VICTORIAN MARKET READINESS TO SUPPORT THE EARLY RETIREMENT OF YALLOURN POWER STATION

FOR ENVIRONMENT VICTORIA

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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, with a strong history of providing trusted, data-driven analysis for public and private sector customers in Australia and Asia.

We have worked with over 150 customers across Australia and 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.

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1. EXECUTIVE SUMMARY

- RepuTex has been engaged by Environment Victoria to analyse the readiness of the Victorian energy system to support the potential early retirement of the Yallourn power station.

- Analysis models a Reference Case forecast, which considers Victorian energy reliability and wholesale electricity prices in line with the scheduled closure of Yallourn from 2029-32; along with an Alternative Case, which models preparing for the 'earliest possible' retirement of Yallourn in 2023, in line with a three-year notice of closure period.

- The Alternative Case considers the installation of new capacity that could be built within this three year lead-time to prepare for any early retirement of the Yallourn power station, or other sudden unavailability of Victorian brown coal units. Although there are many possible combinations of capacity additions, this analysis models a reasonable number of additions that are already currently in planning or being considered, such as the KerangLink interconnector development, the extension of large- and small-scale renewable energy capacity, and new energy storage investment.

- Findings indicate that under the Reference Case forecast, Victoria is modelled to have a tight reserve condition in 2019-20 and is expected to be reliant on import capacity during future 'one-in-two year' maximum demand events. During a more severe 'one-in-10 year' event, Victoria could need all brown coal units available to ensure system reliability (with an average of two brown coal units modelled to normally be unavailable under such events).

- Under the Alternative Case scenario, a combination of large- and small-scale renewable energy (an additional 2.6 and 0.3 GW, respectively), along with 'big battery' storage (0.6 GW), small 'virtual power plants' storage (0.5 GW), and other demand-side participation (0.2 GW), can provide the available resources necessary to compensate for the absence of Yallourn by the summer of 2023-24.

- This includes both enough annual energy to mitigate wholesale prices rises and maintain regional power reliability though heatwaves and other extreme events to prevent 'blackouts'. Additionally, this scale-up of controllable Victorian energy resources is likely to reduce reliance on other states to provide power during extreme events.

- Under this scenario, modelling indicates that with effective planning the Victorian market can compensate for the closure of Yallourn as early as April 2023. Even if Yallourn continues to operate beyond this date, these new measures (large- and small- scale renewable energy capacity, energy storage and interconnector upgrades) would position Victoria to mitigate future capacity failures as existing facilities age.

- Building additional electricity generation capacity and storage solutions under the Alternative Case is modelled to create 27,000 job-years and bring $6.8 billion in additional state economic activity.

- In addition, the early retirement of Yallourn is modelled to reduce Victoria's electricity sector emissions to 60 per cent below 2005 levels, abating approximately 85 million tonnes of carbon dioxide between 2023 and 2033 relative to the Reference Case forecast within Victoria.

- Investment in replacement electricity supply under the Alternative Case scenario is modelled to reduce wholesale power prices compared to the Reference Case forecast. Medium-term wholesale electricity prices are modelled to decline from over $100 per MWh in 2018-19, toward $70 per MWh by 2022, underpinned by a lower dependence on gas generation, the accelerated installation of small-scale rooftop solar PV and distributed energy storage, along with the continued uptake of large-scale renewable energy projects over the next three years.

2. BACKGROUND

Following the retirement of the Hazelwood power station in 2017, the 1,480 MW Yallourn power station has become Victoria's oldest operating coal-fired power station, currently supplying around 20 per cent of the state's electricity needs. Yallourn has announced a schedule to progressively phase out its four generation units from 2029, in a staged four-year shutdown that will conclude by 2032.

Assumptions within the Australian Energy Market Operator's (AEMO's) 'central' scenario suggest that Yallourn could continue to be profitable through 2032, underpinned by the asset's low fuel cost structure and position within the dispatch merit order. While 'baseload' generators are expected to come under increasing competition from low-cost renewable energy supply, and more flexible capacity, Yallourn is not modelled to be an economically driven closure in the National Electricity Market (NEM).

In 2015, AGL announced the closure of its Liddell coal-fired power station (now scheduled for the beginning of April 2023), while Queensland's 700 MW Callide B coal-fired power station has announced a closure in 2028, ten years ahead of its previously planned closure in 2038-39. Despite competitive headwinds for the remaining coal-fired generators, the announced retirement of these assets is expected to improve the profitability of remaining coal plants in the system, with the potential for further closures of coal-fired generators to potentially extend the economic life of Yallourn. However, short-term economic benefits are expected to be offset by operating challenges for coal-fired generators, such as:

- the decreasing reliability of aging generation during hotter weather and the timing, extent and cost of major refurbishments;
- the costs of coal unit ramping (following variable resources) as renewable energy penetration increases;
- the high emissions intensity of coal-fired generation and uncertainty regarding state and federal decarbonisation policy;
- commodity price volatility and supply uncertainty; and
- potential cuts in energy consumption, especially decreases in operational demand.

In light of these headwinds, EnergyAustralia has suggested that 'substantial changes' to the energy market could lead it to close Yallourn earlier than anticipated, noting that, "our plans are to run the plant to 2032 or for as long as policy and regulations permit, and there's not a substantial change in the market."[1] As a result, the early retirement of Yallourn remains a live issue for Victorian electricity market participants, planners and policymakers, suggesting that measures should be taken to prepare the local market for the potential retirement of the aging coal-fired generation fleet.

[1] The Age, Yallourn coal-fired power plant due to shut down from 2029, June 25.

RepuTex ENERGY

3. ABOUT THIS ENGAGEMENT

3.1 Scope of Analysis

RepuTex has been engaged by Environment Victoria to analyse the potential impact of the early retirement of the Yallourn power station on the regional energy system. Specifically, analysis seeks to understand the readiness of the Victorian system to support the retirement of output from Yallourn under a modelled reference case and possible 'early' retirement scenario, for the purposes of understanding the availability of alternative sources of power supply and potential wholesale price impacts.

To understand the market impact of an early retirement of Yallourn power station on large-scale generation mix and wholesale electricity prices in Victoria, analysis considers the following cases:

1. **A Reference Case**: Analysis of market shape and wholesale electricity prices assuming the phased closure of Yallourn over 2029-32, in line with scheduled timelines.

2. **Alternative Case**: Analysis of market shape and wholesale electricity prices assuming the 'earliest' retirement of the Yallourn power station in 2023 (in line with a three-year notice period) and the implementation of policy measures within this lead time.

Scenarios are intended to inform how the Victorian market could prepare for any early retirement of the Yallourn power station, or sudden unavailability of Victorian brown coal units, and the options available to policymakers on a short lead time of three years. Analysed outputs within this report include:

- **What new capacity (or demand reduction) could replace the output from the Yallourn power station** based on a plausible and cost-optimised combination of large-scale renewables, rooftop solar, energy storage, demand response and energy efficiency within the modelled timeline; and

- **What are the resulting impacts on energy prices** of the early retirement of the Yallourn power station and the implementation of measures within this lead time.

3.2 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 transmission expansion decisions in each region of the NEM as well as 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 modelled case, adapted from Australian Energy Market Operator's (AEMO's) Integrated System Plan 2019-20.[2] These common assumptions include:

- **Average fuel prices** (real 2019 dollars). On average, Biomass: $0.53 per Gigajoule (/GJ); Brown Coal: $0.64/GJ; NEM Gas: $10.75/GJ.

- **Capacity additions and closures**: Announced retirements are assumed to occur (e.g. last 3 units of Liddell in April 2023). Economically optimised capacity additions and closures are proposed by our electricity model based on annual dispatched generation. These proposals are cross-checked by analysts to find indicative units based on capacities that best meet retirement volume criteria and RepuTex's view on the relative economics and forecast profitability of each unit. Many combinations of technology-type closure patterns could meet these requirements; therefore any named facility retirements should be treated as indicative only.

- **Snowy 2.0**: The government's proposed 2.2 GW Snowy 2.0 pumped hydro project is assumed to be committed and fully commissioned by March 2025.

[2] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook-Sept-19.xlsx

- **Renewable Policy Targets**: The Large-scale Renewable Energy Target (LRET) of 33 TWh to 2030 is assumed in continue without changes. New entry renewable capacity required to meet a target of 40 per cent renewable energy generation as a percentage of total Victorian generation by 2025 and 50 per cent renewable energy generation as a percentage of total Victorian generation by 2030 targets are met, including a contribution for distributed energy resources.

- **Reliability**: In our capacity outlook model, each region must have a minimum level of firm capacity available. Firm capacity is able to be shared across interconnected regions based on interconnector capabilities and typical coincident available capacities in neighbouring regions.

- **Technology costs:** Based estimates derived from AEMO's ISP large-scale renewable build cost trajectory for CSIRO 4- and 2-degree outlooks from GenCost 2018.[3]

- **Behind the meter (BTM) technologies**: Demand Side Participation (DSP), Rooftop PV, PV non-schedule generation (PVNSG), electric vehicles, distributed (embedded) energy storage, and aggregated energy storage assumptions correspond to AEMO's Central and Step Change ISP scenarios.

- **Network assumptions**: New network developments are assumed to be undertaken to address network strength as new capacity comes online, such as augmentation of the western Victoria grid. This occurs in a staggered way, with actions implemented in stages to match AEMO's ISP, e.g. EnergyConnect 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 2033.

Please refer to Appendices for further details on our modelling approach and policy settings.

[3] Available at https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1

4. REFERENCE CASE

4.1 Change in Installed Capacity in Victoria

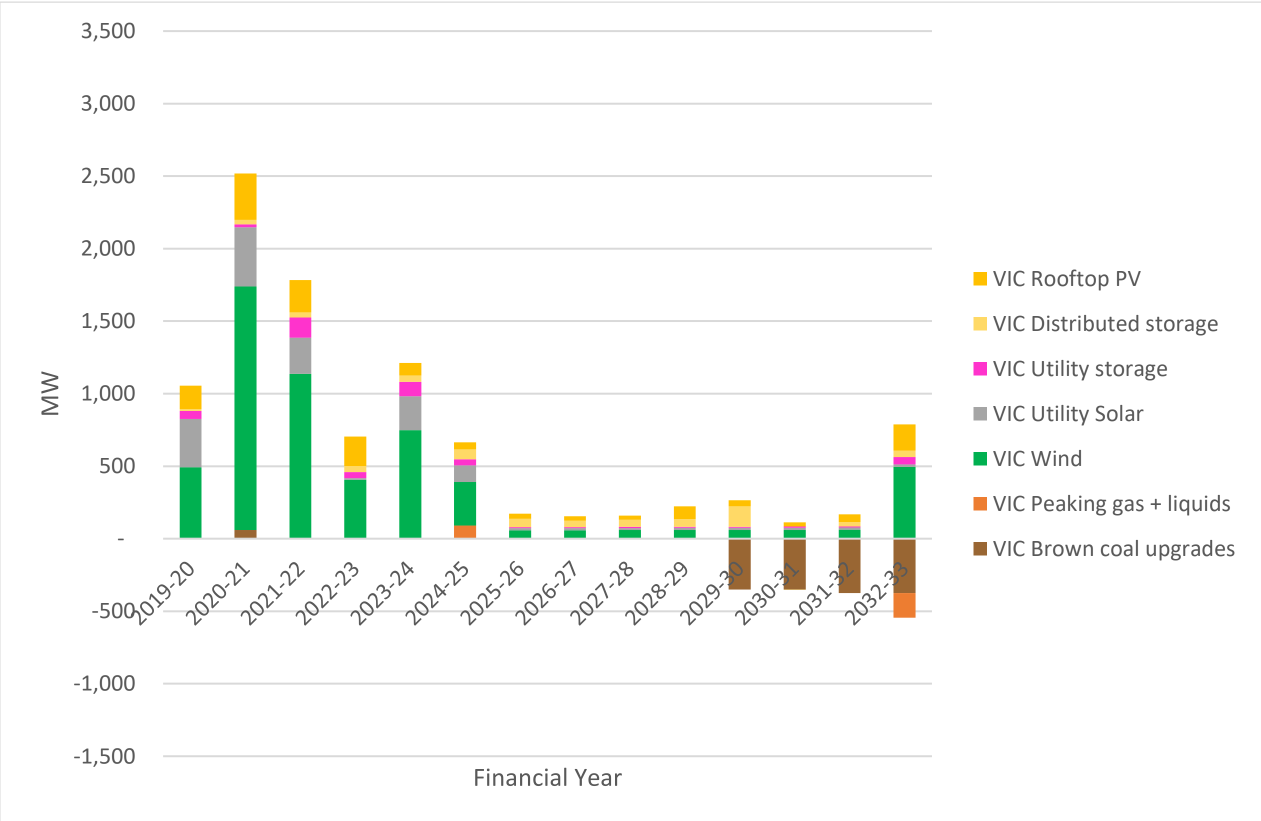
Analysis under our Reference Case models around 3.4 GW of new large and small-scale renewable energy capacity being added to the Victorian system over the next two years, with the current build rate driven by the high electricity price environment, a rush of developers seeking to access limited transmission infrastructure, attractive long-term power purchase agreements (PPAs), rapidly falling solar and energy storage costs, and Commonwealth and state renewable energy targets.

Due to growing delays between initial construction and the full commissioning of Australian renewable energy projects, modelling indicates around 1 GW of new large-scale renewable capacity entering the market in 2019-20, with a further 2.4 GW of new capacity in 2020-21, and 1.3 GW in 2021-22. These delays are largely underpinned by approvals for electrical connection, set against shortening construction timelines as Australia builds construction experience in utility-scale solar and wind projects.

After 2022, project development is forecast to decline to the mid-2020s, with annual average additions of about 800 MW of new capacity each year as electricity consumption flatlines in Victoria, while overdevelopment in some regions becomes apparent as transmission access and marginal loss factors (MLFs) are forecast to reach their most congested points, and regional wholesale prices decline.

