Department of Environment, Land, Water and Planning

Victorian electricity sector renewable energy transition

ENERGY MARKET MODELLING REPORT

18 October 2022

Contents

List of Figures

List of Tables

Abbreviations List

Abbreviation	In full
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CBA	Cost-benefit analysis
CGE	Computable general equilibrium
DELWP	Department of Environment, Land, Water and Planning (Victoria)
CO2e	Carbon dioxide equivalent
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FOM	Fixed operation and maintenance
FY	Financial year
kV	Kilo volt
ICE	Internal combustion engine
IIO	Infrastructure Investment Objectives (report, NSW)
ISP	Integrated System Plan
LRET	Large-scale renewable energy target
MLF	Marginal loss factor
MVA	Mega volt amp
MW	Megawatt(s)
NEIR	NSW Electricity Infrastructure Roadmap
NEM	National Electricity Market
O&M	Operation and maintenance
ODP	Optimal development path
POE	Probability of exceedance
QNI	Queensland New South Wales interconnector
QRET	Queensland renewable energy target
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
USE	Unserved energy
VNI	Victoria New South Wales interconnector
VCR	Value of customer reliability
VOM	Variable operation and maintenance
VRET	Victorian Renewable Energy Target
WACC	Weighted average cost of capital

Executive Summary

DELWP commissioned Jacobs to undertake modelling of the future pathway for the National Electricity Market, and the Victorian component of that market. The modelling is designed to obtain insights into the potential future structure of the market, associated impacts on prices to customers, supply reliability and environmental outcomes (especially greenhouse emission reductions).

The results in this report reflect modelling initially undertaken in March 2022 and are dependent on market conditions, regulatory structures, and market expectations at that time.

Approach

The scenario modelled is denoted the VRET scenario. This follows assumptions under the AEMO Step Change scenario, which has a rapid reduction of emissions plus a step change in the rate of electrification and uptake of electric vehicles (as part of rapid emission reduction in other sectors of the economy). As a result of the latter, demand for electricity across the NEM grows more rapidly to 2050. This scenario also assumes the Victorian Government's recently announced offshore wind targets.

The method to modelling electricity market impacts and the assumptions used are contained in the body of the report. The range of assumptions reflects:

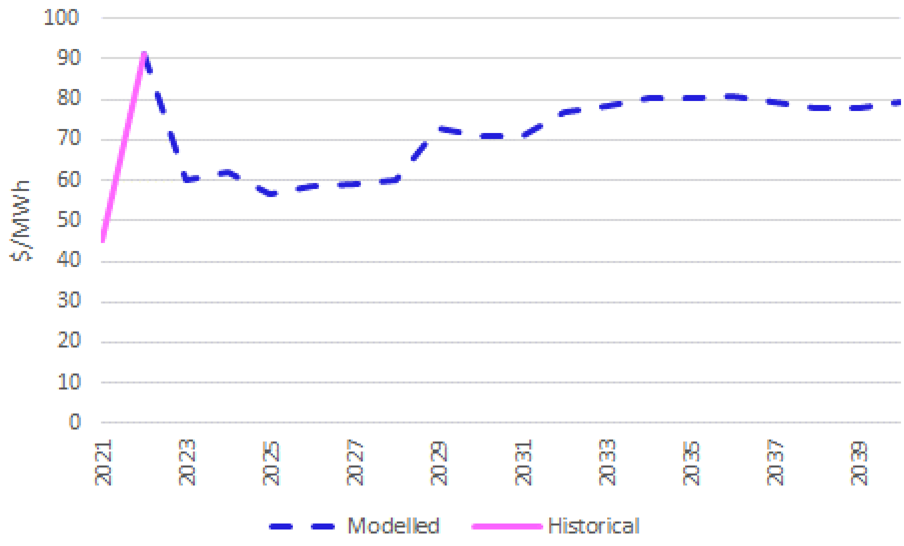
- The pace of decarbonisation in the economy and the electricity sector's role in decarbonisation.
- The timing of retirement of the coal fleet, which effectively means the timing at which the NEM comprises largely non-synchronous plant.
- The role that enhanced interconnection can play to improve reliability and cost of the electricity supply system.

Key findings – Wholesale prices

Figure 1 indicates some of the outcomes on wholesale prices across the scenarios. The findings from the analysis indicates that:

- **The transition to renewable energy results in lower wholesale electricity prices compared to recent price hikes over the next decade**. Prices are projected to fall from recent highs when global fuel prices (for gas and black coal) fall back to long term trends and as more renewable energy enters the NEM. The long-term wholesale prices are projected to remain below the levels recorded in 2022 and in line with Victorian average prices over the previous few years (which averaged $74/MWh over 2018 to 2021 and $87/MWh between January 2018 and September 2022). Any price increase can also be muted by the type of action implemented to decarbonise the grid (for example, extending the renewable energy target or contracts for differences may lead to more muted prices on the wholesale market and will reduce market risks and hence reduce the investment cost of new generation).
- **Price impacts will also differ if technology costs fall faster than assumed or if there is a breakthrough in new technology** (particularly for low emission deep storage or low emission dispatchable capacity)

