commission, <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-A-Potential-for-SA-in-additonal-processing-of-SA-minerals-deposits.pdf>

[120] For additional information see, University of Adelaide (2022), 'Potential economic impact of transitioning South Australia's heavy industry and mineral sectors', <https://www.sapc.sa.gov.au/inquiries/inquiries/south-australias-renewable-energy-competitiveness/commissioned-research-to-support-the-inquiry/Question-E-Potential-economic-impact-of-transitioning-South-Australias-heavy-industry-and-mineral-sectors.pdf>

Equilibrium (CGE) modelling approach based on a scenario where a large South Australian copper/gold mineralisation project with annual output of 60 kt for copper and 100koz for gold (or roughly the order of magnitude of Prominent Hill or Carrapateena) decided to export refined metal rather than ore. It was assumed that there would be no additional mining activity (e.g. the mine would proceed in the base case as well as the impact scenario), and that energy requirements of the refining would be met through additional South Australian renewable energy.

The study analysed the impact of such a mineral processing plant which by the time it reached full output in 2026-27 would increase refined non-ferrous metals exports by $889 million at 2021 average prices and would continue at that volume relative to a baseline with no additional metal refining. Based on this analysis, the study found the following key macroeconomic net impacts in 2029-30 relative to the base case:

- gross state product is 0.3 percent higher ($0.4 billion);
- capital investment is 0.4 percent higher ($180 million) after having, in the project development phase, reached a level 1.2 percent higher in 2025-26;
- overseas export volumes are 4.9 percent higher ($800 million);
- employment (employed persons basis) is 0.3 percent higher (2,400 persons);
- the increase in employment is largely met from net migration to South Australia, so that population is 0.3 percent higher – about 5,000 extra people in 2029-30; and
- real wages in South Australia are virtually unchanged.

Impacts from a potential green iron sector are likely to be significantly larger given the larger average project size but require substantially higher private sector investment.

This modelling exercise compares a policy scenario in which there is a substantial increase in demand for 'green' copper from South Australia, or in which the cost of refining copper and/or of transporting ore, increases sufficiently to overcome the current cost disadvantages of undertaking refining activity in South Australia. In the base-case scenario South Australia's relative demand or relative cost for green copper does not increase sufficiently to result in additional mineral processing in the State.[121]

4.4 Barriers to the development of a South Australian green minerals sector

At present, substantial mineral processing activity is located in those few regions where the processing activity is large enough to achieve economies of scale. As a result, it is more cost effective for mining jurisdictions to export ores and for those to be processed in those major industrial hubs where there are economies of scale.

Substantial mineral processing could relocate to South Australia if the transition to green minerals shifts the relative costs such that South Australia's potential green minerals advantages in terms of abundant green energy resources close to potential mineral processing locations, and relatively short transport distances between mining locations and processing are large enough to outweigh the benefits of economies of scale in existing minerals processing hubs.

Finding 35: There is a potential opportunity from increased minerals processing, but it will depend on the cost of shipping and on reducing wholesale power costs in South Australia.

[121] Ibid. (University of Adelaide (2022))

One of the main potential barriers identified from industry consultations is the extent to which the state's renewable energy supply would need to increase, and be effectively firmed from zero-carbon sources, to supply the energy needs of new processing facilities at a competitive cost. These electricity needs are likely to be GW-scale both for the direct use of electricity, and to generate green hydrogen for those industrial processes that cannot be electrified. This transition to GW-scale renewable energy will require planning and investment to ensure a reliable energy supply by incorporating storage and/or net-zero hydrogen. It will also need resolution of those approvals-related barriers to renewable energy discussed in sections 2.4, 2.5 and 2.6.

Additional energy needs are likely to be particularly significant for a potential green iron sector (through the export of direct reduced iron or pelletised magnetite rather than iron ore). Industry consultations suggest that there would be a requirement for an additional consistent supply of around 10 GWh of firm greenhouse gas free electricity (over six times the current average generation in South Australia). Such a large-scale expansion of net-zero electricity would require the consideration of all options for firming, targeting first the regions where new investments are most likely.

The estimated cost of this 10 GW of firm green energy supply (which would be delivered through something like an addition to capacity of 18 GW of new wind and 14 GW of new solar, firmed with storage of >200 GWh) would be of the order of ~$90 billion. To give an indication of the scale of renewable energy required for this type of project, current South Australian installed capacity is 2.1 GW of wind and 0.4 GW of grid-scale solar PV. This means the potential green iron sector alone would require nine times more wind energy than the state currently uses, and 35 times as much grid-scale solar as currently generated.

Finding 36: Green iron developments would require very significant amounts of renewable energy, and this could not be delivered without addressing current barriers in the approvals systems. It is also likely to require very substantial increases in transmission infrastructure in the state.

The second potential barrier highlighted by industry is the potential cost of green hydrogen needed to be competitive in minerals processing. Green minerals value chains are likely to require substantial quantities of green hydrogen. Most industry stakeholders reported that green hydrogen would need to be available in South Australia at a cost substantially below its current levels for green minerals projects to be economically viable.

Twenty-seven per cent of industry stakeholders consulted reported that green hydrogen would need to cost $1/kg; 27 per cent reported $2/kg as their competitiveness threshold and a further 36 per cent nominated $3/kg or less (costs based on current electrolyser capital costs and current solar PV costs estimated at around $5/kg). Achieving such costs would require both substantial reductions in the cost of green electricity (which is likely to be achieved at a production level because of the expected cost reductions for solar and wind, but it is not yet clear whether these cost reductions will flow through to electricity users), and significant cost reductions for electrolysers.

The facilitation of exports was of concern to minerals sector stakeholders, a number of whom identified the need for the upgrade and expansion of deep-sea ports. Without the ability to access additional port facilities that can accommodate the rapid expansion of green commodity exports from the state, the sector would face a significant barrier to market entry. In particular, green iron ore and its derived products would be at a disadvantage in global markets.

Finding 37: As is the case with the potential green hydrogen export opportunity, the relative lack of suitable export ports is a barrier to green minerals development.

Market access to sufficient water resources within the state will also be vital in, or a potential limiting factor to, the further expansion of the iron/steel sector in South Australia. Water is expected to be a limiting resource for the production of net-zero hydrogen via electrolysis and for the beneficiation/upgrading of iron ore. Hence a means to make sufficient quantities available, at a competitive price was also identified as a priority by industry.

Finding 38: Lack of availability of suitable quality water is likely to be a barrier for potential new green minerals developments.

Many processing activities undertaken at mine sites, such as crushing and grinding, are energy intensive and are regarded as difficult to electrify.

Extracting critical minerals from existing South Australian ore bodies (and potentially from tailings and other mine waste) is regarded as potentially feasible but the optimal approaches are not yet understood.

Targeted research and development (R&D) focussed the use of leachate techniques (which reduce the need for crushing and grinding) on South Australian specific ore compositions could facilitate low-energy use development of the state's mineral resources, and allow a better assessment of the prospect of undertaking critical minerals mining in concert with more traditional deposits. Given the timelines of R&D it would be prudent to start such activity in the near term.

Recommendation 12

The State Government supports research and development relevant to the green minerals sector around optimising leachate-processing approaches and exploring the opportunities to extract critical minerals from existing base metals deposits.

5. Enhancing competitive advantages from renewables and enabling economic development

Despite the range of barriers identified in this inquiry, it remains the case that renewable energy has the ***potential*** to deliver competitive advantages for South Australia. However, a necessary precondition for realising any of these potential benefits is addressing the factors that are delaying the large-scale expansion of wind and solar power in South Australia and getting in the way of consumers realising the gains from falling spot market electricity prices. This makes the renewables sector itself the most immediate focus.

If these policy barriers can be addressed (see short term priorities below), and the State is able to secure reductions in electricity costs as a result of its endowments, then other potential opportunities may emerge (see medium- and longer-term priorities).

Short-term priorities

At the core of any potential benefits from renewable energy is the expected significant ongoing falls in the cost of grid-scale solar PV power and continued falls in the cost of wind power, which if they are passed through to energy users will reduce costs for all electricity users, and potentially enable new industries such as green hydrogen and green minerals (see section 5.1). Without those cost reductions, and the ability to readily install large amounts of renewable energy, none of the other opportunities can be realised. This process may also require reforms to the National Energy Market (NEM) (see section 5.2).

This means that addressing the barriers facing renewable energy deployment are the most pressing issue for the State Government in terms of helping to realise the state's potential competitive advantage from renewable energy. This is the case, not only because of the direct benefits of facilitating lower power prices and decarbonisation, but also because of the role of renewables as an enabler for other opportunities.

To the extent that potential opportunities exist in data centres and similar electricity intensive sectors, addressing the factors inhibiting the roll out of wind and solar PV in South Australia, and the factors that limit the pass through of low spot-market electricity prices to consumers, will provide significant support without the need for any further action.

Medium term priorities

If the State Government is able to remove enough of the barriers facing the deployment of renewable energy in the state, and the barriers preventing electricity users from realising the benefits of the low spot prices, steps to remove impediments to development of a local green hydrogen sector are a reasonable medium-term priority in realising the State's potential competitive advantage from renewable energy.

Longer-term priorities

The potential opportunities for the State around green minerals will be dependent on both low cost and abundant renewable energy, and the availability of competitively priced green hydrogen. This means that seeking to facilitate green minerals opportunities is a longer-term potential priority as it will only be feasible if both barriers to renewables are addressed, and a local green hydrogen sector emerges. The longer (and medium) term objectives will only be captured as uncertainties in export markets are resolved.

Finding 39: Activities to help realise competitive advantages from renewables have a logical sequence. A prudent approach to managing risks would involve an initial focus on facilitating the roll out of renewables, then to green hydrogen, and finally only moving on to green minerals if the renewables and green hydrogen are successful.

Recommendation 13

The State Government should sequence its activities around the opportunities from renewable energy, with an initial focus on addressing the barriers to renewable energy development.

5.1 Shift government from a barrier to an enabler for renewables

The first step the State Government can take to increase the chance that South Australia can secure competitive advantages from renewable energy is to reform those policies and procedures introduced by South Australian Government agencies that make it harder and more expensive to install renewables. As discussed in sections 2.4 and 2.6, South Australia has shifted from having the most favourable planning regime in the NEM to a planning regime that is less favourable than other states.

Impediments to renewables have been created through the planning system, with the introduction of setbacks and a major projects approvals system that is regarded as slow, opaque, error prone and difficult to navigate.

The Office of the Technical Regulator (OTR) (the SA Government body which regulates electricity) introduced a generator connection standard after the system black event which requires each new power plant to either provide inertia or fast frequency services to the grid (see section 2.6). This adds substantially to the cost of new renewable projects in South Australia compared to those located interstate, increasing the cost by around 10 to 20%.

At the time the OTR introduced the requirements it was a plausible emergency measure reflecting uncertainty about how well system stability was being managed. But despite the Australian Energy Market Operator (AEMO) introducing several measures aimed at improving the stability of South Australia's grid the OTR has retained the requirements.

Recommendations 1 (setbacks), 2 (reforming major projects processes), and 9 (removing the OTR's generator connection requirement) of this inquiry set out a pathway for the South Australian Government to stop its own agencies from acting as an impediment to renewable energy opportunities.

