MARSDEN JACOB ASSOCIATES

economics
public policy
markets
strategy

Modelling Snowy 2.0 in the NEM

Public Report

3 December 2018

A Marsden Jacob Report

Prepared for Snowy Hydro Limited
3 December 2018

Marsden Jacob Associates
ABN 66 663 324 657
ACN 072 233 204

economists@marsdenjacob.com.au

Authors

Andrew Campbell - Marsden Jacob Associates
Peter McKenzie - Marsden Jacob Associates
Hana Ramli - Marsden Jacob Associates
Bruce Low - Marsden Jacob Associates

About Us

Established in 1996, Marsden Jacob Associates has grown to be Australia's leading dedicated natural resource economics, policy and strategy advisory. We employ talented economists and policy advisors who specialise in solving practical, real world problems relating to water, energy, environment, natural resources, agriculture, earth resources, public policy and transport. We work with a wide range of cross-disciplinary partner firms to deliver best project outcomes for our clients.

www.marsdenjacob.com.au

MARSDEN JACOB ASSOCIATES

Contents

Figures

Tables

Acronyms and abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
DWP	dispatch weighted price
FAM	Firming Analysis Model
FCAS	frequency control ancillary services
FID	Final Investment Decision
FOM	fixed operations and maintenance
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LDC	Load Duration Curve
LGC	large-scale generation certificate
LNG	liquefied natural gas
LRET	Large-scale Renewable Energy Target
LRET	Large Scale renewable Energy Target
LRMC	long run marginal cost
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NSW	New South Wales
OCGT	open-cycle gas turbine
PDC	Price Duration Curve
PJ	petajoule
PV	photovoltaic
QLD	Queensland
RET	Renewable Energy Target
RIT-T	regulatory investment test—transmission
RTE	Round Trip Efficiency
S1.0	Snowy 1.0
S2.0	Snowy 2.0
SHL	Snowy Hydro Limited
SRAS	System restart ancillary services
SRES	Small-scale Renewable Energy Scheme
SRMC	short run marginal cost
TAS	Tasmania
VIC	Victorian Renewable Energy Target
VOM	variable operations and maintenance
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital

Executive Summary

This report presents the non-commercial findings of an independent study by Marsden Jacob Associates on the operation of Snowy 2.0 in the NEM.

Key findings presented are the underlying narrative of how the NEM will develop, key issues to this development, the extent of Snowy 2.0 operation, and how future uncertainties will influence future NEM developments.

This report follows the feasibility modelling (and report) undertaken by Marsden Jacob Associates in 2017.

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

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 SHL. 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":

- **Dispatchable capacity** is that which is controllable (i.e. either up or down);
- **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 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 SHL. These quality and value relationships include:

- Its **central location** that provides for maximum consumer access, NEM wide balancing of VRE, and security against critical transmission outages;
- 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);

- 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;
- Its **economic value to be robust** against uncertain future outcomes;
- 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.

Modelling: Structure, Approach and Scenarios

Work Undertaken

The work for this report included:

- Review and update of all assumptions and potential outlook scenarios. This included:
  - the findings from a visit to recent European pumped storage developments
  - a study by a third party expert on the performance of the existing NEM coal generators and options to increase their flexibility
  - recent studies and publications by AEMO including the Integrated System Plan, Gas Statement of Opportunities and Electricity Statement of Opportunities
  - Marsden Jacob Associates market and cost data;
- Developing the approach to modelling the NEM over the study period of 2018-19 to 2074-75;
- Development and use of models that vary from long term spreadsheet approaches to detailed market simulation;
- Developing the scenarios and assumptions based on a review of future uncertainties;
- Modelling and analysis of the fundamental economics of storage as the amount of Variable Renewable Energy (VRE) increases;
- Explicit modelling and the assignment of carbon emission reductions to the service provided by Snowy 2.0;
- Detailed review and incorporation of the operating rules that apply to Snowy 1.0 and that would apply to Snowy 2.0;
- Detailed modelling that includes capital and operating costs;
- Modelling of a number and spread of scenarios.

Modelling Approach

The long study period meant that two modelling approaches and models were used to address the 55-year study period:

- 2018/19 to 2046/47: detailed simulation modelling of the NEM under two cases:
  - Snowy 2.0 is not developed (termed the "without Snowy 2.0" case)
  - Snowy 2.0 is developed and enters service 1 July 2025 (termed the "with Snowy 2.0" case);
- 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).

Scenarios Modelled

The scenarios were developed from a review that included demand outlook, distributed PV and storage, large scale renewable technologies, commodity costs, potential energy policy, and investment risk.

The review concluded that irrespective of future energy policy (particularly emission limits), all scenarios will have an underlying narrative of increasing VRE supported by firming, where firming will be provided by existing dispatchable generation (which will decrease as existing power stations close) and new entry storage and gas generation. This trend may be accelerated or delayed by the early closure of coal power stations or by extending coal generation (through delayed closure of existing power stations and/or new coal power stations). Without pricing emissions, the long-term mix of generation would tend to a lower level of VRE and storage and a higher level of emissions.

The Base Scenario was developed to be consistent with the above. Its assumptions were based largely on public domain data which included current energy policy, announced developments, AEMO demand projections and transmission developments identified in the ISP. Gas costs were based on an assessment by Marsden Jacob based on a report commissioned by SHL. The Base Scenario was considered to represent a central scenario.

From the Base Scenario, eight alternative scenarios were developed and modelled. These represented potential changes to demand growth, hydrological conditions, future energy policy, coal power station outlook, and future capital costs. The names and brief descriptions of these scenarios are presented in Table ES1 below.

Table ES1 Scenarios Modelled

Scenario Name	Description
Base	Current policy (LRET, VRET, QRET) only. Base assumptions – coal closures, costs etc.
Low Emissions	Policy for emissions – 45% by 2030, 80% reduction by 2050. Changes included high rooftop PV and Basslink II developed (600 MW link for Tas to VIC).
Coal Early Closure	50-year coal plant closure – which limits Gladstone to 2026 and Loy Yang A to 2038.
High Demand	AEMO high demand case (Fast Scenario).
Hydrology Wet	All hydro generation has annual production increased by 10% post 2025.
Hydrology Dry	All hydro generation has annual production decreased by 10% post 2025.
High EV Penetration	50% by 2030; 80% by 2040 (% is cars on the road). Two EV battery charging profiles were modelled.
Coal Bull	1,500 MW of new coal NSW in 2027, 1,500 MW of new coal in Qld in 2036.
High Battery	Double battery cost curve depreciation rate and additional regulatory requirement for battery installation to accompany VRE development.

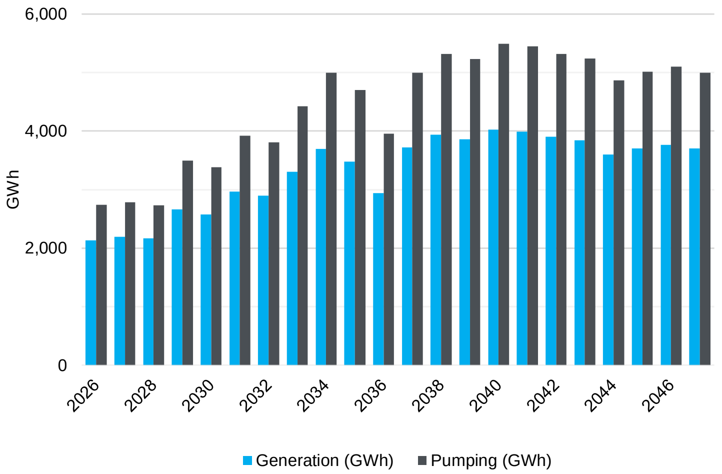
Modelling Results

Base Scenario

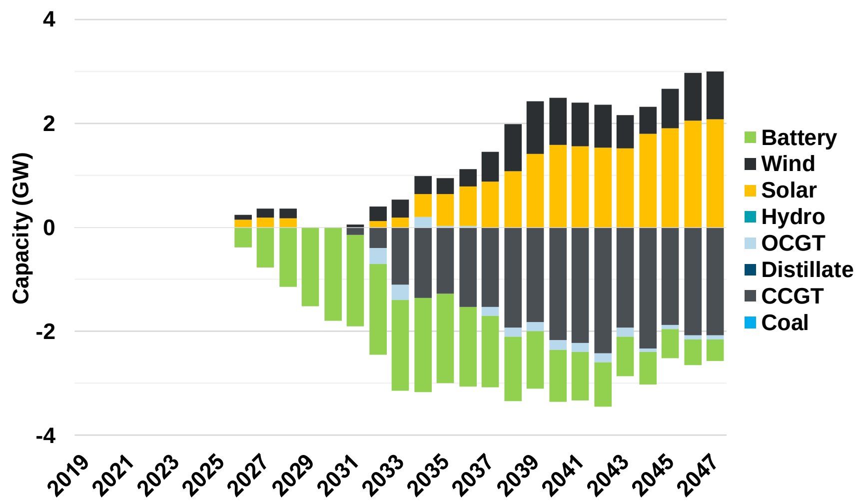
A summary of the annual outcomes for the Base Scenario over the period 2018-19 to 2046-47 is shown in Figure ES2 below. Shown are:

- For the "with Snow2.0" case the installed generation capacity;
- The change in installed capacity in moving from the "without Snowy 2.0" to the "with Snowy 2.0" case;
- For the "with Snowy 2.0" and "without Snowy 2.0" cases, the NEM carbon emissions;
- Snowy 2.0 generation and pumping volumes.

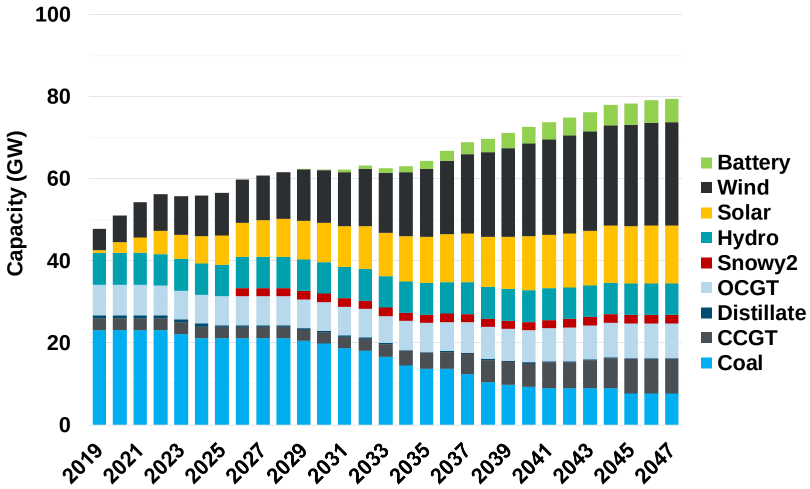
Figure ES2 Base Scenario - Modelling Outcomes 2019 to 2047



S2.0 Generation and Pumping GWh



Installed Capacity – With S2.0 MW



Installed Capacity – With S2.0 MW

Source: Marsden Jacob Associates: Base Scenario

Observations from the Base Scenario Results

Installed generation:

- VRE (solar and wind) increases over the study period. There are two reasons for this:
  - Economics – spot market revenues available to VRE compared to costs. This reflects the firming provided by the flexibility of the existing dispatchable generation. As coal power stations close the firming available without new investment reduces
  - Replacing the closing coal plant. New generation is required and the options without new coal generation are base load gas generation or VRE with firming provided by peaking gas generation and battery storage;
- Snowy 2.0 provides support and firming for VRE generation. It results in about 3,000 MW of additional VRE generation and a reduction of about 2,000 MW of gas generation (mainly CCGT). Snowy 2.0 results in a reduction of about 1,000 MW of batteries in the initial years of Snowy 2.0 operation, with this reduction diminishing due to the additional VRE that enters.

Emissions:

- Emissions reduce due to coal power station closures and no new coal power stations being developed;
- Emissions level off in the 2040's at about a 65% reduction (compared to 2005 levels). This reflects the economics of battery storage that would be required to support the higher levels of VRE required to further reduce emissions, i.e. battery economics would need to significantly improve in order to get a larger reduction in emissions. The level of additional cost reduction required would appear to make this most unlikely.

Snowy 2.0 operation:

- Snowy 2.0 annual generation and pumping volumes are related by the Round Trip Efficiency (RTE) which averages about 76% at commissioning;
- Snowy 2.0 pumping volumes increase as VRE increases (incentivised by coal generator closures);
- Coal generation closure with VRE unchanged reduces pumping opportunities and consequently Snowy 2.0 generation;
- From the mid-2040's onwards the closure of coal power stations acts to slightly reduce pumping volumes as a high proportion of the coal generation closed is replaced by gas generation. This reflects the volumes and associated costs of storage that would be required to replace gas generation (as the need for firming capacity increases).

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

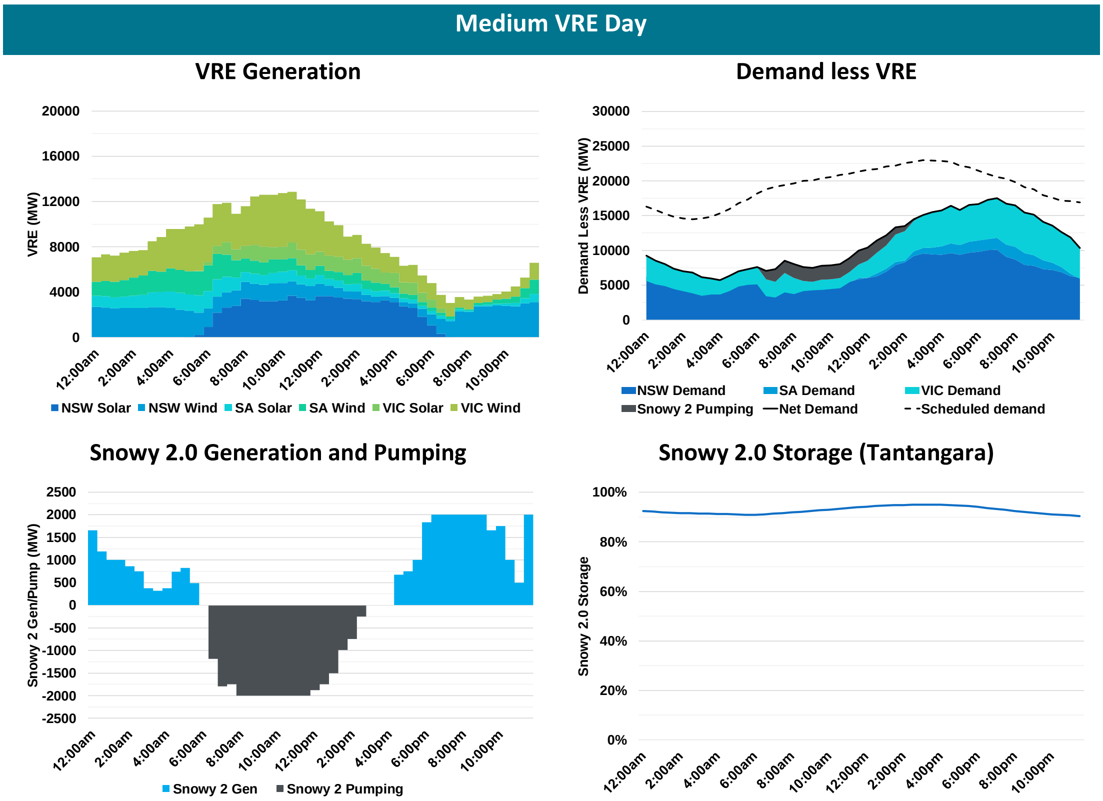
The modelling of the Base Scenario provided for the operation of Snowy 2.0 (and all other generators) to be observed on a day by day basis through the modelling period. This illustrated the variability of Snowy 2.0 operation due to factors that include season, day-type, amount of VRE installed, weather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

From this a pictorial representation of Snowy 2.0 operation under various conditions over the study period was developed and is shown in Figure ES1 below. For each of the three days of different VRE output the figure shows over each day:

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

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

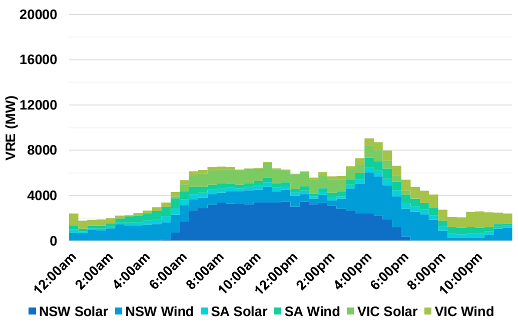
Figure ES1 Daily Snowy 2.0 Operation – Average types days



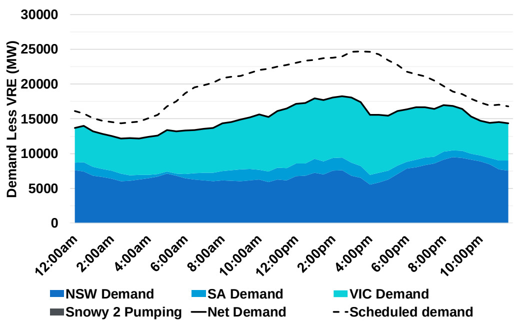
- Snowy 2.0 generates at the start and finish of the day.
- Snowy 2.0 pumps in the middle of the day (corresponding to high solar output).
- This will be a typical day when Snowy 2.0 enters. The extreme variations in VRE energy output will increase as the amount of installed VRE increases.
- Overall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

Very Low VRE Day

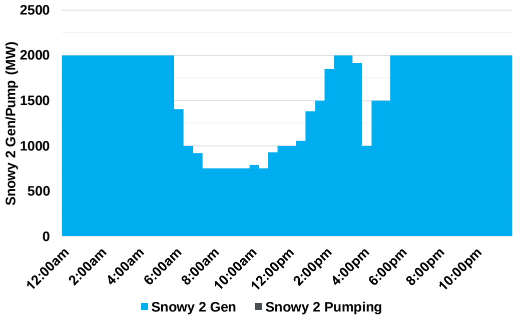
VRE Generation



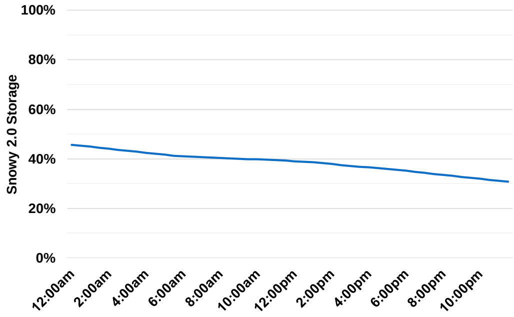
Demand less VRE



Snowy 2.0 Generation and Pumping



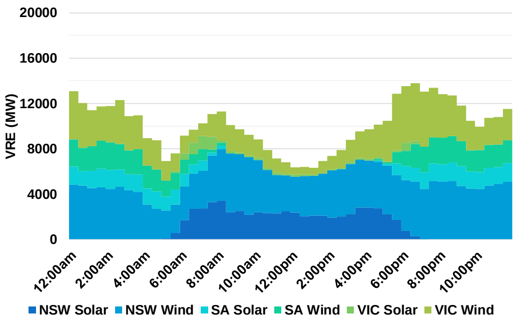
Snowy 2.0 Storage (Tantangara)



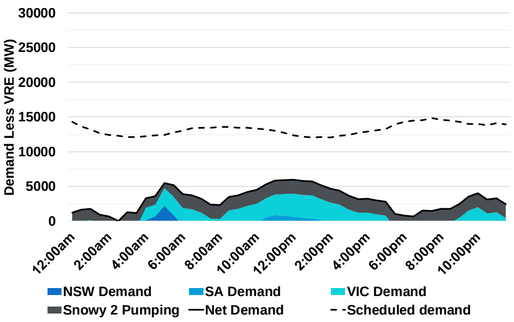
- Snowy 2.0 generates all day with generation reducing in the middle of the day (corresponding to high solar output).
- Snowy 2.0 provides generation capacity when VRE is low and when coal/gas generators are unavailable.
- This type of day will increase in frequency as VRE increases.
- Snowy 2.0 storage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

Very High VRE Day

VRE Generation

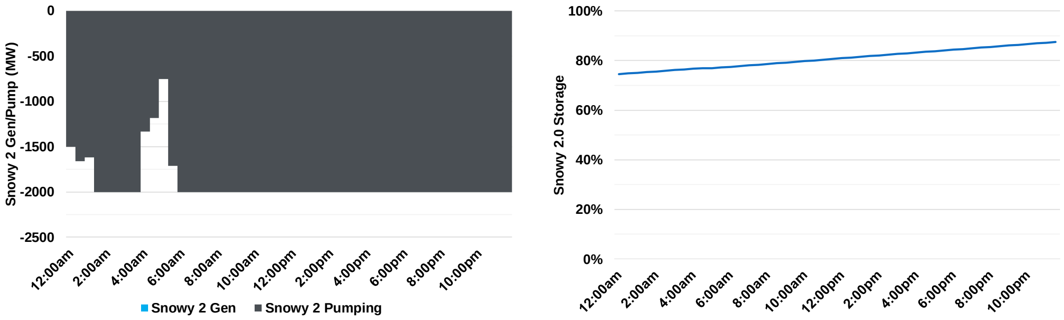


Demand less VRE



Snowy 2.0 Generation and Pumping

Snowy 2.0 Storage (Tantangara)



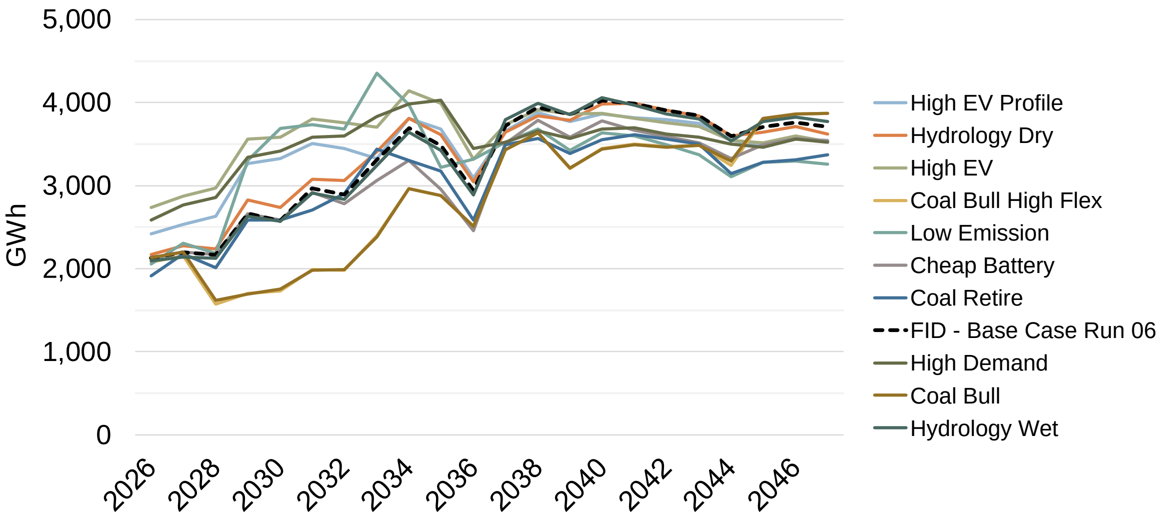
- Snowy 2.0 pumps all day with a small reduction due to a small lull in VRE generation.
- Snowy 2.0 provides for surplus VRE generation to be saved over a whole day for later use.
- This type of day will increase in frequency as VRE increases and thermal generation reduces.
- Snowy 2.0 storage increases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

Source: Marsden Jacob Associates

Alternative Scenarios

The alternative scenarios were described in Table ES1. Figure ES4 shows for the base and alternative scenarios, the Snowy 2.0 generation (GWh).

Figure ES4 Modelled Scenarios –Snowy 2.0 Generation GWh



Source: Marsden Jacob Associates

A key message from the modelling and results of these scenarios was the increasing complexity and sensitivity of NEM market outcomes as the existing coal generators close. Increasingly, the "layers" of generation with different Short Run Marginal Costs (SRMC) that has existed, and currently exists, will be replaced with low marginal cost generation, gas generation and storage (which will likely have the opportunity value of sales at gas generation costs). This results in a price dynamic that is more sensitive to change.

The key observations from each of the alternative scenarios are briefly presented below.

Low Emissions:

- Before 2030:

- compared to the Base Scenario the Low Emissions Scenario requires additional coal closures, addition VRE for energy replacement and firming support including Basslink II (600 MW);
   - development time means additional VRE is needed prior to the date of the coal closures – this results in lower prices during this period;
   - the quantity of coal closure results in less dispatchable generation and higher prices after the coal plant closes.
- After 2038, an 80% emissions reduction by 2050 requires coal closure and replacement by a larger component of VRE than in the Base Scenario. This increases the requirement of storage with storage hours over 18 hours.

Coal Early Closure:

- Similar dynamic to the Low Emissions Scenario prior to 2030 and in the late 2040's, with the difference that there is no requirement for VRE from an emissions perspective. This reduces the VRE developed as replacement generation;
- The early closure of Loy Yang A (2038) reduces pumping volume but increases the hours that gas generation sets spot price.

High Demand:

- A higher level of generation development including battery storage;
- Emissions are higher, requiring greater investment in VRE and associated firming assets if emissions are to be limited;
- Snowy 2.0 brings on more VRE than in the Base Scenario;
- Both Snowy 1.0 and Snowy 2.0 have increased revenues.

Hydrology Changes Wet and Dry:

- Changed Snowy 1.0 generation volumes;
- Changed Snowy 1.0 and Snowy 2.0 generation volumes are those components which have the lowest value (i.e. near the value of water).

High EV Penetration:

- Demand increase is substantial by 2040 – equivalent to about a 4,000 MW base load power station;
- Results in a substantial increase in new generation by 2036 compared to the Base Scenario. This lessens the relative size of the Eraring closure;
- Demand will have a level of control and a proportion of batteries may be "aggregated[1]" and may have some central control.

Coal Bull:

- These new coal generators replace a portion of the exiting coal generators closing;
- Emissions are naturally higher.

High Battery:

- The reduction in battery costs (given by a doubling in the rate of cost battery module cost reduction) was not sufficient to have battery entry (with storage over 2 hours) economic. However, this would reduce the cost of regulated battery entry and an increase in battery entry of 3,000 MW (4 hours storage) compared to the Base Scenario was assumed.
- A conservative assumption was used that the increased level of battery entry does not invoke a market response (which would include an increase in VRE). This scenario showed:

[1] This terminology is use by AEMO.

- the increased competition to Snowy 2.0 resulted in the level of arbitrage prices and volumes being reduced
- the relative low quantity of storage hours limited the impact
- Snowy 1.0 and Snowy 2.0 revenue reductions were relatively small.

Conclusions

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 plants close:

- 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 time frames from daily to yearly. See a pictorial representation of this transformation in Figure ES4;
- NEM outcomes may become more sensitive to the reliability of existing power stations and demand forecast errors;
- 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 (i.e. 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

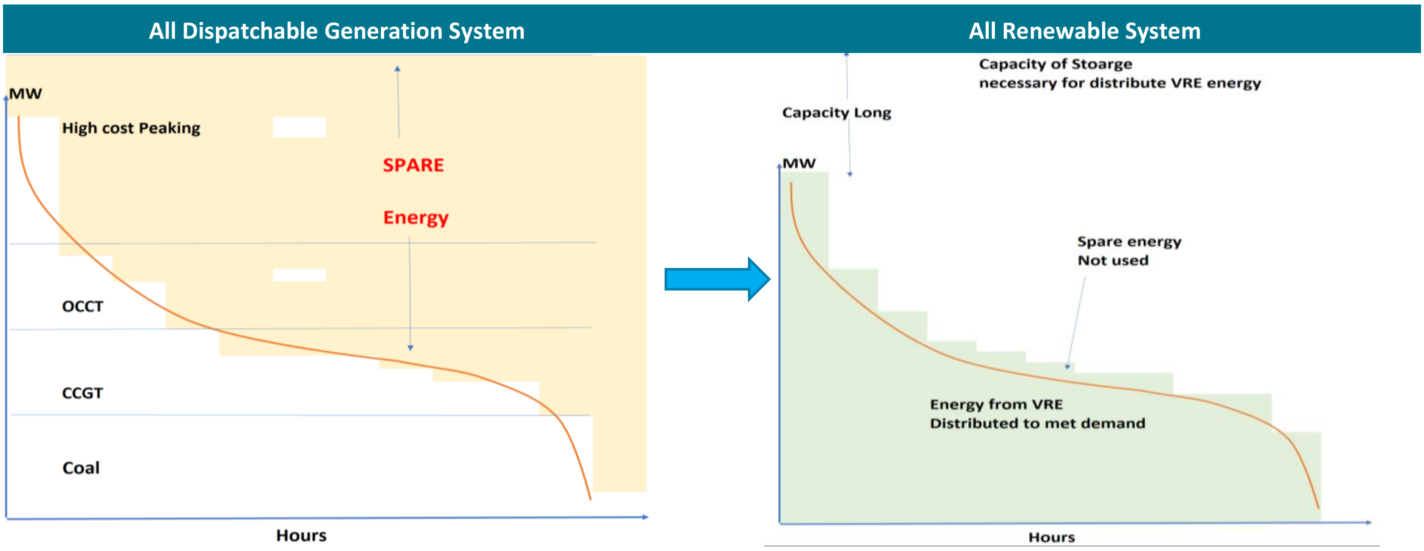
Before the closure of Eraring, the lowest cost option for reducing emissions is replacing coal generation with VRE generation, together with the level of firming required (with most firming being available from the existing dispatchable generation).

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 ES4 Changing Characteristic of the NEM



The figure above show 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.

Source: Marsden Jacob Associates

1. Introduction

This chapter introduces this report, its intent and structure, and the conventions used throughout the report.

1.1 Report Intent

Marsden Jacob Associates (Marsden Jacob) were commissioned by Snowy Hydro Limited (SHL) to undertake modelling of the economic impact Snowy 2.0 would have on the National Electricity Market (NEM), the level of carbon emissions in the NEM, and the performance and associated spot market financials of Snowy 2.0.

The outcomes of this work included an underlying narrative of how the NEM will develop, key issues to this development, the extent of Snowy 2.0 operation, how future uncertainties will influence future NEM developments, and confidential financial results.

This report presents the above (excluding confidential financials) including approach, assumptions and scenarios, and graphical displays of key NEM outcomes.

This reflects the intent of this report which is to provide a description supported by modelling on the key issues and developments that will be necessary in the NEM, the services Snowy 2.0 would provide, and how these would influence other NEM requirements.

1.2 Report Structure

This report has been structured to provide a detailed account of the modelling undertaken and explanation of the findings. The report being has been structured into a main body and appendices.

This "main body" report has been structured to provide the following:

- Characterisation of the changing NEM and the changing economics of generation plant in the NEM;
- Review of the key factors that will influence modelling outcomes;
- The role and value storage will provide in the NEM and how this value increases as the amount of Variable Renewable Energy (VRE) increases;
- From this review, a description of the scenarios modelled and their assumptions;
- How the modelling was undertaken including a description of the models used;
- The modelling results and an explanation of the results;
- Conclusions from the modelling.

The report presents a number of chapters that provide background to the economics of the NEM moving forward before the actual modelling is introduced and the modelling results presented. Chapters considered important to the background of the economics of the NEM and modelling results are as follows:

- Chapter 7 on NEM transformation dynamics. This links the changing nature of the NEM to the modelling approach and Snowy 2.0;
- Chapter 8 on Post 2047 – firming under High VRE. This describes and quantifies the nature of the changing NEM and the role and nature of firming VRE.

1.3 Notes to this report

Dollars

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

Financial years

Unless otherwise stated:

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

Snowy Hydro

Snowy 1.0 (or S1.0) refers to the Snowy Mountains Hydro scheme excluding Snowy 2.0.

Snowy 2.0 (or 2.0) refers to the proposed 2,000 MW pumped storage scheme.

Snowy Hydro Limited (SHL) refers to the owner of Snowy 1.0 and Snowy 2.0.

