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[1] Firm capacity refers to the capacity that can be relied upon to be available at the time of maximum demand.

1 Summary

Snowy Hydro and its consultants have undertaken investigation and modelling to analyse the international and domestic markets and the potential for success of the Project in the National Electricity Market (***NEM***), both as an asset and an incorporated business model supported by potential energy diversification. The business modelling is described with multiple influences adding to the modelling approach and the outcomes and impact of the Project.

1.1 Introduction

Third-party specialist economists Marsden Jacob Associates (**MJA**) were commissioned to undertake an economic modelling exercise and deliver a confidential report: Modelling Snowy 2.0 in the NEM Report (MJA) (**MJA Report**). The MJA Report presented the following:

1. The NEM's future market state and options to address the associated NEM price and reliability issues, and the benefits and comparative economics that the Project would provide;
2. A multi-stage approach to the assessment of the economic and market benefits and potential value of the Project through a least-cost planning simulation approach characterised by macro assumptions and policy that may influence this, including additional economic entry of intermittent generation;
3. Rationale for the Project, future NEM mix, the technologies available for generation; and energy storage and associated cost outlooks; and
4. An assessment of how these benefits would be shared and the resulting impact the Project would have to wholesale electricity energy prices and resulting customer prices.

1.2 Background

The NEM is moving towards a mix of renewable generation technologies that are increasingly intermittent, thus less predictable and reliable in nature. The reasons for this degree of intermittent penetration are, and will continue to be, environmental, political and economic. Examples include the uncertainty around energy policy, Australian commitment to international carbon emissions targets,[2] and the falling costs of producing renewable energy. Legislated or proposed energy policy by Federal and State governments, such as the proposed National Energy Guarantee (***NEG***), are attempts to address the resulting trilemma of affordable, reliable, and environmentally responsible production of electricity.

[2] Australian Government, 2017. Australia's 2030 climate change target. Available at: http://www.environment.gov.au/system/files/resources/c42c11a8-4df7-4d4f-bf92-4f14735c9baa/files/factsheet-australias-2030-climate-change-target.pdf [Accessed November 23, 2017].

The economic evaluation of the Project has had to resolve the essentially unpredictable factors into a series of valuation cases. The analysis has shown, unsurprisingly, a very broad range of possible outcomes. However, it has also shown a high degree of convergence of likely future outcomes across the following inter-related factors:

1. Renewable penetration, at both grid and distributed levels, particularly relating to rooftop photovoltaic (***PV***) installations;
2. Domestic and commercial load growth, both average and peaking;
3. Smelter closures;
4. Coal plant closures; and
5. The penetration of electric vehicles (***EV***)

This work has assisted Snowy Hydro's understanding of likely and boundary scenarios in the future NEM. As at Final Investment Decision (***FID***), the position is consistent with that presented at Feasibility: that the likely scenarios are convergent.

1.3 Scope and exclusions

A number of due diligence activities were performed prior to FID. Areas of focus include:

1. Demand/supply modelling for the current and future market states of the NEM, including:
    a. Performing economic benefit analysis to the market modelling in order to identify the most economically rational sources of new generation;
    b. Investigating the market potential for storage products; and
    c. Predicting the future NEM generation mix and market state under the 'with' and 'without' Project scenarios.
2. Assumptions review:
    a. Government policy-mandated decarbonisation targets;
    b. Cost curve trajectories of competing technologies of supply;
    c. Market bidding behaviours;
    d. Macroeconomic factors influencing the NEM;
    e. Capex; and
    f. Opex.

Exclusions to this chapter include:

1. Snowy Hydro portfolio modelling to understand under various scenarios the value of the Project over time and uncertainty in Net Present Value (***NPV***) terms (see *Supporting Chapter Six - Revenue sources and portfolio modelling*);
2. Valuation - translate economic fundamental analysis of the NEM supply-demand trajectory over time into net financial cash flows to derive Project present value (see *Supporting Chapter Eight - Valuation and selected business base*); and

3. Fit-for-purpose governance and approvals structure to approve the Project (see *Supporting Chapter Twenty - Governance* and *Supporting Chapter Eleven - Environment, permits and approvals*).

1.4 Activities undertaken

To assess the potential economic value of the Project, Snowy Hydro collaborated with independent third-parties to determine the viability of the Project. Market models were designed based upon international and domestic market research and assessed:

1. **The Project in the NEM** - for the Feasibility Study, MJA produced public and confidential market reports regarding the relationship between the NEM and the completed Project to discern the impacts on both the NEM and Snowy Hydro's business case. These reports and modelling have been leveraged to deliver improved and more detailed information to the stakeholders. The focus of these deliverables has changed from benefits to the public to the Snowy Hydro business case;
2. **Energy supply-and-demand research** - a study tour to Europe raised questions over the additional flexibility offered by coal-fired power stations in the NEM. An independent expert was thus engaged to determine the current and potential future plant operational flexibility of Australian plants on a least-cost basis. Deliverables included an assessment of current operational flexibility in comparison to comparable overseas coal fleets, and a report for each coal-fired station that owns optionality with respect to one or more potential upgrades or operational changes that would increase flexibility of the station, and the associated capex and other costs. Another independent expert reviewed the East Coast gas market to understand the demand, supply and cost outlook and determine the potential of building an energy retail business. The Australian Energy Market Operator (***AEMO***)'s National Gas Forecasting Report (2016) advised for planning solutions that prioritise flexibility, innovation and options to defer investment until some certainty across the energy market is resolved. Another independent expert was engaged to report on the dynamics of current and future Australian coal pricing assessing coal supply-and-demand and cost and risk-based consumer price forecasts by assessing the capacity of export and domestic demand to 2030 against production and distribution infrastructure;
3. **Climate trends** - A 'base case' dataset (1999-2015) using long-term historic Water Utilisation Factors (***WUFs***), modified to represent 2024-2040. Inflow data for the 1999-2015 period was selected as it includes frequent dry events and reduced average inflow, a pattern expected to continue in the future. See *Supporting Chapter Eighteen - Hydrology* for further discussion of climate factors;
4. **Portfolio Diversification and transmission** - Snowy Hydro leveraged MJA's feasibility study work to determine the competitive viability of procuring intermittent energy. Snowy Hydro undertook a Renewable Energy Procurement Program (***REP-P***) in order to create a more diverse company

portfolio, in turn potentially complementing the Project. It consisted of procuring approximately 888 megawatts (***MW***) of wind and solar offtakes; The procurement of wind and of solar offtakes would diversify Snowy Hydro's portfolio, and complement the Project, utilising energy procured through the REP-P process for managing existing exposures and growth; AEMO's transmission development decisions impact the Project's viability and cost. Snowy Hydro and MJA analysed AEMO's Integrated System Plan (***ISP***) Report 2018, particularly the modelling used for the 'with' and 'without' cases of the Project. MJA separately assessed commercial drivers in the NEM, with or without the Project;
Snowy Hydro and MJA assessed the impact of the Project on existing operations, examining the economic and market values of bidding, supply capacity, flexibility and portfolio constraints on existing operations.

The MJA FID Report is the most up to date version of modelling outcomes, and contains the following components:

1. Overview of the NEM, Large-scale Renewable Energy Target (***LRET***) and gas market;
2. Historical analysis of NEM prices and volatility;
3. The economics of new and existing dispatchable generation, renewable generation, batteries and interconnection;
4. How the Project (aka Snowy 2.0) would provide value to the NEM;
5. A description and results of market modelling undertaken over a range of scenarios;
6. Real option value provided by the development of Snowy 2.0 for a potential Snowy 3.0; and
7. How Snowy Hydro would operate and create value with and without Snowy 2.0, and under the various scenarios contemplated.

Results from the Feasibility and FID reports relevant to the overall market are explored in depth in this chapter, while results from the FID report are explored in depth in the following supporting chapters:

1. *Six - Revenue sources and portfolio modelling;*
2. *Seven - Drivers of revenue;*
3. *Eight - Valuation and selected business case;* and
4. *Nine - Scenario Analysis*.

The MJA FID methodology was designed to:

1. Quantify how the NEM is expected to develop;
2. Quantify storage capacity and energy (in MWh) as the NEM develops;
3. Quantify the value Snowy 2.0 would provide to the NEM and the cost if Snowy 2.0 were not developed;
4. Model the Snowy 2.0 impact on total Snowy Hydro net revenues;
5. Identify key uncertainties and their impact on the Snowy 2.0 business case;
6. Determine the economics of Snowy 2.0 across a wide range of scenarios; and
7. Provide a transparent modelling approach.

The MJA study addressed:

1. Review of the transforming NEM;
2. Identification of key influences on Snowy Hydro spot market revenues and costs; Characterisation and operation of Snowy Hydro portfolio with and without Snowy 2.0;
3. The economics of Snowy 2.0;
4. The likely impact of Snowy 2.0 on carbon emissions in the NEM;
5. Development of a Base Scenario and modelling of that scenario;
6. Development and modelling of alternative scenarios; and
7. Modelling conclusions.

1.5 Logic underpinning the benefits of the Project

Increasing penetration of intermittent generation has implications for wholesale and retail electricity supply cost, reliability, and environmental outcomes.

Beneficially integrating increasing levels of intermittent generation with existing generation is a complex whole-of-supply-chain challenge:

1. **Generation** - increased penetration of intermittent generation (wind, solar) increases variability in residual demand for dispatchable generation (coal, gas and hydro). Absent storage, the economics of base load generation decrease, with consequent market instability and price impact;
2. **Retail products** - retail prices reflect the wholesale cost of energy borne by retailers. A portfolio including intermittent generation requires even more dispatchable generation, to follow changes in both the retail load and the intermittent generation so that the retail load remains hedged;
3. **Storage** - energy storage provides the dispatchable capacity that intermittent generation cannot: ie it 'firms' the intermittent generation;
4. **Project benefits** - Pumped-Hydro Energy Storage (***PHES***) has several benefits over batteries, including: lower cost, higher capacity, firming capability, longer continuous generation, longer life, and contribution to network stability (inertia and interconnection).

Large-scale PHES will lower consumer prices, stabilise the power grid and enable deeper penetration of variable / intermittent renewable generation, directly addressing all three elements of the electricity trilemma:

1. **Affordability** - increased wholesale competition and reduced or stabilised spot prices;
2. **Security** - increased resilience of the NEM;
3. **Environmental** - long-term enabler of additional least-cost renewable generation.

Given its context and constraints, the analysis concludes that the Project is economically feasible and adds material value to the Snowy Hydro Group.

1.6 MJA market modelling

Snowy Hydro engaged MJA as long-standing specialists in modelling the NEM. MJA concluded that, as the NEM generation fleet mix becomes increasingly intermittent and unreliable, the proposed Project is a material part of any solution to long-term stability in the NEM. The potential range of solutions includes future increase to PHES with the appropriate transmission system augmentation.

MJA's future base case market state estimation in the NEM was built upon:

1. The current and known regulatory framework;
2. State and Federal renewable targets;
3. AEMO forecast transmission upgrades (see *Supporting Chapter Sixteen - Transmission* for details); and
4. Assumptions regarding current and forecast generation mix, storage, consumer demand, and fuel prices.

Key Findings

The key findings of this study relate to the Snowy 2.0 value proposition and the benefits Snowy 2.0 would provide to the NEM and to Snowy Hydro. These are summarised in turn below:

Variable, Dispatchable and Firm Capacity

While is it recognised that generation from Variable Renewable Energy (***VRE***) does not provide firm capacity, the study highlighted the need to make the further distinction between 'dispatchable capacity' and 'firm capacity':

1. **Dispatchable capacity** is that which is controllable (ie either up or down);
2. **Firm capacity** is that capacity which is both dispatchable and which can be relied upon to be available. Dispatchable generation from storage with limited hours of storage also does not provide firm capacity as it may not be available to generate when needed. The study found that firm capacity requires at least 24 hours of storage.

Snowy 2.0 Quality and Value Provision

Snowy 2.0's qualities of capacity and storage size, central location, and ancillary service provision make it unique in the NEM. Snowy 2.0 would provide both dispatchable and firm capacity. These unique qualities provide for substantial value to the market, consumers, and Snowy Hydro. These quality and value relationships include:

1. Its **central location** that provides for maximum consumer access, NEM-wide balancing of VRE, and security against critical transmission outages;
2. Its **large level of storage** (175 hours conservatively) provides for energy security and firming against extreme market conditions, both of which will become of increasing value to risk mitigation in the future. In the longer-term storage value will move to be proportional to storage hours. (These are matters not capable of being managed by storage with less than about 24 hours of storage);
3. Its **flexible operating** nature provides for increased market stability and efficiency. This has its pumping demand (of up to 2,000 MW) operating in response to the changing availability of surplus coal and surplus VRE, and its generation operating in response to spot price signals and commercially and economically replacing gas plant and batteries that would have been developed and used. Such operation directly supports the development of new VRE and emissions reductions;
4. Its **economic value to be robust** against uncertain future outcomes;
5. Its ability to **transition smoothly** into operation.

While the transmission developments identified in the AEMO ISP between NSW-VIC-SA are considered to be needed regardless of Snowy 2.0 development (as they support the Renewable Energy Zones (***REZ***) and interregional transmission limits necessary to address the closing coal plants), Snowy 2.0 would provide additional value to this transmission. Snowy 2.0 could potentially reduce transmission asset costs due to its complementary operational nature to other types of assets.

Benefits to the NEM

Supports Trilemma

On a NEM-wide basis the above relationships would provide for Snowy 2.0 to directly and substantially contribute to the trilemma issues of reliability, price, and emissions reduction as the existing coal fleet closes and replacement firm capacity and energy production is required.

Avoids Excess Supply

Snowy 2.0 would utilise otherwise unused low-cost generation (unused coal and VRE) and provide dispatchable and firm capacity that can operate for days if required, with the effect that the NEM would operate more efficiently and with lower emissions.

Benefits to Snowy Hydro

Snowy Hydro would capture a substantial amount of the value provided by Snowy 2.0. The modelling findings on the value Snowy 2.0 would provide to Snowy Hydro are as follows:

1. MJA independently calculated that the central case (Base Scenario) has the NPV impact on Snowy Hydro net spot market revenues due to Snowy 2.0 of over $3.0 billion (period 2018-19 to 2074-75).[3] This excluded contract sales revenues which are very substantial;
2. Almost all of the nine scenarios modelled have an NPV impact on Snowy Hydro net spot market revenues due to Snowy 2.0 in the range of $3,0 billion to $4.0 billion. The only outlier is the low carbon emissions scenario (45% by 2030, 80% by 2050) which was above the range.
3. The multi-day storage provided by Snowy 2.0 will be of increasing value as VRE enters in the NEM and coal generators exit;
4. The impact of Snowy 2.0 on Snowy Hydro is complex, as the impact of Snowy 2.0 could result in Snowy 1.0 revenues being either lower or higher than they would have been otherwise, depending on market developments (excluding effects on contract revenue);
5. The sensitivity of spot price outcomes (and net spot market revenues to Snowy Hydro) to market changes will increase as the existing coal generators close;
6. The impact of reduced hydro water inflows was not significant to the value provided by Snowy 2.0. This reflects that Snowy 2.0 operation is not reduced, it is the lowest value Snowy 1.0 generation that is reduced and reduced hydro inflows across all NEM would result in slightly higher spot prices.

MJA consulted a variety of sources in developing its modelling, including site visits, Snowy Hydro-commissioned studies, AEMO material and its own internal market and cost data.

MJA undertook detailed modelling in a variety of formats, considering, eg, storage economics, emission reductions, operating rules, costs and prices, in multiple scenarios.

The economics of the Project were determined as the differential between the spot market revenues Snowy Hydro would earn with the Project and without the Project. The modelling considered four aspects of Snowy 2.0 economics:

[3] The impact of Snowy 2.0 on Snowy Hydro is given by the difference of Snowy Hydro net spot market revenues between the 'with Snowy 2.0' case and the 'without Snowy 2.0' case

1. Combined revenue (Snowy 1.0 plus Snowy 2.0);
2. Impact of Snowy 2.0 on net spot revenues under two scenarios: without Snowy 2.0 with no alternative investment, and without Snowy 2.0 but an alternative investment is made);
3. Impact of Snowy 2.0 on NEM market benefits; and
4. Carbon emissions impact of Snowy 2.0.

To facilitate comparison, the operating parameters of the existing Scheme (Snowy 1.0) and the Project (Snowy 2.0) were precisely defined as detailed below.

Though they are a very substantial component of market revenues, contract sales were excluded from the analysis because they are a product of Snowy Hydro modelling; modelling that leverages MJA modelling but is post hoc by Snowy Hydro.

The central Base Scenario (from which eight alternative scenarios were modelled), was based on increasing VRE supported by firming provided by existing dispatchable generation and new entry storage and gas generation. The Base Scenario was:

1. Consistent with current energy policy and announcements (eg AEMO Neutral Outlook and ISP);
2. Incorporated the most likely assessment of economic condition and costs; and
3. Guided by rational economics.

Two models were developed of the NEM covering a 57-year period:

1. **2018-19 to 2046-47 (PROPHET modelling)** - detailing two cases: the Project is not developed ('without Snowy 2.0') and the Project commences operation 1 July 2025 ('with Snowy 2.0').[4] The PROPHET detailed simulation modelling stopped at 2047 as simulation past this date would be too uncertain;
2. **2047-48 to 2074-75 (MJA Firming Analysis Model)** - fundamental analysis of firming needs under different levels of VRE and the associated value of storage to determine the annual value of the Project.[5]

The modelling produced a number of general conclusions:

1. **Risk** - the NEM will become increasingly uncertain and complex with increasing risks as the existing coal plant closes;
2. **Firming** - firming capacity availability will decrease as coal plant closes. As additional VRE is added, there will be an increasing need for new firming assets;
3. **Emissions reduction** - as coal plants close and the amount of VRE increases, economics favour gas generation. This limits capacity for

[4] The PROPHET Simulation Model is an advanced simulation model of common clearing price electricity markets. It is used by many parties in Australia (portfolio generators and retailers) and has been used in many major assignments in Australia and overseas.

[5] The MJA Firming Analysis Model is a proprietary model, built in-house, with its objective being to hypothesise the amount of firming required under various levels of VRE penetration in the NEM.

emissions abatement. Further emissions reduction would require a regulatory mechanism (eg the NEG), which would favour deep storage.

2 Activities Undertaken

2.1 Overview

The key activity undertaken was MJA economic modelling of the NEM, leading to the production of two stages of reporting (Feasibility Study and FID). Other external and internal studies were conducted with the following aims:

1. Improving the base case inputs used by MJA between the initial Feasibility Study modelling and final FID modelling;
2. Developing reasonable alternative inputs for scenario analysis and sensitivity testing; and
3. Providing context and additional insight into key market drivers.

2.2 MJA engagement

2.2.1 Overview

Snowy Hydro engaged independent market experts MJA as a third-party specialist economic modelling firm with comprehensive experience in the NEM. Multiple stages of work have been undertaken by MJA to deliver information regarding the relationship between the NEM and the Project (as a completed asset), MJA has modelled the impact the Project (aka Snowy 2.0) would have on net revenues obtained by Snowy Hydro, the economics of the NEM, and the level of carbon emissions in the NEM.

The Feasibility Study

For the initial Feasibility Study, the key work packages from MJA were:

1. Stage One Public Market Report;
2. Stage Two Confidential Market Report;
3. Market modelling underpinning the Public Report;
4. Additional market and commercially confident modelling not contained in the Public Report; and
5. Report presentation and discussion with key Snowy Hydro stakeholders.

The FID Study

Since the Feasibility Study, the aforementioned reports and modelling have been leveraged to deliver improved and more detailed information to stakeholders. In addition, the focus of these deliverables has changed from benefits to the public, to benefits to the Snowy Hydro business case for assistance in informing the investment decision.

The work undertaken Pre-FID primarily concerned leveraging the established reports and modelling, and changing focus so that modelling was focused on business case impacts. The market modelling work package included the following four key deliverables:

1. Base case assumptions review;
2. Sensitivity/scenario review and structuring;
3. Operating regimes of Snowy Hydro portfolio; and
4. Provision of data output in an agreed format.

In addition to these deliverables, a modelling database was developed to address matters concerning simulation and Least-Cost Model (***LCM***) components. The approach of this database includes:

1. Design of the PROPHET database;[6]
2. Sourcing of all data;
3. Investigation into particular matters;
4. Initial development based on Short-Run Marginal Cost (***SRMC***) bidding;
5. Documentation;
6. Calibration of database and options for this;
7. Testing and documentation of the tests; and
8. Establishment of a central or 'reference case' based on AEMO data. Both MJA and Snowy Hydro had access to this database for modelling.

The MJA Report is the most up to date version of modelling outcomes, and contains the following components:

1. Overview of the NEM, LRET and gas market;
2. Historical analysis of NEM prices and volatility;
3. The economics of new and existing dispatchable generation, renewable generation, batteries and interconnection;
4. How Snowy 2.0 would provide value to the NEM;
5. A description and results of market modelling undertaken over a range of scenarios;
6. Real option value provided by the development of Snowy 2.0 for a potential Snowy 3.0; and
7. How Snowy Hydro would operate and create value with and without Snowy 2.0, and under the various scenarios contemplated.

Results from the Feasibility and FID reports relevant to the overall market are explored in depth later in this chapter, while results from the FID report are explored in depth in supporting chapters Six through Nine..

2.2.2 Characteristics of long-life assets

Snowy 2.0 is a large long-life asset with economics that requires assessment over 50-plus years in a market that is currently undergoing rapid change. The typical economic profile of a long-life large asset is marginal economics on service entry

[6] PROPHET is a publicly available NEM spot price simulation software which simulates five- and 30-minute market outcomes under various scenarios. It models supply bid stacks assuming competitive market behaviour by market participants to maximise economic profit.

(due to its size) and 20% to 35% of asset value associated with the last half of the asset life.

Long-life assets also have the issue that the long period of economic assessment may result in current pricing structures not being applicable in the later years of the asset. A standard approach to address this issue is to assess value on the opportunity cost of the project, this being the costs that would be needed if the asset was assumed not in service.

2.2.3 Statement of objectives

The MJA FID methodology was designed to:

1. Quantify how the NEM will develop in an outlook of reducing costs of solar/wind generation and battery storage, closing coal plant, and moderate if any demand growth;
2. Quantify and illustrate the requirement, value and fundamental economics of storage capacity (MW) and storage energy (MWh) as the NEM develops;
3. Quantify the value Snowy 2.0 would provide to the NEM and the cost of the required alternative if Snowy 2.0 were not developed;
4. The impact Snowy 2.0 would have to total Snowy Hydro net revenues;
5. The key uncertainties and how these could impact the business case for Snowy 2.0;
6. The economics of Snowy 2.0 across a wide range of scenarios; and
7. A modelling approach that provides for transparency in the economic assessment.

2.2.4 Approach

The approach consisted of four aspects:

1. A process designed to ensure completeness and rigour;
2. The use of modelling designed to address the requirements of the study;
3. Quality control process; and
4. Collaborative approach with Snowy Hydro.

2.2.5 Study steps

The study steps addressed the following:

1. Review of the NEM and the transformation that is occurring;
2. Identification of the key factors that would influence Snowy Hydro spot market revenues and costs. This included:
    a. Changes to coal plant parameters such as minimum generation levels; and
    b. Gas costs into the future.
3. Characterisation of Snowy Hydro portfolio with and without Snowy 2.0 and the manner Snowy 1.0 and Snowy 2.0 would operate within that portfolio;
4. Defining how the economics of Snowy 2.0 would be expressed;
5. Defining the approach to the impact Snowy 2.0 would have to carbon emissions in the NEM;

6. Development of a Base Scenario and modelling of this scenario;
7. The modelling used different models for the periods:
   a. 2018-19 to 2046-47; and
   b. 2047-48 to 2074-75.
8. Development of alternative scenarios for modelling, and modelling these in the same manner as the Base Scenario; and
9. Modelling conclusions.

2.2.6 Models

Two models were used:

1. **Market simulation model PROPHET** – this model captures in detail:
   a. The physical characterisation and constraints of generators and transmission;
   b. The NEM market arrangements (ie bidding, spot price formation, settlements);
   c. Snowy 1.0 and Snowy 2.0 physical specification and operating rules;
   d. Dynamics of the NEM and how Snowy 1.0 and Snowy 2.0 would operate within the NEM; and
   e. Statistical variations due to demand variations associated with weather, generator breakdowns, wind and solar variability etc; and
2. **MJA Firming Analysis Model (*FAM*)** – this model quantifies the fundamental requirement for firming services as VRE increases in the NEM, and the economic limits of VRE, and how this relates to the economics of Snowy 2.0.

2.2.7 Quality Control

MJA strictly adhered to its quality processes that have been developed for assignments requiring large amounts of information and modelling. These included:

1. Use of standard and augmented as necessary assumptions databases/spreadsheets;
2. Documentation and audit trails of all study steps;
3. Peer review of assumptions and modelling on a regular basis;
4. Reference to similar modelling where differences required explanation; and
5. Regular updates and meeting with Snowy Hydro and explanation of identified issues.

2.2.8 MJA-Snowy Hydro Co-operation

Marsden Jacob worked closely with Snowy Hydro throughout the modelling study. This involved:

1. Regular weekly update meetings;
2. Workshops on modelling approach and assumptions;
3. Participation in Snowy Hydro work on matters such as coal plant flexibility; and

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4. Regular discussion on matters relating to the operation of Snowy 1.0 and Snowy 2.0, NEM outlook, assumptions and modelling results.

2.2.9 Notes to the FID report

Dollars

Unless otherwise stated all dollars in this report are real 1 July 2018 Australian dollars.

Financial years

Unless otherwise stated:

1. A generator entering in a financial year refers to the start of that financial year (eg 2027/28 means 1 July 2027); and
2. A generator closing in a financial year refers to the end of that financial year (eg 2027/28 means 1 July 2028.

