RepuTex ENERGY

COST AND RELIABILITY ANALYSIS OF A PARIS-COMPLIANT ENERGY TRANSITION IN NSW

November 2020

Re-powering NSW: Achieving 100% Renewable Energy by 2030

Document:	Final Report
Pages:	27
Date:	November 2020
Contact:	Bret Harper, Director of Research
Team:	Electricity
Revisions:	1. Added one paragraph with an update on the NSW Government's legislated Electricity Infrastructure Roadmap. 2. Changed Executive Summary figures for RE100 from annual average capacity growth to cumulative capacity growth.

ABOUT REPUTEX

Established in 1999, RepuTex is a leading provider of advanced modelling services for the Australian electricity, renewable energy and emissions markets. Our forecasts and analysis have been at the forefront of energy and climate thinking for over two decades. We have worked with over 150 customers across Asia-Pacific, including government policymakers, regulators, large energy users and large emitters, project developers and investors.

RepuTex has offices in Melbourne and Hong Kong, with a team of analysts with backgrounds in energy commodities, policy, meteorology and advanced mathematics. The company is a winner of the China Light and Power-Australia China Business Award for energy and climate research across Asia-Pacific.

To learn more, please visit www.reputex.com

CONTACT US
Client Services Australia: +613 9600 0990
Client Services Asia: +852 2899 2418

SUBSCRIPTIONS
Click here to email our Subscriptions team for product and pricing information.

For more, visit http://www.reputex.com/

CONTENTS

1. EXECUTIVE SUMMARY

- RepuTex has been engaged to analyse the potential for New South Wales (NSW) to achieve an energy transition consistent with the Paris Agreement, pursuing efforts to limit the global temperature increase to 1.5° Celsius (C) above pre-industrial levels by transitioning to 100 per cent renewable energy generation by 2030. This analysis identifies technical barriers to reaching such a goal, how these may be overcome, and how much new renewable generation capacity and energy storage must be added to the system each year to reach the goal.

- In 2019-20, coal and gas accounted for almost 83 per cent of electricity generated in NSW, with wind, solar and hydro providing a little over 17 per cent.

- Modelling of current government policies based on the Australian Energy Market Operator's (AEMO's) Central planning scenario forecasts 4.6 GW of new renewable energy capacity will be added to the NSW system over 10 years. This is likely to transition renewable energy generation in NSW from about 17 per cent in 2020 to approximately 43 per cent by 2030.

- Ageing thermal generators are anticipated to face uncertainty around the timing of their closure, and that of their competitors, with operators incentivised to delay announcing retirement decisions due to the potential for improved profitability as other coal-fired plants exit the system. This is calculated to lead to inefficient investment in maintaining or upgrading plants, which could increase the cost of generation, or result in unplanned exits as competitive headwinds increase. Uncertainty around the timeline for the closure of ageing thermal generation is also estimated to exacerbate investor risk, leading to delayed investment or increased risk for new projects, translating into higher electricity prices for consumers.

- In this business-as-usual (BAU) scenario NSW wholesale electricity prices are forecast to be between $50 and $80 per MWh throughout the decade, underpinned by increasing fossil fuel prices and the commissioning of one large-scale renewable energy zone (REZ).

- In contrast, under a 100 per cent renewable (RE100) scenario by 2030, NSW renewable energy generation must grow six-fold from about 12 Terawatt-hours (TWh) in 2019-20, to approximately 72 TWh by 2030-31.

- This implies current variable renewable energy (VRE) capacity of around 8 GW growing to roughly 32 GW in 2030, including:
  - 18,000 MW of large-scale wind and solar; and
  - 6,000 MW of distributed PV

- Energy storage grows by over 10,000 MW, including:
  - Almost 8,000 MW of dispatchable storage including Snowy 2.0;
  - Almost 3,000 MW of behind the meter batteries.

- As the bulk of annual electricity generation in NSW shifts to low-cost renewable energy, coal-fired capacity in NSW is projected to decline from 10 GW in 2020 to zero in 2030.

- Under a RE100 scenario, short-term annual average wholesale electricity prices are forecast to be maintained below business-as-usual levels, with averages oscillating as high as $60/MWh following the closure of Liddell coal-fired units in 2023, and as low as $47/MWh as transmission projects fully connect Snowy 2.0, expand the Queensland interconnection, and open a new Renewable Energy Zone in New England.

- Barriers that must be overcome to achieve 100 per cent renewable energy generation by 2030 (RE100), include:
  - the continued integration into the grid of low-cost VRE generation and flexible capacity,
  - the development of enough transmission infrastructure, and
  - a coordinated, orderly phase-out of coal-fired generation to ensure enough VRE can always be steadily integrated to maintain supply during the transition, including during peak demand events

- New policy and investment settings will be required to overcome the identified barriers, including:
  - a Clean Energy Target,
  - a co-ordinated exit of coal-fired facilities, and
  - an Energy Security Target.

- After Liddell Power Station in the Hunter Valley closes in 2023, the reliability of electricity generation in NSW can be maintained under a RE100 scenario, supported by:
  - the Queensland and Victorian minor transmission upgrades,
  - the commissioning of five capital projects totalling 220 MW granted under the Emerging Energy Program, and
  - the addition of several hundred MW of additional dispatchable energy storage in the form of batteries.

- In November, the NSW Government announced the Electricity Infrastructure Roadmap that is anticipated to deliver 12 GW of new transmission capacity through the Central-West Orana, New England and South-West Renewable Energy Zones (REZs) by 2030. It is also calculated to add at least additional 2 GW of distributed storage capacity. The policy could reinforce NSW's path towards its new-zero by 2050 goal, provide policy certainty and market signals for investment in REZs, both for renewable generation and transmission networks.

2. ABOUT THIS ENGAGEMENT

2.1 Background

On 14 March 2020, the New South Wales (NSW) government released the first stage of its net-zero climate change strategy for 2020 to 2030, aiming to set the state on a pathway to net-zero carbon emissions by 2050. The strategy sets an interim target to reduce emissions by 35 per cent from 2005 levels by 2030, with no stated targets for individual sectors of the economy.

The electricity generation sector is the largest source of greenhouse gas (GHG) emissions in the NSW economy, contributing 39 per cent of NSW's total emissions. While NSW is the only state in the National Electricity Market (NEM) without a renewable energy target, the region is expected to experience a large and rapid transition as renewable energy investment continues to grow and existing coal-fired power stations retire, including the Liddell Power Station by April 2023, anticipated to be followed by Vales Point, Eraring, and Bayswater by the middle of next decade.

The pace of change in the NSW electricity system, however, remains an open question, with the risk of large-scale generators unexpectedly exiting the market ahead of their expected closure dates, while pressure continues to build for governments to adopt more ambitious net-zero timelines – characterised by a phase out of subcritical coal power as early as 2030 – compatible with an average temperature rise of "well below 2°C" (1.4 - 1.8°C) by the end of the century.[1]

Policymakers and market participants must therefore take steps to prepare for faster decarbonisation pathways, ensuring adequate resources are put in place to offset potential early dispatchable capacity losses, while maintaining energy security, reliability, and affordability.

2.2 Scope of Analysis

RepuTex has been engaged by the Nature Conservation Council to analyse the potential for NSW to reach 100 per cent renewable energy generation by 2030. Specifically, analysis seeks to understand the technical barriers to achieving such an outcome, the required intervention to overcome the identified barriers, and the build rate for NSW to achieve 100 per cent renewable energy by 2030. Analysis subsequently considers the impact of such a transition on wholesale electricity prices and energy reliability.

To understand the market impact of a 100 per cent renewable energy scenario on capacity and wholesale electricity prices in NSW, analysis considers the following cases:

1. **Business-as-usual (BAU)**: The pace of the energy transition is determined by market forces under current federal and state government policies, in line with AEMO's 2020 Integrated System Plan (ISP) Central Scenario[2]. This scenario reflects the most likely market drivers based on coal retirements at the end of their technical life, constrained renewable energy investment, current gas prices and technology trajectories, moderate economic growth and energy consumption, and relatively static generation capacity.

2. **100 per cent renewable energy (RE100) scenario**: Analysis of growing VRE capacity and energy generation equivalent to 100 per cent NSW forecast electricity consumption in 2030, while closing all closing all coal-fired units in NSW and maintaining energy reliability and security.

[1] See for example, World Energy Outlook 2020, International Energy Agency, figure 4.7, and Climate Analytics, 2019.
[2] With Central-West Orana Renewable Energy Zone sensitivity.

2.3 Modelling Approach and Key Assumptions

In delivering this project, we utilise our proprietary National Electricity Market Renewable Energy Simulator (NEMRES), which calculates annual generation and capacity expansion decisions in each region of the NEM based on intra-hourly dispatch modelling to imitate the Australian Electricity Market Operator's (AEMO's) dispatch engine. For more information, refer to Appendix B.

A common set of assumptions is applied in each scenario, with different policy settings overlayed to provide a materially different outcomes in each case. Common assumptions include:

- **Fossil fuel prices:** Coal prices escalate at an average rate of 1.5 per cent annually. Financial Year 2020-21 gas prices are assumed to average $5.73 in Sydney escalating an average four per cent per annum over the modelling period to A$7.88 in 2030.

- **Snowy 2.0**: The government's proposed two Gigawatt (GW) Snowy 2.0 pumped hydro project is assumed to be committed and fully commissioned by March 2025.

- **Announced closure and committed capacity additions**: Announced retirements are assumed to occur (e.g. last 3 units of Liddell in April 2023), as is new capacity associated with projects financially committed as of July 2020.

- **Renewable Energy Targets**: All existing state and federal renewable energy targets are assumed to be fulfilled, including the 33,000 GWh large-scale renewable energy target (LRET), the 50 per cent Queensland renewable energy target (QRET), the 100 per cent Tasmania renewable energy target (TRET) and the 50 per cent Victorian renewable energy target (VRET) by 2030.

- **NSW electricity strategy**: NSW renewable energy zones (REZs) are assumed to be developed in line with current statements. The Central-West Orana (CWO) REZ is assumed to add network capacity of 3,000 megawatts (MW), with construction proposed to begin in 2022. Comparably the NSW Government is in the "early stages" of planning an 8,000 MW REZ located in the New England. In line with current policy, development of this REZ is expected to take a number of years to design and build and is not considered in the BAU case.[3]

- **Reliability and Energy Security Target**: Each region is required to have a minimum level of firm capacity available to continuously achieve the real-time balancing of supply and demand. Firm capacity can be shared across interconnected regions based on interconnector capabilities and typical coincident available capacities in neighbouring regions. New South Wales' Energy Security Target is required to be met.

- **Network assumptions**: Network developments are assumed to be undertaken to address network strength as new capacity comes online. This occurs in a staggered way, with actions implemented in stages to match AEMO's ISP, e.g. the Energy Connect interconnector between New South Wales (NSW) and South Australia (SA). Assumptions for energy curtailment and Marginal Loss Factors (MLFs) are estimated and adjusted to reflect these actions, with short-term bottlenecks and losses assumed to be temporary, prompting augmentations within the forecast period to 2030.

- **Technology costs:** Gradual improvements in renewable energy and consumer technology projections are applied from CSIRO's 2020 GenCost report. Trends are assumed to be slow throughout the 2020s (i.e. storage and electric vehicles). More aggressive global decarbonisation is assumed to lead to faster technological improvements, such as reductions in battery costs.

Please refer to the Appendices for further details on our modelling approach and other assumptions.