Should the South Australian Government be interested in facilitating development of a large-scale hydrogen sector it will also likely be necessary to address those aspects of the management of pastoral lands that make the location there of green energy projects that are not wind power very difficult. This is because the areas of South Australia with the best co-location of excellent wind and solar resources (and the only parts of South Australia that match the combined wind and solar resource on the central coast of Western Australia for their combined capacity factor) are located on pastoral lands in the state's north.

Recommendations 3 (extending the favourable treatment of wind power to any renewable generation), 4 (modernise processes around the approval of renewable energy developments on pastoral lands), 5 (requiring data sharing by those granted exploration

licenses for renewable energy) and 6 (giving certainty to pastoralists around the financial implications of renewable developments on their lease) set out proportionate measures the State Government could take.

All of these policy settings are within the direct control of the State Government and are therefore easiest to affect. However, fully realising the benefits of renewables and securing an efficient energy transition will also require actions at the NEM level. Potential policy initiatives are discussed in section 5.2.

5.2 Facilitating the renewable energy transition

As discussed in section 2.2, the current operations of the South Australian region of the NEM, in particular the illiquid hedging market, and the lack of incentives for new on-demand electricity supply, mean that consumers are seeing little of the benefits of falling spot market prices. The Commission is also concerned that current aspects of the NEM either inhibit the energy transition or get in the way of electricity users realising the benefits of low-cost solar and wind power.

Optimising the NEM for the renewable energy transition is beyond the scope of this inquiry, and as such we have not made any recommendations concerning that topic. Policy intervention in these areas will in most cases need to be national (or at least at the NEM level), and so in most cases the role for the South Australian Government would be primarily one of advocacy within national forums. Policies that would facilitate the transition to renewable energy whilst minimising the costs to electricity consumers potentially include:

- strategic planning of infrastructure needs for grid stability and system strength in a decarbonised grid, tarting from the requirement of a fully decarbonised grid and then working back down the expected trajectory to a decarbonised grid identifying what will be required, and by when;
- undertaking a review from first principles of the current NEM market structure and pricing rules including assessments of alternative market structures used in other countries to identify whether the current system is optimal in terms of facilitating a transition to a stable, renewable energy-based power system, at low cost to consumers;
- making the case for national price incentives for green storage. The renewable energy storage target proposal recently advanced by Bruce Mountain and colleagues at Victoria University[122], and the approach proposed by Tim Nelson and colleagues at Griffith University[123] to use a modified version of the existing retail reliability obligation to fund the establishment of a capacity reserve (with the carbon intensity of suppliers of on-demand capacity being gradually reduced) both seem promising approaches. Governments could also undertake more direct action such as using the Clean Energy Finance Corporation to provide very cheap finance to green storage projects as a subsidy, or by directly supplying green firming services themselves, as will be the case with the South Australian Hydrogen Jobs Plan;
- facilitating an increase in the number of providers of on-demand electricity supply in South Australia, particularly of zero greenhouse gas supplies such as long-duration

[122] Mountain, B., P. Harris, T. Woodley and P. Sheehan (2022), 'Electricity storage: the critical electricity policy challenge for our new Government. A policy proposal', <https://www.vepc.org.au/_files/ugd/92a2aa_3abddb7f37994760b86e0c921a692b5b.pdf>

[123] <https://www.energy.gov.au/sites/default/files/2022-08/Iberdrola%20Response%20to%20Capacity%20Mechanism%20Project%20High-level%20Design%20Paper_Working%20Paper.pdf>

batteries, green-hydrogen fuelled power plants and pumped hydroelectric power plants; and
- reviewing market rules that potentially allow large energy suppliers to influence prices. Depending on the findings of the review this could potentially include banning or restricting re-bidding, and/or banning or restricting internal transactions within vertically integrated 'gentailers', requiring all transactions to occur in the spot market or the publicly traded hedging markets.

5.3 Maximising the potential opportunity from green hydrogen

The most potentially significant opportunities for the state to come out of renewable energy transition, should the barriers to renewable energy development in South Australia be addressed, are likely to be around green hydrogen, either for export or for use in green minerals projects.

As discussed in Chapter 3, South Australia (along with Western Australia) has a competitive advantage in green hydrogen production because it has regions with world-class co-location of wind and solar resources. This allows renewable power to be produced through more hours of the year, reducing the cost of producing green hydrogen as the high capital cost of the electrolyser is spread over a greater volume of hydrogen.

However, as discussed in section 3.5, there is considerable uncertainty about the eventual scale of the international trade in green hydrogen. This uncertainty, at least in terms of the scale of the potential opportunity for South Australia, is compounded by the significant focus on hydrogen opportunities in other jurisdictions. At the lower end of the plausible estimates for Australian exports, demand could be satisfied by a single large project such as bp's proposed Asian Renewable Energy Hub in the Pilbara.

There remains considerable uncertainty around the international demand for hydrogen. There are options at the national level to work with trading partners to reduce those uncertainties, which will also provide important intelligence for South Australia and opportunities for the state to demonstrate its competitiveness. However, even if the international trade in renewable hydrogen proceeds at a scale that makes multiple projects around Australia feasible, South Australia has several sources of competitive disadvantage which risk partially or wholly offsetting the advantages provided by the state's renewable energy endowments (see the discussion in section 3.4). The most significant elements of competitive disadvantage are:

- limited access to relevant skills because of the small existing gas sector workforce in the state;
- gaps in infrastructure, particularly a port or ports with the infrastructure and berthing facilities required for large-scale gas exports;
- lack of access to suitable water in the most suitable areas for green hydrogen production;
- lack of relevant experience in the construction sector of successfully developing large-scale gas sector industrial infrastructure, and lack of experience in government of successfully facilitating such developments,
- significantly greater distance to key markets that other prospective sites in Australia; and
- lack of local offtake opportunities to kick-start the sector before export opportunities emerge.

Green hydrogen opportunities in South Australia are entirely dependent on the ability to install abundant, low-cost, wind and solar PV generation. Undertaking the steps outlined in section 5.1 to address policy related barriers to renewable energy investment in South Australia is a necessary, but not sufficient, condition for realising the potential green hydrogen opportunities.

The Commission is of the view, based on its stakeholder consultations, that if the Hydrogen Jobs Plan decides to purchase green hydrogen via a tender or some other competitive selection process, that it could at least partially address the barrier posed by lack of local offtake opportunities. The highest priorities for State Government attention, because they can be addressed through investment, and because of the potential impact they have on private sector cost structures appear to be:

1. ensuring a sufficient water supply for green hydrogen (and green minerals) opportunities, as well as incumbent mining projects;
2. providing a gas export port with sufficient capacity to allow green hydrogen exports;
3. addressing the gaps in the local gas sector skills base due to the current small workforce in the oil and gas sectors in South Australia; and
4. addressing the capability gaps within the state public sector arising from not having managed such large-scale industrial projects in the past.

Investing the necessary resources to address the state's competitive disadvantages is likely to require significant financial resources. The State's high levels of existing debt, below average rates of GSP growth (past and forecast future) which makes it harder to pay down debt through revenue growth, and expected need to borrow further to meet already announced infrastructure commitments in other policy areas (see Box 3.2) impose constraints on the scale of any support. If the State Government decided that supporting the potential development of a green hydrogen export sector is a priority for the state, then hard choices will need to be made about freeing up capital funds within the state budget, by cancelling or deferring other large investment projects.

Such investment would also be risky. In addition to the delivery risks that accompany large construction project, there is also the considerable uncertainty about the eventual scale of international trade in green hydrogen, the amount of any such trade Australia would secure, and the risk that given private sector investors may locate in other states to take advantage of their areas of competitive advantage around green hydrogen.

This means that if a decision was made to pursue opportunities in green hydrogen, it is likely that they would only be secured if the State gets everything right – a world-class plan, world class people (management and delivery), with the right delegated authority to deliver the right project(s), and collaboration with key potential trading partners. And the State would also need some good luck; that enough international demand for green hydrogen trade emerges.

If a green hydrogen export sector does eventuate, private investment decisions are likely to be made quickly to secure commitments to end-users. That would also require those making the investment decisions to be confident that any relevant barriers would be addressed.

One way of mitigating these risks is to ensure detailed planning is undertaken early, with any actual construction (whether funded by the private sector or by government) deferred until the uncertainties have been resolved sufficiently to make the investment prudent. We will need to have a flexible fiscal mindset to allow bold fiscal decisions to be taken if the economic business case for a project stacks up.

Finding 40: Any infrastructure required to address barriers to hydrogen development may need to be delivered in a short timeframe to secure investment. Sophisticated planning and preparation are ways of accelerating the delivery time without undertaking substantial financial commitments.

Recommendation 14

The State Government undertakes planning now for what would be required by a hydrogen export sector (such as commercial management of Port Bonython, infrastructure development at Port Bonython, and access to infrastructure corridors). Decisions on whether such works are more appropriately funded by the State Government or private investors can be made when appropriate.

Recommendation 15

The Commission recommends that the Chief Executive of the Department of the Premier and Cabinet be tasked with assessing whether the state public sector has the right skill sets and the right structures to secure green hydrogen opportunities in the face of national and global competition. Western Australia and Queensland are expected to have a competitive advantage relative to South Australia because of their greater experience in facilitating large-scale resource projects.

5.4 Maximising the potential opportunity from green minerals

Policies to facilitate the development of a green minerals sector in SA have a very significant overlap with those required to facilitate the development of a green hydrogen sector. Low-cost and abundant renewable energy, and low-cost green hydrogen are likely to both be pre-conditions for the emergence of a green minerals sector, but if the State removes the impediments to renewable energy (as recommended in section 5.1) and is successful in facilitating the emergence of a green hydrogen sector then that would set the preconditions for taking advantage of potential green minerals opportunities.

Barriers identified by industry stakeholders in addition to the need for renewable energy and green hydrogen, and for which there is a potential rationale for government involvement of some form, include:

- development of a commercially managed export port at Port Bonython;
- access to infrastructure corridors, connecting renewable energy projects to industrial hubs; and
- access to water from common access infrastructure.

Each of these has also been identified as a potential barrier to the development of a green hydrogen sector, and so it may be the case that in the development of a green hydrogen sector they are resolved. But to the extent to which they remain as barriers, addressing them may be necessary to realisation of green minerals opportunities.

Other areas identified by industry in the consultations appear to be outside the scope of prudent government intervention.

Appendices

Appendix 1: Terms of Reference

SOUTH AUSTRALIAN PRODUCTIVITY COMMISSION INQUIRY INTO SOUTH AUSTRALIA'S RENEWABLE ENERGY COMPETITIVENESS

I, Steven Marshall, Premier, hereby request that the South Australian Productivity Commission (SAPC) undertake an inquiry into South Australia's renewable energy competitiveness.

Background

Action to limit global warming is triggering significant structural adjustment in the global economy. Structural change creates challenges and opportunities.

The South Australian (SA) Government has set goals to reduce SA's greenhouse gas emissions by more than 50 per cent below 2005 levels by 2030 and to achieve net zero emissions by 2050.[1]

The SA Government has made considerable progress in driving the expansion of renewable energy production to the point where in 2019-20 SA produced 56.6 per cent of its electricity from renewable sources (SA has no coal-fired generation).[2]

But many other states of Australia and nations globally are aggressively pursuing renewable energy expansion policies to, amongst other things, grasp economic development opportunities.