Snowy Hydro

1. Snowy 1.0 refers to the Snowy Mountains Scheme excluding Snowy 2.0.
2. Snowy 2.0 (or the Project) refers to the proposed 2,000 MW pumped-storage scheme.
3. Snowy Hydro Limited (Snowy Hydro) refers to the owner of Snowy 1.0 and Snowy 2.0.

Modelling

1. Scenarios refer to the developments and outcomes in the NEM.
2. Cases refer to Snowy Hydro development options (do nothing or Snowy 1.0, Snowy 1.0 plus other assets, Snowy 1.0 plus Snowy 2.0).

2.3 European Study Tour

2.3.1 Overview

In May 2018, a team of both Snowy Hydro and MJA personnel travelled to Switzerland, Germany and Portugal to visit a range of PHES sites and head offices (the ***Study tour***). The purpose of the Study tour was to understand and learn the lessons from major PHES projects in Europe where actual market conditions had resulted in less favourable economics than had been projected and that formed the basis of the projects being developed. The projects are summarised in Table 1.

PHES project name	Size	Commissioning
Linth-Limmern (Switzerland)	4 x 225 MW / 35 hours	2015/16
Nant de Drance (Switzerland)	900 MW / 23 hours	2019 (originally 2018)
Atdorf (Germany)	1,400 MW / 9 hours	2032
Frades II (Portugal)	760 MW / 130 hours	2017

Table 1: PHES plants visited on Study Tour

A desktop study involved research into the market conditions being experienced in European countries, in addition to how PHES plants were performing in this context.

Initial research highlighted problems due to regulatory changes and unexpected market events such as the Global Financial Crash. In Germany, regulatory events such as the introduction of 'Energiewende' in 2011 subsequently meant an oversupply of solar energy in the market.[7] This caused daytime price volatility and price spread to decrease, and thus decreased the value of PHES projects. Combined with a fall in wholesale power prices, over-supply of generators to the market, and decline in coal and gas fuel costs, plants such as Linth-Limmern were forced to operate at a loss and others were decommissioned.

This investigation into experiences of European counterparts prompted questions into how they utilised market modelling when building the business case, and whether they recognised similar market benefits/uncertainties as those highlighted by MJA. The team also sought to understand the financing strategy of these counterparts, and how regulatory, market, project cost and schedule uncertainties were incorporated.

The Study tour to the four aforementioned facilities in Europe was arranged to enable further investigation into how the following factors influence these developments:

1. Funding options and structures employed;
2. Commercial parameters and structures in place;
3. Market design factors that most influence success, or otherwise;
4. Risk management over the life of the project;
5. Valuation process and reporting;
6. Approval processes; and
7. Structuring commercial procurement processes and matching that to financing.

2.3.2 Findings

Findings of the Study tour included more detail into regulatory environment, competitors, unexpected events, and consequent conclusions into the likely decisions made by investors at the time. Technical findings such as variable speed machines having an increased ability to perform ancillary services.

A summary of the key parallels and differences found between the Project within the NEM, and that of visited PHES projects in European markets, are provided in Table 2.

[7] A large-scale energy transition strategy involving subsidisation of solar and wind energy and a phase out nuclear plants.

Parallels	Differences
General	
All assets have a long lifetime - A worthwhile investment even if current market conditions are less than ideal	Various European PHES had issues with wholesale risk due to only being a generator, and not a retailer - Snowy Hydro's vertical integration mitigates wholesale risk
Projects consistent with Government long-term plans	Availability payments are sought to keep plants in service for peak demand periods
The services provided by PHES are complex and subject to higher risk than thermal generation assets	
Market characteristics/design	
Increasing uncertainty in spread of potential outcomes in electricity markets	NEM is (currently) an energy-only market with a very high Market Price Cap
The value drivers of energy supply are increasing in complexity and in a number of ways	Long-term contracting is available in the NEM
	Solar and onshore wind in the NEM has much better economics than in many parts of Europe
	New technologies are better understood than late last decade
Market outlook/Investment decision	
Economic outlook scenarios originally did not include seismic and what were considered infeasible scenarios	Demand forecasts are better and the flat outlook for NEM demand and associated drivers are better understood
Investment trend of solar/wind development, followed by base load closure	European PHES based investment decisions on historical data, and underestimated level of growth in renewable energy (particularly wind and solar) - The Project is based on a renewable energy future
	Recent European PHES project entered operation in a market with substantial over capacity - The Project is forecast to enter market during a shortage of capacity

Table 2: Summary of findings

In addition, a broad range of considerations that Snowy Hydro must address were presented during the Study Tour. These included, but were not limited to the following:

1. Questions of how the asset matches the value drivers of the market;
2. The uncertainty regarding, and impact from, Government policies;
3. The world is increasingly volatile and inconceivables can occur eg recession, Liquified Natural Gas (***LNG***) plant closing and gas surplus;
4. Market dynamics and the complexity of PHES economics;
5. Impacts of new technologies;
6. The imperative of undertaking proper and complete due diligence and non-reliance on other party assessments; and
7. Due to lack of certain assumptions, the spread of potential market outcomes and risk profile are wider than many studies in the past have

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considered. The economics of Snowy 2.0 need to be assessed from a fundamentals perspective and need to account for the widening spread of potential market scenarios and outcomes within each scenario.

These findings were incorporated into MJA modelling through 'exploratory modelling,' wider breadth of scenarios, translation of economics to revenue, review of competitors, and investigation into the way that the Project supports government policy.

2.4 Thermal plant flexibility

2.4.1 Overview

The Study tour found that investments in increasing the flexibility of existing European thermal power plants had occurred. This increase in flexibility of nuclear and coal plant, as well as an increased electricity demand, combined with both increased interregional transmission and improved wind/solar forecasting over time (all market-driven), had eroded the value of PHES storage for these European projects.

In Germany, fossil fuel generation was found to be routinely providing a large degree of output flexibility to accommodate variations in renewable energy production in Germany. These findings were accentuated through the analysis of 2017 paper on thermal plant flexibility by Agora Energiewende.[8]

Gas and hard (black) coal generation provide the most firming potential to the variations in electricity demand and VRE generation. Lignite (brown coal) and nuclear closely follow in firming potential for demand and VRE generation. The level of investment and potential flexibility being achieved was higher than originally thought by Snowy Hydro, and thus raised questions of how much additional operational flexibility could be achieved by the coal-fired power stations in the NEM in Australia.

A formal engagement with an independent expert was conducted to determine the current and potential future plant operational flexibility of Australian plants. Deliverables included an assessment of current operational flexibility in comparison to comparable overseas coal fleets, and a report for each coal-fired station that owns optionality with respect to one or more potential upgrades or operational changes that would increase the flexibility of the station, and the associated capex and other costs.

2.4.2 Findings

Plant performance was compared from a number of sources: AEMO registration, historical performance seen in market data, original design specification and the independent expert's experience as industry consultants. The principle of conservatism was applied in assumption selection provided for MJA market

[8] Agora Energiewende (2017): 'Flexibility in thermal power plants – With a focus on existing coal-fired power plants'.

modelling and selection was carried out as an independent expert-MJA-Snowy Hydro collaboration to best represent current and projected operational reality.

In terms of international comparisons, the independent expert found that:

1. **Minimum generation** - Australian black coal plants at 30% to 40% of maximum output are similar to North American plants but not as good as state-of-the-art European facilities at 20% to 25%;
2. **Ramp rates** - The values found for Germany and North America suggest that Australian plants were designed for higher ramp rates than even the latest European plants. Design values for Australian black coal units are typically 5%/minute, compared to state-of-the-art German plants at 3% to 6%; and
3. **Cold and hot start times** - Design values for the NEM sub-critical plants are consistent with international best practice; the typical design hot start times for the NEM sub-critical are shorter than German values.

The independent expert identified and costed options for improving operational flexibility at seven power stations.

2.5 East Coast gas market

2.5.1 Overview

An independent expert was engaged to provide a review of the East Coast gas market. A better understanding of the demand, supply and cost outlook for the east coast Australia gas market was sought to assist in the decision regarding building an energy retail business.

The scope of work included the following four packages:

1. East coast demand;
2. Domestic gas supply;
3. LNG project demand and supply; and
4. Gas price forecasts.

2.5.2 Findings

The expert's findings were included in a report.

The AEMO National Gas Forecasting Report (2016), included a robust outlook for LNG and Gas Power Generation (***GPG***) as a large variable for gas demand. The difference between weak and strong gas consumption scenarios was large, and AEMO advised for planning solutions that prioritise flexibility, innovation and options to defer investment until some certainty across the energy market is resolved.

The expert's gas demand forecasts are summarised and compared to AEMO's in Table 3**.**

Gas Demand	Expert's forecast	Reason
GPG	Growth - Sensitive to gas price assumptions	Growth to support intermittent renewables and some retiring coal generation
Industrial	Flat - Key risk is demand destruction under high gas price scenario	Higher prices and energy deficiencies offsetting growth
Residential and commercial	Flat	Increasing appliance efficiency and use of electric options
LNG	Flat - Significantly less than AEMO who have not adjusted for lower GLNG	Plants operating at close to contracted quantities
Overall	Flat - Lower than AEMO	Above factors

Table 3: Expert's gas demand forecasts

Domestic gas supply is a function of the time horizon considered, risk, and uncertainty. It was found by the independent expert that Qld Coal Seam Gas (***CSG***) comprised 91% of eastern Australia's 2P (proven + probable) gas reserves, meaning that the northern gas production could meet northern demand, but southern demand would not be met by southern production. There is potential for a shortfall to occur in VIC post-2022 if there is no additional gas supply.[9] The predictions additionally include a likelihood of a large amount (20,000 petajoules (***PJ***)) of gas to be delivered to Melbourne to be at a low price (<$9/gigajoule (***GJ***)), however when reserves operated by LNG projects are subtracted, the amount delivered at the low price reduces significantly (<1,000 PJ). It was concluded that future potential gas supply is a function of the time horizon considered, risk and uncertainty. Table 4 provides an overview of three LNG projects on Curtis Island and their roles in domestic market sales.

LNG project	Operator	Annual Contract Quantity (Mtpa)	Nameplate capacity (Mtpa)	Role
QCLNG	Shell	8.2	8.5	Flexibility and capability to be active in the domestic market
GLNG	Santos	6.0	7.8	Short gas reserves. The JV is less aligned around domestic gas sales
APLNG	Origin Energy (upstream) Conoco-Phillips (downstream)	8.6	9.0	Capability to sell into domestic market, but already has a material contracted domestic portfolio and strong LNG demand from China

Table 4: LNG projects and their role in domestic market sales

[9] AEMO Victorian Gas Planning Report Update March 2018.

The basis of LNG pricing into most of Asia and a key part of the LNG price analysis is Brent or the Japan Customs-cleared Crude (***JCC***) oil price. These oil price scenarios enable an estimate of the LNG netback pricing from the Curtis Island LNG to key gas hubs. In terms of LNG regasification, AGL's Crib Point LNG regasification project is planned to provide 50 to 100PJ by 2021. This regasification project comprises a floating storage and regasification unit (***FSRU***) which is a fast-to-market technology and can be 50% the cost of an onshore gas development.

Investigation into gas prices yielded the following results:

1. Short-term gas hub prices have grown from around $6/GJ in 2016 to $7-10/GJ in 2018;
2. Contracted gas prices are trending upwards, with most recent contracts at $8.4-10/GJ;
3. LNG imported from the USA - based on USA Henry Hub forward gas prices, gas could be landed in VIC for <A$12.5/GJ…noting that higher oil prices may vary lower USA prices further for shale gas with liquids;
4. Gas-fired power generation - Combined-cycle gas turbine (***CCGT***) electricity generators can buy gas up to $10/GJ based on the electricity forward curve…as expected, less efficient open-cycle gas turbines which target peak power prices, are unable to run long-term above $6-8/GJ;
5. Oil prices:
    a. Varied over a wide range in recent history;
    b. Brent oil or JCC, are used to determines most of Asia's LNG pricing; and
    c. Oil prices around US$65/bbl may be expected, but there is still scope for considerable volatility.
6. LNG netback prices
    a. LNG netback = short-run price of indifference to LNG export;
    b. LNG netback gas price from Curtis Island projects delivered to Melbourne is expected to be around A$12/GJ; and
    c. LNG netback pricing and domestic short term prices show some volatility and a possible trend, noting that the last two LNG trains only started in 2016.
7. Multiple scenarios have been modelled for gas delivered to Melbourne.

The expert concluded that there was still a high degree of uncertainty as to how the gas market will play out on the east coast of Australia. Multiple scenarios were identified as having potential to materially change the long-term outlook, which included scenarios:

1. Aggressive use of Australian Domestic Gas Security Mechanism by the federal government;
2. Overreaching of LNG imports;
3. New play is successfully developed;
4. Demand destruction due to high prices;
5. Carbon tax favouring gas use over coal; and
6. High oil prices increasing Asian LNG prices.

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2.6 Coal pricing dynamics

2.6.1 Overview

Snowy Hydro wished to better understand the current dynamics of coal pricing in the Australian market. An independent expert was engaged to prepare a report and present a workshop that covered the fundamentals underlying fuel pricing in the Australian domestic market in addition to provision of a likely range for future domestic coal prices.

The scope of work included two key packages of work:

1. Overview of coal supply-and-demand associated with Eastern Australia's electricity market; and
2. Coal supply cost and risk-based consumer price forecasts.

The first package of work included:

1. Description of coal transport infrastructure in Eastern Australia providing a general picture of the locations of key coal production basins, mines and power stations and the infrastructure (rails, roads, conveyors) that connects them;
2. Demand for coal by power station (2015 to 2030) based on assumed load factors, thermal efficiencies and coal qualities;
3. An overview of port and rail capacity at Eastern Australian coal export ports; and
4. Production by mine (2015 to 2030), split between exports and domestic for all mines and projects that could reasonably service demand for domestic energy coal during this period.

The second package of work included:

1. Domestic supply costs (presented as domestic supply cost curves for 2018, 2025 and 2030) on a Free-On-Transport (***FOT***) basis at the mine gate;
2. Export pricing outlook;
3. A discussion on the respective power of coal producers and buyers in the domestic market in the short, medium and long-term, as coal supply contracts progressively roll off in the next ten years;
4. Netback pricing to Australian supply mines on an FOT basis;
5. Individual coal power station coal cost forecasts, yearly to 2030; and
6. Risk-based range of domestic prices ($/GJ) relative to the independent expert's Base Case Newcastle benchmark export thermal coal price. This included a look at the dynamics affecting the price outlook for coal in the short, medium and long-term as well as the key risks that could impact on coal availability and pricing and provide associated commentary.

2.6.2 Findings

The report yielded the following key results:

1. Export coal prices to 2030 are expected to be higher than the 2000-2018 period, driven by higher costs of marginal supply;
2. Most coal power stations in NSW and some coal power stations in Qld will need to renew contracts in the period 2022 to 2026. Prices for these renewals will be higher than current levels, as they will reflect parity with post-2022 export prices, which will be higher than pre-2010 export prices; and
3. Coal power stations in VIC and the majority of coal power stations in Qld will have fairly steady coal costs to 2030, as they are not exposed to export prices. The mines supplying these stations produce brown coal or lower grade black coal not suitable for export and/or they are isolated from export infrastructure.

2.7 Statistical hydrology and climate analysis

The feasibility study identified key climate trend projections relevant to the Project from a review of externally published scientific research. Using the historical long-term hydrological statistics for the Scheme is not considered a good representation of future climate conditions to which the Project will be exposed.

Consultation among relevant business units and MJA was undertaken in early September to decide how climate projections could be incorporated into MJA scenario modelling (using a base and drought hydrological case).

A 'base case' dataset was derived from January 1999 to December 2015 actual inflows using long-term historic WUFs (measured in GWh/GL) and have been modified to represent January 2024 to December 2040. Inflow data for the 1999-2015 period was selected as it includes frequent dry events and reduced average inflow, a pattern expected to continue in the future. The 'drought case' incorporates a further 10% reduction to represent projected future declines.

For more details on Scheme hydrology, see *Supporting Chapter Eighteen*.

2.8 Renewable Energy Procurement Program (REP-P)

The REP-P was undertaken by Snowy Hydro in order to create a more diverse company portfolio, in turn potentially complementing the Project. It consisted of procuring approximately 400 MW of wind and 400 MW of solar offtakes.

Snowy Hydro would be able to utilise the energy procured through the REP-P process for managing existing mass market, wholesale and Commercial & Industrial (***C&I***) exposures as well as growth opportunities in these segments: each having different 30-minute profiles.

MJA feasibility study work was leveraged by Snowy Hydro through an analysis which determined the competitive viability of procuring intermittent energy.

See *Supporting Chapter Six*, for a detailed overview of the REP-P and its role in diversifying the Snowy Hydro S1 portfolio, but not the S2 portfolio. This is until a potential second tranche of energy purchases is undertaken which would require S2 firming as the S1 firming is wholly subsumed by tranche one of the REP-P.

2.9 Transmission and Interconnector investigation

Transmission developments are a key parameter regarding the Project's viability and cost. There is a large amount of uncertainty in this area due to undisclosed and undecided transmission development decisions by AEMO.

Multiple levels of work have been undertaken by Snowy Hydro and MJA to create a range of scenarios and assumptions to address the most likely outcomes.

An analysis of AEMO's ISP Report 2018, particularly the modelling used for with and without cases of the Project, was undertaken by Snowy Hydro and MJA. On conclusion of this analysis, MJA completed a separate transmission modelling exercise. This was in order to change from the ISP's focus to more commercial driver focus of NEM asset development.

The modelling by MJA and Snowy Hydro included the following activities:

1. Development of interconnector development scenarios with and without Snowy 2.0;
2. Establishment of interconnector limits to be used in MJA NEM modelling for both cases; and
3. Adjustment of modelling and assumptions so that transmission (regulated) was assumed to be developed in order to support Victorian Renewable Energy development.

Transmission is discussed in further detail in *Supporting Chapter Sixteen*.

2.10 Snowy Hydro existing operations

Activities to model the impact of the Project on existing operations were undertaken by both Snowy Hydro and MJA and subsequently incorporated into modelling. These activities addressed the following components:

1. **Bidding strategies** - bidding strategies of Snowy Hydro consolidated and other market participants as portfolios of co-owned assets. With increasingly renewable energy environment and exiting of reliable baseload generation, strategies will be influenced. See *Supporting Chapter Seven* for further detail;
2. **Dissynergies** - New products were explored to meet the new storage and capacity needs of the market and hence capture the economic, market and other synergy values of the project. See Supporting *Chapter Six* for further detail;
3. **Increased flexibility** - In an industry where changes can happen very quickly, such as new technologies, plant closures or policy changes, flexibility to adapt has significant 'option' value; and
4. **Portfolio constraints** - constraints such as hydraulic and water constraints to ensure periodical generation and pumping volumes co-exist with the

day to day constraints imposed on the Snowy portfolio. See *Supporting Chapter Eighteen* for further detail.

3 Logic underpinning the benefits of the Project

3.1 Overview

Increasing penetration of intermittent generation will continue to produce challenges that, if not adequately addressed, will have implications for wholesale and retail electricity supply cost, reliability, and environmental outcomes.

The dynamic of integrating increasing levels of intermittent generation with existing generation in a manner that captures the economic benefits while maintaining reliability is complex and involves the total supply chain analysis.

3.2 Generation

Supply reliability is based upon matching generation and demand at all times and requires controlled (or dispatchable) generation to be economic and available when required. However, the demand to be supplied by dispatchable generation is the residual after zero-cost intermittent generation is dispatched, which reflects the volatility and uncertainty of the combined wind and solar generation fleet. Based on reasonable projections of the penetration of solar (both rooftop PV and large-scale) and wind generation, by 2030 the residual demand supplied by dispatchable generation (ie coal, gas and hydro) has the potential to vary from near zero in some States to very high levels.

In principle, the transformation can be thought of as moving from generators providing base, intermediate and peaking roles (ie different combinations of energy and capacity) to a system where generators supply either energy or capacity and where capacity uses previous energy generated (ie storage) and must be increasingly flexible.

The consequences are profound. Without new entry energy storage:

1. Increasingly, the proportion of generation provided by base load will decrease. By virtue of the low, sub-optimal level of generation and unpredictable operating mode, the economic value of baseload generation will decrease. This has implications for existing coal plant and potential new coal plant, should they eventuate; and
2. The increasing role of intermediate and peaking generation will be supplied by coal operating in this high ramping mode and gas generation. Gas generation may be needed more for capacity than energy, also impacting the economics of this plant.

The dynamic of lower energy storage could result in market instability and price impacts. Experience in the NEM supports this, for example, the economic exit of base load in South Australia due to renewables new entry. The notion that increasing renewables or non-dispatchable generation will result in long-term lower prices by suppressing coal or gas generation has shown to be largely incorrect. Such generation will either close or reduce its participation in the market, with resulting step changes in price outcomes:

VRE may have near zero explicit marginal cost, but this valuation often precludes the implicit firming cost required to prevent system instability both by peakers as well as baseload generation.

3.3 Retail products

Electricity retail prices reflect the wholesale cost of energy borne by retailers. This cost is highly influenced by procurement risk and a key driver to that procurement cost is the reliable and long-term management of intermittent generation and the cost to firm it up to a load-following product. Retail load varies with each trading interval and perfectly hedging this load requires a portfolio of wholesale contracts and dispatchable generation that can vary to follow the changes in the retail load. A portfolio including intermittent generation requires even more dispatchable generation, to follow changes in both the retail load and the intermittent generation so that the retail load remains hedged.

See *Supporting Chapter Six* for a more detailed discussion of the value in firming intermittent generation to a flat or load-following product.

3.4 Storage

Energy storage addresses intermittency issues by providing the dispatchable capacity that cannot be supplied by intermittent generation. The amount of storage required can be thought of as that required to supply adequate generation reserves after economic dispatchable generation is included.

The amount of storage required to support intermittent generation is likely to be substantial, and with the quantity required responding to events that may be unforeseen. This requires a solution that is reliable, lowest-cost, and responsive.

The absence of sufficient storage could mean surplus renewable supply becomes an economic loss.

3.5 Project benefits

Storage technologies include battery and pumped-storage hydro. The deployment and economics of these technologies into the NEM will ultimately be driven by the retirement of current plant, the capacity that can be provided, the amount of energy that can be stored, operational flexibility available, and length of life cycle. The key benefits of pumped storage, when compared to batteries, are:

1. Batteries are high-cost and currently have limited storage, typically one to four hours. Their cost also increases significantly when used for more than one charge/discharge cycle per day. Batteries also have a limited life (approximately 10 to 15 years); and
2. The Project is a pumped-storage scheme using proven technology that entails:

a. Lower relative costs than batteries;
b. Unparalleled scale: 2,000 MW of capacity;
c. The capability to run continuously for seven days or 15 days during the peak period before it needs to be 'recharged';
d. Additional inertia to the power system (required for stability purposes);
e. Increased interconnection between NSW and VIC; and
f. A project life cycle of 50+ years.

3.6 Summary of benefits

The benefits the Project would provide to the total market, retailers, and Snowy Hydro are summarised in Table 5.

Area	Benefits
Wholesale energy supply	1. Maintaining economics of base load generation; 2. Reduction in gas Open-Cycle Gas Turbine (***OCGT***) and CCGT plant required; 3. Lower costs of generation operation; 4. Longer-term reliability; 5. Provision of a firming service for wholesale electricity supply; 6. Increased sharing of generation between SA/VIC and NSW/Qld; 7. Increased generation inertia and greater system stability; and 8. Availability of spinning generation for the provision of spinning reserve.
Retail	1. Lower cost and availability in firming intermittent generation; 2. Lower energy procurement costs; and 3. Increased retail competition.
Snowy Hydro	1. Price arbitrage in the spot market; and 2. Sales of hedging contracts.
Customers	1. Improved Security and Reliability 2. Lower retail prices.

Table 5: Project benefits summary

3.7 Conclusion

Large-scale PHES will lower consumer prices, stabilise the power grid and enable deeper penetration of currently poorly-integrated variable renewable generation, directly addressing all three elements of the electricity trilemma: affordability, security and environmental.

3.7.1 Solving the trilemma

1. **Affordability** - The impact of an additional 2,000 MW of new generation supply creates competition for wholesale supply, thus reducing spot price volatility. The price and availability of wholesale contracts would improve and provide more competition. The addition of storage at a higher volume and lower cost than the battery alternative would increase spot prices during periods of pumping or surplus supply and enable thermals to avoid ramping or low generation inefficiency costs that they would otherwise need to recover at peak times, thus reducing or stabilising spot prices that better reflect the economics of supply;
2. **Security** - The Project increases the flexibility of the NEM to respond to unforeseen changes such as plant closures or policy changes. Additionally, the Project provides a capability to displace energy across time that can, for example, enable better management of power station failures, or ensure sufficient capacity to respond to intermittent generation; and
3. **Environmental** - The Project would be an enabler of additional least-cost renewable generation in the 2030s, which would be close to being economic without firming. The Project would provide a cost-effective and reliable firming service for this renewable generation to operate in the NEM, and be a significant component of the retailers' energy mix.

The Project would have the capacity and storage size to address the full needs of the NEM in this environment. When the share of intermittent generation in the NEM further increases as renewable generation costs become even lower, additional large-scale storage will be required. The development of the Project provides for further pumped-storage development and the real option to quickly address additional coal-fired plant closures that may occur due to the age and working condition of generators.

The business analysis conducted internally and by independent experts, in the context of the Study and within the confines of the information afforded by this undertaking, concludes that the Project is economically feasible and adds material value to the Snowy Hydro Group.

4 MJA Market Modelling

4.1 Overview

Snowy Hydro engaged independent market experts MJA as a third-party specialist economic modelling firm with decades of experience in the NEM. The economic outcome and findings of MJA's studies concluded the proposed Project will be increasingly required as part of the solution to carry a long-term future system stability burden of the NEM. A range of solutions to an increasingly intermittent and unreliable NEM generation fleet mix is required, including a potential to further increase PHES into the future with the appropriate transmission system augmentation.