[3] NSW Government Electricity Strategy; https://energy.nsw.gov.au/renewables/renewable-energy-zones

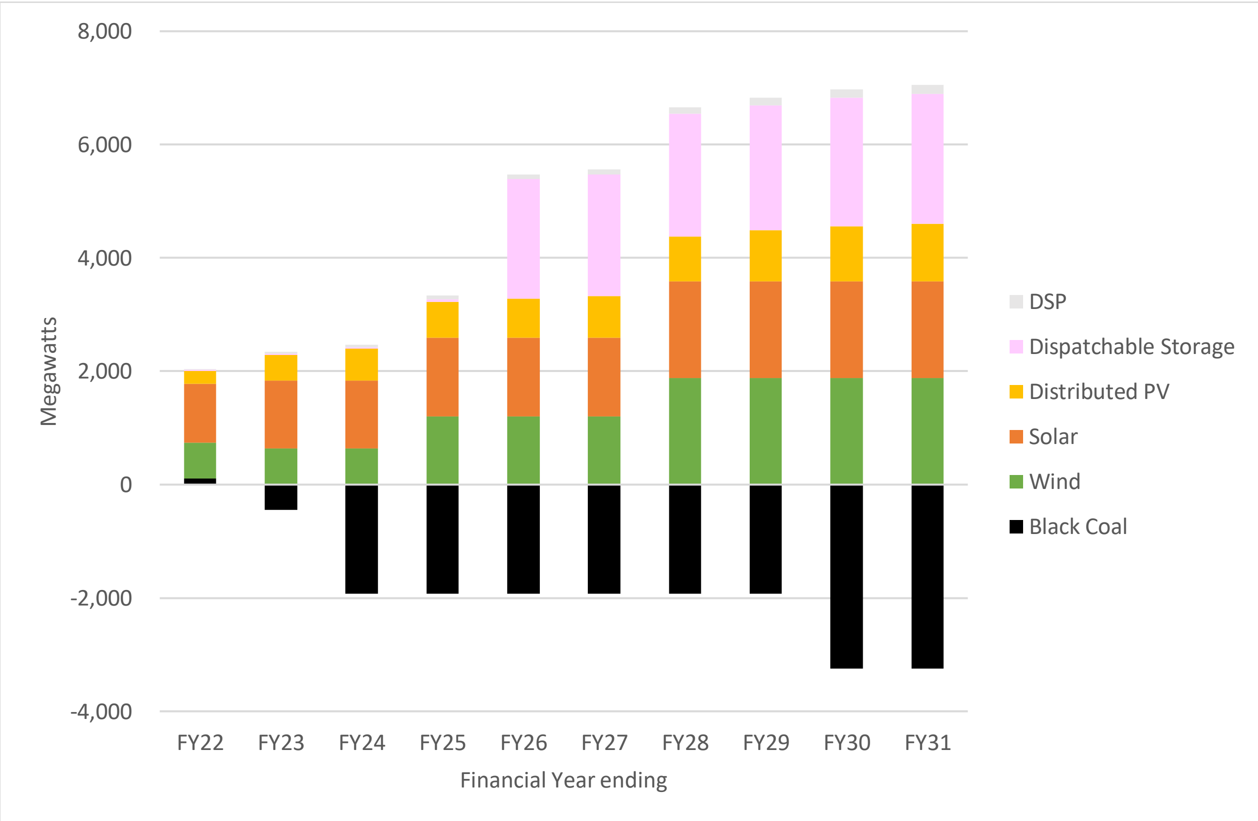
3. RESULTS: BUSINESS-AS-USUAL

3.1 Change in Installed Capacity in NSW

Analysis under our BAU case forecasts around 2.3 GW[4] of new large and small-scale renewable energy capacity being added to the NSW electricity system by FY23. Currently committed large-scale projects were driven by developers seeking to access limited transmission infrastructure, attractive long-term power purchase agreements (PPAs), the Commonwealth renewable energy target, rapidly falling solar and energy storage costs, and the previously high electricity price environment.

The CWO REZ is anticipated to add two GW of large-scale renewable energy capacity, with the first GW added by FY25, and another GW ahead of a second coal fired plant closing in 2029. Project commissioning in all other NSW REZs is, however, expected to be constrained for the remainder of the decade as transmission access blocks further large-scale VRE development in the state. Annual average additions could amount to between 330 MW of new renewable capacity each year. In cumulative terms, the BAU case estimates 3.3 GW of large and small-scale renewable capacity will be commissioned in NSW by 2025, growing more slowly to only 4.6 GW by 2030.

Figure 1: Cumulative NSW New Entry / Retired Capacity by Technology to 2030.



Note: Stacked bars represent change in capacity from July 2020 at the beginning of the financial year.
Source: RepuTex, 2020.

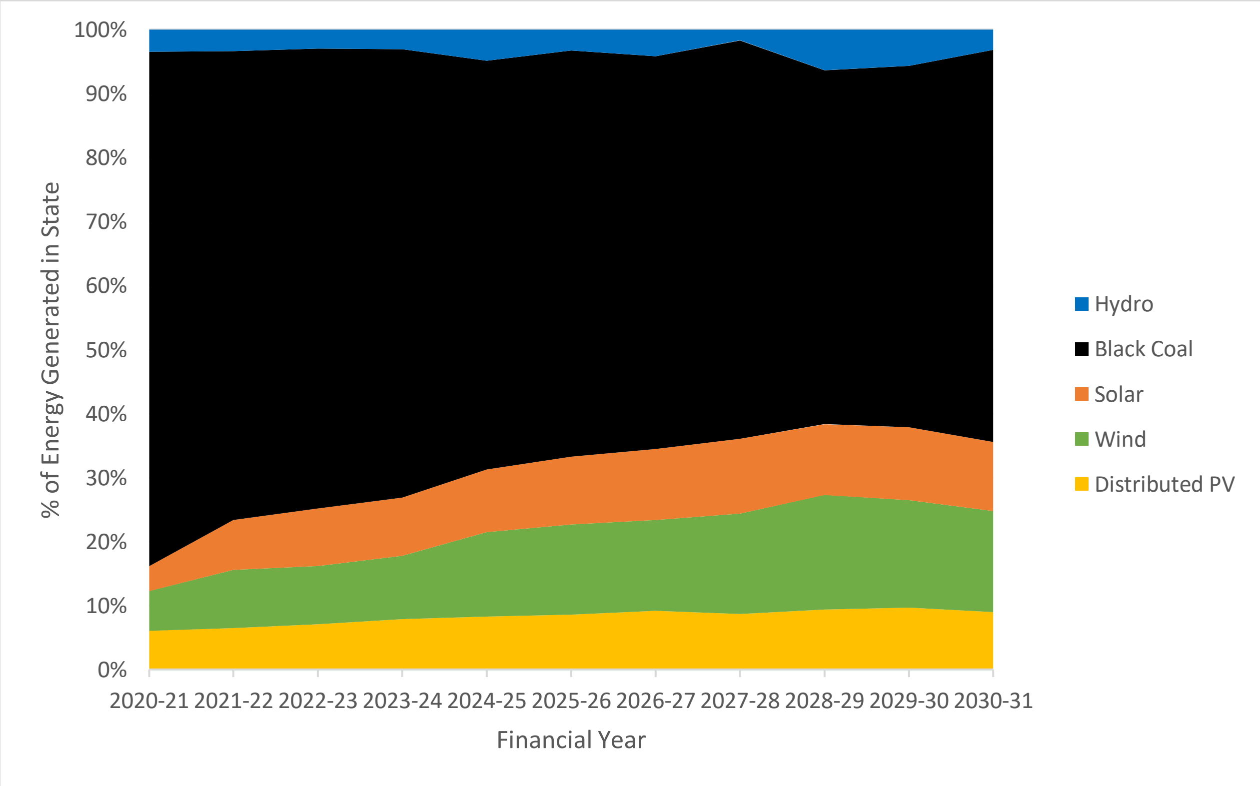
[4] 1.7 GW of this large-scale solar and wind capacity is already committed, while 0.45 GW is modelled to come from distributed PV.

Unlike neighbouring regions, which are forecast to accommodate a growing supply of variable renewable energy (VRE), opportunities for developing new dispatchable capacity in NSW are likely to remain limited by the presence of excess black coal-fired generation capacity and the addition of 2,000 MW of new capacity from Snowy 2.0. By the end of the decade, remaining black-coal capacity is modelled to benefit from growing VRE in neighbouring regions as large coal-fired facilities close in other states. Queensland, South Australia, and Victoria are all anticipated to experience steepening 'duck curves' as increased solar generation reduced demand during the day, but evening demand peaks require generation to increase be large amounts over a relatively short time-frame. Additionally, while Victoria's brown coal units have the lowest fuel costs of coal-fired generators, they are relatively inflexible and therefore vulnerable to the rapidly falling minimum demand forecasts during the autumn and spring 'shoulder' seasons within the region. As a result, neighbouring regions are expected to more often rely on NSW's ramping capacity to meet morning and evening peaks.

Without further investments in VRE and transmission, NSW is projected to accommodate only two major thermal plant closures before the end of the decade, with the scheduled closure of Liddell in 2023 and an additional 1,320 MW closed by 2029-30 due to declining profitability and advanced age. Additional unexpected coal plant closure, for example due to plant failure or declining profitability, would pose a risk to reliability and security of supply in this scenario without early investment in additional VRE, dispatchable capacity and interconnection.

3.2 Energy Generation in NSW

Figure 2: Annual change in energy generation in NSW 2020 to 2030.



Source: RepuTex, 2020.

Replacement energy for the closure of two of NSW large black coal-fired facilities could come from the remaining black-coal units in NSW generating more, or cheaper sources of energy as they become accessible. The degree to which this cheaper energy is available is largely dependent on the timing of transmission infrastructure. As new transmission is built to the CWO REZ and neighbouring regions of Queensland, South Australia, and Victoria, cheaper energy will tend to displace any gains made by the remaining black coal fired units. During both day and night, imports of lower cost energy from a combination of excess brown coal and VRE is expected to grow as transmission infrastructure is upgraded, eroding the high volumes black coal fired generation throughout the decade.

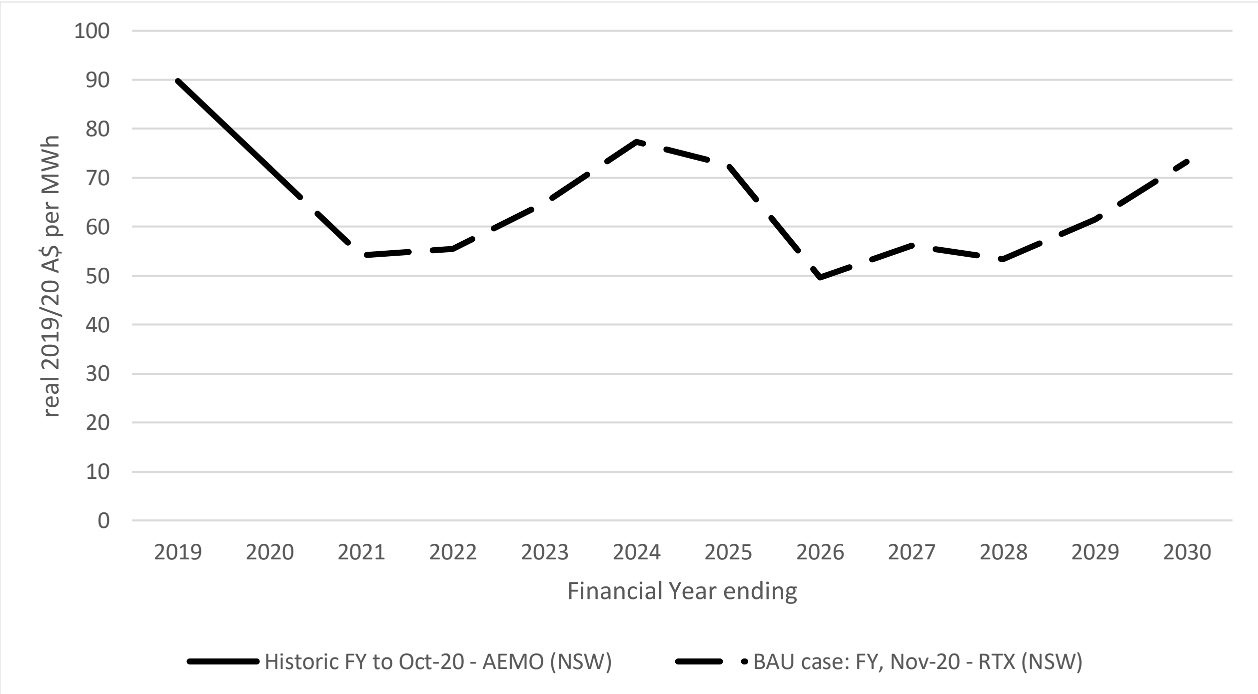
Committed projects and the planned development of the CWO REZ is likely to see NSW VRE generation quickly grow from about 18 per cent in 2020-21 to approximately 33 per cent by 2030-31. With more large-scale renewable energy development in NSW anticipated to be blocked by transmission constraints, however, black coal is calculated to continue to provide most of the energy in NSW under the BAU case.