Figure 1: Wholesale price impacts, time weighted average price, Victoria

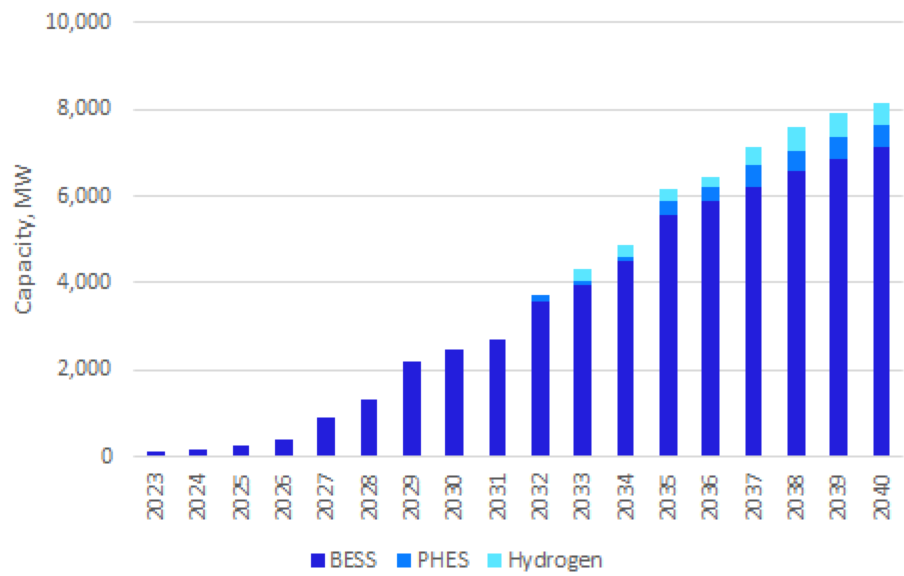


Key findings – supply reliability and capacity requirements

The modelling is designed to meet reliability targets (e.g., the retailer reliability obligation and unserved energy targets). That is, the model's optimisation involves finding the least cost investment pathway that meets demand growth and policy objectives and meets the imposed reliability targets. Hence there is no observed deterioration in reliability across the modelled scenario, but there are changes to the level of firm (dispatchable reserve) capacity to meet the reliability targets.

The modelling indicates that no additional firm capacity (above what exists or is committed to proceed) is required in Victoria to 2026. From 2026, the retirement of coal plant (across all NEM states) and the higher proportion of variable renewable generation leads to increased need for firm capacity. The retirement of brown coal plant by 2035 and higher demand across the modelled period mean that significantly more energy storage is required. When the brown coal plants retire, there is a need for additional deep storage or low emission dispatchable capacity (in this study, modelled as hydrogen-based gas-turbine generation).

Figure 2: Firm capacity requirements, Victoria, utility scale



The requirement for firm capacity could be greater if the assumed (that is, AEMO's assumption for Step Change) uptake in distributed (behind the meter or premises based) storage did not eventuate. Under the assumption used in the modelling, there is almost as much storage behind the meter as there is utility scale storage.

Key insights

In terms of renewable generation and storage capacity requirements, the modelling found that from 2025 to 2030 an additional 4,000 MW of large-scale capacity is required in Victoria. From 2031 to 2040, an additional 18,300 MW of large-scale capacity (including energy storage and large-scale renewable capacity) is required in Victoria. To put this into context this is more than the currently installed capacity of wind and large-scale solar PV across the NEM. This represents a build rate of around 1,500 MW of new capacity per annum in Victoria alone, equivalent to two large scale wind or solar plant each year, although this is within historical annual build rates.

The retirement of coal plant leads to capacity build (both renewable and energy storage) being brought forward. In Victoria, this additional build in large scale renewables is mostly in wind capacity with only modest increase in large scale solar PV (due to the high uptake of distributed behind the meter solar PV crowding out investment in large scale plant).

The offshore wind introduced under Victoria's announced target will deliver a firmer wind portfolio. It largely displaces new build of onshore wind capacity, with only circa 2,400 MW of onshore wind added compared with 9,000 MW of offshore wind from 2030 to 2040. This offshore wind capacity also leads to less firm dispatchable capacity than would otherwise have been required due to different patterns of generation with proportionally more generation during the evening peak demand periods. The offshore wind capacity effectively enhances the firm component of the wind portfolio. With offshore wind, there is also likely to be less volatility in generation, and combined with the higher levels of evening generation, enables displacement of thermal capacity and energy storage capacity.

The proposed interconnectors with Tasmania and NSW provide clear benefits in reducing the need for firm capacity in Victoria and capacity more generally across the NEM. Thus, they enable meeting the reliability targets at lower cost. The interconnectors also enable sharing of excess (otherwise curtailed) renewable energy generation effectively reducing the cost of meeting abatement targets.