MJA's future base case market state estimation in the NEM was built upon the current and known regulatory framework, and State and Federal renewable targets. Transmission upgrades were based on the AEMO ISP published in June 2018, plus further analysis. The scenario is further characterised by historic and known macro assumptions of existing baseload thermal generation, planned thermal and smelter retirements, increasing penetration of large-scale renewables, EVs and battery storage, demand-side management by consumers, and fuel price inputs.

4.2 MJA Executive Summary

4.2.1 Overview

This chapter presents the findings of an independent study by MJA of the operation and net spot market revenues that Snowy Hydro's existing hydro scheme (termed Snowy 1.0) and Snowy 2.0 (the proposed 2,000 MW pumped hydro storage scheme) would obtain under a range of NEM development scenarios. This report follows the feasibility modelling (and report) undertaken by MJA in 2017.

Key Findings
The key findings of this study relate to the Snowy 2.0 value proposition and the benefits Snowy 2.0 would provide to the NEM and to Snowy Hydro. These are summarised in turn below: <u>Variable, Dispatchable and Firm Capacity</u> While is it recognised that generation from VRE does not provide firm capacity, the study highlighted the need to make the further distinction between 'dispatchable capacity' and 'firm capacity': 1. **Dispatchable capacity** is that which is controllable (ie either up or down); 2. **Firm capacity** is that capacity which is both dispatchable and which can be relied upon to be available. Dispatchable generation from storage with limited hours of storage also does not provide firm capacity as it may not be available to generate when needed. The study found that firm capacity requires at least 24 hours of storage. <u>Snowy 2.0 Quality and Value Provision</u> Snowy 2.0's qualities of capacity and storage size, central location, and ancillary service provision makes it unique in the NEM. Snowy 2.0 would provide both dispatchable and firm capacity. These unique qualities provide for substantial value to the market, consumers, and Snowy Hydro. These quality and value relationships include: 1. Its **central location** that provides for maximum consumer access, NEM wide balancing of VRE, and security against critical transmission outages; 2. Its **large level of storage** (175 hours conservatively) provides for energy security and firming against extreme market conditions, both of which will become of increasing value to risk mitigation in the future. In the longer-term, storage value will move to be proportional to storage hours. (These are matters not capable of being managed by storage with less than about 24 hours of storage); 3. Its **flexible operating** nature provides for increased market stability and efficiency. This has its pumping demand (of up to 2,000 MW) operating in response to the changing availability of surplus coal and surplus VRE, and its generation operating in response to spot price signals and commercially and economically replacing gas plant and batteries

that would have been developed and used. Such operation directly supports the development of new VRE and emissions reductions;
4. Its **economic value to be robust** against uncertain future outcomes;
5. Its ability to **transition smoothly** into operation.

While the transmission developments identified in the AEMO 2018 Integrated System Plan between NSW-VIC-SA are considered to be needed regardless of Snowy 2.0 development (as they support the Renewable Energy Zones and interregional transmission limits necessary to address the closing coal plants), Snowy 2.0 would provide additional value to this transmission. Snowy 2.0 could potentially reduce transmission asset costs due to its complementary operational nature to other types of assets.

Benefits to the NEM

Supports Trilemma

On a NEM-wide basis, the above relationships would provide for Snowy 2.0 to directly and substantially contribute to the trilemma issues of reliability, price, and emissions reduction as the existing coal fleet closes and replacement firm capacity and energy production is required.

Avoids Excess Supply

Snowy 2.0 would utilise otherwise unused low-cost generation (unused coal and VRE) and provide dispatchable and firm capacity that can operate for days if required, with the effect that the NEM would operate more efficiently and with lower emissions.

Benefits to Snowy Hydro

Snowy Hydro would capture a substantial amount of the value provided by Snowy 2.0. The modelling findings on the value Snowy 2.0 would provide to Snowy Hydro are as follows:

1. MJA independently calculated that the central case (Base Scenario) has the NPV impact on Snowy Hydro net spot market revenues due to Snowy 2.0 of over $3.0 billion (period 2018-19 to 2074-75).[10] This excluded contract sales revenues which are very substantial;
2. Almost all of the nine scenarios modelled have an NPV impact on Snowy Hydro net spot market revenues due to Snowy 2.0 in the range $3.0 billion to $4.0 billion. The only outlier is the low carbon emissions scenario (45% by 2030, 80% by 2050) which was above the range.
3. The multi-day storage provided by Snowy 2.0 will be of increasing value as VRE enters in the NEM and coal generators exit;
4. The impact of Snowy 2.0 on Snowy Hydro is complex, as the impact of Snowy 2.0 could result in Snowy 1.0 revenues being either lower or higher than they would have been otherwise, depending on market developments (excluding effects on contract revenue);
5. The sensitivity of spot price outcomes (and net spot market revenues to Snowy Hydro) to market changes will increase as the existing coal generators close; and
6. The impact of reduced hydro water inflows was not significant to the value provided by Snowy 2.0. This reflects that Snowy 2.0 operation is not reduced, it is the lowest value Snowy 1.0 generation that is reduced and reduced hydro inflows across all NEM would result in slightly higher spot prices.

4.2.2 Work undertaken

The work for this report included:

1. Review and update of all assumptions and potential outlook scenarios. This included:

[10] The impact of Snowy 2.0 on Snowy Hydro is given by the difference of Snowy Hydro net spot market revenues between the 'with Snowy 2.0' case and the 'without Snowy 2.0' case

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    a. the findings from a visit to recent European pumped-storage developments;
    b. a study by an independent expert on the performance of the existing NEM coal generators and options to increase their flexibility;
    c. an independent study on the outlook of the east Australia gas market;
    d. recent studies and publication by AEMO including the ISP, Gas Statement of Opportunities and Electricity Statement of Opportunities;
    e. MJA market and cost data;
2. Developing the approach to modelling the NEM over the study period of 2018-19 to 2074-75;
3. Development and use of models that vary from long-term spreadsheet approaches to detailed market simulation;
4. Developing the scenarios and assumptions based on a review of future uncertainties;
5. Modelling and analysis of the fundamental economics of storage as the amount of VRE increases;
6. Explicit modelling and the assignment of carbon emission reductions to the service provided by S2.0;
7. Detailed review and incorporation of the operating rules that apply to S1.0 and that would apply to S2.0;
8. Detailed modelling that includes capital and operating costs, and spot price outcomes and associated wealth transfers between parties; and
9. Modelling of a greater number and spread of scenarios.

Note: All dollars are real July 2018 Australian dollars unless otherwise specified.

4.2.3 Modelling: Structure, Approach and Scenarios

Project Economics

The economics of the Project considered in MJA's report relates to the net spot market revenues that would be earned by Snowy Hydro hydro assets without the Project and with the Project. The difference between these two cases represents the increase in value (associated with spot market operations) the Project would provide to Snowy Hydro.

It is noted that contract sales (most notably cap contracts and load-following contracts) and associated value are not included in this report. They are modelled using MJA fundamental market analysis outcomes as inputs by Snowy Hydro modelling - see *Supporting Chapter Six.* Contracts contribute a very substantial component of market revenues.

The modelling consisted of:

1. Developing the approach to modelling the NEM over the study period of 2018-19 to 2074-75;
2. Developing the scenarios and assumptions based on a review of future uncertainties;

3. Undertaking the modelling; and
4. Results review.

Modelling Approach

The long study period meant that two modelling approaches and models were used to address the 57-year study period:

1. 2018/19 to 2046/47: detailed simulation modelling of the NEM under two cases:
    a. Snowy 2.0 is not developed (termed the 'without Snowy 2.0' case); and
    b. Snowy 2.0 is developed and enters service 1 July 2025 (termed the 'with Snowy 2.0' case).
2. 2047/48 to 2074/75: fundamental analysis of firming needs under different levels of VRE and the associated value of storage (capacity and hours of storage). From this, the annual value of Snowy 2.0 post-2047 was derived together with the associated revenues of the with Snowy 2.0 and without Snowy 2.0 cases.

4.2.4 A Day in the Life of Snowy 2.0 and how this will change

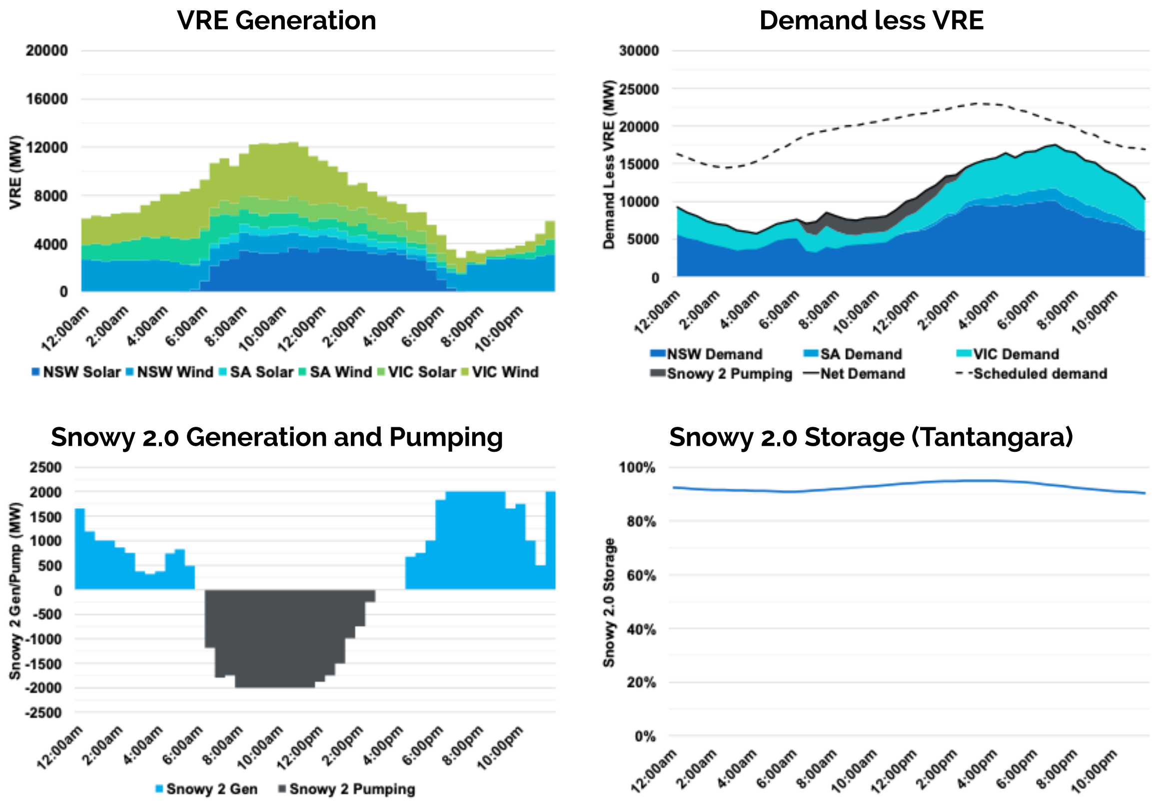
The modelling of the Base Scenario provided for the operation of Snowy 2.0 (and all other generators) to be observed on a day by day basis through the modelling period. This illustrated the variability of Snowy 2.0 operation due to factors that include season, day-type, amount of VRE installed, weather impact of wind/sunshine and demand and generator outages.

From this, a pictorial representation of Snowy 2.0 operation, under various conditions over the study period, was developed and is shown in Figure 1 below. For each of the three days of different VRE output the figure shows over each day:

1. VRE generation;
2. Demand less VRE generation – this is the demand to be supplied by dispatchable generation;
3. Generation (positive) and pumping (negative); and
4. Total Tantangara reservoir level.

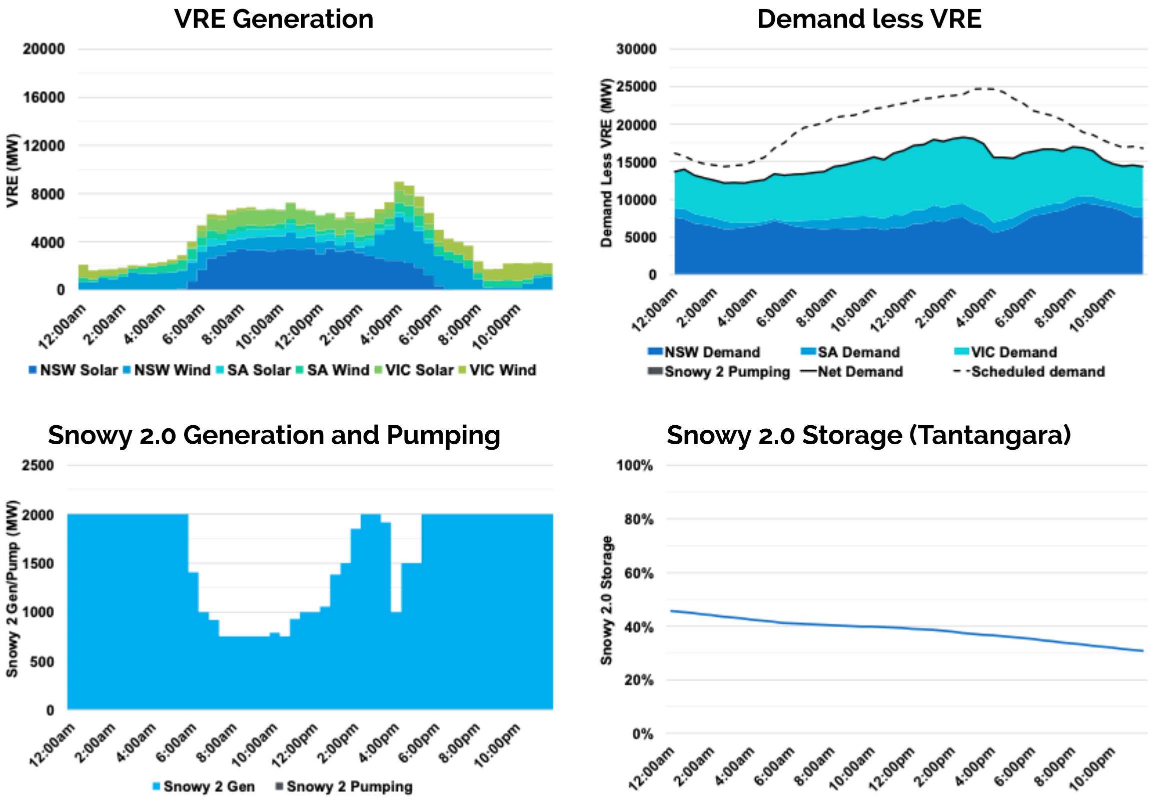
The commentary below each graph describes the day and what changes occurred.

Medium VRE Day

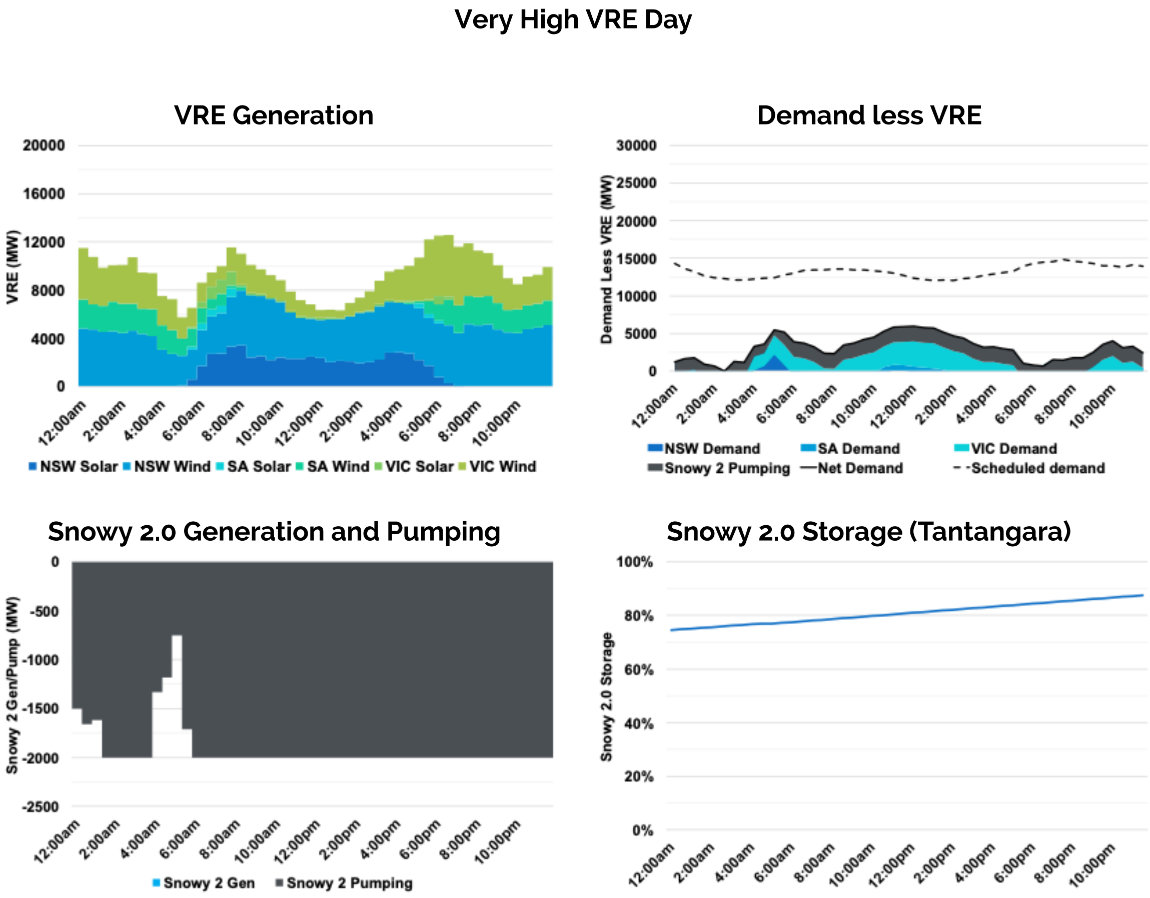


1. Snowy 2.0 generates at the start and finish of the day.
2. Snowy 2.0 pumps in the middle of the day (corresponding to high solar output).
3. This will be a typical day when Snowy 2.0 enters. The extreme variations in VRE energy output will increase as the amount of installed VRE increases.
4. Overall 2.0 storage level (Tantangara) stays about the same.

Very Low VRE Day



1. Snowy 2.0 generates all day with generation reducing in the middle of the day (corresponding to high solar output).
2. Snowy 2.0 provides generation capacity when VRE is low and when coal/gas generators are unavailable.
3. This type of day will increase in frequency as VRE increases.
4. Snowy 2.0 storage drops slightly. This level of generation can be done for many days on end.



1. Snowy 2.0 pumps all day with a small reduction due to a small lull in VRE generation.
2. Snowy 2.0 provides for surplus VRE generation to be saved over a whole day for later use.
3. This type of day will increase in frequency as VRE increases and thermal generation reduces.
4. Snowy 2.0 storage increases slightly. This level of pumping can be used to capture excess VRE generation for many days on end.

Figure 1: Daily Snowy 2.0 Operation – Average types days [Source: MJA]

4.2.5 Conclusions

A number of conclusions were drawn from the analysis and modelling undertaken and these are summarised below.

Risk

The NEM will become increasingly complex with increasing risks as the existing coal plant closes:

1. Post-2035 the risks to system reliability and energy purchase risk will increasingly include energy sufficiency. Energy sufficiency risks will reflect VRE energy production variability over timeframes from daily to yearly.
2. NEM outcomes may become more sensitive to the reliability of existing power stations and demand forecast errors; and

3. Like the South Australian situation, the risks to supply reliability and energy purchase risk may not be fully understood. This will include the risk of weather conditions changes that may impact VRE generation variability and consumer demand profiles.

Firming

The substantive amount of existing dispatchable generation (ie coal, gas and hydro generators) provides for a certain level of VRE generation to be absorbed in Victoria, NSW and Queensland without the need for new firming assets.

As the existing coal generators close, the amount of existing (and no cost) firming capacity available will decrease. This will require new firming assets (in the form of new gas generators and storage) to be developed. The amount of new firming assets required for a given amount of additional VRE will increase moving forward (as the coal plant closes and VRE is added).

Emissions Reduction

Before the closure of Eraring, the lowest-cost option for reducing emissions is replacing coal generation with VRE generation, together with the level of firming required (with most firming being available from the existing dispatchable generation).

Once Eraring and other coal plants close, increasing levels of VRE would require increasing amounts of new firming assets, with economics having this increasingly composed of gas generation. This limits the level of emissions reduction to about a 65% level of abatement (compared to 2005 level).

In the long-term, the economics of reducing emissions by more than about 65% (compared to 2005) would require an emissions reduction mechanism.

A constraint on emissions when coal plant has substantially closed would involve VRE with substantial storage and a reduced reliance on gas generation. The value of large storage is magnified under such conditions.

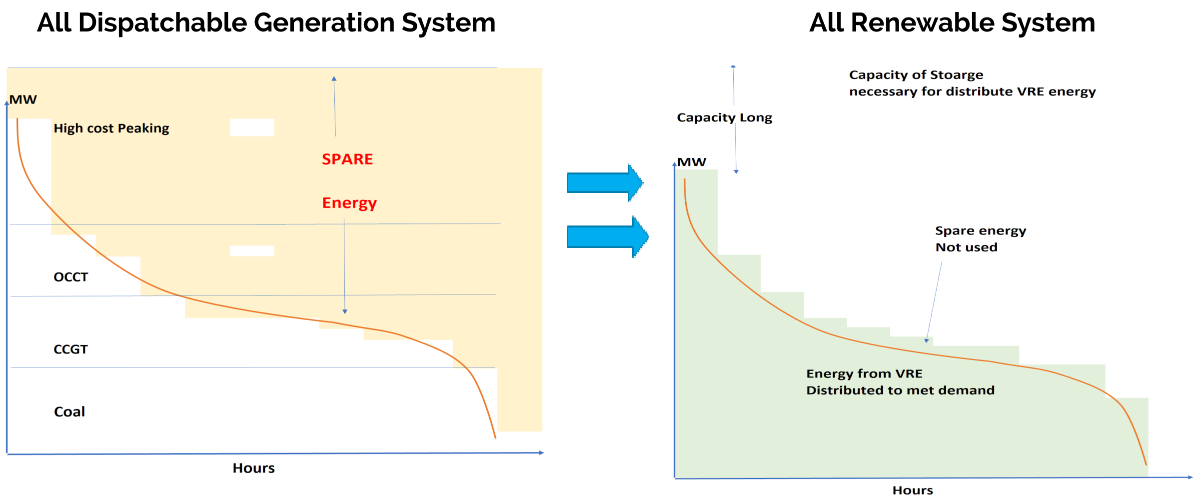


Figure 2: Changing Characteristic of the NEM [Source: MJA].

Figure 2 above shows two load duration curves and how the energy is supplied in each.

The transformation from a mostly dispatchable generation system to a mostly renewable system (with firming) involves moving from a market where reliability is determined by periods of capacity shortage to a market where reliability is determined by periods of either capacity shortage and/or energy shortage.

4.3 Defining Snowy 1.0 and Snowy 2.0

The characterisation of the physical and operational profile of Snowy 2.0 and Snowy 1.0 is fundamental to the value of these assets separately and together. This section presents the representation used in the modelling of Snowy 1.0 and Snowy 2.0.

This is presented in terms of:

1. The physical assets and transmission connection to the NEM;
2. Hydrology (ie water storage and flows);
3. Round Trip Efficiency (***RTE***) (or cycle efficiency);
4. How Snowy 1.0 and Snowy 2.0 would bid in the NEM; and
5. Operating rules.

4.3.1 Snowy 2.0

Power station

Snowy 2.0 is a PHES scheme that would operate between Tantangara Dam (the high reservoir) and Talbingo Dam (the low reservoir). The Snowy 2.0 scheme involves a tunnel between these reservoirs with the pumping/generator station being located near the Talbingo reservoir. For the purposes of MJA's report, the name of this new generating station is Snowy 2.0 Power Station. Snowy 2.0 does not require the construction of any new dams and it would not affect irrigators and downstream water users.

The key features of the Snowy 2.0 pumped hydro scheme are:

1. Six x 333 MW turbines with a total capacity of 2,000 MW;
2. Three of these turbines are 'variable speed' turbines that provide for increased flexibility of operation;
3. The period of full and continuous operation when headwater reservoir is full is 175 hrs (which equates to 7.3 days);
4. RTE losses are about 24% (ie 76% cycle efficiency). These losses vary depending on the MW levels used when pumping and the MW levels used when generating;
5. The maximum capacity of Snowy 2.0 operation is about 43% (which corresponds to 57% pumping). Given the need to ramp up and down the maximum capacity factor would be less than say 38%; and
6. This capacity of Snowy 2.0 would increase the capacity of the Snowy Hydro scheme to 5,720 MW (an increase of 53%).

Snowy 2.0 Cycle Efficiency

The RTE of Snowy 2.0 (or any pumped storage including Tumut 3 Power Station pumping) refers to the ratio of the energy generated from a quantity of water to the energy required to pump that quantity of water.

Pumped-storage RTE = generated energy / pumping energy

This RTE depends on factors such as the level of generation/pumping compared to maximum generation/pumping, and water level in the upper pond. For a hydropower station with multiple generators and pumps, it would also depend on how generation and pumping are shared across the generator and pump units.

Snowy 2.0 consists of six generator units all of which can pump and with three of these being variable speed machines. The modelling assumed that at various levels of power station generating and pumping the cycle efficiency reflected the optimum use of these generators/pumps.