3.3 Long-term Wholesale Electricity Price

Under our BAU case, long-term NSW wholesale electricity prices are predicted to decline from around $90 per MWh (/MWh) in 2018-19 to between $50 and $60/MWh, underpinned by declining fossil fuel prices and the commissioning of large-scale renewable energy projects.

After the closure of Liddell in 2023, prices are projected to increase about 40 per cent to more than $70/MWh before declining again until the closure of a second black coal-fired plant in 2029. The BAU case assumes a relatively static situation in NSW - in contrast to neighbouring states with renewable energy targets - with minimal supply additions beyond current commitments. NSW instead benefits from its central position in the NEM, with access to a variety of cheaper coal and VRE resources from neighbouring regions, while having a relatively large amount of flexible capacity to call upon in all except the most extreme hours of maximum demand. Together, these factors should maintain relatively low wholesale electricity prices throughout the decade, however, this could supress traditional signals for the private sector to invest in more dispatchable capacity within NSW ahead of major closures.

Figure 3: BAU case NSW annual wholesale electricity prices.



Source: RepuTex, 2020.

Although wholesale electricity prices are anticipated to remain relatively low in the BAU case, this doesn't necessarily hold true for long-term consumer costs under a 3 to 4°C warming scenario. For example, several long-term factors are likely to increase business and residential expenses, including the likely increase in severe weather, which could increase electricity bills. Other costs associated with a 3 to 4°C scenario are estimated to be much larger, with damage per person in Australia projected to be more than A$19,000 per household, per year, every year.[5]

[5] At 4°C global warming, damages per person in Australia are projected to be US$4,886, or roughly US$13,945 per household, per year, every year." Sources: Uni Melbourne, Journal: Earths Future, the Australian Institute.

4. TRANSITIONING NSW TO A 100% RENEWABLE ENERGY SYSTEM BY 2030

4.1 Technical barriers to achieving RE100 by 2030

Under BAU, NSW renewable energy generation is anticipated to grow from about 17 per cent in 2020 to approximately 33 per cent by 2030. As an alternative pathway, this scenario calculates the additional measures that could be implemented to transition the NSW market away from coal-fired electricity generation to 100 per cent renewable energy in the same timeframe. Specifically, this entails the addition of enough renewable capacity to generate the energy equivalent of NSW's annual energy consumption, while maintaining energy security and reliability requirements in a cost-effective way.

In order to meet these objectives, several barriers must be overcome, including:

- Ensuring the phase-out of coal-fired generation is orderly to safeguard against several coal-fired generators closing at once without an adequate amount of replacement capacity to address peak demand events and maintain price competition;
- The continued integration of low-cost VRE generation and flexible capacity; and
- The development of sufficient transmission infrastructure to overcome congestion and support new capacity additions.

These barriers are interrelated. For example, transmission infrastructure will be required to transition NSW from being dependent on a number of large coal-fired plants, to being supported by a diverse set of intra- and inter-state energy sources. Major transmission infrastructure normally has a lead time of several years, however, and will largely determine when, where, and how much new renewable energy and storage capacity can be brought onto the system. This in turn determines the how quickly coal-fired facilities can retire, while still maintaining a secure and reliable electricity system.

To underpin this scenario, we assume the development of policy and investment settings to overcome the identified barriers. Settings are designed to rapidly transition the NSW energy generation sector via a co-ordinated, flexible, and transparent plan to achieve 100 per cent renewable energy by 2030, which minimises uncertainty and ensures sufficiently strong signals for private sector investment. These policy and investment solutions are outlined below.

4.2 Overcoming the identified barriers

4.2.1 The development of a Clean Energy Target and the co-ordinated exit of coal-fired facilities

Ageing thermal generators face uncertainty around the timing of their closure, and that of their competitors, with operators incentivised to delay announcing retirement decisions due to the potential for improved profitability as other coal-fired plants exit the system. This can lead to inefficient investment in maintaining or upgrading plants, which can increase the cost of generation, or result in unplanned exits as competitive headwinds increase. Uncertainty around the timeline for the closure of ageing thermal generation also exacerbates investor risk, leading to delayed investment or increased risk for new projects, both of which can translate into higher electricity prices for consumers.

In a RE100 scenario, coal-fired capacity is calculated to close much sooner than is currently anticipated, with large increases in very low cost VRE displacing other higher cost forms of bulk energy generation. This requires the remaining dispatchable capacity to extract value from 'following' VRE up and down. As variability increases, however, this eventually favours more flexible power, rather than the economics of supplying large amounts of energy.

Even with current mechanisms such as the notice of generation closure (~three years) and planning documents such as the Electricity Statement of Opportunities (ESOO), there is a risk that a large-scale generator may unexpectedly exit the market before adequate resources are put in place to offset associated dispatchable capacity losses (and other system services provided by larger generators). A coordinated policy framework will therefore be required to maintain energy reliability and security, and avoid high prices, by guiding investment in new generation, utility storage, demand-side management, and interconnections ahead of expected coal-fired facility retirements.

To support the dual energy transformation goals of ensuring the co-ordinated phase out of coal-fired generation and continued investment in renewable energy generation, we assume the design of a clean energy target (CET) for NSW, setting a trajectory for new renewable energy generation increasing from around 13 GWh in 2020-21 to 72 GWh in 2030-31. During this timeframe, coal-fired generation is assumed to be proportionally reduced as renewable energy generation increases, with uneconomical coal-fired facilities retired as annual capacity factors fall below 50 per cent. In considering the closure schedule (refer to Section 5.3), consideration is primarily given to operating costs and the reliability of each facility's coal supply, along with recent investment in upgrades.

4.2.2 Ensuring a long-term Energy Security Target is met

The primary risk to NSW's electricity reliability is a capacity shortfall attributed to a large generator exiting the market prior to its dispatchable capacity having been sufficiently replaced, or due to an unplanned outage at multiple large units. NSW is therefore planning to establish an Energy Security Target (EST) to provide certainty about how much new electricity is needed to support a reliable energy system.

The proposed EST is set at an amount equivalent to peak demand experienced in NSW every 10 years (10 per cent probability of exceedance) - which typically occurs under heatwave conditions - plus a reserve margin to cover the loss of two of the largest NSW generating units. AEMO forecasts 1-in-10-year peak demand for the summer of 2020-21 to be 13,786 MW, rising to 14,523 by 2029-30.[6] The firm supply rating for each of the two largest generating units in the state is currently 680 MW (Eraring). Accordingly, the EST for 2020-21 is anticipated to be 15,146 MW.[7] We calculate NSW firm capacity and imports from other states for 2020-21 at 15,545 MW. Therefore, the EST could be met this year with the help of imports from other states.

As the market recovers from COVID-19 impacts this year, maximum demand is estimated to increase next year, and resume a slight upward trend for the remainder of the decade. This is expected to proportionally increase the EST.[8] Meanwhile, as coal-fired units are closed, the amount of firm capacity and imports from other states may fall without investment in new dispatchable capacity and interconnectors. Because new large capacity and interconnector projects can take several years to commission, it is important to monitor whether commitments in the private sector are likely to maintain the EST in the years ahead.

To avoid the potential loss of reliability over the forecast period, the RE100 scenario predicts needing an additional 600 MW of dispatchable energy storage by the summer of 2023-24, along with the commissioning of projects under the Emerging Energy Program, the early completion of the EnergyConnect interconnector to SA (available by the summer of 2023-24), and the QNI and VNI minor transmission upgrades currently being completed.

4.2.3 The development of medium and deep energy storage

In the critical period between the closure of Liddell and the commissioning of new transmission infrastructure in the mid-2020s, new dispatchable energy storage is anticipated to play an important role in improving NSW reliability in a variety of low probability, but high consequence events. For example, if a major interconnector becomes unavailable, demand exceeds the 1-in-10-year forecast, EnergyConnect is not completed as quickly as assumed, and/or more than two coal-fired units are unavailable, hundreds of

[6] AEMO, Electricity Statement of Opportunities (2020).
[7] i.e. 13,786 MW + (680 MW x 2) = 15,146 MW
[8] For as long as NSW large coal units remain available. After the large coal units are closed, smaller gas and hydro units are forecast to lower the EST.

MW of dispatchable energy storage could help to keep the lights on and reduce the duration and magnitude of price spikes.

Medium storage (with at least 4 hours of energy generation) in NSW is forecast to provide additional flexibility to absorb midday solar. NSW also has the advantage of interconnections to three other regions (following the development of the proposed EnergyConnect project), giving greater scope for sharing excess renewable generation and dispatchable reserves with other regions. Shallow battery storage (that tends to cycle daily) is rapidly proving to have a robust business case, evidenced by development of 'big battery' and Virtual Power Plant (VPP) projects that value fast ramping and FCAS services over energy value. Medium storage projects, on the other hand, are only forecast to achieve a full cycle on approximately 40 per cent of days, which makes the business case less attractive.

Although there are some projects proposing to build or upgrade pumped hydro facilities, the long lead-time of these projects, combined with transmission uncertainty and competition from other technologies (such as long-duration batteries) can result in these projects being leap-frogged. This is partially because the energy arbitrage value that pump hydro projects rely on is currently restricted to a limited number of events. This medium storage capacity will become more critical around 2024-25 when Humelink may not yet be commissioned, but thermal capacity begins to move to more flexible operation, where it can go offline during times of light load or low prices.

Deeper energy storage (>24 hours) is also useful given:

- Its ability to reduce gas powered generation, lowering GHG emissions and electricity prices.
- Its availability during periods in which demand is high, yet renewable generation is relatively low (<20% of demand), assisting in reducing reliability risks.
- Its ability to reduce the size of network augmentation.
- Its ability to sufficiently replenish prior to times of peak demand, allowing for an extra margin of safety in real world situations without perfect foresight.
- Its ability to take advantage of seasons with modest energy demand and strong renewable availability, e.g. spring, when it can spend more time charging, or refilling, than generating.

Furthermore, deep storage availability and dispatchability becomes more critical as thermal dispatchable capacity retires. Although the value of deeper storage in reducing VRE spill is evident, this must be balanced against the higher capital cost of additional longer-term storage. Current modelling suggests hundreds of MW of deep pumped hydro, in addition to Snowy 2.0, could make good use of at least part of the excess renewable energy generated throughout the year. Policymakers should be aware, however, there are several emerging technologies - e.g. hydrogen or other green fuels - that may prove to be of higher value, particularly in combination with non-electricity sector opportunities. Indeed, a RE100 scenario may well place NSW in a position to move significantly beyond 100 renewable energy after 2030.

4.2.4 The development of transmission infrastructure

As has become clear in recent years, the most immediate barrier to developing large amounts of more renewable energy is not a lack of renewable resources, financing, or construction resources, but the physical connection and delivery of energy to the NEM. The transmission network in renewable rich zones was designed to deliver relatively small amounts of power to rural areas rather than receive and transmit large amounts of power generation across the state to cities. As a result, the current transmission system in those areas is inadequate to connect the volume of new renewable development necessary, while expanding transmission typically takes several years to accomplish.

New transmission projects, such as EnergyConnect and HumeLink, are well underway and are anticipated to be delivered in the next five years. These projects are calculated to upgrade NSW's southern transmission network, providing full access to new capacity at Snowy 2.0 and the Wagga Wagga REZ. A RE100 scenario, however, could necessitate transmission access to at least four of NSW's nine REZs. While each REZ is already served by the NEM, they do not currently have enough transmission to accommodate more than a few hundred MW of new generation, despite having the potential to develop thousands of MW of new renewable capacity.