As the market goes towards less thermal plant, there is a need for more longer-term deep storage and dispatchable plant (e.g., hydrogen-based generation). Wind and solar generation exhibit strong seasonal patterns with more of each occurring in the spring and early summer period and less of each in the late autumn and early winter period. For the latter period, increased heating load (especially in a decarbonised world where less gas is being used for heating) leads to extended periods when renewable generation does not meet demand, with the duration being longer than is economically provided by battery storage. Deep storage or dispatchable capacity is required for these periods, often on a consecutive daily basis.

The modelling found that more rapid decarbonisation may put some upward pressure on electricity prices in the long term (but lower than what has been observed in the market recently). The upward pressure comes from:

- more firm capacity being required earlier.
- bringing on renewable generation earlier.
- more intraregional network build to accommodate additional renewable capacity.

The form of policy to encourage more rapid decarbonisation or lower than projected technology costs would tend to mute any upward pressure on price. This is particularly the case for (any) policy support for deep storage options or dispatchable (e.g., hydrogen) capacity.

Victoria's offshore wind targets will also likely mute any upward pressure on price.

1. Introduction

The Department of Environment, Land, Water and Planning (DELWP) has engaged Jacobs for energy market modelling of potential future pathways for the transition of the electricity market in Victoria. This work is required to inform DELWP about the impacts of future Victorian electricity market development on the volume and share of renewable electricity generation and storage that will be required in Victoria through to 2040, and associated impacts on wholesale prices, supply reliability and investment patterns.

For this study, DELWP required results up to 2040. The scenario modelled is based on the AEMO's 2021/22 Step Change scenario but with DELWP specified assumptions.

This report summarises the key results, their implications for Victoria's energy market development, as well as a brief description of modelling assumptions and methodology.

In terms of assumptions, the primary focus of this report is on the following updates:

- Offshore wind announced targets
- Coal retirement dates
- Transmission augmentation timing
- Step Change assumptions

The modelling and the analytical framework that underpins it has been tried and tested in a series of studies and builds on this previous work for DELWP. The modelling provides estimates of the market benefits arising from offshore wind developments, renewable energy development, coal closure timings and transmission upgrades. Our modelling infrastructure aligns with AEMO's modelling suite, including using the PLEXOS modelling framework to represent the NEM. More detail on this is provided in the next section.

The modelling described in this report was undertaken in March 2022 and is dependent on market conditions, regulatory structures, and market expectations at that time.

2. Method and Assumptions

This section presents the key assumptions and the method that is used in the modelling of the study. Additional details on the modelling software and inputs underpinning this analysis are provided in **Appendix A.**

2.1 Modelled simulations

Energy market modelling in this report is built around the development of a scenario based around AEMO Step Change scenario assumptions. The corresponding interconnector timing are as shown in **Table 1** below.

Table 1: VNI West and MarinusLink inclusion assumptions

VNI West	MarinusLink
1 July 2031	750MW Link 1 by 1 July 2033; 750 MW Link 2 by 1 July 2035

2.2 Key modelling assumptions

The key assumptions are provided in **Table 2**.

While the assumptions underpinning the modelling in this report offer useful insights into potential energy market impacts of an accelerated transition to renewable energy in Victoria, there are a number of plausible changes to the assumptions which if they eventuated would be likely to see wholesale prices be lower than would otherwise be the case. Some of the most significant of these include:

- Federal Government initiatives to accelerate deployment of renewable energy (e.g., deployment of the $20 billion *Rewiring the Nation* fund) or lower overall emissions in line with their now legislated 43% emissions reduction target.
- Accelerated delivery of VNI West and/or MarinusLink.
- Higher levels of uptake of household solar and batteries than modelled.
- State Government funding to achieve the recently announced energy storage targets.
- Greater renewable energy ambition in other States in the NEM.