Modelling

Scenarios refer to the developments and outcomes in the NEM.

Cases refer to SHL development options (do nothing or Snowy 1.0, “with Snowy 2.0” = Snowy 1.0 + Snowy 2.0).

2. Study Approach and Methodology

The modelling for this study was undertaken after considerable preparatory work and modelling design had been completed. This work was an essential component of the methodology development and modelling. This chapter provides a brief review of the work undertaken, the objectives and requirements of the modelling, and the methodology developed and used.

2.1 Work Undertaken

The work undertaken for this modelling study included the following:

Review of all assumptions;

- Detailed review of the AEMO Integrated System Plan (ISP) report and supporting material;
- Review of recent generator (conventional and renewable) and storage capital costs reports and estimates (AEMO ISP) and comparison of these to Marsden Jacob models and estimates;
- Detail review of the recent AEMO demand forecasting reports (National Electricity Forecasting Report 2017 and its March 2018 update, and the Electricity Statement of Opportunities 2018);
- Detailed review of the publications and modelling undertaken by ElectraNet on the application of the RIT-T to Riverlink;
- Detailed review of the National Energy Guarantee reports and development of an approach for how these proposals would be incorporated into the modelling;
- Involvement in a recent study by a third party expert on the performance parameters of the coal generators currently operating in the NEM (e.g. minimum generation levels, ramp rates) and costed options that could be undertaken to improve the flexibility of these generators.

Methodology

- Participation in a tour of recent pump storage projects in Germany, Switzerland and Portugal. This involved discussions with the planning and operations personnel of these pumped hydro projects;
- Review of the uncertainties and factors relevant to the future development of the NEM;
- Modelling methodology for allocation of the carbon saving attributable to Snowy 2.0 and the modelling of these savings;
- Development of models for modelling the period to 2047 and for addressing the modelling requirements post 2047.

Snowy 2.0

- Discussions and review with SHL of the operating rules that Snowy 1.0 and Snowy 2.0 would operate to;
- Detailed discussions and data exchange on the operating characteristics of Snowy 2.0. This included the Round Trip Efficiency profile, variable speed machines, start times etc;

Modelling process

- Development of standardised formats and reports / excel sheets for the provision of assumptions, scenarios and modelling results;
- Internal review of assumptions and modelling outcomes.

Modelling Preparation

- Development of the databases for modelling over the period 2019 to 2047. Review and calibration of the modelling in the early years modelled (2019) to the current market dynamic;
- Development of the spreadsheet model 'Firming Analysis Model" for investigating the NEM and value provided by storage with specified storage hours as the percentage of VER increases (addressing the NEM post 2027);
- Comparison of results to a region that has high VRE – South Australia.

Modelling

- Undertaking the modelling of the scenarios and assumptions developed;
- Taking lessons from early modelling and feeding this into updated modelling.

2.2 Lessons from the European Tour

The purpose of the European tour was to understand and learn the lessons from major pumped storage projects in Europe.

The European tour presented issues that ranged from technical and policy, to approaches toward asset investment and due diligence. Key finding from this tour that are relevant to this report are grouped under topic headings below.

Pumped hydro:

- The economics of a Pumped Hydro Scheme (PHS) is complex due to the separate factors that can impact buy prices and sell prices and volumes;
- The complexity is increased due to the transformation of power systems to renewable generation;
- In decarbonising economies, there is a long-term need for pumped hydro.

Policy and regulation:

- Governments can introduce major changes that result from major events;
- Market design may lag technology resulting in market revenues not fully equating to the economic value.

Market dynamics:

- A technology (such as solar) can impact the market in different ways depending on many factors such as the mix of other generation;
- The market, using existing and new technologies, will attempt to deliver the services of value, such as flexibility and fast response;
- Old technologies such as coal plant can change through increased plant flexibility and commitment to avoid operation at low/negative prices.

Increased uncertainty:

- With no assumptions certain, the spread of potential market outcomes is wider than many studies undertaken in the past have considered;
- The probabilities of major changes are higher than "normal" market analysis would indicate.

2.3 Characteristics of Long-life Assets

Snowy 2.0 is a large, long-life asset with economics that require assessment over 50-plus years in a market that is currently undergoing rapid change.

Long life assets 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 based on the opportunity cost of the project, this being the costs that would be needed if the asset was assumed not in service.

2.4 Methodology

2.4.1 Statement of Objectives

The methodology was designed to:

- 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;
- Quantify and illustrate the requirement, value and fundamental economics of storage capacity (MW) and storage energy (MWh) as the NEM develops;
- 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;
- Identify the key uncertainties;
- A modelling approach that provides for transparency in the economic assessment.

2.4.2 Approach

The approach consisted of four aspects:

- A process designed to ensure completeness and rigour;
- The use of modelling designed to address the requirements of the study;
- Quality control process.

2.4.3 Study Steps

The study steps involved the following:

- Review of the NEM and the transformation that is occurring;
- Identification of the key factors that would influence NEM outcomes. This included:
  - changes to coal plant parameters such as minimum generation levels
  - gas costs into the future;
- Characterisation of the manner Snowy 1.0 and Snowy 2.0 would operate;
- Defining the approach to the impact Snowy 2.0 would have to carbon emissions in the NEM;
- Development of a Base Scenario and modelling of this scenario;
- The modelling used different models for the periods:
  - 2018-19 to 2046-47
  - 2047-48 to 2074-75;
- Development of alternative scenarios for modelling, and modelling these in the same manner as the Base Scenario;
- Modelling conclusions.

2.4.4 Models

Two models were used:

- Market simulation model PROPHET – this model captures in detail:
    - the physical characterisation and constraints of generators and transmission
    - the NEM market arrangements (i.e. bidding, spot price formation, settlements)
    - dynamics of the NEM and how Snowy 1.0 and Snowy 2.0 would operate within the NEM
    - statistical variations due to demand variations associated with weather, generator breakdowns, wind and solar variability etc.;
- 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.

2.4.5 Quality Control

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

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

3. 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 chapter presents the representation used in the modelling of Snowy 1.0 and Snowy 2.0.

This chapter presents for Snowy 2.0:

- The physical assets and transmission connection to the NEM;
- Hydrology (i.e. water storage and water inflows);
- Round Trip Efficiency (or cycle efficiency);
- How Snowy 1.0 and Snowy 2.0 would bid in the NEM.

3.1 Snowy 2.0

3.1.1 Power station

Snowy 2.0 is a pumped hydro storage 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 this 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:

- 6 x 333 MW turbines with a total capacity of 2,000 MW;
- 3 of these turbines are "variable speed" turbines that provide for increased flexibility of operation (see Appendix 1);
- The period of full and continuous operation when headwater reservoir is full is 175 hrs (which equates to 7.3 days);
- Round Trip Efficiency (RTE) losses are about 24% (i.e. 76% cycle efficiency;
- The maximum capacity of Snowy 2.0 operation is about 43% (which corresponding to 57% pumping). Given the need to ramp up and down the maximum capacity factor would be less than say 38%;
- This capacity of Snowy 2.0 would increase the capacity of the Snowy Hydro scheme to 5,720 MW (an increase of 53%).

3.1.2 Snowy 2.0 Cycle Efficiency

The RTE of Snowy 2.0 (or any pumped storage including T3 pumping) refers to 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, water level in the upper reservoir etc. For a hydro power station with multiple generators and pumps, it would also depend on how generation and pumping is 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.

3.1.3 Connection to the NEM

The AEMO Integrated System Plan (ISP) presented a transmission plan that has:

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

The ISP indicated that the transmission upgrades between VIC, NSW and Snowy 2.0 are needed regardless of whether Snowy 2.0 is developed, but that they would be developed to coincide with Snowy 2.0 entry should Snowy 2.0 proceed.

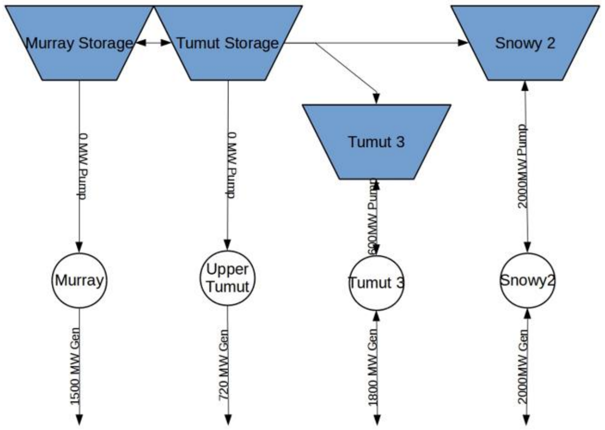
3.2 Snowy 1.0 and Snowy 2.0 Hydrology

Figure 1 shows the configuration of Snowy 1.0 and Snowy 2.0 used in the modelling. The following are noted:

- 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;
- The inflows to Eucumbene include the inflows to Tantangara;
- Tumut includes Tumut 3 and Tumut 3 pumping;
- The Tumut 3 reservoir is used to account for Tumut 3 pumping. Talbingo is the head reservoir for Tumut 3 Power Station;
- Snowy 2.0 is a separate scheme with a lower and upper reservoir (Tantangara). Tantangara has its inflows assigned to Murray and Tumut (Tantangara is connected to Eucumbene through a diversion tunnel.);
- Water can be provided to Tantangara if Snowy 2.0 generation is required and Tantangara water level is low.

[2] 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).

Figure 1 Snowy Hydrology



Source: Marsden Jacob Associates

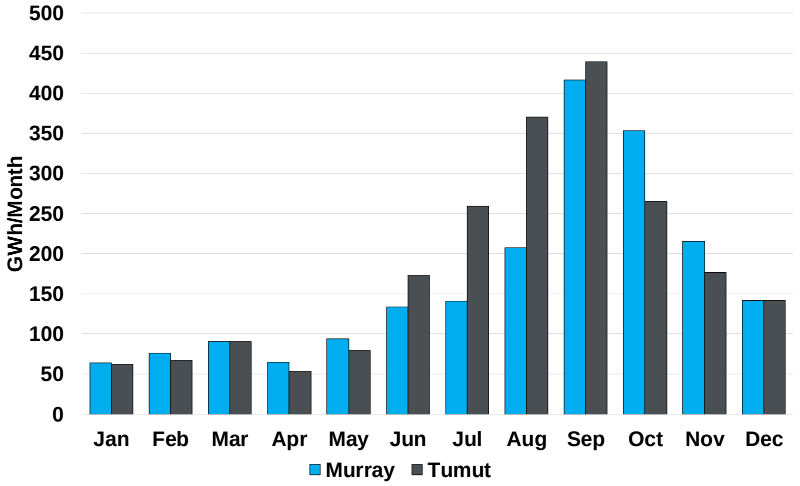
3.2.1 Pattern and variability of Inflows

The inflows to the Murray and Tumut sides of the scheme (which represent the sum of inflows to all reservoirs) 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 2 presents the monthly pattern of inflows to Murray and Tumut. This data was available from AEMO and SHL.

Figure 2 Snowy 1.0 – Murray and Tumut Average Annual Inflow Profile



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

3.3 Snowy 1.0 Operation

The modelling assumed that Snowy 1.0 operates independently to Snowy 2.0 (although in practice they share Talbingo and there is a relationship) except under circumstances of very low Tantangara reservoir storages, in which case water may be transferred at a specified rate from Eucumbene (represented as Tumut and Murray share separately) to Tantangara.

In all scenarios except drought scenarios, Snowy 1.0 was operated to use its allocated water and to use the flexibility provided by the large size of Eucumbene to match generation and pumping with market opportunities over each year.

3.3.1 Operating Rules

For each of the Tumut and Murray schemes independently, the operating rules were provided by SHL and related to the preferred times and conditions to operate Snowy 1.0 and Snowy 2.0.

3.3.2 Snowy 2.0 Offer and Bid Curves

Murray, Tumut (i.e. Snowy 1.0) and Snowy 2.0 dispatch on a half hourly (or 5 minutely) basis were determined separately through 10 band offers curves (to generate) and 10 band bid curves (to pump), in the same way this is done in the actual NEM.

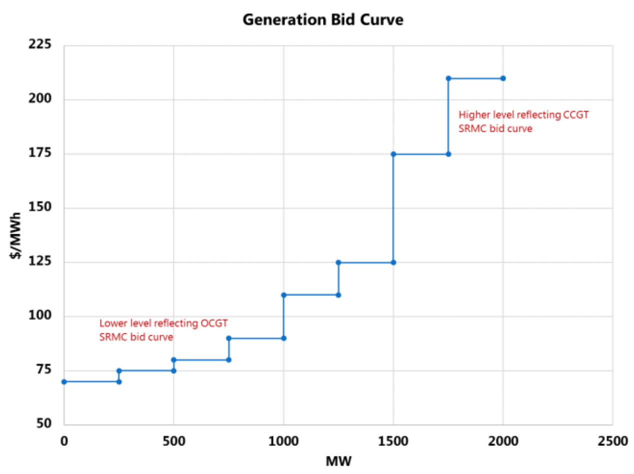
The curves were established and dynamically varied through a simulation model run. Variations in the offer and bid curves were modelled in response to changing reservoir levels that supply each respective scheme, and market conditions. The stepped offer and bids curves also ensured that Snowy 2.0 ramping up and down from full pumping to full generation was undertaken over a suitable amount of time. The price profile of the bid curve reflected the "value of water". Economic operation requires that the value of water is correctly determined and not frequently changed.

The offer and bid curves were developed through testing the respective profile of the curves and the required "gain" on the control loops associated with regulating the respective reservoirs. The modelling did require some modelling iterations to obtain the optimum trading from SHL. Each profile has 10 steps and were developed to have Snowy 2.0 operate in an optimum manner.

Figure 3 presents an example of the offer and bid curves used in the modelling for Snowy 2.0.

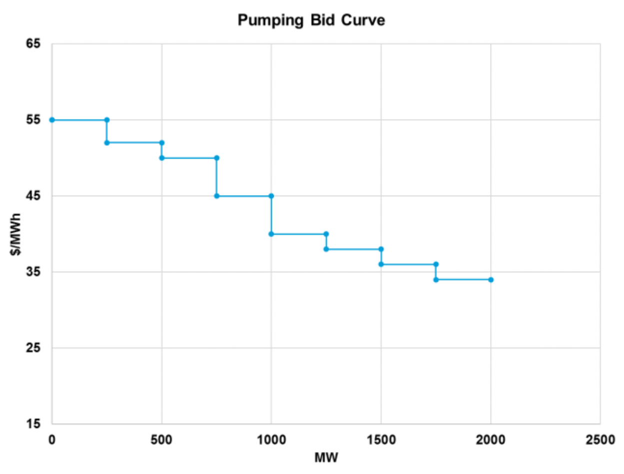
Figure 3 Example Pumping and Generation Bid Curve

Offer Curve (for generation)



The generation offer curve is determined based on most recent bid curves for alternative comparable capacity such as OCGT and CCGT.

Bid Curve (for pumping)



The pumping bid curves take into account the lowest possible bid curve in NEM such as renewables and coal.

Source: Marsden Jacob Associates

4. Presenting the Impact of Snowy 2.0

The chapter presents the framework used for presenting the impact of Snowy 2.0 to the NEM.

There were two aspects considered in this study:

- The first is 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 total NEM 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.
- The second, which can be considered as part of market benefits, is the carbon emissions impact of Snowy 2.0. The methodology for undertaking this is described in Chapter 22 with the results of modelling.

The sections below present descriptions of the above noted issues.

4.1 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 (i.e. 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 AER for use in the RIT-T was used as the basis for the framework for quantifying the economic impact Snowy 2.0 would have to the NEM[3].

The components of market benefits used in the study are:

- Capital costs of new assets – generation and transmission;
- Change in fixed costs associated with changed retirement dates of existing generators;
- 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).

4.2 The NEM "with Snowy 2.0" and "without Snowy 2.0"

For each scenario modelled the impact of Snowy 2.0 was determined through:

- 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"
- 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".
- Comparing the differences on an annual basis between the two modelled cases.

—

[3] The definition of market benefits as presented in the RIT-T was presented in the State 1 report.

4.3 Firming

In the energy market, the services Snowy 2.0 provides have been expressed in ways such as spot price arbitrage.

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:

- Spot market:
  - 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
  - provides firm capacity thereby reducing the amount of peaking capacity required;
- Retailer hedging / firming products:
  - the firm capacity that Snowy 2.0 provides in the spot market can be sold as cap contracts
  - 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
  - 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:

- Dispatchable generation and storage is required for firming to support the x% of demand being supplied by VRE;
- There is also 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;
- These two components are difficult to separate;
- 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 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 (i.e. there is some VRE "spill").

5. Modelling Assumptions

NEM scenarios provide a description of how the NEM will develop which includes quantitative assumptions on matters that include demand growth, costs, new generation and transmission policy, and so on. This chapter presents the assumptions that populate the scenarios presented in this report. Some assumptions contain a range of values and each scenario specifies the value(s) used.

The development of the scenarios and modelling approach began with a review of the NEM outlook and underlying assumptions developed by AEMO as part of their information provision and planning roles, announcements by relevant parties, State and Federal policy, and current NEM outcome trends.

From this review a set of "base assumptions" were developed. The base assumptions were developed from sources that include the following:

- The most recent publications by AEMO:
  - Electricity State of Opportunities 2018 (ESOO 2018) published August 2018
  - Integrated System Plan (ISP) published July 2018
  - National Electricity Forecasting Report 2017 Update published March 2018;
- Gas projections from Marsden Jacob assessment;
- Coal plant reliability and flexibility parameters (from the review by a third party expert);
- Assessments by Marsden Jacob.

A summary of the key assumptions is presented in the sections that follow.

5.1 Demand growth

The last 10 years of demand projections from AEMO are well understood, which is that demand growth flattened and decreased over the period 2008 to 2017 and has now appeared to have levelled off, while AEMO continued to overstate projections until possibly 2016. The reasons for this were energy efficiency, increased electricity prices and rooftop PV. This graph from the AEMO 2018 ESOO is shown in Figure 5.

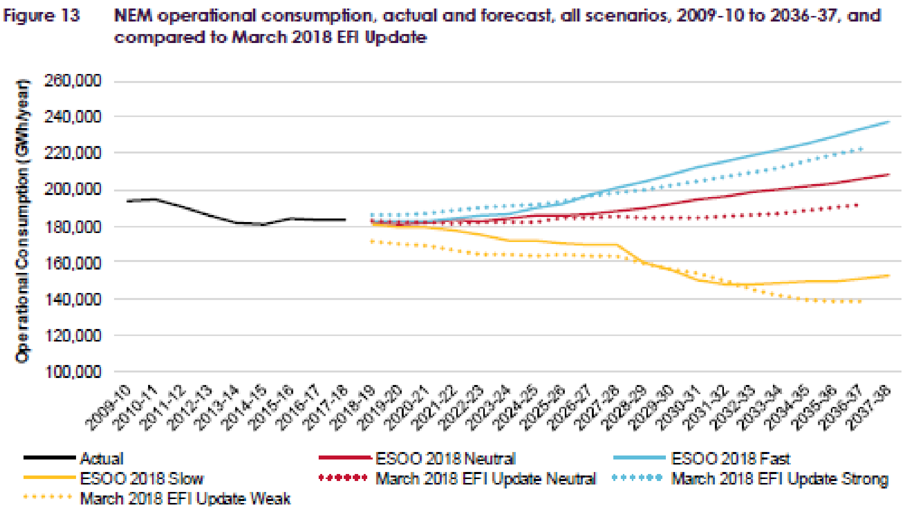
The AEMO demand projects contained in the 2018 ESOO (shown in Figure 4 below) show an increase in NEM wide demand outlook from the flatter outlook contained in the 2017 ESOO. While AEMO do not publish details of their projections, reasons for the increase over 2017 are the Portland smelter remaining in service and higher economic activity.

Marsden Jacob commenced modelling using the flatter 2017 AEMO demand projection and this demand outlook was the basis of the base case demand projection used. While conservative when compared to the AEMO 2018 demand projection, the "flatter" 2017 AEMO demand outlook is considered reasonable and prudent when the wide variation between the low demand outlook and high demand outlook is considered.

There is potential for demand to be higher than projected. Components of demand that would result in increased demand are Electric Vehicles (EV's), lower electricity prices, increasing population, and increasing industrial demand.

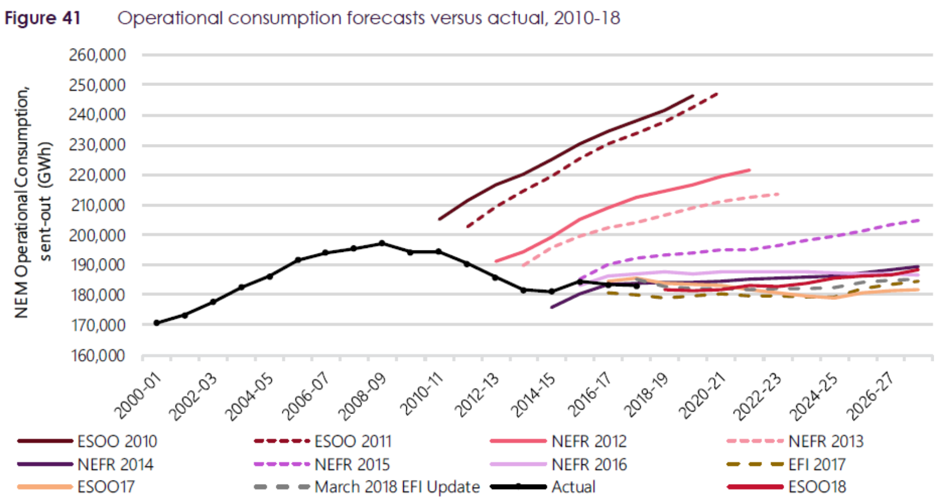
Lower demands primarily result from industrial demand reduction (including smelters) and higher take-up of behind-the-meter rooftop PV and battery storage.

Figure 4 AEMO NEM Wide Demand Projection contained in the 2018 ESOO



Source: Figure 13 AEMO 2018 ESOO

Figure 5 Historical NEM Projections to Actual



Source: Figure 41 AEMO 2018 ESOO

5.2 Coal generator closure profile

The closure profile of the existing coal generators in the NEM is a very important assumption. A longer continuation of the coal power stations would delay the development of new VRE and gas generation and would dampen the value of storage.

Apart from Liddell, there are no publicly announced coal generator retirements. Assessments by AEMO and transmission planning bodies on the closure profile is based on power station age and assessments of remaining economic life. It is understood AEMO also undertake confidential talks with the power stations to support their assumptions.

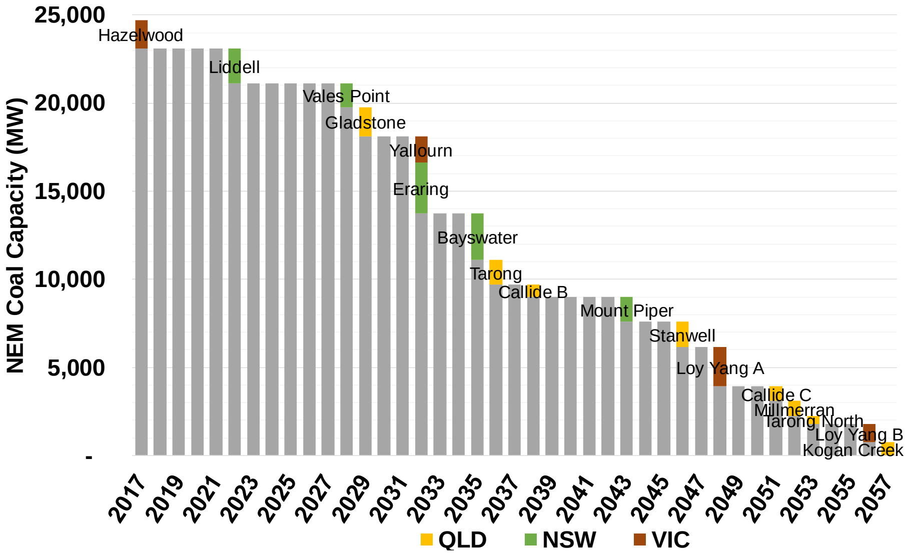
The basis of the coal closure profile used in the modelling was the profile presented in the AEMO ISP. This closely matched coal plant closing after 50 years of service except for Loy Yang A and Loy Yang B which closed after 60 years of service. The closure dates are shown in Table 1. Figure 6 shows the reduction in coal power station capacity resulting from this closure profile.

Table 1 Coal Power Stations Closure Dates (Base Scenario)

State	Power Station	Closure Date
Queensland	Tarong	2036
	Tarong North	2053
	Stanwell	2046
	Callide Power Plant	2051
	Callide B	2038
	Millmerran	2052
	Kogan Creek	2057
	Gladstone	2029
New South Wales	Eraring	2032 (calendar) (1)
	Vales Point	2028
	Mount Piper	2043
	Bayswater	2035
Victoria	Loy Yang A	2048
	Loy Yang B	2056
	Yallourn	2032

Note (1) Origin Energy have indicated that Eraring will be closed by 31 December 2032

Figure 6 NEM Wide Coal Generator Closure Profile



Of note are the following:

- By 2035 55% of coal plant would have closed
- By 2045 75% of coal plant would have closed
- All existing coal plant would have closed by 2060.

Source: Marsden Jacob Associates

Marsden Jacob slightly modified this closure profile for the purposes of minimising the size of annual disruptions that would likely be agreed to prior to closure. This had coal generator closures organised in order to minimise annual step changes (to minimise disruption and maintain reliable supply).

5.3 Existing coal generator performance

Coal power stations remain the dominant generation type in all States other than SA and Tasmania, and the operation of these plants can have a significant influence on the economics of new generation.

The key performance issues for operating coal plant are:

- Availability, also referred to as generator reliability;
- Minimum Generation ("mingen") – this is the minimum level of output before high cost auxiliary fuel is required (making reduction in output below this level expensive);
- Ramp rate – the maximum rate at which a generator unit can increase or decrease power (MW) output.

These performance issues are relevant to the economics of VRE and consequently storage.

5.3.1 Coal Generator Ramp Rates

Increased ramp rates would reduce the amount of surplus low-cost coal generation for pumping and increase the amount of fast response capacity provided by coal plant, thereby reducing the supply need from other sources.

5.3.2 Coal Generator Forced Outage Rates

Generator forced outage rates are important as reduced generator reliability would act to increase spot price volatility due to generator breakdown, thereby increasing the economics of gas plant, VRE and storage.

Table 2 shows the generator forced outage rates provided by AEMO, those assessed by a third party expert, and the differences between these.

Table 2 Coal Generator Forced Outages Rates

Power Station	AEMO	Third Party	Difference
Eraring	4	5	1
Mt Piper	1	3	2
Bayswater	2	3	1
Tarong	2	5	3
Stanwell	1	3	2
Callide B	3	6	3
Tarong North	0	5	5
Callide C	6	6	0
Millmerran	8	9	1
Kogan Creek	3	4	1
Vales Point	4	6	2
Liddell	3	16	13
Gladstone	5	7	2
Loy Yang A	4	4	0
Loy Yang B	3	3	0
Yallourn	6	8	2

From previous work undertaken by Marsden Jacob staff, modelling has shown that in relation to the impact on power system reliability, an increase in the FOR is approximately equivalent to the removal of generator capacity equal to the average capacity reduction associated with the increased FOR.

The average increased in FOR (excluding Liddell) is 1.7%, which is equivalent to an amount of coal capacity of about 300 MW.

Marsden Jacob used the third party expert assessed FORs in the scenarios modelled.

Source: AEMO and Third Party Expert

5.3.3 Coal Plant “mingen” levels

Reduced mingen levels would reduce the amount of “surplus” coal generation that would be available for pumping at low spot prices. Of the three coal plant performance issues noted, reducing mingen levels is likely to provide the greatest impact to the economics of pump storage through the influence this would have on the availability of low-priced pumping energy.

Review of mingen levels and actual coal plant operation showed that for most coal plant there was an alignment of design values and observed outcomes, and that these were the same as AEMO published data. There were four exceptions:

- Mt Piper, Bayswater, Loy Yang A had minimum levels 50MW lower than AEMO;
- Millmerran: AEMO minimum 170MW, market data 320MW.

The modelling used the actual observed minimums.

Through the work by a third party expert various options were identified that could reduce mingen levels. These were considered through sensitivity analysis.

5.4 Transmission development

The AEMO ISP published in June 2018 presented a long-term transmission development plan based on the NEM moving to increased levels of VRE generation and storage as the coal plant closes. This outlook was founded on the stated need to decarbonise and the basis that VRE plus firming will be lower cost than coal and gas generation, even in the absence of carbon abatement limits (and associated pricing).

The major upgrades proposed in the ISP were as follows:

- Increased interconnection capacity between NSW and QLD (upgrades of 190 MW and 460 MW for a total of 650 MW in both directions by 2020);
- Increased interconnection capacity between NSW and VIC (170 MW in both directions);
- Riverlink - an 800 MW interconnector between SA and NSW;
- Bannaby link[4]: provides Snowy 2.0 connection to NSW (reference node) and a 2,000 MW increase (in both directions) between Snowy and Sydney;
- Kerang link[5]: 2,000 MW increase (in both directions) between Snowy and Melbourne.

The ISP had the Bannaby and Kerang links developed by 2035 without Snowy 2.0 to support the increased transmission and Renewable Energy Zones (REZ) required (associated with increasing VRE), with Bannaby link developed to coincide with Snowy 2.0 and Kerang link moved forward to 2030 should Snowy 2.0 be developed.

It was concluded that the transmission timing in the Base Scenario would be as are presented in Table 3. The 2026 development of the Bannaby and Kerang links in the Base Scenario reflected a belief that these will be required with the closure of NSW and Vic power stations, to support VRE development and provide firm capacity to SA via Riverlink.

[4] ISP refer to Bannaby link as Snowy link North

[5] The ISP refer to Kerang Link as Snowy link South.

Table 3 Transmission Development Scenarios

Update	Without Snowy 2.0		With Snowy 2.0	
	Base Scenario	AEMO ISP	Base Scenario	AEMO ISP
Riverlink	2024	2022 to 2025	2024	2025
NSW-QLD upgrades	2025	2025	2025	2025
Vic-NSW upgrade	2021	2021	2021	2021
Bannaby Link	2026	2035	2026	2026
Kerang Link	2026	2035	2026	2035

5.5 Supply side options and costs

The generator options considered in the modelling were as follows:

- HELE coal plant;
- Gas plant – CCGT, OCGT, and reciprocating;
- Renewable generation - solar generation and wind generation.

The main storage providers in the NEM and that were considered in the modelling were as follows:

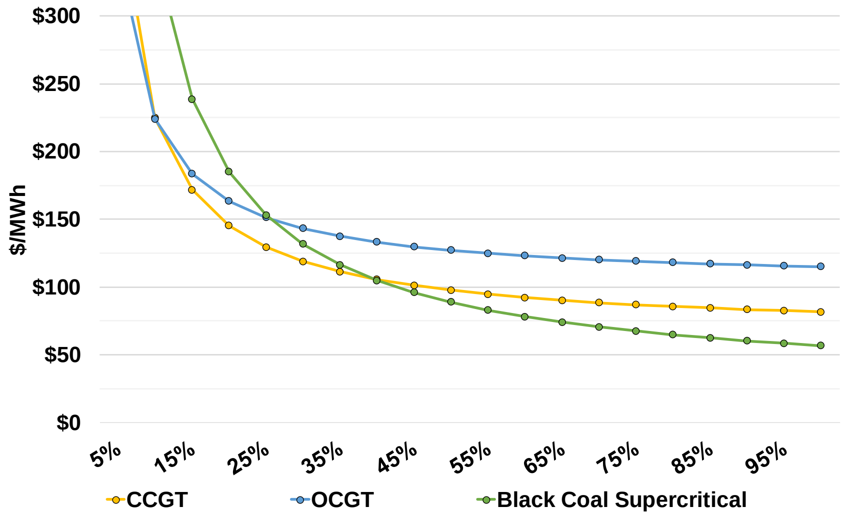
- Large scale pumped hydro schemes. There are only two:
  - Snowy 2.0 which includes the potential further development of Snowy 3.0;
  - Battery of the Nation – Basslink II plus potential developments to the hydro systems in Tasmania. This is supported by the Tasmania government and has economics that requires Riverlink to be developed (which appears near committed) and increased VRE development. Battery of the Nation has not been costed and has unknown economics.
- Small scale pumped hydro schemes. The geography of Australia limits the number of sizeable and economic sites. Two that are being considered are Kidston6 in northern Queensland (200 MW and 8 hours of storage) and Cultana in South Australia (up to 250 MW). The Kidston project was assumed to be developed in the modelling.
- Batteries. Batteries were the principal storage technology developed in the AEMO ISP modelling, and possibly are the most direct competitor to pumped hydro storage in the NEM. However, on the current cost curves batteries with storage hours of over about 4 hours will not be economic on spot market revenues until past 2040.