The NSW government has announced the prioritisation of three Renewable Energy Zones (REZs): Central West Orana, New England, South West NSW. For the purposes of this modelling, we estimate the major development of North West NSW REZs based on estimated industrial load growth in the Narrabri region,

the lack of specific plans for the future development of the South West NSW REZ, and the North West NSW REZ's proximity to a new high voltage backbone (associated with the QNI Large upgrade), relative to the transmission upgrades needed to improve stability in South-West NSW.
Under a 100 per cent renewable energy scenario, transmission infrastructure to priority REZs will need to be developed earlier than currently expected to accommodate a rapid increase in renewable energy by the mid-2020s, and to prepare for the closure of coal-fired units (scheduled or unscheduled) with minimal reliability and price impacts. In addition to accessing new REZs, the closure of coal-fired capacity is forecast to require extending existing transmission infrastructure serving the major coal-fired plants to add more flexibility and redundancy links into the cities. In contrast to centralised dispatchable plants, major demand centres in Sydney and Newcastle may need to be able to access larger and more variable power flow between the northern and southern portion of the grid. These portions of the grid are modelled to, in turn, connect with larger interconnections to neighbouring regions in Queensland, South Australia, and Victoria. These larger interconnectors will be crucial to exporting excess renewable energy, and provide increased options for dispatchable power during regular high demand/low supply events.

Given the long-lead time that is necessary to build transmission infrastructure (normally four to eight years), upgrades will be required to be treated as a priority to unlock a path to 100 per cent renewable energy by 2030. Although each project required for this scenario has already been identified by AEMO and TransGrid planning documents, many are not currently expected to be necessary until the late 2020s or 2030s. If viewed from the perspective of a RE100 by 2030 scenario, however, there is a need for these projects to progress at a much faster rate.

In line with our existing capacity assumptions, the RE100 case assumes the following upgrades and commissioning of transmission infrastructure:

Figure 4: Development of transmission infrastructure to allow for RE100 scenario.

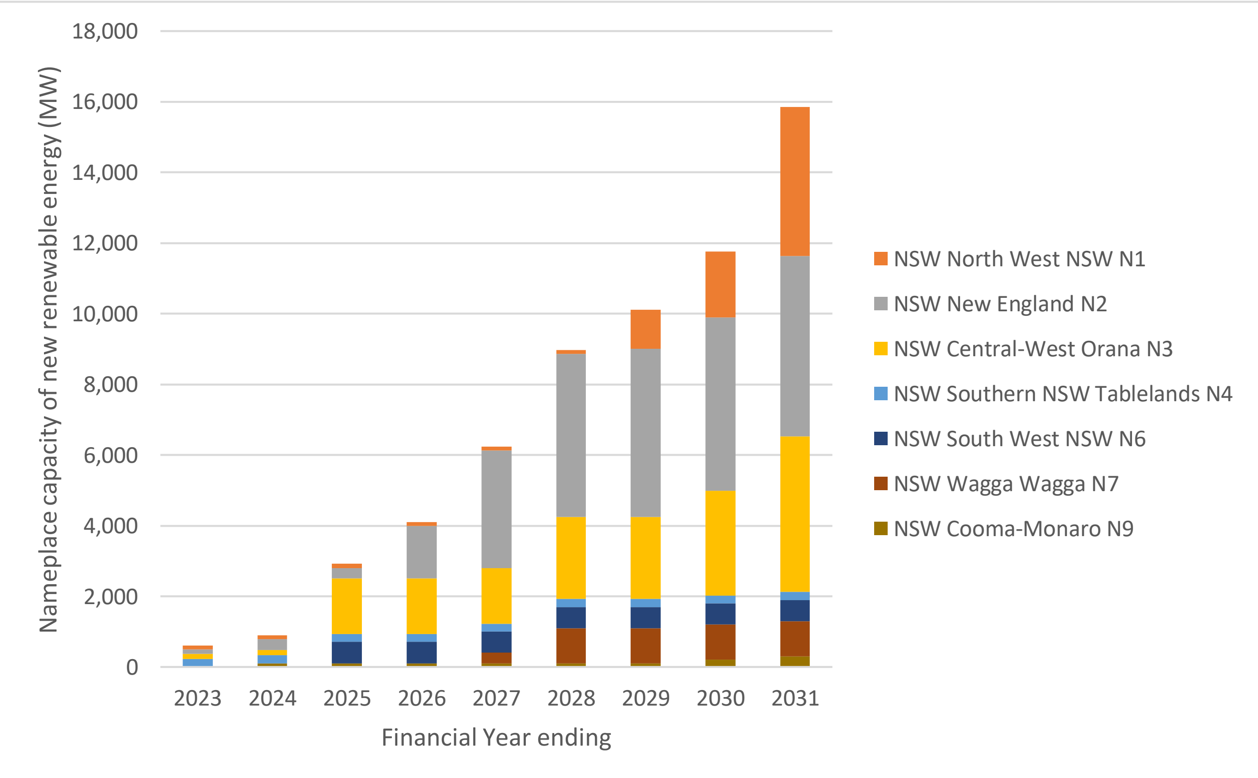
Project	Need	Capacity	Commissioning Timing by scenario[9]	
			BAU	RE100
QNI Minor	Additional energy supply from Queensland, help transport energy from New England REZ to cities, and improve the capacity for existing generation to meet peak demand. Satisfied RIT-T in April 2020.	Increase transfer from Qld (+165-215 MW depending on wind)	June 2022	June 2022
VNI Minor	Recommended critical short-term investment to increase transfer capacity of existing corridor from Vic to NSW.	Increase transfer from Vic to NSW (+170 MW)	Jun 2022	Dec 2021
EnergyConnect: a proposed 330kV interconnector between SA and NSW	Access and share VRE between NSW, SA, and Vic;	Increase transfer from SA (+800MW) & access SW NSW REZ (+380 MW)	Jun 2024	Dec 2023
HumeLink: a proposed major transmission line in NSW to connect the Snowy Mountains hydro scheme to the Greater Sydney load centres	Greater access for major load centres to renewable and peaking generation in southern NSW and VIC during times of peak demand; unlock additional solar energy in southern NSW.	Access additional capacity of Snowy 2.0 (+2,000MW) & Wagga Wagga REZ (+1,000MW)	Jun 2025	Jun 2025
Central West Orana (CWO) REZ links: expansion of the central	Connect CWO REZ to existing HV backbone	Access CWO REZ stage 1 (+3,000 MW) & stage 2 (+5,000MW)	2024-25	2024-25 (stage 1)

9 Date ranges refer to options with two staged commissioning. Please refer to Appendix A for further information.

west network to add generation hosting capacity as part of the NSW Electricity Strategy	between Bayswater and Mt Piper			to 2029 (stage 2)
New England REZ: network expansion	Upgrades to connect New England REZ to HV backbone between NSW cities and Qld	Access New England REZ Stage 1 (+4,500MW) & Stage 2 (+6,000 MW)	2035-36	2025 (stage 1) to 2029 (stage 2)
Major demand centre reinforcement	Extend and reinforce HV backbone that exists between cities and coal plants.	-Increase transfer from Snowy, SA and Vic via southern loop and NW NSW, New England, & Qld via northern loop.	2026-27 to 2032-33	2025 to 2029
QNI Medium & Large: interconnector upgrades	Increase efficient access to VRE generation at NSW REZs & share resources more efficiently between regions as coal-fired generators retire.	Increase transfer from Qld (1,370MW) & access NW NSW & New England (+2,000 MW)	2032-33 (Option 2E); 2035-36 (Option 3E)	Dec 2025 to 2029
VNI West: proposed interconnector between Vic and NSW	Access and share VRE between regions; maintain supply reliability following closure of coal-fired generation.	Share VRE and dispatchable power resources more efficiently & access SW NSW REZ (+1000MW) via the 'Kerang route'	2035-36 (Option 6)	2027-28
North West New South Wales (NW NSW) REZ expansion	Access additional solar energy near the NSW-Qld interconnector to fulfill 100% target	Access NW NSW (+4,000MW)	2032-33	2030

Of the transmission projects listed in Figure 4, the first stages of the CWO (+3 GW) and New England (+4.5 GW) REZ links are the most crucial to the RE100 case, allowing for the full commissioning of at least 4 GW renewable energy capacity by 2025-26. Upgrades and commissioning of transmission infrastructure is modelled to continue growing to 16 GW by 2030-31.

Figure 5: Installed capacity by REZ (MW) – RE100 (guided by timing assumptions in Figure 4).



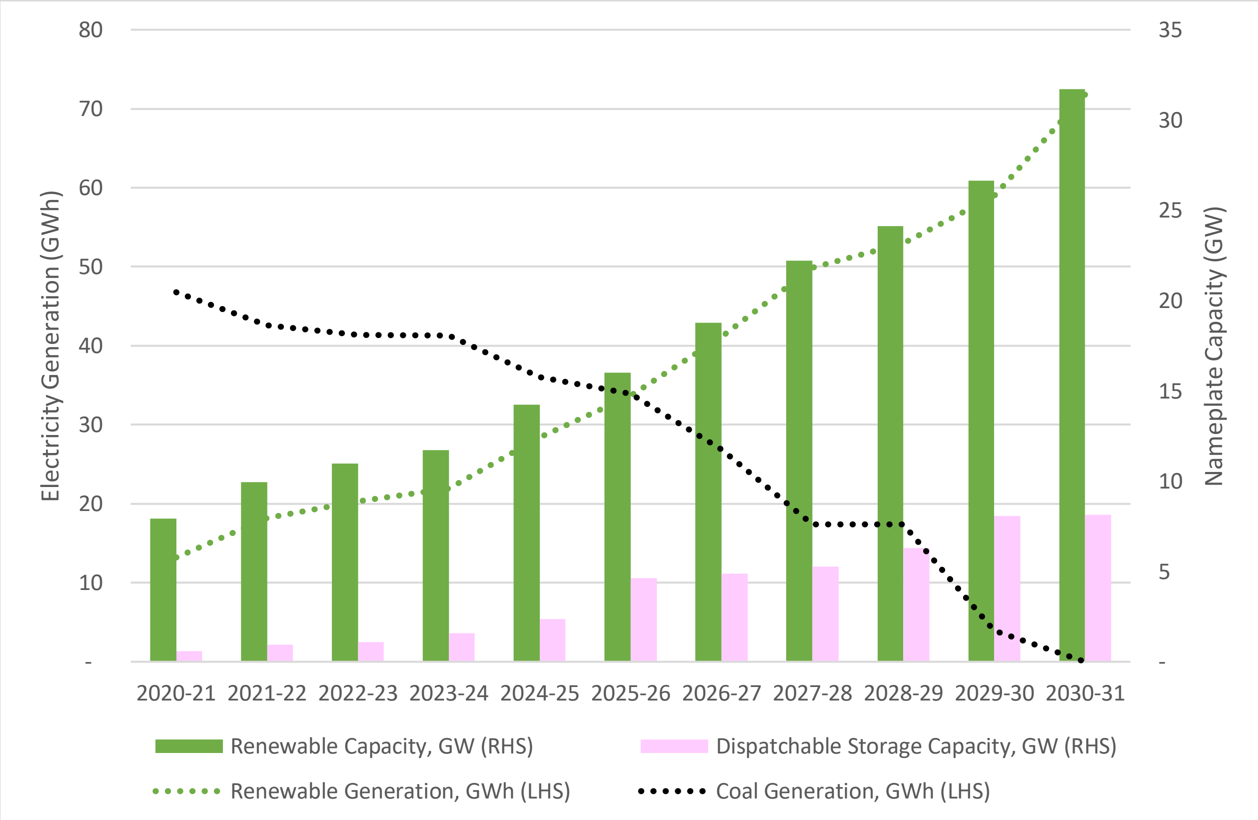
Source: RepuTex Energy, 2020. Note: Capacity installed is assumed to be constructed by the beginning of each financial year. Years are financial year ending. This includes the cumulative development of VRE capacity beyond existing and committed projects.

5. RESULTS: RE100 SCENARIO

5.1 Change in Installed Capacity in NSW

As the impact of COVID-19 dissipates, annual electricity consumption is expected to recover to around 70 TWh in the near term, growing slightly to approximately 72 TWh by 2030.[10] To achieve 100 per cent renewable energy by 2030, NSW renewable energy generation will therefore need to grow six-fold from around 12 TWh today, to 72 TWh by 2030. Although initially constrained by the build-out of new transmission infrastructure in the first half of the decade, new large-scale renewable capacity is modelled to accelerate in the second half of the decade. From a current renewable capacity of 8 GW, we calculate capacity will grow to 32 GW in 2030, translating to an average of 3-4 GW of new capacity each year, annually generating around 72 TWh of electricity.