In cumulative terms, around 6.9 GW of large and small-scale renewable capacity is modelled to be commissioned in Victoria by 2025, growing more slowly to just 7.5 GW by 2030 without additional long-term energy storage, or national energy and emissions reduction policy. State level support ensures that the Victorian 50 per cent renewable energy target by 2030 is effectively met five years early, reducing further capacity growth to just 100 to 200 MW of new renewable capacity per year.

Figure 1: Annual Victorian New Entry / Retired Capacity by Technology to 2033. Note: Brown coal capacity additions in 2020-21 reflect 45 MW upgrade projects at Loy Yang B1 for completion by November 2020.



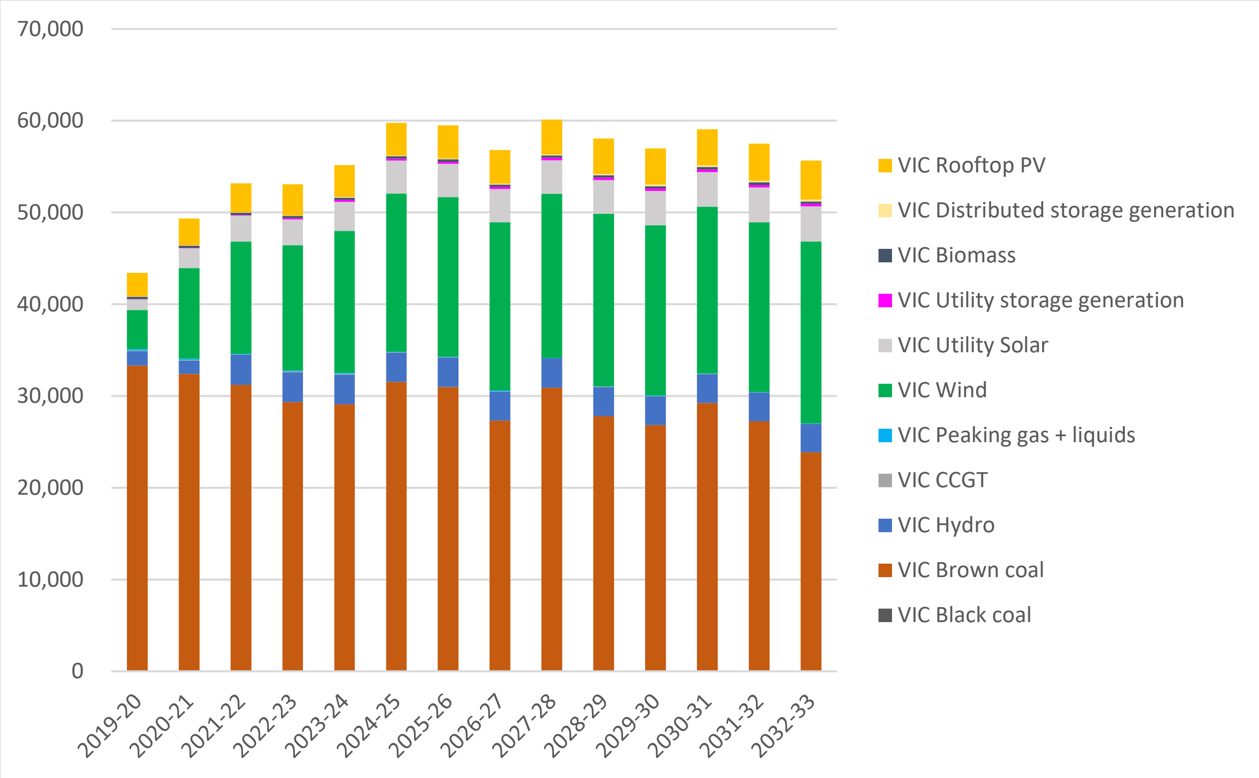
Source: RepuTex, 2019.

Under this forecast, Victoria does not see major thermal generator closures until the end of the decade, with the scheduled closure of 1,450 MW of brown coal capacity (Yallourn) and 170 MW of gas (Somerton) between 2029 and 2033. Despite consistently lower prices, brown coal generators are modelled to continue to find a market for their energy by exporting larger portions of their baseload energy to New South Wales via an upgraded NSW-VIC interconnector. Only once NEM generation begins to exceed around 60 per cent renewable energy capacity, and solar energy provides around 15 per cent of Victorian generation, is there no further profitability in running all of Victoria's brown coal units.

4.2 Energy Generation and Greenhouse Gas Emissions

Although Victoria's energy generation and consumption have become relatively balanced, growth in solar and wind energy production could see Victoria's energy generation grow by about 10 TWh by 2024, effectively replacing the energy formerly provided by the brown coal fired Hazelwood power station. This may see Victoria return to be a major electricity exporter, with low-cost brown coal energy continuing to be exported to New South Wales and Queensland, which face relatively higher fuel costs, while electricity consumption in Victoria remains very flat though the mid-2020s.

Figure 2: Annual change in energy generation in Victoria 2020 to 2032.



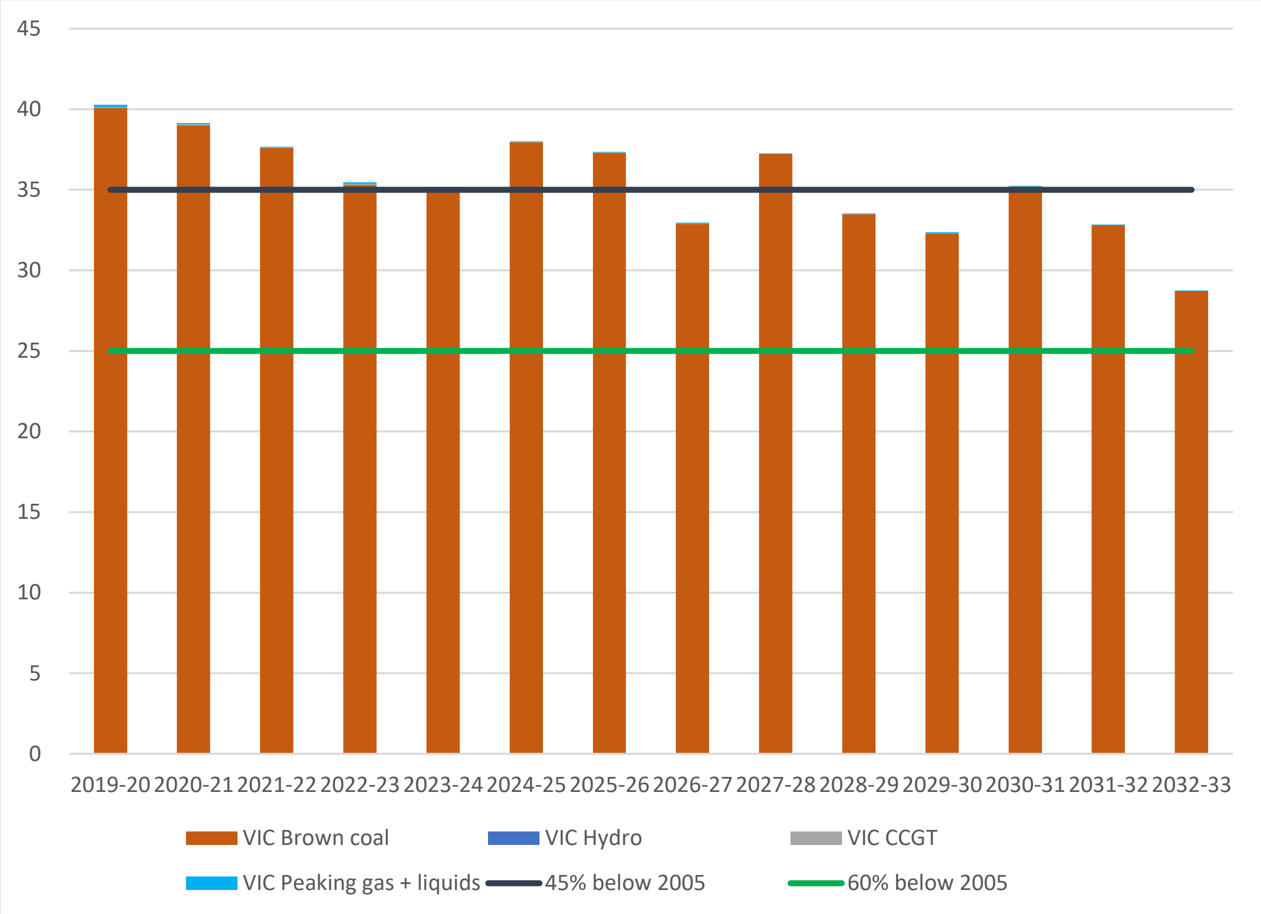
Source: RepuTex, 2019.

A new energy balance is achieved in the second half of the 2020s that should see marginal growth in renewable energy replacing a slow decline in brown coal generation volumes. Modelling forecasts renewable energy in Victoria will grow from around 27 per cent of generation in 2020 to approximately 49 per cent by 2025, and 55 per cent by 2030.

Despite the rapidly growing penetration of renewable energy generation in the early 2020s, however, greenhouse gas emissions are not modelled to decline at the same rate if brown coal energy is exported to other NEM regions. Modelling indicates, however, that as Victoria surpasses around 50 per cent renewable energy generation at least one brown coal unit could be idled without being needed to meet the state's minimum demand profile. Such a closure should correspond with Victorian electricity emissions beginning to decline to more than 45 per cent below 2005 electricity emission levels.[4]

[4] Assuming electricity emissions in 2005 were 63.5 Mt in Victoria. DELWP: Victorian GHG Emissions Report 2019.

Figure 3: Victorian electricity sector emissions



Source: RepuTex, 2019.

An independent expert panel recently advised that reducing the state's total emissions 45 per cent below 2005 levels by 2030 would be an economically and environmentally responsible target on the pathway to the legislated target of net zero emissions by 2050 consistent with a 2°C trajectory. Reducing emissions 60 per cent below 2005 levels by 2030 would be more consistent with a well-below 2°C trajectory and the objectives of the Paris Agreement on climate change.[5]

4.3 Energy Reliability to Meet Maximum Demand

Under our Reference Case, Victoria is modelled to have a tight reserve condition, even after the anticipated return of Loy Yang A2 (500 MW) and Mortlake 2 (259 MW)[6] units in mid-December 2019. On average Victoria has two brown coal units unavailable during maximum demand events, which for illustrative purposes are shown as two units at Yallourn in figure 4. In such a situation, Victoria could be heavily dependent on import capacity over interconnectors during even a typical 'one-in-two year' (50 per cent Probability of Exceedance or POE[7]) maximum demand event.

During a more severe 'one-in-10 year' event (10 per cent POE), Victoria could need all brown coal units available to ensure reliability. Although total import capability under normal conditions can be 1,700 MW, Victoria's total import capability is often limited during maximum demand events. For example, though New South Wales (NSW) often has surplus generation capacity, this capacity shares transmission infrastructure with hydro generation in north-eastern Victoria, which is often de-rated at times of high temperature, while

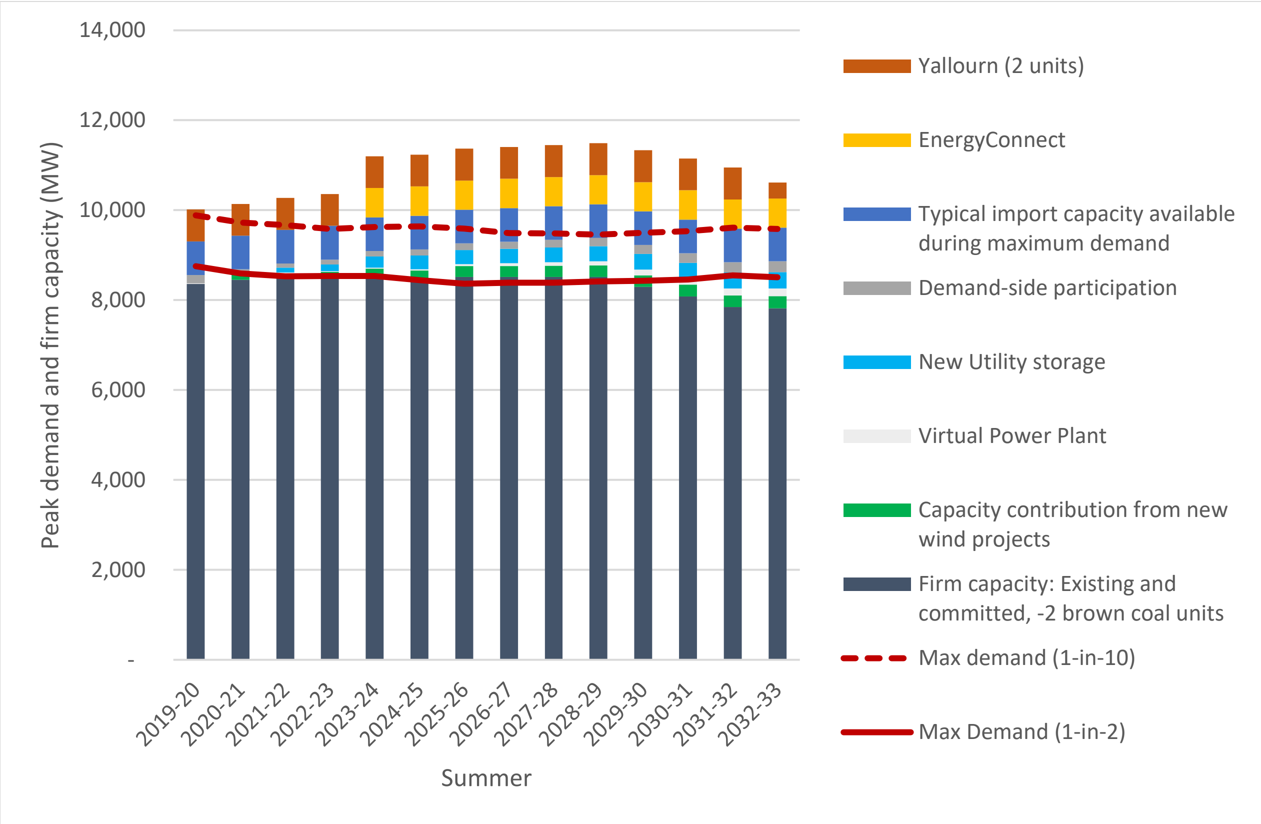
[5] Independent Expert Panel on Interim Emissions Reduction Targets for Victoria (2021-2030): March 2019.
[6] Capacity refers to summer 2019-20 rating of unit.
[7] POE is the likelihood that a demand forecast will be met or exceeded. A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10, while a 50% POE forecast is based on average weather and is expected to be exceeded, on average, ever second year.

transmission capacity can be heavily reduced if bushfires are present around the transmission line, which traverses bushfire-prone areas of regional Victoria. In parallel, imports from South Australia can be limited by hot summer weather patterns that are often correlated between Victoria and South Australia. As a result, when Victoria is under stress due to peak demand, South Australia also typically experiences high demand. Even though imports from Tasmania are not typically limited, outages of key infrastructure such as the Basslink undersea cable have occurred in the past.