Table 2: Key scenario assumptions

Parameter	VRET scenario
Scenario narrative	AEMO's ISP **2022 'Step Change'** with carbon budget below.
Emissions targets	All NEM states achieve net zero economywide emissions by 2050. No interim targets for Victoria.
Carbon budget	NEM emissions budget of 891 Mt CO2e from 2024 to 2050 achieved via draft ISP closure dates with Victorian changes below.
Commonwealth emissions policy	26% emissions reduction policy by 2030 on 2005 levels, achieved in practice with **no** additional emissions policy at the national level.
State and federal government renewable energy policies: LRET/VRET/QRET/NEIR	LRET = 33,000GWh in 2020, continuing to 2030. VRET = 40% renewable generation by 2025; 50% renewable generation by 2030.[1] QRET = 50% renewable generation by 2030.[2] NEIR = 12GW of additional renewable capacity and 2GW of additional storage capacity by 2030.[3]
Demand growth	AEMO's ISP 2022 'Step Change'.
Demand side participation	AEMO's ISP 2022 'Step Change'.
Alcoa	Continues indefinitely.
Rooftop solar PV	AEMO's ISP 2022 'Step Change' with minor adjustments for Victoria.[4]
Electric vehicle (EV) uptake	AEMO's ISP 2022 'Step Change' including Victoria and New South Wales EV targets.
Non-EV electrification	AEMO's ISP 2022 'Step Change'.
Victorian coal closure	From 2028 to 2035
Non-Victorian coal closure	Aligned with AEMO's ISP 2022 'Step Change'.
Large scale storage	SIPS from summer 2021. Victoria introduces a 350MW / 1,400MWh battery from 1 July 2026. Solar Homes batteries based on Solar Victoria rebates. Neighbourhood Battery Initiative implementation category batteries.
Offshore wind targets	In accordance with Victoria's offshore wind targets: o At least 0.1 GW in 2029, 0.35 GW in 2030, 1 GW in 2031 and 2 GW in 2032. o 4 GW in 2035. o 9 GW in 2040.
Gas prices	AEMO 2021 Low based on Lewis Grey Advisory.
Coal Prices	AEMO 2021 Low based on Wood Mackenzie.
Other transmission (not in Table 1)	Committed and actionable projects as per 2020 ISP. REZ Stage 1 projects completed by 1 January 2025 (details below).
Snowy Hydro	1 December 2026 for full operations (2.04 GW; 350,000 MWh).
Technology costs	AEMO 2021 GenCost High VRE.
WACC	AEMO's ISP 2022 Central assumption (5.5%).

[1] The VRET target represents the total renewable generation in Victoria divided by the total generation in Victoria.
[2] The QRET target represents the total renewable generation in Queensland divided by the total demand in Queensland.
[3] The renewable investment in NSW is based on NSW Infrastructure Investment Objectives (IIO) modelling outcomes.
[4] DELWP has provided to Jacobs more detailed data of the PV uptake from Solar Homes that were not included in AEMO's 2022 ISP.

2.3 REZ Stage 1 transmission projects

The Victorian REZ Development Plan Stage 1 is incorporated into the modelling of the VRET scenario. The total additional generation enabled from all Stage 1 projects is up to 3,000 MW, with the following delineation:

Contestable Projects (System strength)	• Murray River REZ – up to 300 MW • Western Victoria REZ – up to 600 MW • South-West REZ – up to 600 MW
Minor Network Augmentations	• Murray River REZ – up to 112 MW • South-West REZ – up to 81 MW • Central North REZ – up to 12 MW
Mortlake Turn-In Project	Up to **1,500 MW** of additional capacity on the network to enable existing and already proposed renewable energy generator projects to maximise their approved output.

2.3.1 AEMO's Step Change scenario and differences to our modelling

AEMO's ISP is a 'whole-of-system' plan that offers a roadmap for development in the NEM. The 2022 Draft ISP[5] considers four scenarios that cover a broad range of plausible trends and events in its operating environment through the power system's transformation. A consensus of stakeholder representatives has favoured the Step Change scenario as the most plausible.

The basis of the modelling used by Jacobs for this report is AEMO's ISP 2022 Step Change scenario. This scenario assumes a rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action to reduce greenhouse gas emissions. It assumes early action is undertaken to meet Australia's net zero policy commitments that aims to limit global temperature rise to below 2° compared to pre-industrial levels.

Rather than building momentum, Step Change assumes a sustained fast-paced transition from fossil fuel to renewable energy in the NEM, both large and small scale. Step Change also assumes a rapid change in global policy commitments to reduce greenhouse gas emissions. These factors lead to falling costs of energy production, due to increased low-cost renewable generation investments improving the economies of scale in manufacturing.

Increased digitalisation helps both demand management and grid flexibility, and energy efficiency and wide-spread electrification are both important elements of the energy transition. Under this scenario, by 2050 most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion engine (ICE) vehicles has ceased. Some domestic hydrogen production is used to support the transport sector (largely for long-haul transportation) and as blended pipeline gas, with some industrial applications after 2040, particularly in cases where electrification is not possible.

However, while this scenario is supported by industry participants as being the most representative of a likely future outcome of the four scenarios modelled by AEMO, Jacobs has assumed some differences in our modelling assumptions. We have modelled different closure dates for coal generation in Victoria than the dates assumed by AEMO in Step Change. This is based on our understanding of the Victorian market paired with advice from relevant Victorian stakeholders.

[5] https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en . Note the Final 2022 ISP was published after the modelling for this study was completed.

Under the AEMO's ISP, power system investment is selected through their capacity outlook model with the aim of minimising the cost for the whole NEM power system. In our modelling we have the same starting point in terms of the capacity plan as AEMO, but we perform several iterations with our time-sequential model and our capacity outlook model to ensure that all generation and storage plants that are installed recover their investment costs over their lifetime from revenue transactions occurring in the wholesale market under existing market arrangements. As a result, our projected investment plan represents the least cost market driven investment path.