Snowy Hydro provided MJA with the efficiency of Snowy 2.0 generation and pumping at different operating levels based on the input of equipment manufacturers in the Project's procurement process,

Connection to the NEM

The AEMO ISP presented a transmission plan that has:

1. A new 800 MW interconnector between SA and NSW developed by 2024 (referred to as 'Riverlink');
2. A 2,000 MW increase in interconnection capacity between VIC and NSW in both directions.[11] The timing of this interconnection was 1 July 2025 if Snowy 2.0 is developed and 2035 if Snowy 2.0 is not developed; and
3. Snowy 2.0 connected to NSW via a new 2,000 MW link.

The ISP indicated that the transmission upgrades between VIC, NSW and Snowy 2.0 are needed regardless of whether or not Snowy 2.0 is developed, but that they would be developed to coincide with Snowy 2.0 entry should Snowy 2.0 proceed.

4.3.2 Snowy 1.0 and Snowy 2.0 Hydrology

Figure 3 shows the configuration of Snowy 1.0 and Snowy 2.0 used in the modelling. The following are noted:

1. Eucumbene, which is the major reservoir for the Murray power stations and Tumut power stations, is represented as separate storages for these two sides of the Snowy scheme. Each has the inflows and storage associated with the Murray side and Tumut side respectively;
2. The inflows to Eucumbene include the inflows to Tantangara;
3. Tumut separately models Tumut 3 and Tumut 3 pumping;
4. The Tumut 3 pond is used to account for Tumut 3 pumping. Talbingo is the head pond for Tumut 3 Power Station;

[11] The ISP referred to this transmission as Snowylink South (which is the transmission developed in Victoria) and Snowylink North (which is the transmission developed in NSW).

5. Snowy 2.0 is a separate scheme with a lower and upper pond (Tantangara). Tantangara has its inflows assigned to Tumut (Tantangara is connected to Eucumbene through a diversion tunnel.); and
6. Water can be provided to Tantangara if Snowy 2.0 generation is required and Tantangara water level is low.

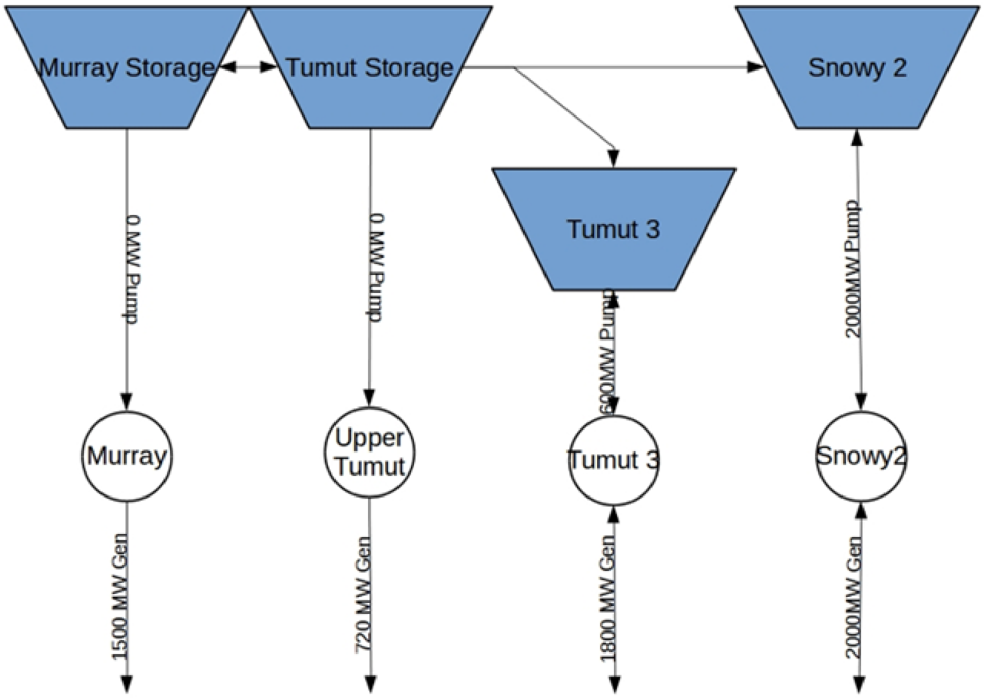


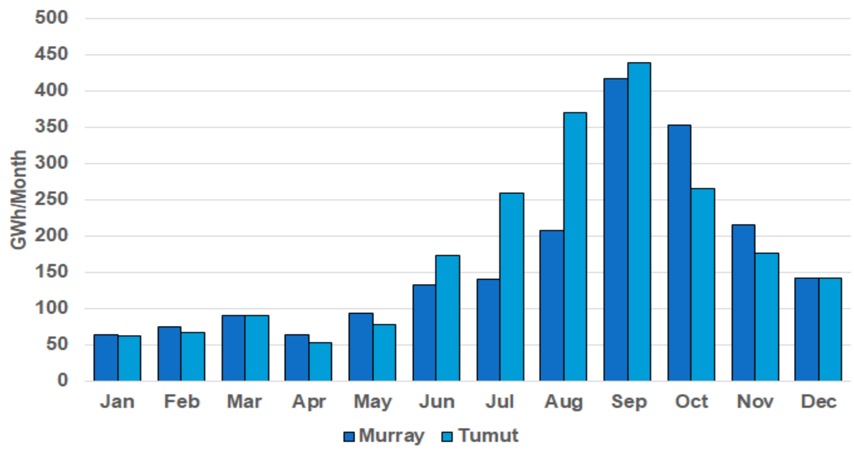
Figure 3: Snowy Hydrology [Source: MJA]

Pattern and variability of Inflows

The inflows to the Murray and Tumut sides of the scheme (which represent the sum of inflows to all ponds) are expressed as GWh of generation (measured at the power station).

The modelling of most cases used the average inflow pattern and maintained this monthly pattern constant on a yearly basis. Separate modelling was done to examine inflow variability.

Figure 4 presents the monthly pattern of inflows to Murray and Tumut. This data was available from AEMO and also Snowy Hydro.



The monthly pattern shows inflows to be low over the summer, increasing during winter and at their highest during the snowmelt (spring thaw), and then decreasing.

Figure 4: Snowy 1.0 - Murray and Tumut Average Annual Inflow Profile [Source: MJA]

4.4 Expressing the Economics of Snowy 2.0

This section presents the framework used for expressing the economics of Snowy 2.0. This formed the basis for the design of the modelling and presentation of modelling results and for the calculation of the economics of Snowy 2.0.

Note: 'Net spot market revenues' refers to the revenues of spot market generation sales less the costs of pumping (Tumut 3 for Snowy 1.0 and Snowy 2.0 pumping for Snowy 2.0).

There are four aspects of Snowy 2.0 economics considered in this study:

1. The revenue Snowy 1.0 plus Snowy 2.0 (ie Snowy Hydro as a whole) would be expected to make and the potential spread of these revenues due to market and other conditions. This is only concerned with the performance of Snowy 1.0 and Snowy 2.0 on the assumption Snowy 2.0 is developed. This would typically be relevant to lenders;
2. The impact Snowy 2.0 would have to Snowy Hydro revenue and costs, that is the impact to Snowy Hydro net spot revenues (ie the change between the with Snowy 2.0 case to the no Snowy 2.0 case). This would typically be relevant to an investment decision.
3. The impact Snowy 2.0 would have to NEM market benefits (being the NEM wide capital and operating costs required to supply electricity to consumers). This requires comparing Snowy Hydro projected capital and operations costs on the basis Snowy 2.0 is developed to that on the basis Snowy 2.0 is not developed. This would typically be the result required by a regulator to support a large investment; and
4. Which can be considered as part of market benefits, is the carbon emissions impact of Snowy 2.0.

All results are presented as quarterly and annual results and are also expressed as an NPV over the study period.

The sections below present descriptions of the above-noted issues.

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4.4.1 Snowy Hydro revenue and costs

This study was confined to the revenues and pumping costs of Snowy Hydro generators in the NEM and excluded costs associated with construction of Snowy 2.0 and fixed operating costs. Revenue minus pumping costs is referred to as net revenue.

Revenues and costs were determined separately for Snowy 1.0 and Snowy 2.0 and added to produce Snowy Hydro total revenue and costs.

The revenues and cost streams for Snowy 1.0 and Snowy 2.0 considered in this report are as follows:

1. Spot energy physical trades. This is often referred to as energy price arbitrage; and
2. Supply of ancillary services (the amount of ancillary service supply had the potential revenue assumed to be small).

Exclusion from this report (MJA inputs used in Snowy Hydro internal modelling):

1. Contract sales and associated payments – this is an overlay to the spot market.

Table 6 presents the revenue and costs streams for each of Snowy 1.0 and Snowy 2.0.

Category	Component	Issues	Revenues modelled
Spot market	Energy	Generation revenue	Yes
		Pumping costs	Yes
Spot market	Frequency Control Ancillary Services (***FCAS***) provision	Revenues relatively small	Excluded
		Costs relatively small	Excluded
Contract market	Caps and load-following	Sales revenue large	Excluded
		Support costs moderate	Excluded

Table 6: Snowy 1.0 and Snowy 2.0 Revenue and Cost Components [Source: MJA]

4.4.2 Market Benefits

The market benefits of a project in the NEM refer to the change in the costs of supply-and-demand across the NEM excluding the costs associated with the Snowy 2.0 project (ie capital and operation over the economic life of the project). In this context, economic benefits exclude wealth transfers between participants in the NEM.

The concept of 'market benefits' as developed by the Australian Energy Regulator (***AER***) for use in the Regulatory Investment Test - Transmission (***RIT-T***) was used as the basis for the framework for quantifying the economic impact Snowy 2.0 would have to the NEM.

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The components of market benefits used in the study are:

1. Capital costs of new assets – generation and transmission;
2. Change in fixed costs associated with changed retirement dates of existing generators; and
3. Change in operating costs – fuel and variable operations and maintenance (VOM) associated with changed operating regimes. This can include the provision of ancillary services.

Revenue changes from other services such as FCAS are small and the system is assumed to be developed under all scenarios to satisfy the supply reliability criterion (meaning benefits from changes in unserved energy would also be small).

4.4.3 The NEM with and without Snowy 2.0

For each scenario modelled the impact of Snowy 2.0 (whether in relation to Snowy Hydro revenue and costs, or market benefits) was determined through:

1. Modelling the NEM over the study period on the basis Snowy 2.0 is developed. In all scenarios this is referred to as the 'With Snowy 2.0 case';
2. Modelling the NEM over the study period on the basis Snowy 2.0 is not developed and that all assets between the with Snowy 2.0 and without Snowy 2.0 (existing or new) are the same. This is referred to as the 'Without Snowy 2.0 case' or the 'No Snowy 2.0 case';
3. Based on the without Snowy 2.0 case (for any scenario), assign a portion of the developments that occurred in the market that did not occur in the with Snowy 2.0 case. This is referred to as the 'No Snowy 2.0 with Replacement' case. This case assumes the assets transferred to Snowy Hydro are operated and priced the same; and
4. Comparing the differences on an annual or quarterly basis between the two modelled cases.

Of note is that the market benefits and total NEM carbon benefits are the same for the differences between:

1. The With Snowy 2.0 case and No Snowy 2.0 case; and
2. The With Snowy 2.0 case and No Snowy 2.0 with Replacement case.

4.4.4 Firming

In the energy market, the services Snowy 2.0 provides have been expressed in ways such as spot price arbitrage. Spot market revenues were presented in the sections above.

These services can also be expressed in terms of firming and this report will refer to Snowy 2.0 providing firming to either VRE generators or to the purchases of VRE generation output.

Snowy 2.0 firming refers to the following:

1. **Spot market:**

   a. spot price arbitrage that improves the dispatch weighted price of VRE by increasing demand (battery charging or pumped hydro pumping) at times of high VRE generation; and
   b. provides firm capacity thereby reducing the amount of peaking capacity required; and
2. **Retailer hedging / firming products**:
   a. the firm capacity that Snowy 2.0 provides in the spot market can be sold as cap contracts;
   b. spot price arbitrage and firm capacity, through the substantial storage available to Snowy 2.0, can be combined to provide (high value) load-following contracts; and
   c. These products have a premium over the underlying value obtained in the spot market. (Without the ability to obtain a load-following or cap contracts, VRE is of limited use in hedging wholesale energy purchases).

On a NEM wide basis, firming refers to the amount of dispatchable generation and storage (such as Snowy 2.0) required to support an amount of VRE generation.

When VRE generation is supplying x% of demand:

1. Dispatchable generation and storage is required for firming to support the x% of demand being supplied by VRE;
2. There is dispatchable generation required to supply the remaining (1-x) % of demand. There would be surplus dispatchable generation from the (1-x) % component of the demand being supplied by the dispatchable generation. This would reduce the firming required of the x% component of demand being supplied by VRE;
3. These two components are difficult to separate; and
4. As the level of VRE increases, there is less firming provided by dispatchable generation required to supply demand and a greater reliance on assets such as Snowy 2.0.

The 'bottom line' is that there is an (optimum) cost of dispatchable and storage required when VRE is supplying a certain percentage of demand. Here we note that supplying x% of demand by VRE may require VRE capable of generating greater than x% of the required energy (ie there is some VRE 'spill').

4.5 Models Used and Approach

4.5.1 General

The MJA studies required the NEM to be modelled over the period 2018/19 to 2074/75 under the assumption that Snowy 2.0 is not developed and that Snowy 2.0 is developed and enters on 1 July 2025 (ie commences in 2025/26).

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4.5.2 Selection of Model Type

The study required the NEM to be modelled over the period 2018/19 to 2074/75 under the assumption that Snowy 2.0 is not developed and that Snowy 2.0 is developed and enters on 1 July 2025 (ie commences in 2025/26). Further, the modelling was required to properly represent the hourly/daily/weekly/seasonal variations that are fundamental to the operation of generators in the NEM. This includes:

1. The dynamics of generator bidding and how this translates on a 30-minute (or 5-minute) basis to generator dispatch levels and regional spot price outcomes; and
2. The variability of demand, VRE and other uncertainties and how this impacts the value of storage capacity (MW) and hours in storage.

The long study period also meant that the character of the NEM would be significantly changing and that the level of uncertainty would be very large for the last 20 years of this period.

To accommodate these matters the modelling approach involved the use of two models over this study period:

1. **2018/19 to 2046/47**:
    a. detailed NEM modelling of the NEM capable of representing NEM dynamics and outputting generator dispatch and regional price outcomes; and
    b. the period incorporates the year prior to the commencement of Snowy 2.0 and the first 23 years of Snowy 2.0 operation;
2. **2047/48 to 2074/75**:
    a. Given the uncertainty regarding issues such as demand level and what plant mix might exist, the modelling was based on the fundamental value of storage in a market developing as previously described (ie increasing proportion of energy supplied by VRE).

These bases for the model types are described below together. This is followed by a more detailed description of the models.

Model Type - 2018/19 to 2046/47

Least-cost models (also referred to as linear program optimisation models) minimise (or maximise) an objective function subject to a set of constraints.

In electricity markets, such models minimise the future capital and operating costs subject to all the physical constraints of the power system, capital and operating costs, and other matters such as emission limits or costs. It is understood that this type of model was used by AEMO in much of the modelling undertaken for the 2018 ISP.

Least-cost models

1. LCMs minimise an 'objective function' subject to constraints:
    a. Constraints written as: a1 x Var1 + a2 x Var2 + ... <=RHS
2. Each year of the study period is divided into a number of sectors. Examples are:

   a. Three seasons x two day types x six periods per day (36 periods per year); and
   b. Four seasons x 12 periods per day (load duration).
3. Objective function expresses the NPV cost of supplying the load over the study period: $\sum$ capital costs + $\sum$ operating costs
4. Constraints apply to each time sector and include:
   a. Generation = demand; and
   b. flow on an interconnector < limit.
5. The solution is twofold:
   a. primary solution: values of Var1, Var 2 … (decision variables); and
   b. dual solution: shadow price for each binding constraint - change in objective function cost of increasing the RHS by I unit.

A least-cost modelling approach was not suitable for use in this study for reasons that include:

1. They are not time-sequential and do not address the cumulative production of energy over time (that is essential for storage operation);
2. They do not incorporate variability such exhibited by VRE and demand;
3. They do not incorporate generator bidding. Price reported are based on generator costs clearing the market similar to SRMC bidding);
4. They do not provide for operating rules that may apply through time t0 be included;
5. Spot prices outcomes are not suitable for asset due diligence purposes; and
6. Assumptions need to be made regarding the amount of generation reserve required.

Market simulation

Market simulation is a time sequential approach that provided for all the issues noted above to be addressed.

Market simulation is the preferred (and almost exclusively used) approach to generator due diligence modelling and was the approach used in this study for the period 2018-19 to 2046-47.

The model used was the PROPHET market simulation model.

Model Type - 2047/48 -2074/75

The level of uncertainty post 2047/48 (and it could be argued before then) includes the level and profile of demand, transmission, NEM market rules, capital and commodity costs and so on. This means that detailed simulation of the NEM is likely to have a level of uncertainty that would 'swamp' the detailed results.

What is clear is the basis of all the scenarios has demand increasingly being supplied by VRE with firming being provided by storage and gas generation. The basis of the modelling was to ascertain the necessity and value of storage through its opportunity cost. This is a standard approach to valuing long-life assets.

The analysis was undertaken using the FAM which was developed specifically for this modelling exercise.

4.5.3 PROPHET electricity market model

The PROPHET electricity market model was used for the detailed market modelling over the period 2018/19 to 2046/47.

The PROPHET Simulation Model is an advanced simulation model of common clearing price electricity markets. It is used by many parties in Australia (portfolio generators and retailers) and has been used in many major assignments in Australia and overseas.

PROPHET simulations were used to simulate the NEM in terms of:

1. Physical operations (generator dispatch, generator outages, transmission lines flows);
2. Market operations (generator offers and demand bids, market clearing and regional spot prices determination, settlements); and
3. Bidding behaviour of participants.

The representation used in the model included:

1. The time step of the simulation was 30 minutes. Modelling using 5-minute time steps was also undertaken;
2. All generator units individually represented – unit size, ramp rates, mingen levels, heat rates, forced outage rates, planned maintenance etc;
3. Regional demand net of rooftop PV;
4. Rooftop PV development;
5. Individual hydro generators (also referred to as dispatchable renewable generators);
6. Interregional transmission lines with AEMO provided flow limits;
7. Batteries with offers (to discharge) and bids (to charge);
8. Gas and coal costs;
9. Solar and wind generation based on historical half hourly generation;
10. Regional demand levels based on half-hourly profiles;
11. Rooftop PV and distributed storage individually represented;
12. Pumped-storage pump existing and proposed. These plants buy and sell in the NEM with respective water storages monitored;
13. Snowy 2.0 representation as previously detailed;
14. Existing (portfolio) ownership represented and assumed to continue in the future;
15. Generator portfolios offer to sell in the NEM based on their consumer market share (which establishes supply commitments and risk); and
16. Reliability setting of the Market price Cap (***MPC***) and (Cumulative Price Threshold (***CPT***).

The steps involved in the PROPHET model included:

1. The model was benchmarked to the NEM as currently operating through an explicit representation of trading entities, contracts and other matters;

2. The benchmark structure was modified through the simulation to represent the changing NEM;
3. Changed assumptions were included as required;
4. Internal consistency was maintained through all simulations (ie economic opportunities for new generators are acted on);
5. Internal review of input and output files as part of the quality control process; and
6. Provision of results in agreed formats.

4.5.4 Firming Analysis Model

The MJA FAM is a proprietary model, built in-house, with its objective being to hypothesise the amount of firming required under various levels of VRE penetration in an assumed region (or regions) of the NEM.

Given the uncertainty around the likely structure of generation capacity in the NEM post-2047, and the expectation that VRE will make up a significant proportion of total energy generation, the FAM was designed to enable scenario analysis at various market levels of VRE to estimate the requirement for gas and storage firming capacity.

The analysis showed that at low levels of VRE there is enough excess thermal, dispatchable capacity in the market that the need for firming is very low. As VRE increases, however, the need for firming increases exponentially such that at 100% VRE (with no thermal generation in the market, including no gas peaking for firming) the need for firming in the form of storage (batteries or PHES) is very large. The FAM looks to quantify these firming requirements for various regions or combined regions in the NEM, and at various levels of VRE.

Most of the modelling looked at the combined region of NSW-SA-VIC due to the proposed interconnector upgrades and our expectation that those regions (including Snowy 1.0 and 2.0) will increasingly act more like a 'super-region' rather than individual regions (states/territories). Sharing firming capacity between regions reduces the total amount of storage required, just like the current VIC-SA interconnectors currently reduce the need for firming South Australia's high level of wind generation.

Finally, given gas peaking and storage (either batteries or PHES) can be substituted for each other, the FAM also enables the trade-off between levels of gas and levels of storage to be analysed at a given level VRE penetration. For storage, this includes the requirement in terms of both capacity (MW) and hours of storage (ie the MWh that can be stored).

4.5.5 Economic criteria

General

Simulation modelling over the period 2018-19 to 2046-47 principally involved the closure of coal plant and the development of VRE, gas and storage plant.

This was done on the assumption Snowy 2.0 enters and does not enter. Snowy 2.0 economics was not a criterion (for Snowy 2.0 to enter) in the 'with Snowy 2.0' model run cases.

The development of VRE and gas generation (Open-Cycle Gas Turbine (***OCGT***) and CCGT) was based on rational economics. New assets enter when economic and assets retire when not economic. The criteria for these plants was the requirement to cover their fixed and operating costs through revenues obtained in the spot market.

Battery storage

The development of battery storage is complex. The issue with battery storage is that battery storage (with limited hours of storage) is and will likely continue to enter despite batteries currently not being economic and an outlook (based on the forward cost curves) that batteries will not be economic until past 2040 (for storage with hours of storage over about 2 hours). We note the following

Appendix 'Battery Economics and Entry' of *Modelling Snowy 2.0 in the NEM Appendices (MJA)* examined the economics of batteries in the NEM. The analysis showed that, on the forward outlook of costs, batteries will not be economic at storage level near over 3 hours.

The section 'Firming under High VRE' showed that:

1. Firming services will require a substantial amount of storage and/or gas fast start generation; and
2. A storage facility requires at least 24 hours storage to support the sale of a capacity-type contract.

On the basis that batteries will be required to support VRE entry, the analysis concluded batteries will likely enter through the following means:

1. Limited storage with a solar or wind generator to smooth the VRE profile;
2. Government sponsored for reliability and security; and
3. By regulation. This would require VRE enter to be with a battery for daily smoothing (such as to address minimum load issues) and security post-2030. This would be influenced by other storage such as Snowy 2.0.

4.6 Post-2047 - Modelling firming under high VRE

The detailed market simulation modelling stopped at 2047 as simulation past this date (30 years into the future) was not considered appropriate given the significant level of uncertainty that exists.

The approach post-2047 was based on the opportunity cost of Snowy 2.0. The FAM model was developed to ascertain the opportunity value of storage under a spread of VRE supply outlooks post 2047. This opportunity value was used to extend the net market revenues from the simulation modelling post-2047.

This chapter characteristics the NEM under various levels of VRE and establishes the firming requirements in terms of storage and dispatchable generation. These requirements are found to be substantial at a level of VRE exceeding 80%. The opportunity value provided a floor value and was used to support the assumptions of revenues post 2047.

4.6.1 Approach to Snowy 2.0 valuation post-2047

The 50-year economic life of Snowy 2.0 means that Snowy Hydro revenues post-2047 are an important component of asset value.

The FAM model was used to quantify the opportunity value of Snowy 2.0 in the NEM post-2047.

The approach to this was as follows:

Combined SA-VIC-NSW region

The modelling undertaken was based on a combined SA-VIC-NSW region. This recognised that transmission developments (as outlined in the ISP) will result in these regions being more connected than in the past;

VRE energy production variability

Given that the amount and nature of firming is to manage to the variability of VRE energy production, the first step was to quantify the variability of VRE. This involved a review of the variability of VRE over time periods of daily, weekly, monthly, seasonal and annual. This variability is the key factor determining firming and storage needs (hours of storage) and the need for thermal generation.

Trade-off in firming provided by storage and dispatchable generation

The FAM model was used to determine the trade-off between storage and dispatchable generation over a year at different levels of VRE. This indicates the economics and opportunity cost of storage.

This was done for the hypothetical case of a system 100% supplied by VRE and then for lower levels of % VRE.

Comparison to the SA region

As a basis of comparing the finding of the modelling to actual market outcomes, a review of the situation in SA was undertaken. This comparison supported the modelling results.

Opportunity value

The opportunity value of Snowy 2.0 was determined by quantifying the least-cost replacement of Snowy 2.0 with firming provided by storage and gas generation.

At a higher level of VRE (ie VRE is supplying a high percentage of demand), the required storage levels become very large as they reflected the energy variability of VRE on a seasonal and annual basis. This indicated the economic limits of VRE generation.

The opportunity cost of Snowy 2.0 was undertaken on a conservative basis of firing VRE over periods of a month and the findings were presented as a floor in value.

The following sections present the findings of the above issues.

4.6.2 VRE variability

The purpose of this section was to characterise the VRE energy production variability over different time periods. VRE variability was investigated as follows:

1. On the SA-VIC-NSW combined region;
2. Using actual solar and wind generation traces (ie 30-minute production) for three years 2015, 2016 and 2017. Each year was represented by a combination of ten wind and solar traces in order that the diversity across the SQA-VIC-NSW combined region was included; and
3. Over different time periods ranging from a day to seasonal to yearly.

Monthly variation

The historical average capacity factor of the sample of ten wind and solar assets over the SA-VIC-NSW combined region is shown in the figure below. This figure shows the monthly capacity factor deviation from this annual average.