Figure 7 presents the costs of these generator types and battery storage:

- Costs of conventional thermal plant (coal, CCGT, OCGT) are not expected to decrease significantly, noting that coal HELE plant are expected to decrease in cost. The cost for these plants, expressed as $/MWh, increase as the capacity factor reduces (as capital is supporting as lower level of generation). The cost of these plants in 2019 is a function of capacity factor;
- Solar and wind generation costs are projected to continue to decrease. As these types of generators have a fixed capacity factor they are expressed as $/MWh;
- Battery costs, expressed as $/kW, vary with the amount of storage hours. This means that storage hours need to be specified – the costs shown in the figure below are based on 4 hours storage.

[6] https://www.genexpower.com.au/project-details.html

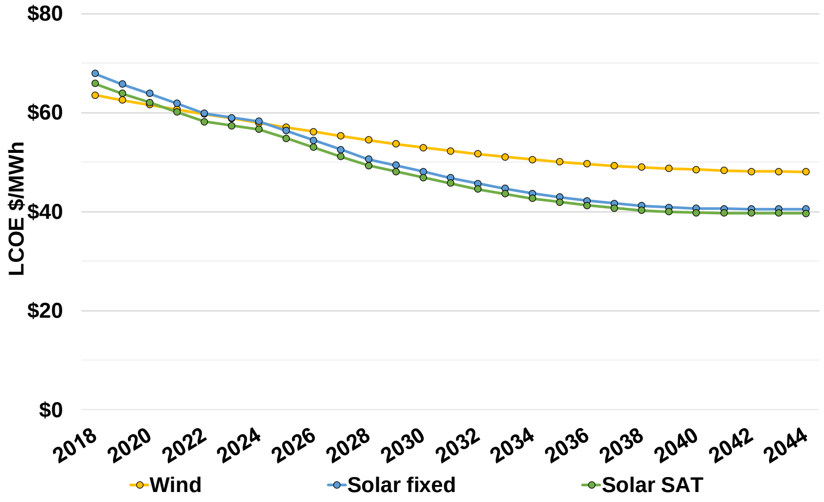
Figure 7 Costs Generation – VRE and Thermal, and Batteries



Thermal Generation LCOE $/MWh

As dispatchable generation output is controllable, cost is expressed based on the capacity factor of operation.

Source: Marsden Jacob Associates

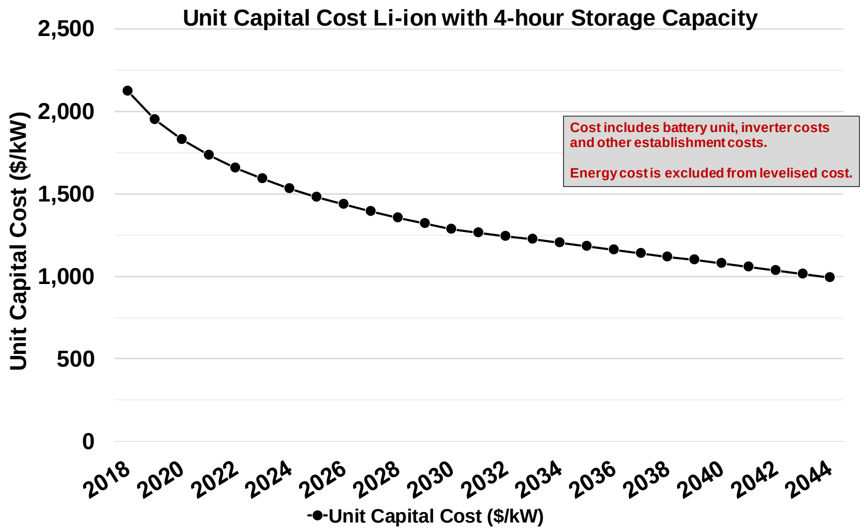


Solar and Wind Generation LCOE $/MWh

Solar and wind generation operate based on sunlight and wind.

Cost is based on generation at the expected available outlook level.

Source: Marsden Jacob Associates



Battery Costs $/kW/year

Battery costs are more appropriately expressed as $/kW/year based on a specified level of storage (usually expressed as hours of operation when storage is full).

Source: Marsden Jacob Associates

5.6 Gas and Coal Costs

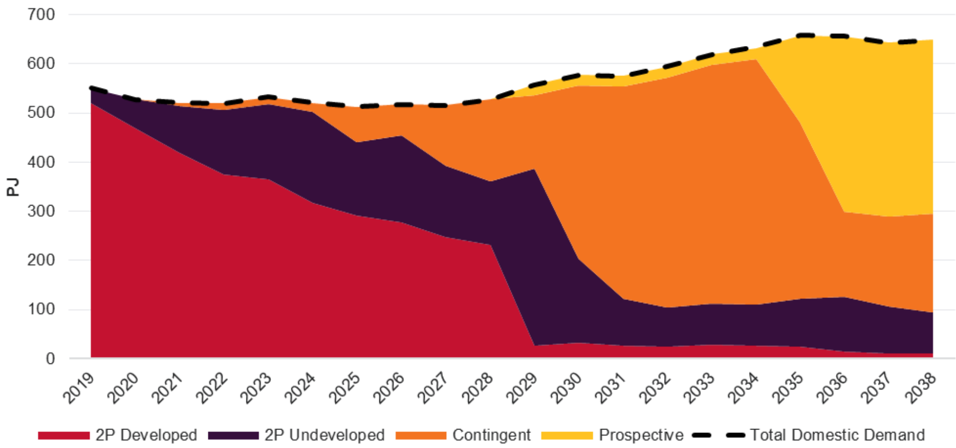
Gas and coal costs are fundamentals to NEM market outcomes, the arbitrage price spread (while these plants are operating), and the economics of the various generation technologies.

The AEMO 2018 GSOO indicated that while the gas outlook may have improved in the medium term, the gas reserve outlook is that substantial new reserves are required and that these will likely be at higher cost. Taken from AEMO publications:

> "A change in international market dynamics, lower demand for gas-powered generation, new pipeline interconnections and the Federal Government's Australian Domestic Gas Supply Mechanism (ADGSM) have delivered an improved outlook for Australia's east-coast gas markets."[7]
>
> "The reserve mix required to meet domestic demand is shown in Figure 8 below [Figure 3 in the AEMO report], with rapid decline in production from 2P developed and undeveloped reserves clearly visible, mostly from fields located within the southern states.
>
> As existing fields decline, exploration and development will be needed to deliver these contingent and prospective resources to market. These new gas supplies will help improve adequacy of supply but, as flagged in the 2017 GSOO, supply from these fields is likely to be more costly than existing production."[8]

The reserve outlook published in the 2018 GSOO is presented below. As observed by 2025 there is a substantial shortfall in the known commercial gas required to satisfy demand[9].

Figure 8 AEMO 2018 GSOO - Status of reserves and resources to meet domestic demand, 2019-38



Source: AEMO 2018 Gas Statement of Opportunities, June 2018. For eastern and south-eastern Australia

To assist in the outlook of gas prices, SHL commissioned a study to provide an outlook of the east coast gas market. This outlook concluded that the gas supply outlook was very tight, in particular:

- Supply from Gippsland which produced 360 GJ in 2017 (about 50% of the east coast domestic gas demand) would have a production output of half this by 2026 and exhausted by 2036;
- Lifting the gas moratorium in Victoria would have little impact for at least 10 years and possibly for much longer;
- NSW is unlikely to have any significant gas production;

—

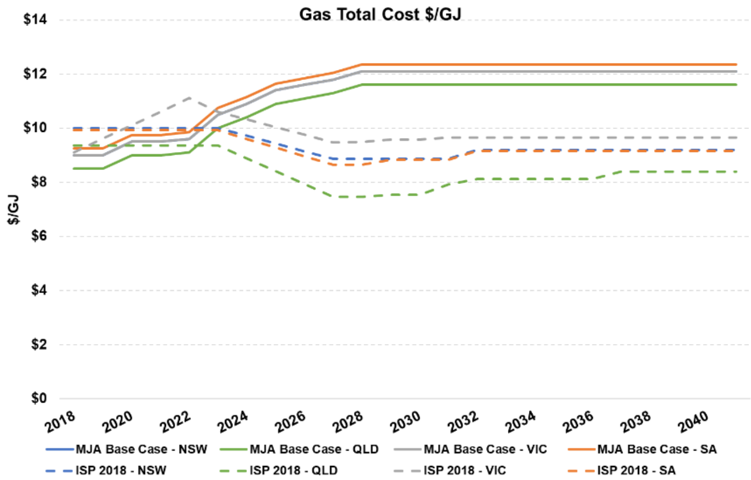
[7] http://energylive.aemo.com.au/News/Sector-changes-deliver-improved-gas-supply-outlook
[8] AEMO 2018 GSOO Executive Summary
[9] Proven and Probably (2P) commercially recoverable from known accumulations. 50% probability that the quantities will equal or exceed the estimate
Contingent gas is potential recoverable from known accumulations but not ready for commercial development
Prospective resources are potentially recoverable from undiscovered accumulations such as shale gas

- All low-cost Queensland Coal Seam (CSG) has been allocated for export. The Queensland CSG available for the domestic market is lower productivity and higher cost gas;
- Gas from Northern Territory remains prospective and high prices may be required for this to be commercial (i.e. made 2P gas);
- Imported gas will possibly be needed.

The consequences of this is significant level of uncertainty regarding where the future gas will come from and the cost of this gas. The resulting indicative gas prices were higher than that used by AEMO in the ISP modelling and had a floor of about $8/GJ delivered to Melbourne.

Using the above information and Marsden Jacob's own modelling, the gas price outlook (for delivered gas) for the Base Scenario, and the AEMO outlook used in the ISP modelling, are shown in Figure 9 below.

Figure 9 Delivered Gas Prices $/GJ



Source: Marsden Jacob Associates

5.7 Behind the meter response and costs

The modelling separately modelled rooftop PV, behind the meter batteries, and incorporated demand response.

Rooftop PV

The projections of rooftop PV were those developed by AEMO for the ISP. Changes to this projection were made on a scenario basis.

Behind the meter batteries

The projections of distributed batteries were developed based on economics and usage profile. This was consistent with that of the AEMO ISP. The charging and discharge profile were developed by Marsden Jacob, and this was also close to that used by AEMO in the ISP modelling.

Electric Vehicle's may participate in grid storage, but the initial findings from high penetration markets suggests they're unlikely to. Our initial research suggests that EV batteries are more likely to draw from the grid than contribute to the grid (Vehicle-to-Grid).

Demand Management

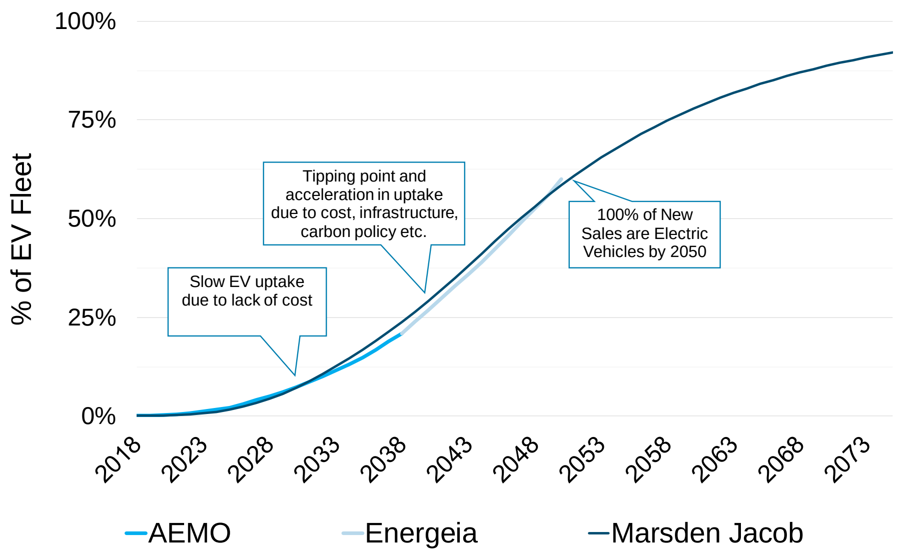
Demand side management was included in the modelling. The assumptions were that used by AEMO in the ISP modelling.

5.8 Electric Vehicles

Marsden Jacob expects that take-up of EVs is likely to be slow out to the mid-2020's given the relatively higher cost of EVs compared to Internal Combustion Engine (ICE) vehicles, as well as factors including insufficient charging infrastructure, a low number of different models, and concerns about range and servicing. We then expect a strong acceleration in take-up as EVs become cost competitive, the technology is proven, and infrastructure is in place. We expect to see saturation by 2055-60 (which would equate to about 55-60TWh of new demand), given EVs are expected to be considerably cheaper to buy and operate and zero (or very low) carbon emissions policies are likely to be in place. There will likely be only a small number of "vintage' ICE vehicles remaining in operation.

AEMO's current ('neutral' scenario) expectations for EV penetration are for 2% of the fleet (440k vehicles) to be EV by 2025, 7% (1.6m vehicles) by 2030 and 21% (5m vehicles) by 2038, and recent forecasts by Bloomberg New Energy Finance (BNEF) are similar to AEMO. Marsden Jacob forecasts out to 2075 are shown in the following figure.

Figure 10 EV Projection



5.9 Emissions and Renewable Energy Policy

Environmental policy on limits on emissions and renewable generation is a fundamental assumption of NEM modelling. The current situation is as follows:

- The coalition have a policy that by 2030, electricity sector emissions will not exceed 26% of 2005 levels. They are proposing that this level not be changed and that no mechanism be introduced pre-2030 to satisfy the 26% emissions reduction;
- The coalition are silent on post 2030 emissions policy;
- While the coalition abandoned the National Energy Guarantee (NEG) there appears to be some consensus that the reliability obligation, in some form, be completed and implemented;
- The opposition have a policy of having NEM emissions limited to 45% below 2005 levels by 2030 and a renewable energy target of 50% by 2030;
- The opposition have indicated that NEG type arrangements would be considered for implementing the 45% emissions reduction policy.

The modelling scenarios undertaken and presented in this report contained those with and with emissions reduction limits.

The base assumptions had no emissions limits.

5.10 Marginal Loss Factors

The changing flow patterns in the NEM are resulting in large changes in Marginal Loss Factors (MLFs). For new renewable generators, particularly in northern Queensland this has MLS's substantially decreasing. This is a significant issue for the developers of new solar and wind facilities.

AEMO have held sessions canvassing potential solutions to this and potential options for changes to the approach to MLFs. This includes the introduction of Dynamic Marginal Loss Factors (DMLFs).

This is what was used in the modelling.

5.11 Renewable Energy Schemes

Currently there are three renewable energy schemes in operation. These schemes and their status are described below.

5.11.1 The Large-scale Renewable Energy Target (LRET)

LRET Overview:

- A federal government legislated scheme that commenced operation in 2020 and that is due to terminate on 31 December 2029;
- Covers the NEM, the Western Australian and Northern Territory electricity markets;
- Renewable generators create Large Scale Generation Certificates (LGC's) and each year wholesale energy purchases (mostly retailers) are required to purchase an individual obligation of LGCs. Individual obligations are determined by prorating that year's scheme target in proportion to energy purchase levels. There is a penalty for each LGC that should have been purchased;
- The maximum penalty price (called the Shortfall Penalty) is set at $65 per LGC, non-tax-deducible and constant in nominal terms over the life of scheme.

The committed generation eligible for LGCs is projected by Marsden Jacob to result in a significant stockpile of surplus LGCs not required.

5.11.2 The Victorian Renewable Energy Target (VRET)

VRET Overview:

- The VRET is a Victorian Government legislated renewable generation scheme that has a target of having Victoria 25% supplied by renewable generation by 2020 and 40% supplied by renewable generation by 2025;
- Complementary to the Federal LRET before 2020 and additional after 2020;
- VRET operates by offering long-term contracts to successful renewable energy projects (reverse auctions are held periodically);
- There are no tradable certificates.

The targets of this scheme are achievable and have been assumed to be met in the Base Scenario.

5.11.3 Queensland Renewable Energy Target (QRET)

QRET Overview:

- The QRET is a Queensland Government non-legislated renewable generation scheme that has a target of having Queensland 50% supplied by renewable generation by 2030;
- The QRET operates by offering long-term contracts to successful renewable energy projects (reverse auctions are held periodically);
- There are no tradable certificates.

The targets of the QRET will be challenging to meet for the following reasons:

- The substantial amount of coal plant in QLD and with Gladstone is the only power projected to retire pre-2030 (and this is in 2029);
- QLD is more suitable for solar generation and not suitable for large amounts of wind generation;
- Solar generation is more difficult to integrate than wind generation.

The targets of this scheme are achievable (although difficult) and have been assumed to be met in the Base Scenario.

5.12 Expressing the Percentage of Renewable Generation

The modelling results 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 LRET. The LRET reports the percentage of renewable energy supplied as follows:

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

The modelling for this study did not differentiate between pre and post 2997 renewable generation. The basis for the reporting the percentage of renewable generation in this study was as follows:

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

The calculation excludes biomass generation on which there is little information, but which LGCs are reported by the Clean Energy Regulator in their LGC register. This is currently about 2,500 GWh (about 2,000 GWh in Queensland). For Queensland we would expect biomass generation to contribute about 3% to4% to the QRET target of having electricity supplied by 50% renewables by 2030.

6. Ancillary and Other Services

This chapter presents the ancillary service revenue streams that generators can earn on the NEM, and a possible new service associated with energy security. The likely path of ancillary service prices is indicated

6.1 Frequency Control Ancillary Services

Frequency Control Ancillary Services (FCAS) were described in the Marsden Jacob Feasibility report and are not described here.

In relation to these services we note the following:

- FCAS services are 5-minute services with the quantity reflecting uncertainties in demand and generation;
- Batteries are well suited to providing FCAS services (raise or lower) and can do this to the extent they have spare raise to lower capacity. The amount of storage a battery has is not relevant as ancillary services operate over 5 minutes;
- While FCAS prices, particularly the raise services (6 second, 5 minute and regulation) have been averaging between $15 and $26 for 2017-18, these prices level are expected to decrease as increased supply enters the market. Increase supply will come from the demand side and batteries (small and large);
- The quantity of FCAs is small, averaging about 500 MW per service;
- The quantity of FCAS supplied is not expected to increase as the uncertainty in VRE will reflect improved output forecasting and increasing diversity;
- The result of the above is potentially a large excess of FCAS supply and an expected reduction in FCAS prices, down to below $5/MWh.

6.2 Energy Security Service

As the NEM develops to a higher percentage of generation from VRE, the reliability of supply will increasingly reflect both capacity adequacy and energy adequacy.

Energy adequacy would require the reservation of energy that can be called upon when energy reserves are low. This would increasingly reflect hydro reserves and possibly gas availability.

The value provided by an energy reserve may translate into a service contracted by AEMO. Snowy 2.0 would be an ideal supplier of such a service.

7. NEM Energy Market Transformation

The NEM is undergoing a transformation associated with the reducing costs of large-scale and distributed renewable generation, and moving forward the closing of aging coal power stations. The economics / narrative of this transformation is common to all future scenarios.

The purpose of this chapter is to describe the dynamics and economics of this transformation and the factors that will determine NEM development under different development scenarios.

The description is complex but important to the understanding of the economics of NEM development under the different scenarios presented in this report.

This chapter presents the underlying evolution that is occurring in the NEM and that is common to all scenarios, and which underpins the economic trade-off between different supply options. This is a natural precursor to the design of the modelling and scenarios.

While not quantitative, this chapter does utilise the outlook of the reference assumptions presented previously in this report.

In the context of Snowy 2.0 development it is convenient to divide the development of the NEM into three developments periods as follows:

- 2018 – 2025: This is the period prior to the (assumed) commencement of Snowy 2.0 and is a period that has a substantial increase in VRE. This period sets the market conditions that will exist when Snowy 2.0 would enter;
- 2025 – 2047: This period is the first 23-years of Snowy 2.0 operation. During this period most of the existing coal plant will close and the nature of the NEM will change substantially;
- 2048 to 2075: During this period, it is expected that the NEM will move to very high levels of VRE.

A summary of these periods is described in the table below.

The changing dynamics in each of these periods is presented in the sections that follow. The last section then presents the manner spot prices would be expected to behave accounting for the described changed NEM.

Table 4 NEM Development Periods

Before Snowy 2.0	After Snowy 2.0 Enters	
2018 – 2025: Increasing VRE	**2025 – 2047: Transition to near all VRE**	**2048 to 2075: Near all VRE**
• Increasing renewable generation in VIC and Qld. • Liddell closes (in NSW) requiring (according to AEMO) 1000 MW of replacement firm capacity into NSW. In 2022 this is provided by gas generation, battery, new VRE and increased interconnection to NSW. • SA-NSW interconnector (Riverlink) developed in 2024. • Gas market remain tight. • Coal plant operation starting to change. • Reduced retail margins and tighter wholesale energy purchase risk management.	• Major transition upgrades in 2025 (Kerang link and Bannaby link) provide increased support between SA-Vic-NSW. SA/Vic/NSW have the characteristics of a single region. • LRET and VRET have been completed. QRET has continuing VRE development in QLD. • Vales Point projected to close in 2028. • Continuing large scale VRE development reflects coal plant closures and a 2030 renewable or emissions policy. • All coal plant closes in NSW by 2044. • Post mid-2030's NEM energy surplus is reducing and firming capacity is increasingly required – storage and gas peaking. • Increase in load following contracts.	• NEM moves to a system dominated by VRE and firming largely provided by storage and gas plant. • Value of storage increases due to the increasing amount if VRE required to be stored for later use. • Likely that the transmission interconnection will be further developed. • Increasing periods of excess VRE result in spot prices reducing. • Price spread for Snowy 2.0 reflects low buy costs and gas type sell prices.

7.1 NEM: 2018 to 2025

7.1.1 NEM in 2018 - Mostly Thermal

The largest NEM States of Queensland, NSW and Victoria are predominately supplied by thermal generation (coal and gas). Tasmania is near all hydro, with some wind generation. SA is close to 60% supplied by wind and solar generation with support from SA gas generators and connection to Victoria.

On a total NEM wide basis the energy supplied by generation in 2017/18 was:

- 72% coal generation;
- 10% gas generation,
- 7% dispatchable renewable generation (hydro);
- 7% VRE (large scale wind and solar generation);
- 4% rooftop PV.

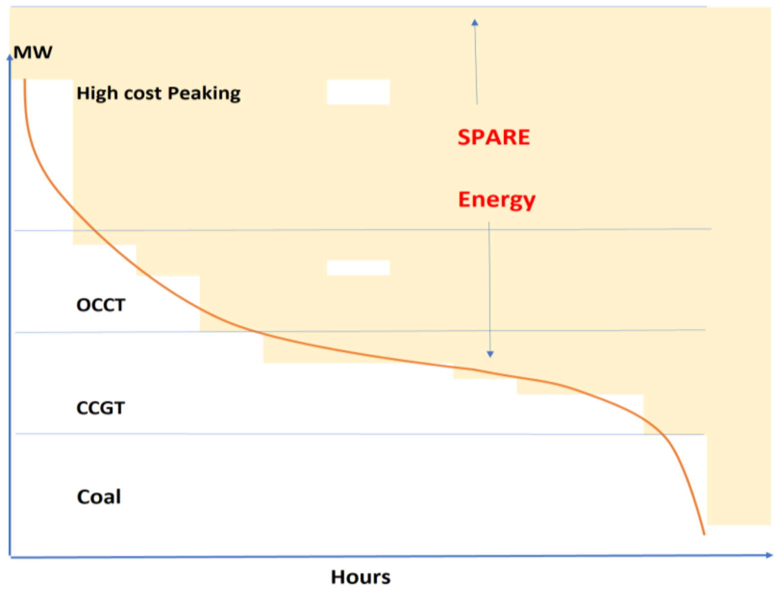
QLD / NSW / VIC

The characteristic of generation supply under a system dominated by dispatchable thermal generation (which applies to VIC, NSW and Qld) is illustrated in Figure 11. This figure shows a load duration curve[10] over a year and the generator types that supply this demand "stacked" from lowest operating cost to highest operating cost. From this figure we note the following:

[10] A load duration curve is the half hourly demands ordered from highest to lowest.

- All periods (except for a few hours each year during times of very high demand) have a substantial amount of spare generation. This means that the system is "energy long", as the unused generators can be used at any time to supply additional energy;
- System reliability is determined by the availability of generator capacity at times of very high demand (or when there are multiple generator outages);
- A "reasonable" amount of VRE generation can be absorbed within the flexibility of the thermal fleet (and possibly some moderate amount of storage);
- Spot prices reflect the supply and demand of thermal generators each dispatch period (can be volatile);
- Wholesale energy purchases do not require firming products.

Figure 11 All Thermal System



An all thermal system is energy long and possibly capacity tight.

Reliability is determined by capacity adequacy.

Tasmania

Tasmania is 95% hydro, 5% wind, with support from Basslink to manage energy surpluses and deficits.

Unlike systems high in thermal generation where supply reliability is determined by capacity outages, prior to Basslink, Tasmania had surplus capacity but had the risk of being short energy during drought years (and being long energy in wet years). This necessitated the need to have thermal generation for energy reserve (Bell Bay Power Station). An important factor in the economics of Basslink was the energy support it provided to Tasmania. The recent failure of Basslink highlighted the risk of energy shortages in a predominantly renewable power system.

South Australia

SA is a high VRE region supported by interconnection with Victoria, gas generation and a battery. SA is near the limit of the amount of VRE it can support. Additional gas plant is not economic before Torrens Island A closes, and additional interconnection is required for any new VRE development in SA to be undertaken. The benefits the proposed SA-NSW interconnector provide to SA are both improved supply reliability and the option to further develop VRE in SA.

7.1.2 NEM developments changes: 2019 to 2025

Major developments and issues influencing the NEM development over the period to 2025 include the following:

- An outlook of very little if any demand growth;

- A substantial amount of new VRE generation committed to enter in Victoria, NSW and Queensland, financially supported by the LRET, VRET, QRET;
- South Australia is near the limit of the amount of VRE that can operate within SA. For additional VRE to be developed in SA new interconnection is required (to and from SA);
- The closure of Liddell, which has been assessed[11] as resulting in NSW being 1,000 MW short of capacity. The capacity deficit is proposed to be supplied by a CCGT plant (indications are about 400 MW), increased interconnection to Victoria (150 MW) and Qld (300 MW), a possible battery and additional VRE;
- In 2025 the introduction of Snowy 2.0 would provide 2,000 MW of additional capacity;
- A substantial level of transmission development is projected (detailed in the AEMO Integrated System Plan). This is based on the transformation from predominately coal generation to predominately VRE generation:
    - among other things, Riverlink will provide for more VRE generation development in SA
    - Kerang link and Bannaby link will provide for REZs in Victoria and NSW
    - QLD-NSW interconnection upgrades will provide low cost generation from Qld to reach NSW;
- An outlook (as reflected in the forward curve) of reducing spot prices (from current levels averaging about $90/MWh) as the large amount of committed VRE enters;
- An outlook of a very tight gas market with gas prices projected to reflect international LNG gas prices;
- The potential for deteriorating reliability of the aging coal generators due to an observed increase in coal generator breakdowns;
- Government focus on limiting portfolio use of generator market power through potential penalties (such a requiring certain level of portfolio disaggregation);
- Uncertain federal environmental policy ranging from no new policy (Coalition) to a 45% reduction in emissions by 2030 (Labor). One element of agreement may be enacting the reliability obligation of the NEG.

7.1.3 NEM in 2025

The NEM will be different in 2025 than it is now and assuming Snowy 2.0 is developed by 1 July 2025:

- The NEM will have significantly more VRE installed than in 2018. Victoria will be supplied by 40% renewable, SA 86% supplied by VRE, NSW 20% and QLD 38% supplied.
- The amount of coal and gas plant provides for VRE to be absorbed into the system without the need for material firming assets;
- Transmission upgrades between SA-Vic-NSW will have been completed. This will have the effect of reducing both spot price differences between SA-VIC-NSW (due to both losses and flow constraints) and will have these three regions largely behave like a single “super” region. NSW-Vic arbitrage opportunities would be reduced;
- The QRET in Qld, plus no coal closures in QLD will have QLD a net exporter during solar generation periods to NSW;
- Coal generator operation will be forced more often to mingen levels, which will offer low cost pumping opportunities;
- Solar and wind generation have an increasing discount on average spot price.

---

[11] By AEMO

There would be insufficient time to develop a new coal power station before 2025, and a new coal power station would not be required regardless given the coal plant that will still be operating in 2025 and the entry of Snowy 2.0.

7.2 2025 to 2047 – Coal Plant Closing

The period 2025 to 2045 is the 20-year period where the NEM regions Vic, NSW and Qld move from being supplied mostly from thermal power stations to being mostly supplied from VRE (with support from gas and storage). This transition is projected to occur rapidly.

In the absence of any policy on emission limits, economics and investor preference will dictate how the closing coal generators will be replaced. This is given by spot price revenues and wholesale purchase risk. The potential new generators will be VRE (plus increasingly firming), gas and coal generation.

Coal generation development has significant hurdles and these hurdles are likely to increase moving forward. This is due to the bank lending policies on such assets, regulatory risk and the risk of negative consumer reaction[12]. That higher risk places gas plant ahead of coal plant for required thermal generation.

Gas generation has the risk of securing gas supply and at prices that would provide for such investments to be economic. The preference maybe for peaking supply that does not require significant quantities of gas.

VRE has the lowest cost of energy production but requires firming. As VRE increases, firming will be provided by surplus thermal plant and increasingly new gas plant and storage. Storage is essential once surplus low-cost VRE generation is required to be stored for later use. VRE will not replace dispatchable plant capacity, and firming capacity from storage and/or gas plant will be required.

The economics of replacing coal generation by VRE will be complex and difficult. In this regard the following are noted:

- On the current cost outlook for batteries, battery storage, to the amount that will be required in terms of capacity and energy, will not is not economic. The economics of battery development will likely require support by regulation (i.e. VRE generation will be required to include a certain amount of storage);
- Gas generation will be needed to provide the dispatchable capacity resulting from the closure of coal plant and the limited battery development expected;
- Snowy 2.0 would provide both storage and firm capacity (given it ability to operate for many continuous hours/day);
- Energy in storage will have an increasing value as it provides for both improved spot price arbitrage and the sale of premium based firming products.