Another difference to the ISP modelling is that AEMO is co-optimising the generation and transmission investment with its gas supply model that is used to assess gas reserves, production and transmission capacity adequacy while our model does not consider any gas related constraints.

Despite these differences in assumptions, the Jacobs modelling largely reflects AEMO's Step Change scenario.

3. Modelling Results

The following sections summarise the key results, their implications for Victoria's energy market development, and price and generation outcomes. The focus is the impact of additional renewable energy, coal retirement dates and transmission augmentation timings.

The scenario is based on previous modelling conducted for DELWP underpinned by the AEMO 2022 Step Change trajectory. This scenario features a rapid change in the market with coal retirements occurring before the end of their technical life and a carbon budget aimed at limiting global temperature rise to under 2 degrees.

The key alternative assumption to AEMO's Step Change scenario are:

- The VNI West interconnector upgrade to NSW from 1 July 2031, Marinus 1 in 1 July 2033 and Marinus 2 in 1 July 2035.
- Victorian offshore wind targets included (2 GW in 2032, 4 GW in 2035, 9 GW in 2040).
- Brown coal plant retired by 2035.

3.1 Summary

A summary of the results is contained in Table 3.

Table 3: Wholesale prices, renewable generation and emissions, Victoria

	2022	2025	2030	2035	2040
TWA price, $/MWh	90	57	71	80	79
DWP wind, $/MWh	76	40	49	57	40
DWP solar, $/DWP	48	24	38	47	43
Wind generation, TWh	9.1	13.1	16.9	36.8	48.8
Solar generation, TWh	2.1	2.6	2.9	5.5	6.4
Emissions, Mt CO_2e	38.5	35.5	23.5	5.9	0.2

3.2 Wholesale prices

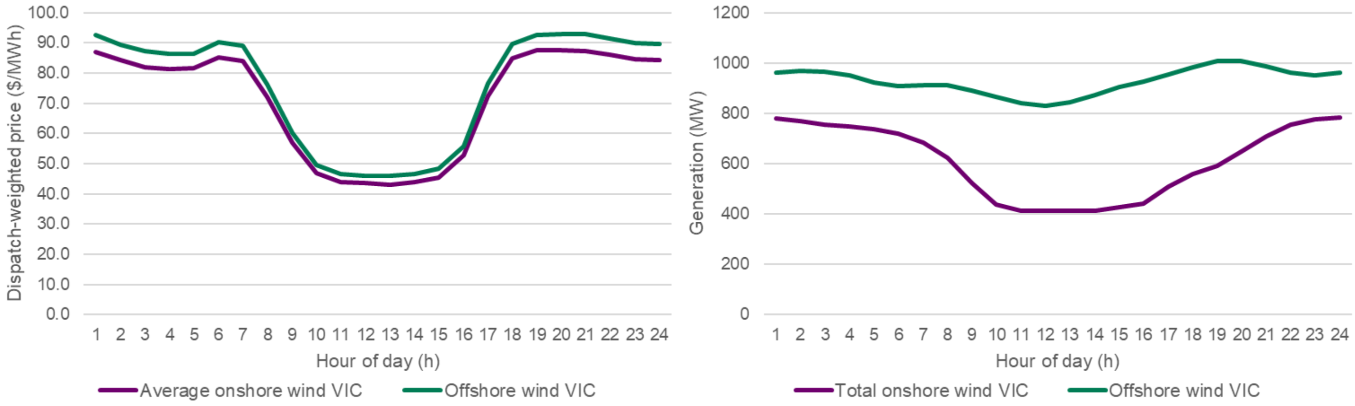
The time-weighted wholesale market prices are projected to fall from current levels of around $90/MWh in 2021/22 to around $57/MWh in 2025 before rising to around $80/MWh by 2035 under the scenario assumptions adopted in this study. In the late 2030s, the prices start to decline driven by the offshore wind capacity increasing to meet the 2040 target.

The primary driver of increasing prices from 2025 to 2035 is the higher demand trajectories and the retirement of coal plant across the NEM. Demand growth is underpinned by the assumed rate of electrification, fuel-switching, electric vehicle uptake and general economic growth assumptions.

Initially the diversity of the offshore wind profile in Victoria complements the other sources of generation in the grid, increasing reliability, leading to some downward pressure on prices. The offshore wind profile differs to the Victorian onshore wind profile, as can be seen in Figure 3. The offshore wind profile is more consistent across the day with higher generation during the evening peaks. From the dispatch-weighted prices, it is evident that the offshore wind generators receive more during the evening peak, and approximately $5/MWh more than the onshore wind assets.

Offshore wind is treated as bidding at zero marginal cost into the market, displacing thermal generation and onshore wind in Victoria. All thermal and stability issues associated with the offshore development are assumed to be resolved in the building process with no additional costs attributed to the energy market. Instead, it is assumed that offshore wind receives support from Government through similar mechanisms to VRET auction projects or through revenue raising measures.