Figure 6: Clean energy target for NSW in RE100 scenario.



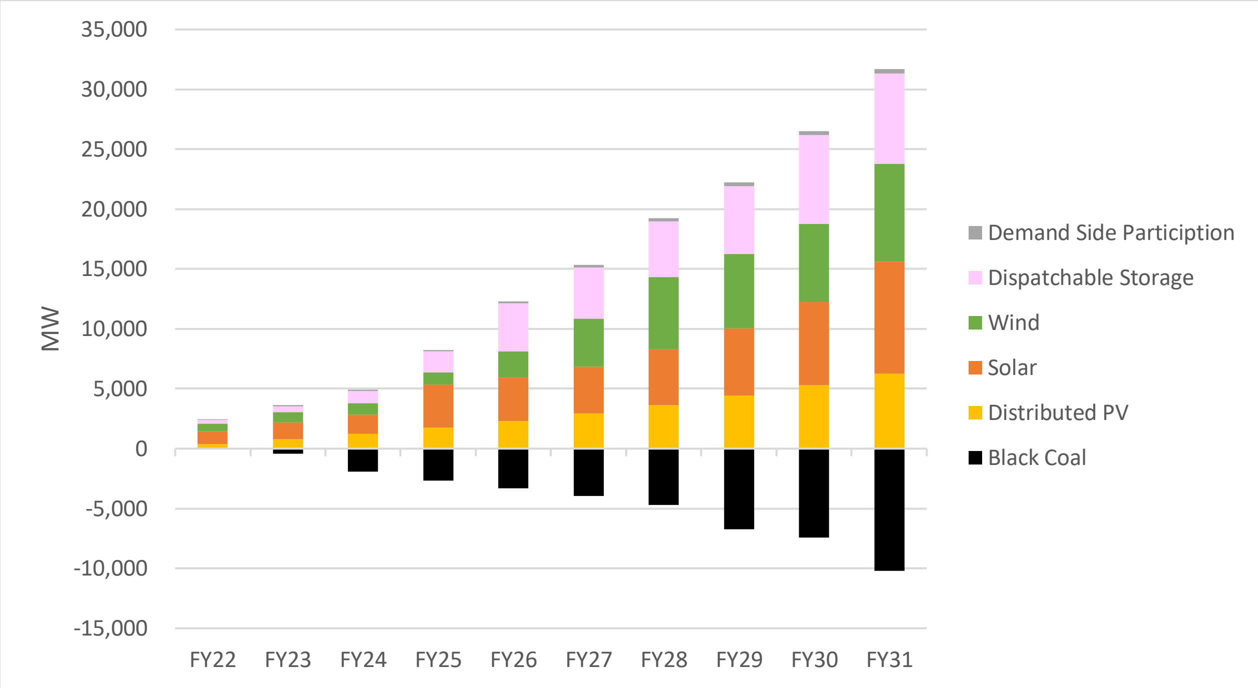
Source: RepuTex Energy, 2020

Note: Commissioned capacity values (GW) correspond to the beginning of each financial year (1 July), while generation values (GWh) correspond to annual generation at the completion of each financial year.

As shown in Figure 6, although the annual build rate is ambitious over a 10 year period, it represents reasonable annual average additions of 2.4 GW of large-scale renewables, 0.6 GW of dispatchable storage[11], 0.65 GW of distributed PV and 0.3 GW of BTM batteries. Of the total 32GW of additions, 18 GW could come from new large-scale solar and wind, backed by almost 8 GW of new dispatchable storage, (including 2 GW from 'Snowy 2.0'), and 6 GW from 'Behind-the-Meter' (BTM) distributed solar PV, almost half of which is forecast to be matched with its own BTM small-scale batteries storage.

[10] AEMO 2020 ESOO and TransGrid NSW Transmission Annual Planning Report 2020.
[11] Calculation of average additions excludes 2,000 MW of storage assumed to be added through 'Snowy 2.0'.

Figure 7: Annual NSW New Entry / Retired Capacity by Technology to 2030.

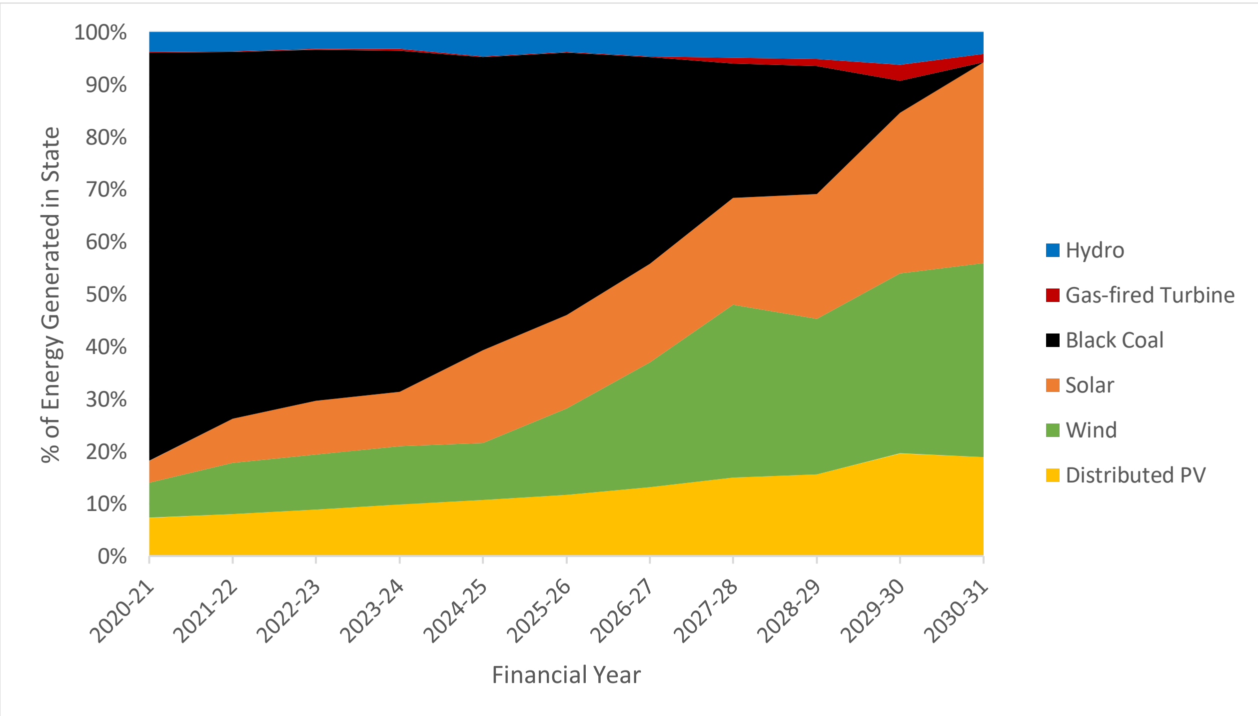


Source: RepuTex Energy, 2020

5.2 Energy generation in NSW

Continuous growth in in VRE capacity is anticipated to translate into considerable growth in low-cost VRE generation. This is calculated to displace black coal fired generation in NSW with increasing frequency, and eventually erode the case for black coal fired generation entirely. Therefore, instead of energy generation continuing to shrink in NSW, generation could grow to the point that NSW is estimated to become a net energy exporter to neighbouring regions in years when there is excess coal or VRE output.

Figure 8: Annual change in energy generation in NSW 2020 to 2030.



Source: RepuTex Energy, 2020.

5.3 Retirement of coal-fired generation

With the bulk of annual electricity generation provided by low-cost renewable energy, coal-fired generation is estimated to decline by 10 GW by 2030, roughly in proportion to the amount of growing renewable energy, reaching zero coal-fired generation after the winter of 2029. As this occurs, existing coal-fired generators are expected to transition from providing 'baseload' energy generation to a critical bridging role, providing dispatchable power to ensure that energy reliability and security are maintained. This dispatchable power function is forecast to be best provided by coal-fired generators given the current lack of gas, hydro, interconnections, storage or other means in NSW to fulfill this role.

In the RE100 scenario, coal-fired capacity is anticipated to close much sooner than is currently assumed under our BAU case. In line with the implied CET trajectory shown in Figure 6, coal-fired generation is assumed to be proportionally reduced from 47 GWh in 2020-21 to zero in 2030, in line with the addition of replacement capacity. As noted in Section 4.2.1, uneconomical coal-fired facilities are assumed to be permanently closed as annual capacity factors fall below 50 per cent, with the closure schedule based on the relative operational costs and reliability of coal supply, along with recent upgrade investments. As a result, Bayswater is modelled to be the last coal plant to close, running at around half the fuel cost of other facilities, with more reliable access to Hunter Valley coal, and recent upgrades to each of its four units.

In cases where plants have offsetting advantages in terms of fuel costs and/or security, secondary factors include the age of a unit's turbines, including recent upgrades. For example, in this modelling, Mt Piper has newer turbines and is therefore closed after Vales Point, however, this could be reversed if announced upgrades to Vales Point are committed. Given these plants are of similar size, the impact is similar regardless of which plant is modelled to close first.

Figure 9: Indicative coal-fired unit closures modelled in RE100 scenario

Closure Date	Closed permanently (MW nameplate)	Modelled as units
April 2022	500	Liddell4
April 2023	1,500	Liddell1,2,3
April 2024	720	Eraring1
April 2025	660	Vales Point1
Sep 2025	660	Vales Point2
Sep 2026	720	Eraring2
Sep 2027	2,040	Eraring3, Mt Piper1&2
Sep 2028	720	Eraring4
Sep 2029	1,370	Bayswater1&2
Apr 2030	1,370	Bayswater 3&4

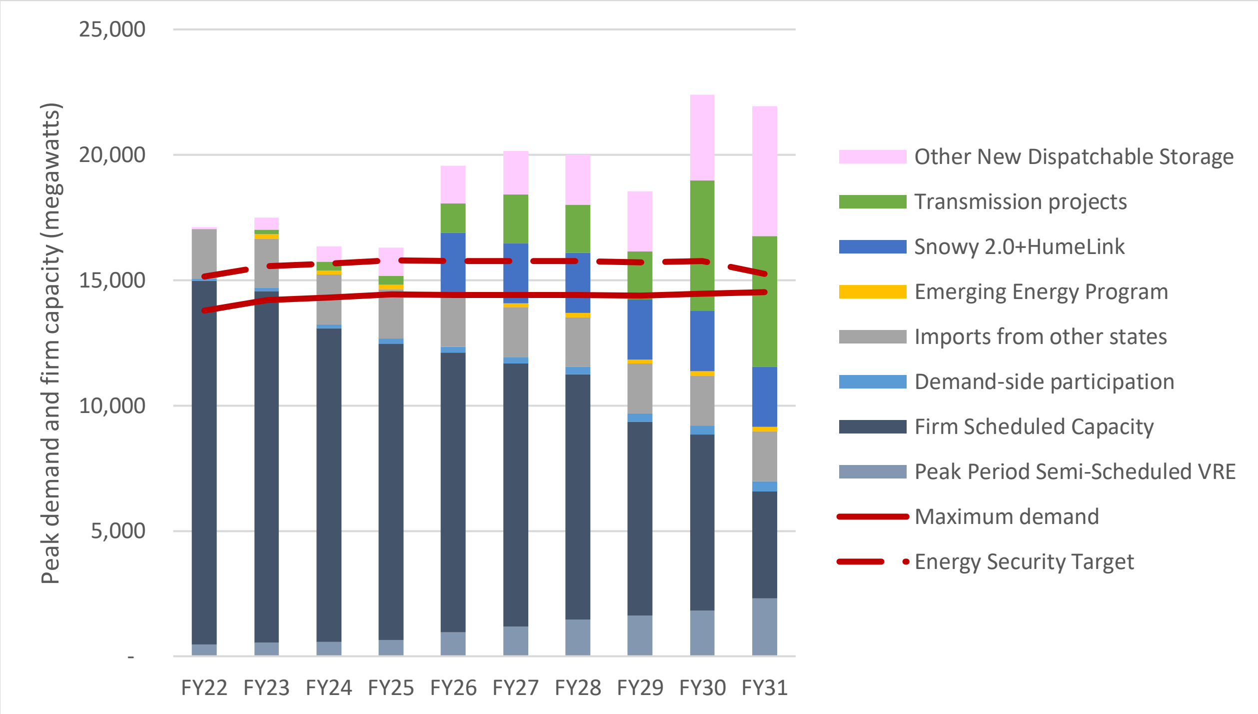
5.4 Energy Reliability to Meet Maximum Demand

As noted in Section 4.2.2, the primary risk to NSW electricity reliability is anticipated to be a capacity shortfall attributed to a generator exiting the market without having been sufficiently replaced, or due to an unplanned outage. NSW is implementing an Energy Security Target (EST) calculated at the capacity level needed to meet customer demand during a summer heat wave while maintaining a reserve margin to account for the unexpected loss of two of the state's largest available generating units.[12]

In both the BAU and RE100 scenarios, the EST's tightest years could be in the years after Liddell closes at the end of FY23 and when Humelink accesses additional dispatchable capacity from southern NSW, assumed to occur by the end of 2024-25. In the RE100 case, a coal-fired unit is estimated to close in both years, creating the need for several hundred MW of new dispatchable storage ahead of each of these closures to maintain the EST.