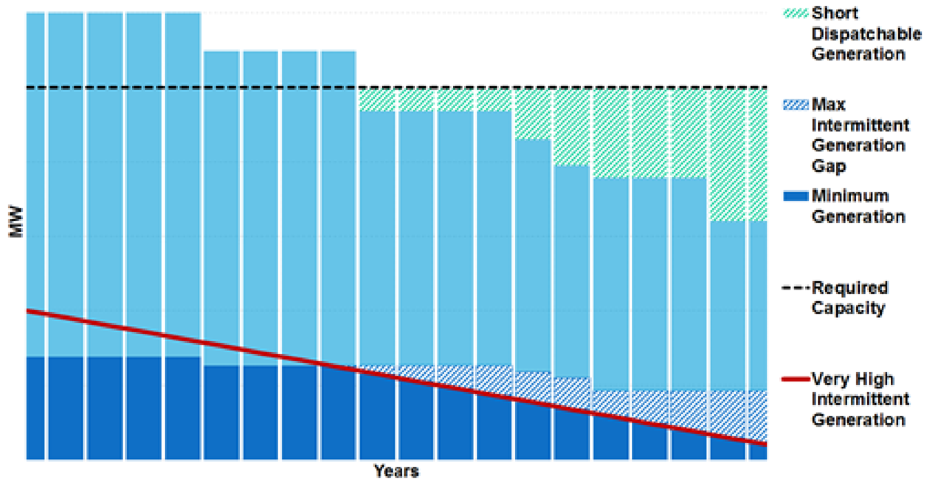
The transition of coal plant closure and increasing VRE will result in a changing dynamic over the period:

- Minimum generation level (mingen) presented by the coal fleet will reduce, thereby reducing one component of surplus generation available for pumping;
- The dispatchable capacity provided by the coal fleet will reduce, providing opportunities for new capacity to operate (and that will be required to meet high demands). This is likely to be gas plant or storage.

This is illustrated in Figure 12 which shows that as coal plant closes, total coal mingen levels decrease and a capacity deficit will emerge.

[12] The risk of coal development was identified in the Finkel report which placed a high-risk weighting on such investment.

Figure 12 Changing balance in the future (MW)



Source: Marsden Jacob Feasibility Report

7.3 2048 to 2075 – Move to high levels of VRE

Post 2047 (the last year of the PROPHET modelling) the operation and economics of the NEM will have been totally transformed. While the outlook is that there will be coal plant operating in Victoria and Queensland, these plants will be intra-marginal and will have little impact on the dynamics of the NEM. The transformation will be such that the current market arrangements may need radical change.

Given the above, NEM outcomes and economics over this period were considered by addressing the start and end points of this period and how the NEM may develop between these. Key considerations were as follows:

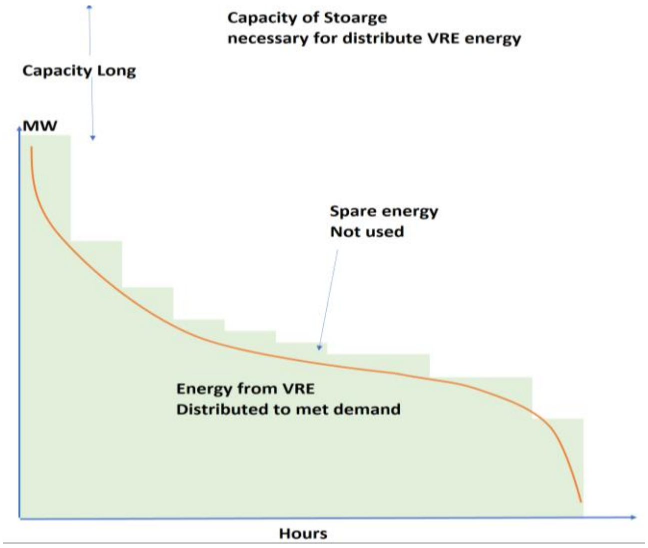
- The nature and economics of firming assets;
- The economic limit of the amount of VRE generation that can operate in the NEM. This will define the NEM once all the coal plant has closed;
- The transition to a NEM with no operating coal plant from its position in 2047.

7.3.1 Dynamics of a Near All Renewable Power System

In the same manner as Figure 11, Figure 13 below shows the load duration curve and generation supply over a year under an all renewable power system. The following are observed:

- Renewable generation would be that required to satisfy the total demand GWh. This would require a level of installed VRE such that demand is met in a year of very low VRE (due to low wind and/or solar conditions). This is different to a thermal system where generation is developed based on capacity requirements;
- Storage would be required to capture and store surplus VRE and use this for generation when VRE output is short of demand;
- The amount of storage capacity (MW) required would at a minimum be the winter evening peak demand - a time when there is no solar output and wind generation may be very low.
- The amount of energy storage would need to be sufficient to cover sustained periods of low VRE output and to capture sustained periods of surplus VRE output. Such periods include:
    - days of low wind and solar
    - “wind drought” which can be for extended periods (weeks)
    - seasonal variations – solar is high in summer and low in winter
    - drought years where hydro generation is low.

Figure 13 All VRE and Storage System (2075)



All VRE and storage system is energy short and possibly capacity long.

Reliability is determined by energy adequacy and capacity adequacy.

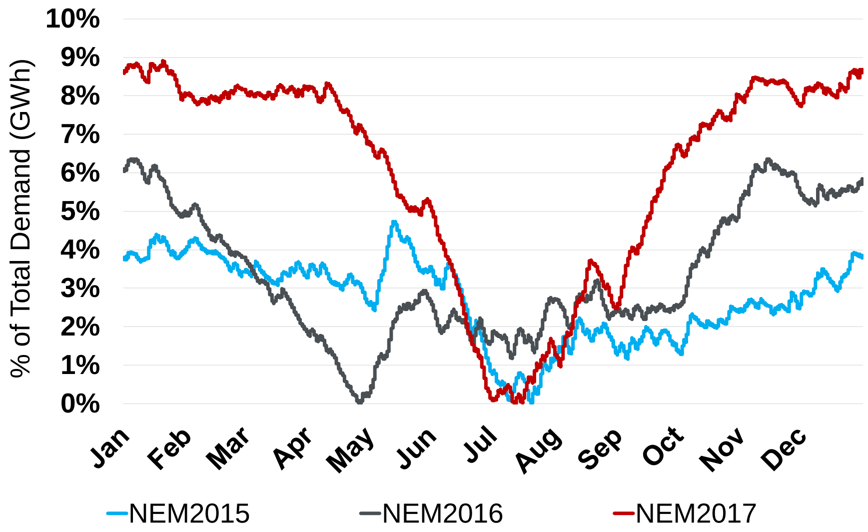
Source: Marsden Jacob Associates

7.3.2 VRE Output Variability

The profile of VRE generation through a year can vary significantly from year to year. There can be very large seasonal and annual variations. This means that at a very high level of VRE, thermal generation support would be required.

The variability of VRE generation output through a year is illustrated in Figure 14, which shows the state of charge, as a percentage of total annual demand (132 TWh for the NSW-VIC-SA region) using three different VRE production traces from the actual NEM outcomes in the years 2015, 2016 and 2017. The seasonal and weekly variation are substantial.

Figure 14 Cumulative Output of a mix of VRE Generators in SA/Vic/NSW



Source: Marsden Jacob Associates

The seasonal profile of VRE output would increasingly become an issue when VRE becomes a substantial component of generation and storage volume is limited. This requires sufficient VRE in winter when solar is low, meaning that VRE is in surplus in summer. This has several consequences:

- Less energy available for pumping in winter;

- Requirement for higher use of thermal plant in winter;
- Higher winter prices and lower summer prices.

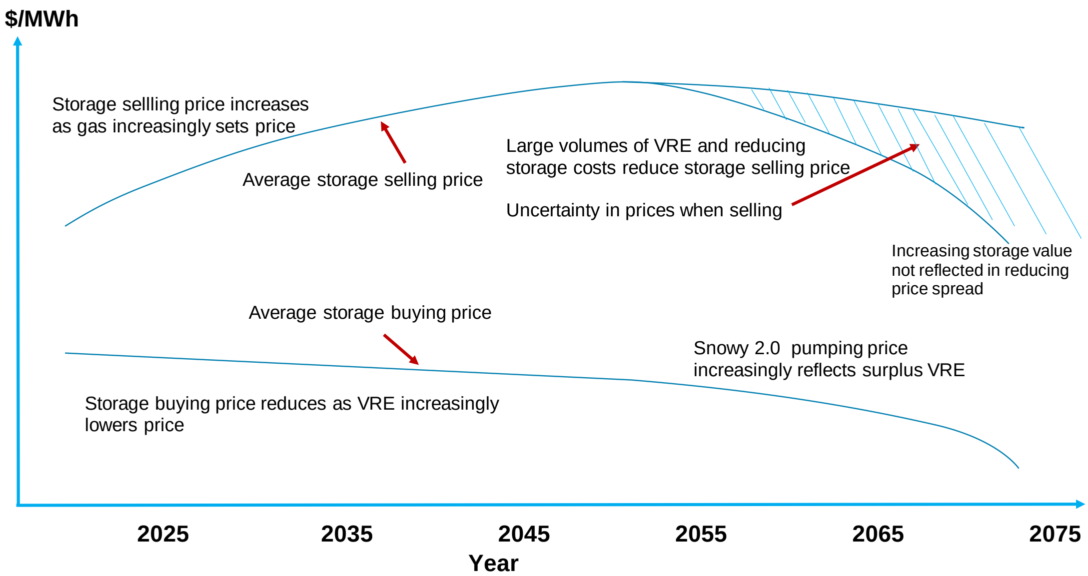
The availability of water for Snowy 1.0 does not fit this trend. Snowy 1.0 and Tantangara are operated such that reservoirs are low entering the winter period in order to address the risk of 1 in 10 year water inflows. However, Snowy 2.0 would provide an element of coverage here by being able to operate at high levels during the winter period when solar is low.

7.4 NEM Spot market and Price Dynamics

Spot prices outcomes will reflect the changing NEM dynamics presented in the previous sections.

The logic of this translation is presented in the figure below. This shows the manner spot price dynamics would be expected to change and what this means for pumped storage and the modelling undertaken. An explanation for the various time periods follows.

Figure 15 Trend in Long Term NEM Development



Coal	Starts to close	All NSW coal plant retired	All coal closed
Gas	Gas provides support	Gas remaining lower cost than storage	Gas closing
Storage	Storage needed to support increasing VRE		Value of storage increasing

Source: Marsden Jacob Associates

2018

- Current (2018) spot prices in the NEM. This has:
- NSW/Vic/SA spot prices closely linked but with periods where regional spot prices “separate” through constrained flows at times of high system stress;
- NSW and Vic dispatch and price outcomes reflect the SRMC of the generation mix (brown coal, black coal, CCGT, OCGT), capacity value and portfolio composition;
- VRE not impacted by coal generator mingens;
- SHL pump storage largely reflects black coal to gas arbitrage;
- VRE generation economics reflects that the average spot prices received by VRE is higher than their average cost.

Market models are typically “calibrated” to the NEM dynamics as described above.

2025

When Snowy 2.0 enters in 2025, spot prices in SA/Vic/NSW would be expected to reflect a range from marginal coal generation prices to periods of high-priced coal generation and gas generation prices. Snowy 2.0 trading is largely between these prices.

Increased transmission by 2025 and possibly after that results in a narrowing of price differences between regions, reduced spot price volatility (due to increased diversity) with the price differences reflecting power flow losses across interconnectors.

2025 - 2040

As VRE increases and coal generation reduces, the profile of spot prices would be expected to reflect increased hours of surplus VRE and increased hours when “firming” generation from gas generation or storage is required.

As storage has limited energy it would tend to price its generation to shadow gas generation prices.

Further, uncertainty in price outcomes would have some batteries buying while other are charging. The amount of “overlap” would be related to the cycle losses (which influences storage buy /sell spread) and the different outlooks of physical traders.

Increasing levels of storage would have this storage increasingly bid for supply from surplus VRE and these bids may clear the market. The economics of batteries would require very high arbitrage revenues and it is unlikely that there would be a surplus of battery storage competing for VRE charging energy. Gas generation would form an important component of firming and price setting.

The result is that over the period 2025 to 2040 Snowy 2.0 buying (i.e. pumping) prices would decrease and Snowy 2.0 selling (i.e. generation) prices would increase. This increasing spread combined with an increased volume of buying and selling has Snowy 2.0 net revenues increase (i.e. generation revenue less pumping costs).

Post 2040

Leading up to the closure of all coal plants in NSW (by 2044) the dynamic of the NEM will be radically changing. Very large quantities of storage would be required to support very high quantities of VRE, if VRE is to be economic. Based on the current cost of VRE and storage, the absence of a price or limit on emissions would limit the level of VRE that would be economic. Snowy 2.0 will provide for additional VRE generation.

The value of storage and the difficulty of “efficient” NEM wide storage operation could result in storage operation being coordinated centrally, by AEMO. This could be with a voluntary service or mandated as part of revised market arrangements.

Gas priced generation would clear the market. When clearing the market storage generation may also shadow gas generation. As the amount of energy supply from storage increased, there would be increasing market power as generation from storage is limited (i.e. if it’s used this period then it will cannot be used in the next period). The value of coordination of storage facilities would be expected to increase.

Post 2055

Under the assumption of a near all-renewable power system with very large energy storage (for a given amount of capacity), spot prices would have little shape of volatility as the market would always clear from VRE generation or from stored VRE generation. However, this is not economically feasible.

The coal closures will be replaced by VRE, gas generation and storage. Pumping opportunities will increase while selling price may remain high or reduce by a moderate amount.

8. 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 modelling approach post 2047 was based on the opportunity cost of Snowy 2.0, that is the alternative assets that would be required if Snowy 2.0 were not developed. The FAM model was developed to ascertain the opportunity value of storage under a spread of VRE supply outlooks. This opportunity value was used to extend the simulation modelling that ended in 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 level of VRE exceeding 80%.

8.1 Approach to Snowy 2.0 Valuation Post-2047

The 50-year economic life of Snowy 2.0 means that SHL revenues post 2047 is an important component of the economics of Snowy 2.0. 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 the combined SA-VIC-NSW region. This recognised that transmission developments (as outlines 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 the profile and 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 was a key factor in determining the firming and storage needs (hours of storage) and the economics trade-off of 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 indicated the economics and opportunity cost of storage. This was done for the hypothetical case of the combined region 100% supplied by VRE and then for lower levels of % supplied by 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 high levels of VRE (i.e. VRE is supplying a high percentage of demand) the required amount of storage becomes very large as this reflects 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 firming VRE over periods up to a month, and the finding were presented as a floor in value.

The following sections present the finding of the above described modelling.

8.2 VRE Variability

The purpose of this section was to characterise VRE energy production variability over different time periods.

VRE variability was investigated as follows:

- On the SA-VIC-NSW combined region;
- Using actual solar and wind generation traces (i.e. half hourly production) for three years 2015, 2016 and 2017. Each year was represented by a combination of 10 wind and solar traces in order that the diversity across the SQA-VIC-NSW combined region was included;
- Over different time periods ranging from a day to seasonal to yearly.

Monthly variation

The historical average capacity factor of the sample of 10 wind and solar assets over the SA-VIC-NSW combined region is shown in Figure 16 below. This figure shows the monthly capacity factor deviation from this annual average.

The following are noted:

- The average annual VRE capacity factor over these years was 31% (32% for wind and 24% for solar);
- 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 in a market 100% VRE supplied.

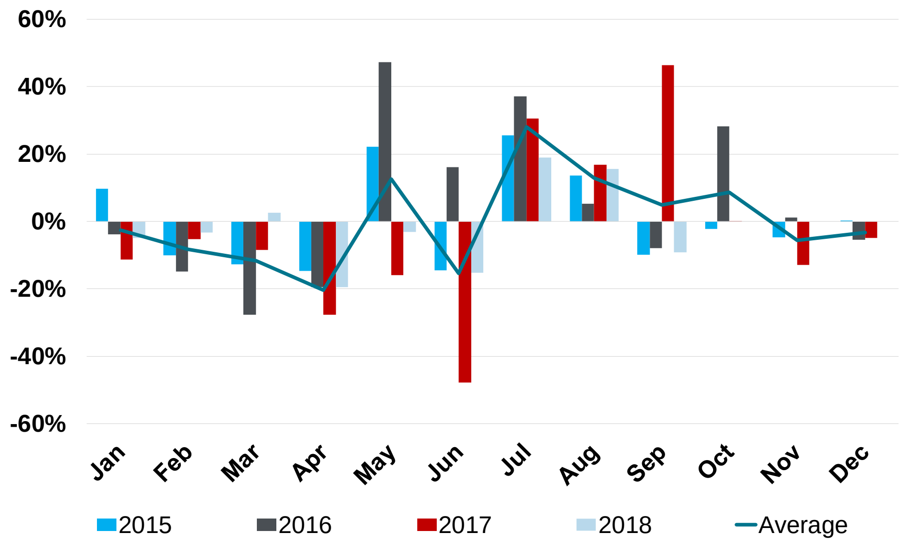
Variation over a year

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

First by plotting the cumulated energy production over a year using the three SA-VIC-NSW production traces (i.e. 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 (i.e. the demand is 100% supplied by this VRE). This is shown Figure 17 below.

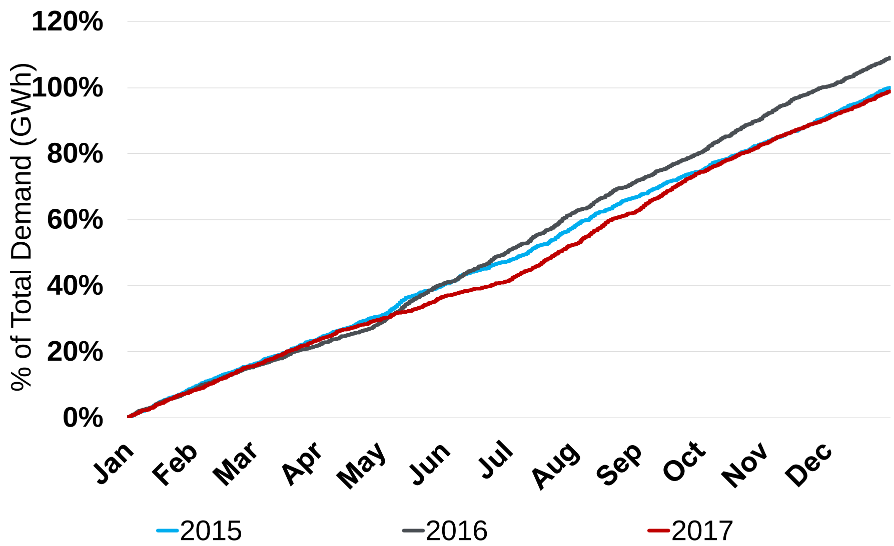
We observe that there is variation through the year and that over a year the variation was that the 2016 trace produced about 10% more energy over the year than the other traces.

Figure 16 Historical Monthly VRE Generation Deviation from Annual Average



Source: Marsden Jacob Associates

Figure 17 Cumulated VRE Energy Production over a year



Source: Marsden Jacob Associates

The intra-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 18 below, which plots energy in store expressed as percentage of the annual system demand (this is the same graph as Figure 14).

From Figure 18 the following are noted:

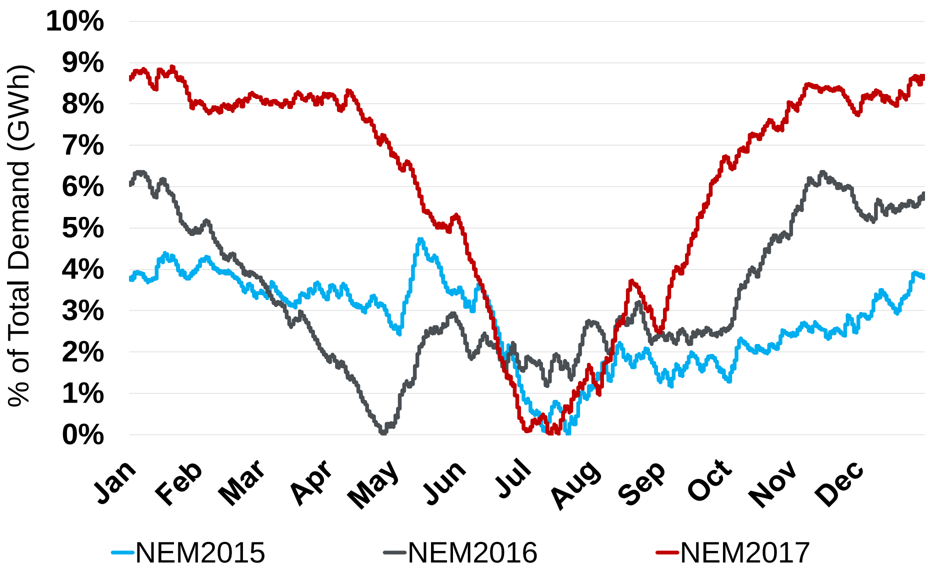
- The differences in seasonal and annual profiles are evident;

- Based on the 2017 VRE production trace, an amount of storage equal to about 8.9% of the annual demand is required to have the VRE generation allocated to when it is required. For the 2015 trace this is about 6.4%.
- Assuming a storage level of 12 hours, the amount of storage capacity required is 20 to 37 times the level of maximum demand. Clearly this is not a viable scenario.

Conclusions from the above analysis are as follows:

- 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 in winter;
- As VRE in the NEM is currently small (except in SA) and there is surplus thermal plant to "absorb" the seasonal variation in VRE, currently 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;
- 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;
- The significant energy transfer requirement strongly indicates that deep storage (i.e. storage with a large energy storage capacity) will be required.

Figure 18 Seasonal Energy Variability shown by Charging Patterns



Source: Marsden Jacob Associates

8.3 Trade-off between Storage and Dispatchable Generation - Annual Modelling

The section describes and presents the results of modelling that used the Firming Analysis Model (FAM)[13] over a year. By modelling over a year, the modelling incorporated VRE energy production variability between seasons.

The modelling was used to:

- Quantify the firming needs in the SA-VIC-NSW combined region (assuming no connection to Queensland or Tasmania) at various levels of VRE penetration;
- 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 levels 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.

Table 5 Cases Modelled using the FAM Model

% 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

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

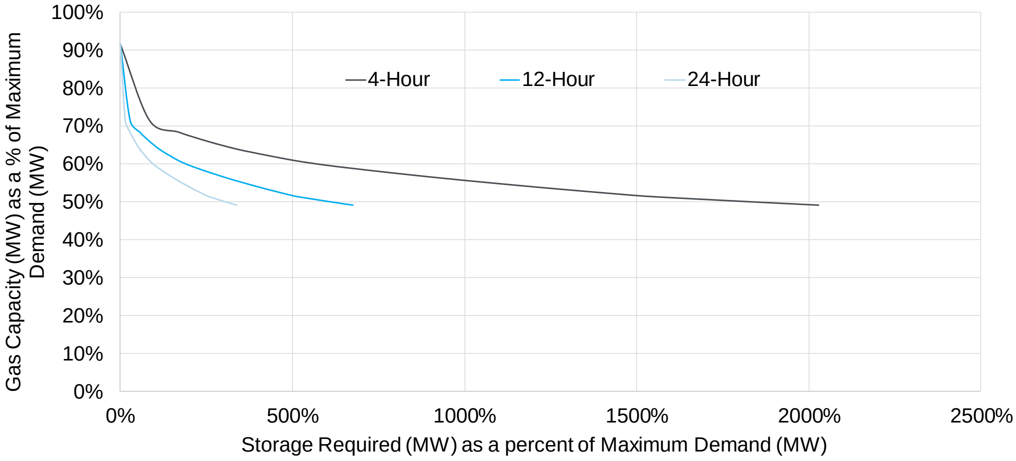
Figure 20 summarises the results presented separately for the three different years of VRE (2015, 2016 and 2017). Shown are:

- The installed capacity of storage (MW) required as a percentage of maximum demand to satisfy system reliability. This is based on the assumption that VRE provides a level of firm capacity given by 7% of its installed capacity;
- The hours of storage needed based on that level of installed capacity (MW).

We 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 in under this scenario. This is, therefore, more of an extreme or high case scenario.

[13] 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.

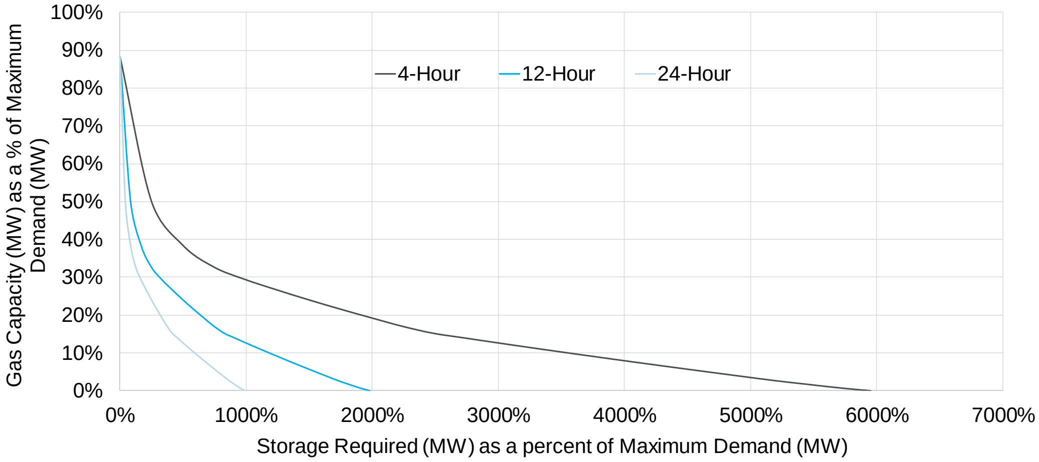
Figure 19 FAM Model Results – Trade-off of Dispatchable Generation v Storage



50% VRE

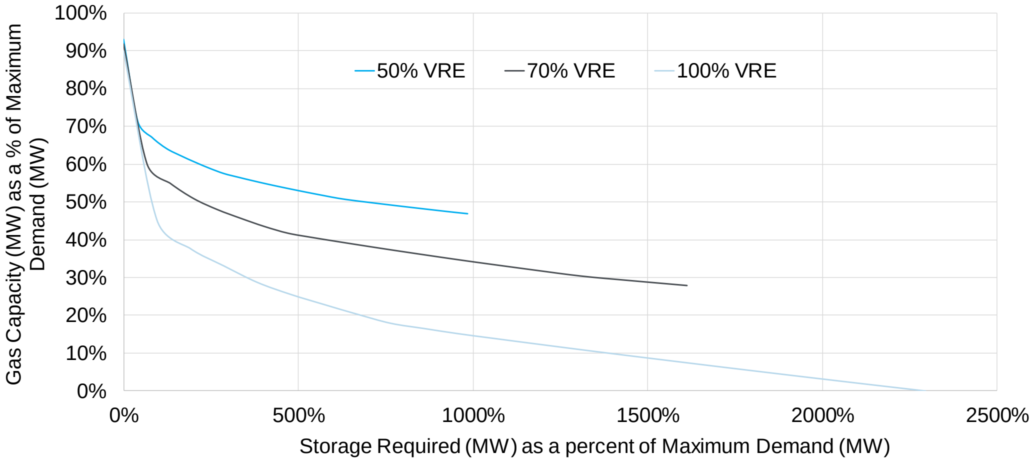
4, 12 & 24-Hour Storage

Source: Marsden Jacob Associates



100% VRE
4, 12 & 24-Hour Storage

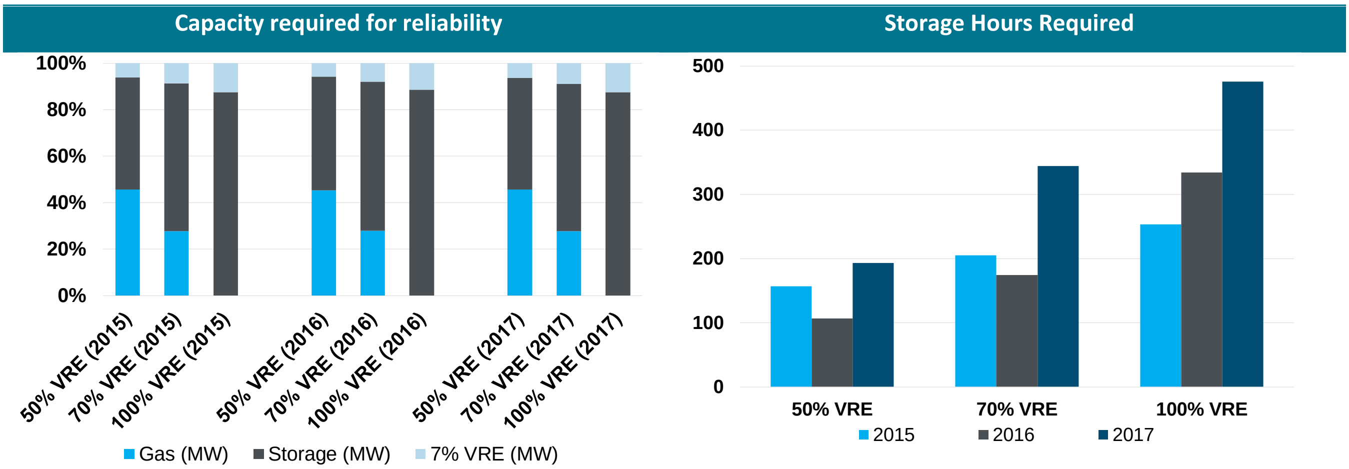
Source: Marsden Jacob Associates



50%, 70%, 100% VR
12-Hour Storage

Source: Marsden Jacob Associates

Figure 20 Minimum Storage to Capture VRE Variability over a Year



Source: Marsden Jacob Associates

8.4 Trade-off between Storage and Dispatchable Generation – Monthly Modelling

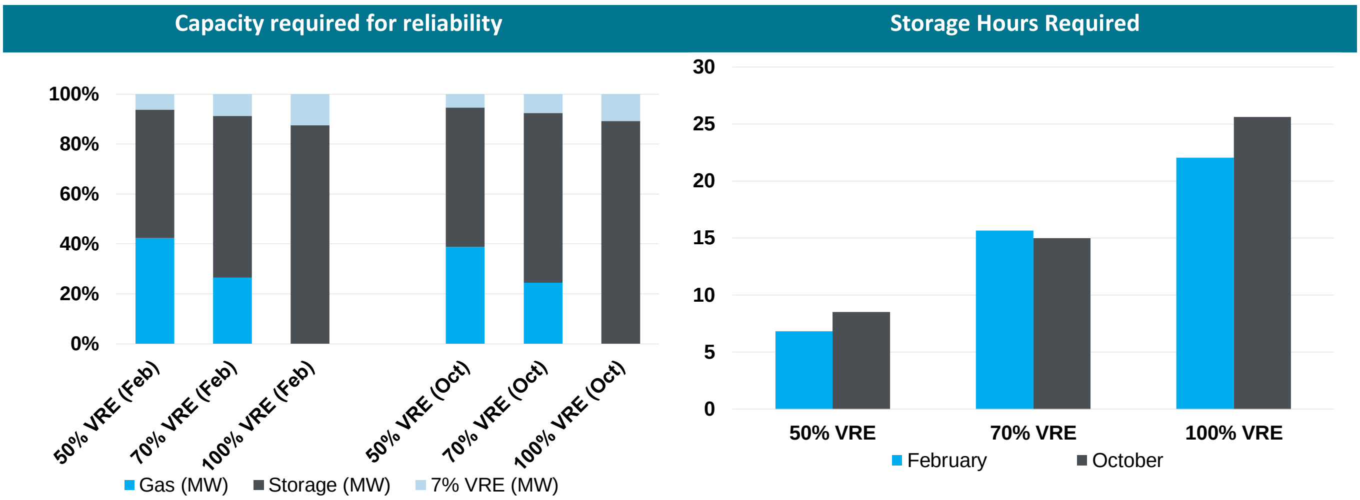
This section presents the results of FAM modelling used to quantify the storage needs in the SA-VIC-NSW combined region at various levels of VRE penetration over monthly periods. By limiting the modelling to a month, the modelling excluded VRE energy production variability between seasons.

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 was limited to considering the level of firming/ storage required to manage the month to month variations in VRE.

Figure 21 summarises the stoarge needs to capture VRE variability within a month:

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

Figure 21 Minimum Storage to Capture VRE Variability within a month



Source: Marsden Jacob Associates

8.5 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 observations are made.

- 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;
- 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;
- 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;
- As installed gas capacity (MW) increases, the storage requirement decreases rapidly:
  - 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 21)
  - the modelling showed this happened at a gas capacity factor of about 41-42% (compared to a capacity factor of almost 60% for gas capacity or about 50% of maximum demand) and spill reached about 3.5% of total generation (GWh);
- 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 22). This happened at a gas capacity factor of about 35-40%, but with spill reaching about 25% of total generation (GWh).