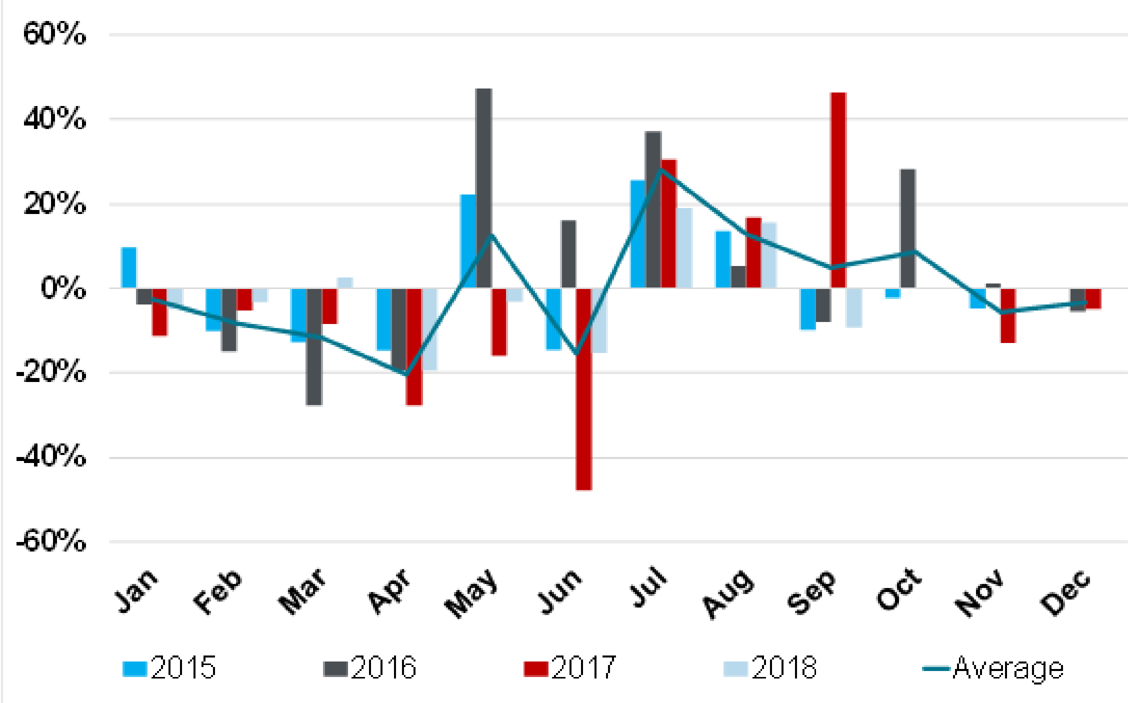


Figure 5: Historical Monthly VRE Generation Deviation from Annual Capacity Factor [Source: MJA]

The following are noted:

1. The average annual VRE capacity factor over these years was 31% (32% for wind and 24% for solar); and
2. There can be very significant monthly differences. For example, in May 2016 the average capacity factor for NEM VRE was 46%, compared to an

average capacity factor of 26% in May 2017. This variability would dictate the size of storage required over a year in a market 100% VRE supplied.

Variation over a year

The variation in VRE energy production over a year was quantified and illustrated as follows:

First by plotting the cumulative energy production over a year using the three SA-VIC-NSW production traces (ie. 10 traces from the year 2015, 2016 and 2017 years). The traces have been expressed as a percentage of their average annual quantity and assuming this is the demand level to be supplied (ie the demand is 100% supplied by this VRE). This is shown in Figure 6 below.

We observe that there is variation through the year and that over a year the variation was that the 2016 trace produced about 10% more energy over the year than the other traces.

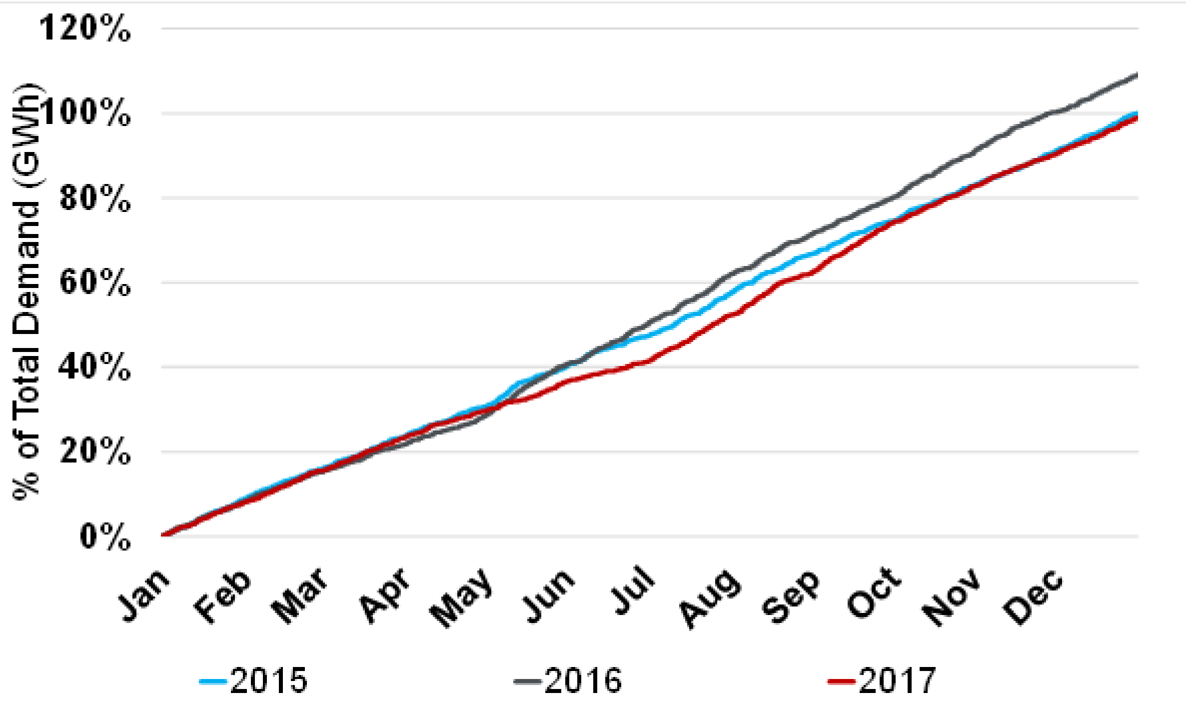


Figure 6: Cumulated VRE Energy Production over a year [Source: MJA]

The inter-year variations of energy production were identified by determining the level of energy that would be required to be stored (and discharged) through the year based on the VRE energy production profiles above. To remove the impact of annual production level, the three VRE 30-minute production profiles were all scaled such that each had their annual energy production equal annual demand (thus having demand assumed to be 100% supplied by this VRE). This is shown in Figure 7 below, which plots energy in store expressed as a percentage of annual system demand.

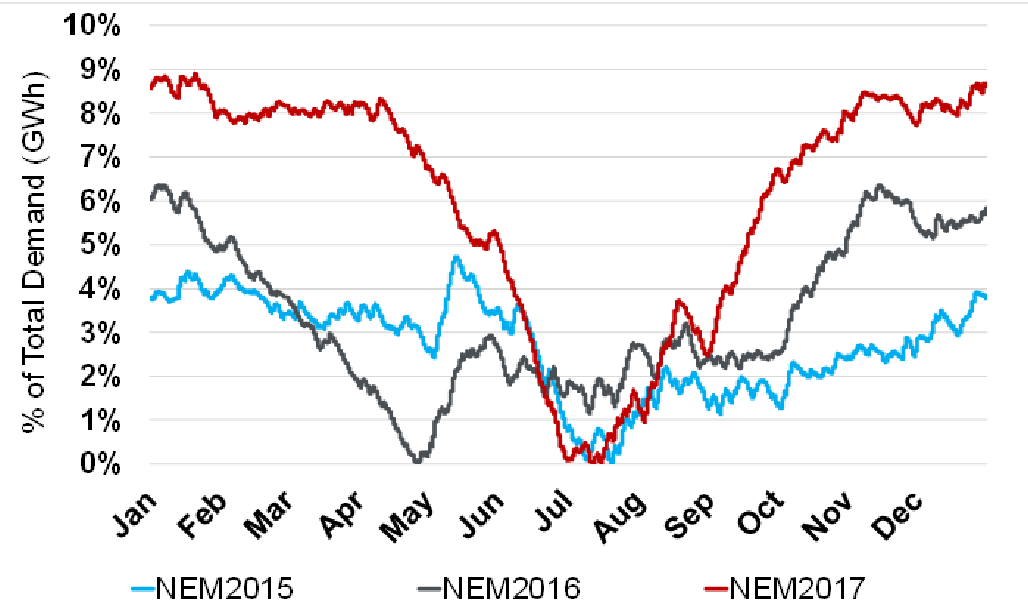


Figure 7: Seasonal Energy Variability shown by Battery Charging Patterns [Source: MJA]

From Figure 7 the following are noted:

1. The differences in seasonal and annual profiles are evident;
2. Based on the 2017 VRE production trace, storage equal to about 8.9% of annual demand is required to have the VRE generation allocated to when it is required. For the 2015 trace this is about 6.4%; and
3. At a storage level of 12 hours, these energy storage numbers equate to capacity required of 20 to 37 times the maximum demand. Clearly, this is not a viable scenario.

The above analysis concluded the following:

1. There is significant seasonal influence on VRE output. Solar capacity factor is on average 15% higher in summer than winter (35-45% higher generation) and wind is also slightly higher in summer than winter;
2. As VRE in the NEM is currently small (except in SA) and there is surplus thermal plant to 'absorb' the seasonal variation in VRE, this seasonal influence is not evident. However, the trend is for solar to become a much greater share of VRE in the coming years. This will create a significant seasonal variation in VRE production going forward;
3. There is also significant variation in annual VRE production, differing by as much as 9% between years (total GWh generated). Such a variation would need to be managed as the penetration of VRE increases; and
4. The significant energy transfer requirement strongly indicates that deep storage (ie storage with a large energy storage capacity) will be required.

4.6.3 Trade-off between storage and dispatchable generation - annual modelling

The section describes and presents the results of modelling that used the FAM over a year.[12] By modelling over a year the modelling incorporated VRE energy production variability between seasons.

The modelling was used to:

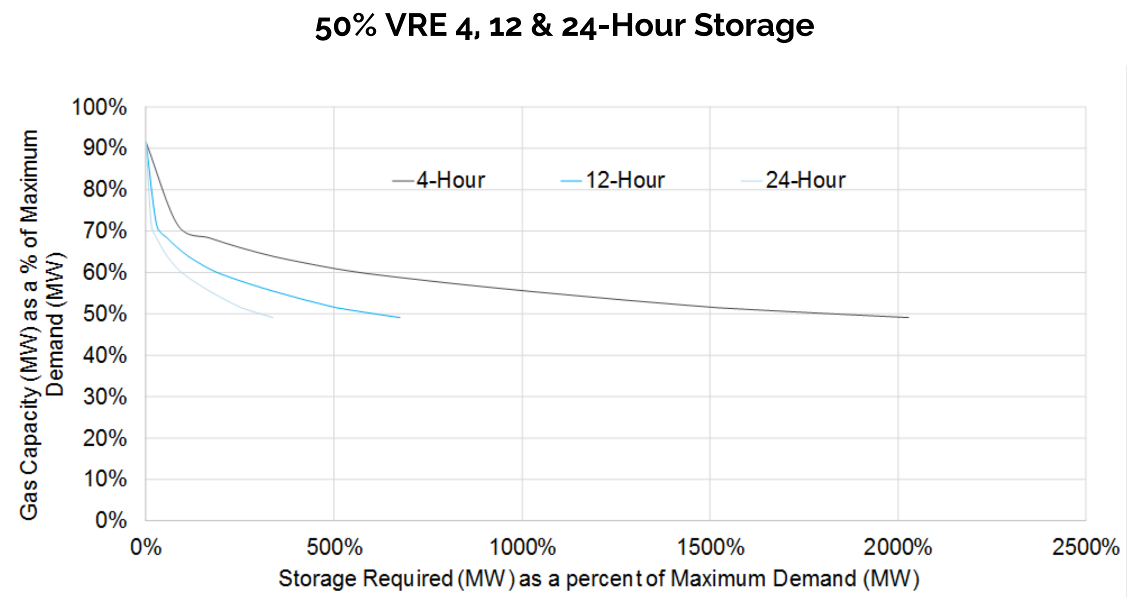
1. Quantify the firming needs in the SA-VIC-NSW combined region (assuming no connection to Queensland or Tasmania) at various level of VRE penetration; and
2. Quantify the trade-off between storage (MW and storage energy) and dispatchable generation.

The modelling was undertaken over a sample year (using the VRE traces presented in the previous section) under two levels of assumed VRE penetration, two cases of the mix of solar and wind generation, and various level of storage hours. The cases modelled are shown in the table below, and the results are presented in the figure that follows. For simplicity, dispatchable generation is referred to as gas generation.

% Demand supplied by VRE	Solar/wind generation mix	Battery storage (hours)
50%	25%/75%	4, 12 and 24 hours
100%	25%/75%	4, 12 and 24 hours
70%	50%/50%	12 hours

Table 7: Cases Modelled using the FAM Model

The level of gas generation in each case is that to supply that component of demand not supplied by VRE (ie when VRE is supplying 50% of demand, gas is supplying the remaining 30%).



[12] The FAM model determined the amount of storage capacity needed given the percentage of demand supplied by VRE, amount of dispatchable generation, and storage hours.

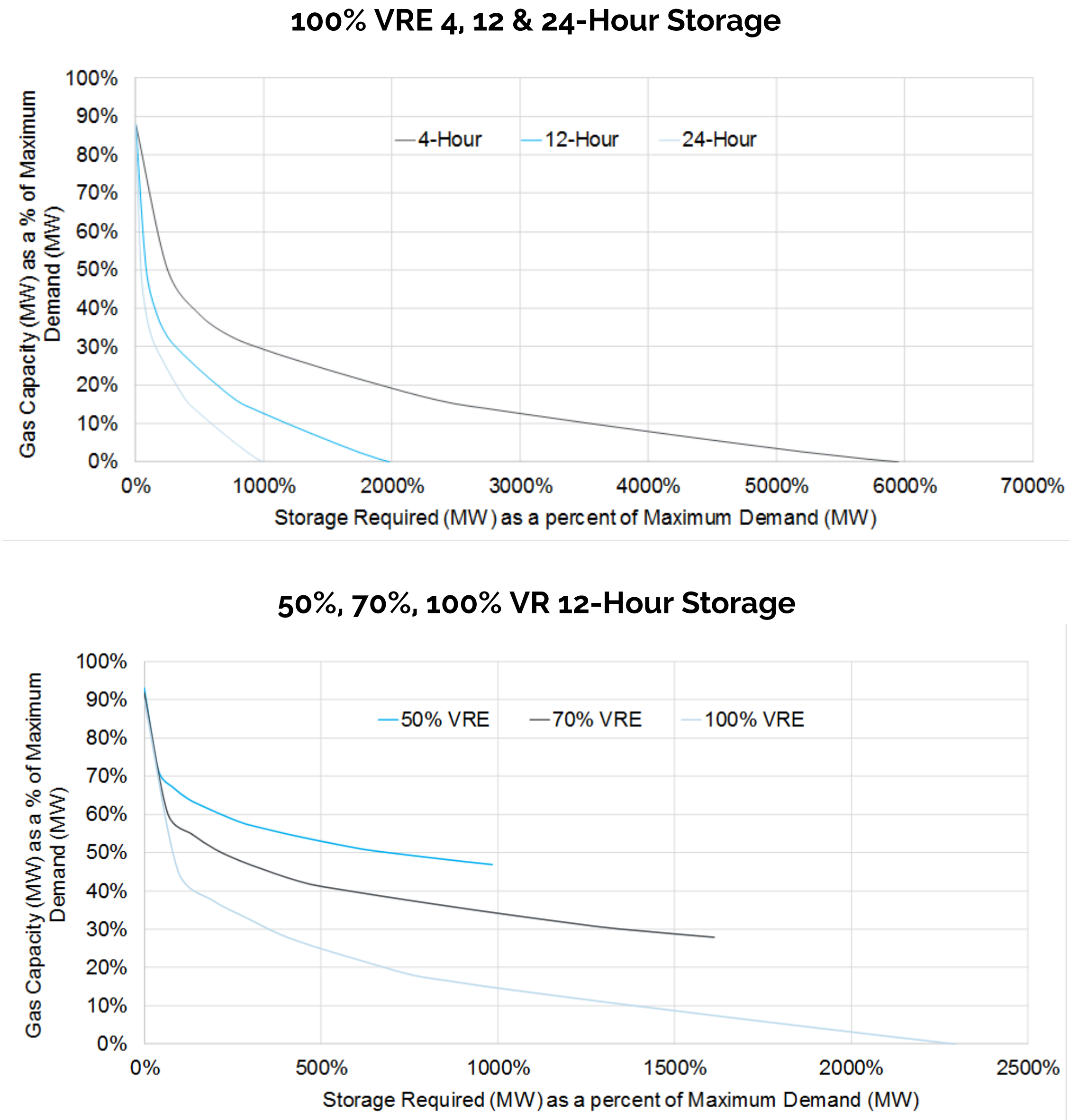


Figure 8: FAM Model Results – Trade-off of Dispatchable Generation v Storage [Source: MJA]

Figure 9 summarises the results presented separately for the three different years of VRE (2015, 2016 and 2017). Shown are:

1. The installed capacity of storage (MW) required as a percentage of maximum demand to meet system reliability. This has assumed that with VRE provided a level of firm capacity given by 7% of its installed capacity;
2. The hours of storage needed based on that level of installed capacity (MW).

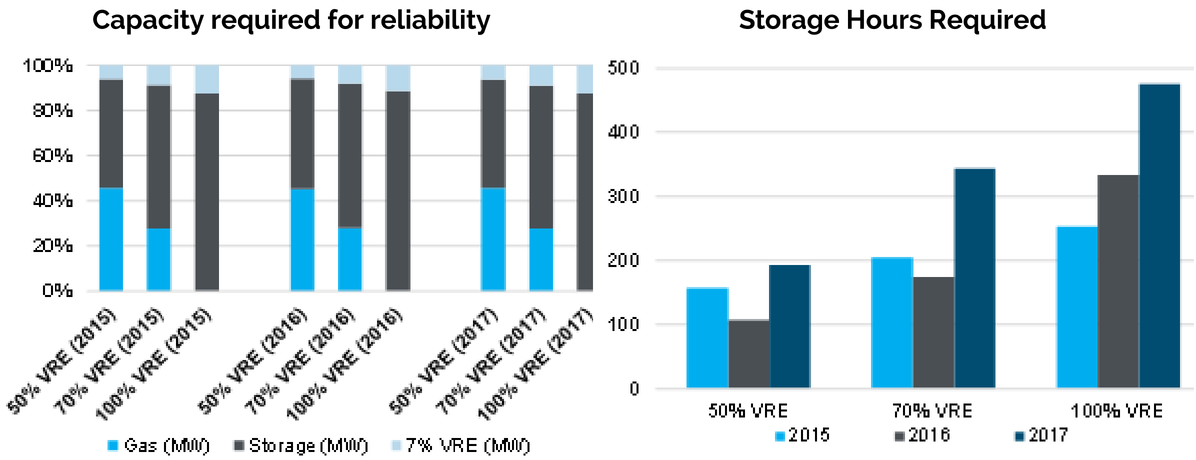


Figure 9: Minimum Storage to Capture VRE Variability over a Year [Source: MJA]

Note that this 'yearly modelling' assumed a completely closed system with no alternative means to balance supply-and-demand other than through firming. It assumes no interconnectors, no demand-side management, and no other temporary generation supply sources. Given the dominant impact of seasonality on VRE variability, the results above showed that a very significant amount of storage would be required under this scenario. This is, therefore, more of an extreme or high case scenario.

4.6.4 Trade-off between storage and dispatchable generation – monthly modelling

This section presents the results of FAM modelling used to quantify the storage needs in the SA-VIC-NSW combined region at various levels of VRE penetration over monthly periods. By limiting the modelling to a month, the modelling excluded VRE energy production variability between seasons.

The results of this modelling provided a more conservative, or 'floor level' scenario. In other words, it removed the extreme seasonality observed through the year and looks at firming/ storage required to manage month to month variations in VRE.

Figure 10 summarises the storage needs to capture VRE variability within a month:

1. The left graph shows capacity as a percentage of the total capacity required for reliability (with VRE presented as 7% of its installed capacity); and
2. The right graph shows the storage hours required.

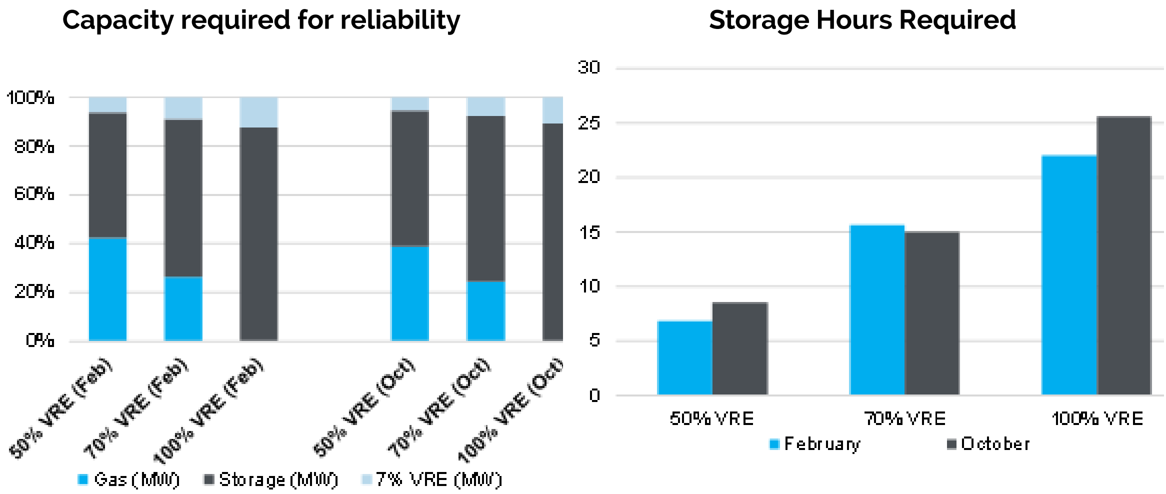


Figure 10: Minimum Storage to Capture VRE Variability within a month [Source: MJA]

4.6.4 Firming – gas/storage trade-off

The key finding is that, under a 100% VRE scenario, the system would require about a day's storage (24 hours) with an installed capacity of over 90% of maximum demand to manage the variation of VRE over a 4-week period. This excludes major lulls in wind or solar generation that can occur.

The previous section has presented the storage needs on the basis of the percentage demand supplied by VRE. Dispatchable generation was also used for firming and there is an economic trade-off between storage and dispatchable generation.

The following observation are made:

1. Variability requires that firm capacity be provided. Firm capacity requires at least 1 day and more possibly 2 days of storage to provide a firm capacity-type contract in a market that is reliable;
2. The higher the percentage of demand supplied by VRE the greater the spill energy and the greater the cost and benefits to capture this spill energy;
3. As VRE increases the economics strongly moves to increased gas generation and increased VRE spill. Small storage cannot address this spill as it is the consequence of seasons with very high spill while other seasons have no spill and are short capacity;
4. As installed gas capacity (MW) increases, the storage requirement decreases rapidly:
    a. For example, for a 50% VRE system each small increase in gas (MW) results in a material reduction in storage requirement until gas (MW) is about 70% of maximum demand (refer to Figure 9); and
    b. The modelling showed this happened at a gas capacity factor of about 41-42% (compared to a CF% of almost 60% for gas capacity of

~50% of maximum demand) and spill reached about 3.5% of total generation (GWh).

5. For a 100% VRE system, the introduction of a small amount of gas firming significantly reduces the storage requirement until gas (MW) is about 40% of maximum demand (refer to Figure 10). This happened at a gas capacity factor of about 35-40%, but with spill reaching about 25% of total generation (GWh).

4.6.5 Review of SA

A review of SA in 2017 showed the following:

1. For calendar year 2017, SA generated 34% of total GWh from wind. The rest was gas/thermal (62%) and importing via the interconnectors. Net interconnector flows (net of exports) were 4% of total State energy, however, its total gross imports were 14% of total energy (ie exported 10% and imported 14%);
2. SA does not currently have as much battery storage (MW or MWh) as MJA's modelling would suggest it needs based on its level of VRE penetration. The primary reason SA can function adequately without significantly more storage is due to its use of the interconnectors (Heywood and MurrayLink). SA is essentially using the interconnector like a giant battery, importing when it needs (discharging) and exporting excess VRE production (charging). To balance the market without the interconnector, SA would have needed storage of over 1,200 GWh in 2017. If this was 4.2-hour storage similar to the Tesla batteries used as Hornsdale, this would have required over 285,700 MW of installed capacity – versus the mere 100 MW of Hornsdale; and
3. Maximum Operational Demand in SA was 3,046 MW over the year, and it had (still has) about 3,000 MW of installed dispatchable gas/thermal capacity. Hence, in addition to using the interconnector, SA has almost enough dispatchable capacity to meet maximum demand. Our modelling of storage needs under high VRE assumes a reduction in thermal generation with the underlying desire to reduce emissions and generate a greater proportion of energy from renewable sources. It also assumes there is no excess thermal/ dispatchable capacity. As shown in the results of the FAM, if we introduce significantly more gas capacity into our modelling, and reduce capacity factors, then the storage requirement does come down.

4.6.6 Conclusions – Snowy 1.0 and Snowy 2.0 revenue profile post-2027

The modelling of the firming and the role storage will play under a market of high VRE showed that the requirements for storage are substantial. The modelling also showed that under such conditions the value of storage increasingly becomes commensurate with the hours of storage.

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This has shown at a minimum, Snowy 2.0 would replace 2,000MW of dispatchable storage capacity, and would replace an amount of energy storage (GWh) that would move to days of storage as the percentage of demand supplied by VRE increased to high levels.