[12] Currently two of Eraring's 680 MW units.

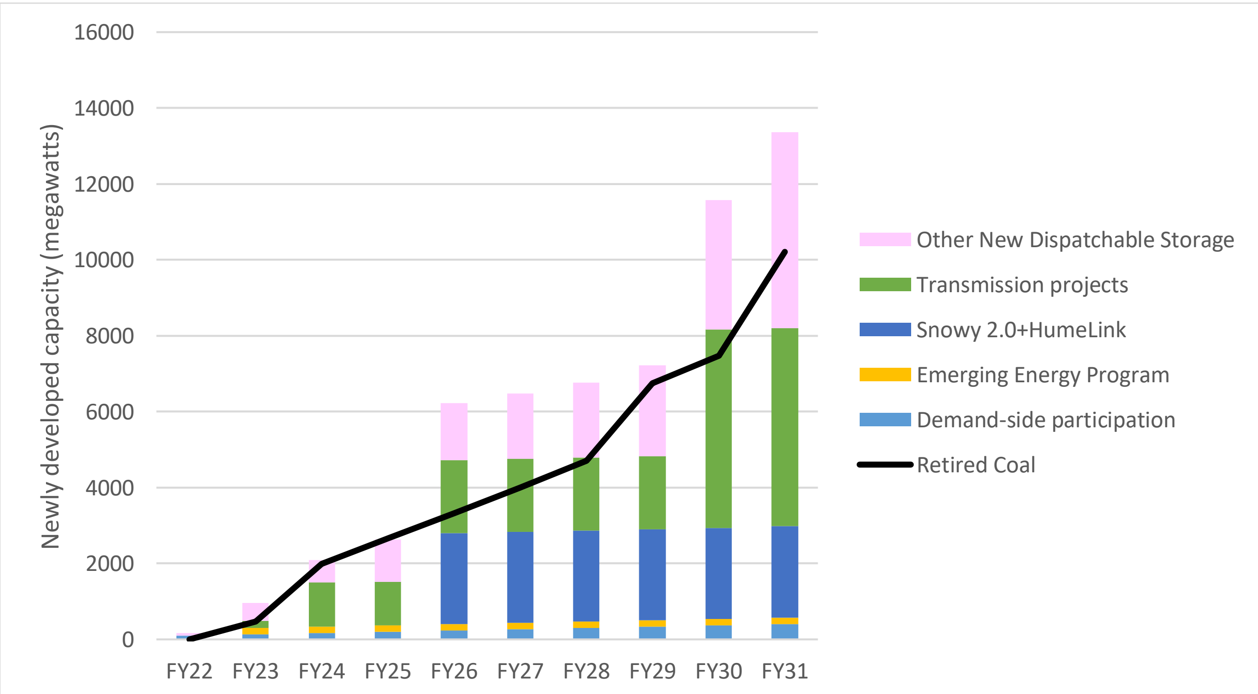
Figure 10: Outlook for the EST in the RE100 scenario



Source: RepuTex, 2020.

Although the capacity does not change markedly from FY24 to FY25, NSW is still forecast to be accelerating from 35 per cent renewables to 44 per cent, necessitating increased capacity options in the form of hundreds of MW of dispatchable storage capacity. In FY 26, the completion of the completion of Snowy 2.0 and the HumeLink transmission upgrade, and the QNI medium interconnector to Queensland is likely to be enough to meet the EST for the remainder of the decade. Although coal units are modelled to continue to close every year, analysis indicates that major investments in dispatchable energy storage and interconnector upgrades will mean a 100 per cent renewable NSW is projected to have more energy reliably to meet maximum demand than ever before.

Figure 11: Assumed energy storage and transmission capacity (RE100 scenario).

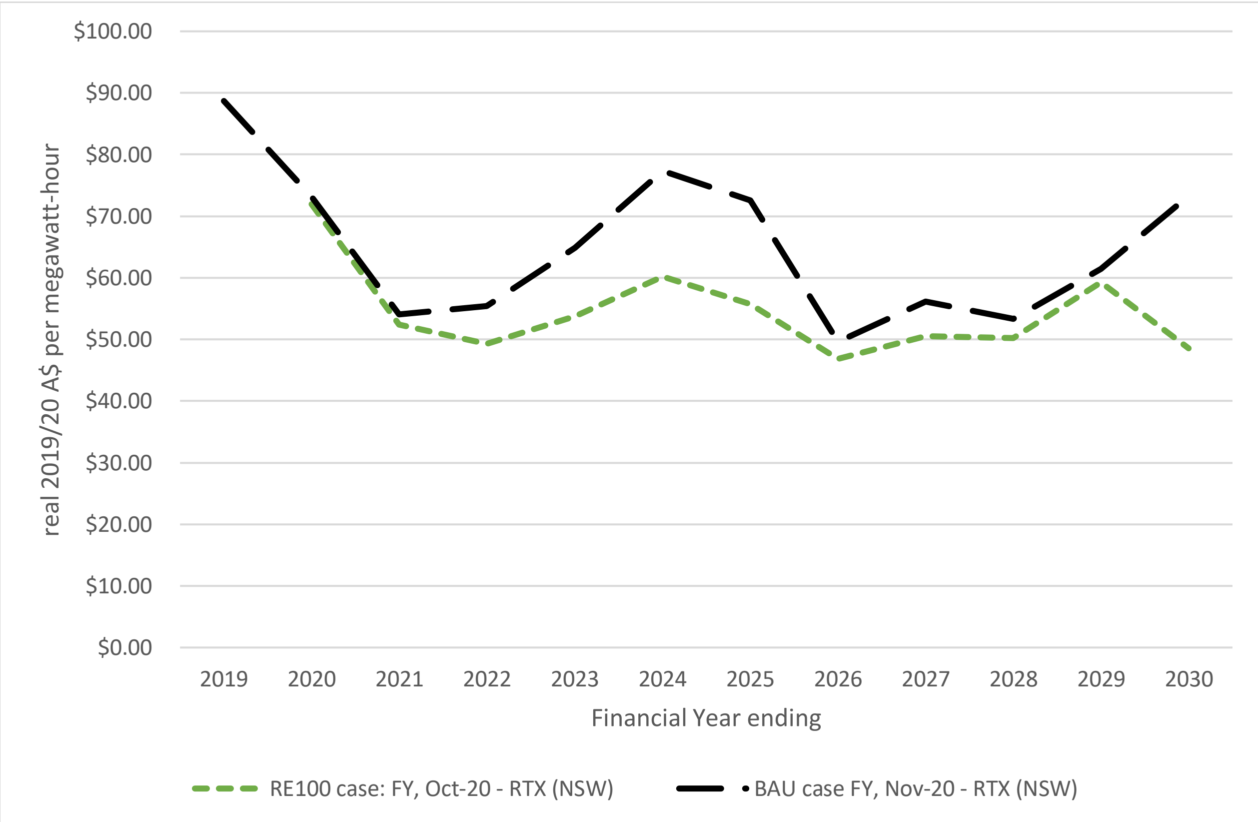


Source: RepuTex, 2020.

5.5 Long-term Wholesale Electricity Price

NSW short-term average wholesale electricity prices are anticipated to reach about $50/MWh in 2021-22, similar the BAU case. This is driven by spot prices that are calculated to be cheaper during the day with stronger signals for energy shifting, i.e. higher early evening prices. The additional battery storage could mitigate most of the price impact. Therefore, while spot prices are estimated to be more volatile, the annual average is expected to be not that different from the BAU case in these years. The completion of EnergyConnect to South Australia is forecast to allow more cheaper daytime (solar) and night-time (brown coal/wind) energy to be imported but may do little to help to relieve evening price peaks in NSW. Thus, the tightening of the supply-demand balance in 2023-24 is modelled to see prices rising to approximately $60/MWh, before transmission projects further expand the Queensland interconnection, fully connect a new REZ in New England and Snowy 2.0.

Figure 12: Wholesale Projections (NSW)



Source: AEMO and RepuTex, 2020

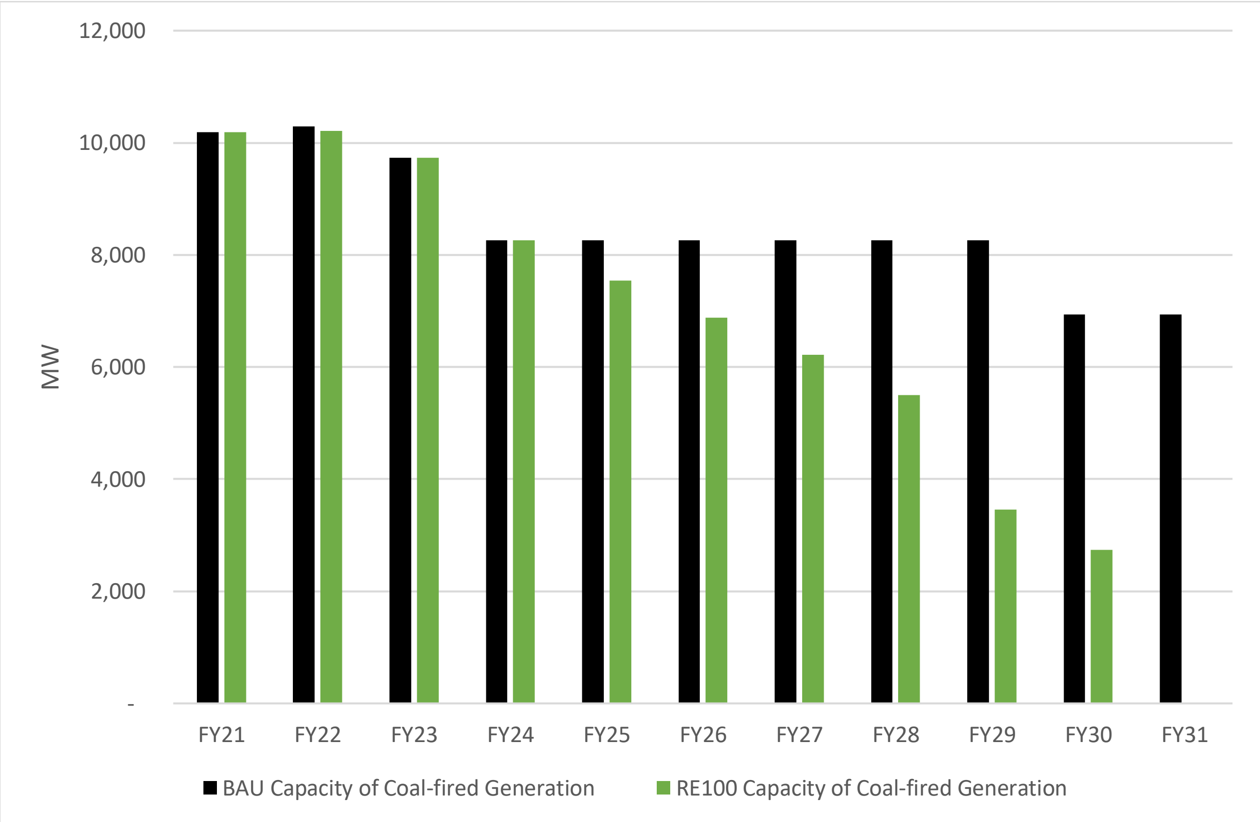
After the middle of the decade, a flood of new renewable energy is predicted to make the NSW electricity market noticeably more competitive, with dispatchable capacity from Snowy 2.0 and other sources projected to firm increasing supply volatility, resulting in average prices declining back toward around $50/MWh. As NSW progressively works its way down to just one remaining coal-fired plant in 2029, however, the supply-demand balance should again tighten, especially during the winter months, with growing reliance on deep storage, energy imports, and the remaining firm generation units during low VRE events. Eventually the development of additional deep storage, four REZs becoming fully developed, and major interconnector upgrades to all neighbouring regions would allowing the last coal plant to close while also lowering the average price back toward $50/MWh.