8.6 Review of South Australia

A review of SA in 2017 showed the following (additional details are contained in Appendix 8):

- For calendar year 2017 SA generated 34% of total GWh from wind. The rest was gas/thermal (62%) and importing via the interconnectors. While net interconnector flows (net of exports) were 4% of total State energy, its total gross imports were 14% of total energy (i.e. exported 10% and imported 14%).
- SA does not currently have as much battery storage (MW or MWh) as our 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 1,200GWh in 2017. If this was 4.2-hour storage similar to the Tesla's batteries used as Hornsdale, this would have required over 285,700MW of installed capacity – versus the mere 100MW of Hornsdale.
- Maximum Operational Demand in SA was 3,046MW over the year, and it had (still has) about 3,000MW 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.

8.7 Conclusions – Snowy 1.0 and Snowy 2.0 Revenue Profile post 2047

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.

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 increases to higher levels than is currently the situation in the NEM in 2018.

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

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

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

The analysis shows that this is conservative, such that if 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 are as follows.

Table 6 NPV of Annualised Storage Costs – 2047 to 2075

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

*Source: Marsden Jacob Modelling (*discount rate of 4.55%)*

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

9. Storage and Firm Capacity

The previous chapter 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 chapter 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 chapter.

The assessments of the storage hours required to supply frim capacity in the previous and this chapter 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.

9.1 Storage Hours - Normal Market Conditions

Analysis was undertaken to investigate the value storage hours would provide under normal market conditions (i.e. 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:

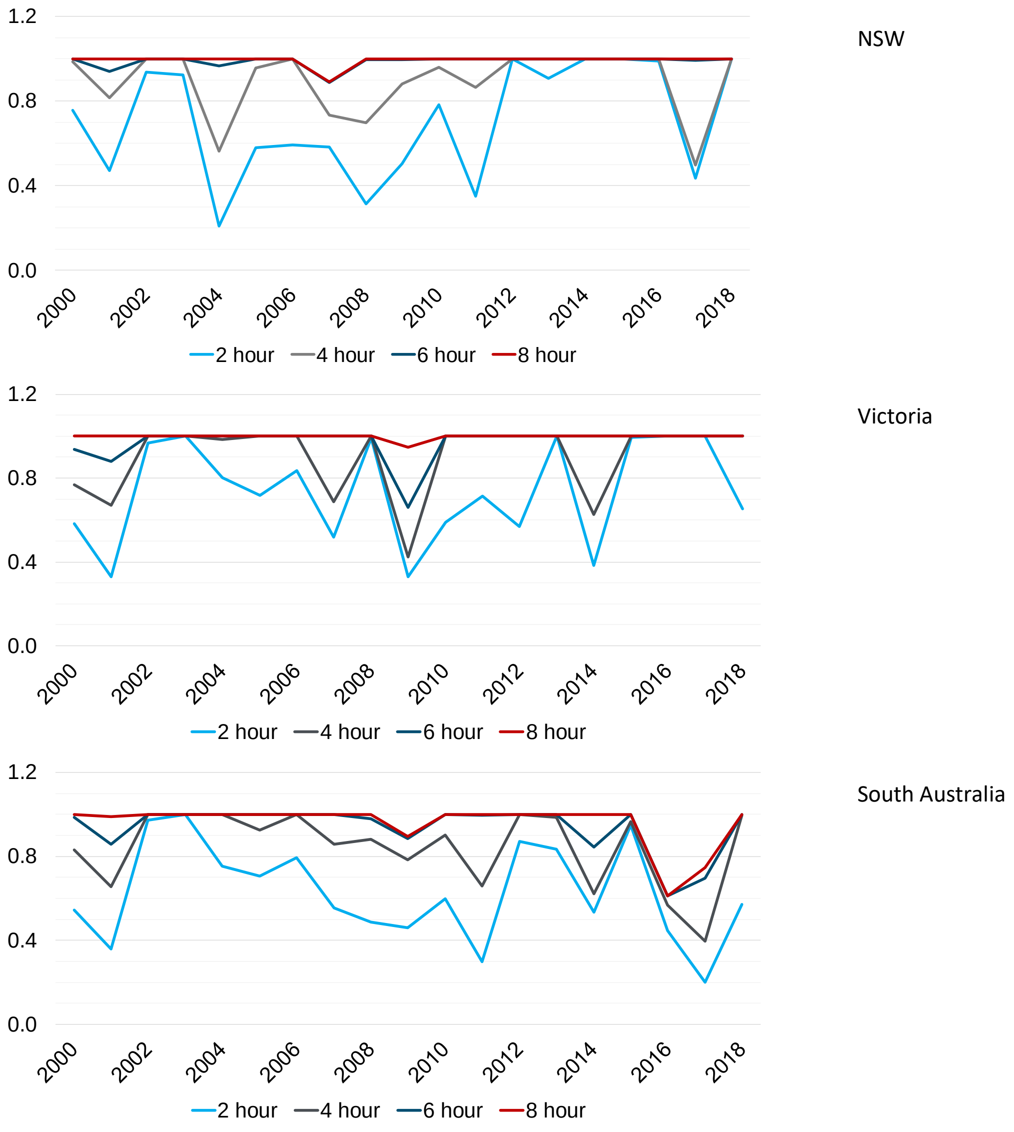
- Fair cap contract value: this is the value of a $300 cap contract in that state and year (i.e. what a cap contract would pay). This is the reference about which the performance of the battery was assessed;
- Captured Value: this is the proportion of the cap contract payments that would be covered by battery discharge (i.e. 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 (i.e. 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 22 below. This is shown for NSW, Victoria and South Australia. As expected, the greater the storage hours the higher the Captured Value

Figure 22 Historical Analysis – Proportion of $300 Cap Value Captured by a Battery with storage of 2, 4, 6, 8 Hours (1)



Note (1): This is the percentage of cap payments that is covered by battery generation.

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 7 below.

Table 7 Historical Exposure to $300 Cap Payment using Limited Energy Storage (1)

	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%

Note (1): This is the percentage of cap payments not covered by battery generation.

9.2 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 Cumulative Price Threshold (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 the table below:

Table 8 Cumulative Price Threshold

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

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.

9.3 Comparison to Physical Firming Requirements

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

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

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

The assessment of storage required to provide a firm cap contract (presented in this chapter) shows that the amount of storage required is 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.

10. Models Used and Approach

The suitability of the model(s) used to meet the objective of the modelling and how these model(s) are used are essential matters in any modelling study. The actual models used also determines what can be modelled and what can be provided through the modelling. This chapter presents the models used and the basis for the selected types of models.

10.1 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 (i.e. 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:

- 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;
- 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:

- 2018/19 to 2046/47:
  - detailed NEM modelling of the NEM capable of representing NEM dynamics and outputting generator dispatch and regional price outcomes
  - the period incorporates the year prior to the commencement of Snowy 2.0 and the first 23 years of Snowy 2.0 operation;
- 2047/48 to 2074/75:
  - 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 (i.e. increasing proportion of energy supplied by VRE).

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

1.1.1 Model Type - 2018/19 to 2046/47:

There are two main types of models used in the long-term modelling of the NEM. These are market simulation and least cost modelling. These are briefly described below.

Least cost models

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 the 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. See box below. 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

- Least Cost Models minimise an "objective function' subject to constraints.
  - constraints written as: a1 x Var1 + a2 x Var2 + ... <=RHS
- Each year of the study period is divided into a number of sectors. Examples are
  - 3 seasons x 2 day types x 6 periods per day (36 period per year)
  - 4 seasons x 12 periods per day (load duration)
- Objective function expresses the NPV cost of supplying the load over the study period : ∑ capital costs + ∑ operating costs
- Constraints apply to each time sector and include:
  - generation = demand
  - flow on an interconnector < limit
- Solution is twofold;
  - primary Solution: values of Var1, Var 2 … (decision variables)
  - 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:

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

Market simulation

Market simulation is a time sequential approach that provides 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.

10.1.1 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 for this period was to ascertain the necessity and value of storage through its opportunity cost. As previously mentioned, this is a standard approach to valuing long life assets.

The analysis was undertaken using the Marsden Jacob Firming Analysis Model (FAM) which was developed specifically for this modelling exercise.

10.2 PROPHET Electricity Market Model

10.2.1 The PROPHET Simulation 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:

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

The representation used in the model included:

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

- Reliability setting of the Market price Cap (MPC) and (Cumulative Price Threshold (CPT).

The steps involved in the Prophet model included:

- The model was benchmarked to the NEM as currently operating through an explicit representation of trading entities, contracts and other matters;
- The benchmark structure was modified through the simulation to represent the changing NEM;
- Changed assumptions were included as required;
- Internal consistency was maintained through all simulations (i.e. economic opportunities for new generators are acted on);
- Internal review of input and output files as part of the quality control process;
- Provision of results in agreed formats.

Additional detail of the Prophet model is provided in Appendix 3.

10.3 Firming Analysis Model

The MJA Firming Analysis Model (FAM) is a proprietary model, built in-house, with its objective being to hypothesise the amount of firming required under various levels of Variable Renewable Energy (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.

Our 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 PHS) 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-South Australia-Victoria due to the proposed interconnector upgrades and our expectation that those regions (including Snowy Hydro 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 PHS) 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 (i.e. the MWh that can be stored).

10.4 Economic Criteria

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. Coal plant was excluded for the reasons previously stated.

This was done on the assumption Snowy2.0 enters and does not enter. Snowy 2.0 economics was not a criterion (for Snowy2.0 to enter) in the “with Snowy 2.0” model run cases.

The development of VRE and gas generation (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.

10.4.1 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 post 2040 (for storage with hours of storage over about 2 hours).

We note the following

Appendix 4 “Battery Economics and Entry” 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 previous chapter “Firming under High VRE” showed that:

- Firming services will require a substantial amount of storage and / or gas fast start generation;
- 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:

- Limited storage with a solar or wind generator to smooth the VRE profile;
- Government sponsored for reliability and security;
- 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.

11. NEM Scenarios and Assumptions

Assessing the economics of Snowy 2.0 required that the operation of SHL (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 chapter presents and describes the scenarios modelled.

11.1 Scenario Development

In the context of this 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 NEM spot market outcomes and Snowy 1.0 and Snowy 2.0 operation. 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 Snowy 2.0 operation and include the following:

- Electricity demand growth;
- Electric Vehicles uptake;
- 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);
- Profile and regulation of coal plant closures (such as indicted in the Finkel review);
- Costs of storage (both in front of and behind the meter);
- Costs of solar generation and wind generation;
- Commodity prices – gas and coal;
- 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:

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

The scenarios modelled (i.e. Base Scenario and alternative scenarios) are presented in Table 9. They are intended to represent a balanced spread of outcomes that account for the potential changes that can occur in the NEM.

The scenarios are each described in the sections that follow.

Table 9 Scenarios Modelled

Scenario Name	Change from	Description
Base		Current policy (LRET, VRET, QRET) Proposed NEG (26% emissions reduction by 2030) Announced generation closures and entry Most likely coal closure program (Eraring, Yallourn, Vales Pt) Most likely new PHS development No emissions reduction target post 2030 Rational economics (entry and exit based on economics)
Low Emissions	Base	Policy for emissions – 45% by 2030, 80% reduction by 2050 High rooftop PV (with base assumption on batteries) Basslink II developed (600 MW link form Tas to Vic)
Coal Early Closure	Base	50-year coal plant closure i.e. early coal closure (e.g. LYB closes at year 50)
High Demand	Base	AEMO high demand case
Hydrology Wet	Base	Wet increases inflows to all east coast hydro facilities SHL modelling (pre '25): CP19 Wet sequence MJA modelling (post '25): + 10% inflows p.a.
Hydrology Dry	Base	Drought reduces inflows to all east coast hydro facilities SHL modelling (pre '25): CP19 Dry sequence MJA modelling (post '25): - 10% inflows p.a.
High EV Penetration	Base	50% by 2030; 80% by 2040 (% is cars on the road)
Coal Bull	Base	1500 MW (i.e. Liddell n-1 capacity, WACC of 9% [government policy risk mitigated] from 2025)
High Battery	Base	Battery cost curve depreciation rate is twice that in the Base Scenario

The Slow Demand growth scenario[14] (the AEMO low demand growth outlook) was not modelled. The reasons for this were as follows:

- The Base Scenario had a lower level of demand outlook that the Neutral growth scenario contained in the 2018 ESOO. This difference was quite substantial post 2030;
- The basis of the 2018 Slow demand growth outlook was not considered suitable for modelling given the increasing Australian population and energy demand.

In all the scenarios modelled Snowy 3.0 is assumed not developed. The reason for this is to value Snowy 2.0 on the basis of opportunity costs excluding other SHL developments.

The scenarios are each described in the sections that follow.

—

[14] In comparison to the Neutral scenario, AEMO state the following regarding the Slow scenario
"reflects a lower forecast for new dwellings, electric vehicles, energy-efficiency impacts, and less residential consumption in response to retail price rises, compared to the Neutral pathway. Under the Slow change scenario, annual delivered consumption growth remains relatively flat in the short term, followed by a slight increase, mainly in the latter half of the outlook period. This results in growth of 11 % (or 0.5% annual average) over the 20-year forecast."
"assumes a reduced incentive for further drilling beyond existing well production. It follows the production profile of existing wells, declining to minimum production levels by 2029."
"consumption is forecast to fall, especially in the long term. This scenario's assumptions include slower economic growth, reduced consumer confidence, and sluggish export markets, combined with input price pressures from electricity, which place more loads at risk of closure. These risks increase over the 20-year outlook, due to persisting weak economic conditions eroding business resilience."

12. Base Scenario

This chapter 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 Integrated System Plan and deviates only in a small number of factors where there was reason to do so.

As such the Base Scenario represents a “central outlook”. It is the scenario about which the alternative scenarios are undertaken.

This chapter first presents a description of the Base Scenario. This is followed by presenting the modelling results of the Base Scenario on a financial year basis. Presented are:

- A description of the scenario including key assumptions;
- Annual results on NEM wide outcomes in the with Snowy 2.0 and without Snowy 2.0 cases:
  - generator capacity by generator type that enters and leaves the NEM
  - the changes in generator capacity entry and exit that result from Snowy 2.0 entry
  - the percentage of generation that is renewable - by State and by type of renewable generation
  - the total NEM carbon emissions with Snowy 2.0 and without Snowy 2.0;
- Annual results for Snowy 2.0 pumping and generation volumes.

Chapter 13 presents details of modelling outcomes within a year.

12.1 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.

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 or post 2030.

The absence of any Federal policy on renewables or carbon emissions (other than the existing LRET) means that just the Victorian (VRET) and Queensland (QRET) State renewable energy targets remain, and the Base Scenario assumes that both of these 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.

In relation to coal generation, observed trends in lending policies for coal power stations, regulatory risk and costs mean that new coal generation was 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 coal generator retirements assumed in this scenario and expected and committed coal plant 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 required in addition to that available from the existing thermal generators is provided by new gas generators and batteries with 4 to 5 hours of storage. Batteries remain uneconomic at storage hours greater than about 2 to 3 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 Snowy 2.0 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 REZs required (for the VRE developments). 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 a 60% emissions reduction by 2050.

The details of the assumptions are shown in Table 10.

Table 10 Base Scenario Assumptions

Class	Assumption	Source
Snowy	Start Date & Capacity	2026 - 2000MW
	Snowy Inflows	SHL 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 - SHL
	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 PHS	Committed Only
	Battery - Regulation	MJA - Base
	Battery - Installed Costs	MJA - Base

The following sections present the modelling results of the Base Scenario[15].

12.2 Base Scenario - Installed Generator Capacity

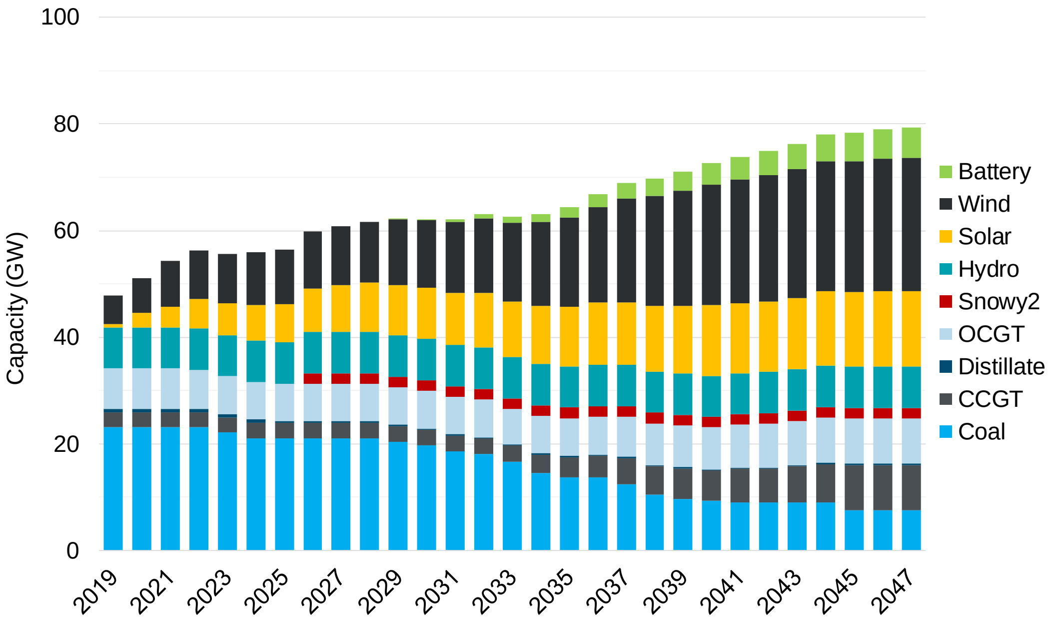
The figures below present the installed capacity by generator type over the study period to 2047. These are shown as installed capacity for the whole NEM (Figure 23) and as firm capacity for the SA-VIC-NSW combined region (Figure 24).

Figure 23 shows the decrease in coal generation, increase in gas generation capacity (CCGT and OCGT) and the large increase in wind and solar capacity. Battery storage enters on a larger scale from 2030, based on the need to have this accompany VRE entry. Before 2030 existing dispatchable generation is largely able to provide the flexibility (and firming required).

VRE generation does not provide 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 firming provided by dispatchable generation[16]. Presenting VRE generation in terms of the equivalent firm capacity provides for the total level of firm capacity (and reliability of generation supply) to be gauged.

Figure 24 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. We observe that the analysis in Chapter 10 had illustrated that batteries need at least 12 to 24 hours (and likely more) to qualify as firm capacity. This means the capacity contribution from batteries is over stated in the figure. The figure excludes the capacity from Basslink and the NSW-QLD interconnector, which are usually defined as providing firm capacity.

Figure 23 With Snowy 2.0 – NEM Generator Installed Capacity (MW)



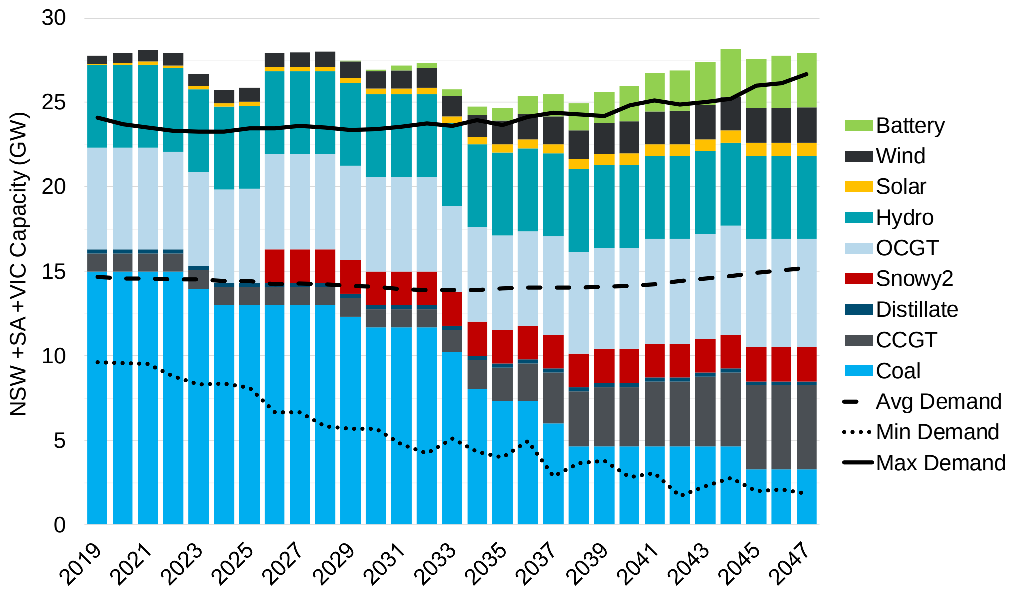
Installed capacity refers to the nameplate rating of generators.

Source: Marsden Jacob Associates

[15] The base Scenario results are Ron06

[16] This is an estimate that has been used by AEMO in the past and is consistent with the assessment of Marsden Jacob.

Figure 24 With Snowy 2.0- SA-VIC-NSW - Generator Contribution to Firm Capacity (MW)



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

For VRE this has been assessed to be 7% of nameplate rating.

Source: Marsden Jacob Associates

This figure shows that the SA-VIC-NSW region has very little capacity reserve for generation within the combined region and that support from Tasmania (via Basslink) and Queensland (via QLD-NSW interconnection) would be required. Other observations are as follows:

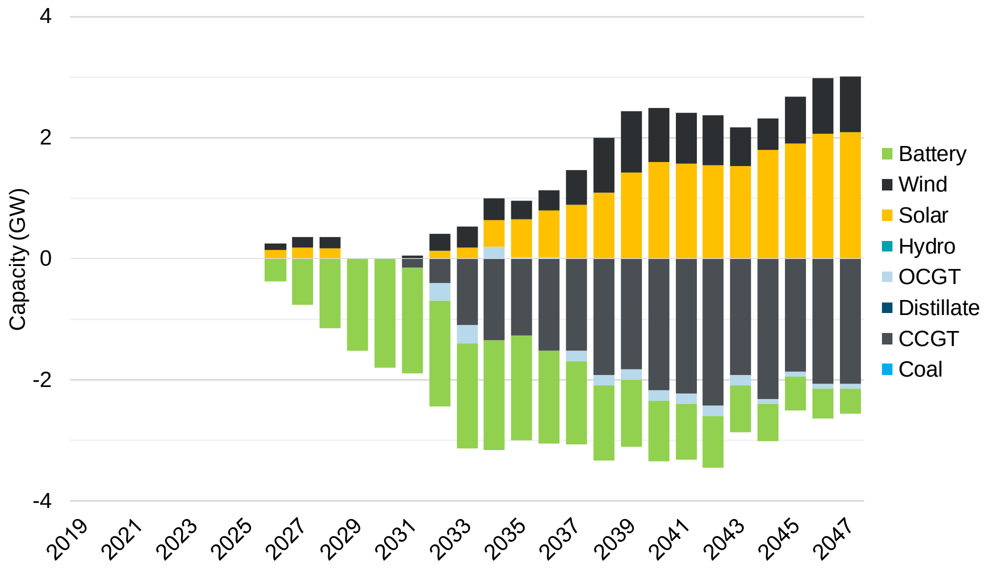
- The period 2033 to 2036 is very tight due to the substantial reduction in coal generation during that period. A significant amount of CCGT is developed during this period, but additional development is not economic due to the amount of VRE and storage that enters in the year shortly after this;
- High gas costs place a premium on generation heat rate[17]. 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;
- Snowy 2.0 becomes essential to the capacity adequacy from 2034 onwards;
- The number of parties that can provide cap and load-following contracts decreases from 2030 onwards.

Figure 25 shows the change in installed generation capacity due to the entry of Snowy 2.0. This shows the following:

- There is additional solar and wind generation, which has a combined installed capacity of about 3,000 MW. The reason for this increase being higher than Snowy 2.0 capacity is the diversity of VRE (VRE averages considerably less than 2,000 MW);
- The large storage volume provided by Snowy 2.0 (175 hours) means that 1 MW of Snowy 2.0 storage has significantly more value than 1 MW of 4-hour storage;
- The entry of Snowy 2.0 delays batteries, initially by as much a 2,000 MW and then by a small amount by 2045. This is a reflection of the following:
  - battery costs decrease over the study period
  - the additional VRE entry that is provided by Snowy 2.0.

[17] IN electricity system that have high fuel cost, generator heat rate has always been a key issue.

Figure 25 Change in NEM Installed Capacity due to Snowy 2.0



Source: Marsden Jacob Associates

12.3 Base Scenario - % Supply from Renewable Generation

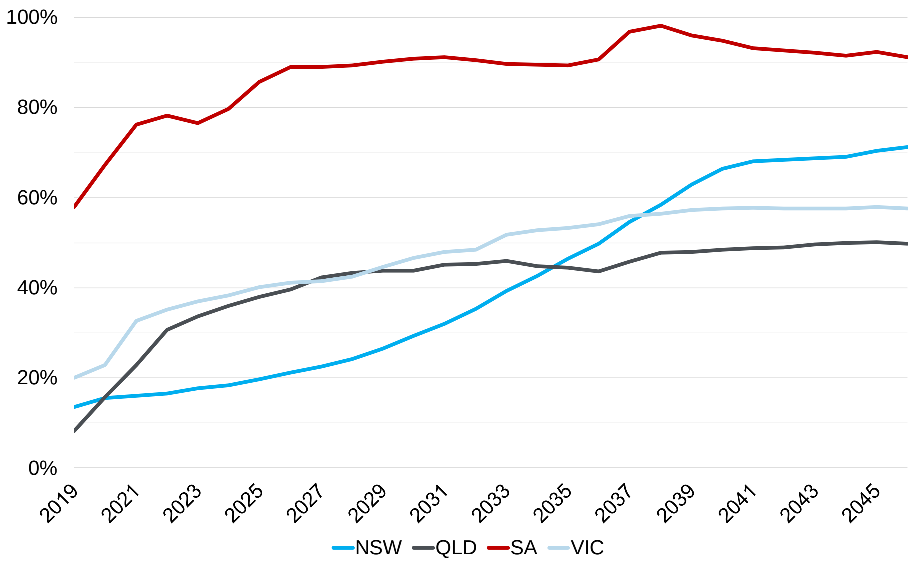
Section 10.2 defined the calculation of the percentage of demand supplied by renewable generation. This is the demand supplied by rooftop PV, dispatchable renewable generation (mainly existing hydro) and large scale VRE (non-scheduled and semi-scheduled) compared to total demand.

By State and total NEM, the percentage of demand supplied by renewable generation is shown in Figure 26. Figure 27 shows on a NEM wide basis the type of renewable generation over this period. This shows:

- 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;
- QLD VRE increases rapidly to have 50% of demand supplied by renewable generation (QRET target) by 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 of demand supplied by renewables in QLD flattens post-2030;
- Victoria has a significant early increase in VRE due to the VRET, and then has a steadier increase reflecting the economics of VRE and the closure of Yallourn power station;
- NSW starts from a low level of VRE. The NSW coal plant closures in the 2030's result in a significant increase in VRE during this period.

The net result is that without Snowy 2.0 by 2047 the NEM is 59% supplied by renewable generation. The percentage of VRE generation in front of the meter is 47%.

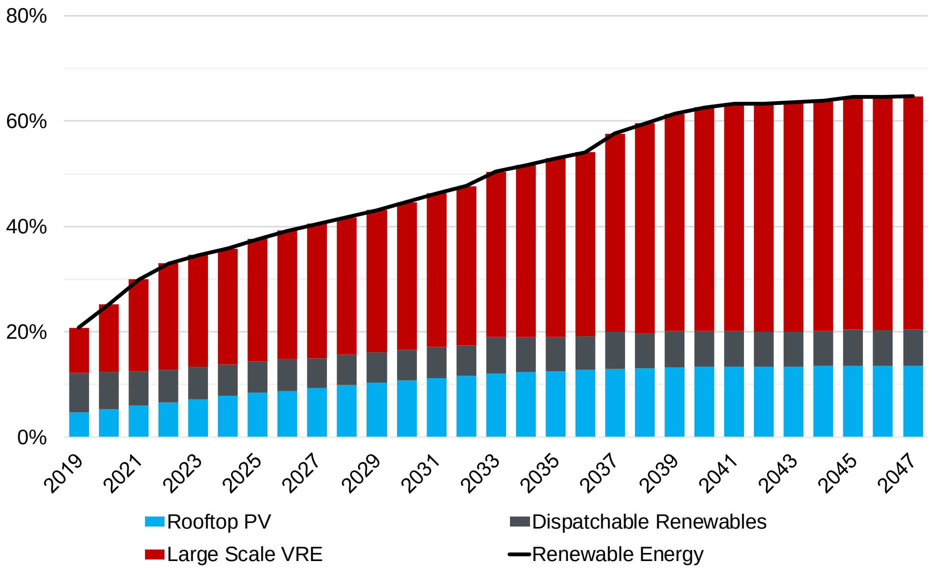
Figure 26 Percentage of Demand supplied by Renewable Energy



Note. The graph opposite excluded biomass renewable generation (about 5% by 2030 in Queensland)

Source: Marsden Jacob Associates

Figure 27 NEM -% renewable Generation by Category

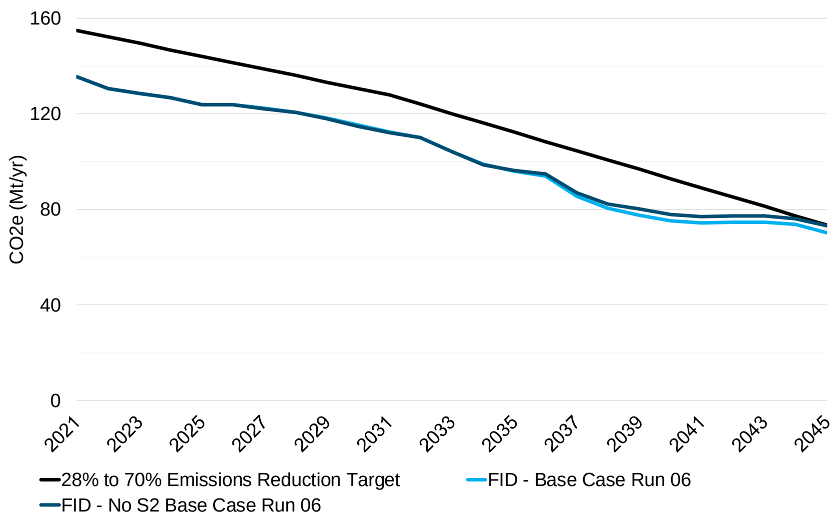


Source: Marsden Jacob Associates

12.4 Base Scenario – NEM Carbon Emissions

Figure 28 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 26% in 2030 to 70% in 2050.

Figure 28 Carbon Emissions MT/Year



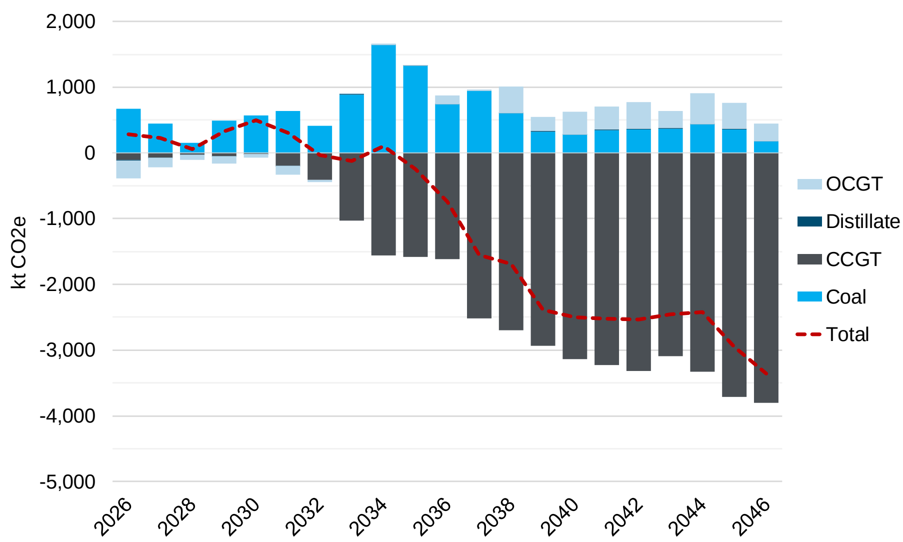
Source: Marsden Jacob Associates

From this figure the following are noted:

- The reduction is due to coal plant closing and the replacement of this generation with gas and VRE (and no new coal plant);
- The levelling off in emission reductions post 2040 is due to the remaining coal plant operating at higher capacity factor and increasing gas plant development and operation as the limits of what Snowy 2.0 and battery storage can economically provide are reached;
- The impact of Snowy 2.0 on carbon emissions is more pronounced post 2035. The reason for this is the increasing VRE generation that requires significant storage to capture and be used to reduce gas and coal generation.