Based on our long-term forecasts of the cost of battery storage of various hours, we have estimated the implied annualised cost of 2,000 MW of storage of various hours of storage.

As a **conservative estimate** based on the monthly analysis presented in this chapter:

1. Storage of 6-8 hours is required for 50% VRE;
2. Storage for 15-17 hours for 70% VRE; and
3. Storage of about 24 hours for 90% VRE.

The analysis shows that this is conservative, such that if sufficient storage was installed to allow for annual variations and seasonality in a fully closed system, the hours required would be materially more.

The NPV of these annualised storage costs between 2047 and 2075 is shown in Table 8.

% VRE	50%	70%	90%
Hours of storage	8	16	24
NPV of annualised costs*	$1.15 bn	$1.76 bn	$2.37 bn

Table 8: NPV of Annualised Storage Costs – 2047 to 2075

Snowy 2.0 would provide the equivalent value of at least 32 hours in the 70% case and 4 days in the 90% case.

Not all of this value would be captured in spot prices, and hence reflected in revenues post-2047, with Snowy 2.0 capturing some value through contracts in later years.

Principles for establishing S1.0 and S2.0 net spot market revenues post 2047

From the modelling undertaken a set of principles were developed on how to extend the results of the simulation modelling past the final year modelled of 2046/47. The principles developed are based on the following:

1. To link the values to the last years of simulation modelling; and
2. To be conservative in the estimate recognising the uncertainties that exist.

Rules of S1.0 and S2.0 net spot market revenues post 2047

From this the rules for the revenues and associated value of S2.0 post-2047 were developed as follows:

1. For the Base Scenario, extend the average of the last three years of the simulation modelling to 2075. This recognises that there is no emissions policy and the trajectory of emissions may change;
2. For all scenarios that exclude a limit of emissions (which was all except for the Low Emissions Scenario) the profile of S1.0 and S2.0 net spot revenues will linearly transition to the level given by the base scenario in 2060. This recognises that the end point of these scenarios, under the same policy

framework, will be very similar and that the relativity of value, both between time periods modelled and between scenarios, shows to be maintained; and

3. For all scenarios that include a limit of emissions (which is only the Low Emissions scenario) the profile of S1.0 and S2.0 net spot revenues will linearly transition to the level given by the base scenario in 2060, plus an increase to recognise the increased value of storage when emissions are constrained. For the 80% emissions limit by 2050, the increase in value over the base case is taken to be 20%.

4.7 Storage and Firm Capacity

The previous section presented the value and requirement of storage in providing physical firming of VRE generation. Firm capacity is also reflected in the risk of forward agreed prices for wholesale energy sales, such as through swap and cap contracts. The ability for energy purchasers (such as retailers) to have access to competitively priced contracts is an essential part of the NEM.

This section assesses the firmness of storage capacity as a function of storage hours and compares this to the hours derived through a consideration of physical firming presented in the previous section.

The assessments of the storage hours required to supply firm capacity in the previous and this section are similar.

The number of hours of continuous operation available to a storage facility provides for increased value in spot price arbitrage, firming VRE and selling capacity or load-following contracts. In addition to this, the NEG reliability arrangements, should these be introduced, would provide for potential value in the provision of firm dispatchable capacity.

In providing firming and capacity-type contracts, the risk for a storage facility with limited hours of storage is that it has no capacity to supply energy when required. This risk is a function of storage hours.

This can be divided into normal market operation and contingency events.

4.7.1 Storage hours - normal market conditions

Analysis was undertaken to investigate the value storage hours would provide under normal market conditions (ie under spot price outcomes that have occurred). The was undertaken assuming the storage facility was a battery with a stated number of hours of storage as follows.

Using historical 30-minute energy spot prices for each state over the period 2000 to 2018 (YTD) the ability of a battery to 'cover' the difference payments associated with providing a $300 cap contract at its rated capacity (MW) was modelled. This was done for batteries with storage of 2, 4, 6, and 8 hours. The analysis had the battery operate (buy and sell) over each year accounting for the charging time required.

The results of this analysis were expressed as follows:

1. Fair cap contract value: this is the value of a $300 cap contract in that state and year (ie what a cap contract would pay). This is the reference about which the performance of the battery was assessed; and
2. Captured Value: this is the proportion of the cap contract payments that would be covered by battery discharge (ie generation);

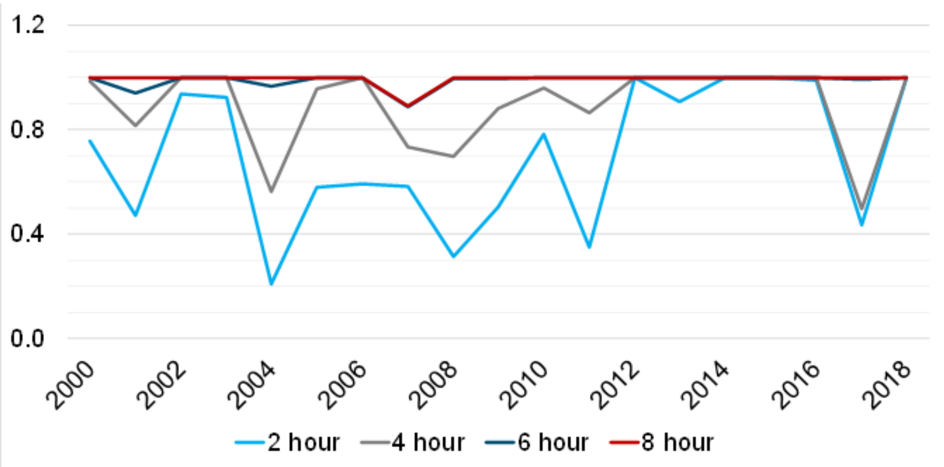
Missing Value: this is the payments that would be missing by using a battery of 2, 4, 6, and 8 hours to cover a $300 cap contract (ie the $300 cap contract payments that the battery would not cover).

The relationship between these is as follows:

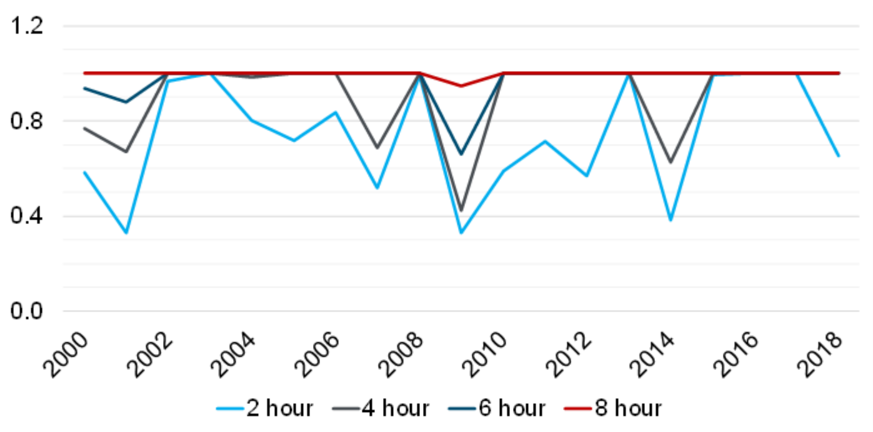
Captured Value + Missing Value = Fair Cap Contract Value

The results of this modelling, expressed as the ratio of Captured Value to Cap Value, are shown in Figure 11 below. This is shown for NSW, VIC and SA. As expected, the greater the storage hours the higher the Captured Value.

NSW



Victoria



South Australia

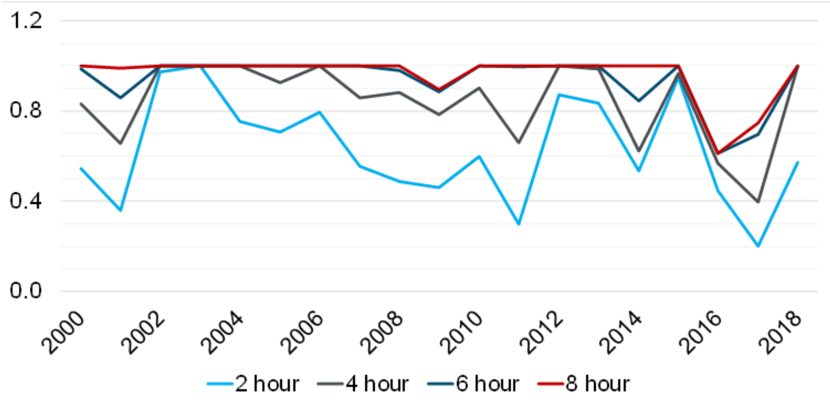


Figure 11: Historical Analysis – Proportion of $300 Cap Value Captured by a Battery with storage of 2, 4, 6, 8 Hours[13] [Source: MJA]

From this analysis the historical risk/exposure of providing a $300 cap contract using limited energy storage was determined and expressed as the percentage of cap payments not covered by battery generation. This was determined as the annual average, annual maximum and annual minimum over a number of years and regions for each storage level (2, 4, 6, 8 hours). The results are shown in Table 9 below.

	Average	Maximum	Minimum
2 Hours	37.9%	79.0%	0.0%
4 Hours	15.3%	44.6%	0.0%
6 Hours	5.5%	26.5%	0.0%
8 Hours	3.1%	17.4%	0.0%

Table 9: Historical Exposure to $300 Cap Payment using Limited Energy Storage[14] [Source: MJA]

4.7.2 Storage hours – contingency events

Energy security requires long-term storage to address potential capacity shortages due to major plant outages and/or limited energy production. This equates to a level of storage to have a battery provide the same contribution to generation reliability as an OCGT plant. The historical prices used in the above analysis included periods of administered pricing which disguised somewhat major events that can occur.

The CPT provides a guide as to the level of storage required for risk management and security. The table below shows the hours and days at the average price shown before the CPT is reached (assumed to be $200,000) after which administered pricing would commence. This is shown in Table 10 below.

[13] This is the percentage of cap payments that is covered by battery generation.
[14] This is the percentage of cap payments not covered by battery generation.

Average Price	Hours	Days
$14,000	14	0.60
$10,000	20	0.83
$5,000	40	1.67
$1,000	200	8.33
$300	667	27.78

Table 10: CPT [Source: MJA]

This suggests a storage of at least 1 day (24 hours) would be required to provide a similar level of service as a cap contract.

4.7.3 Comparison to physical firming requirements

The previous section identifies that as a **conservative estimate** (based on the monthly analysis) that:

1. Storage of 6-8 hours is required for 50% VRE;
2. Storage for 15-17 hours for 70% VRE; and
3. Storage of about 24 hours for 90% VRE.

We also note that this is for normal conditions and does not include wind lulls etc

The assessment of storage required to provide a firm cap contract (presented in this section) shows that the amount of storage required is measured in days, based on protecting prices in the order of $5,000.

This shows that the two approaches to valuing storage in the NEM are consistent.

4.8 NEM scenarios and assumptions

4.8.1 General

Assessing the economics of Snowy 2.0 required that the operation of Snowy Hydro (Snowy 1.0 and Snowy 2.0) be modelled under a range of potential NEM scenarios that included water inflow conditions over the study period. These scenarios were populated with assumptions previously presented. This section presents and describes the scenarios modelled.

4.8.2 Scenario development

In the context of the MJA Report, a scenario is an internally consistent description of the factors that influence the development of the NEM and the manner parties respond to these factors. Example of these factors are economic growth, technology costs and so on.

The scenarios were developed based on a consideration of the factors that would influence the spot market revenues obtained by Snowy Hydro (Snowy 1.0

and Snowy 2.0). The 56-year study period meant that the fundamental drivers of market change were required to be identified and explicitly accounted for.

The factors that would influence the spot market revenues obtained by Snowy Hydro (both positive and negative) included the following:

1. Electricity demand growth;
2. EV uptake;
3. Emissions abatement policy beyond the (non-legislated) 26% reduction by 2030 (which is projected to be met based on current renewable generation development commitments and announced coal power station closures);
4. Profile and regulation of coal plant closures (such as indicated in the Finkel review);[15]
5. Costs of storage (both in front of and behind the meter);
6. Costs of solar generation and wind generation;
7. Commodity prices – gas and coal;
8. Level of water inflows to hydro plant across the NEM including Snowy 1.0.

The structure of the scenarios modelled consisted of a Base Scenario and alternative scenarios that represented significant changes from the Base Scenario.

The Base Scenario was developed as the central scenario. The basis of this scenario was as follows:

1. Consistency with current energy policy and announcements;
2. Incorporation of the most likely assessment of economic condition and costs;
3. Developments and market operations consistent with rational economics.

The scenarios are intended to represent a balanced spread of outcomes that account for the potential changes that can occur in the NEM.

See *Supporting Chapter Nine* for more.

4.8.3 Percentage of renewable generation

The modelling result reported on the percentage of demand supplied by renewable generation. The basis of this calculation is as follows.

The calculation of the percentage of renewable generation was undertaken on the same basis as reported in the Large-scale Renewable Energy Target (***LRET***). The basis of Calculation of % of renewable Energy used in the LRET was as follows:

$$Renewable\ Generation_{\%} = \frac{LRET\ Target_{GWh} + PV_{GWh} + Pre\ 1997\ RG_{GWh}}{Australian\ Electrcity\ Demand_{GWh}} \times 100$$

Equation 1: Renewable generation percentage (LRET) calculation

[15] (Finkel et al. 2017).

The modelling for this study did not differentiate between pre- and post-1997 renewable generation. The basis for reporting the percentage of renewable generation in this study was as follows:

$$Renewable\ Generation_{\%} = \frac{Rooftop\ PV_{GWh} + \ Hydro_{GWh} + Large\ scale\ VRE_{GWh}}{Operational\ Deand\ _{GWh} + Rooftop\ PV_{GWh}} \times 100$$

Equation 2: Renewable generation percentage calculation

4.9 Base case scenario

This section presents the description of and modelling results for the Base Scenario. The Base Scenario uses assumptions largely from the AEMO Neutral Outlook of the 2018 ISP and deviates only in a small number of factors where there is considered reason to do so.

As such the Base Scenario represents a 'central case'. It is the case about which other model runs are undertaken.

The results are presented on a financial year basis. Presented are:

1. A description of the scenario including key assumptions;
2. Annual results on NEM wide outcomes in the with S2.0 and without S2.0 cases:
   a. NSW spot prices;
   b. Generator capacity by generator type that enters and leaves the NEM;
   c. The changes in generator capacity entry and exit that result from S2.0 entry;
   d. The percentage of generation that is renewable - by State and by type of renewable generation; and
   e. the total NEM carbon emissions with and without S2.0.
3. Annual results for S1.0 assuming S2.0 not developed, and S1.0 and S2.0 assuming S2.0 is developed:
   a. Generation and revenues of S1.0 and S2.0;
   b. S2.0 pumping and generation volumes, and average pumping and generating prices received; and
   c. Change in market benefits and Snowy Hydro profitability due to S2.0.

4.9.1 Scenario description and assumptions

The Base Scenario represents the NEM moving forward where wholesale electricity demand remains fairly flat, the amount of EV penetration is as projected by AEMO, rooftop PV continues along current trends and batteries are increasingly developed (which acts to reduce the 'duck curve' in demand' emerging in the NEM). This is the outlook provided by the AEMO Neutral demand outlook.

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The current policy setting of a 26% reduction in emissions by 2030 (compared to 2005 levels) remains, although there is currently no legislated abatement policy applying either before 2030 or post-2030.

The absence of any Federal policy (other than the existing LRET to 2020) means that just the Victorian (***VRET***) and Queensland (***QRET***) State renewable energy targets remain, and the base scenario assumes that both are met. Renewable generation that is currently under construction or committed to be built is built and this results in the Federal LRET being met.

Observed trends in lending policies and regulatory risk and costs mean that new coal generation is not developed. This is a significant outcome for the development of the NEM. The existing coal power stations remain in service based on the most recent information (which is close to that assumed in the AEMO ISP). There are no early retirements assumed in this scenario and expected and committed closures are staggered to minimise disruption. Loy Yang A and B are assumed to operate to a 60-year life.

Post-2030, VRE development is largely in response to the closing of coal power stations. In the absence of Snowy 2.0, firming of VRE is provided by the existing thermal generators, new gas generators, and batteries with 4 to 5 hours of storage. Batteries remain uneconomic at storage hours greater than 1 to 2 hours, although battery economics improves as battery costs reduce and VRE increases. The economics of batteries limits the amount of economic firming that can be provided by battery storage. Batteries are developed based on likely regulatory requirements, 5-minute price risk, and daily smoothing of VRE.

The major transmission upgrades of Riverlink, Bannaby link and Kerang Link are developed by 2025-26 regardless of S2.0 entry. The rationale for this is that Riverlink is considered committed, additional firm capacity to SA and Victoria requires Bannaby link, and the economics of VRE to replace the closing power stations require all the above developments to support the REZ required. Upgrades between NSW and Queensland are economic and proceed. These upgrades will limit interregional spot prices differences and will have SA-Vic-NSW act like a single region.

The cost of Basslink II and Tasmanian pumped storage (not known) and the absence of a price on emissions results in Basslink II not being developed.

The closing of the existing coal power stations and replacement with VRE and gas generation acts to reduce carbon emissions. The NEM would be expected to exceed at least a 60% emissions reduction by 2050.

The details of the assumptions are shown in Table 11.

Class	Assumption	Source
Snowy Hydro	Start Date & Capacity	2026 - 2000MW
	Snowy Inflows	Snowy Hydro Average Monthly Inflows
Economic	Economic Assumptions	AEMO ISP 2018 Neutral
	Bid Calibration	Base R06
	Policy	Current (QRET, LRET, VRET)
	Carbon Target	26% by 2030 - 70% by 2050
Demand & Rooftop PV	Demand - Annual	AEMO ISP 2018 Neutral
	Demand - EV	Included in Projection
	Demand - Traces	Fin Yr 2017/18
	Rooftop PV - Annual Capacity	AEMO ISP 2018 Neutral
	Distributed Storage - Annual Capacity	AEMO ISP 2018 Neutral
Generator specs and costs	Fuel Cost - Coal	AEMO ISP 2018
	Fuel Cost - Gas	MJA - Snowy Hydro
	Marginal Loss Factors	AEMO 2018/19
	Plant Forced Outage Rates	AEMO ISP 2018
	Unit Specifications	AEMO ISP 2018
	New Entrant - LCOE	MJA - Base
Links	Interconnector	MJA - Base
	Intraregional Constraints	AEMO
Generators	Generators - Scheduled Retire	MJA Profile 1
	Generators - Scheduled Existing	AEMO ISP 2018
	Generators - Semi-Scheduled Existing	MJA Renewable List
Storage	Non-Snowy Inflows	AEMO ISP 2018
	Non-Snowy PHES	Committed Only
	Battery - Regulation	MJA - Base
	Battery - Installed Costs	MJA - Base

Table 11: Base Scenario Assumptions [Source MJA]

The following sections present the modelling results of the Base Scenario.[16]

4.9.2 Base scenario - spot prices

Figure 12 shows the NSW spot price outcomes for the with Snowy 2.0 and without Snowy 2.0 cases.

[16] The base Scenario results are Run Version 6 (R06).

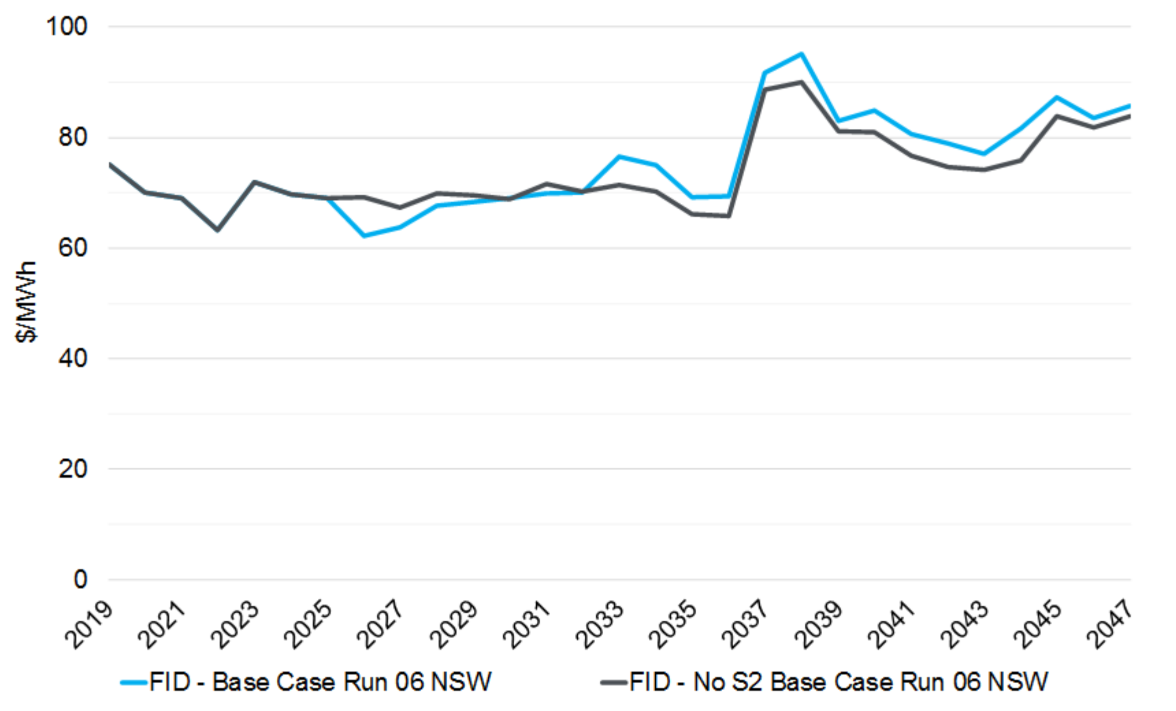

Figure 12: NSW Spot Prices $/MWh [Source: MJA FID Base R06 2018]

The annual profile of the spot prices (with and without S2.0) can be understood as follows:

1. The many curve inflections reflects the large 'lumpy' changes that occur due to the closures of the coal power stations;
2. The gradual increase in spot prices reflects:
    a. A reduction in the amount of lower SRMC coal plant operating and clearing the market;
    b. An increase in higher SRMC gas plant operating and clearing the market; and
    c. The reduction in the total 'mingen' levels of the coal plant that can result in low spot prices, and coal plant being forced to operate at or below this level.
3. The increasing level of VRE moderates the spot prices outcomes, but the increase in VRE generation is less than the reduction in coal generation output with the difference being provided by gas generation.

Snowy 2.0 operates in the market, as do all generators, with the aim of maximising the services provided and obtaining the market value for these services. The difference between the with S2.0 and without S2.0 spot prices can be understood as follows:

1. When S2.0 enters the market there is an oversupply of capacity resulting in lower spot prices. This is a time when:
    a. Developments have been undertaken by AGL and EnergyAustralia (***EA***) to address the closure of Liddell;
    b. A large amount of renewable generation would have entered the NEM and continues to do so in Qld under the QRET (that increases net power flows from Qld to NSW).

2. By about 2030 the market returns to the balance that would be the case without S2.0. S2.0 operates to shadow gas generation when generating resulting in slightly lower spot prices, and acts to increase demand (by up to 2000 MW) when pumping. The net effect is spot prices being similar with or without S2.0.

The change in the generation mix (including behind the meter rooftop PV) results in the pattern of daily NSW spot prices changing. This is shown in Figure 13 which shows the average 30-minute spot price profile in the years 2019, 2028, 2038, and 2047. The following are noted:

1. By 2028 there is a pronounced 'duck curve' in the spot price profile caused by solar generation (behind and in front of the meter);
2. The price sensitivity of prices during the period 9 am to 4 pm reduces post-2028. During this period the 'duck curve' does increase but the proportion of the time the market is marginal on coal and VRE remains closely the same;
3. Overnight spot prices are higher post-2028 due to storage (behind the meter, EV, and large-scale) charging during this period;
4. Evening peak demands increase due to the increased reliance on gas generation noting that storage also competes with gas generation during this time.

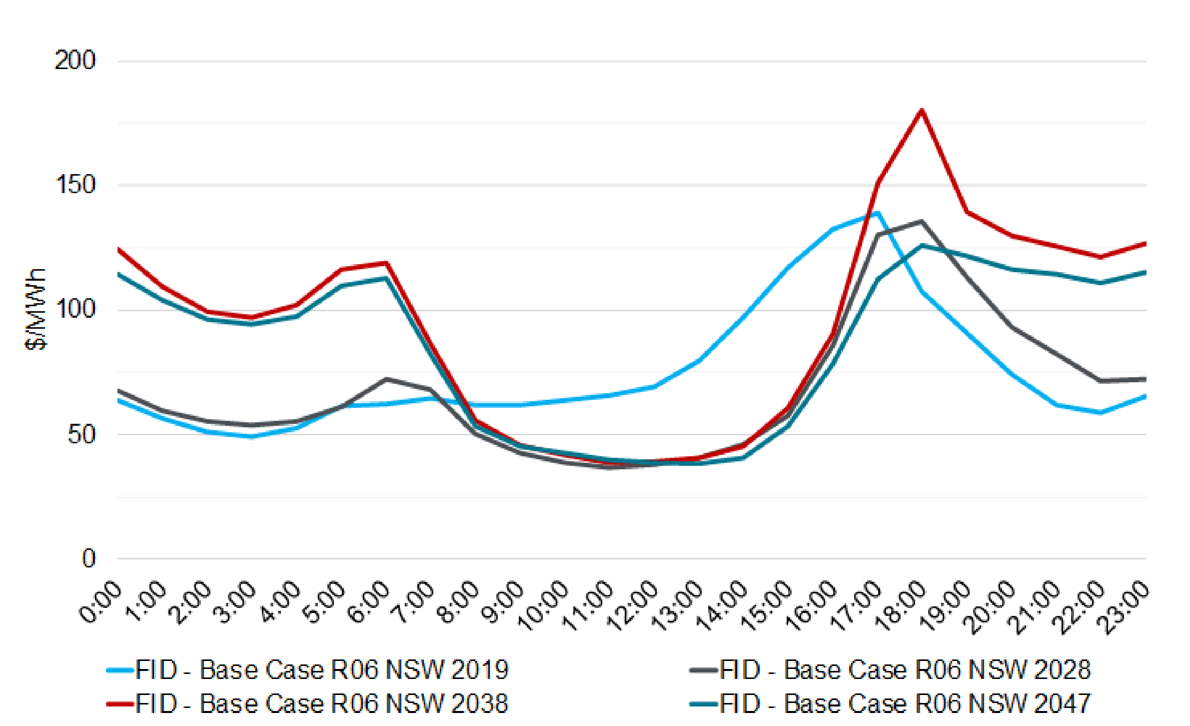

Figure 13: NSW - Daily Average Spot Price Profile - Sample Year $/MWh [Source: MJA FID Base R06 2018]

4.9.3 Base Scenario - installed generator capacity

The figures below present the installed capacity by generator type over the study period to 2047. These are shown as installed capacity for the whole NEM (Figure 14) and as firm capacity for the SA-Vic-NSW combined region (Figure 15).