In such circumstances, Victoria can use its robust set of emergency response powers, and the Market Operator would be able to use its direction powers and the Reliability and Emergency Reserve Trader (RERT), to make enough capacity from non-market generators available to bridge this shortfall, if required. However, this was only ever envisioned as an emergency measure. Continuing to rely on this approach would be expensive for consumers and disruptive to some businesses. For this reason, it is appropriate to address the shortfall in a timely manner.

Victoria's reliability target shortfall is forecast to improve as assumptions about a decline in maximum demand displace the need for some additional capacity in the future, and large capacity additions currently under construction are fully commissioned (such as Dundonnell and Stockyard Hill wind farms) and contribute at least some capacity during maximum demand events. The region is also forecast to augment transmission interconnection capabilities throughout western Victoria and reinforce a small interconnection at Red Cliffs near Mildura[8] as early as 2023-24, which may be able to be linked to a new EnergyConnect (formerly Riverlink) interconnector between NSW and South Australia (SA).

Figure 4: Maximum demand outlook for the Victoria energy reliability to 2033.



Source: AEMO's Generation Information (Nov 2019) and RepuTex 2019.

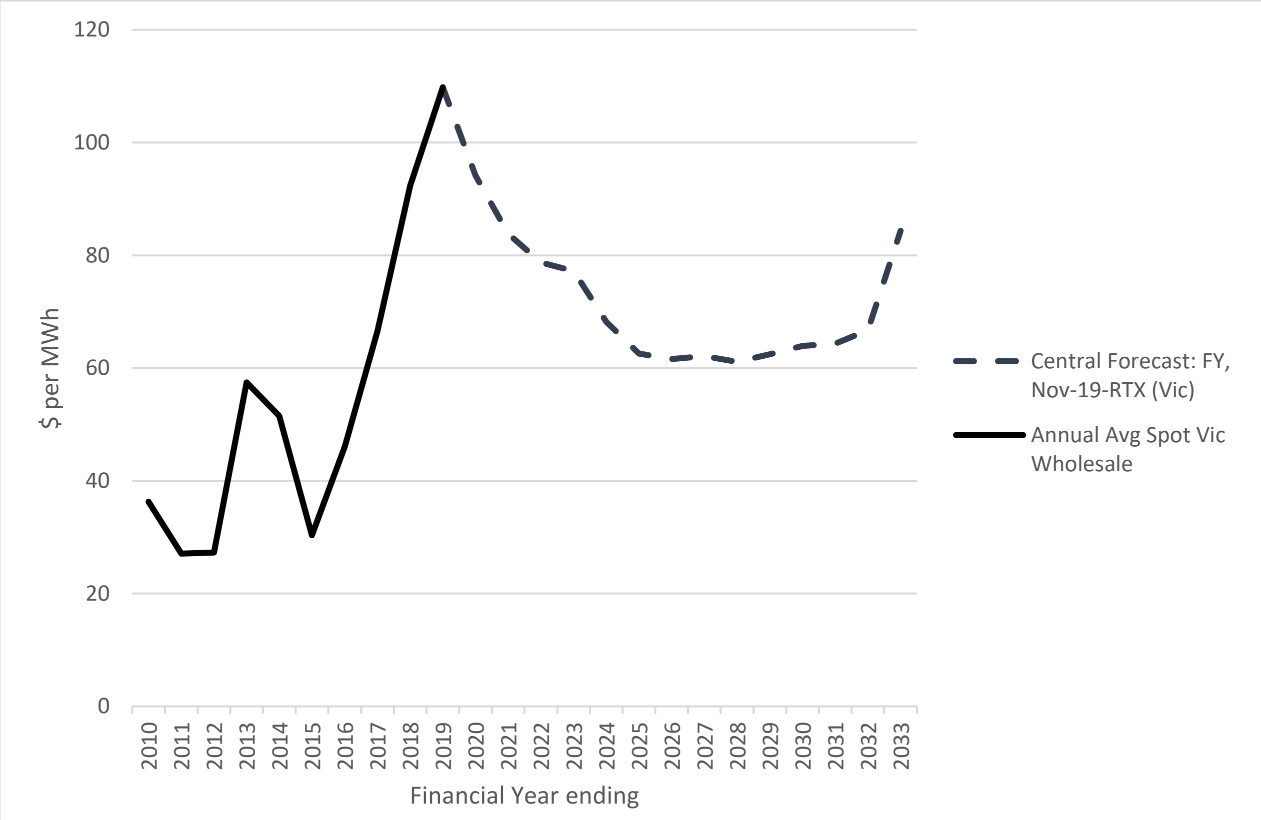
[8] E.g. 2 x 220 kV new circuits between Red Cliffs and Buronga.

4.4 Wholesale Price Implications

Under our Reference case, long-term Victorian wholesale electricity prices are shown to decline from over $100 per MWh in 2018-19 toward $80 per MWh, underpinned by the commissioning of large-scale renewable energy projects. This effect is also supported by the accelerated installation of small-scale rooftop solar PV and distributed energy storage associated with Victorian Solar Homes Program.

After a brief gap in 2022-23, modelling of current policy settings anticipates continued investment in new Victorian wind capacity driven by the VRET, brought forward by developers seeking to capitalise on new investment in transmission infrastructure. This investment is forecast to drive wholesale prices toward $60 per MWh, with other investment limited to growth in smaller ‘rooftop’ PV installations. Wholesale prices are maintained at low levels as effective energy consumption declines (from the grid’s operational perspective), powered by increased ‘rooftop’ PV self-generation. Together, these factors could maintain relatively low wholesale electricity prices throughout decade.

Figure 5 – Reference case Victorian annual wholesale electricity prices.



Source: RepuTex, 2019.

Lower prices are also an indication of an increasing supply-to-demand ratio, putting pressure on major thermal generators. Modelling suggests that these closures are most likely to occur at facilities with higher fuel costs outside of Victoria, such as gas-fired generation in South Australia and black coal-fired generation in NSW and Queensland. Such closures would help to maintain remaining coal-fired generator volumes, including Victoria’s major brown coal-fired units though the 2020s.

As noted, by the end of the decade - as NEM generation begins exceeding around 60 per cent renewable energy and solar energy starts providing more than 15 per cent of Victorian generation - the scheduled closure of large brown coal units is modelled to lift the wholesale price back toward $80 per MWh, particularly after a fourth brown coal unit closes in 2032. This is driven by reduced competition for major thermal generation in Victoria, and a heavier reliance on dispatchable facilities with higher fuel costs, such as black coal (from NSW) and gas.

5. ALTERNATIVE SCENARIO: PREPARING FOR THE EARLY CLOSURE OF YALLOURN

While Victorian brown coal facilities are some of the lowest-cost thermal generators in the NEM, and do not necessarily face imminent economic closure, headwinds for coal-fired generation - such as the failure of ageing equipment and expensive maintenance, competition from lower cost renewable energy, and concerns over large greenhouse gas emissions - suggest that the closure of the Yallourn power station prior to 2032 is a live issue for the Victorian electricity market. As a result, measures should be taken to prepare for the potential retirement of Victoria's aging coal-fired fleet.

To better understand the potential impact of the early retirement of the Yallourn power station on the regional energy system, we consider an alternative scenario which models the 'earliest' retirement of Yallourn in 2023, assuming a three-year notice period[9]. This is modelled to reflect a 'worst case' scenario for the Victorian energy system, informing how the risk of severe events and the sudden unavailability of brown coal units may be minimised though proactive planning on a short lead time.

5.1 Additional Measures to Support Energy Security

As shown in Figure 4 (Section 4.3), while available capacity is modelled to remain tight under our Reference Case, Victoria is shown to have sufficient local and import capacity to meet 'one-in-two year maximum demand over the next five years. However, under more extreme situations - such as 'one-in-ten year' maximum demand - Victoria is dependent on having all its dispatchable market capacity available. The unavailability of one or two units at Yallourn, or its early closure, therefore, reflects a potential threat to Victorian energy security during severe maximum demand events.

Should Yallourn's 1,420 MW of summer capacity be removed from the Reference Case, and no other initiatives introduced, Victorian total scheduled generation capacity would be reduced to around 7,500 MW[10]. Even with a limited amount of additional capacity from committed large new renewable projects and current interconnectors, energy security may be vulnerable during 'one-in-10 year' events that could reach maximum demand of more than 9,600 MW[11]. In addition, an energy security and/or reliability reserve buffer is required for different situations that can arise, such as the unavailability of multiple large units, or an interconnector, and/or peak demand conditions in more than one region at a time.

Victorian policymakers are therefore expected to implement additional measures to support grid reliably in readiness for the early retirement of a Yallourn sized generator from the local market. Although there are many combinations of investments that could be constructed to optimise the replacement of a brown coal generator, the Alternative Case considers the following measures to reduce peak demand and enhance firm supply within the specified lead time (before the summer of 2023-24):

1. **Fast track the development of the KerangLink interconnector.** The fast tracking of the KerangLink interconnector by the end of 2023 is expected to unlock up to 2,200 MW of existing flexible capacity in New South Wales. A new large interconnector can also facilitate sharing of Victorian renewable energy supply during high wind periods and incentivise further development of Victoria's renewable resources that are currently transmission constrained. Although the KerangLink interconnector is assumed to be completed by the end of 2023 to contribute to reliability after the closure of Yallourn, this scenario also includes capacity from the EnergyConnect interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales by the beginning of 2024. Without at least one of these new interconnectors, existing excess load-following capacity in NSW is often unable to access the Victorian market during maximum demand

[9] On 8 November 2018 the Commission made a final rule that requires large electricity generators to provide at least three years notice to the market before closing. This information will help market participants respond to possible future shortfalls in electricity generation, for example by building replacement capacity. The rule is based on one of the recommendations in the Finkel Panel review.
[10] AEMO: Generation Information, Scheduled Capacities – Summer 2023-24 (2019, November 14); Victorian Region.
[11] AEMO's Central scenario: ISP 2019-20, Operational (Sent-Out) – Summer 2023-24 (10 per cent POE)).

conditions, which limit flows on existing infrastructure. KerangLink would also allow access to the committed Snowy 2.0 project after the summer of 2024-25.

2. **Double the capacity of Victorian rooftop PV from 2,000 MW in 2019-20 to more than 4,000 MW by the summer of 2023-24.** This is equivalent to returning to (and maintaining), around 6,000 rooftop PV installations per month in Victoria, in line with the beginning of the Victorian Solar Homes policy.[12] At only 18 per cent of dwellings with a PV system, there is room for further growth in rooftop PV in Victoria, with potential for an increase energy generation by around 2.8 TWh in the next three years, equivalent to the annual output of one unit at Yallourn. Rooftop PV is a cost-effective source of energy at the 'point-of-use', contributing to demand reduction (particularly in summer), but is not considered 'available capacity' during maximum demand given a significant portion of maximum demand events can occur after sunset.

3. **Installation of utility-scale storage.** The installation of utility-scale storage from about 55 MW today to almost 600 MW by the summer of 2023-24 may be in the form of large, two-hour duration batteries that can be installed in a modular fashion targeted at the point where they are needed, such as near clusters of large renewable generators and other grid constraints. Although this capacity could also be provided by pumped hydro storage, the large pipeline of announced battery projects is considered more realistic under a three year lead timeframe.

4. **Installation of distributed battery energy storage.** Rapid growth in the installation of distributed battery energy storage in Victoria, from around 70 MW in 2019-20 to 560 MW by the summer of 2023-24 can regularly contribute between 1.4 and 1.5 GWh of capacity in 2023-24. This occurs through the daily absorption and discharge of primarily rooftop PV, distributed during evening and overnight periods when the energy is needed most. Although distributed storage does contribute to peak demand reduction, it is not necessarily able to be dispatched by the grid operator without being aggregated into a 'virtual power plant'.

5. **Growth in aggregated sharing models for distributed battery storage systems**. The growth of aggregated sharing models for distributed battery storage systems such as Virtual Power Plants, operated by a retailer or aggregator to act as an alternative supply source for arbitrage or emergency response, is modelled to provide approximately 280 MW of capacity by the summer of 2023-24, around half of all distributed battery storage.

6. **Increased demand side participation**. An increase in demand side participation, where the grid operator is able rely on entities to reduce peak demand from both aggregated residential and large industrial sources, is able to provide around 160 MW by the summer 2023-24.

7. **Continuation of wind energy growth**. There are more than enough proposed wind generation projects to meet and exceed the capacity modelled in this analysis. However, without final investment decisions on these projects, there is a risk that they will not proceed. These projects include 2.6 GW of installed wind capacity beyond what has already been committed for a total of 5.8 GW by the summer of 2023-24.

The impact of these measures is discussed below.

[12] The original design of the scheme, which started in July 2019, offered only 3,333 rebates each month, putting an effective cap on the market below pre-policy installation rates.

5.2 Change in Installed Capacity in Victoria

Under the Alternative Case, enough capacity is built in the next three years to support the possible early retirement of Yallourn. This involves building almost 6 GW of new large-scale renewable capacity by the summer of 2023-24, as shown in Figure 6(a),[13] with utility-scale wind technologies generally assumed to continue to outcompete solar in Victoria, owing to a lower initial levelised cost of energy, more favourable generation profile, and superior wind resource. Almost all this capacity is assumed to be built in the Reference Case forecast, however, without final investment decisions on these projects there is a risk that they could be delayed, or not proceed fast enough, to be fully commissioned by the summer of 2023-24.