In this highly competitive environment, and given the SA Government's investment to date, it is the right time to:

- conduct a thorough economic assessment of SA's renewable energy competitiveness; and
- identify any:
  - steps the SA Government may take to enhance this competitive position; and
  - economic development opportunities that may realistically flow from the actual or prospective competitiveness position.

Terms of Reference

The purpose of this inquiry is to:

1. Assess SA's actual or potential renewable energy competitive advantage (both within Australia and globally) in terms of renewable energy cost, location, quantity, reliability, emissions levels, and other relevant factors.
2. Recommend any further actions the SA Government could take to create or enhance the actual or potential competitive advantage.
3. If a competitive advantage exists or is attainable, recommend what areas of potential economic development warrant further thorough investigation by the SA Government.

[1] South Australian Government, Climate Change Action Plan 2021-2025 p1
[2] Ibid p18

Inquiry Process

The SAPC will seek input from relevant experts (including from within the SA Government, principally from DEW and DEM) and draw on prior work conducted in this field.

The SAPC will consult with relevant public and private sector organisations in SA and other Australian jurisdictions, industry, professional associations and other key stakeholders.

Temporary assignment of employees from relevant public sector agencies may be arranged by the office of the SAPC in accordance with *Premier and Cabinet Circular 046 – The South Australian Productivity Commission* to support the inquiry.

The SAPC is to publish a draft report containing recommendations for consultative purposes. A final report is to be provided to me no later than 7 months from the date of receipt by the SAPC of these terms of reference.

Hon Steven Marshall MP
PREMIER OF SOUTH AUSTRALIA

15 / 11 /2021

Appendix 2: Submissions, commissioned research, and consultations

Organisation name	Submission number
Submissions to the inquiry	
Angus Bruce	FR1
Premier's Climate Change Council	FR2
SA Power Networks	FR3
Commissioned research to support the inquiry	
Carbon & Energy Markets Pty Ltd: *Financial sustainability of renewable energy under National Energy Markets rules*	
The University of Adelaide *Potential economic impact of transitioning South Australia's heavy industry and mineral sectors*	
The University of Adelaide *Potential for SA in additional processing of SA minerals deposits*	
University of Wollongong *Projections of spot price volatility in South Australia*	
University of Wollongong *Wholesale and retail price projections for the National Electricity Market*	

Appendix 3: Wind and Solar Endowments

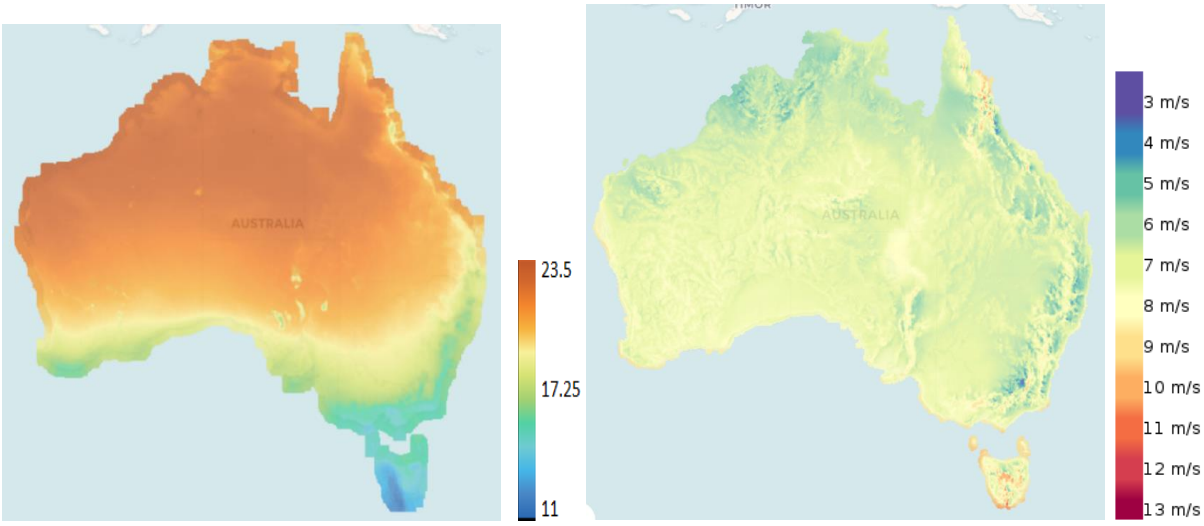
This appendix provides an analysis of South Australia's wind and solar endowments and their variability, including the complementarity of wind and solar. It also provides a technical discussion on the levelised costs of electricity (LCOE) and trends in LCOE for different technologies across countries over time.

A3.1 South Australia's endowments

South Australia is seen as having favourable renewable endowments in solar and wind. This section examines South Australia's resource potential for wind and solar, compared to the rest of Australia. Figure A3.1 presents the average daily solar exposure, and average wind speed at a height of 100 metres above ground level, for Australia.

South Australia's solar resources, especially in the state's north are among the best in Australia and are close to major loads or population centres, with only Brisbane, Perth and Darwin having a higher average daily solar exposure. South Australia also has some of the most consistent solar, especially in summer.

Figure A3.1: Mean daily global horizontal irradiance exposure (left) and average wind speed at 100 m above ground level (right)



Note: these maps include littoral areas with renewable potential and so some coastal waters are also shaded
Source: https://www.nationalmap.gov.au/

South Australia has relatively high wind speeds but also has a high variation of wind power. This pattern is characteristic of much of Australia's high-wind resource areas. In terms of unavailability, South Australia (and Western Australia) has some of the most reliable winds outside of the Great Dividing Range and similarly has some of the longest mean continuous wind availability lengths. However, South Australia's wind resources are also largely coincident, which indicates that aggregating wind resources across large areas of the state is unlikely to mitigate the effects of low wind speeds, so other technologies or storage will be required.

There is some indication that solar and wind in South Australia are complementary throughout an average day, with wind speeds at their lowest during daylight hours. However, the Commission has not identified any research that precisely quantifies the coincidence of wind and solar in South Australia or the frequency of 'dunkleflaute' events (periods when production of electricity from both wind and solar is low simultaneously). The presence of

high-quality resources of both wind and solar in South Australia presents an advantage in reducing the amount of firming required compared to regions with only one main resource.

Capacity factors

The renewable energy resource potential in a region is typically expressed not in terms of wind speed or solar irradiance, but in terms of the electricity generation potential, typically represented as a capacity factor. This represents the ratio of actual electricity produced over a period to the maximum possible electricity that could be generated.

Table A3.1: AEMO capacity factors for Australia for Renewable Energy Zones (REZ)s (analysis does not include regions outside the National Energy Market (NEM))

REZ name	Region	Solar		Wind	
		Solar PV %	Solar Thermal %	High %	Low %
North Queensland Clean Energy Hub	QLD	30	42	51	40
Northern Queensland	QLD	29	34	-	-
Barcaldine	QLD	32	45	42	35
Isaac	QLD	28	33	48	36
Fitzroy	QLD	31	39	44	35
Darling Downs	QLD	32	40	44	38
North-west New South Wales	NSW	31	41	25	25
New England	NSW	31	39	36	37
Central west New South Wales	NSW	30	40	34	30
Southern New South Wales tablelands	NSW	-	-	44	43
Murray River (NSW)	NSW	28	33	34	32
Murray River (VIC)	VIC	28	33	34	32
Riverland (NSW)	NSW	29	34	33	32
Riverland (SA)	SA	29	34	33	32
Broken Hill	NSW	32	44	38	33
Western Victoria	VIC	-	-	46	36
Mayne	VIC	-	-	41	42
Gippsland	VIC	-	-	35	34
South-east South Australia	SA	-	-	42	38
Mid-north South Australia	SA	-	-	42	40
Yorke Peninsula	SA	-	-	41	39
Northern South Australia	SA	30	37	37	37
Leigh Creek	SA	32	44	41	41
Roxby Downs	SA	32	42	-	-
Eastern Eyre Peninsula	SA	28	29	42	40
Western Eyre Peninsula	SA	29	33	40	36
North-east Tasmania	TAS	-	-	46	45
North-west Tasmania	TAS	-	-	51	44
Tasmania midlands	TAS	-	-	53	47

Source: AEMO 2021 Inputs and assumptions workbook.[124]

Solar and wind generally tend to have low capacity factors given the intermittency of the energy sources (wind of sufficient speed, and sunlight of high enough intensity) they use to generate electricity.

[124] Approximate capacity factors of renewable resources. Capacity factors depend on the 'reference year' modelled – estimates here are for 2013-14 reference year.

Capacity factors are important as they explain much of the difference in levelised cost for renewables across Australia. This is because construction costs represent a significant portion of total costs of renewable energy, so higher capacity factors spread these costs across more electricity generated (although remoteness and other site-specific costs can also cause differences).

Based on data from the Australian Energy Market Operator (AEMO) (which only covers regions able to be connected to the NEM, and therefore excludes Western Australia and the Northern Territory), Leigh Creek and Roxby Downs have among the highest capacity factors for solar PV and solar thermal in the NEM, while the Eyre Peninsula has the lowest.

In the case of wind, Tasmania and North Queensland have the highest capacity factors in the NEM (Table A3.1). AEMO's capacity factor estimates indicate that northern South Australia is among the best for solar and South Australia is among the middle for wind.

A3.2 Variability of Wind and Solar

As wind and solar resources are variable in their nature, measures of average speed, irradiance or power generation can provide an incomplete picture. This section presents estimates of variability of wind and solar resource strength. The Commission has not calculated any of these measures and instead has looked only at past studies.

Measures of variability

There are many possible measures of variability for wind and solar, including standard deviation, coefficient of variation, robust coefficient of variation and interquartile range.[125] In general, the most used measure of solar variation appears to be the coefficient of variation (CoV).[126] For wind however, the CoV is found to not be robust and instead the robust coefficient of variation (RCOV is preferred.[127]

Another technical consideration in measuring variability of wind and solar resources is choosing what to measure. Some studies measure variation of wind speed, while others measure wind power density (WPD), which is the amount of power available per square meter of swept area of a wind turbine (measured in Watts per square meter). Similarly, for solar, various measures of solar irradiance include global horizontal irradiance (GHI) and direct normal irradiance.

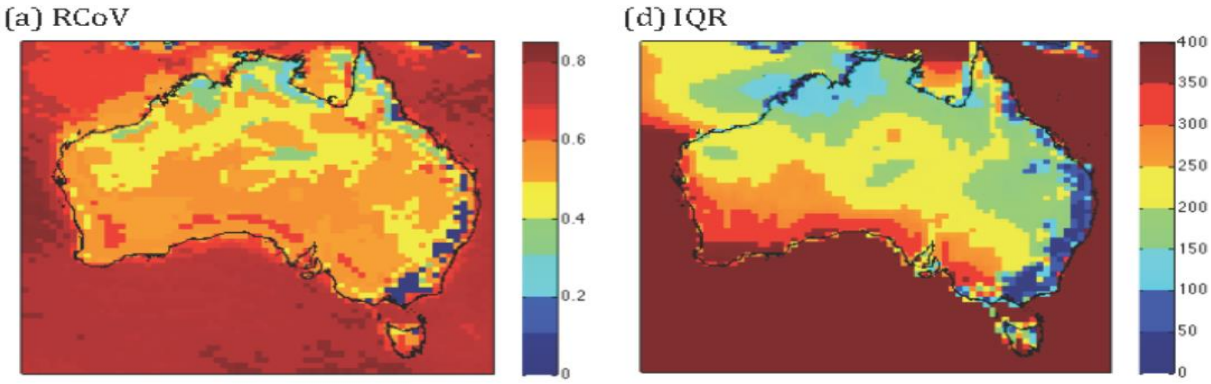
Normalised measures of variability can also be complemented, with measures of availability (the proportion of time the resource is above a specified threshold) and coincidence (the proportion of time the resource strength is above a specified threshold in adjacent areas) used to provide a more complete picture.