Figure 29 shows the basis for the impact Snowy 2.0 has on emissions. The reduction is largely due to the additional VRE that Snowy 2.0 brings in to the NEM and the reduction in gas generation that results.

Figure 29 Emissions Reduction due to Snowy 2.0

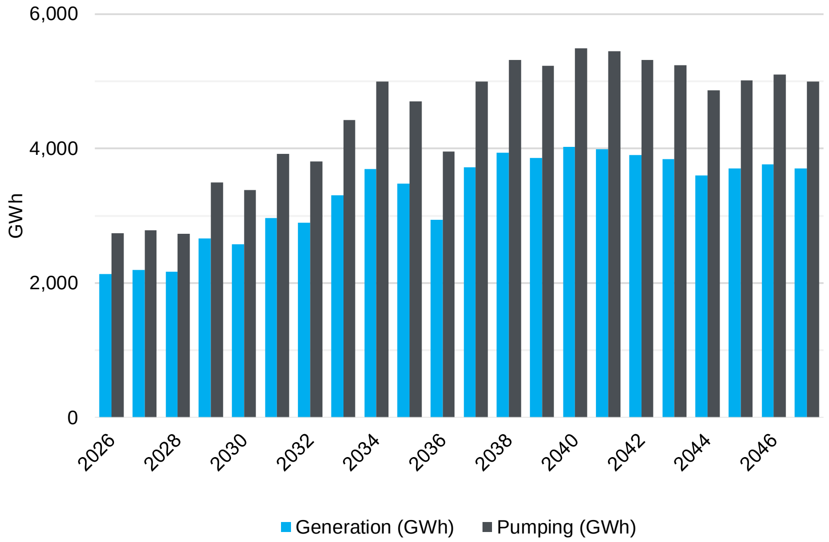


Source: Marsden Jacob Associates

12.5 Base Scenario – Snowy 1.0 and Snowy 2.0 Operation

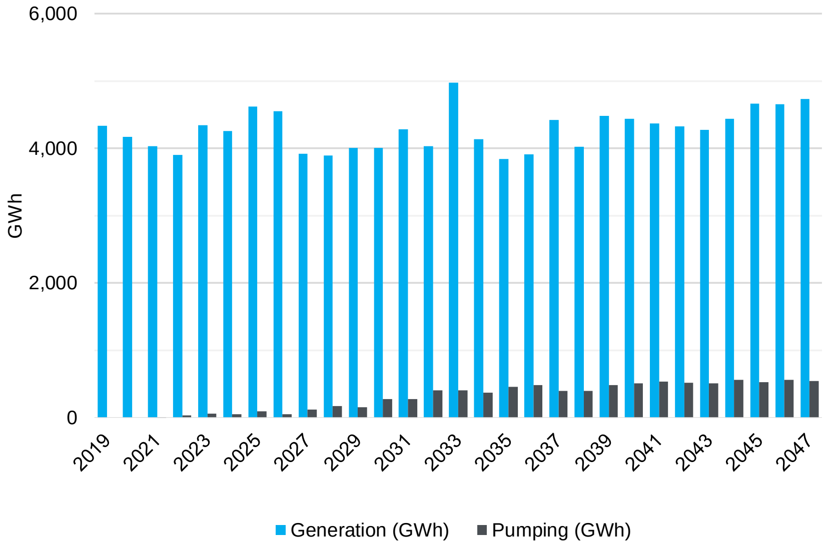
- This section presents the modelling results associated with the operation of Snowy 1.0 and Snowy 2.0:
- Figure 30 shows for Snowy 2.0 the amount of generation and the amount of pumping;
- Figure 31 shows for Snowy 1.0 the amount of generation and the amount of T3 pumping.

Figure 30 Snowy 2.0 - Annual generation and pumping (GWh)



Source: Marsden Jacob Associates

Figure 31 Snowy 1.0 - Annual pumping and generation



Source: Marsden Jacob Associates

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

Snowy 2.0:

- The amount of pumping energy compared to generation energy reflects the RTE of Snowy 2.0 which averages about 76%;

- The amount of pumping increases over the period 2026 to 2035 as VRE entry provides for increased low-cost pumping energy;
- The closure of coal generators results in reduced availability of pumping energy due to coal generators operating near minimum generation levels less often. The reduction in Snowy 2.0 pumping (and consequently less Snowy 2.0 generation) in 2032 and 2036 are due to the closure of Eraring and Bayswater respectively. The closure of Bayswater is more pronounced as this is in additional to the closure of Eraring;
- Pumping (buying) prices decrease over the period reflecting the increasing amount of VRE energy available for pumping;
- The "step" increase in Snowy 2.0 pumping prices is due to the closure of Eraring and the step down in the minimum generation level of the combined coal generators, thereby reducing the quantity of very low-cost pumping energy.

Snowy 1.0:

- 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 study period Snowy 1.0 averaged 4,421 GWh p.a.;
- The increase in T3 pumping volume reflects increased pumping opportunities as the amount of VRE increases.

13. Base Scenario: Intra-year Outcomes

A review of 30-minute modelling 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.

The previous chapter presented the annual results of the detailed modelling over the period 2019 to 2047 for the Base Scenario.

This chapter presents for the Base Scenario Snowy 2.0 operation over a sample year – pumping and generating volumes.

13.1 Snowy 2.0 Operation

Snowy 2.0 generation and pumping MW's were plotted against the NSW spot price duration curve for a sample of years and this is shown in Figure 32 below.

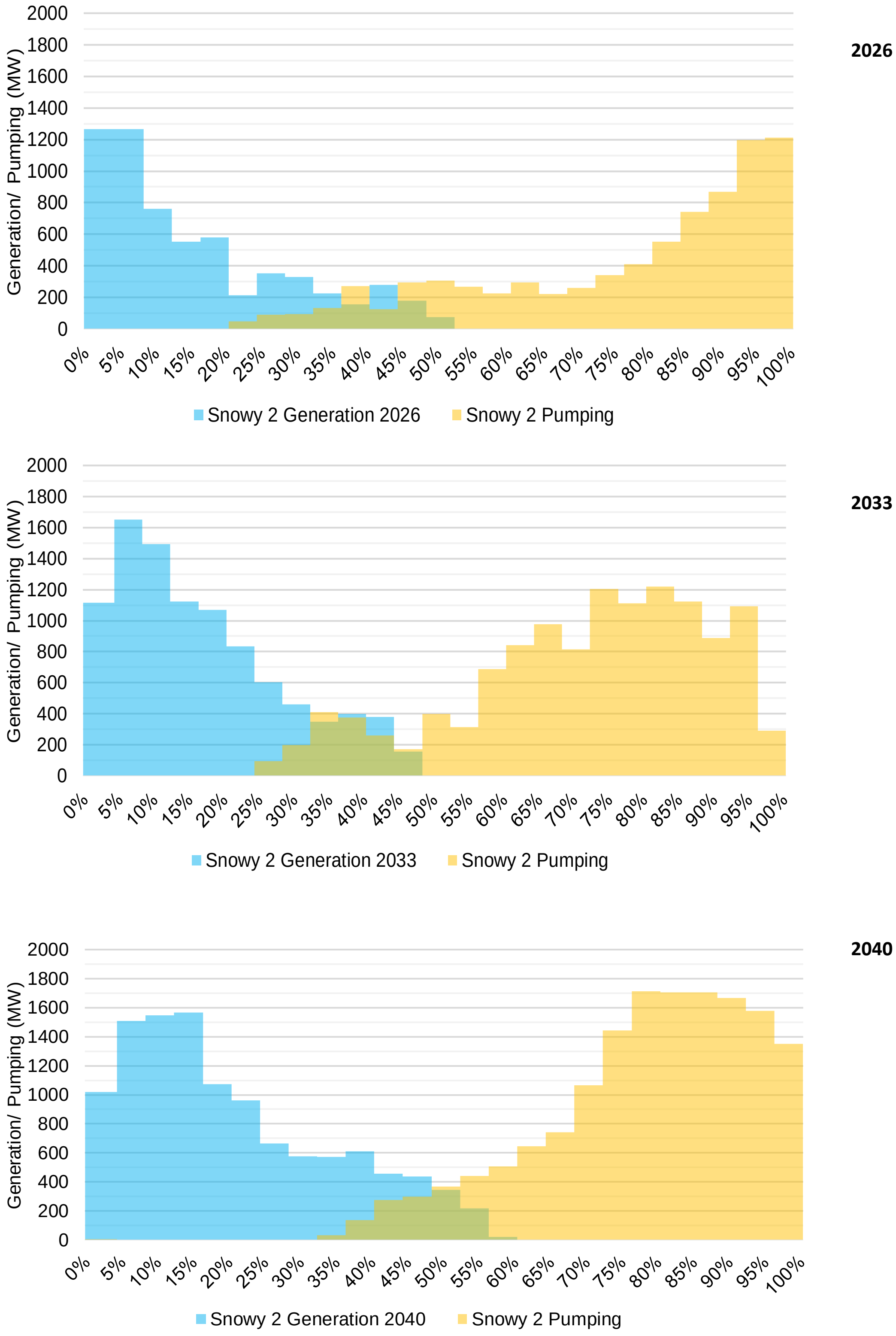
The generation and pumping MW's are averages over 5% "buckets" (and thus do not show the maximum in each bucket). For each year this figure shows:

- The NSW spot price duration curve;
- The MW's of pumping (right hand side of each graph and in yellow);
- The MW's of generation (left hand side of each graph and in blue).

The following observations are made:

- Generation occurs at high spot prices and pumping at low spot prices;
- The level of pumping reflects the level of generation and the RTE (and vice versa);
- The stepped characteristic is associated with a different number of Snowy 2.0 generator/pumping units operating;
- 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;
- 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;
- There are very low prices where Snowy 2.0 is not pumping at 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;
- 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 Snowy 1.0. This would occur less in actual practice due to better planning;
- The value lost through not capturing all low and high prices is a slight reduction in SHL value.

Figure 32 Base Scenario: Snowy 2.0 Gen and Pump MW sorted by Spot Price



Source: Marsden Jacob Associates

Table 11 below shows the percentage of time Snowy 2.0 was generating and pumping at 2,000 MW and less than 2,000 MW in the years 2026, 2033, 2040 and 2047(in the Base Scenario) ordered by spot price (high to low).

Table 11 Base Scenario – Percentage of Pumping and Generating at 2000 MWs

Generation				Pumping			
Year	Less than 2000MW	2000MW	Total	Year	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%

14. Low Emissions Scenario

This chapter presents the description of, and modelling results for, the Low Emissions Scenario. It represents how the NEM, under the assumptions contained in the Base Scenario, would develop if a policy were implemented that required emissions reductions (compared to 2005 level) of 45% by 2030 and 80% by 2050.

The modelling showed that substantial changes (compared to the Base Scenario) were required by 2030 and in the late 2040's.

14.1 Description and assumptions

This scenario assumes that a policy of a 45% reduction in emissions by 2030 (calendar year) and an 80% reduction by 2050 (calendar year) is enacted and met in the NEM.

As the mechanism under which this would be implemented can impact spot prices, this was needed to be assumed.

The assumptions regarding these issues are described below.

1.1.2 Abatement Strategies

Actions required to satisfy this high abatement scenario included the following:

- Coal plant operating less (recognising capacity would be required for power system reliability). This can be achieved through temporarily closing down coal generator units (for example on a seasonal basis) or operating units at a lower capacity factor;
- Early closures of coal plant;
- Accelerated development of rooftop PV (through appropriate incentives);
- Increased large-scale VRE development (which will be required to be significantly higher than in the Base Scenario);
- Required increase in VRE firming (gas generation and storage) to support the increase in VRE;
- Basslink II developed – due to the increased need for firming together with a policy on emissions abatement.

Coal Plant closures

The amount of coal power station reduction required by 2030 was similar to the level of coal plant reduction the Base Scenario had in 2036. This would in effect mean moving forward the coal plant closured that the Base Scenario had in 2036 to 2030. The generation profile of coal plant assumed was as follows:

Closure:

- Eraring closed over the period 2027/28 to 2028/29;
- Loy Yang A closed over the period 2044/45 to 2045/46;
- Stanwell (all units) closed in 2046/77.

Seasonal operations (only servicing summer and winter):

- 50% of Bayswater from 2015/26 onwards;
- 100% of Loy Yang B from 2034/35 onwards;
- 50% of Millmerran from 2034/35 onwards;
- 50% of Callide from 2034/35 onwards;
- 25% Stanwell from 2034/35 onwards (only in "without Snowy 2.0" Case).

Large-scale VRE Development

With coal generation at the level of the mid 2030's by 2030, the development of VRE generation was required to be accelerated in order that the installation level of VRE in 2030 was similar to what the Base Scenario had in 2036.

The development of VRE to meet the level required in 2030 would need to be undertaken in the years leading up to 2030. This development would occur in the years before the closure of any coal power stations. Post-2030 the need for accelerated development of VRE would be gone.

Rooftop PV development

Consistent with a 45% emissions reduction policy would be incentives to increase the development of rooftop PV. The 2018 AEMO ESOO only provided a single outlook for rooftop PV development.

It was assumed that incentives would be put in place to accelerate rooftop PV installation. The assumption was that the AEMO rooftop PV development profile was moved forward by 5 years (i.e. the level of PV installation reached in 2030 was that projected by AEMO to be in 2035).

To meet the 2050 emissions target, post 2030 the development of rooftop PV would need to continue on an accelerated path compared to the Base Scenario.

From a total system generation perspective, the impact of rooftop PV and large-scale PV is very similar (but not the same). Rooftop PV is not tracking and consequently has a narrower profile. More kW of rooftop PV is required for the same kWh of output compared to large scale PV due to the poor orientation on many rooftop PV systems.

Battery installation

The significant firming required would likely result in the introduction of regulation requiring new VRE to have accompanying storage. The amount was assessed in the modelling.

Basslink II

It is assumed that a 600 MW DC interconnector between Victoria and Tasmania would be developed (i.e. Basslink II) and that this would enter in 2028. The basis of this assumption was as follows:

- The substantial firming capacity that would be required in the NEM;
- Basslink II offers lower firming costs than batteries[18];
- Tasmania can be expected to have over 600 MW of export capacity above the 500 MW on the existing Basslink under most conditions;
- The July 2018 report by TasNetworks costed a 600 MW link (Option 1) in the indicative range of $1.4–$1.9 billion and a 1,200 MW link (option 2) in the range $1.9–$2.7 billion. The 1,200 MW link would require the development of pumped storage capacity to have the generation to utilise the additional 600 MW capacity available over Option 1. The cost of the pumped hydro in Tasmania is not known;
- The earliest Basslink II can enter has been quoted as 6 to 7 years.

—

[18] Based on the published costs of Basslink up to 600 MW. Above this the costs, which would include pump storage development in Tasmania, are not known.

14.1.1 Mechanism

The mechanism used to achieve a 45% emissions reduction is relevant to pricing and spot price outcomes. Alternatives to this are policies that have been previously suggested:

- A price on carbon emissions (i.e. similar to the Carbon Pollution Reduction Scheme);
- Emission Intensity Scheme;
- Clean Energy Target (recommenced in the Finkel review);
- NEG-type emissions compliance arrangements;
- Government intervention to close coal power stations (an option forwarded in the Finkel review).

The Australian Labor Party have indicated that NEG-type arrangements may be preferred. These arrangements put the obligation on retailers and large energy purchasers to demonstrate that the generation used/contracted to supply their demand satisfies the emission reduction requirement. Low emission generation can be purchased through the trading of NEG emission certificates.

Under this arrangement there would be a penalty of non-compliance, which, if based on the level of non-compliance, would have a monetary value proportional to the total emissions exceeded. This lends itself to a $/tonne compliance cost. Compliance costs do not add to the spot price.

Under a scenario of high emissions abatement (such as a 45% reduction by 2030) there may be required a quantum of gas generation being dispatched over coal generation. Under a carbon price this would result from the emissions cost increasing the SRMC of coal above the SRMC of gas. The dynamic is different to that under the emissions-type arrangements as proposed under the NEG, as there are no costs directly associated with emissions in the pool (i.e. all generator SRMCs remain unchanged).

Early closure of one of more coal power stations would be part of an optimum strategy to achieve lower emissions. Such an outcome may be beyond what could be achieved through a NEG-type arrangement and would require direct government intervention / incentive.

Given a mix of coal and gas plant required to replace coal generation (to lower emissions), there would be a requirement for gas generation to offer a dispatch price under that of coal generation. Under this scenario:

- The emissions contract would pay gas generation SRMC + capital for its generation. The contract would require actual generation;
- Gas generation would bid under coal generation;
- Coal generation would clear the market more often. With its bids unchanged it would receive a lower spot price;
- Renewable generation receives lower revenue than in the no emissions abatement scenario;
- There is a substantial contract premium provided to the gas generation plant. This is not hedging spot price but paying for actual generation to reduce emissions;
- The economics of coal generation would require this generation to shadow gas generation, as has been observed in the NEM since the closure of Hazelwood Power Station. This would be assisted by the knowledge that gas generation would be operating under coal generation for a proportion of the time. This would mean clearing prices are largely unchanged;
- There is likely to be some residual generation that bids to maintain peak prices near new entry levels;
- Price spread for storage plant would potentially reflect significant excess coal generation and high prices when either coal or gas was clearing the market.

14.2 Low Emissions Scenario – NEM Outcomes

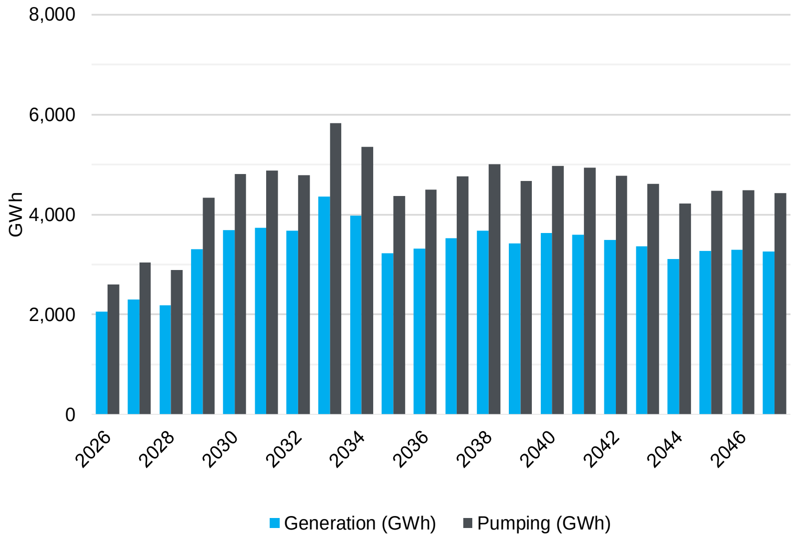
This section presents a selection of the modelling results from the Low Emissions Scenario. Shown are:

- For the "with Snow2.0" case, the change in installed capacity moving from the Base Scenario to the Low Emissions Scenario (i.e. positive if the Low Emissions Scenario is higher);
- The change in installed capacity moving from the "Without Snowy 2.0" case to the "With Snowy 2.0 case" (i.e. positive if the "with Snowy 2.0" case is higher);
- For the "with Snowy 2.0" case and "without Snowy 2.0" case the level of NEM carbon emissions;
- Snowy 2.0 generation and pumping volumes.

Snowy 2.0 Generation and Pumping

The change in Snowy 2.0 generation from the Base Scenario reflects increased VRE providing more pumping energy and reduced coal generation reducing available pumping energy. This results in high Snowy 2.0 generation by 2030 but less in 2047.

Figure 33 Low Emissions Scenario Modelling Results – Snowy 2.0 Annual Generation

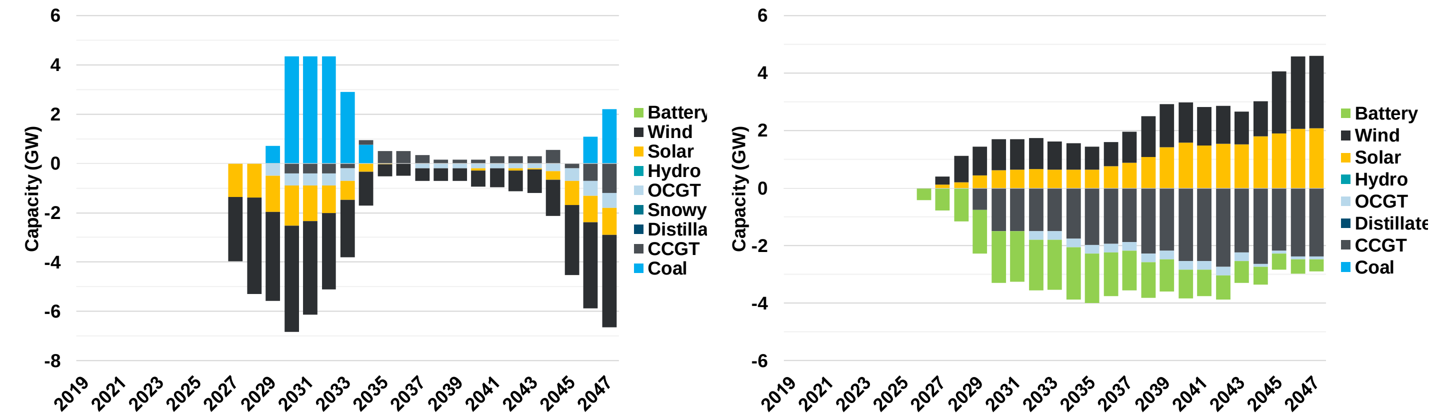


Source: Marsden Jacob Modelling Low Emissions Scenario

Installed Generation and storage capacity

The profile of generation installation reflects accelerated development such that by 2029 the installed capacity is similar to what the Base Scenario was in 2035. The Low Emissions Scenario has a higher level of rooftop PV development and Basslink II developed.

Figure 34 Low Emissions Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW



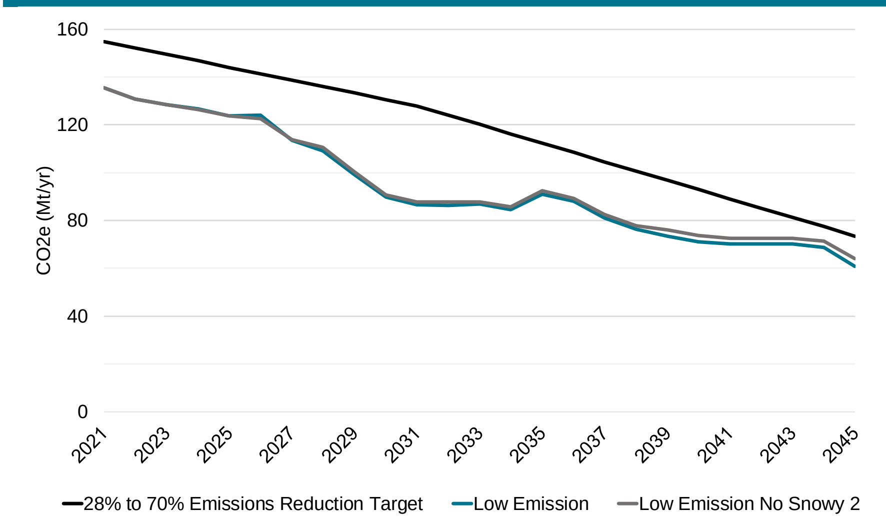
Source: Marsden Jacob Modelling Low Emissions Scenario

Carbon Emissions

The changes provide for the level of carbon emissions in 2030 (calendar year) to be near the 45% targeted reduction (compared to 2005 levels). Commentary on the emissions profile is provided below.

Figure 35 Low Emissions Scenario Modelling Results – NEM Carbon Emissions MT

S1.0 and S2.0 cases – Carbon Emissions Mt



- The changes provide for the level of carbon emissions in 2030 (calendar year) to be near the 45% targeted reduction (compared to 2005 levels). The profile has:
- A fast reduction in emissions in the late 2020's to satisfy the 2030 target;
- Post-2030 the profile of emissions flattens out (as the market returns to near where it was in the Base Scenario);
- Action is taken in the late 2040's to address the 2050 emissions target. This has emission rapidly reduce to reach that target through the closure of coal power stations.

Source: Marsden Jacob Modelling Low Emissions Scenario

15. Early Coal Closure Scenario

Some of the existing coal power stations could close earlier than has been assumed in the Base Scenario. This could arise from policy changes or from economics associated with aging assets. The implications of coal plant closing earlier are complex as it involves replacing both the firm capacity and the energy production foregone.

15.1 Description and assumptions

One of the recommendations of the Finkel Review was the early closing of coal power stations. A potential policy was limiting their operating life to 50 years[19]. This was the assumption of the Early Coal Closure Scenario. Table 12 presents the dates when the existing coal power stations reach 50 years of age.

Table 12 Early Coal Power Station Closure

	No of Units	Unit Size MW MW	Commissioning Start	Finish	Age Years	Year when 50 Years Old
Queensland						
Tarong	4	350	1984	1986	32	2036
Tarong Nth	1	450		2003	15	2053
Stanwell	4	350		1996	22	2046
Callide C	2	420		2001	17	2051
Callide B	2	350		1988	30	2038
Millmerran	2	450		2002	16	2052
Kogan Creek	1	750		2007	11	2057
Gladstone	6	280		1976	42	2026
New South Wales						
Eraring	4	720	1982	1984	34	2034
Vales Point	2	660	1978	1979	39	2029
Mt Piper	2	700	1992	1993	25	2043
Bayswater	4	660	1985	1986	32	2036
Liddell	4	500	1971	1973	45	2023
Victoria						
Loy Lang A	4	550	1984	1988	30	2038
Loy Yang B	2	483	1993	1996	22	2046
Yallourn	2	350				
	2	375	1972	1974	44	2024

The coal plant that would retire earlier than in the Base Scenario were as follows:

- Gladstone would close in 2026 (rather than the Base Scenario assumption of 2029);
- Loy Yang A would close in 2038 (rather than the Base Scenario assumption of 2048);
- Loy Yang B would close in 2046 (rather than the Base Scenario assumption of 2056).

—

[19] Report - Independent Review into the Future Security of the National Electricity Market, Blueprint for the Future June 201 Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel – Page 175 reads: "The Lifetime limits on coal-fired generators: A lifetime limit would require coal-fired generators to close once they reach a certain age. The lifetime limit would be approximately consistent with the expected investment life of the generation asset. A lifetime limit of 50 years was modelled as a scenario for this Review.

The consequences of this are:

- The period 2034 to 2038 would have a total of 9,820 MW of base load generation close (Eraring, Tarong, Bayswater, Callide B, and Loy Lang A). This would require gas and storage generation to provide at least this much capacity together with a substantial amount of additional VRE generation;
- With Liddell and Vales Point power stations having closed prior to 2030, NSW would only have 700 MW of coal generation (Mt Piper) after 2036;
- The closure of Loy Yang A in 2038 alone, a 2,000 MW base load power station that operates at high capacity factor, would have a very significant impact, both in terms of capacity and energy to be replaced;
- All coal generation in Victoria would have exited by 2046.

The absence of an emissions limit in this scenario would provide for gas plant to be developed. However, such development may have substantial risks:

- Gas supply is uncertain, both in terms of availability and price. A significant increase in GPG development would likely be reflected in increased gas prices (for term supply) and also the requirement for a substantial investment in gas pipelines;
- Given that the early coal closure policy is based on a policy of emissions reduction, gas plant would have a risk associated with potential future emissions policy.

For the purposes of this scenario it was assumed that gas generation, with the required gas supply, would be available at the costs assumed in the base case. It is likely, thought, that gas cost would be higher due to an increase in gas demand.

The substantial firming requirements also provide for Basslink II to be developed under the same assumptions as in the Low Emissions Scenario.

15.2 Early Coal Closure Scenario – NEM Outcomes

This section presents a selection of the modelling results from the Early Coal Closure Scenario. These are the standard set that are used in all the scenarios (and that were described in the Base Scenario).

Snowy 2.0 Generation and Pumping

Closing coal generation and replacing with gas generation reduces the availability of pumping energy. This results in a lower level of Snowy 2.0 generation, as shown in Figure 36 below.

Installed Generation and storage capacity

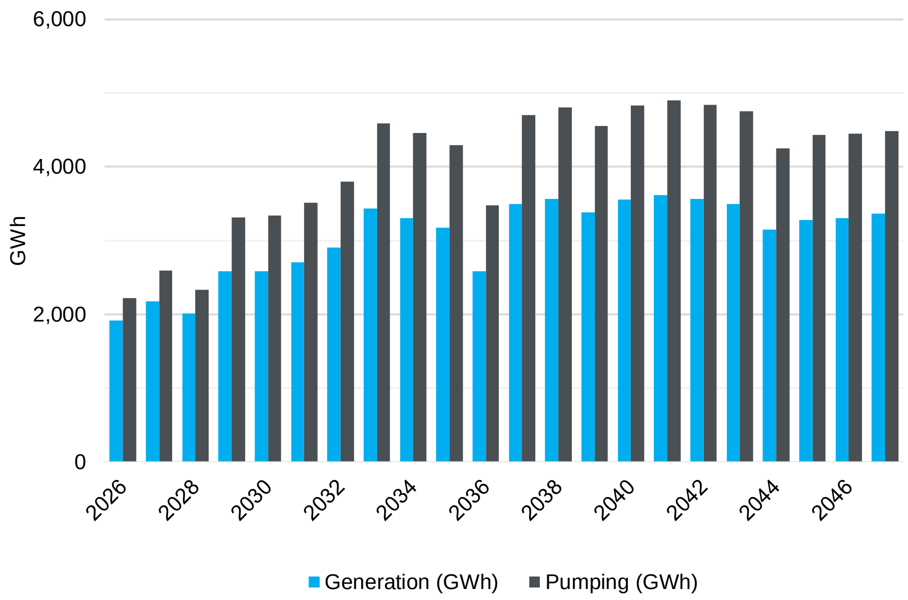
The change in installed generation from the base Scenario reflects the changed economics associated with the additional closed coal generators. Without a signal to reduce emissions, a large component of this would be gas generation.

In practice there may be a significant risk associated with the development of new gas generation:

- Gas generation may be required to be curtailed in the future if stringent emissions limits were introduced post development of the gas generation;
- The availability and cost of gas could be uncertain.