Figure 6(a): Annual average change in large-scale Victorian New Entry Capacity to 2024.

Source: AEMO Generation Information, 2019 and RepuTex, 2019.

Major differences in capacity between the Alternative Case scenario and Reference Case forecast include an extra 270 MW of utility storage capacity ahead of Yallourn's closure in 2023 and another 230 MW of distributed storage after Yallourn's retirement. The difference in annual average capacity change between the Alternative Case and Reference Case are shown in Figure 6(b).

Aside from the closure of Yallourn in 2023 under the Alternative Case, most change in capacity shown in Figure 6(b) occurs under the Rooftop PV category, adding an average of 320 MW[14] of capacity more than the Reference Case forecast between 2020 and 2024, or an increase of almost 4,000 installations per month. This would be above the average baseline rate of 210 MW per year or about 2,500 installation per month in the Reference Case forecast.[15] Therefore, the Alternative case scenario's total Victorian Rooftop PV additions average 530 MW per year, or about installation rates to approximately 6,500 systems per month (in line with levels seen under the Victorian Solar Homes policy). By maintaining this accelerated installation rate, total installed Rooftop PV could grow to more than 4 GW over the next few years, rather than just 2.7 GW at the lower installation rate as shown in Figure 6(c).

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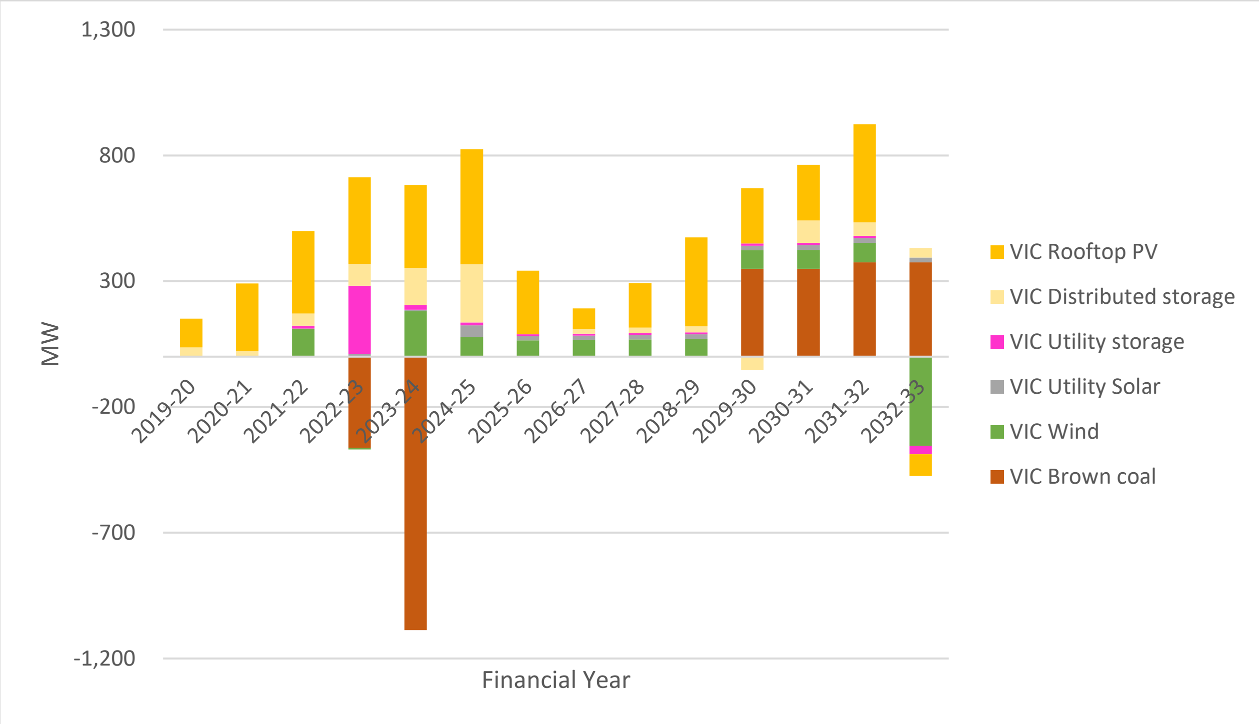
[13] In line with AEMO's existing and committed project pipeline information as of 14 November 2019.
[14] For reference, each of the four units at Yallourn are either 350 or 375 MW in nameplate capacity.
[15] Mostly associated with higher-income residential solar installed by those above the means-tested threshold and smaller (<100 kW) commercial rooftop solar.

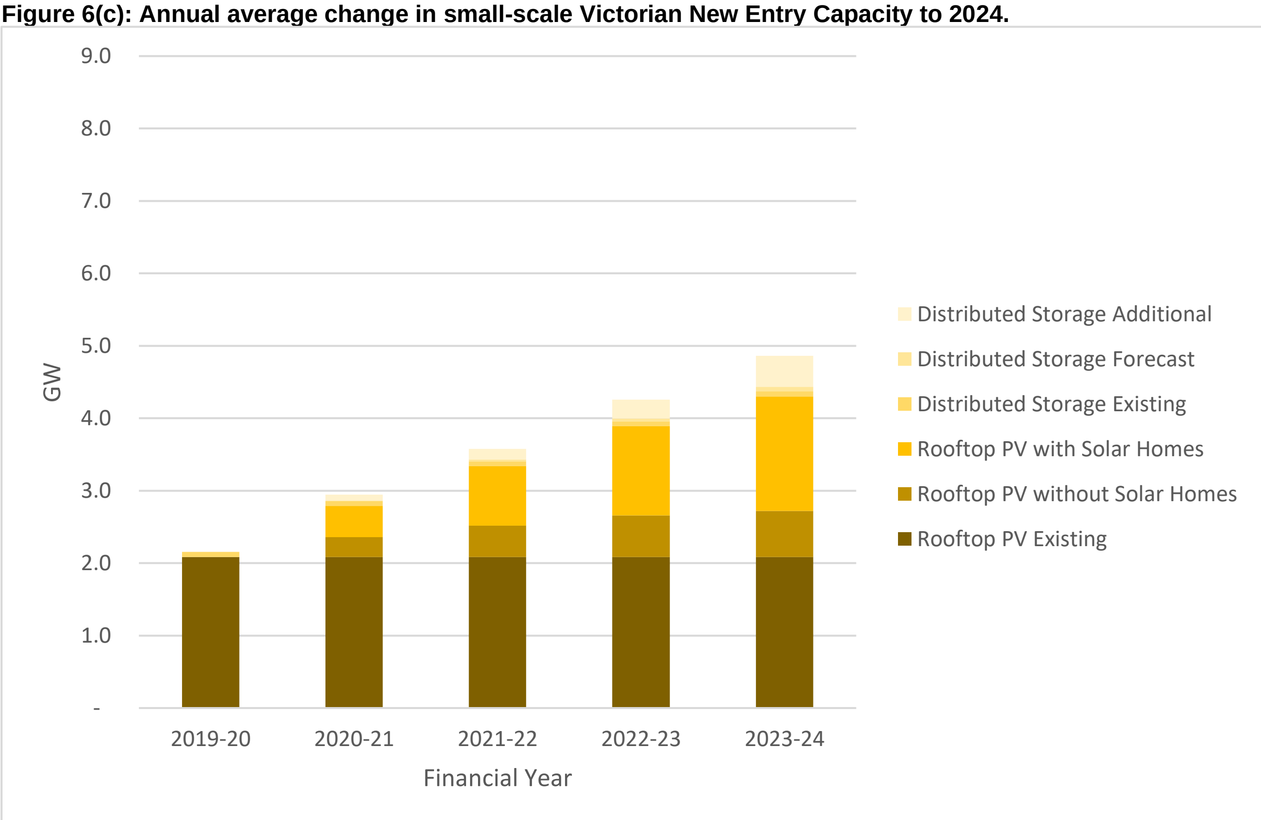
Figure 6(b): Annual average difference from the Base Case forecast in New Entry and Retired Capacity in Victoria to 2033.



Note that negative values in 2032-33 do not represent closures, but reflect net differences to the Reference Case forecast, where a large amount of capacity is added after Yallourn closes (rather than being built ahead of the closure as in the Alternative Case).

Source: RepuTex, 2019.

Figure 6(c): Annual average change in small-scale Victorian New Entry Capacity to 2024.



Source: AEMO ISP, 2019-20 and RepuTex, 2019.

Although a relatively small proportion of installed capacity, distributed (i.e. small-scale) battery storage will need to grow many times its current level (<100 MW) to between 500 and 600 MW over the next few years. Of this kind of small-scale storage, approximately half will need to be aggregated into programs that are 'available' (to generate power), to be able to contribute to reliability.

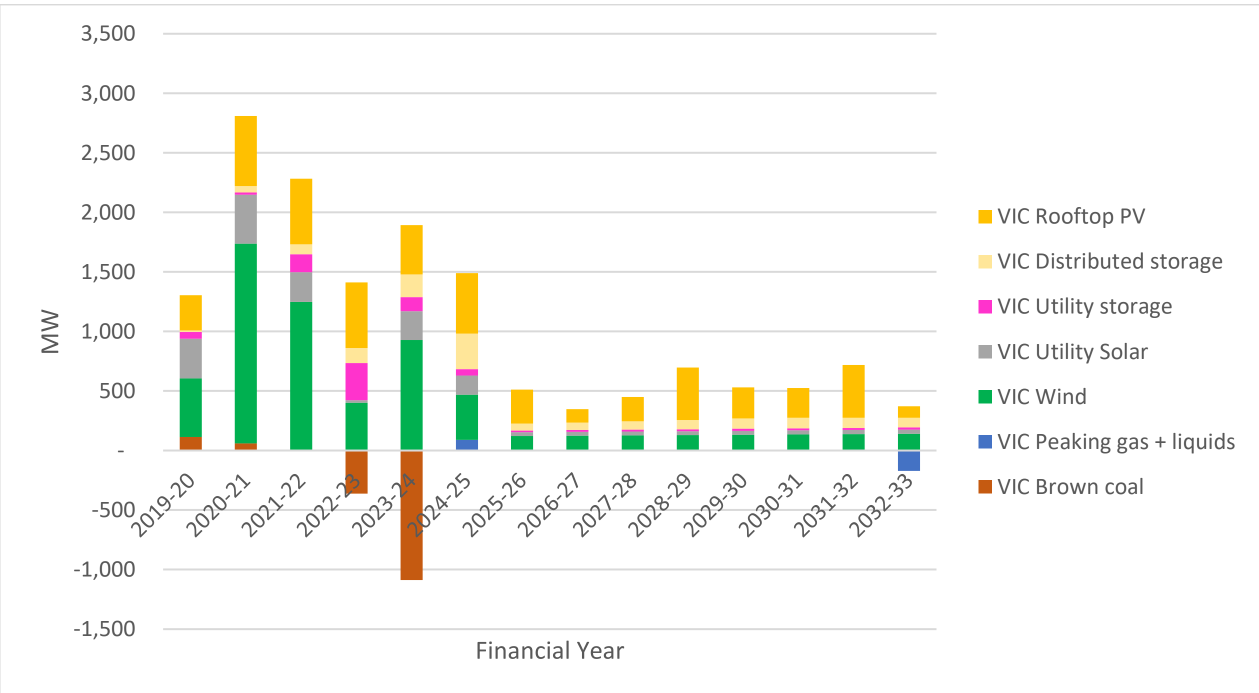
Enabling households to tap into battery value streams additional to the standard 'solar self-consumption' approach will be crucial in driving uptake by making batteries more attractive. These include hard, financial benefits like virtual power plant (VPP) participation revenues (for energy market participation as well as grid services), which help shorten payback periods, as well as non-financial benefits such as improved energy self-reliance and blackout protection.

Table 1: Existing and committed versus additional capacity support required by summer 2023-24.

Type of capacity	Already existing or committed	Additional capacity required by summer 2023-24	Total (non-hydro) renewable & storage capacity by summer 2023-24
Wind power	3.2 GW	2.6 GW	5.8 GW
Utility Solar	1.1 GW	0.3 GW	1.4 GW
Utility Storage	0.1 GW	0.6 GW	0.7 GW
Distributed Storage	0.1 GW	0.5 GW (0.3 GW aggregated as VPP)	0.6 GW
Rooftop PV	2.2 GW	2.1 GW (1.8 GW expected to be delivered by Solar Homes)	4.3 GW

In annual average terms, 930 MW of wind, 220 MW of utility solar, 130 MW of utility storage, 150 MW of distributed storage, and 520 MW of rooftop PV are assumed to be added each year in Victoria by 2025. As it becomes clear the VRET has been met by mid-decade, however, and wholesale electricity prices continue to decline, utility scale development is modelled to weaken to annual average additions of just 130 MW of wind, 30 MW of utility solar, and 20 MW of utility-scale storage as shown in Figure 6(d). Additions of annual average distributed capacity remain stronger at 260 MW of rooftop PV and 80 MW of distributed storage per year due to the more favourable economics of self-generation.

Figure 6(d): Annual average change from present in Victorian New Entry and Retired Capacity to 2033.