Wind variability

In general, South Australia has relatively high wind speed variability, as measured by both RCoV and interquartile range, as seen in Figure A3.2.

[125] For a full discussion of possible measures and an assessment of each in the context of wind speed see Joseph C. Y. Lee, M. Jason Fields, and Julie K. Lundquist (2018) 'Assessing variability of wind speed: comparison and validation of 27 methodologies' *Wind Energy Science* 3, 845
[126] The CoV is a normalised standard deviation, or the standard deviation divided by the mean of a time series.
[127] The RCoV is defined as the Median Absolute Deviation divided by the median of a time series.

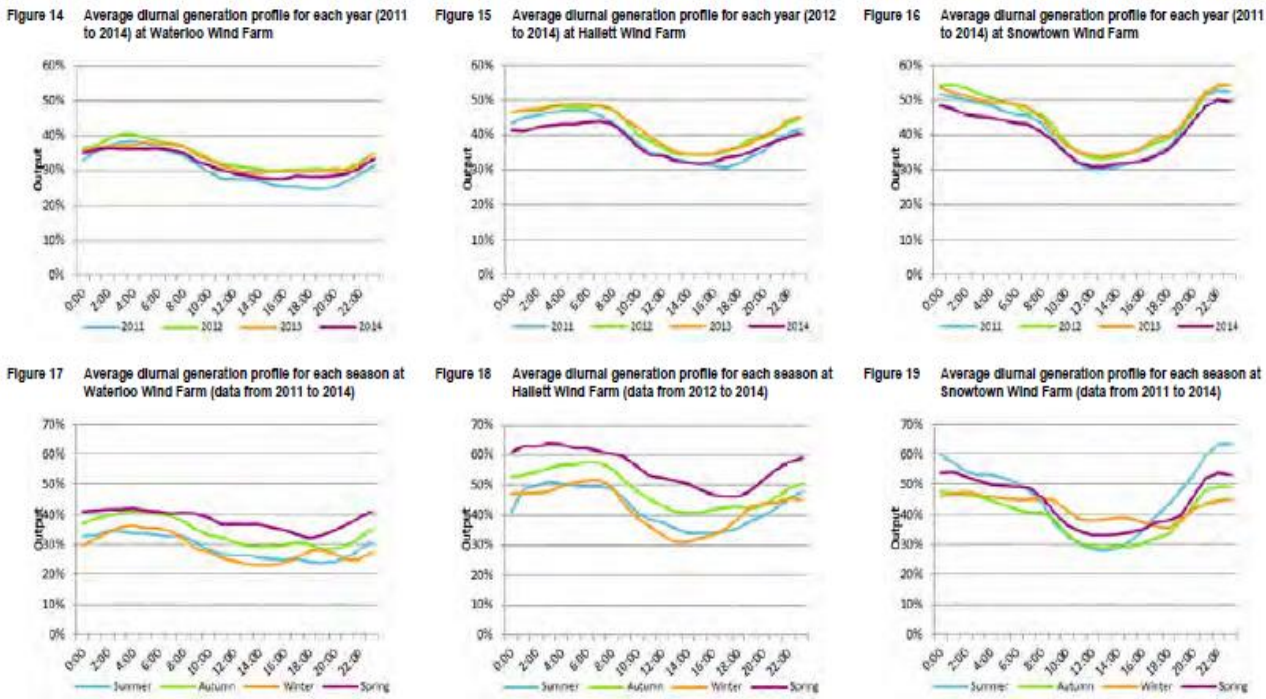
Figure A3.2: Map of wind variability in Australia



Source: Hallgren W, Gunturu UB, Schlosser A, The Potential Wind Power Resource in Australia: A New Perspective. PLoS ONE 9(7): e99608 (2014)

A co-location study by AECOM[128] looked at the average annual diurnal generation profile for three wind farms in South Australia, as well as seasonal differences. These are presented in Figure A3.3. While this demonstrates some interannual variation in wind output for each, the average daily patterns are broadly consistent across years. There are some seasonal differences; however, while these differ across locations, the daily wind profile appears to be broadly similar for each.

Figure A3.3: Average diurnal generation profile, various sites in South Australia, various years and by season

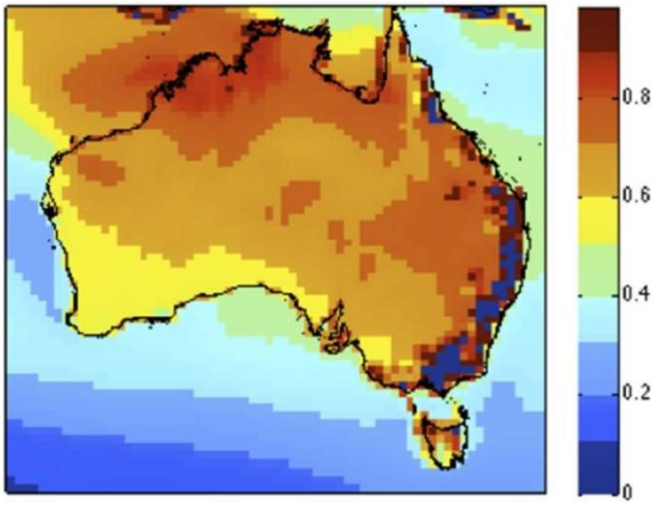


Source: AECOM (2016)[129]

[128] AECOM (2016), Co-location Investigation, prepared for ARENA, Sydney: AECOM, <https://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf>
[129] *Ibid*

In terms of reliability of wind resources, South Australia and Western Australia have some of the most reliable wind resources outside of the Great Dividing Range (which is not generally suitable for grid scale renewable energy). Figure A3.4 shows the proportion of time WPD was below 200 Wm^{-2}, which is the threshold most wind turbines require for generation.

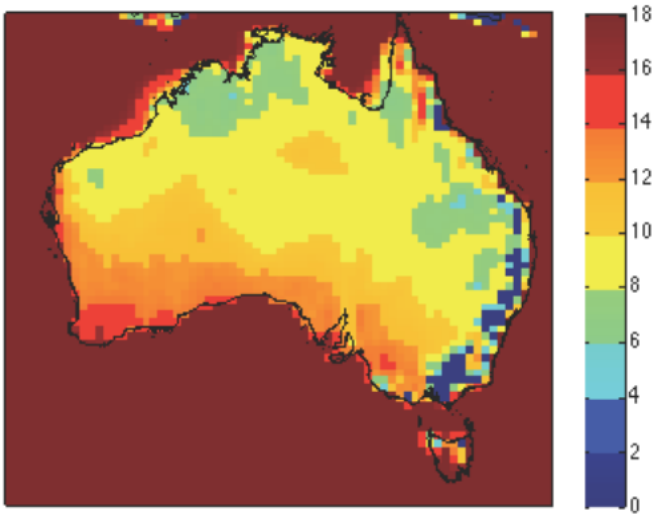
Figure A3.4: Proportion of time WPD is below the operational threshold of wind turbines at 50m above ground level



Source: Hallgren W, Gunturu UB, Schlosser A, The Potential Wind Power Resource in Australia: A New Perspective. PLoS ONE 9(7): e99608 (2014)

The average length of continuous wind availability, presented in Figure A3.5, is also relatively high in much of South Australia, especially near the coast.

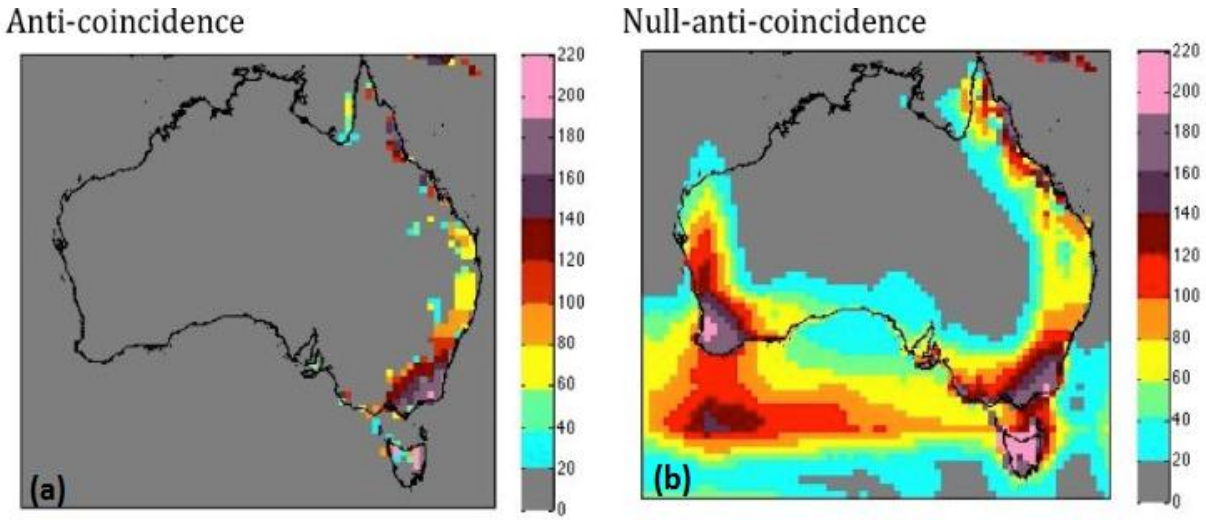
Figure A3.5: Mean length of continuous wind availability at 50m above ground level (hours)



Source: Hallgren W, Gunturu UB, Schlosser A, The Potential Wind Power Resource in Australia: A New Perspective. PLoS ONE 9(7): e99608 (2014)

South Australia also scores low in terms of anti-coincidence (i.e. differences in timing of wind availability between regions), presented in Figure A3.6. This indicates that wind patterns are similar across broader areas. This suggests that aggregating wind turbines across larger areas is unlikely to mitigate intermittency.