Figure 3: Offshore and onshore wind average hourly prices (left) and generation (right)



As the offshore wind capacity increases, its capacity factor remains around 45% and dispatch-weighted price is above $54/MWh, as can be seen in **Table 4**. The entry of the VNI-West interconnector to NSW results in an uplift in the offshore wind economics, with curtailment reducing from 2.1% to 0.4% and dispatch-weighted price improving to $61/MWh.

In Figure **4** it is evident that offshore wind generation comprises a large proportion of Victoria generation by 2040 (36%). The additional offshore wind capacity is built in the Gippsland region and therefore it is highly correlated by 2040. The diversity benefit diminishes, and market curtailment rises.

Table 4: Offshore wind statistics

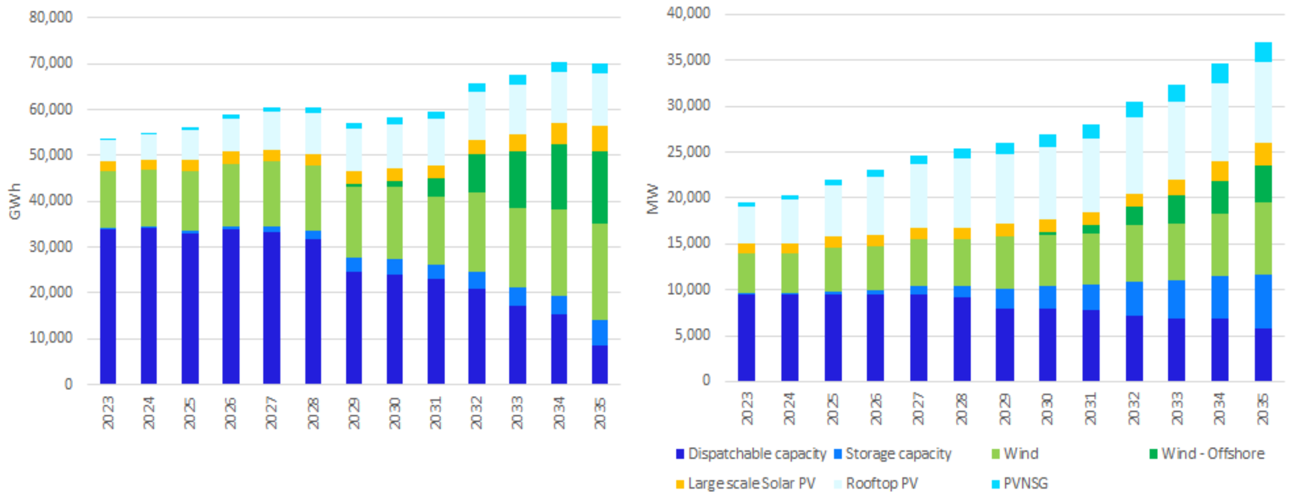
Financial year	Capacity (MW)	Capacity factor (%)	Curtailment (%)	Dispatch-weighted price ($/MWh)
2029	100	38.9	0.2	75.7
2030	350	37.9	0.2	73.6
2031	1,000	45.6	2.1	54.1
2032*	2,000	46.6	0.4	60.7
2033	3,000	46.2	0.5	59.3
2034	3,500	45.7	1.0	57.6
2035	4,000	45.0	2.0	54.8
2036	5,000	45.3	3.4	54.3
2037	6,000	44.4	5.5	49.0
2038	7,000	42.6	7.7	44.3

*VNI West entry in financial year 2032 (1 July 2031)

3.3 Capacity and generation mix

The capacity and generation outlook for Victoria under this scenario is displayed in Figure **4.**

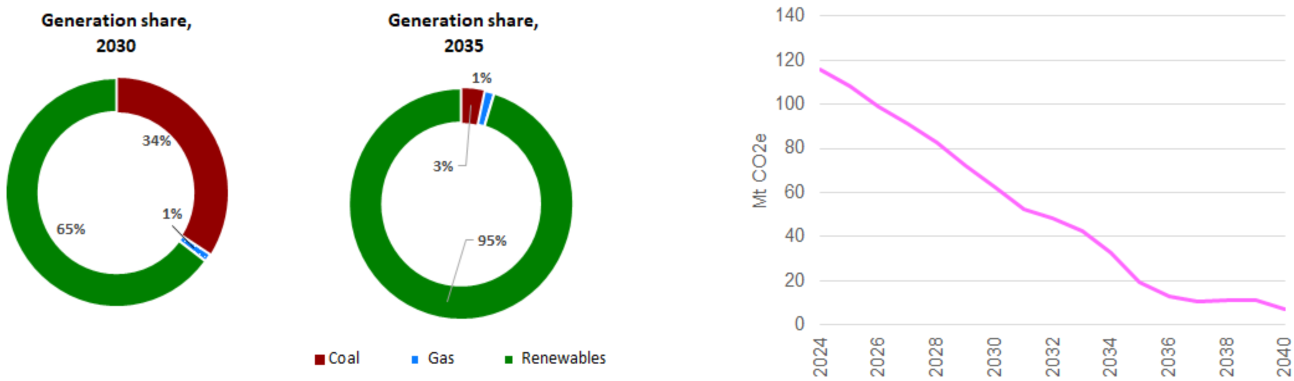
Figure 4: Victoria capacity and generation outlook



Wind and solar generation grow modestly to 2029. The coal fleet winds down in other regions of the NEM, with replacement renewable capacity primarily entering in New South Wales under the New South Wales Roadmap or Queensland. The flow-on impact through interconnection is crowding out investment in Victoria wind and solar generation to 2029.