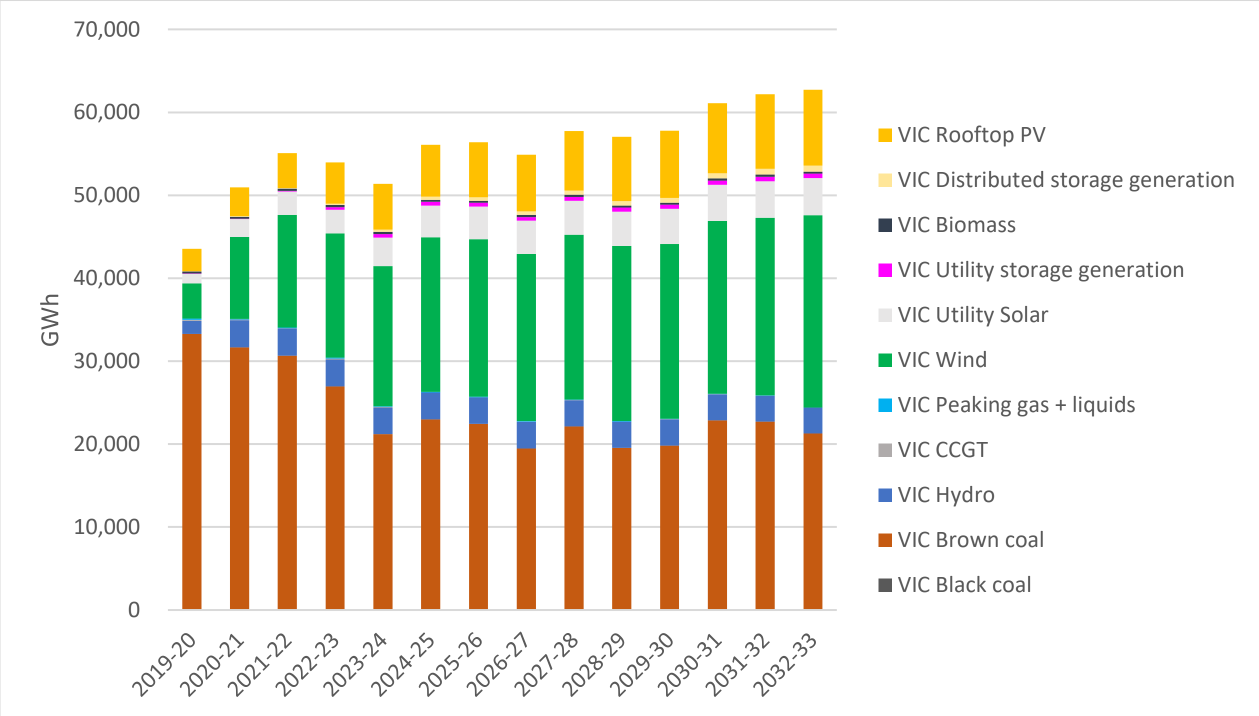
Source: RepuTex, 2019.

Under this scenario, Yallourn is assumed to be removed from the market in April of 2023, retiring 1,450 MW of nameplate capacity. In figure 6(d), this is illustrated as annual change in average capacity by fuel type, equivalent to around one Yallourn unit in 2022-23 and the remaining three units in 2023-24.

5.3 Energy Generation and Greenhouse Gas Emissions

The amount of energy generated in the modelled Alternative Case remains in broadly line with the Reference Case, with Victoria resuming its role as an electricity exporter from the beginning of the 2020s. Energy generation is slightly higher than the Reference Case in the initial years due to increased PV installations. After Yallourn's closure in 2023, energy generation is shown to be lower than the Reference Case, however Victoria remains a net electricity exporter until the end of the decade, even as brown coal generation falls from about 30 TWh per annum to closer to 20 TWh per annum.

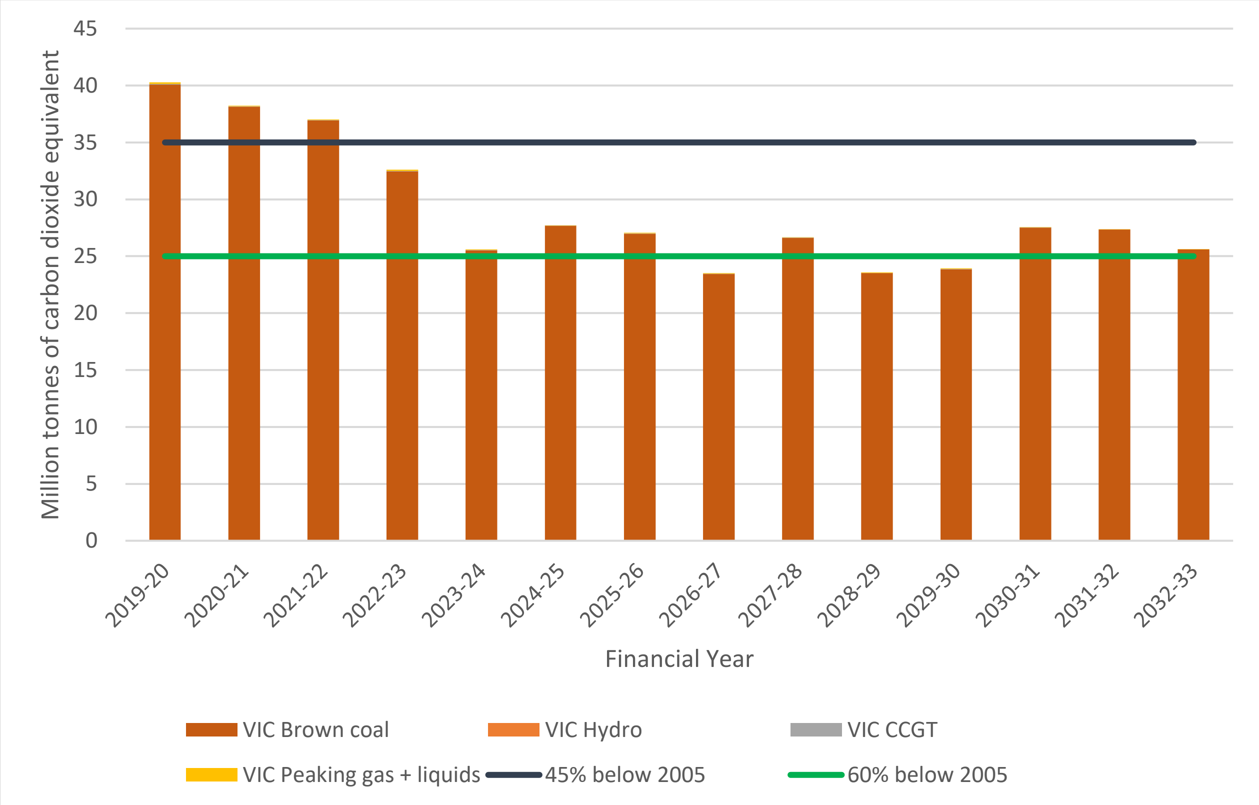
Figure 7: Alternative Case energy generated in Victoria.



Source: RepuTex Energy, 2019

The decline in brown coal generation results in a decline in Victorian electricity sector emissions, shown in Figure 8. In line with reduced brown-coal capacity, we model Victoria's electricity sector emissions falling from around 40 Mt in 2020 to approximately 26 Mt in 2023-24, 60 per cent below 2005 levels. This is around 8 Mt lower each year than the Reference Case, or 85 Mt of emissions abatement by 2033.

Figure 8: Alternative case, Victorian electricity sector emissions.



Source: RepuTex Energy, 2019

5.4 Energy Reliability to Meet Maximum Demand

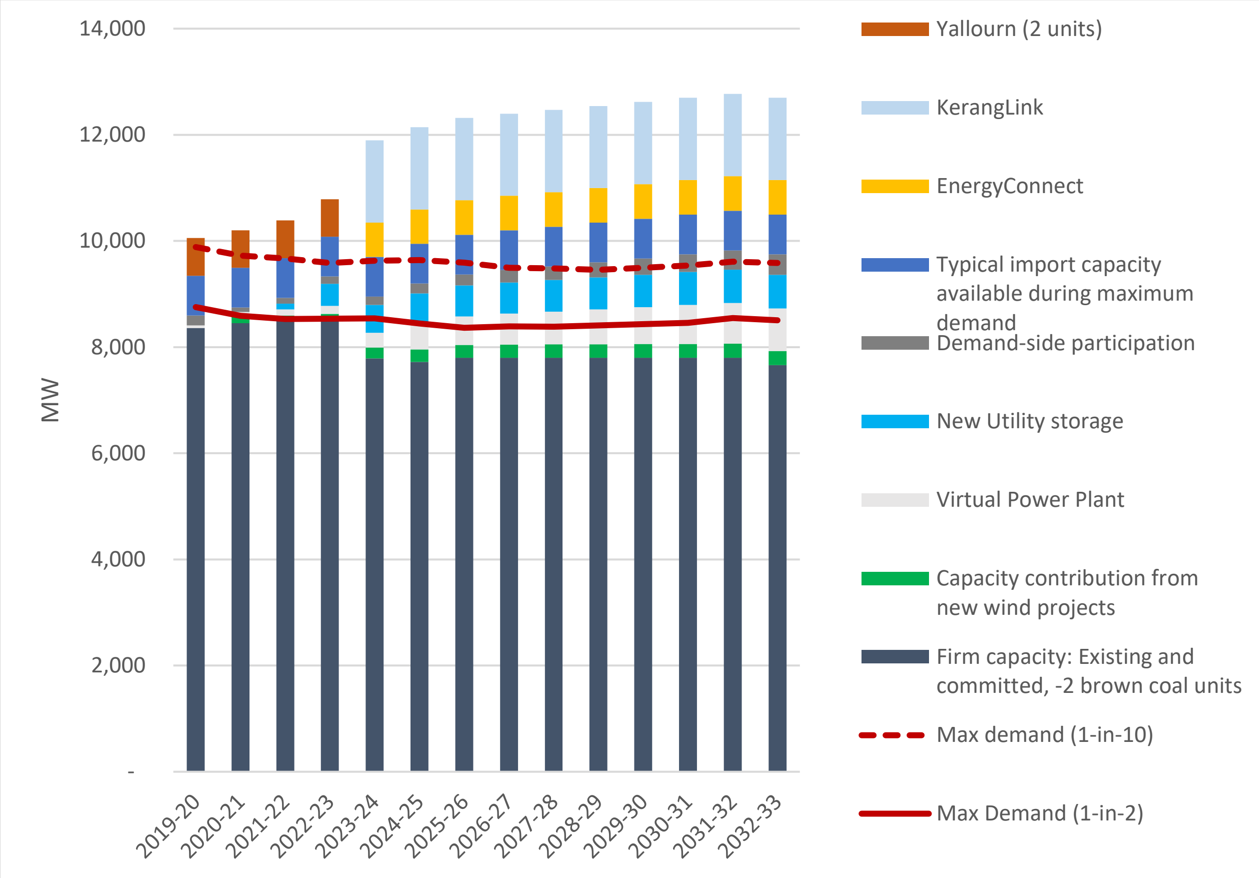
Whereas under the Reference Case forecast Victoria may be reliant on yet-to-be approved import projects, in the Alternative Case, Yallourn's capacity is largely replaced by a fleet of energy storage capacity. As shown in Figure 9, the closure of four brown coal units at Yallourn from April 2023 is offset by the inclusion of new renewable energy capacity, along with energy storage and interconnector upgrades. Victoria is shown to more readily maintain energy reliability during typical 'one-in-two year' maximum demand events through the end of the decade. In more extreme 'one-in-10 year' events, demand-side participation combined with current levels of import capacity from existing interconnectors ensure enough power supply.

New interconnector projects, such as EnergyConnect[16] and KerangLink[17], could provide additional energy reliability as early as the summer of 2023-24 to back up other capacity that may become unavailable. While technically feasible, these interconnectors are yet unapproved, and would likely be delayed if not expedited though the co-operation of relevant entities. As such, this case focuses on the scale-up of Victorian utility-scale storage and virtual power plant capacity to reduce reliance on new import transmission being built by the summer of 2023-24.

Despite the closure of Yallourn as early as April 2023, modelling indicates that the Victorian market can compensate for the loss of available capacity through effective planning within a three year lead time. Even ahead of an official closure decision, Victoria could be better prepared to address capacity failures by increasing the current rate of projects already committed or in planning stages, such as large- and small-scale renewable energy capacity, energy storage and interconnector upgrades.

[16] Formerly Riverlink.
[17] Also known as Snowy Hydro South.

Figure 9: Cumulative VIC New Entry / Retired Capacity by Technology (MW).



Source: RepuTex, 2019.

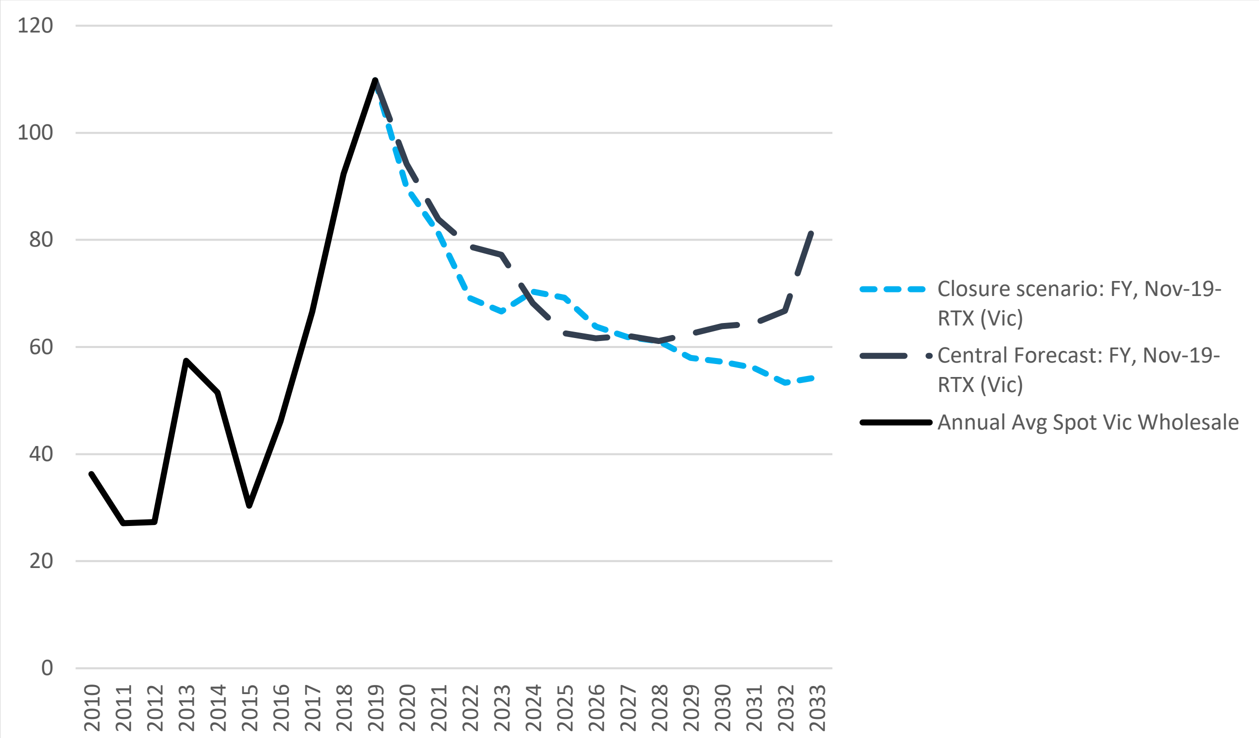
In addition to maximum demand events, this capacity combination also performs adequately during high export, high wind, and minimum demand days. Although Victorian operational demand is normally much lower during these conditions, the sum of total available Victorian generation capacity can also be much lower due to increased levels of planned maintenance scheduled in ‘shoulder’ seasons (e.g. April and October). This necessitates enough capacity flexibility to be able to respond to changing conditions, such as ramping down to reduce supply during high hydro and wind generation and ramping up to replace variable generation such as solar as the sun sets.