Figure A3.6: Maps of anti-coincidence and null-anti-coincidence of wind availability in Australia

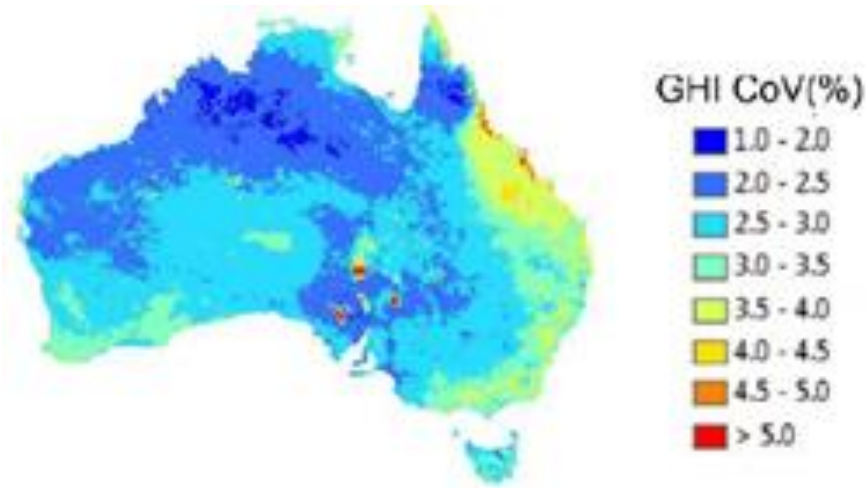


Note: The units indicate the number of grid points in a ,1000 x 1000 km box surrounding the grid point in question which are anti-coincident to the central grid point, which is when the hourly time series of WPD is greater than 200 W m-2 at one of the two points, but not both, for 50% of the total length of the time series
Source: Hallgren W, Gunturu UB, Schlosser A, The Potential Wind Power Resource in Australia: A New Perspective. PLoS ONE 9(7): e99608 (2014)

Solar variability

Inter-annual variability of solar irradiance presents a measure of investment risk for solar PV investments. Generally, South Australia, particularly northern South Australia has some of the lowest interannual variability in southern Australia (see Figure A3.7). Only northern Western Australia, large portions of the Northern Territory and the southern Cape York Peninsula have lower variability. Therefore, there is some evidence that South Australia has some advantages in terms of lower risk for solar PV investments than other locations close to major population centres in Australia.

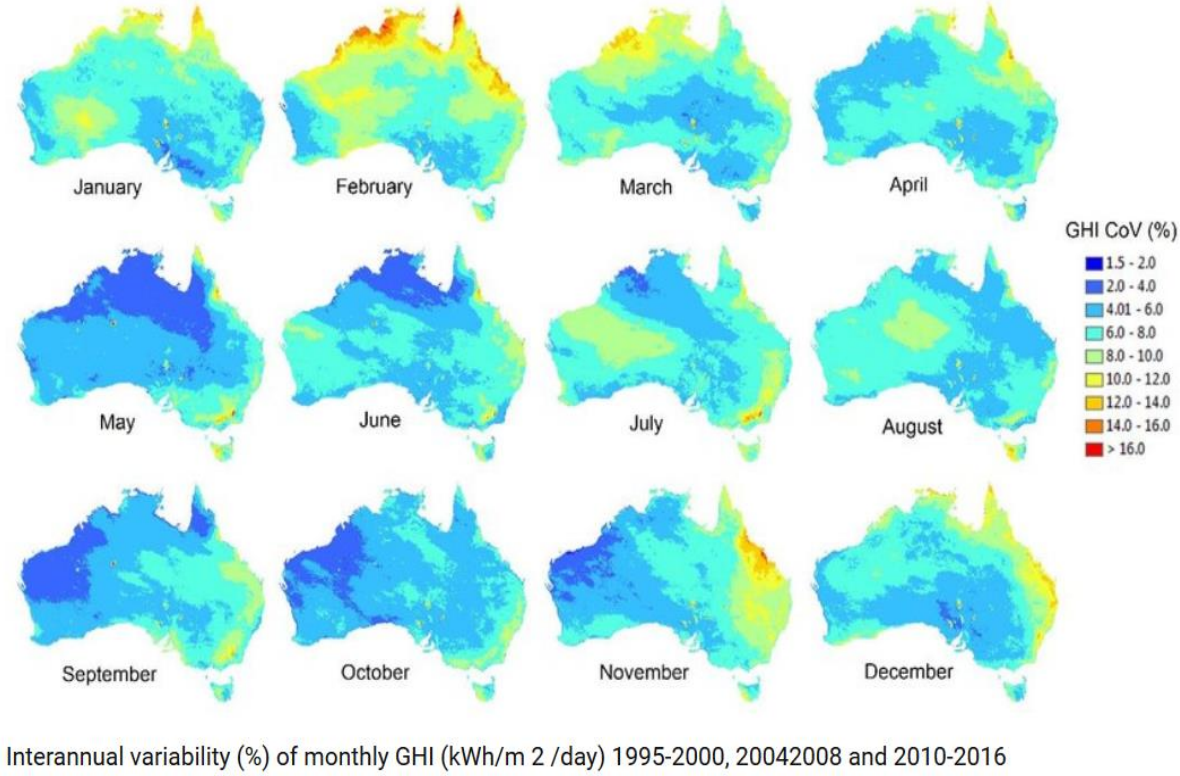
Figure A3.7: Interannual variability of global horizontal irradiance (GHI) in Australia, 1990-2016



Source: J.K. Copper, and A.G. Bruce 'Interannual Variability of the Solar Resource across Australia Conference Paper, Asia-Pacific Solar Research Conference (2017)

South Australia's solar resources are among the lowest variability year-round; this is especially the case in the summer months, while northern and western Australia have lower variability in winter (Figure A3.8).

Figure A3.8: Interannual variability of GHI in Australia, by month



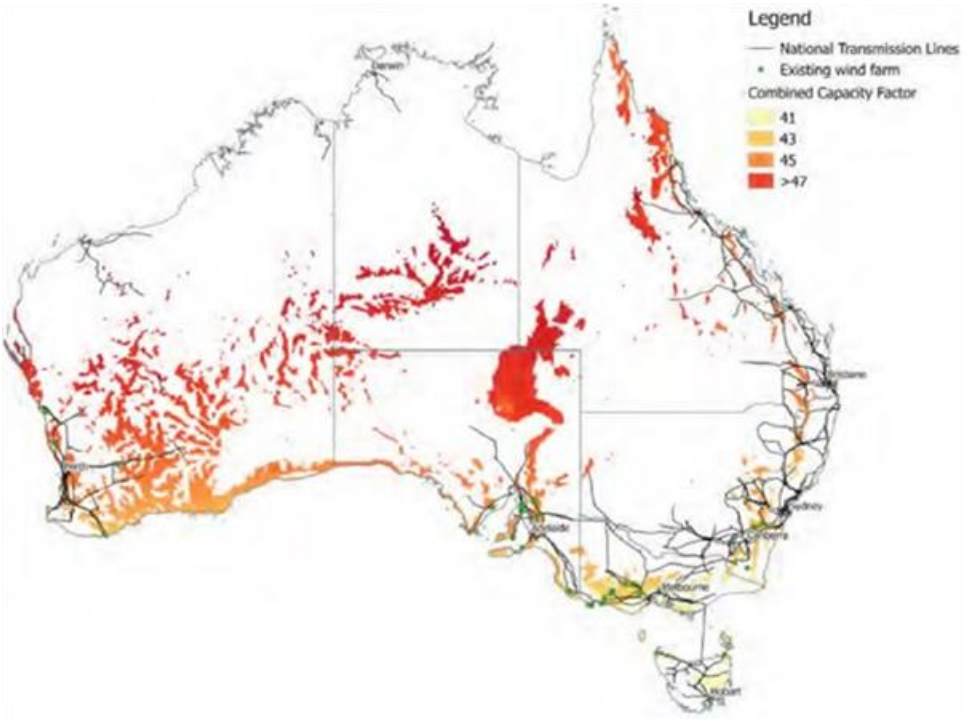
Source: J.K. Copper, and A.G. Bruce 'Interannual Variability of the Solar Resource across Australia Conference Paper, Asia-Pacific Solar Research Conference (2017)

Complementarity of Wind and Solar

Owing to the intermittent nature of renewable energy, without sufficient storage, firming will be required. To date, the Commission has not identified much research as to the degree of complementarity between wind and solar in South Australia and whether this might give South Australia any advantages over other locations. The best source the Commission has identified is the AECOM co-location study[130]. This study found that the greatest co-location opportunities in regions with existing wind generation were in Western Australia and South Australia. While South Australia is also well situated for co-location in regions with no current wind generation, there are also areas of Queensland and New South Wales that currently have no wind generation that are suitable for co-location (Figure A3.9).

[130] AECOM (2016), Co-location Investigation, prepared for ARENA, Sydney: AECOM, <https://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf>

Figure A3.9: Combined capacity factors of wind and solar resources



Source: AECOM (2016) [131]

The AECOM study also looked at daily wind and solar at several existing wind farms across Australia, including three in South Australia, presented in Figure A3.10. At all three wind farms in South Australia, wind speeds were at their lowest during daylight hours when solar was at its peak. This suggests some complementarity of wind and solar in South Australia. However, as these are site specific profiles, it is not clear the extent to which this holds across the state, nor how this compares to other jurisdictions.

[131] AECOM (2016), Co-location Investigation, prepared for ARENA, Sydney: AECOM, <https://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf>

Figure A3.10: Diurnal wind and solar profile, selected wind farms

Figure 31 Snowtown Wind Farm: Wind and solar (average diurnal generation profile)

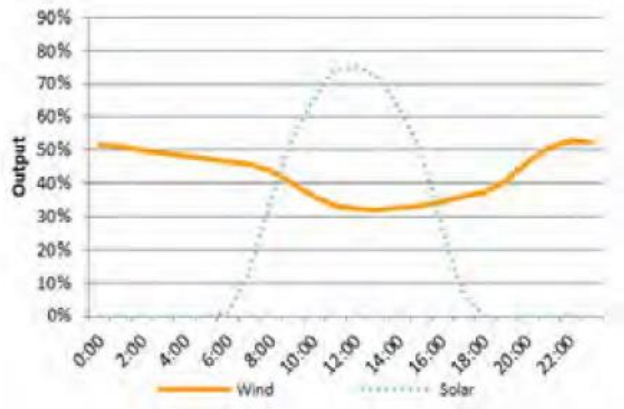


Figure 32 Waterloo Wind Farm: Wind and solar (average diurnal generation profile)

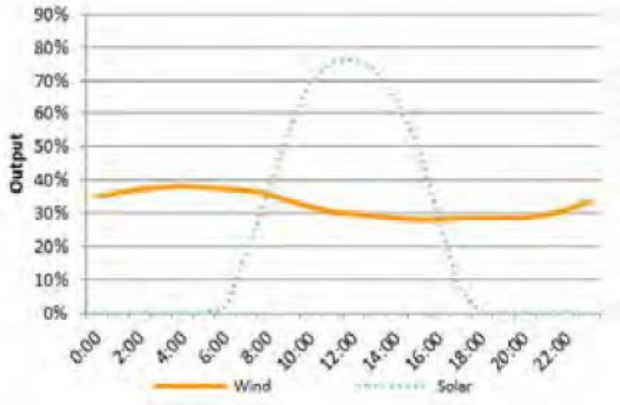
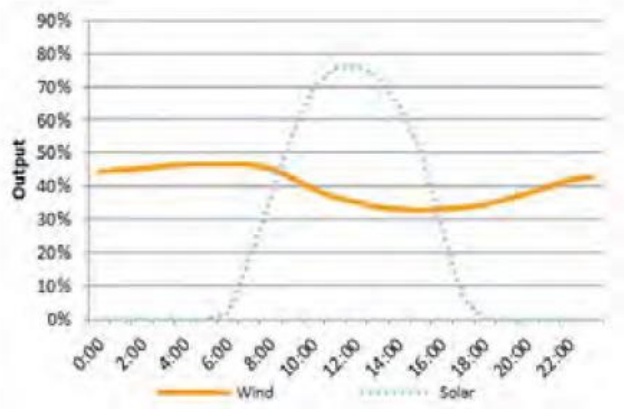


Figure 33 Hallett Wind Farm: Wind and solar (average diurnal generation profile)



Source: AECOM (2016) [132]

A3.3: Levelised cost of electricity

Levelized cost of electricity (LCOE) is an estimated cost of generating electricity for a particular system. It represents the per-kilowatt hour cost of building and operating a generating plant over an assumed economic life of the plant and the costs incurred in the construction, operation and maintenance, as well as the fuel costs. It is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital while a price below it would yield a lower return on capital or a loss. It is a cost-based indicator and does not include revenues.