For the modelled scenario, the percentage share of renewable generation in Victoria for 2030 and 2035 can be seen in Figure **5,** which also displays the emissions in the modelled scenario.

Figure 5: Victoria generation share 2030 and 2035 and emissions



From **Table 3,** Figure **4** and Figure **5** we can observe that:

- The renewable share of Victoria generation in the financial year ending June 2030 is around 65% for calendar year of 2030. This percentage increases to 95% in 2035 as the coal plant retire and new renewable generation is built. Offshore wind forms a component of the replacement capacity for the brown coal retirement along with firming technologies such as battery storage and pumped hydro. As peak demand increases, there are an increasing number of high price periods, resulting in the entry of hydrogen gas turbines operating as peaking generators.

- The NEM carbon budget is met by decarbonising at a faster pace in the early 2030s to recover from the higher emissions in the 2020s. The carbon budget is met through higher renewable uptake.


Appendices

Appendix A. PLEXOS Model

A.1 Model setup

The PLEXOS market simulation model is used to forecast the evolution of generation investment and retirement, emissions of greenhouse gases and regional wholesale prices. It determines dispatch (and resulting price levels) by co-optimising energy and FCAS markets.

There are five key tasks performed by PLEXOS:

- Projects demand profiles over the planning horizon, given a historical load profile, expected energy generation and peak loads.
- Projects the investment profile for new generation and transmission including the type of technology and timing of entry into the market. In Jacobs modelling, the investment plan is chosen on three criteria:
  - **Least cost basis** to meet a given reliability criterion. What is the least cost investment plan for the market, where the differential risks associated with various technologies is reflected through a risk premium on the weighted average cost of capital.
  - **Adjusting the least cost plan** (generally by pushing forward or back the plant selected) to ensure that all plant selected earn an adequate return in investment. We have found from past modelling that relying on the least cost plan may lead to outcomes where selected plant would be unprofitable under current market arrangements.
  - **Meeting the different states' renewable targets**, by using the specific state schemes (i.e., capacity targets, generation targets, renewable certificates etc.)
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models
- Calculate hourly or half-hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and cost impacts of abatement schemes.

New plant or transmission investment, whether to meet load growth, scheme targets or to replace uneconomic plant, are chosen on two criteria:

- To ensure electricity supply requirements are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002%, which is in line with planning criteria used by system operators.
- Revenues earned by the new plant/energy efficiency program equal or exceed the long run average cost of the new generator.

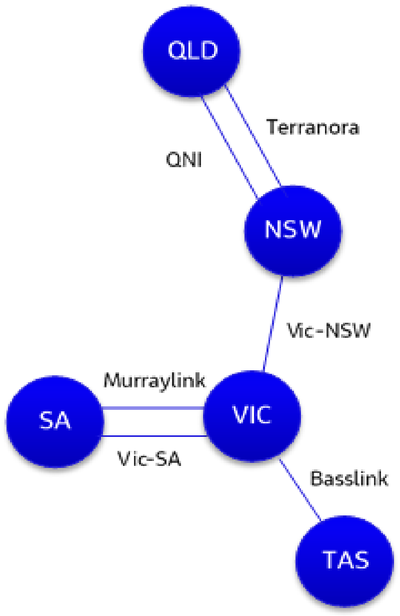
For this modelling engagement two mutually interacting planning models will be utilised:

i) The Long-Term model (LT), this is a model co-optimising new generation investments and transmission developments, as well as renewable energy zone (REZ) development opportunities, using inter-regional transmission and other long-lived thermal generation development decisions. The LT model provides chronological, detailed representations of the long term via a multi-step solve.

ii) The Short-Term model (ST), a suite of models that carry out half-hourly and/or hourly simulation (although it has the capacity to even model 5-minute intervals) based on available data of generation dispatch and regional demand, while considering various power system limitations, generator forced outages, variable generation's availability, and bidding models. It mimics the dispatch process used by AEMO's NEMDE and validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns. The generation and transmission outlook developed in the LT model is used as input to this model.

The NEM is represented in the model through five regional reference nodes (one for each NEM state) connected by inter-regional flow paths and mirrors the operation of the NEM Dispatch Engine (NEMDE), which is responsible for directing generation in the NEM.