5.5 Wholesale Price Implications

In this scenario, medium-term wholesale electricity prices are shown to decline from over $100 per MWh in 2018-19 toward approximately $70 per MWh by 2022, underpinned by a lower dependence on high priced gas generation (particularly during the more expensive winter quarter), the accelerated installation of small-scale rooftop solar PV and distributed energy storage, along with the continued uptake of large-scale renewable energy projects commissioned over the next three years.

Strong growth in rooftop PV and interconnection upgrades with other markets combine to dampen the price increase associated with removing 10 TWh of brown coal generation in 2023. Continuing strong growth in rooftop PV is shown to reduce operational grid demand, while seasonal energy storage provided by Snowy 2.0 balances periods of renewable over- and under-supply. Utility-scale energy storage provides competitively priced frequency control services, while distributed storage shifts Victoria’s evening peak lower, and later into the night, better aligning with Victoria’s wind resource on sunny days. In addition, virtual power plants and demand response mechanisms provide key peaking capacity to reduce the frequency of extreme wholesale prices. Overall these effects suggest a steady and sustainable decrease in prices below $60 per MWh without closing another major thermal generator in Victoria before 2033.

Figure 10 – September 2019: Annual Forecast (Victoria)



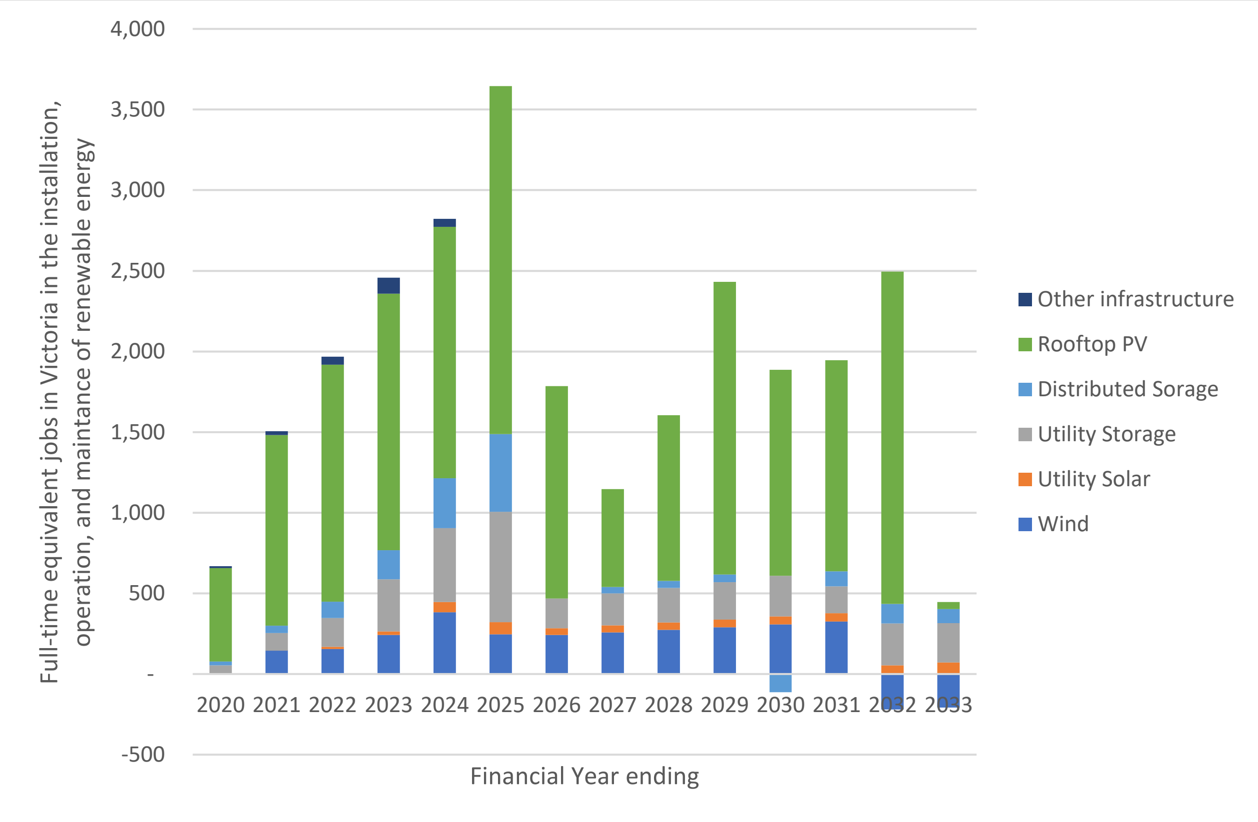
Source: RepuTex, 2019

Although this scenario presents a generally similar wholesale price outcome to the Reference Case, after 2028 we see a divergence in prices as Yallourn is decommissioned and Reference Case prices increase by over $20 per MWh. This is due to the delayed timeline for KerangLink (or other interconnectors) in the Reference Case, which are not built ahead of Yallourn's closure, leaving the Victorian market much tighter and more dependent on gas-fired generation at Newport and Jeeralang to replace the supply from Yallourn (particularly when black-coal from NSW is constrained). In addition, under the Alternative Case we see an additional 1.6 TWh of energy from rooftop PV, supporting lower prices and reduced demand.

6. JOBS AND INVESTMENT

Building additional electricity generation capacity and storage solutions to prepare for an early closure of a brown coal facility is modelled to create 27,000 job-years by 2033, averaging over 1,900 jobs per year over the 14 year period, and provide certainty and investor confidence for the energy industry, driving an additional $6.8 billion in economic activity in Victoria.

Figure 11: Difference in Victorian energy job creation from Reference Case forecast.



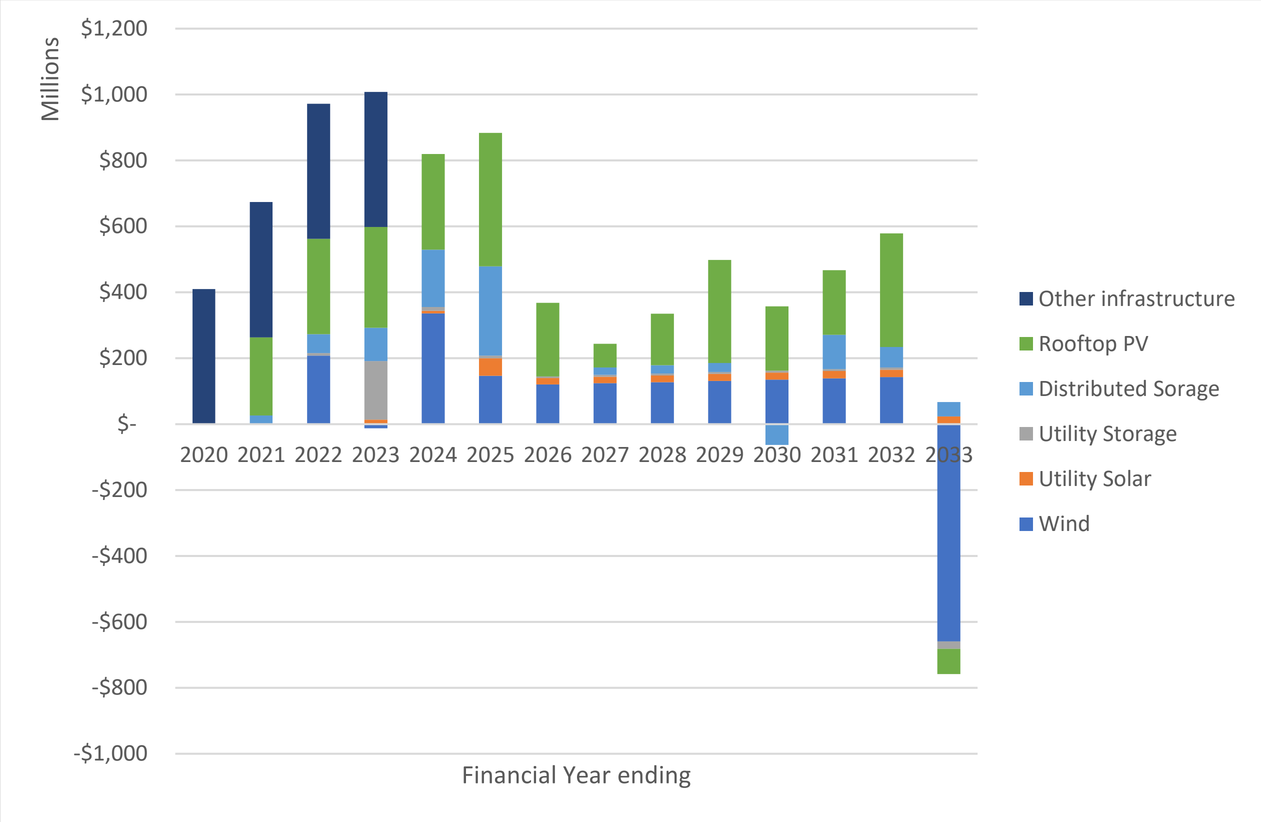
Source: RepuTex, 2019

Two-thirds of job creation is associated with increasing installation rate of rooftop PV. Whereas employment of rooftop solar slows to an average of less than 800 full-time equivalent jobs per year (FTE) under the Reference Case, in line with forecast lower electricity prices, under the Alternative Case employment in rooftop PV doubles to more than 2,000 FTE, underpinned by government policy. Over 14 years this represents nearly 27,000 jobs, or 18,000 more than the Reference Case forecast.

Additional construction also leads to an increase in ongoing operations and maintenance (O&M) jobs associated with the development of new infrastructure, averaging over 1,700 ongoing jobs per year, or more than 1,400 above the Reference Case forecast.

Similarly, increased investment in rooftop PV represents around 43 per cent of the modelled increase in economic activity in Victoria. Even as residential PV installations in Melbourne fall below $1 per watt after 2020, at an average installation rate of 30,000 kW per month the increase in economic activity represents more than $200 million each year.

Over 14 years this represents nearly $3.0 billion in new economic activity over the Reference Case forecast. Other major economic activity is also associated with new transmission infrastructure ($1.6 billion) and additional wind energy development ($0.9 billion).



Source: RepuTex, 2019

Most new investment is concentrated over the next five years as capital-intensive infrastructure is put into place before the summer of 2023-24. Note that the difference in investment is lower in the final year (relative to the Reference Case), where investment in new capacity is deferred until 2033, after all of the units of Yallourn have closed.

7. OTHER CAPACITY OPTIONS

While modelling assumes that the Victorian energy system is largely supported by increased investment in battery storage and demand side measures (including rooftop PV), policymakers may also have a wider range of policy options available in the event of a longer closure lead time, after 2023-24 modelled in this analysis. These include:

Initiative	Available Capacity	Pros and Cons
MarinusLink interconnector from Tasmania to Victoria	600-750 MW by 2026-27	• Addresses Tasmanian and Victorian energy security in the event of an extended outage of Basslink; • Allows increased exports of dispatchable hydro and wind energy to Victoria during periods of high demand; • Defers 450-600 MW of thermal generator investment in the NEM; • Enhance the capability for Tasmanian water storage and hydro facilities to be used as a large battery for flexibly, sending out or absorbing power to and from Tasmania; • Provides a market for the further development of strong Tasmanian wind resources, with anti-correlation to Victorian wind resources particularly during high-pressure weather systems (i.e. sunny days)[18].
Offshore wind, e.g. Star of the South, 2.2 GW total	55 MW available capacity by 2025-26, 2,200 MW available capacity by 2028-29.	• Construction jobs and investment in a region adjacent to the Latrobe Valley; • First power not anticipated before summer 2024-25; • Relatively higher capacity factor than onshore wind. • Utilise existing Latrobe Valley transmission infrastructure.
Open Cycle Gas Turbine (OCGT) generators	200-500 MW by 2024	• Although an OCGT plant could theoretically be constructed quickly, associated feasibility and/or market study updates may take up to three years; • Another large gas generator could primarily displace older gas generation in Victoria; • Pricing is dependent on internationally influenced gas spot prices; • Existing OCGT proposals already exist at Mortlake (Origin) and Tarrone (AGL) in western Victoria; • The business case for adding another peaking generator ahead of the closure of a Latrobe Valley generator is being eroded by the falling cost of firmed renewable energy.

[18] RepuTex, How do weather patterns impact REZ correlations? [Link](#).