The LCOE method is widely used as a practical comparative method to analyse different energy technologies in terms of cost and can be used as a benchmarking tool. It is therefore useful in assessing the economic viability of different generation technologies and of indi-

[132] AECOM (2016), Co-location Investigation, prepared for ARENA, Sydney: AECOM, <https://www.aecom.com/au/wp-content/uploads/2016/03/Wind-solar-Co-location-Study-Final.pdf>

vidual projects.[133] Conceptually simple while containing the most important factors contributing to the economic evaluation of a project, the LCOE approach is able to reflect the key factors of the production cost throughout the lifetime of the power plant in just one number.[134]

Methodology

The LCOE is calculated by taking the net present value of the total cost of building and operating the power plant, and is expressed as:

$$LCOE = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ electrical\ energy\ produced\ over\ lifetime}$$

$$= \frac{\sum_{t=1}^{n} \frac{(I_t + M_t + F_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where,

I_t = investment expenditures in the year t

M_t =Operations and maintenance expenditures in the year t

F_t = Fuel expenditures in the year t

E_t = electrical energy generated in year t

r = discount rate

n =expected lifetime of asset

Key inputs to calculating LCOE include:

- capital costs;
- fixed and variable operations and maintenance costs;
- fuel costs;
- disposition costs;
- financing cost; and
- an assumed utilisation rate (for each plant type).

Capital costs would include the up-front costs associated with the construction of a power plant. For example, engineering, procurement and construction for both generation and other

[133] See for example, Joskow, P. (2011), 'Comparing the costs of intermittent and dispatchable electricity generating technologies', MIT, <http://economics.mit.edu/files/6317>; Allan, G.; Gilmartin, M.; McGregor, P.; Swales, K. (2011): 'Levelized costs of Wave and Tidal energy in the UK. Cost competitiveness and the importance of "banded" Renewables Obligation Certificates, *Energy Policy* 39:1, 23–39.

[134] Díaz, G.; Gómez-Aleixandre, J.; Coto, J. (2015), Dynamic evaluation of the levelized cost of wind power generation, *Energy Conversion and Management* 101, 721–729. DOI: 10.1016/j.enconman.2015.06.023.; Tidball, R.; Bluestein, J.; Rodriguez, N.; Knoke, S. (2010), *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, National Renewable Energy Laboratory <https://www.nrel.gov/docs/fy11osti/48595.pdf>; Myhr, A.; Bjerkseter, C.; Ågotnes, A.; Nygaard, T. A. (2014), Levelised cost of energy for offshore coating wind turbines in a life cycle perspective, *Renewable Energy* 66, 714–728

supporting components of a power plant. Operations and maintenance costs are those incurred in tunning the power plant and include both fixed and variable costs. Disposition costs are usually incurred at the end of the lifecycle of a facility and can vary depending on the type of energy generated.

Other input parameters that are important in the calculation of LCOE include capacity factors, weighted average cost of capital, heat rates[135], consumer price index, lead times for construction and payment milestones.[136]

The capacity factor[137] is an important input in the estimation of LCOE as the costs associated with electricity generation are allocated across each unit of energy produced. The capacity factor therefore gives a measure of the share of the actual electricity generated by a plant. For this reason, some estimates of LCOE are presented over the certain range of values rather than a single figure.

The relative importance of these inputs depends on the type of technology used. For example, solar and wind power plants would have no fuel costs and relatively small operating and maintenance costs. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As discussed in a range of studies, it is important to note that as with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.[138]

Limitations of the LCOE approach

While the LCOE is a useful metric of the overall costs of different energy generating technologies, the literature identifies several key limitations of this approach, including the representation of a complex production process in a single number.[139] For example, an analysis with a narrow focus on LCOE would increase the risk of misinterpretation.

The United States Energy Information Administration (EIA) reported that

> *LCOE does not capture all of the factors that contribute to actual investment decisions, making the direct comparison of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives.*[140]

Another factor is the level of uncertainty associated with this approach, as the calculation of the LCOE requires making assumptions around values relating to the entire lifetime of the

[135] Heat rate is the parameter used to calculate the amount of fuel needed for the energy sent out.
[136] AER (2020), LOCE and LCOS modelling approach, limitations and results: Wholesale electricity market performance report.
[137] defined as the amount of energy produced by a generator as a proportion of its maximum possible production over a given time period
[138] Hwang, Sung-Hyun, Mun-Kyeom Kim, and Ho-Sung Ryu (2019), 'Real Levelized Cost of Energy with Indirect Costs and Market Value of Variable Renewables: A Study of the Korean Power Market' *Energies* 12:13, 2459.
[139] <https://www.sciencedirect.com/topics/engineering/levelized-cost-of-electricity>
[140] U.S. Energy Information Administration (EIA) (2021),'The Levelized costs of new generation resources' in the Annual Energy Outlook 2021, p 3 <https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf>

power plant. In addition, assumptions related to capacity factor and discount rate have significant impact on the estimation of LCOE.[141] [142]

As discussed in several studies of LCOE, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve other factors including projected utilisation rate and the existing resource mix in an area.[143] As such, estimates of LCOE using inputs applicable to one location or region cannot be directly compared with other locations. In addition, it is important to consider the limitations of LCOEs when comparing intermittent and no-dispatchable renewable technologies with fully dispatchable electricity generation technologies.[144]

Not adequately considering all indirect costs of power generation in the calculation of the LCOE is another potential limitation in this approach. These may include environmental externalities, curtailment effects or grid upgrade requirements. Renewable power generation sources such as wind and solar may also incur additional costs related to storage or backup.[145] The literature provides examples of alternative approaches that attempt to address some of these issues, such as an adjusted LOCE approach that accounts for direct and indirect generation costs, electricity demand and fuel prices[146] and a series of complementary measures that can be used in conjunction with LCOE measures.[147]

In addition, care should be taken when comparing estimates of LCOE from different sources as they are dependent on the underlying assumptions and input data.[148] The wide range of assumptions, justifications and data used in LCOE calculations tend to produce widely varying and contradictory results, which are difficult to compare.[149]

Overall, the LCOE approach is useful to support the decision-making process. However, caution must be exercised in interpreting the economic viability of a technology solely on the basis of LCOE.

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[141] Seba, T. and A. Dorr (2021), 'Analysts' inaccurate cost estimates are creating a trillion-dollar bubble in conventional energy assets'. *Utility Dive*, <https://www.utilitydive.com/news/analysts-inaccurate-cost-estimates-are-creating-a-trillion-dollar-bubble-i/596648/>

[142] Nuclear Energy Agency (2018), 'The full costs of electricity provision', Paris: OECD, <https://www.oecd-nea.org/upload/docs/application/pdf/2019-12/7298-full-costs-2018.pdf>

[143] Timilsina, G. (2020), 'Demystifying the costs of electricity generation technologies' Timilsina, Policy Research Working Paper, no 9303, The World Bank, Washington DC.

[144] Joskow, P. 2011, 'Comparing the costs of intermittent and dispatchable electricity generating technologies, MIT, <http://economics.mit.edu/files/6317>

[145] Ibid.

[146] Hwang, Sung-Hyun, Mun-Kyeom Kim, and Ho-Sung Ryu (2019), 'Real Levelized Cost of Energy with Indirect Costs and Market Value of Variable Renewables: A Study of the Korean Power Market' *Energies* 12:13, 2459.

[147] <https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf>

[148] Lai, Chun Sing; Jia, Youwei; Xu, Zhao; Lai, Loi Lei; Li, Xuecong; Cao, Jun; McCulloch, Malcolm D. (2017), 'Levelized cost of electricity for photovoltaic/biogas power plant hybrid system with electrical energy storage degradation costs', *Energy Conversion and Management*. 153, 34–47; *Branker, K.; Pathak, M.J.M.; Pearce, J.M. (2011). '*A Review of Solar Photovoltaic Levelized Cost of Electricity,. *Renewable and Sustainable Energy Reviews, 15:*9*, 4470–4482*

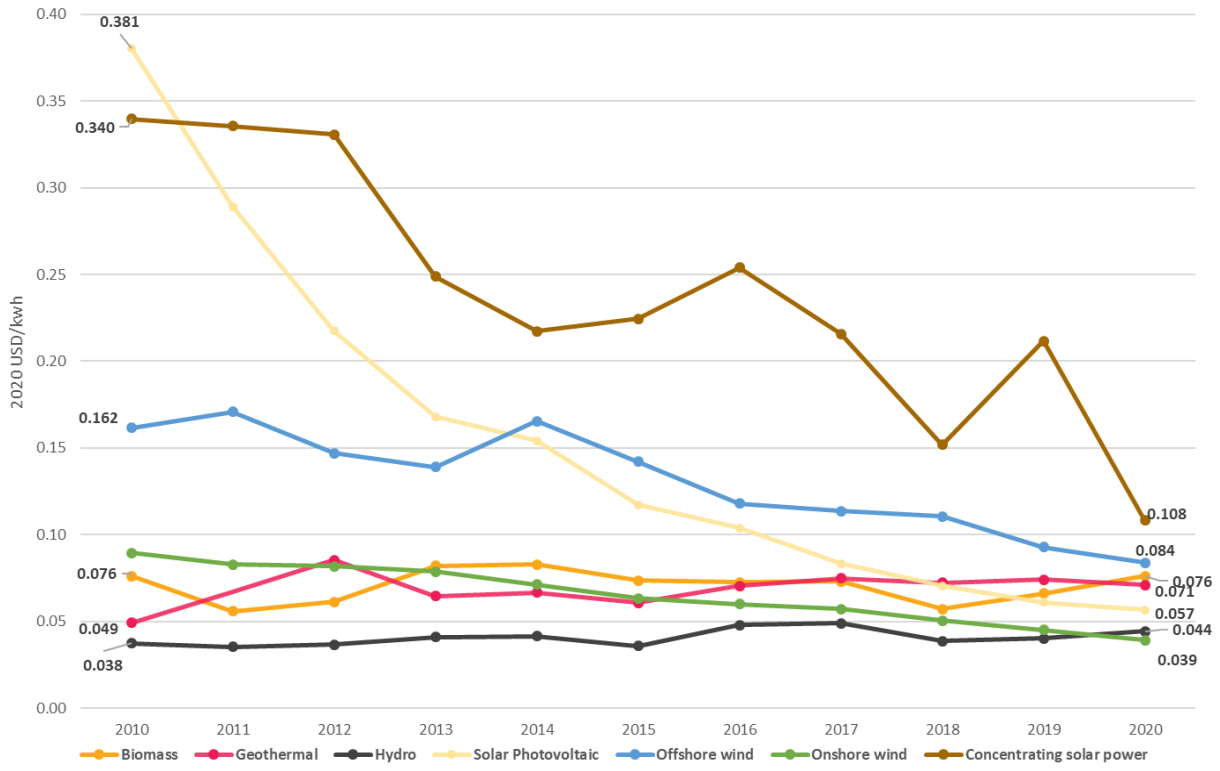
[149] K. Branker, M. J.M. Pathak, J. M. Pearce, 'A Review of Solar Photovoltaic Levelized Cost of Electricity, *Renewable and Sustainable Energy Reviews* 15, 4470-4482, <https://digitalcommons.mtu.edu/cgi/viewcontent.cgi?article=1028&context=materials_fp>

Trends in the LCOE

This section provides a brief overview of trends in the LCOE for different technologies across different regions, noting that measures from different sources are not directly comparable. However, they are useful in understanding the overall trends.