Figure 14 shows the decrease in coal generation, increase in gas generation (CCGT and OCGT) and the large increase in wind and solar capacity. Battery storage enters from 2030 onwards based on the need to have this accompany VRE entry.

VRE generation is not firm capacity because it cannot be relied upon to be available when needed. A value of 7% of VRE capacity has often been used to translate wind generation capacity to the equivalent of dispatchable capacity. Presenting VRE generation in terms of the equivalent firm capacity provides for the level of firm capacity (and reliability of generation supply) to be gauged.

Figure 15 shows the installed generation with VRE capacity set at 7% of its nameplate rating and battery storage shown at nameplate capacity for the SA-VIC-NSW region. This excludes the capacity from Basslink and the NSW-Qld interconnector.

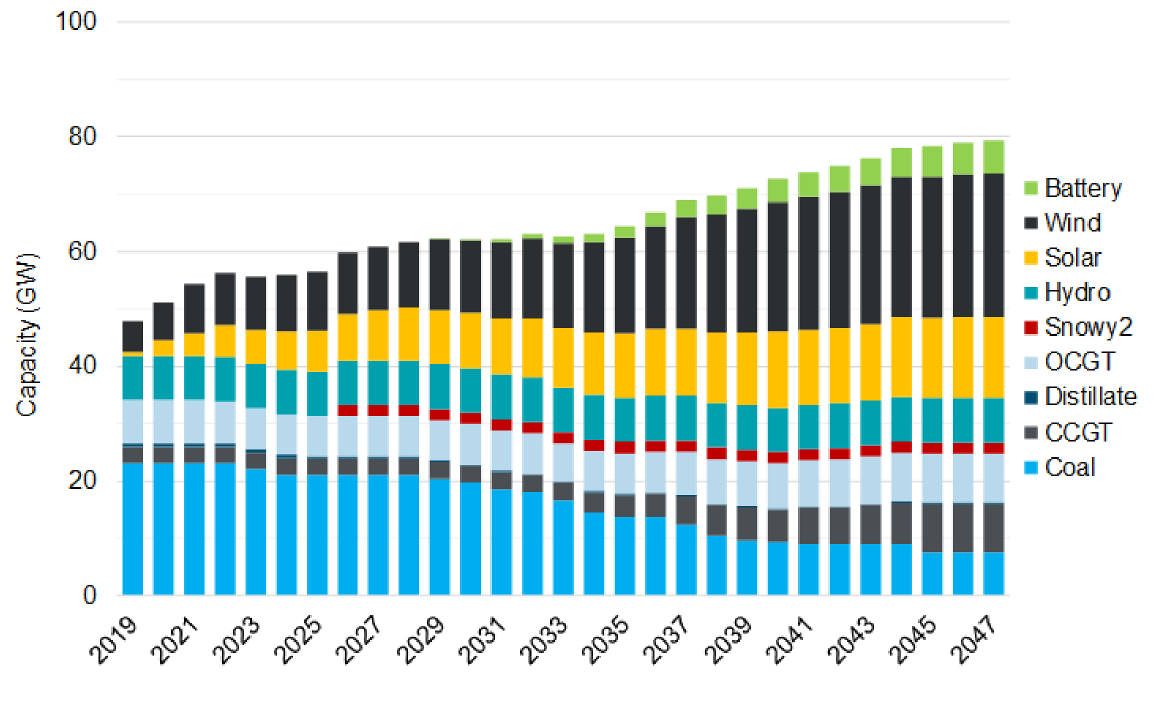

Figure 14: With Snowy 2.0 - NEM Generator Installed Capacity (MW)[17] [Source: MJA FID Base R06 2018]

[17] Installed capacity refers to the nameplate rating of generators.

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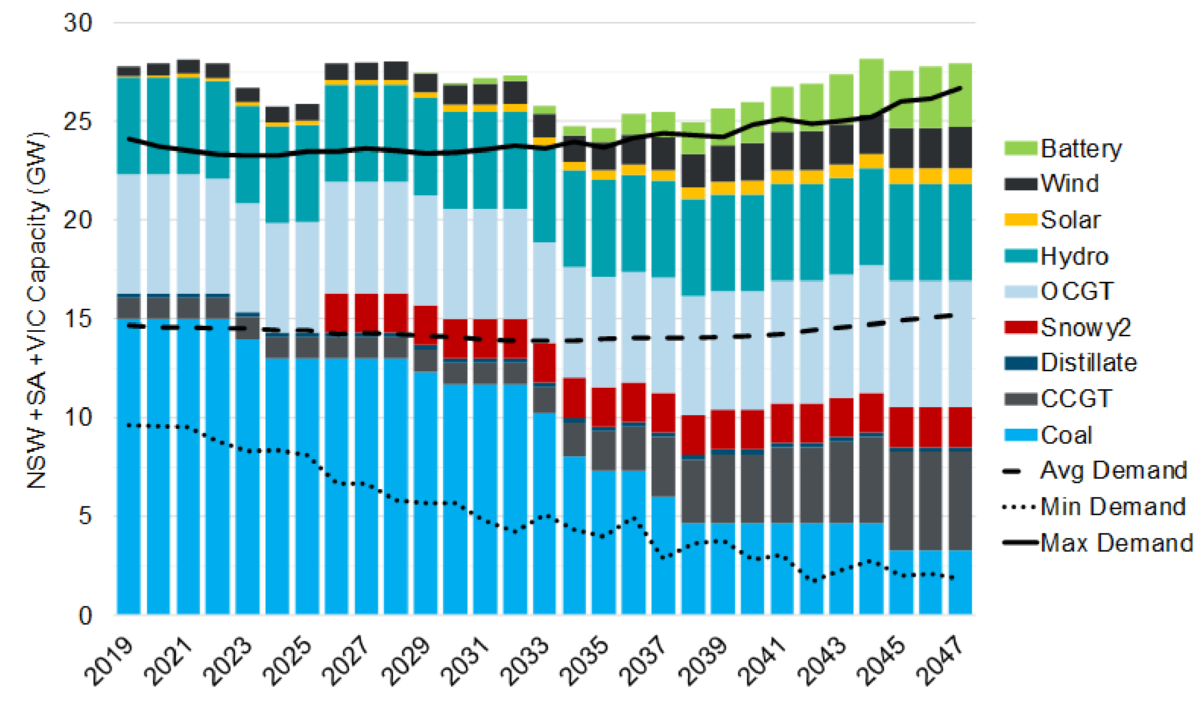

Figure 15: With Snowy 2.0- SA-VIC-NSW - Generator Contribution to Firm Capacity (MW)[18] [Source: MJA FID Base R06 2018]

Figure 15 shows that the SA-Vic-NSW region has very little capacity reserve for generation within the combined region and that support from Basslink and Qld is required. Particular observations are as follows:

1. The period 2033 to 2036 is very tight due to the substantial reduction in coal generation during that period. A significant amount of CCGT is developed during this period, but additional development is not economic due to the amount of VRE and storage that enters in the year shortly after this;
2. High gas cost places a premium on generation heat rate. This is a contributing factor to CCGT plant being developed in place of OCGT plant. As noted in the assumptions, the source of the gas for this generation is not known but could contain a significant amount of imported gas;
3. Snowy 2.0 becomes essential to the capacity adequacy from 2034 onwards; and
4. The parties that can provide cap and load-following contracts decrease from 2030 onwards.

Figure 16 shows the change in installed generation capacity due to the entry of Snowy 2.0. This shows the following:

[18] Firm capacity refers to the capacity that can be relied upon to be available at the time of maximum demand.

1. There is additional solar and wind generation, which has a combined installed capacity of about 4,000 MW. The reason for this increase being higher that Snowy capacity is the diversity of VRE (VRE averages considerably less than 2,000 MW and the deep storage provided by S2.0;
2. The entry of Snowy 2.0 delays batteries. As additional VRE enters additional batteries are developed, which reduces the battery installation difference between the with and without Snowy 2.0 cases; and
3. The additional storage volume provided by Snowy 2.0 means that 1MW of Snowy 2.0 storage has significantly more value than 1 MW of 4-hour storage.

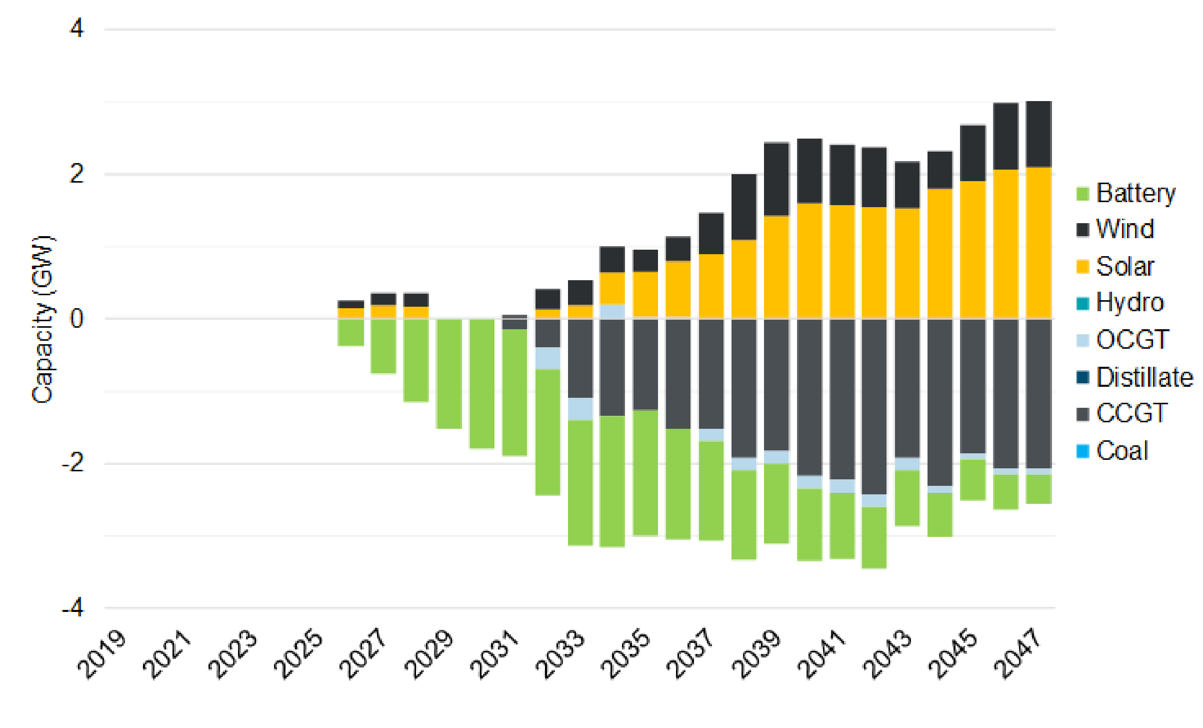

Figure 16: Change in NEM Installed Capacity due to Snowy 2.0

4.9.4 Base Scenario - % supply from renewable generation

The percentage of demand supplied by renewable generation is the demand supplied by rooftop PV, dispatchable renewable generation (existing hydro) and large-scale VRE (non-scheduled and semi-scheduled) compared to total demand.

By State and total, the percentage of demand supplied by renewable generation is shown in Figure 17. Figure 18 shows on a NEM wide basis the type of renewable generation over this period. This shows:

1. SA is currently (2019) about 58% supplied by renewable generation and this will increase due to committed projects and additional VRE projects (enabled by Riverlink). By 2047 SA is about 91% supplied by VRE;

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2. Qld increases rapidly to meet the 50% supplied by renewables (QRET target) by to 2030. This is met mainly by solar. The profile of solar generation compared to wind generation and the late closure of the coal power stations in Qld means that the percentage Qld demand supplied by renewables (situated in Qld) flattens post-2030;
3. Victoria has a significant increase due to the VRET and then has a steadier increase reflecting the economics of VRE and the closure of Yallourn power station;
4. NSW starts from a low level of VRE. The NSW coal plant closures in the 2030's results in a significant increase in VRE during this period.

The net result is that without S2.0 by 2047 the NEM is 59% supplied by renewable generation. The % of VRE generation in front of the meter is 47%.

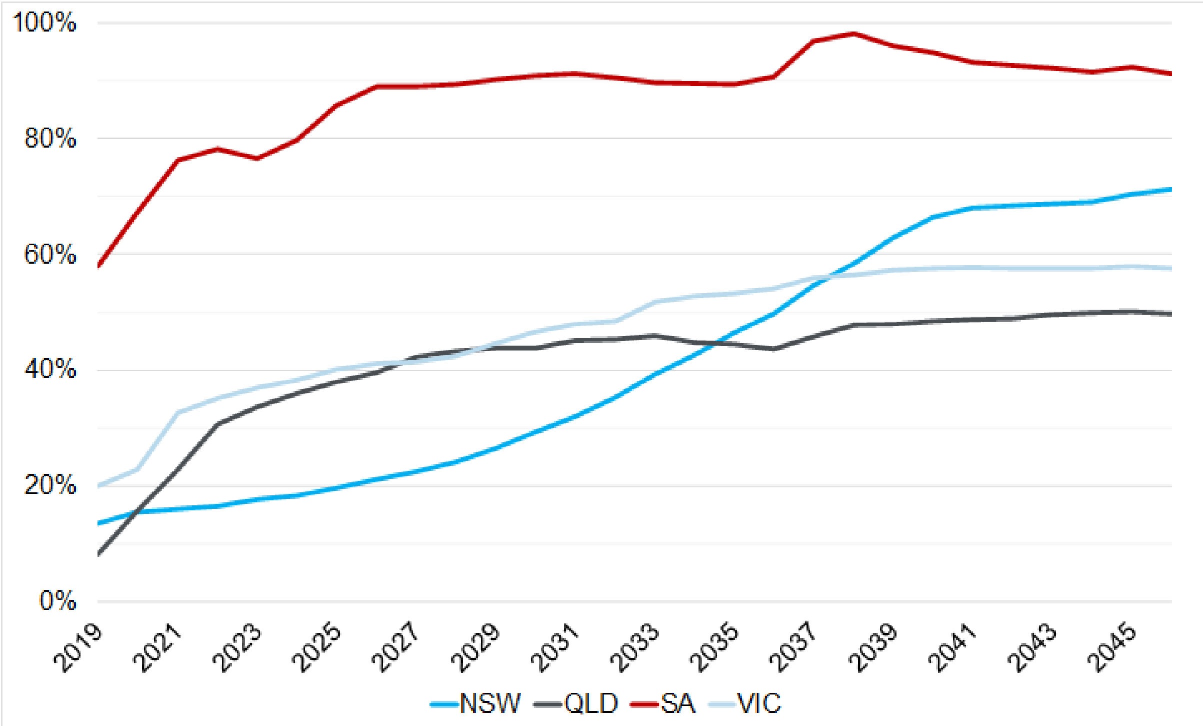

Figure 17: Percentage of Demand supplied by Renewable Energy [Source: MJA HR 30Oct18]

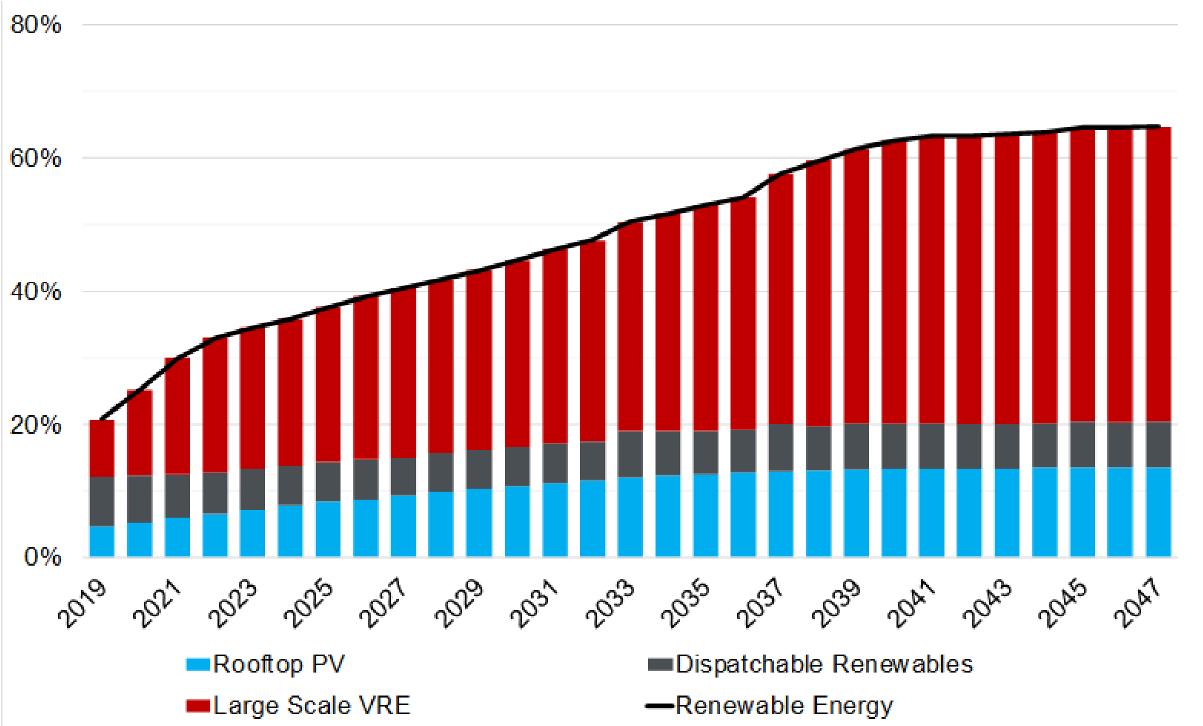

Figure 18: NEM -% renewable Generation by Category [Source: MJA]

4.9.5 Base Scenario - NEM carbon emissions

Figure 19 shows the total NEM carbon emissions in the with Snowy 2.0 and without Snowy 2.0 cases, and for reference a line that represents a reduction in emissions (compared to 2005 levels) of 28% in 2030 to 70% in 2050.

The impact of Snowy 2.0 on carbon emissions is more pronounced post-2035.

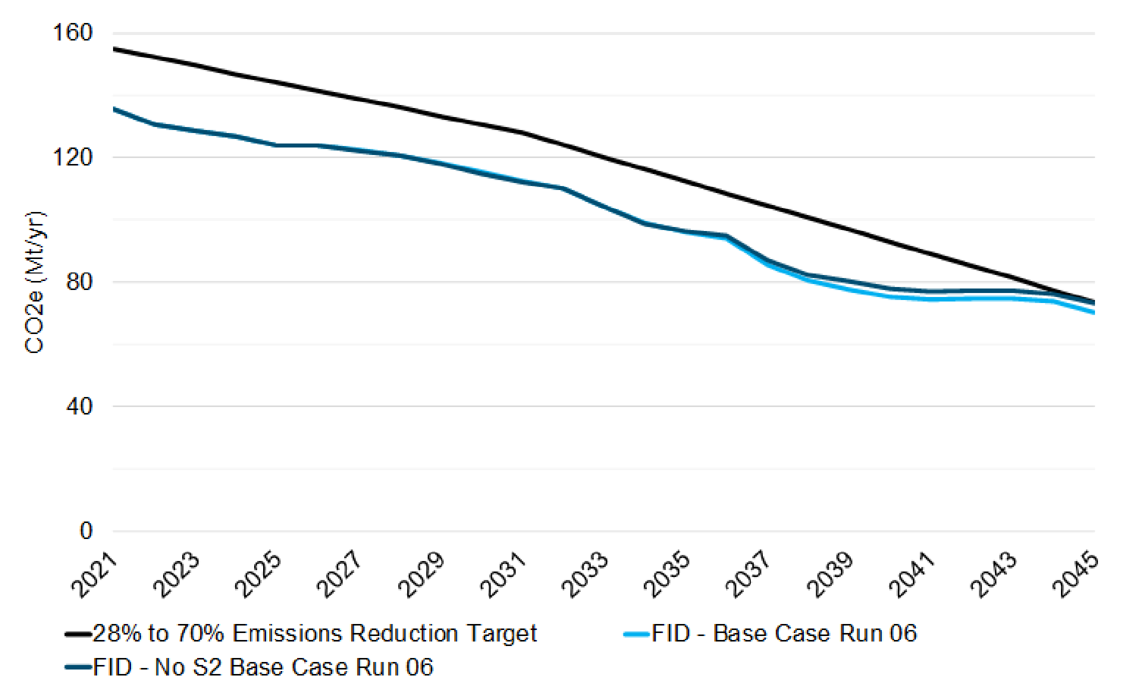

Figure 19: Carbon Emissions MT/Year [Source: FID Base R06 2018]

From Figure 19 the following are noted:

1. The reduction is due to coal plant closing and the replacement of this generation with gas and VRE (and no new coal plant); and
2. The levelling off in emission reduction post-2030 is due to the remaining coal plant operating at higher capacity factor and increasing gas plant development and operation as the limits of what battery storage can economically provide are reached.

Figure 20 shows the basis for the impact Snowy 2.0 has on emissions, excluding the emissions reduction associated with the assets that Snowy 2.0 replaced and that were developed in the without Snowy 2.0 case. The reduction is largely due to the additional VRE Snowy 2.0 brings in to the NEM and the reduction in gas generation (which is increasingly marginal) that results.

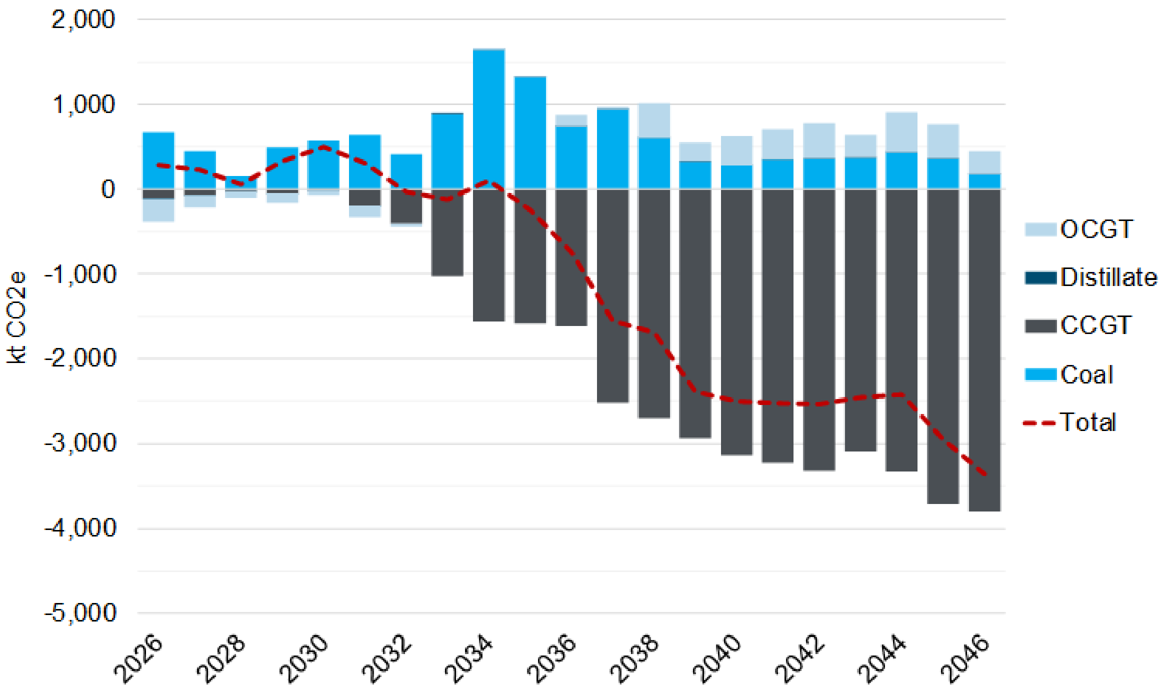

Figure 20: Emissions Reduction due to Snowy 2.0 [Source: FID Base R06 2018]

4.9.6 Base Scenario - Snowy 1.0 and Snowy 2.0 operation

This section presents the modelling results associated with the operation of Snowy 1.0 and Snowy 2.0.

The amount of generation, amount of pumping and the respective average prices for these are shown in Figure 21 and Figure 22, for Snowy 2.0 and Snowy 1.0, respectively.