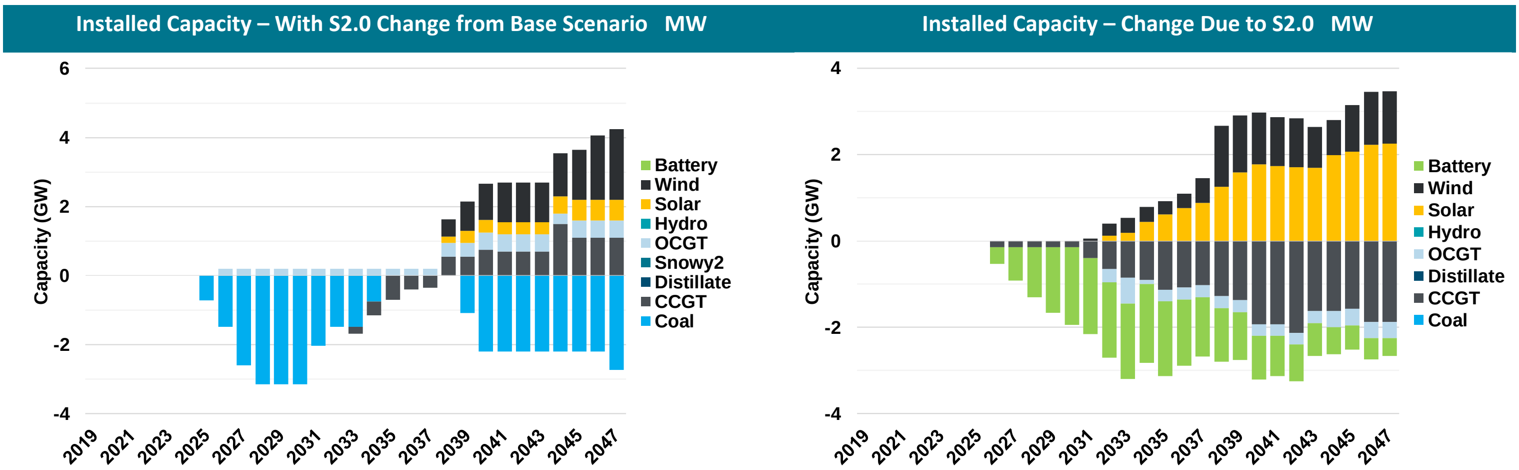
If these risks reduced the development of gas generation and additional VRE and storage was required, this would increase the value of Snowy 2.0 storage.

Figure 36 Early Coal Closure Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



Source: Marsden Jacob Modelling Early Coal Closure Scenario

Figure 37 Early Coal Closure Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW



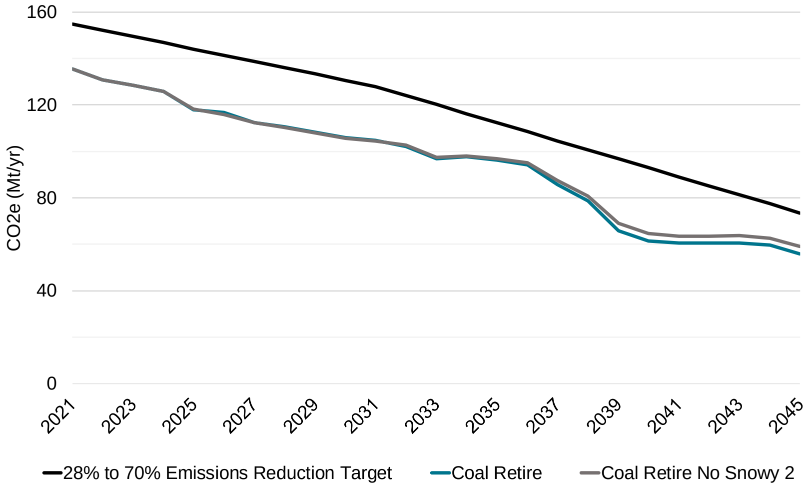
Source: Marsden Jacob Modelling Early Coal Closure Scenario

Carbon Emissions

Closing coal generation necessarily reduces carbon emissions. However, locking in substantial amounts of gas generation may result in a long-term emissions issue which would have been lower as a result of VRE having a longer development time and improved economics due to its reducing cost curve.

Figure 38 Early Coal Closure Scenario Modelling Results – NEM Carbon Emissions MT

S1.0 and S2.0 cases – Carbon Emissions Mt



Source: Marsden Jacob Modelling Early Coal Closure Scenario

16. High Demand Scenario

A higher level of demand growth would require additional new generation, both energy production and dispatchable and firm capacity, compared to the Base Scenario. This would bring forward the time that the 2,000 MW of Snowy 2.0 capacity would be required in the market. It would also lead to a different balance of VRE, thermal generation and storage.

16.1 Description and assumptions

The 2018 AEMO demand projections contained three load growth scenarios, namely Neutral, Fast and Slow. The Fast Scenario represented a higher demand outlook. These scenarios were presented in Chapter 4 of this report.

In comparison to the Neutral scenario, AEMO state the following regarding the Fast scenario[20]:

> "projected stronger growth in new dwellings and more rapid forecast uptake of electric vehicles, residential annual delivered consumption NEM-wide is forecast to go up by half over the 20-year forecast (or 2.5% annual average)."

> "earlier increase in electricity usage than the Neutral scenario, as it assumed LNG companies will be more aggressive in debottlenecking LNG facilities, resulting in more CSG being produced to fill LNG trains. In the longer term, the Fast change scenario considers the possibility of an additional LNG export facility from 2025, ramping up to full capacity export by 2027 and sustained for the remaining forecast period. While there is no current prospect for future LNG facilities, this increase serves in the modelling as a proxy for new electricity-intensive load in Queensland. It does not reflect any known investment under consideration."

This scenario assumes the 2018 AEMO Fast Scenario demand projection. The demand increases over the period in terms of NEM energy and regional NEM maximum demands are shown in the table below.

Table 13 High Demand Scenario Description – Increase from the Base Scenario

	Energy Increase GWh	Maximum Demand Increase MW
2030	20,000	3,000
2040	30,000	5,000
2050	40,000	7,000

In the same manner as the Base Scenario, increased demand had new generation developed though the most economic options. Coal plant was not an option due to the risk issues previously presented.

—

[20] AEMO 2018 ESOO

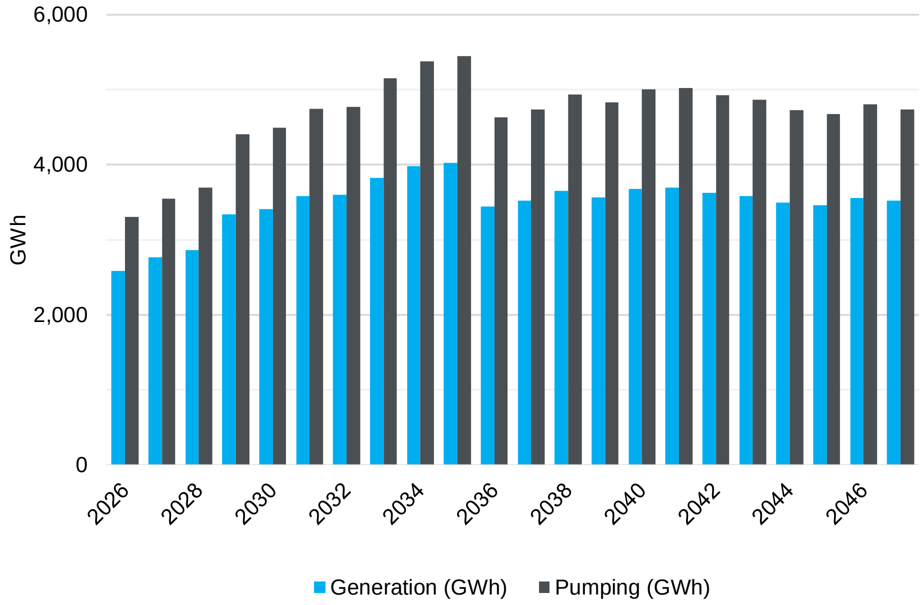
16.2 High Demand Scenario – NEM Outcomes

The figure below shows a selection of the modelling results from the High Demand Scenario. These are the standard results that are used in all the scenarios (and that were described in the Base Scenario).

Snowy 2.0 Generation and Pumping

The level of generation reduces from 2036 compared to the Base case after the closure of Bayswater. This is due to the reduction of pumping energy due to higher demands.

Figure 39 High Demand Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



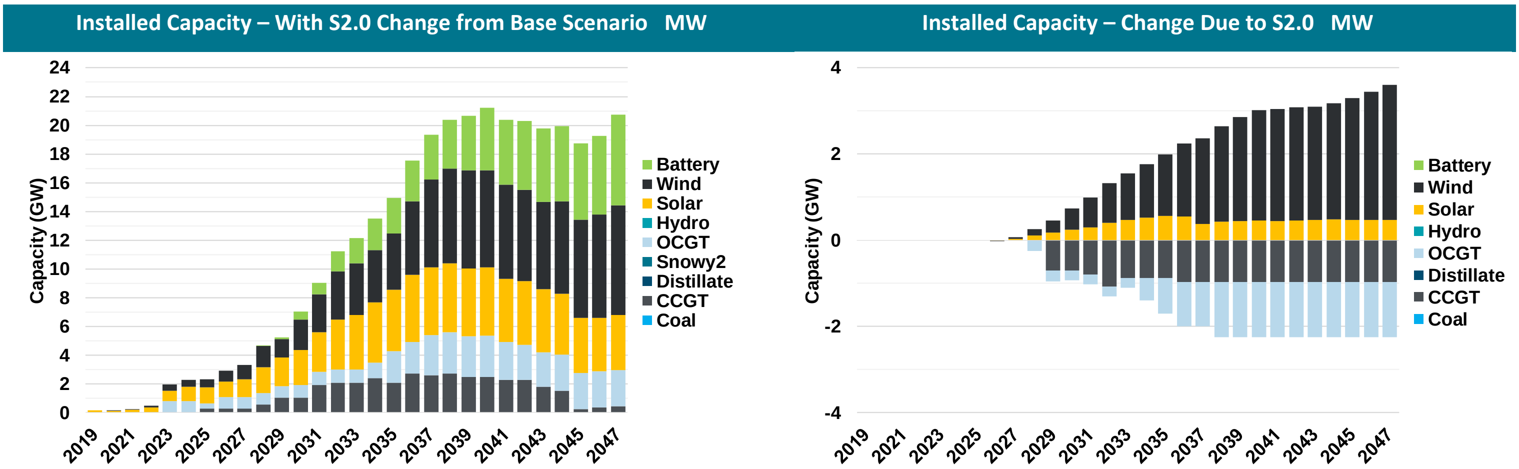
Source: Marsden Jacob Modelling High Demand Scenario 19 October 2018

Installed Generation and storage capacity

The High Demand outlook results in substantial additional investments in gas generation (CCGT and OCGT) and VRE:

- By 2030 the additional investment is about 1,700 MW in gas generation and 5,000 MW in VRE;
- By 2040 the additional investment is about 5,000 MW in gas generation and 12,000 MW in VRE, which provides the firm capacity (gas generation and storage) and energy required to satisfy the increased demand.

Figure 40 High Demand Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW

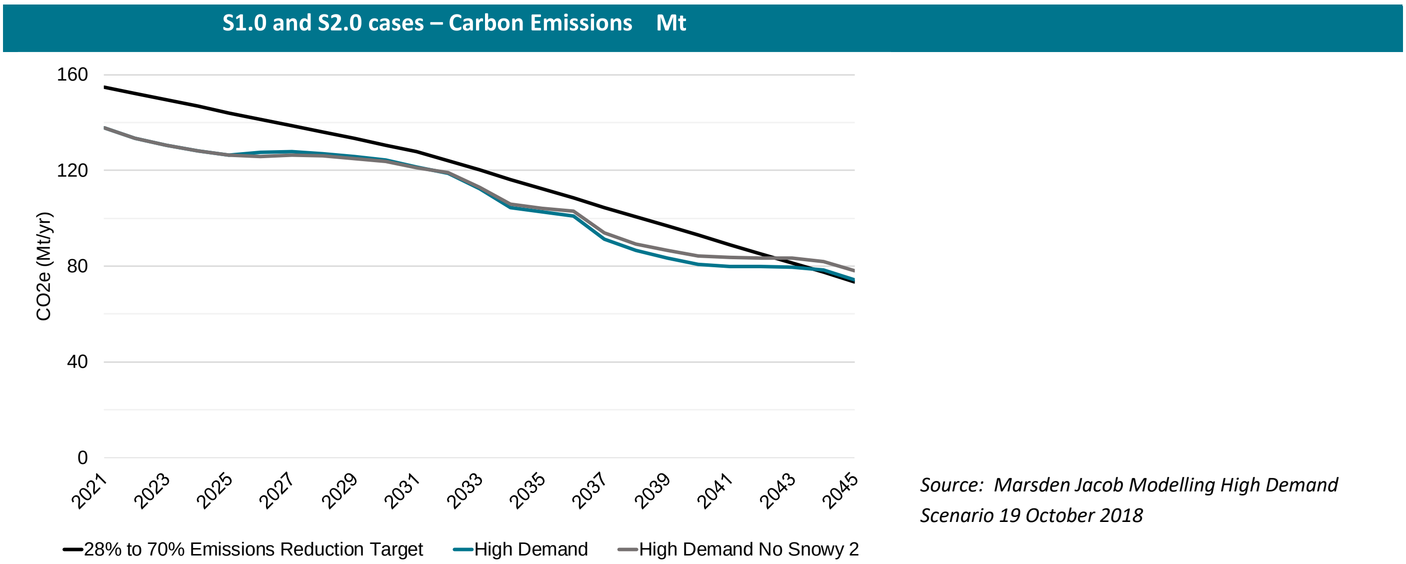


Source: Marsden Jacob Modelling High Demand Scenario 19 October 2018

Carbon Emissions

The higher demand level without an emission limit results in emissions being higher than the Base Scenario. Snowy 2.0, as in the Base Scenario, results in lower emissions through providing for more VRE to economically operate in the NEM.

Figure 41 High Demand Scenario Modelling Results – NEM Carbon Emissions MT



Source: Marsden Jacob Modelling High Demand Scenario 19 October 2018

17. Hydrology Wet Scenario

Hydro power station available generation is subject to the variability of water inflows. Weather variability results in drought and wet years and, while potentially lasting for long periods, are non-permanent. In addition, climate shifts may impact average inflows, and it may not be possible to separate the two causes to changes in inflows.

A hydrology wet scenario has increased water inflows to all hydro plants. This does not impact Snowy 2.0 generation availability which is determined by the availability of pumping energy.

17.1 Description and assumptions

This scenario represents an outlook of continued wet conditions (i.e. compared to that assumed in the Base Scenario) from 2025. These conditions increase the generation available to all hydro power stations (in the NEM) including Snowy 1.0 by an assumed 10% (through the increased inflow of water for generation).

Table 14 shows the average hydro generation from the two major hydro schemes in the NEM plus the other smaller hydro schemes. The hydro power stations in Tasmania (owned and operated by Hydro Tasmania) represent about 66% of the total hydro power generated (GWh) in the NEM, Snowy 1.0 represents about 26% and the remainder less than 10%.

Table 14 Increase in Annual Hydro Generation due to Wet Conditions

Hydro Scheme	Average Annual Generation GWh p.a.	Generation Increase GWh p.a.	Increase in peak period Generation MW (1)
Snowy 1.0	4,000	400	91
Hydro Tasmania	10,000	1,000	228
Other Hydro (2)	1,000	100	23
Total	**15,000**	**1,500**	**342**

Notes (1) This assumes hydro only operates during the top 50% of demand times.
(2) Estimated.

Hydro Tasmania

The market impact of increased water inflows to the NEM hydro power stations would depend how this additional hydro generation is used. Excluding Snowy 1.0, Hydro Tasmania comprises about 90% of hydro generation in the NEM.

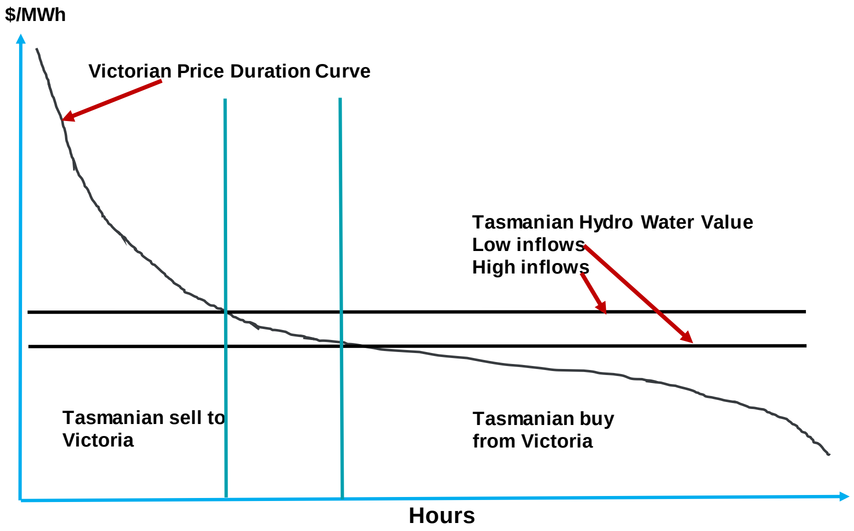
The use of hydro generation from Tasmania is reflected in Basslink flows, which represent the difference between generation in Tasmania (hydro plus wind and possibly gas) and Tasmanian demand. Currently

Tasmania imports about 700 to 1,000 GWh p.a. from Victoria (an amount equal to about 7 to 10% of Tasmanian annual demand)[21].

Hydro Tasmania dispatches hydro generation based on hydro condition, requirements of Tasmania security, Tasmania spot prices, and the value of arbitrage trading across Basslink (this is selling to Victoria when Victorian spot prices are high and buying from Victoria when Victorian spot prices are low).

Figure 42 illustrates the concept of water value for hydro generators in the context of Tasmanian hydro and flows across Basslink. The key point is that in the absence of hydro constraints and with perfect foresight) additional water captures a value equal to the minimum price it was previously willing to sell.

Figure 42 Theoretical Basis – Value of Additional Water to Hydro Tasmania



Theoretically, Tasmania Hydro develops a value for (marginal) water based on minimising the cost of energy purchased from Victoria.

An increase in water inflows to Tasmanian hydro would result in additional sales to Victoria at the marginal value of water. There would not be additional sales at high prices as these sales opportunities would have already been taken.

The figure below shows for the 2017-18 year the historical Victorian spot price duration curve and Basslink flows (corresponding to the Victorian spot price). As observed, there are flows across Basslink in both directions at all Victorian spot prices (except for very high Victorian prices). This illustrates that trading across Basslink (buy and sell) arbitrages Victorian spot price differences over most days.

This meant that additional generation to Hydro Tasmania would likely operate across all Basslink flows.

Snowy 1.0

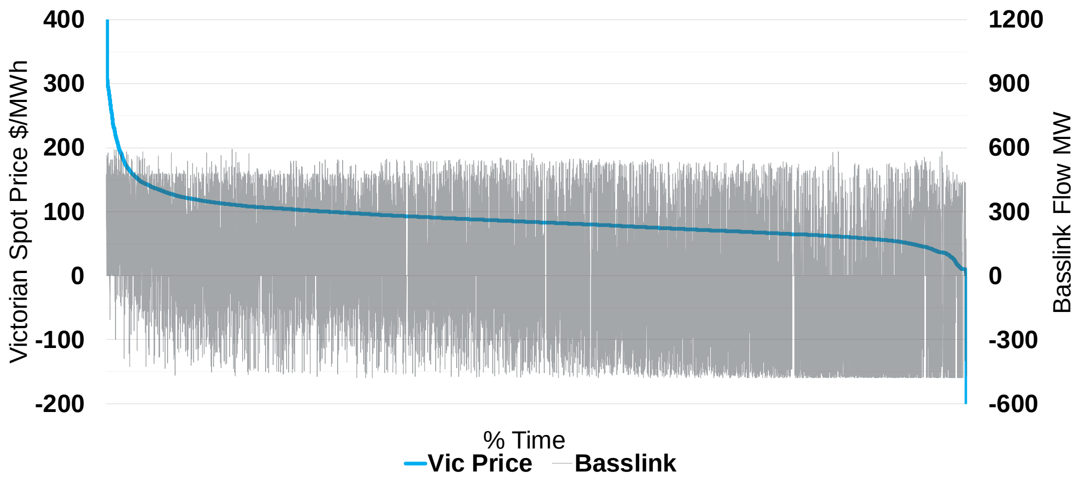
The additional water to Snowy 1.0 would provide for Snowy 1.0 to increase generation.

This would reduce some of the high value operating hours that would have been captured exclusively (within SHL) by Snowy 2.0. The net impact would be an expected increase in SHL enterprise value and a small reduction in the value difference between Snowy 1.0 and Snowy 1.0 plus Snowy 2.0.

---

[21] Project Marinus, Project Specification Consultation Report, Additional interconnection between Victoria and Tasmania, July 2018, Section 2.2: "Based on long-term average inflows, however, Tasmania has a deficit of on-island generation compared to consumption of approximately 700 GWh to 1,000 GWh per annum (approximately 7 per cent to 10 per cent). As a consequence, Tasmania imports a small portion of its electricity from Victoria via Basslink to meet its energy needs."

Figure 43 2017-18 – Victorian Spot Price Duration Curve and Basslink Flows



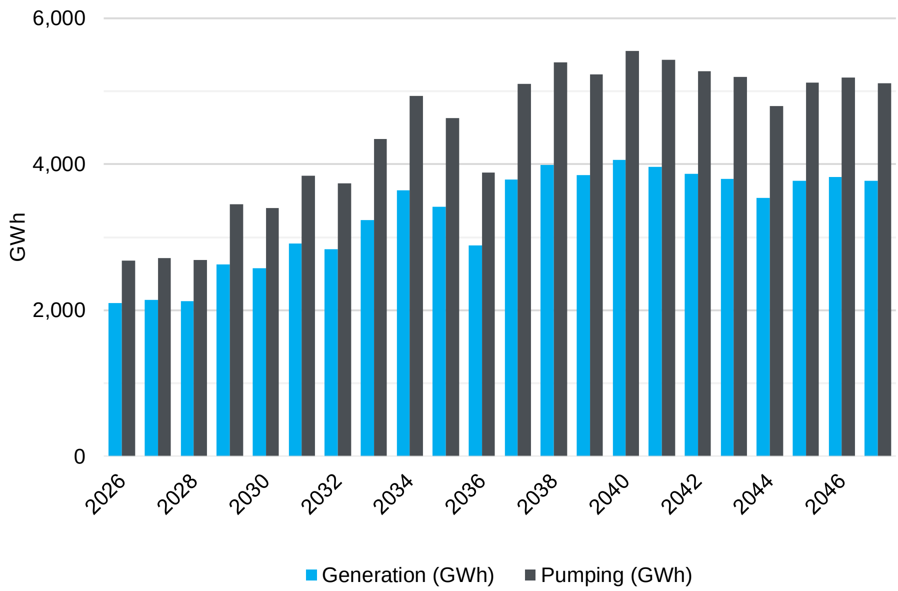
17.2 Hydrology Wet Scenario – NEM Outcomes

The figure below shows a selection of the modelling results from the Hydrology Wet Scenario. These are the standard results that are used in all the scenarios (and that were described in the Base Scenario).

Snowy 2.0 Generation and Pumping

Additional hydro generation provides increased competition to Snowy 2.0 generation and does not provide additional pumping energy.

Figure Hydrology Wet Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes

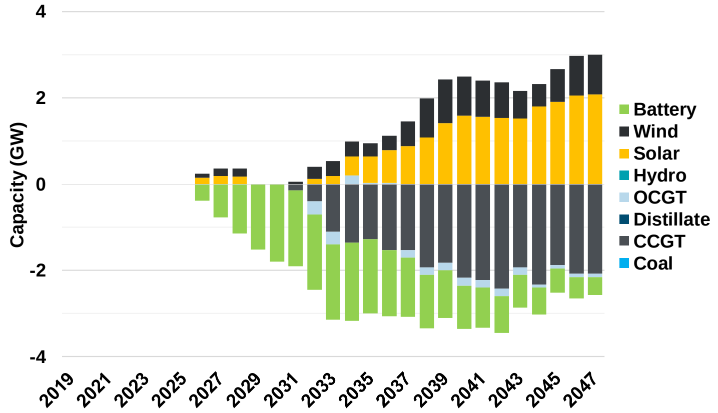


Source: Marsden Jacob Modelling Hydrology Wet Scenario

Installed Generation and storage capacity

There is no change in installed capacity. This reflects the uncertain nature of this additional energy and that it is mainly used the lowest value times of hydro generation.

Figure 44 Hydrology Wet Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW

Installed Capacity – With S2.0 Change from Base Scenario MW	Installed Capacity – Change Due to S2.0 MW
No Change from Base Scenario	

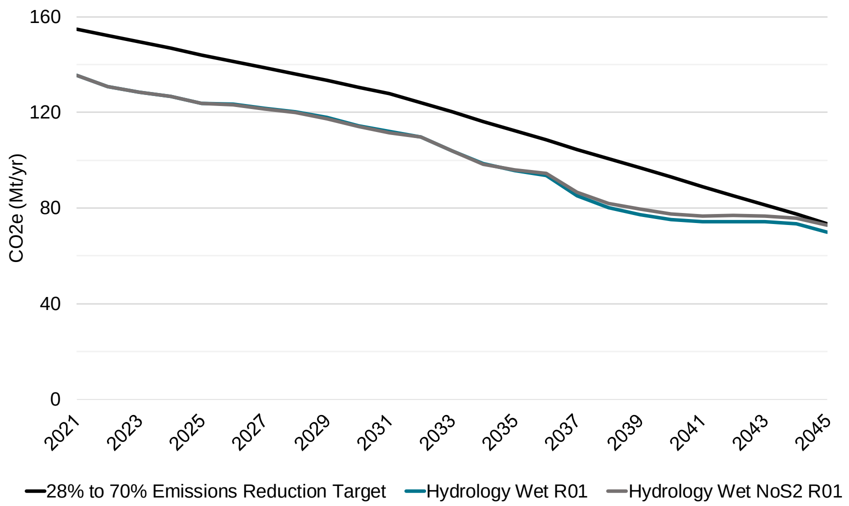
Source: Marsden Jacob Modelling Hydrology Wet Scenario

Carbon Emissions

Additional generation from renewable generation (with no emissions) reduces emissions.

Figure 45 Hydrology Wet Scenario Modelling Results – NEM Carbon Emissions MT

S1.0 and S2.0 cases – Carbon Emissions Mt



Source: Marsden Jacob Modelling Hydrology Wet Scenario

18. Hydrology Dry Scenario

A hydrological dry scenario would reduce Snowy 1.0 generation (and that of other hydro generators). The ability of Snowy 2.0 to increase generation through increased pumping provides a natural "hedge" to Snowy 1.0 and the NEM against such circumstances.

A drought (dry conditions over, say, three years) may have hydro generation decrease significantly, providing greater value to Snowy 2.0 given its ability to increase generation when required. A permanent reduction in inflows would have a different dynamic. This scenario considers a permanent reduction in NEM hydro water inflows.

18.1 Description and assumptions

This scenario represents an outlook of continued dry conditions (i.e. compared to that assumed in the Base Scenario) from 2025. These conditions decrease the generation available to all hydro power stations including Snowy 1.0 by an assumed 10% (through a decrease in the inflow of water for generation).

This is the opposite of the Hydrology Wet Scenario described in the previous section. The issues are the same with the exception that generation levels are assumed to be reduced.

A Hydrology Dry Scenario would decrease the SHL enterprise value but would be expected to increase the value difference between S1.0 and Snowy 1.0 plus Snowy 2.0.

The long-term outlook of climate is that Australia will become dryer and thus hydro yields will decrease.

18.2 Hydrology Dry Scenario – NEM Outcomes

The figure below shows a selection of the modelling results from the Hydrology Dry Scenario. These are the standard set that are used in all the scenarios (and that were described in the Base Scenario).

The following observation are made:

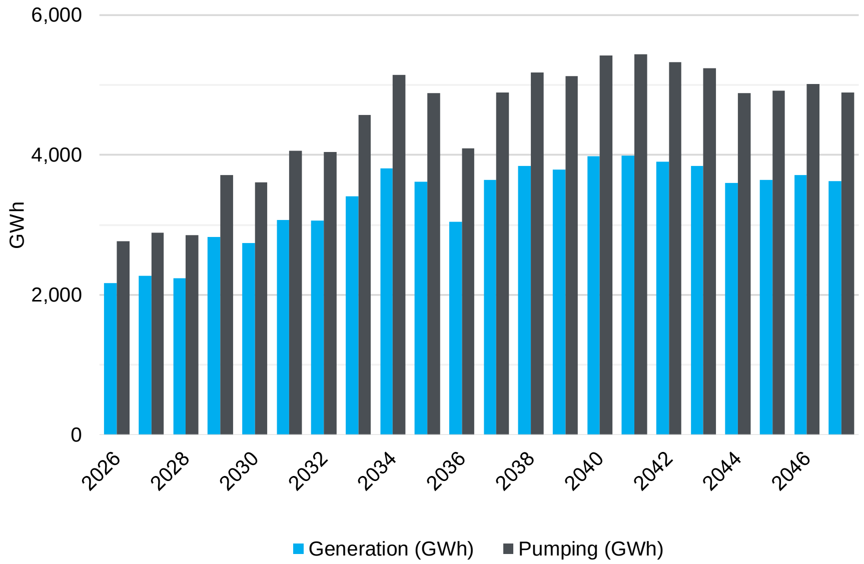
- While the dry scenario had Snowy 1.0 generate less, it also had all other hydro generation in the NEM generate less.
- The reduction in Snowy 1.0 generation occurs at those hours of least value, this is at the "water value" (which may vary through each year). The better this value is correctly assessed at the start of a year (which involves projecting both hydro yield and spot price outcomes) the lower the impact of a reduction in hydro generation would be.
- The reduction in Hydro Tasmania generation, which involves Tasmania net importing a larger amount of energy, should also involve an increase in the Tasmanian water value and changed generation when spot prices are near this value. However, the historical review of Basslink flows previously shown suggests that the change in Basslink flows might occur over the entire Victorian price curve.

- The net impact to Snowy 1.0 is a value loss through lower generation and a value gain through slightly higher spot prices.
- The continuous reduction in hydro production means that the market would settle at a new balance and Snowy 2.0 would not be required to "hedge" SHL during a temporary period (say several years) where Snowy 1.0 generation is substantially lower.

The net result of the modelling has SHL not greatly impacted.

Snowy 2.0 Generation and Pumping

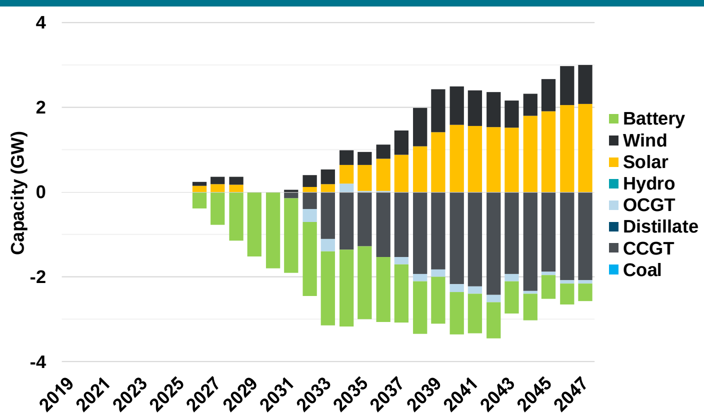
Figure 46 Hydrology Dry Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



Source: Marsden Jacob Modelling Hydrology Dry Scenario

Installed Generation and storage capacity

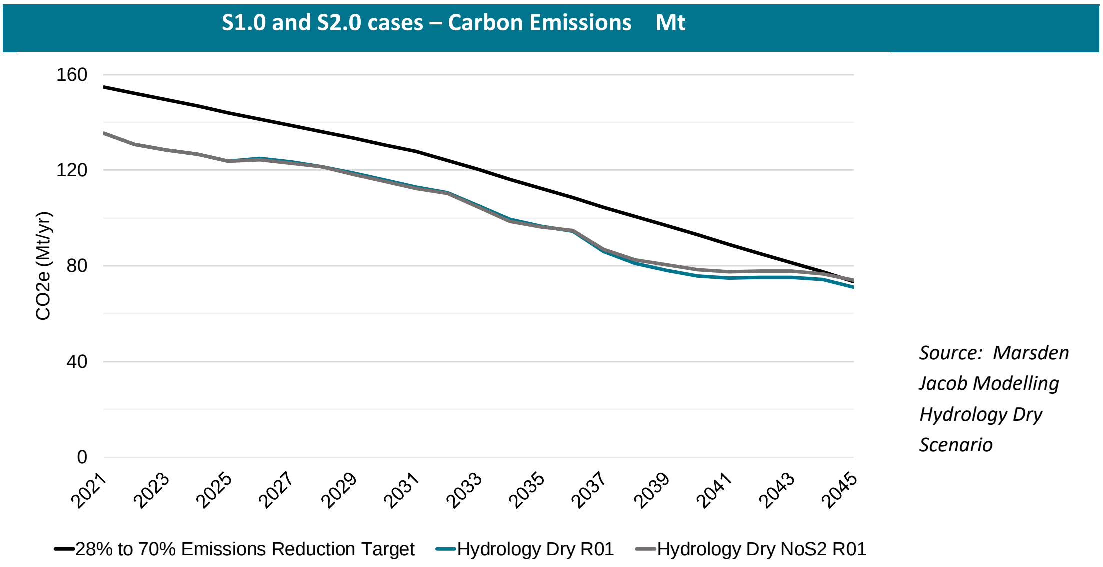
Figure 47 Hydrology Dry Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW

Installed Capacity – With S2.0 Change from Base Scenario MW	Installed Capacity – Change Due to S2.0 MW
No Change from Base Case Scenario	

Source: Marsden Jacob Modelling Hydrology Dry Scenario

Carbon Emissions

Figure 48 Hydrology Dry Scenario Modelling Results – NEM Carbon Emissions MT



Source: Marsden Jacob Modelling Hydrology Dry Scenario

19. High EV Scenario

The rapid development of Electric Vehicles would result in an increase in demand with a profile reflecting charging times and the number of batteries connected to the grid (which may have potential to be used centrally as storage).