According to a recent United Nations Environment Programme (UNEP) report, in the second half of 2019, the LCOE for solar PV was about 83 per cent lower than a decade earlier, while costs for onshore and offshore wind were down 49 per cent and 51 per cent, respectively.[150] Data from the International Renewable Energy Agency (IRENA) also confirm that, globally LCOE has fallen rapidly for solar and to a lesser degree for wind. As illustrated in Figure A3.11, overall, the levelised costs from renewable sources have been decreasing over time, and trending below the costs of conventional fossil fuel technologies. For example, the LCOE for solar PV has fallen from USD 0.38 /kWh in 2010 to USD 0.05/kWh in 2020.

Figure A3.11: Global weighted-average utility scale LCOE by technology, 2010-20



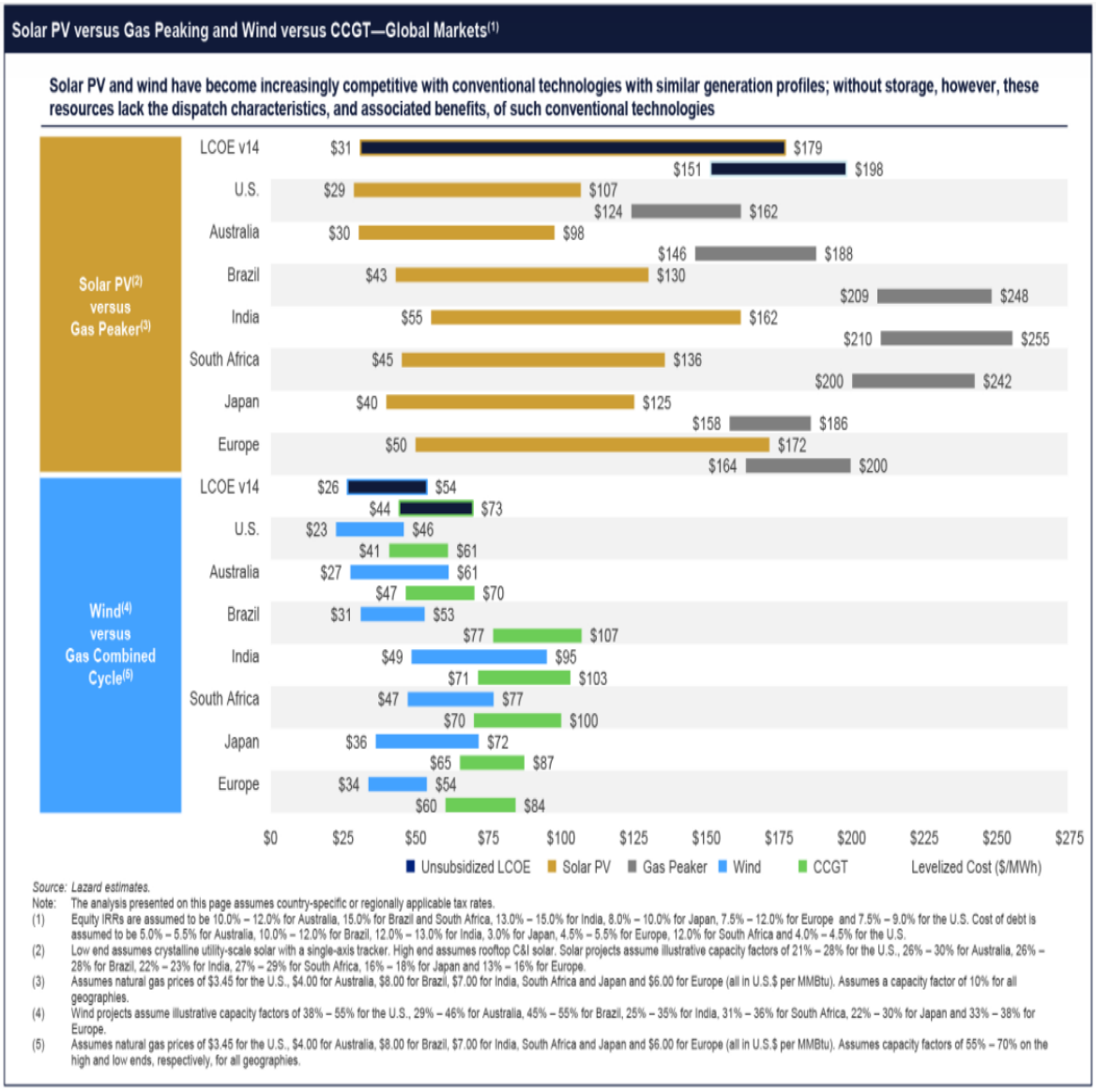
Source: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jun/IRENA_Power_Generation_Costs_2020.pdf

LCOE estimates can be heavily influenced by assumptions made in the calculation. Figure A3.12 presents solar and wind LCOE estimates for selected countries and regions from

[150] FS-UNEP Collaborating Centre for Climate and Sustainable Energy Finance (2020), *Global Trends in Renewable Energy Investment 2020*, United Nations Environment Programme (UNEP) and Frankfurt School, <https://www.fs-unep-centre.org/wp-content/uploads/2020/06/GTR_2020.pdf>

Lazard's annual LCOE Analysis for 2020 (LCOE 14.0).[151] Based on these estimates, the LCOE for solar PV in Australia is relatively low compared to Brazil, India, South Africa, Japan or Europe.

Figure A3.12: Country comparisons of LCOE (Lazard)



Source: https://www.lazard.com/perspective/lcoe2020

However, estimates from IRENA indicates that Australia is more expensive for solar than Brazil, India and China (Table A3.2).

[151] <https://www.lazard.com/perspective/lcoe2020>. Note that these estimates assume equity IRRs to be between 10.0% and 12.0% and the cost of debt to be 5.0%- 5.5% for Australia.

Table A3.2: Commercial sector solar PV LOCE country comparisons (IRENA)

Market	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	2020 USD/kW										
Australia					2 879	2 247	1 979	1 694	1 580	1 384	1 282
Brazil							2 151	1 583	1 242	984	710
China		3 230	2 524	2 142	1 680	1 419	1 299	1 240	947	769	691
France	8 632	4 193	2 922	2 966	2 913	2 288	1 876	2 163	2 022	1 697	1 348
Germany		3 536	2 284	1 949	1 710	1 282	1 369	1 305	1 274	1 127	1 136
India								1 021	912	827	651
Italy	5 466	4 663	2 630	2 076	2 039	1 589	1 459	1 326	1 194	1 153	1 067
Japan			5 298	4 260	3 158	2 449	2 382	2 295	2 100	2 003	1 717
Malaysia					2 680	1 906	1 838	1 285	1 065	932	881
Republic of Korea								1 663	1 462	1 305	1 060
Spain		4 354	3 799	3 559	3 204	1 453	1 437	1 263	1 153	1 092	849
United Kingdom							1 906	1 750	1 681	1 572	1 545
Arizona (US)	7 112	6 289	5 542	4 391	3 615	3 878	3 476	3 143	2 718	2 782	2 600
California (US)	6 565	6 338	5 027	4 687	3 710	3 610	3 739	3 545	3 234	3 132	2 974
Massachusetts (US)	7 014	6 387	5 029	4 277	4 050	3 748	3 662	3 100	3 041	3 077	2 726
New York (US)	7 389	6 624	5 538	4 296	3 829	3 540	3 291	2 860	2 709	2 677	2 815

Source: renewable power generation costs 2020, p77. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jun/IRENA_Power_Generation_Costs_2020.pdf

Appendix 4: Pastoral leases, Crown land and renewable energy

A4.1. Introduction

Land tenure is the legal regime under which the rights to access, use and occupy the land are established. In Australia there are broadly two overarching forms of land tenure – 'freehold' and 'Crown' tenure.

In South Australia, Crown land is owned and administered by the South Australian Government in accordance with the *Crown Land Management Act 2009* (the 'CLM Act'). Crown land may be:

- sold where declared surplus to government requirements;
- reserved for national parks;
- licensed to enable short term access to undertake specified activities or uses
- leased for a range of purposes; or
- dedicated to a custodian (generally a local government authority) for a specific purpose.

Pastoral land is Crown land that has a pastoral lease title issued over it by the Minister responsible for the *Pastoral Land Management and Conservation Act 1989* (PLMC Act), currently the Minister for Climate, Environment and Water. A pastoral lease enables the lessee to occupy and use that land for pastoral and other approved activities in accordance with the PLMC Act. Each pastoral lease includes a range of conditions and reservations which sets out the rights and responsibilities of the relevant parties (e.g. pastoralists and the South Australian Government) and controls access to, and use of, the pastoral lease land. Most pastoral leases across Australia include:

- general conditions (terms of the lease, rental rate etc);
- land management and use conditions (stock grazing obligations, water and land care requirements etc); and
- reservations (Crown retains ownership of the land and certain rights associated with that ownership).

As indicated in Table A4.1, around 69 per cent of all land in South Australia is Crown land with the majority (42 per cent) being Crown land under a pastoral lease. Latest data shows that there are 323 pastoral leases in the state.

Table A4.1: Type and area of Crown land in South Australia [152]

Types of Crown land	Area (ha)	Share of state (%)
Crown land administered by DEW through the Crown Lands Program	4,744,087	4.8
National parks	21,293,062	21.7
Total of above categories of Crown land	26,037,149[153]	26.5
Pastoral lease land under control of PIRSA	41,274,966	42.0

[152] Based on data from the Department of Environment and Water.
[153] Includes all areas of Crown land under the management and control of other agencies and local government plus unalienated Crown land.

Figure A4.1: Type of land tenure in South Australia.