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8. APPENDIX A - OTHER ASSUMPTIONS

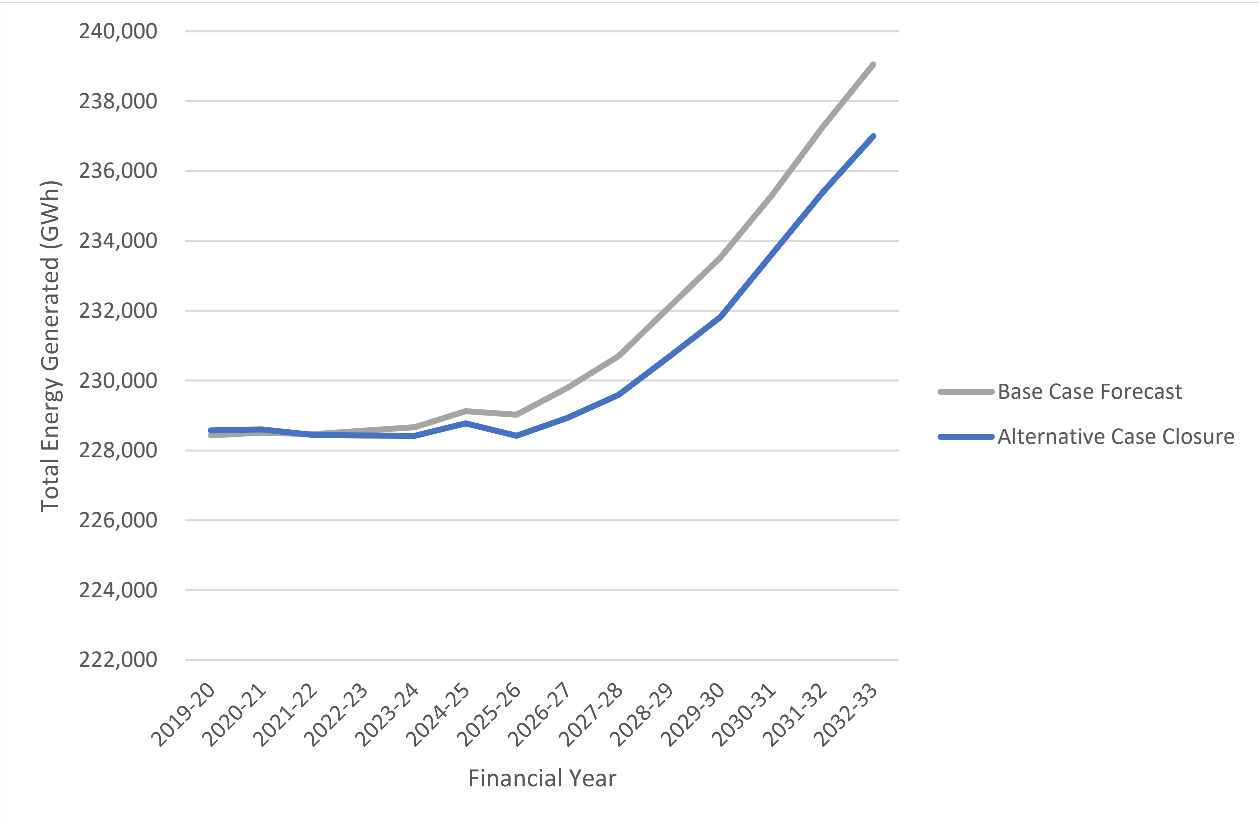
8.1 Electricity Generation

AEMO's assumptions for the 2019-20 ISP are applied as a reference for projected electricity consumption across the NEM. The ISP considers various scenarios, however the Central scenario is primarily used to reflect different levels of consumer engagement and economic growth. The Alternative Case is adjusted to consider the Step Change scenario's assumptions about aggregated battery storage, demand side participation, embedded energy storage, PVNSG, and rooftop PV.

For the NEM, electricity consumption is largely driven by the residential and commercial sectors with centralised electricity generation declining in line with the increased uptake of rooftop solar. The uptake of rooftop solar and energy efficiency is forecast to continue in the residential and commercial sectors.

Although both the Reference Case and Alternative Cases are similar in their total energy generation, the Alternative Case is assumed to achieve less losses from auxiliary loads, distribution and transmission losses, but more behind-the-meter rooftop PV generation and losses associated with energy storage load than the Reference Case forecast. This is due to the assumption of a much higher take up rate of these behind the meter and distributed technologies. The net result is the alternative case results in slightly lower energy generation in each year.

Figure 13 – Modelled Total Generated Energy (including auxiliary load, energy storage load, non-scheduled generation, rooftop solar, distribution and transmission losses) by case for the NEM.



Source: RepuTex Energy 2019.

In the both the Reference Case forecast and Alternative Case, electric vehicle (EV) uptake is modelled to align with AEMO's ISP Central trajectory for EVs, consuming around two per cent of operational demand by 2030 in Victoria, doubling to four per cent by 2033 or approximately 20 per cent of the vehicle fleet.

The Alternative Case considers an accelerated uptake in line with AEMO's Step Change scenario where Victorian rooftop PV grows from 3 GW of capacity (3.5 TWh) in 2021 to 7 GW (8.7 TWh) by 2033. In contrast, our base case forecast only achieves 3 GW of capacity a decade later by 2031.

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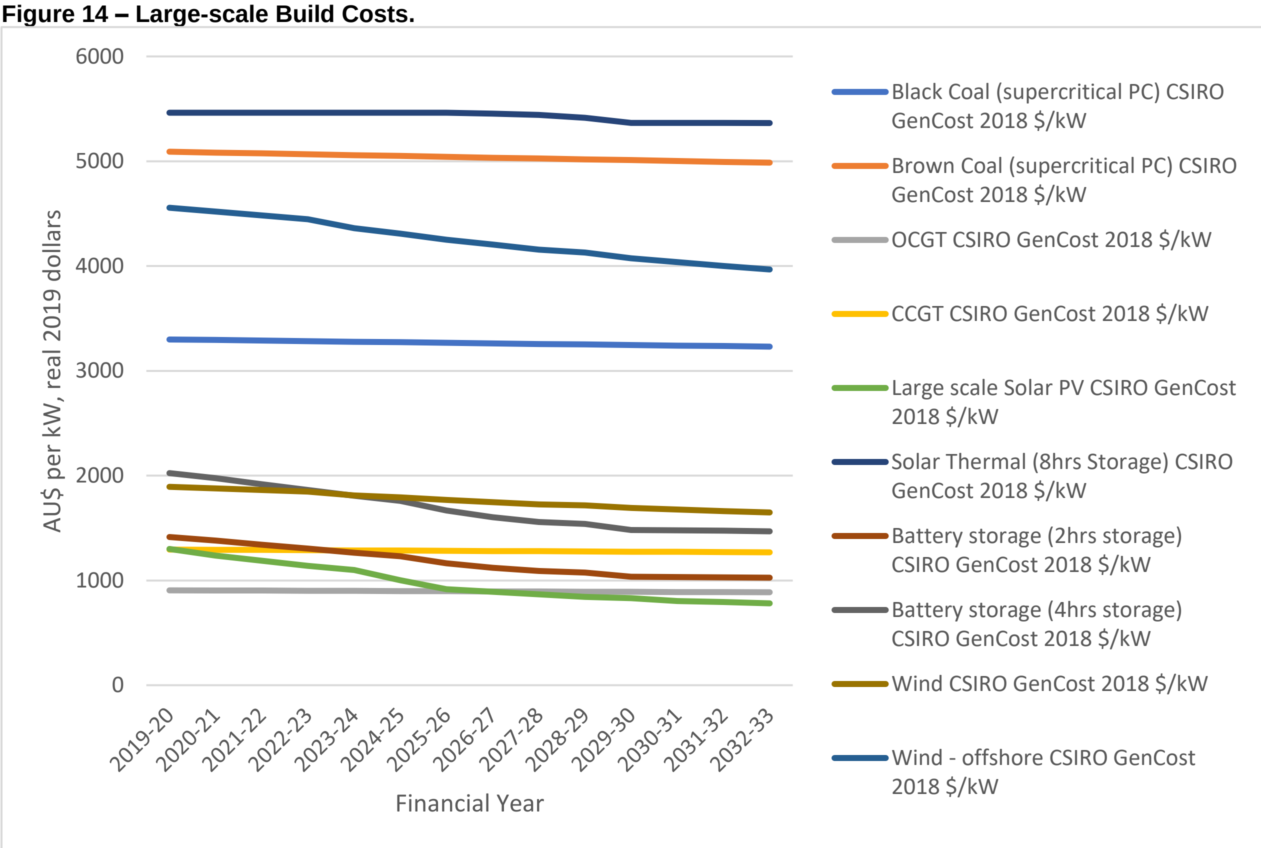
8.2 Other Supply Side Inputs

Large-scale build costs

Large scale solar PV technologies, such as single-axis tracking solar and battery storage, are assumed to experience rapid build cost declines over the next five to ten years, with large scale solar PV to beat even OCGT as least expensive generators to build on a $/ kW basis by 2027.

Figure 14 – Large-scale Build Costs.



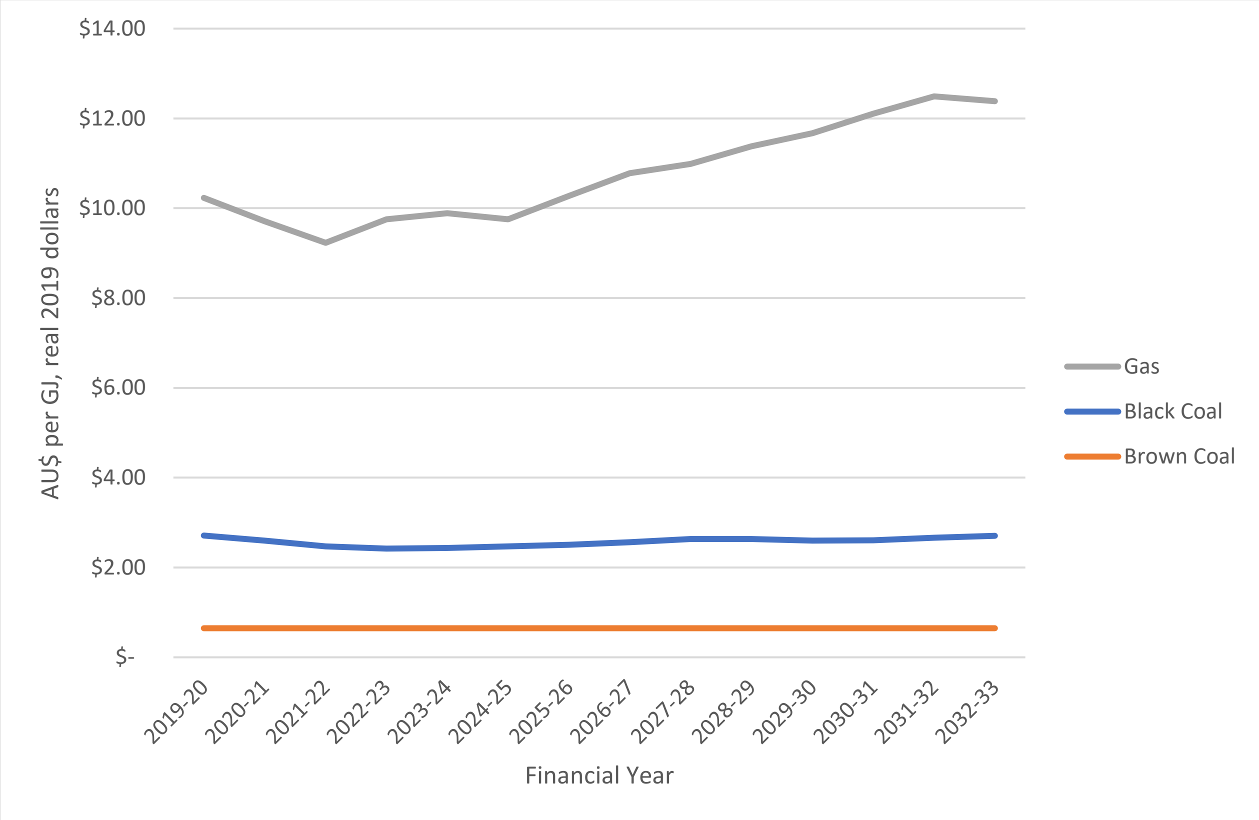
Source: AEMO, Build costs - ISP (September 2019); 2°/2019 Input and Assumptions workbook.

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, India, and Japan. Our wholesale coal price for coal-fired generators is affected by the cost of mining, and whether the coal is of suitable quality for/and can access export markets. Other factors include ownership/vertical integration (for mine mouth developments) and transportation costs.

Australia's east coast gas prices are influenced by forecast supply-demand balance and international LNG price forecasts. Our gas price forecast (Figure 15) reflects the changing dynamics in Australia's gas markets. The immediate decrease in prices is largely attributed to our expectation for a more direct influence of Asian gas markets in the northern hemisphere, allowing more trade between the northern-southern area of the east coast gas transmission pipeline, and increasing competition between domestic gas production and wholesaling, resulting in decreased gas prices for domestic generators connected to the main gas transmission network. We expect many gas-powered generators delivered prices to stabilise around $10 per giga-joule (/GJ) for the intermediate term before rising toward $12/GJ by the 2030s.

Figure 15 – Annual Average Fuel Price for Electricity Generation in NEM ($/gigajoule)



Source: AEMO ISP and RepuTex, 2019.

Entry of conventional coal

In this analysis, conventional coal (i.e. coal-based technologies that do not employ carbon capture and storage) is restricted from market entry. This is due to:

- Community views and corporate sustainability policies,
- Difficulty in securing financing on a commercial basis due to these risks,
- Long-term risk of explicit carbon pricing being reintroduced, and
- Potential difficulty obtaining generation licenses from State and Territory governments,

For the purposes of this study we have assumed that there is no scope for new entrant coal-fired generation investment over the modelling horizon, with all new-entrant thermal generation assumed to be either bio- or gas-fired.