In addition to large-scale REZ development, strong growth in distributed resources and interconnection upgrades with other markets combine to dampen the price increase that would otherwise be associated with removing over 10 GW of black coal generation. Continuing strong growth in rooftop PV is shown to reduce operational grid demand, while deep, seasonal energy storage provided by Snowy 2.0 balances periods of renewable over- and under-supply. While Utility-scale energy storage would provide competitively priced frequency control services, while distributed storage gradually shifts NSW evening peak lower, and later into the night, which better aligns with NSW's wind resource on sunny days. In addition, distributed storage aggregated into Virtual Power Plants (VPP) and demand response mechanisms provide key peaking capacity to reduce the frequency of extreme wholesale spot prices. Overall, these effects - along with the orderly replacement of black coal with renewables - suggest steady and sustainable annual average wholesale prices can be maintained within $10-15/MWh of current prices.

Although this scenario presents a generally similar annual average wholesale price outcome to the BAU Case, by 2030 underlying assets and operation of the system are anticipated to be starkly different. The BAU price is calculated to rely on the cheap day and night-time energy imports from neighbouring Queensland, South Australia, and Victorian regions when they have excess VRE, but could leave NSW with minimal additional development beyond the CWO REZ. By 2030, the delayed transmission infrastructure schedule in the BAU scenario, is estimated to see NSW become even more, rather than less, reliant on an ageing black coal fleet. Although coal-fired facilities are expected to become more expensive to operate, in NSW they may have to keep running to maintain regional reliability without other major investments.

In addition, the BAU scenario is incompatible with the objectives of the Paris Agreement, which aim to limit global warming to less 2°C, beyond which point scientists warn of dangerous and unpredictable impacts of climate change. As noted, beyond wholesale electricity prices, the costs of a 3 to 4°C scenario would begin to impact Australian households, while severe weather would also increase electricity bills.

Figure 13: Trajectory of coal use the BAU and RE100 scenarios (NSW). Note that capacity is measured at the beginning of each financial year.



Source: AEMO and RepuTex, 2020

In contrast, a RE100 scenario would result in a coal-free NSW electricity system, while supporting the decarbonisation of other key sectors of the economy (such as the anticipated mass uptake of electric vehicles beyond 2030). Expected periods of excess renewable energy may also be harnessed by flexible new industries which require very-cheap energy sources, potentially supporting further economic development.

6. APPENDIX A: MODELLING ASSUMPTIONS

6.1 System Strength

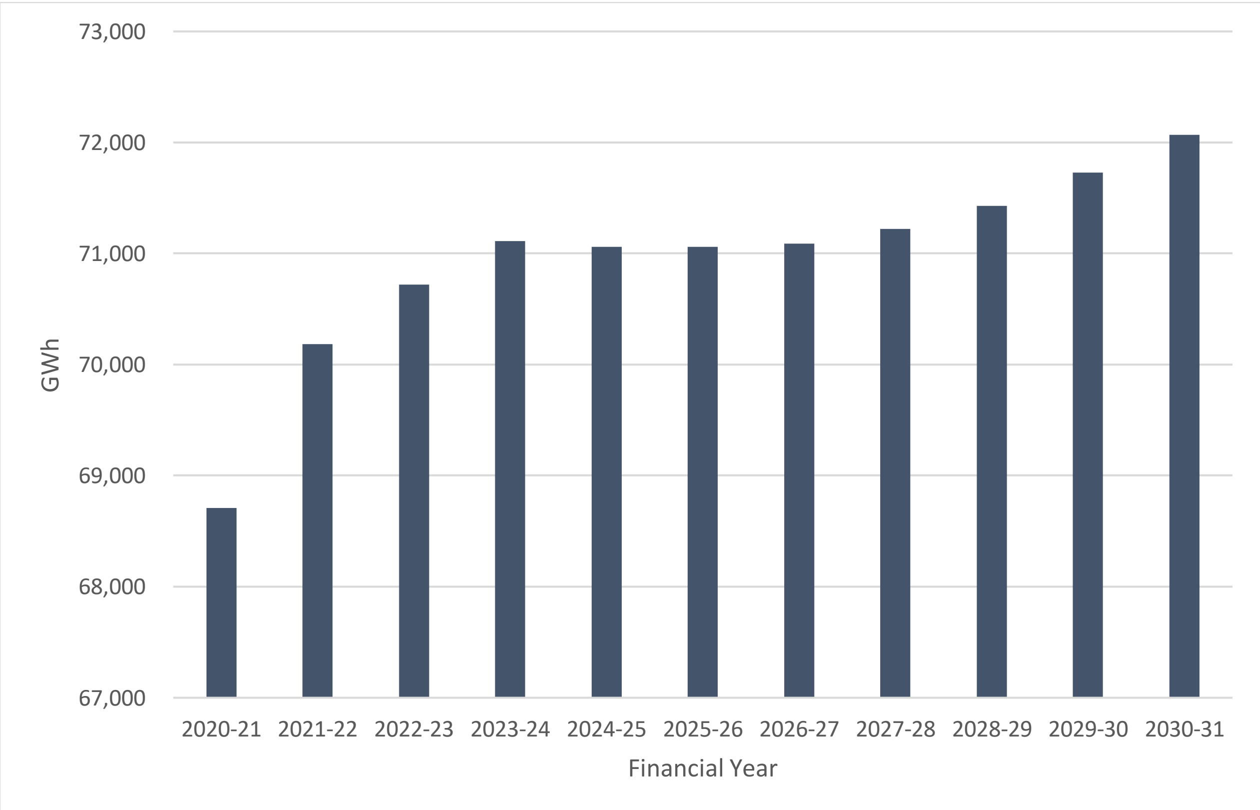
A lack of system strength means the power system can become unstable following a disturbance, such as a lightning strike. In order to prevent this, AEMO may turn off wind and solar generators pre-emptively to reduce demand for system strength. Alternatively (or in conjunction), AEMO may intervene in the market to direct coal, gas, and hydro generators to keep running, increasing supply of system strength.

As generators retire or move to flexible operation, the levels of inertia and system strength in NSW will also reduce. Based on RE100 modelled retirement dates, system strength remediation is anticipated to be required by 2024 and inertia by 2027. Based on BAU scheduled retirement dates, however, system strength remediation is not calculated to be needed until the late 2020s and inertia in the early 2030s. Therefore, in the RE100 scenario, both system strength and inertia mitigation are likely to be needed around five years earlier currently estimated. This highlights the need for a transformation of the power system, whereby if these issued are not addressed, the power system could soon reach a point where the further connection of renewable generation would displace other low cost renewable generation, rather than higher cost units that provide critical system strength to the network.

Although outside the scope of this analysis, reliable and cost-effective solutions will be required under a RE100 scenario. Emerging technologies make it hard to forecast which solutions may be ultimately be chosen, however solutions are likely to include synchronous condensers with flywheels, conversion of retiring generators to synchronous condensers, contracting non-base load synchronous machines (e.g. gas or hydroelectric turbines), ‘synthetic inertia’ from batteries and wind generators, and Fast Frequency Response from Batteries and power electronic based generators (e.g. grid forming inverters).

6.2 Electricity Consumption

Figure A1 – Assumed underlying demand (including rooftop solar) for NSW.



Source: RepuTex 2020.

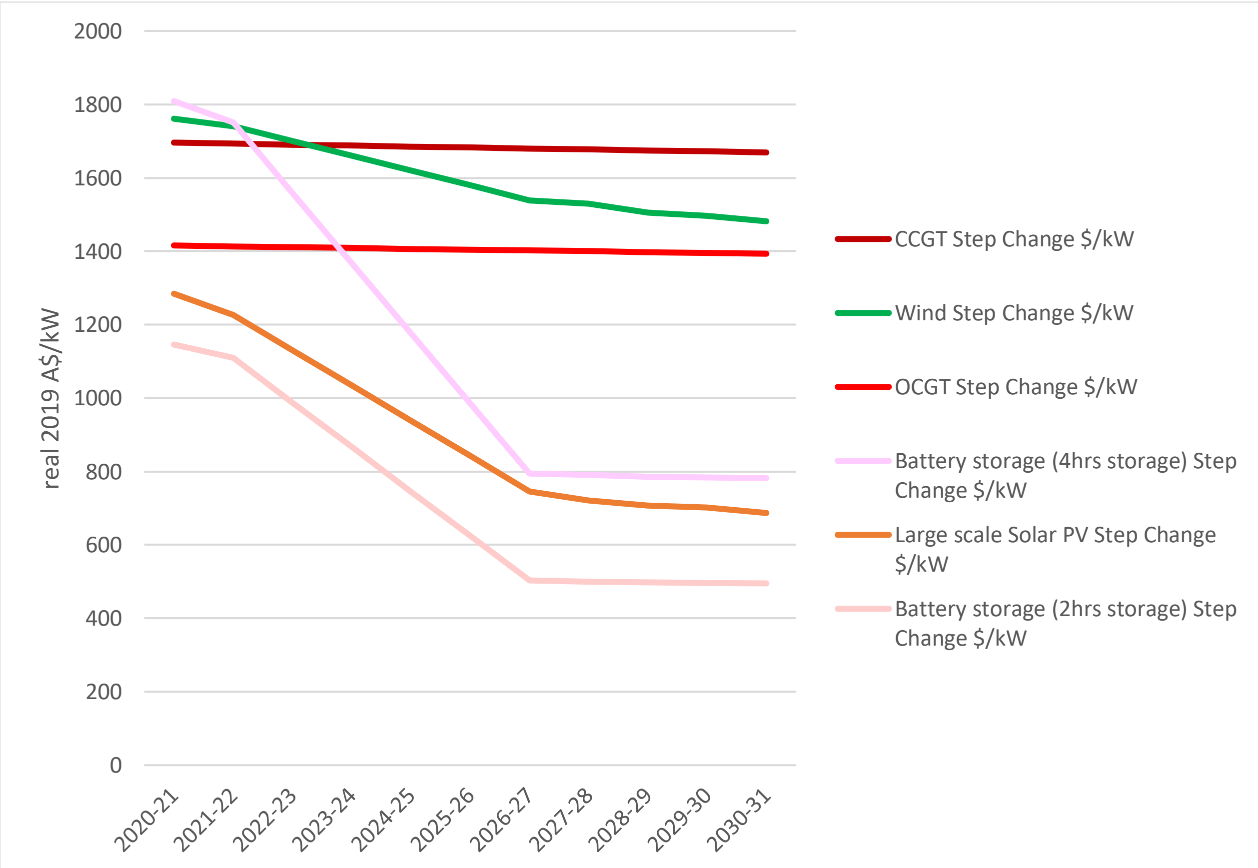
AEMO's 2020 ESOO and TransGrid's 2020 Transmission Annual Planning Report are applied as a reference for NSW forecast electricity consumption. These reports consider various scenarios based on central, step, and slow conditions, reflecting different levels of consumer engagement and economic growth. For NSW, electricity consumption is largely driven by the residential and commercial sectors, with the uptake of rooftop solar and energy efficiency forecast to continue in the residential and commercial sectors through 2030. Despite an assumed shock to electricity consumption in 2020-21, underlying demand is anticipated to increase to about 71 TWh in the middle of the decade before growing to 72 TWh by 2030. Meanwhile, centralised electricity generation declines in line with the uptake of rooftop solar.