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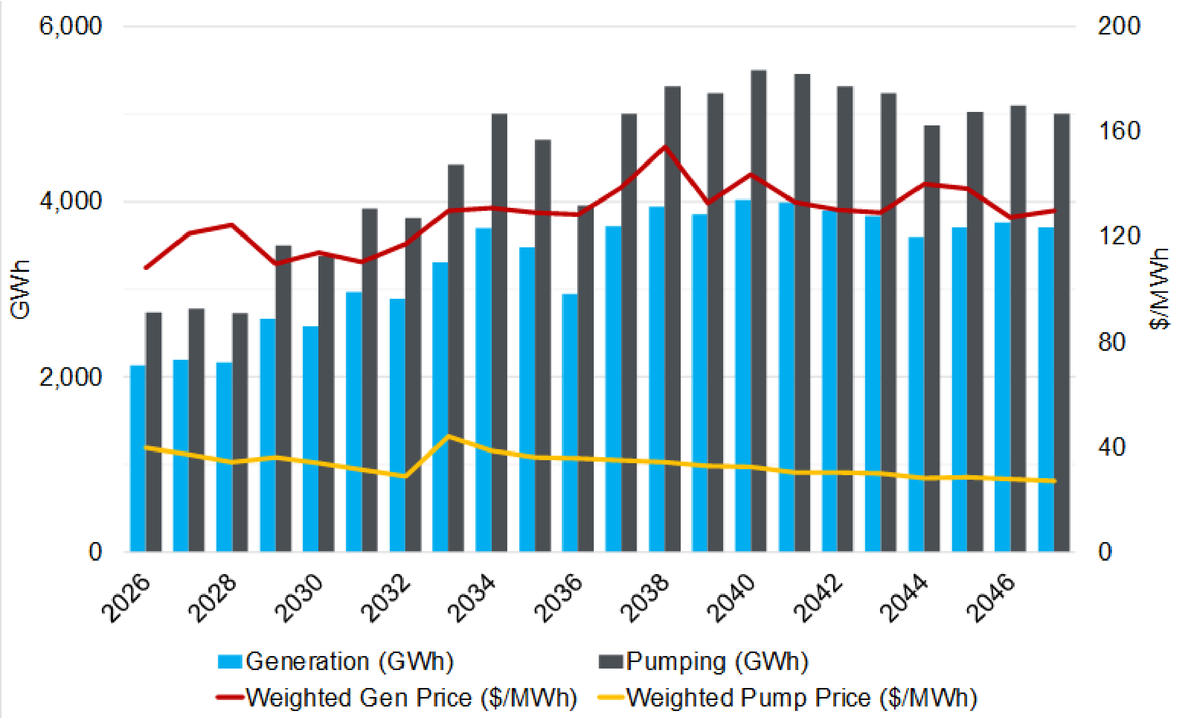


Figure 21: Snowy 2.0 - annual generation and pumping and annual buy and sell prices [Source: FID Base R06 2018]

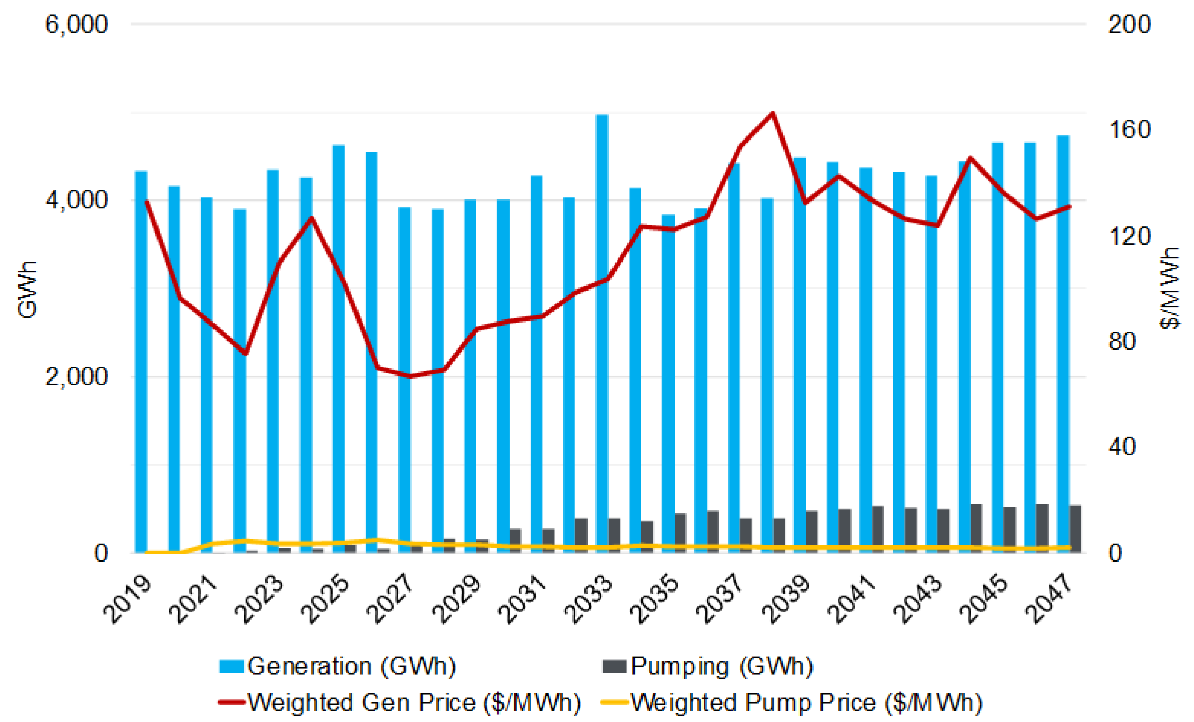


Figure 22: Snowy 1.0 - annual generation and pumping and annual buy and sell prices [Source: FID Base R06 2018]

From these figures, the following are noted for Snowy 2.0 and Snowy 1.0 respectively:

Snowy 2.0:

1. The amount of pumping energy compared to generation energy reflects the RTE of Snowy 2.0 which averages close to 75%;
2. The amount of pumping increases over the period 2026 to 2035 as VRE enters, providing for increased low-cost pumping energy;
3. The closure of coal generators results in reduced availability of pumping energy due to coal generators operating near minimum generation levels less often. The reductions in Snowy 2.0 pumping (and consequently less Snowy 2.0 generation) in 2032 and 2036 are due to the closures of Eraring and Bayswater, respectively. The closure of Bayswater has a more pronounced effect as this is in addition to the closure of Eraring;
4. Pumping (buying) prices decrease over the period reflecting the increasing amount of VRE energy available for pumping;
5. The step increase in Snowy 2.0 pumping prices starting in 2033 is due to the closure of Eraring and the step down in the mingen level of the combined coal generators, thereby reducing the quantity of very low-cost pumping energy;
6. The increase in pumping costs in 2033 reflects a change in buying prices due to the change in seasonal price profiles; and
7. Generation prices reflect the peak period prices, which show a slight increase over the period (reflecting the increasing hours gas generation clears the market).

Snowy 1.0:

1. The variation in annual generation reflects the conditions each year and that water can be stored in one year for use in the next. Over the period 2026-2047 Snowy 1.0 averages 4,291GWh pa, including generation from T3 pumping;
2. Tumut 3 pumping prices reflect the small level of pumping at this station and lower pumping offer prices than Snowy 2.0; and
3. Tumut 3 increases annual pumping volume from <100GWh during the 2020s to >500GWh during the 2040s, reflecting increased pumping opportunities as the amount of VRE increases.

4.10 Base Case Scenario - intra-year outcomes

A review of 30-minute outcomes provides for the operations of the NEM to be viewed and compared to the Snowy 2.0 operating rules and other matters incorporated in the model. This is important as it provides for the annual values (which are a sum of 30-minute values) to be better understood and as a means of validating the operation of the model.

This section presents for the Base Scenario sample years over this period:

1. The profile of NSW spot prices and NSW-VIC interconnector flows; and
2. Snowy 2.0 operation over a year – pumping, generating and the level of Tantangara pond.

4.10.1 Spot price profile

Figure 23 shows the NSW spot price duration curves for the years 2025, 2035, 2045.[19]

The 2019 price profile was very close to what actually out-turned in 2018. The change in profiles over the years shown reflects:

1. The reduction in coal generation and increased amount of time gas generation (and gas priced generation bids) are setting the spot price;
2. A similar 'top end' (ie spot prices greater than $300/MWh) reflecting a similar balance of available capacity to meet demand peaks; and
3. Increasing hours of very low or zero prices. This is associated with excess VRE and VRE generation being curtailed.

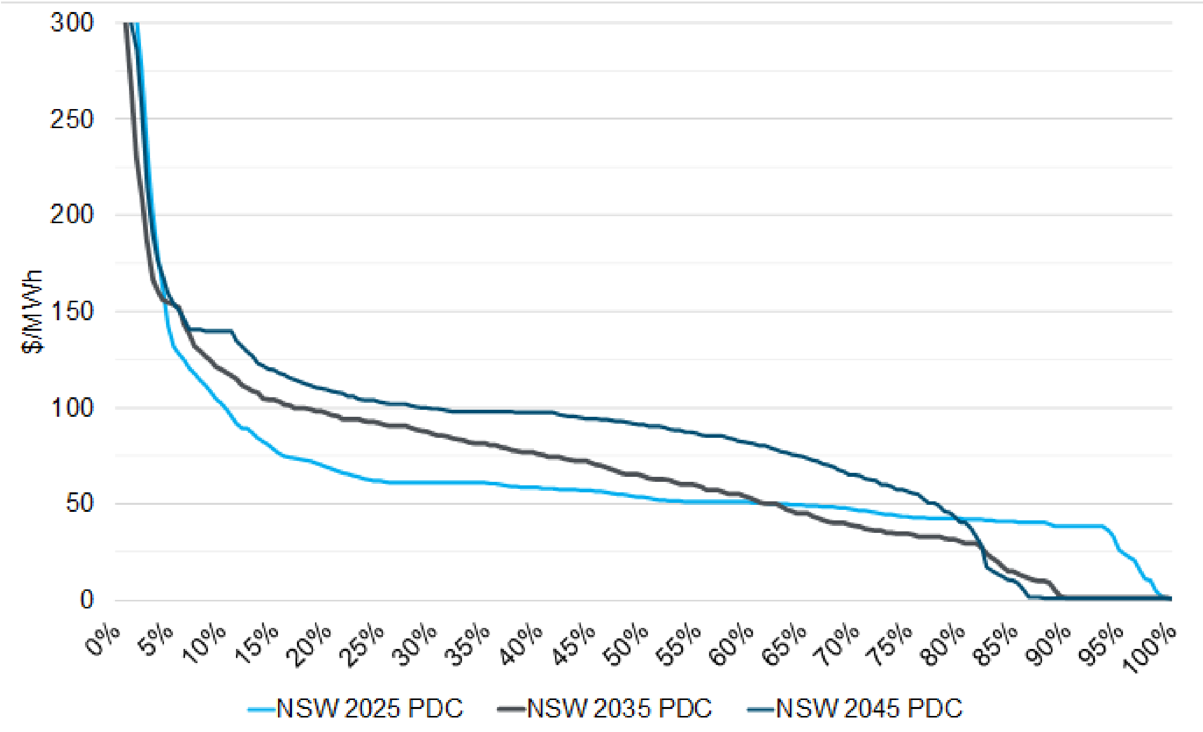


Figure 23: Base Scenario NSW Price Duration Curves - 2025, 2035, 2045 [Source: FID Base R06 2018]

4.10.2 NSW-VIC power flows

Figure 24 shows the NSW-VIC flow duration curves for the years 2025, 2035, and 2045. Positive values are for flow from VIC to NSW. The 2019 flow profile was very close to what actually out-turned in 2018. The change shows net flows from VIC to NSW over the years shown and reflects the following:

1. Additional low-cost generation development in VIC due to the completion of the VRET;
2. The closure of Liddell in 2022 making economic additional power flows from VIC;

[19] A spot price duration curve for a year is the 30-minute (or 5 minute) spot prices ordered from highest to lowest. This then represents the distribution of spot prices – the probability of spot price being above a defined level. It represents a very convenient way to view the annual profile of spot prices.

3. Closure of Yallourn in 2032 reducing the availability of energy from VIC;
4. NSW coal plant closes increasing the economics of power flows from VIC; and
5. Changes as VRE is developed in VIC and NSW.

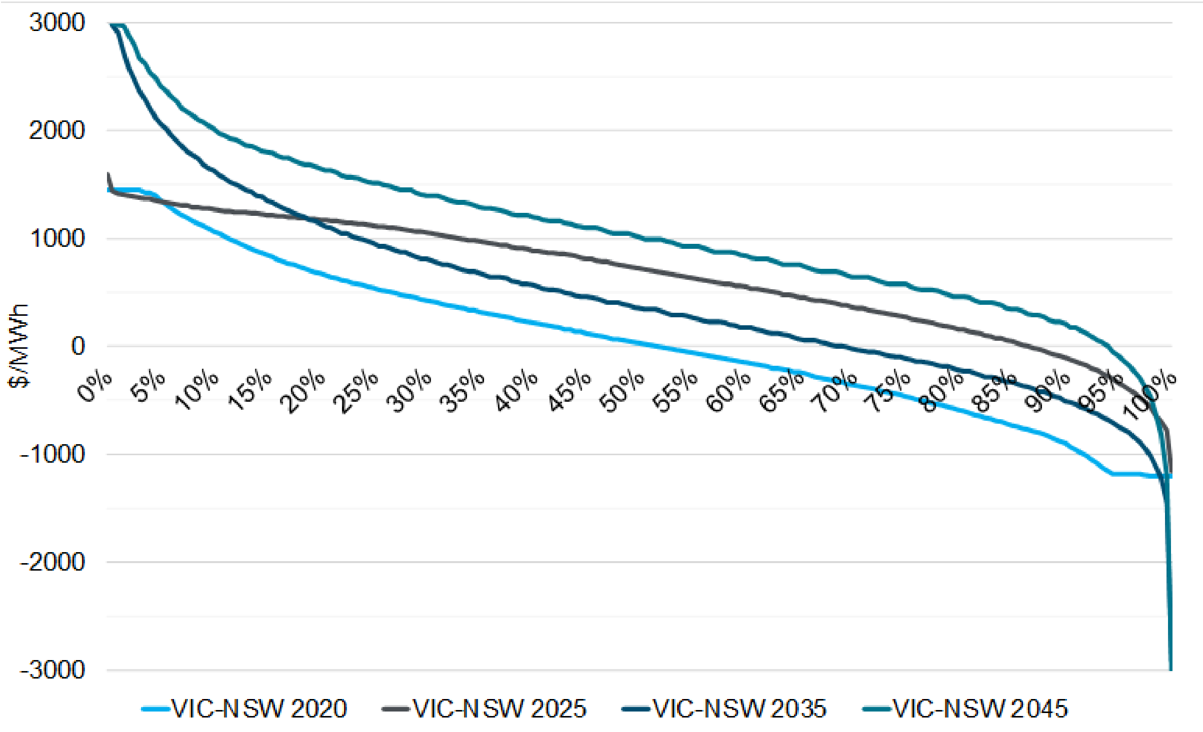
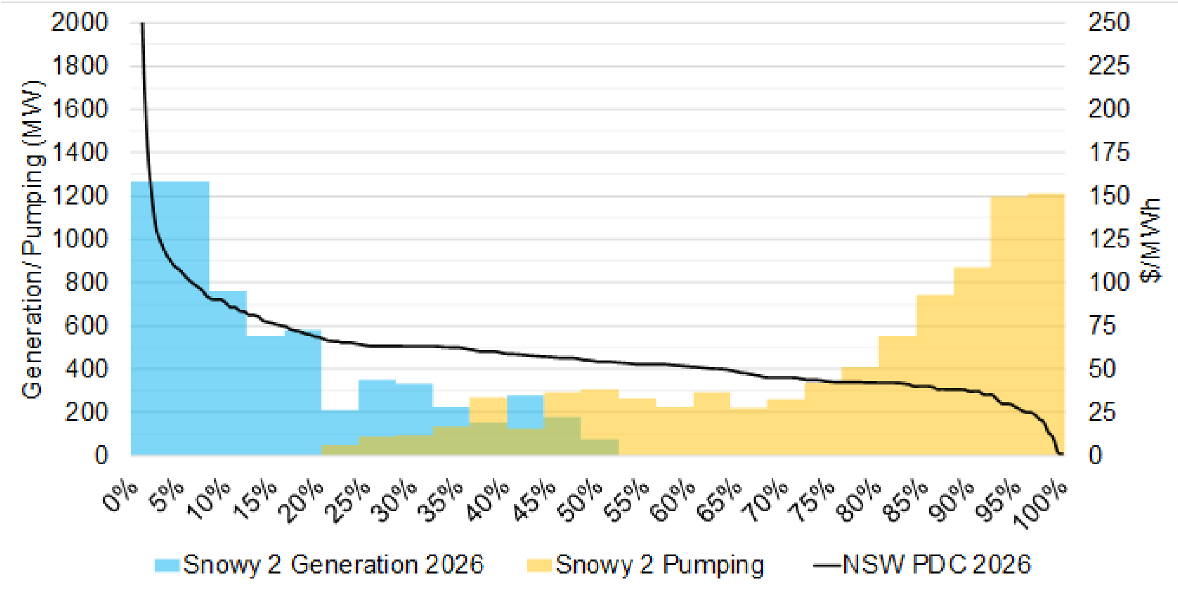


Figure 24: Base Scenario NSW-VIC Flow Duration Curves - 2020, 2025, 2035, 2045 [Source: FID Base R06 2018]

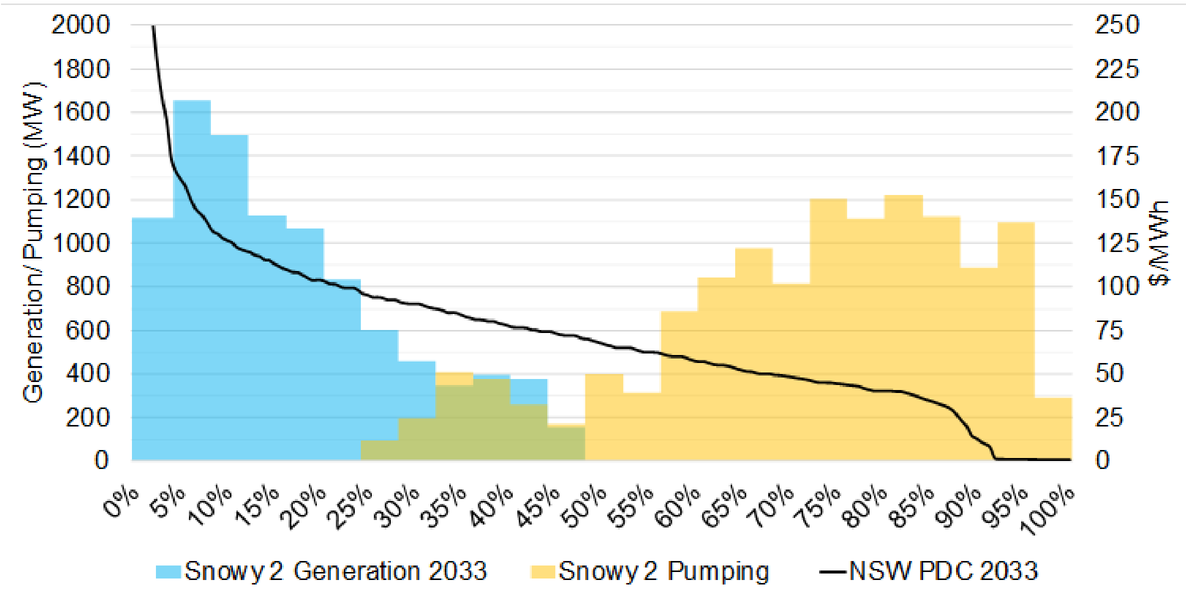
4.10.3 Snowy 2.0 Operation

Snowy 2.0 generation and pumping MWs were plotted against the NSW spot price duration curve for the years 2026, 2033 and 2040, and this is shown in Figure 25 below.

2026


Generation/ Pumping (MW)
$/MWh
2000
1800
1600
1400
1200
1000
800
600
400
200
0
250
225
200
175
150
125
100
75
50
25
0
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Snowy 2 Generation 2026
Snowy 2 Pumping
NSW PDC 2026

2033


Generation/ Pumping (MW)
$/MWh
2000
1800
1600
1400
1200
1000
800
600
400
200
0
250
225
200
175
150
125
100
75
50
25
0
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Snowy 2 Generation 2033
Snowy 2 Pumping
NSW PDC 2033

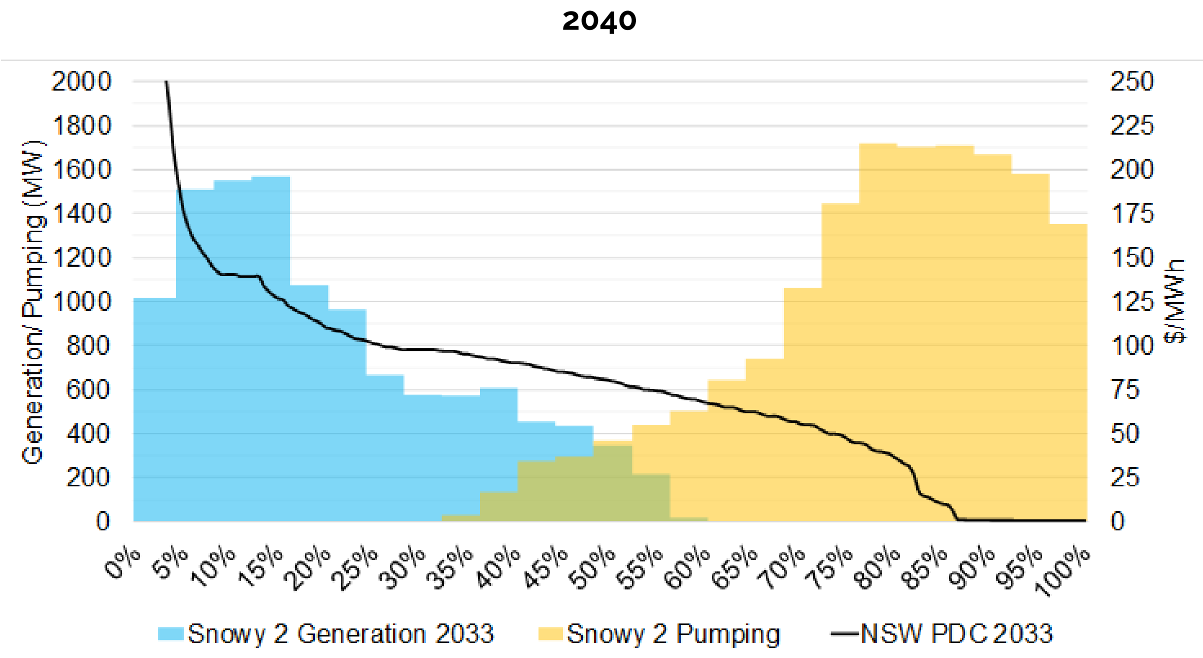


Figure 25: Base Scenario: Snowy 2.0 Gen and Pump MW v NSW Spot Price [Source: MJA]

The generation and pumping MW are averages over 5% 'buckets' (and thus do not shown the maximum in each bucket). For each year this figure shows:

1. The NSW spot price duration curve;
2. The MWs of pumping (right hand side of each graph and in yellow); and
3. The MWs of generation (left hand side of each graph and in blue).

The following observations are made:

1. Generation occurs at high spot prices and pumping at low spot prices;
2. The level of pumping reflects the level of generation and the RTE (and vice versa);
3. The stepped characteristic is associated with a different number of S2.0 generator/pumping units operating;
4. Over each year the lowest price Snowy 2.0 would generate at (and highest price Snowy 2.0 would pump at) change over the year as the average level of daily spot price varies;
5. Over each year there is an overlap with the prices Snowy 2.0 pumps at and generates at. This overlap occurs in different times of the year;
6. There are very low prices where Snowy 2.0 is not pumping a maximum capacity. This is associated with Tantangara being full. This would occur less in actual practice due to better planning and flexible operations that cannot be fully modelled;
7. There are very high prices where Snowy 2.0 is not generating a maximum capacity. This is associated with the shape of the supply curve submitted by Snowy 2.0 (balancing volume and price) and coordination with S1.0. This would occur less in actual practice due to better planning; and

8. The value lost through not capturing all low and high prices is a slight reduction in Snowy Hydro value.

The table below shows the percentage of time Snowy 2.0 was generating and pumping at 2000 MW and less than 2000 MW in the years 2026, 2033, 2040 and 2047(in the Base Scenario).

Generation					Pumping			
	Less than 2000MW	2000MW	Total			Less than 2000MW	2000MW	Total
2026	24.4%	2.9%	27.3%		2026	24.4%	2.9%	27.3%
2033	25.4%	7.6%	32.9%		2033	25.4%	7.6%	32.9%
2040	26.1%	10.1%	36.3%		2040	26.1%	10.1%	36.3%
2047	29.8%	6.9%	36.7%		2047	29.8%	6.9%	36.7%

Table 12: Base Scenario – Percentage of Pumping and Generating at 2000 MWs [Source: MJA]

5 Definitions and abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
C&I	Commercial & Industrial
CCGT	Combined-cycle gas turbine
CPT	Cumulative Price Threshold
CSG	Coal Seam Gas
EV	Electric vehicles
FAM	Firming Analysis Model
FCAS	Frequency Control Ancillary Services
FID	Final Investment Decision
FOT	Free-On-Transport
FSRU	Floating storage and regasification unit
GPG	Gas Power Generation
ISP	Integrated System Plan
JCC	Japan Customs-cleared Crude
LCM	Least-Cost Model
LNG	Liquified Natural Gas
LRET	Large-scale Renewable Energy Target
MJA	Marsden Jacob Associates
MPC	Market price Cap
NEG	National Energy Guarantee
NEM	National Electricity Market
NPV	Net Present Value
OCGT	Open-Cycle Gas Turbine
PHES	Pumped-Hydro Energy Storage
REZ	Renewable Energy Zones

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RTE	Round Trip Efficiency
SRMC	Short-Run Marginal Cost
VOM	Variable operations and maintenance
VRE	Variable Renewable Energy
WUF	Water Utilisation Factors

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