Figure 6 Regional representation of the NEM in PLEXOS



A.2 Model structure

PLEXOS is a stochastic mathematical model which projects electricity generation, prices, and associated costs for the NEM. It optimises dispatch using the same techniques used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on an hourly or half hourly basis for each forced outage sequence given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, and operating restrictions such as:

- Generation constraints – availability (planned and unplanned outages), unit commitment and other technical constraints.
- Transmission constraints – availability (planned and unplanned outages), linearized DC optimal power flow equations, interconnector ratings, and other transmission constraints that may be a function of load, generation or line flow.
- Hydro constraints – hydro units may be energy-constrained, or more detailed storage models may be represented with stochastic hydro inflows.
- Fuel constraints – for example, daily fuel limits or annual take-or-pay constraints.
- Ancillary service constraints – maximum unit response.
- Emission constraints – limits on emission production may be imposed, or carbon prices specified.

Expected hourly electricity prices are calculated by modelling strategic behaviour, based on gaming algorithms such as the Nash Cournot equilibrium, long-run marginal cost recovery (LRMC) or shadow pricing. In this study, Jacobs will use a combination of LRMC bidding for the base load and intermediate plant (after allowing for some contract cover with no strategic bidding) and bidding for peaking plant based on historical behaviour to produce the price forecasts. Jacobs has benchmarked its NEM database to 2019/20 market outcomes to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes.

PLEXOS can model stochastic relationships around almost any input into the model, including availability of generation and transmission assets, variations in peak demand according to probability of exceedance and water levels and inflows at hydro storages.

A.3 Participant behaviour

We assume the current market structure continues under the following arrangements:

- Victorian and NSW generators are not further aggregated
- The generators' ownership structure in Queensland remains as public ownership
- The South Australian assets continue under the current portfolio groupings

In addition, the following assumptions have been made about incumbent generators based on mothballing/retirement announcements to the market.

- Hydro Tasmania announced the eventual sale of Tamar Valley CCGT in 2015. However, the Tasmanian energy security review recommended it be kept on permanently as a backup to Basslink and this appears to be the policy that has been adopted
- AGL announced the retirement of its Liddell power station, located in New South Wales in 2023/24, which represents the end of its technical life.

A.3.1 Contract position and bidding

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed for operational reasons or bid at its marginal cost to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out. This strategy maximises profit in the short-term, excluding any long-term flow on effects into the contract market.

Bidding strategies chosen in the modelling are typically benchmarked to what is considered a representative historical year, and then projected forward with the calibrated PLEXOS bidding parameters locked in.

A.3.2 Generation Expansion in PLEXOS

The model selects new capacity from a range of available fossil fuel and renewable technologies. Parameters for technologies not presently commercially available are included where an estimate can be made of their performance and costs for use in the modelling. In each scenario the least cost mix of plant is dispatched to meet demand, based on fuel and capital costs, and any policy constraints.

The following outlines new plant technologies considered in this market modelling study.

New Plant Technologies considered	Technologies excluded
Wind	Nuclear Generation
Solar PV	Tidal and wave technologies
Concentrated solar thermal	Geothermal
Hydro-electric systems	
Biomass based generation	
Simple and combined cycle gas turbines	
Super and ultra-supercritical coal fired steam turbines	
Integrated gasification combined cycle plant with carbon capture	
Battery storage	
Pumped Hydro	

New entrant technology costs are derived at each applicable point-in-time (generally an estimate of current costs) and future costs are handled within the modelling using learning curves and adjustments for changes in exchange rates.

For gas turbines and conventional Rankine cycle plants (including sub-critical, supercritical and ultra-supercritical, and biomass), Jacobs uses the capital cost estimating tool within the Thermoflow suite of software. This model estimates engineering, procurement and capital (EPC) costs based on technical configurations of each plant appropriate for Australian conditions and fuels. Jacobs applies local factors (such as the unit sizing, suitability for Australia's climate and fuel alternatives) for the configuration of the plants and regional factors (such as labour and other costs for Australian construction environments). These factors are based on our experience and judgement.

The cost estimates are refined using adjustment factors where appropriate based on market soundings and information from other projects (including overseas projects).

In addition to the EPC costs, allowances have been made for coal drying costs, connection costs (for electricity and gas where applicable) and owner's costs. Interest during construction costs are handled separately in the modelling.

Current cost assumptions for the most important key new technologies are based on information from AEMO reports.

A.4 Storage modelling

A range of Bluegrass battery configurations will be modelled at different sizes, as well as varying hours of storage capacity.

A.5 Renewable energy zones

It should be noted that the PLEXOS modelling includes the concept of renewable energy zones (as defined by AEMO) and this allows for the modelling of marginal network losses and transmission constraints (and costs to upgrade) for investments within different renewable energy zones. Energy resource availability and cost, along with generation build limits dictated by the intra-regional network dynamics, are defined according to these zones. Network constraint equations capture transmission limits between zones. Zones with the greatest resources, or those with the lowest resource cost, will likely receive new generation first, provided network limits do not unduly constrain that generation. The AEMO's REZ zones are shown in Figure **7**.

Figure 7 NEM Renewable Energy Zones