6.3 Other Supply Side Inputs

Large-scale Build Costs

As shown in Figure A2, utility scale solar technologies - i.e. Large-scale Solar PV - as well as Large Scale Battery Storage is assumed to experience rapid build cost declines over the next seven years, to become the least expensive generators built on a $ per kW basis. Other technologies are assumed to have relatively gradual build cost reduction in line with the Australian Energy Market Operator's (AEMO) 2020 Integrated System Plan (ISP) and CSIRO GenCost 2020.

Figure A2 – Large-scale Build Costs.

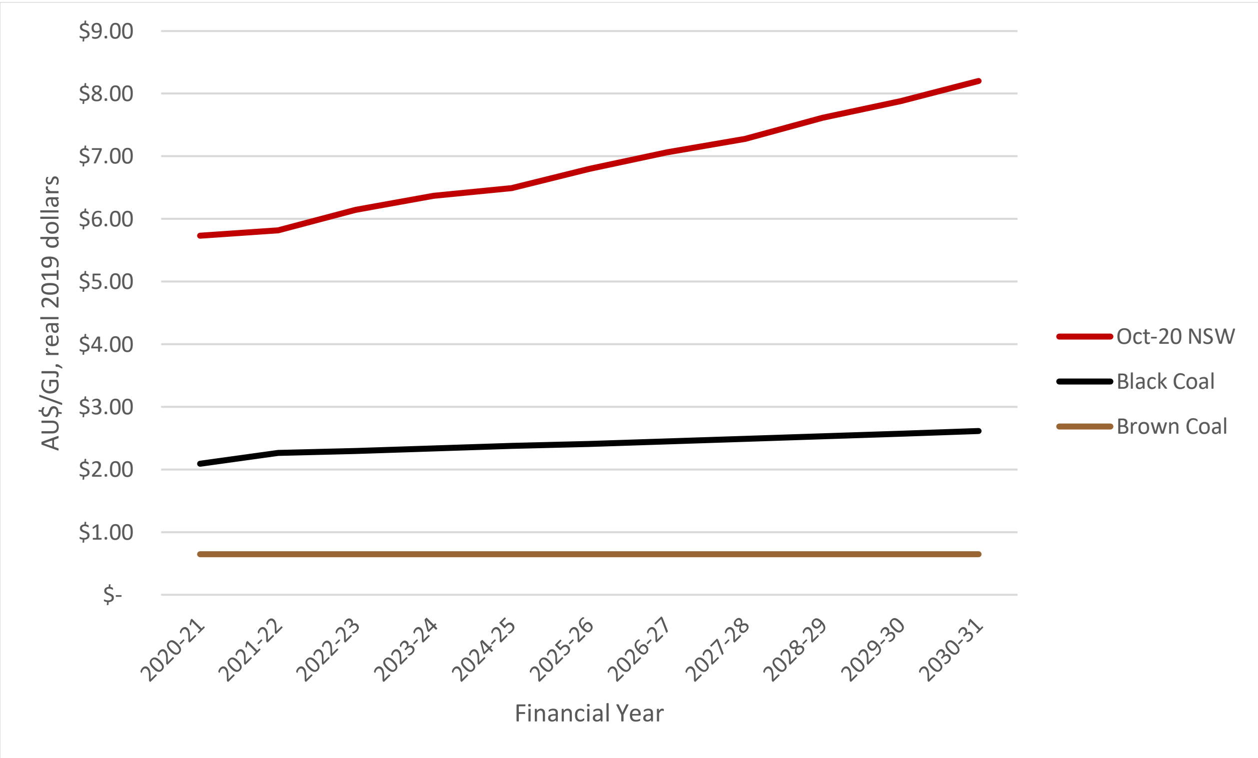


Source: AEMO, Build costs - ISP (July 2020); Step Change/2019 Input and Assumptions workbook.

Coal and gas prices

Black coal has a higher energy content than brown coal and is influenced by thermal coal export markets to countries like China and Japan. Gas prices are also influenced by the forecast east coast supply-demand balance and international LNG and oil price forecasts. Our gas price forecast reflects changing dynamics in Australia's gas markets. The immediate lack of growth in prices is largely attributed to falling demand and uncertainty in the production of major oil producing countries, before a rebound in 2022-23, resulting in price increases for domestic generators purchasing new contracts. We expect prices to continue growing from $6 per giga-joule (/GJ) to around $8 per GJ by 2030 based on an assumed Brent crude oil price of $40 USD per barrel (bbl) growing to $85 USD/bbl, and new local supply with marginal costs of about $9/GJ.

Figure A3 – Annual Average Fuel Price for Electricity Generation in NEM ($/gigajoule)



Source: AEMO ISP and RepuTex, 2020.

7. APPENDIX B: MODELLING APPROACH

7.1 Our wholesale market simulation model

In undertaking this analysis, we utilise our proprietary National Electricity Market Renewable Energy Simulator (NEMRES), which calculates annual capacity changes, energy generation, and transmission expansion decisions, and intra-hourly dispatch, imitating AEMO's dispatch engine.

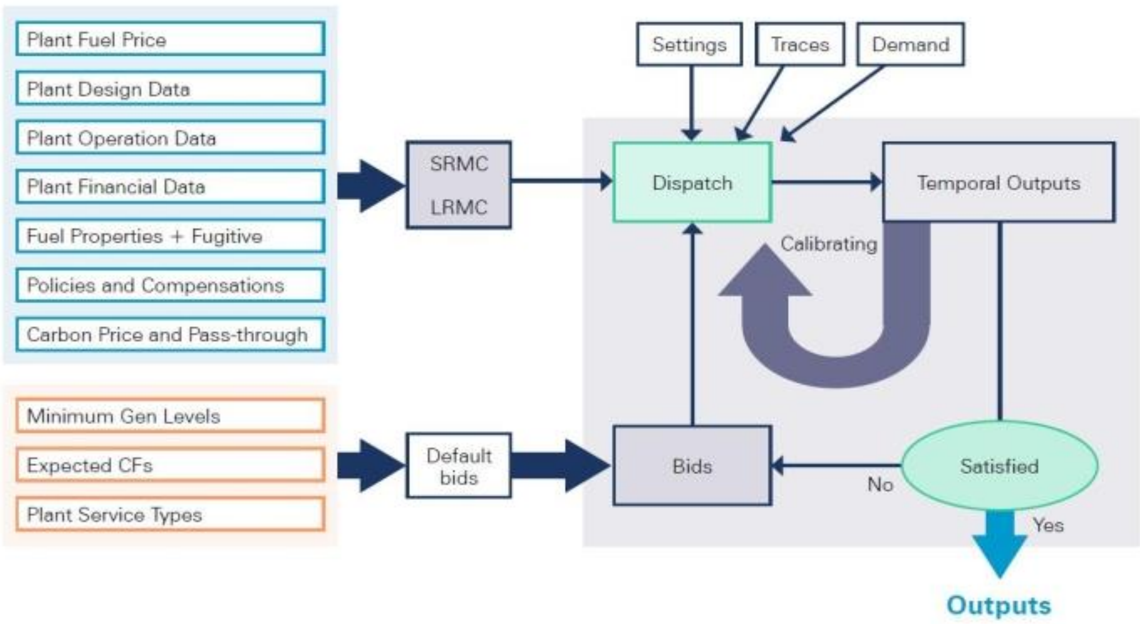
Various rules, laws and policies govern the operation of the NEM, with the key elements being power supply always matching power demand, adjusted for constraints in the electricity transmission and distribution network. The supply side is comprised of fossil fuel and renewable generators that offer capacity based on calibration with current offers and dispatched by AEMO from the least to more costly offers, subject to system conditions, to meet demand.

Demand is affected by several factors such as weather, economic activity and population. Although demand for power has patterns, it is generally unplanned and highly inelastic. System operators rely on demand forecasting for the daily market operation and long-term planning. As such AEMO publishes forecast demand over different time frames, which we apply based on our analysis of annual investments.

NEMRES simulates the NEM least cost dispatch processes and supply and demand conditions in the forecast periods, modelling the resulting generation and emissions from each scheduled and semi-scheduled plant. Contracts impact the percentage of electricity subject to bidding behaviours and spot price revenue. NEMRES explicitly models all scheduled and semi-scheduled power plants, also allowing for non-market plant traces.

The figure below outlines the main model components and model process flows. The central component of NEMRES is the least cost dispatch model, which dispatches the generation of plants based on default bids calibrated to each generator's most recently observed patterns.

Figure B1: RepuTex modelling process



Merit order model

A merit order is constructed via the bids offered by all scheduled and semi-scheduled plants. Our algorithm orders the price bands offered by plants from the least to highest and accumulates the quantities of corresponding power offers accordingly. For each dispatch interval, bids are optimised for individual facility profitability. Hydro generation is allocated by the model based on historical inflows and the associated proportion of run-of-river generation and storable hydro energy. As shown, the input data preparation and model calibration are important blocks, supported by several criteria in checking the validity of model outputs, including analyst checks against closing facilities projected to be the least profitable, and the feasibility of new entrants in each region that have been publicly announced.

Bidding model
The bidding model constructs four price and quantity pairs. All the price and quantity pairs are in percentage of the cost and available capacity of each plant. The first price band of a bid characteristic applies to generation that does not want to be dispatched. The second band relates to the short-run marginal cost (SRMC) or variable operating cost that is calculated based on assumptions for existing and committed facilities. For example, renewable facilities normally have a SRMC less than $10 per Megawatt-hour (MWh), while coal-fired generators fall between $10 and $50 per MWh and gas-fired plants greater than $50 per MWh. The third offer relates to a Levelised Cost of Energy or long-run marginal cost (LRMC) target. The last band is affected by the facility's market power to push the market clearing price higher.

The quantity pair is the percentage that a plant is willing to offer to the market at the four offers outlined above. The quantity is incremental, in that the sum of the four quantity components must be 100 per cent. The quantity at the SRMC cost is related to the generator's contracted level, while the quantity at the LRMC is allocated to the normal design level less the amount that has already been allocated in the previous price bands. The last band can be considered quantity held back to maximise profit.

There are three bidding formats. Long-term forecasting calculates dispatch on an annual demand duration curve and is used for inter-annual forecasting. Medium precision dispatch is performed at the daily level to check and adjust for fuel switching. Half-hour, high precision modelling is performed on critical days to better resolve which facilities are dispatched in atypical situations.

Cost Model
The cost of a generator depends on several factors: plant characteristics such as plant efficiency/heat rate, plant auxiliary usage, fuel cost, fuel combustion emission factor, variable operating & maintenance (VOM), fixed operating & maintenance cost (FOM), etc. Of these variables, fuel costs are updated quarterly, with other variables are adjusted annually. The SRMC and LRMC are calculated by summing each of the fixed and variable cost components.

Offer strategies may be adjusted based on plant profitability. Annual and/or quarterly profit is calculated as total revenue from the sent-out energy + any fixed subsidies less the variable cost associated with per MWh generation and less the annual fixed cost.

Demand model
Annual forecast demand comes with three forecasts for the NEM. One is for annual energy consumption and the other two are for maximum and minimum demand loads. RepuTex fits historical demand profiles to AEMO's various forecasts and aims to mimic the modelling intervals between 365 to 17,520 periods per year, equivalent to averaging demand over 1 to 0.02 days. Weekends and public holidays load profiles are checked and matched as required.

8. CONTACTS

Report title	Cost and reliability analysis of a Paris-compliant energy transition in NSW
Date	November 2020
Confidential	N/A
Primary contact	Bret Harper Director of Research RepuTex Energy and Carbon Level 2, 443 Little Collins Street, Melbourne, Australia T (+61 3) 9600 0990 | M (+61) (0) 459 638 113 | F (+61 3) 9600 3143 | Bret.Harper@reputex.com