9. APPENDIX B - OUR MODELLING APPROACH

9.1 Our Electricity Market Simulation Model

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

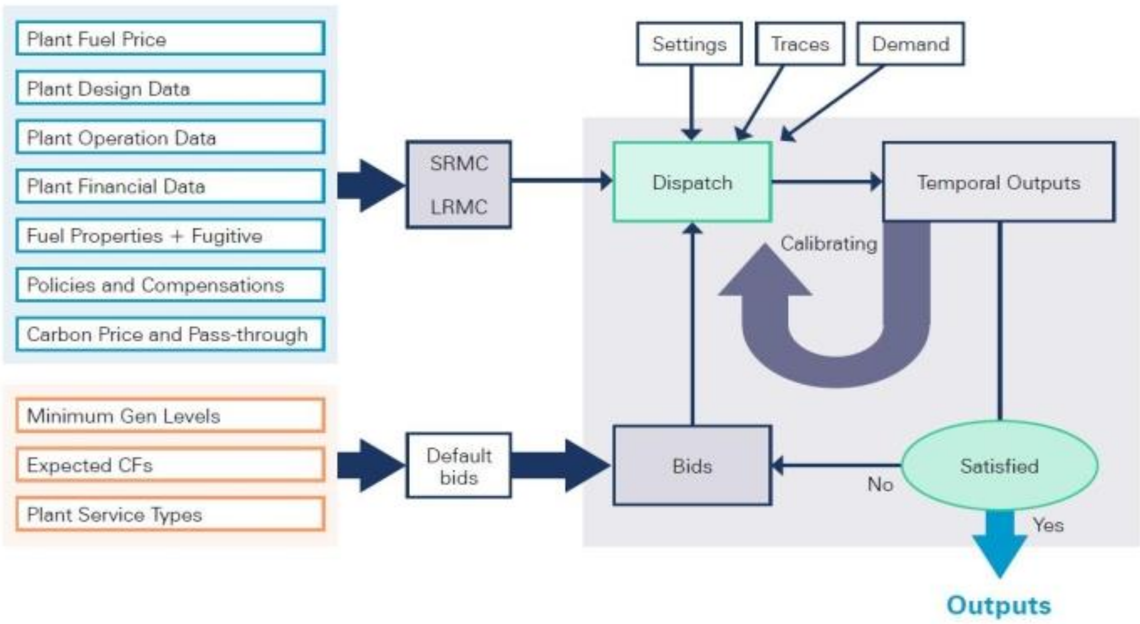
Various rules, laws and policies govern the operation of the NEM, with the key elements being power supply always matching power demand, adjusted for constraints in the electricity transmission and distribution network. The supply side is comprised of fossil fuel and renewable generators that offer capacity 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, population, etc. 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 can simulate the NEM or Western Energy Market (WEM) least cost dispatch processes and supply and demand conditions in the forecast periods, modelling the resulting generation and emissions from each of 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 A: 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 down – i.e. turned-off.

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 are 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 normally be thought of as quality held back to maximise profit.

There are three bidding formats. Long-term forecasting calculates dispatch on 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 normally updated quarterly, whereas most other variables are usually 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.

10. APPENDIX C

10.1 Generator Outages

Victoria's energy generation is forecast to be significantly lower in 2019-20 than in subsequent years. This is based on Victoria experiencing its record lowest quarterly average brown coal generation since the NEM began, of around 3,520 MW. This reflects the exit of significant brown coal capacity and more recent unplanned outages. Unplanned outages, particularly at Loy Yang A, Loy Yang B, and Yallourn power stations, were the key driver of average quarterly brown coal generation being around 600 MW less in Q3 2019 than in Q3 2018.[19] The regularity of 'tube leaks' at most of Victoria's remaining 10 brown coal units over the inter quarter does not bode well for keeping all units available over the most critical summer period Victoria is forecast to experience in 2019-20.

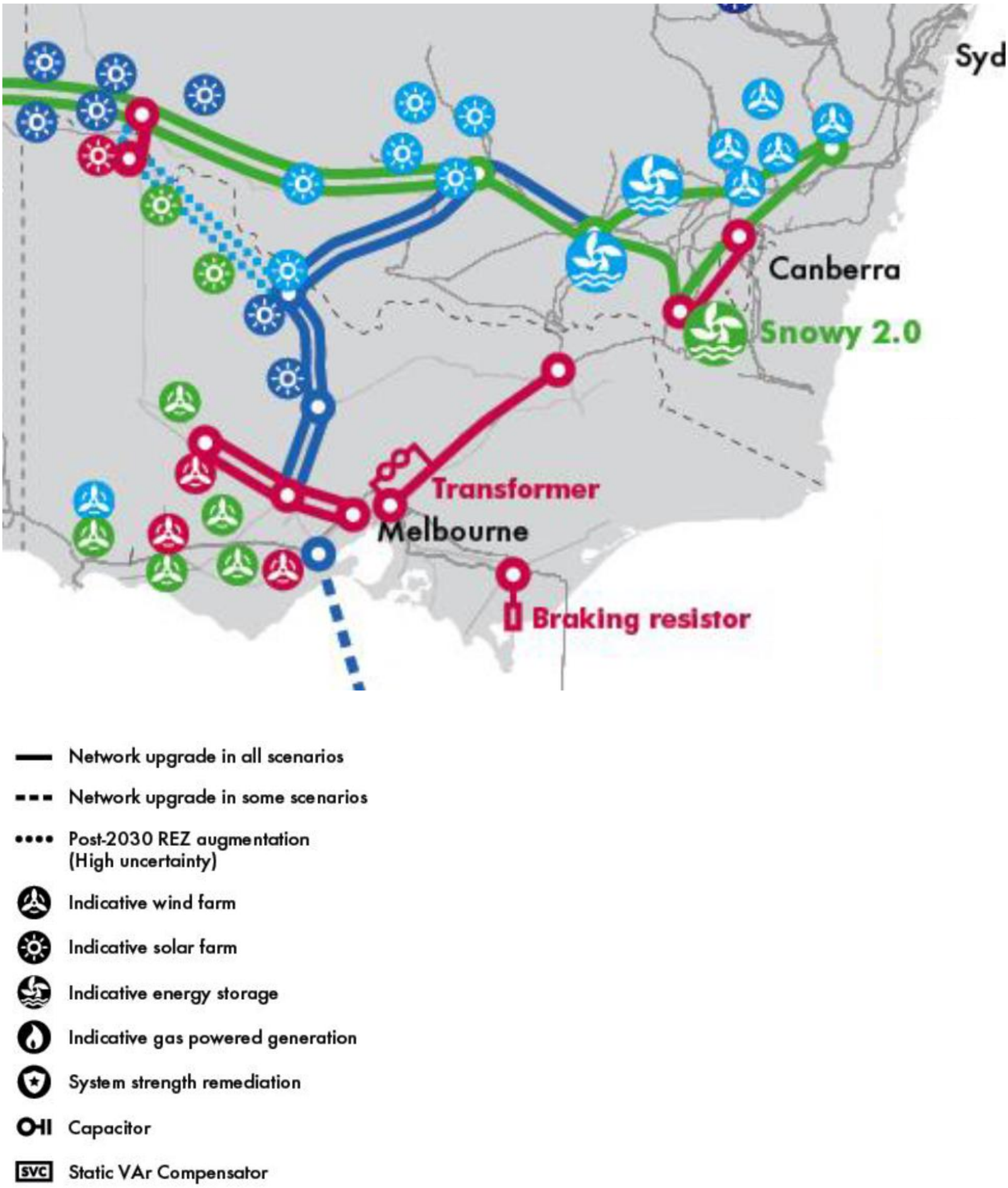
Table C: Generator outages.

STATION, COMPANY	FUEL TYPE, CAPACITY (WINTER RATING)	NUMBER OF DAYS OFFLINE IN Q3 2019	NOTES
Queensland			
Kogan Creek, CS Energy	Black Coal 1 unit, 744 MW	80 days	Planned—Major overhaul completed in October
Gladstone, CS Energy	Black Coal 6 units, 280 MW each	Unit 1: 20 days	Planned
		Unit 2: 34 days	Planned
		Unit 3: 19 days	Planned
Stanwell, Stanwell Corporation	Black Coal 4 units, 365 MW each	Unit 1: 61 days	Planned
New South Wales			
Mt Piper, EnergyAustralia	Black Coal 2 units, 700 MW each	Unit 1: 22 days Unit 2: 40 days	Planned—Managing coal supply issues
Liddell, AGL Energy	Black Coal 4 units, 450 MW each	Unit 2: 22 days	Planned
Bayswater, AGL Energy	Black Coal 4 units, 660 MW each	Unit 4: 60 days	Planned
Eraring, Origin Energy	Black Coal 4 units, 720 MW each	Unit 1: 6 days	Unplanned—'fan issues'
		Unit 2: 10 days	Unplanned—'valve replacement' (forced outage)
		Unit 3: 50 days	Planned (44 days) Unplanned (6 days)—'mill management', 'suspected tube leak'
Vales Point, Delta Electricity	Black Coal 2 units, 660 MW each	Unit 1: 17 days	Planned
		Unit 2: 25 days	Unplanned—'unit trip', 'air heater problems'
Victoria			
Loy Yang A, AGL Energy	Brown Coal 4 units, 552 MW each	Unit 2: 92 days	Unplanned—Electrical issues due back mid-December
Loy Yang B, Alinta Energy	Brown Coal 2 units, 535 MW each	Unit 1: 14 days	Unplanned—Tube leak
Yallourn, EnergyAustralia	Brown Coal 4 units, 382 MW each	Unit 2: 27 days	Unplanned—Tube leak
		Unit 3: 24 days	Unplanned—Tube leak
		Unit 4: 34 days	Unplanned—Tube leak
Mortlake, Origin Energy	Gas 2 units, 292 MW each	Unit 1: 15 days	Planned
		Unit 2: 88 days	Unplanned—Electrical issues but doesn't run often in Q3. Due back mid-December

Source: AER, Wholesale markets quarterly Q3 2019.

[19] AER, Wholesale markets quarterly Q3 2019.

10.2 Map of Integrated Development Plan



Source: AEMO Integrated System Plan, 2018

11. APPENDIX D

11.1 List of Indicative New Developments in Victoria

Shaded entries reflect capacity additions modelled for this analysis.

Project	Fuel	Capacity (MW)	Status
Crowlands Wind Farm	Wind	80	In Commissioning
Mt Gellibrand Wind Farm	Wind	69	In Commissioning
Mt Gellibrand Wind Farm	Wind	69	In Commissioning
Yendon Wind Farm	Wind	144	Committed
Murra Warra Wind Farm - stage 1	Wind	226	Committed
Elaine Wind Farm	Wind	84	Committed
Stockyard Hill Wind Farm	Wind	532	Committed
Moorabool Wind Farm	Wind	320	Committed
Cherry Tree Wind Farm	Wind	58	Committed
Dundonnell Wind Farm	Wind	336	Committed
Bulgana Green Power Hub - Wind Farm	Wind	199	Committed
Berrybank Wind Farm	Wind	181	Emerging
Mortlake South Wind Farm	Wind	158	Emerging
Golden Plains Wind Farm	Wind	950	Publicly Announced
Mount Fyans	Wind	400	Publicly Announced
Willatook	Wind	285	Publicly Announced
Ryan Corner Wind Farm	Wind	235	Publicly Announced
Murra Warra Wind Farm - stage 2	Wind	209	Publicly Announced
Penshurst	Wind	198	Publicly Announced
Star of The South	Wind	2,000	Publicly Announced
Berrybank Wind Farm	Wind	151	Publicly Announced
Alberton Wind Farm	Wind	122	Publicly Announced
Hawkesdale Wind Farm	Wind	109	Publicly Announced
Ben More	Wind	90	Publicly Announced
Inverleigh Wind Farm	Wind	85	Publicly Announced
Woolsthorpe Wind Farm	Wind	73	Publicly Announced
Berrimal Wind Farm	Wind	72	Publicly Announced
Naroghid	Wind	50	Publicly Announced
Warracknabeal Wind Farm	Wind	50	Publicly Announced
Rifle Butts Wind Farm	Wind	40	Publicly Announced
Ferguson Wind Farm	Wind	9	Publicly Announced
Nhill Wind Farm	Wind	7	Publicly Announced
Numurkah Solar Farm	Solar	112	In Commissioning
Bannerton Solar Park	Solar	100	In Commissioning

Winton Solar Farm	Solar	85	Committed
Yatpool Solar Farm	Solar	50	Committed
Yatpool Solar Farm	Solar	44	Committed
Cohuna Solar Farm	Solar	31	Committed
Kiamal Solar Farm - Stage 1	Solar	200	Committed*
Kiamal Solar Farm - Stage 2	Solar	150	Emerging
Carwarp Solar Farm - Stage I	Solar	100	Emerging
Moira Solar Farm	Solar	80	Publicly Announced
Nowingi Solar Storage - Solar	Solar	250	Publicly Announced
Carwarp Solar Farm - Stage II	Solar	200	Publicly Announced
Prairie Solar Farm	Solar	175	Publicly Announced
Glenrowan Sun Farm	Solar	110	Publicly Announced
Wangaratta Solar Farm	Solar	22	Publicly Announced
Mildura Power Station	Solar	10	Publicly Announced
AusNet Services Deakin University Victoria Geelong PV Plant	Solar	7	Publicly Announced
Girgarre Solar Farm	Solar	118	Publicly Announced
Goorambat East Solar Farm	Solar	250	Publicly Announced
Axedale Solar Farm	Solar	180	Publicly Announced
Mallee Solar Farm	Solar	250	Publicly Announced
Murra Warra Solar Farm	Solar	200	Publicly Announced
Horsham Solar Farm	Solar	130	Publicly Announced
Glenrowan Solar Farm	Solar	102	Publicly Announced
Shepparton Solar Farm	Solar	100	Publicly Announced
Naring Solar Farm	Solar	60	Publicly Announced
Kerang Solar Farm	Solar	37	Publicly Announced
Inverleigh Solar Farm	Solar	22	Publicly Announced
GV Community Energy	Solar	12	Publicly Announced
Ouyen Solar Farm	Solar	10	Publicly Announced
Gannawarra Energy Storage System	Other	25	In Commissioning
Bulgana Green Power Hub - BESS	Wind	20	Committed
Kiama Solar Farm Storage	Other	270	Publicly Announced
Kentbruck Green Power Hub	Other	900	Publicly Announced
Inverliegh Wind Farm Storage	Other	12	Publicly Announced

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12. CONTACTS

Report title	Victorian market readiness to support the early retirement of Yallourn power station
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Confidential	N/A
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