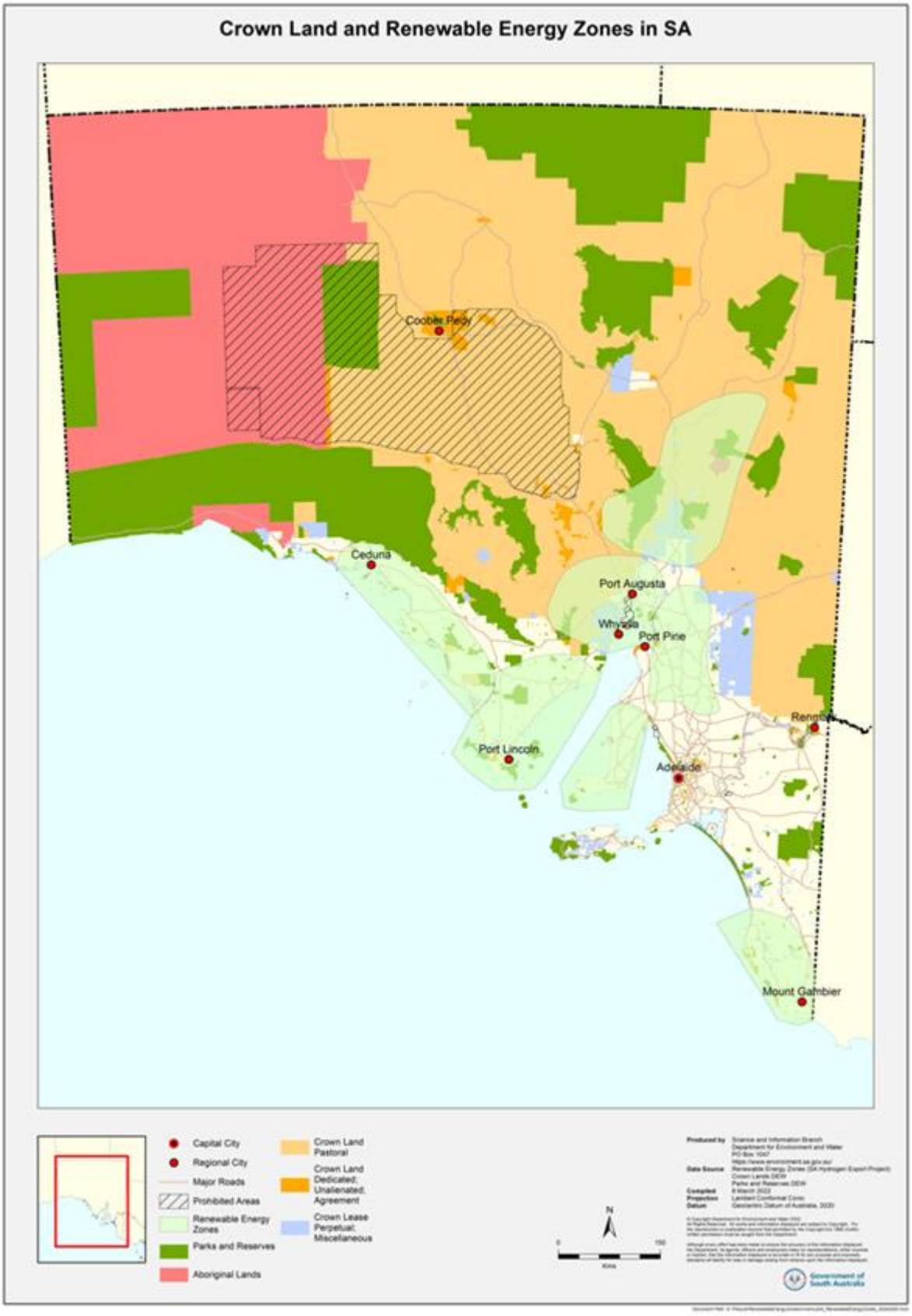


Figure A4.1 on the preceding page maps the extent and location of Crown land and was specifically designed by the Department for Environment and Water (DEW) for this inquiry. The map includes:

- all Crown land under a pastoral lease (yellow area);
- Renewable Energy Zones (REZ's) as proposed by AEMO;
- Aboriginal land held in trust by the Aboriginal Lands Trust pursuant to the *Aboriginal Lands Trust Act 1966*; and
- prohibited areas or land that is owned or controlled by the Commonwealth Department of Defence.

A4.2. Legislative and governance framework

The main regulatory authorities and associated legislation relevant to renewable energy development on pastoral lease land is summarised in Table A4.2 below. Additional regulatory obligations can depend on the nature of the development and the land area involved.

Table A4.2: Overview of pastoral lease regulatory framework relevant to renewable energy development

Legislation	Relevant agency / authority	Application to pastoral Leases / Crown land
***Crown Land Management Act 2009* (+ Regulations) – CLM Act**	Minister for Environment & Water DEW administers and manages Crown land in accordance with CLM Act.	CLM Act provides for the disposal, management and conservation of Crown land. CLM Act does not apply to pastoral lease land (S8) except for: S27 – Ministerial granting of easements (enables a right of way over land to transmit energy etc.) S45 – Ministerial granting of licences (1- to 10-year term) enables non-exclusive access and to undertake specific activities (including building if planning and development approvals are obtained)
***Pastoral Land Management and Conservation Act 1989* (+ Regulations) – PLMC Act**	Minister for Climate, Environment and Water Pastoral Board of SA Pastoral Unit supports the Pastoral Board and Minister for the administration of the PLMC Act.	PLMC Act provides for the management and conservation of pastoral land in SA. Objects include providing for the operation of wind farms on pastoral land concurrently with pastoralist activities. Ministerial approval may provide: • exclusive access to pastoral land prior to granting licence (49J); and • a licence to enable a proponent to access and use of the land for a wind farm (S49B).
Mining Act 1971, Petroleum & geothermal energy Act 2000, Opal Mining Act 1995	Minister for Energy & Mining – DEM	PLMC Act – S22 requires that conditions of a pastoral lease require the lessee to comply with certain Acts including Mining Act etc. This means agreement must be reached with a resource tenement owner where the pastoral land has a resource tenement on it prior to allowing access or use of that land (e.g. S49B requires agreement prior to granting a wind farm on pastoral land with a resource tenement on it).

Legislation	Relevant agency / authority	Application to pastoral Leases / Crown land
***Planning, Development and Infrastructure Act 2016* – PDI Act (+ Code and SPPs)**	Minister for Planning, Planning and Land Use Services (PLUS), Department for Trade and Investment (DTI)	Proponents seeking to develop on Crown land (including pastoral leases) must gain development approval under PDI Act in addition to approvals as per CLM Act and/or PLMC Act to access and use the land. PDI Act process normally includes mandatory referrals and notifications in line with other legislative obligations. Planning code contains specific obligations for renewable energy planning (environmental impact statements) and development (specific limits on wind turbine heights, distance from boundary or setbacks etc).
***Native Title Act (SA) 1994* (+ SA *Aboriginal Heritage Act 1988*)**	Native title - Attorney-General – AGD Aboriginal heritage - Minister for Environment & Water – DEW	A wind farm licence, or solar energy development cannot proceed on pastoral lease land, nor land excised from a pastoral lease until native title has been addressed – includes notification, negotiations and agreement on specific conditions of access and use.
Native Vegetation Act 1991* *Landscape SA Act 2019	Minister for Climate, Environment & Water – Department for Environment and Water	Access and use of Crown land (pastoral leases) may not be granted until relevant obligations relating to protection of natural resources, native vegetation and fauna are met – including significant environmental benefit obligations (SEB).
Electricity Act 1996	Minister for Energy & Mining – ESCOSA	An easement under the CLM Act may not be granted until the proponent has obtained an electricity generation licence.

A4.3 Processes and authorisations

This section provides an overview of the regulatory processes and approvals required to access and use pastoral land for renewable energy purposes.

The PLMC Act is established as an '*Act to make provision for the management and conservation of pastoral land*'. Consistent with that purpose, any applications for access to, and use of, pastoral lease land for renewable energy projects must ensure that pastoralism remains the primary use of that land.

The regulatory processes, obligations and approvals for renewable energy projects on Crown land will vary depending on the tenure over that Crown land (e.g. pastoral lease, unalienated Crown land etc); the type of renewable energy project (e.g. wind farm, solar farm, hydrogen); and additional regulatory obligations associated with the land (e.g. native title, native vegetation, water allowances).

Irrespective of the size and scale of a renewable energy project, the assessment and approvals process to access and use Crown land (including pastoral land) is on a lease-by-lease basis. For example, a project that impacts on several different leases will require each lease to be assessed and any approvals (and associated conditions) will be specific to that lease.

A4.4 Solar developments on pastoral leases

Section 22(6)(c) of the PLMC Act provides that the Pastoral Board (Board) may approve the use of land subject to a pastoral lease for a purpose other than pastoralism. Based on

current legislation, solar projects have been considered to be a 'non-pastoral' use of pastoral land (unless the project directly provides energy for the pastoral activities) as they have prevented pastoralism from operating concurrently due to the nature of the solar development.

To date, the process to obtain approval to access and use pastoral land for solar developments has involved amending the tenure of the land required for the project. There are two general pathways: voluntary surrender and conversation to another form of Crown Lease; or resumption by the Minister responsible for the PLMC Act. The general steps that have been taken for solar developments have been:

- the proponent must seek and obtain agreement with the lessee on the access and use of the land in question – this includes agreeing on appropriate compensation;
- the lessee then applies to obtain Ministerial approval to surrender that land so that it can be excised from the pastoral lease;
- the tenure on that land reverts back to being unalienated Crown land and is dealt with under the CLM Act by DEW;
- the proponent applies for approval of a miscellaneous lease to obtain access to, and use of that land for a period of up to 30 years; or
- the land may be resumed by the Minister under the PLMC Act, with compensation (based on unimproved land use) paid to the lessee and the land then converted to another form of Crown Lease.

The Commission is informed that most solar farm applications on Crown land (all forms) are submitted using the unsolicited bid process and will be managed either by DEW or DTF depending on the project value. There has only been one application received for a solar farm on pastoral lease land.

An alternative to the above process involves the solar development proponent seeking to amend the conditions of the pastoral lease to allow for the non-pastoral purpose on the agreement of the lessee. The Board's guideline on the use of pastoral land for non-pastoral purposes outlines the broad criteria applied by the Board to such applications. PIRSA advise that to date, they have received only one such application and are currently considering the request to vary the pastoral lease for the solar development.

A4.5 Wind farm developments on pastoral leases

In 2014 the objects of the PLMC Act were amended to enable pastoral leases to provide for the operation of wind farms. Division 4 of the PLMC Act provides for:

- Ministerial approval to grant a licence to use a pastoral lease for a wind farm development;[154]
- Ministerial approval to grant exclusive access to the land required in order to conduct investigations and tests for up to 5.5 years prior to the proponent submitting an application for a wind farm licence; and
- the conditions of a pastoral lease must be designed so that the lessee is unable to hinder, obstruct or interfere with a wind farm licence holder (although appeal provisions are included).

As a consequence, applications for wind farm developments on pastoral leases are not treated as non-pastoral land use and may be made direct to the Pastoral Board and relevant

[154] Division 4 of the PLMC Act.

Minister for approval. However, as discussed, the primary purpose of the pastoral lease must still be pastoralism.

PIRSA has advised that, since its inclusion in the PLMC Act in 2014, there have been only three relatively recent applications for wind farm licences on pastoral leases. Two of those applications deal with multiple pastoral leases. PIRSA are working on appropriate criteria to apply to the applications.

A4.6 Renewable energy development and mining provisions on pastoral leases

The PLMC Act contains specific provisions relating to the *Mining Act 1971*, *Petroleum and Geothermal Energy Act 2000, Opal Mining Act 1995,* which impact on the processes and approvals required for renewable energy developments on pastoral leases. In particular, renewable energy project proponents who are seeking to access and use pastoral land over which a resource tenement is held must obtain a land access and use agreement with the holder of the resource tenement (in addition to all other agreements).

A4.7 Easements

An easement essentially provides a renewable energy project proponent with a 'right of way' across land for purposes such as transmission and transport of energy (electricity). An easement over a pastoral lease is granted under the CLM Act – there is no provision in the PLMC Act for granting of easements. Easements are individually negotiated with the agreement of each tenure holder. For pastoral leases, an easement deed must be registered against the pastoral lease and compensation may be paid to the lessee. Normally the application and approval process for easements form part of an overall project application.

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