The most significant impact would be the amount of energy required and the profile of charging. This profile is uncertain.

If this uptake is substantial, the impact to demand, and the profile of charging, has the potential to significantly impact storage operation and value.

This scenario involved modelling a very high level of EV uptake and was done assuming two different charging profiles.

19.1 Description and assumptions

This scenario represents a policy to have by 2040 80% of cars on the road as Electric Vehicles (EVs).

The implications of this are:

- A significant increase in electricity demand from the grid;
- A profile which may have higher demand in low price periods;
- A significant increase in batteries connected to the grid (when charging).

These matters are addressed below.

Increase in energy demand

The figure below presents the profile of annual EV electricity demand for the Base Scenario, 50% EV on road by 2050, and 80% of EVs on road by 2040.

The increase in energy demand resulting from a trajectory of 80% EVs on road by 2040 is substantial (the basis of this demand level is presented in the Appendix 2). By 2032 the increase over the base scenario is about 20,000 GWh per year, representing over 10% of total NEM demand and equivalent to about a 3,000 MW base load power station.

EV Charging Demand Profile

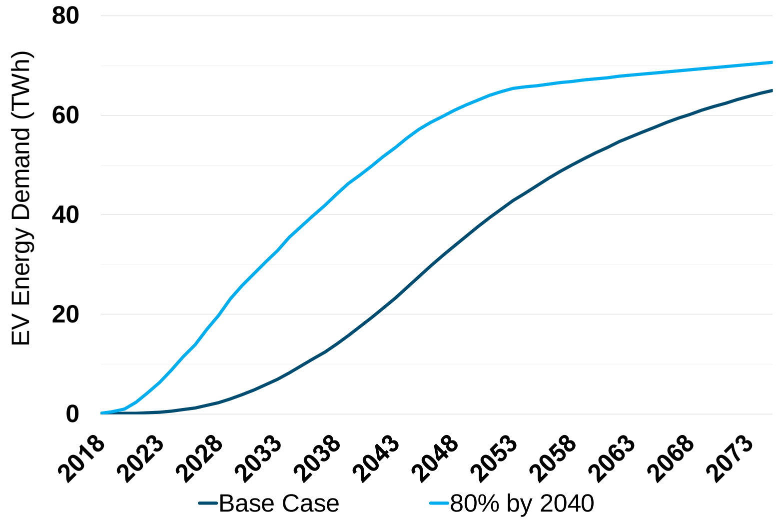
There is very little information on the likely charging profile of EVs'. This profile will be influenced by:

- The time to charge a car – fast charging rates would require significant investment of charging assets (than would have otherwise been needed) and a significant increase in the capacity of the transmission grid;
- The times available to charge – overnight for cars used during the day and continuously for cars parked at residences.

To address this unknown, two profiles were modelled. The names of these scenarios were:

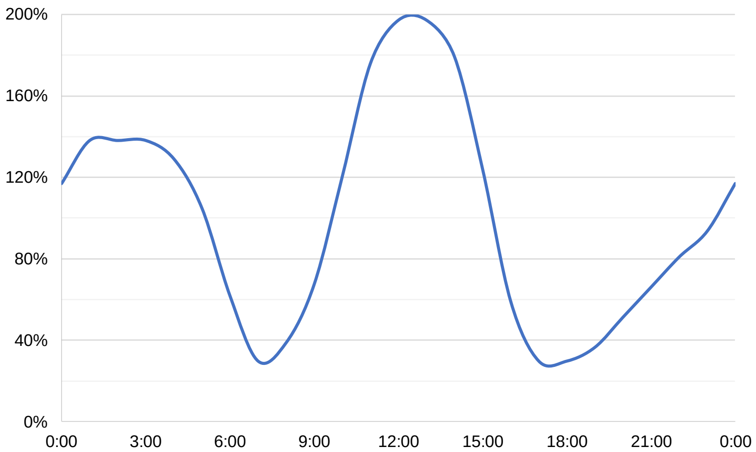
- High EV Flat Increase Scenario. This had the demand increase as a flat level across each day representing continuous charging of cars;
- High EV Profiled Increase Scenario. The profile used is shown Figure 50 below. This had charging during lower demand lower spot price periods.

Figure 49   EV Development Profiles and Energy Requirement



Source: Marsden Jacob Associates

Figure 50   High EV Profiled Increase Scenario – EV Demand Profile



Source: Marsden Jacob Associates

Use of batteries

Evidence to date suggests that batteries from EV will not behave in an "aggregated manner" (meaning control handed over to AEMO for system management purposes) but will more closely follow a "convenience" profile.

With increased penetration of residential solar PV, the likely reduction in solar feed-in tariffs, and the use of 'smart' technology to optimise charging, we would expect that households will look to use their own 'free' solar generation to charge their vehicle where possible. This will have a two-fold benefit of reducing EV charging from the grid as well as reducing the 'duck curve' effect on the aggregate demand profile caused by lower residential demand as a result of increased solar PV generation. We would also expect that retailers will look to use tariffs and other incentives to smooth demand resulting from EV charging.

However, there is also likely to be the availability by the market operator to utilise battery capacity through controls to stop charging for limited period. This would provide capacity value and would reduce the development of firm capacity such as OCGT gas plant and battery capacity.

19.2 High EV Scenarios – NEM Outcomes

This section presents the NEM outcomes for the two high EV scenarios modelled. The results of the modelling of these two cases are presented in turn below.

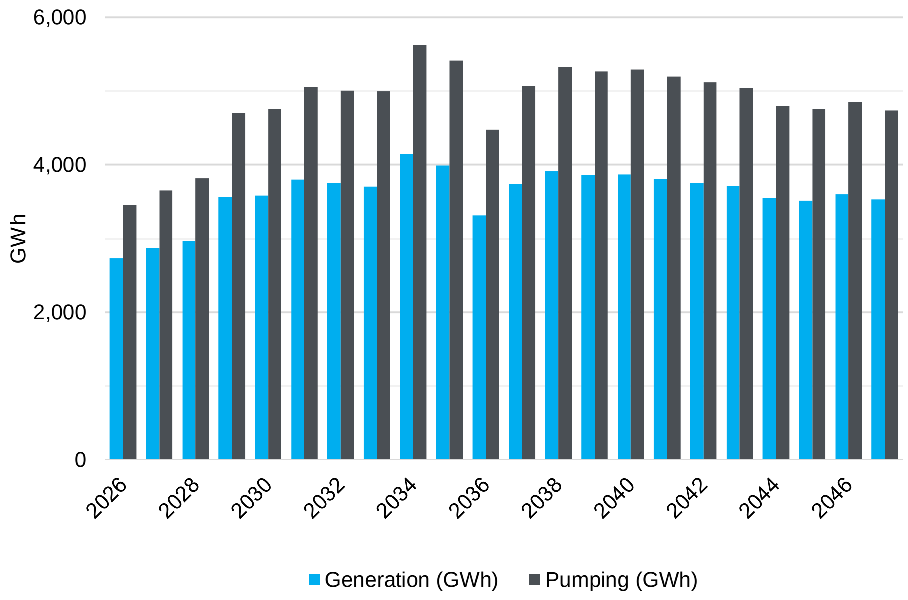
19.2.1 High EV Flat Increase

The figures below show a selection of the modelling results from the High EV Flat Increase Scenario. These are the standard set that are used in all the scenarios (and that were described in the Base Scenario).

Snowy 2.0 Generation and Pumping

The standard graphs showing Snowy 2.0 pumping and generation volumes is shown below. The most notable changes from the Base Scenario are that pumping and generation volumes are slightly lower post 2040 compared to the Base Scenario. The dynamic is complex. The changes are assessed as due to more gas generation and a lower quantity of low priced generation for pumping.

Figure 51 High EV Flat Increase Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



Source: Marsden Jacob Modelling High EV Flat Increase Scenario

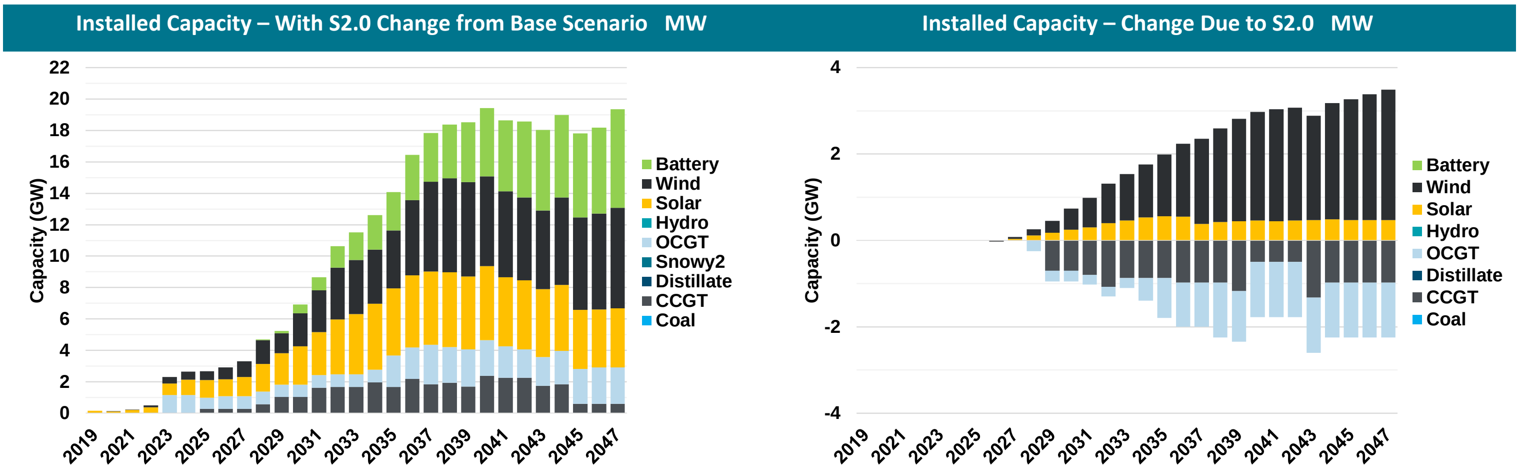
Installed Generation and storage capacity

The standard graphs showing the change in installed capacity are shown below.

The results show that the increase in demand has resulted in the change in VRE due to Snowy 2.0. This had Snowy 2.0 bringing in more wind generation compared to the Base Scenario where Snowy 2.0 brought in more solar generation.

This change highlights the sensitivity and uncertainty in both the amount and type of VRE that Snowy 2.0 would impact, and how market conditions can influence this.

Figure 52 High EV Flat Increase Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW



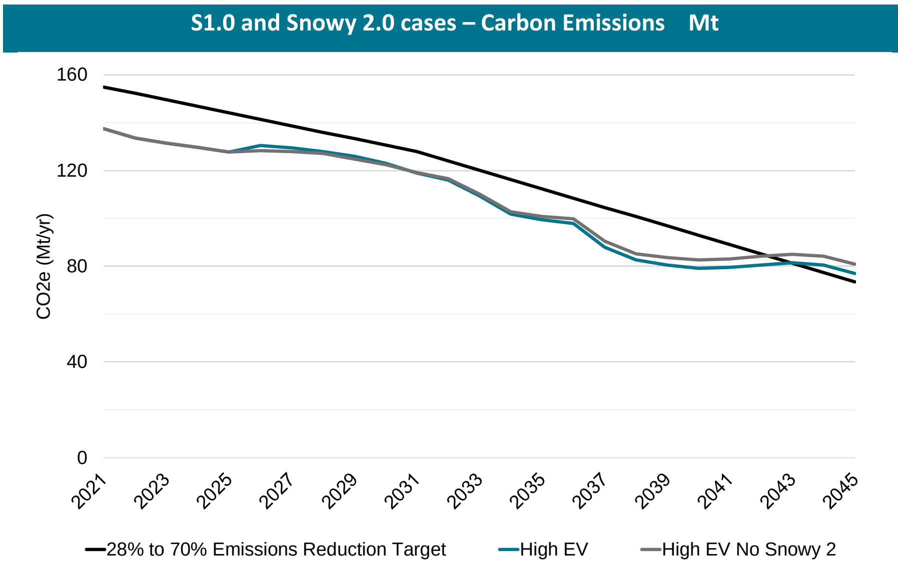
Source: Marsden Jacob Modelling High EV Flat Increase Scenario

Carbon Emissions

The standard graph is showing the level of total NEM carbon emissions ("with Snowy 2.0" and "without Snowy 2.0") is shown below.

As would be expected, the increased demand has resulted in an increase in carbon emissions. The intensity of the increase reflects the type of generation that responded to the increase, which has a lower intensity than that of the average pool.

Figure 53 High EV Flat Increase Scenario Modelling Results – NEM Carbon Emissions MT



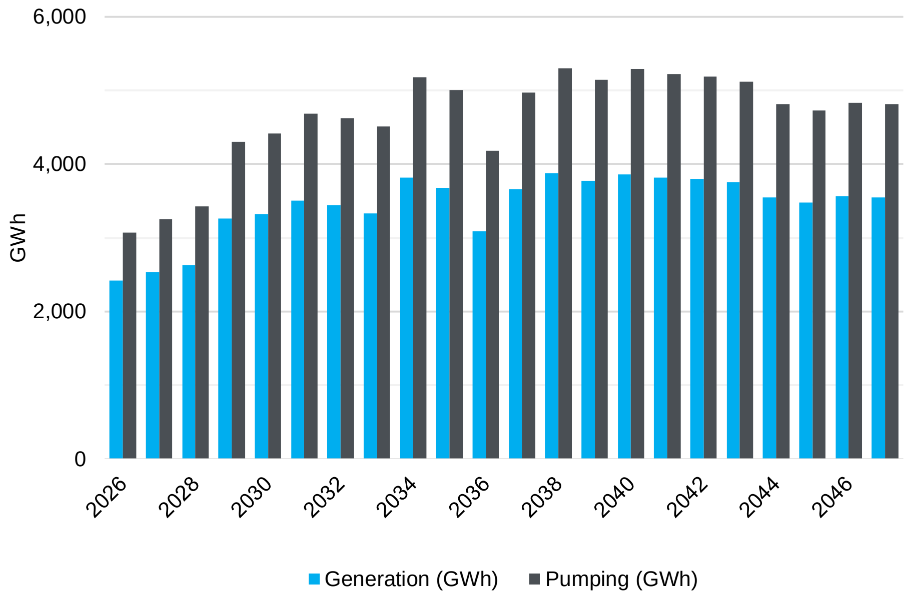
Source: Marsden Jacob Modelling High EV Flat Increase Scenario

19.2.2 High EV Profiled Increase

The figures below show for High EV Profiled Increase Scenario, the results that changed from the High EV Flat Increase Scenario. Shown are the Snowy 2.0 generation and pumping volumes.

Snowy 2.0 pumping and generation volumes are slightly lower. This reflect a reduction in spare VRE due to increased demand at time of low prices.

Figure 54 High EV Profiled Increase Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



Source: Marsden Jacob Modelling High EV Profile Increase Scenario

20. Coal Bull Scenario

This scenario explores the impact of the potential coal generator developments.

If new coal generation were developed, it would reduce the amount of VRE, gas generation and storage that would have otherwise been developed. This would have a complex influence on the NEM and Snowy 2.0, including the possibility of additional pumping energy.

Alternatively, the operations of existing coal generation in a market of increasing VRE can be improved by increasing their flexibility to quickly respond and to operate economically at low levels of generation. This would act to reduce potential pumping energy.

20.1 Description and assumptions

This scenario has regulation enacted that provides for the continuation of coal generation in the NEM including one or more new coal generators being developed. The basis of the regulation is a perceived need to maintain a level of base load generation.

This scenario has two new High Efficiency Low Emissions (HELE) power stations developed as follows:

- 1,500 MW in NSW by 1 July 2027 – this is undertaken to address the closure of Vales Point (which follows the closure of Liddell);
- 1,500 MW in QLD by 1 July 2036 – this is undertaken to address the closure of Tarong Power Station (which follows the closure of Gladstone).

The existing coal generators are incentivised to undertake enhancements that increases their respective flexibility in terms of minimum generation levels, ramp rates and start-up times. The value of this flexibility is justified through avoiding periods of generation when spot prices are low (or negative).

The basis of the amount and location of this generation and improved coal plant flexibility are addressed in turn below.

20.1.1 New Coal Generation

Victoria

When Yallourn Power Station closes Victoria will have closed 50% of the coal generation that was operating in Victoria prior to March 2017 (the date when Hazelwood Power station closed). This could signal the need for replacement base load generation.

The Latrobe Valley (in VIC) is a potential site for a new coal power station. While offering advantages of existing and substantial transmission to Melbourne, this location also has considerable disadvantages:

- If black coal were to be used the location is a long distance from black coal reserves and appropriate rail infrastructure is lacking;
- If brown coal were to be used:
  - there are issues of mine site, generation technology to limit carbon emissions, and capital cost which are very high when using this type of coal;
  - the type of brown coal technology that would be required to limit emissions may not be commercially tested.

A balance of these issues suggests (for the purposes of this scenario) that the Latrobe valley would not be a suitable location for a new coal plant.

New South Wales

The NSW coal fleet has been the "backbone" of the base load generation for NSW in addition to providing flexibility to follow demand and to provide capacity at time of high demands. This has also provided substantial support to Victoria (and to SA).

The very significant closures of NSW black coal plant commencing with Liddell and then Vales Point suggest that this is the time-period and State where replacement of coal plant would be of most value.

The earliest a new coal power station could enter NSW is likely to be about 7 years from the decision to proceed. If such a decision were made during 2019 this could have a power station entering in 2027, just prior to the closure of Vales Point.

It is proposed that a 1,500 MW black coal HELE power station (2 x 750 MW units) is developed in NSW and this plant enters service on 1 July 2027.

Queensland

Characteristics and outlook for Queensland are as follows:

- Queensland is projected to have the highest electricity demand growth in Australia, with much of this in the south east of the State;
- Queensland is a very large state with a long transmission system that matches the relatively low demand in the northern parts of the State;
- Flow patterns have changed significantly due to the amount if solar generation that has been developed in north Queensland. Transmission would be a significant issue and a coal power station would require additional transmission;
- Queensland has the youngest coal fleet with most of its coal generation schedule to retire post 2045;
- A new coal power station is not consistent with current government non-legislated policy of being supplied 50% by renewables by 2030;
- QLD VRE development is mostly solar as wind generation is less suitable. Integration of solar is more difficult than wind generation;
- Gladstone (which is contracted to the Boyne smelter) is due to retire before 2030 and Tarong in the mid 2030's;
- Continuation of supply to the Boyne smelter (about 900 MW) would require new supply from other coal power stations after the closure of Gladstone.

The balance of issues has a scenario where a coal power station is developed in QLD. Consequently, this scenario also assumes that:

- A new 1,500 MW coal power station (2x 750 MW) enters Queensland in 2036 to match the closure of the 1,400 MW Tarong Power Station;
- The new power station is designed to have flexible operation in order that it can response to the high level of VRE generation that would exist in Queensland.

20.1.2 Increased Coal Plant Flexibility

The potential to improve coal plant flexibility to better match the increasing variability of demand to be supplied by dispatchable generation[22] was investigated by a third party expert who represented a report to SHL

Two model runs were done for this scenario (two additional coal generators entering). The names of these scenarios and descriptions are as follows:

- New coal – Unchanged Flex – this scenario has the 2 x HELE generators enter, and existing coal plant have the same flexibility as in the Base Scenario;
- New coal - Increased Flex - this scenario has the 2 x HELE generators enter, and the existing coal plant has improved operating flexibility (compared to the Base Scenario).

The changes to the operating flexibility of the existing coal generators were identified as actions that can reduce the generation level before auxiliary fuel is required, reducing the cost of auxiliary firing, and increased ramp rates. Because generators cannot increase bid prices as generator output is less [23] the assumed changes to coal plant mingen levels are shown in the table below. This has a reduction in mingen levels reflecting both actual mingen reductions and a reduction in auxiliary fuel costs. The total reduction is 1,064 MW.

The impact of this would be reduced availability of surplus (curtailed) VRE generation available for pumping.

Table 15 Assumptions of Reduced Coal Generator Mingen Levels

	Minimum Generation Level per Unit		
	Base Scenario MW	Sensitivity MW	Reduction MW
Mt Piper	275	170	105
Vales point	250	212.5	37.5
Loy Yang A	350	280	70
Yallourn	230	138	92
Eraring	225	190	35

20.2 Coal Bull Scenario – NEM Outcomes

The NEM market outcomes for the two cases (representing different levels of coal plant flexibility) are presented in turn below.

20.2.1 Unchanged Coal Flexibility

The figures below show a selection of the modelling results from the New Coal – Unchanged Flex Scenario. These are the standard set that are used in all the scenarios (and that were described in the Base Scenario).

The following observation are made:

Installed Generation and storage capacity

The new coal capacity replaces coal capacity that closed. Snowy 2.0 brings on additional VRE, but there is less need for new generation and the impact of Snowy 2.0 is less.

Carbon Emissions

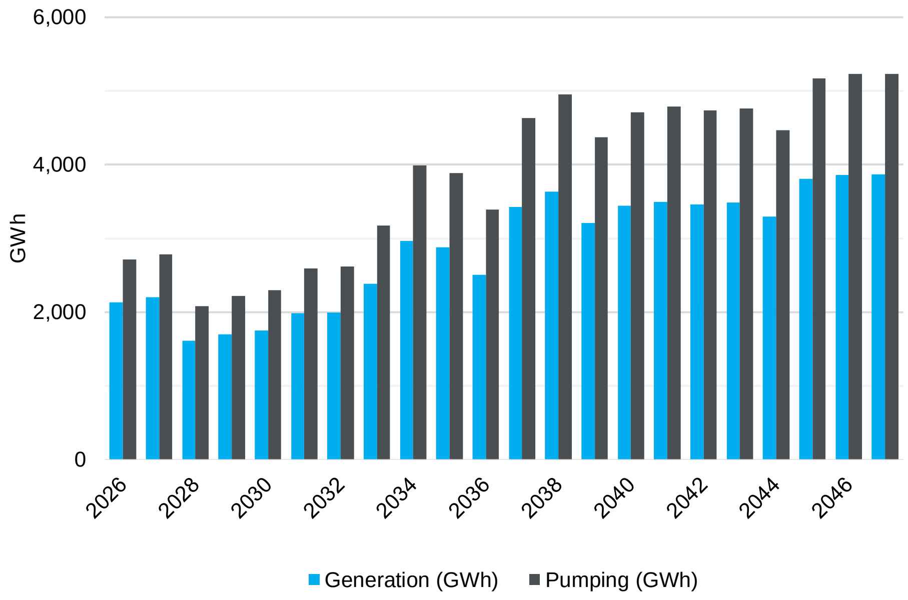
[22] The feasibility report defined the whole demand less VRE, which is the residual demand to be supply by non-VRE generation, as “dispatchable demand”.
[23] The NEM requires that bid prices are higher as output increases.

New coal plant means substantially high emissions. To reduce emissions would require closing coal plant (which negates the rationale and economics of developing new coal plant).

Snowy 2.0 generation and pumping

Snowy 2.0 operation is similar to the Base Scenario. The new coal plant has provided additional pumping energy, but it has also reduced the need for generation.

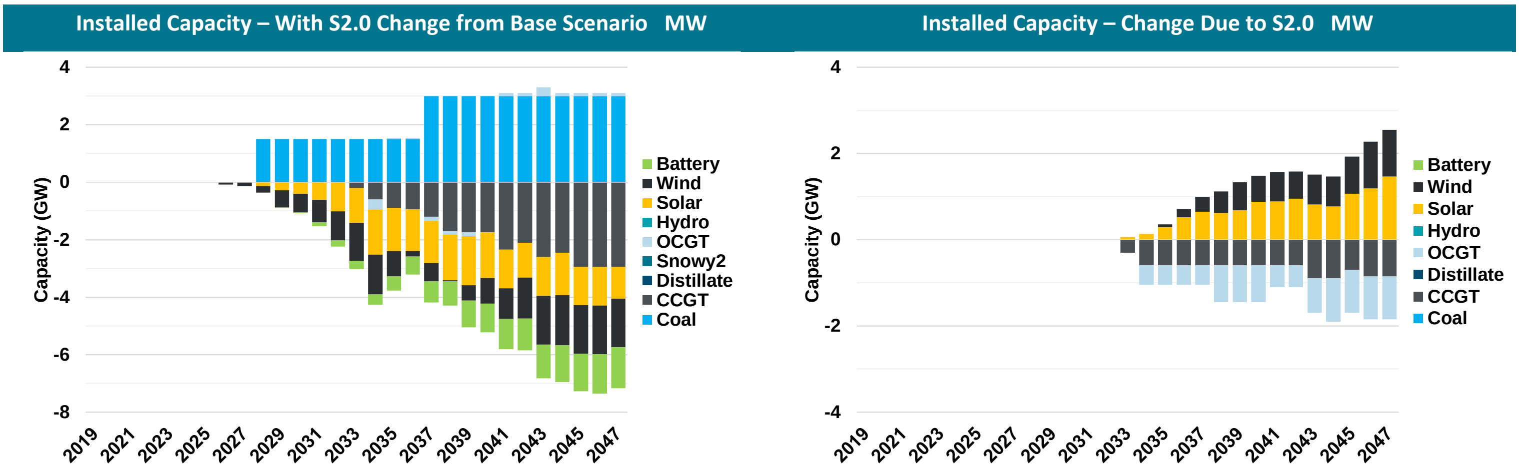
Figure 55   New Coal – Unchanged Flex Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



Source: Marsden Jacob Modelling New Coal – Unchanged Flex

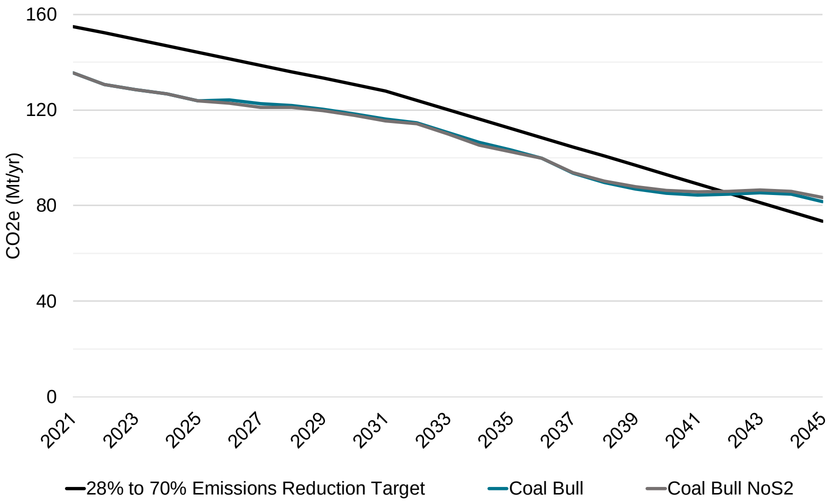
Installed Generation and storage capacity

Figure 56   New Coal – Unchanged Flex Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0   MW



Source: Marsden Jacob Modelling New Coal – Unchanged Flex

Figure 57 New Coal – Unchanged Flex Scenario Modelling Results – NEM Carbon Emissions MT



Source: Marsden Jacob Modelling New Coal – Unchanged Flex

20.2.2 Increased Coal Flexibility

The changes that were observed when the mingen levels of the existing coal plant were reduced were slightly lower Snowy 2.0 pumping and generation. Installed plant changes were unchanged.

21. High Battery Scenario

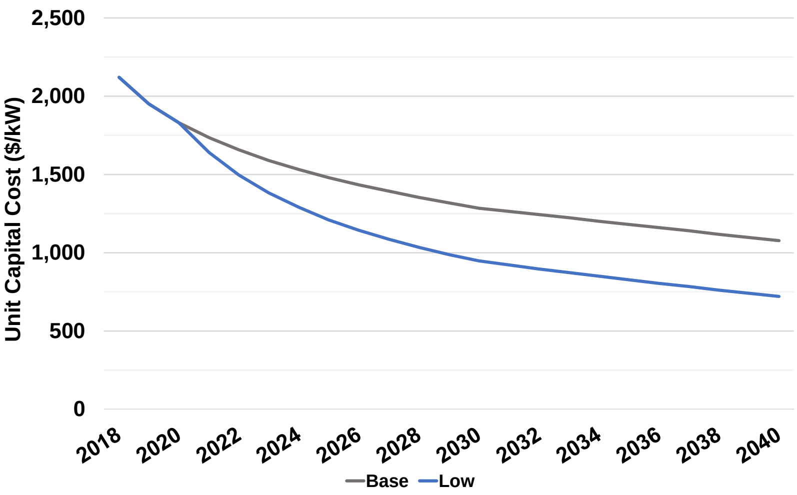
The most direct competitor to Snowy 2.0 is presumably other storage. This competition is both in terms of capacity and hours of storage. While the cost outlook for batteries has them unlikely to be economic on spot market revenues with storage hours over 4 hours, they may enter as a result of regulatory or policy changes, such as a requirement for new VRE. This scenario models a significant increase in battery development.

21.1 Description and assumptions

The scenario examines the consequences of increased battery development. This could be the result of battery costs being significantly lower than that assumed in the Base Scenario and/or regulatory requirements to have batteries accompany VRE development. The assumptions of this scenario are as follows:

- Battery costs reduce at twice the rate assumed in the Base scenario. The resulting battery cost curve is shown in the figure below;
- Batteries enter when economic and arbitrage the spot market (this was also the assumption in the Base scenario);
- There is no change to new entry generators (VRE or gas) associated with the increased battery development. This was done to illustrate the impact of additional batteries.

Figure 58 Battery Costs – Base and Low-Cost Scenario $/MW (4-hour storage)



Battery module costs comprise about 45% of total installation costs. This means that in percentage terms, total battery cost reductions are less than the percentage decrease in battery module costs.

Reduction in Installed Battery Costs

Battery costs are composed of connection costs (to the grid), inverter costs, and the battery module costs. Connection costs are not projected to decrease in real terms, inverter costs slightly and battery module costs significantly.

Battery module costs comprise about 60% of total installation costs. This means that in percentage terms, total battery cost reductions are less than the percentage decrease in battery module costs.

Basis of Battery Entry

The Base Scenario had batteries introduced on the basis that they were required to assist the smoothing of VRE generation that was entering as coal plant closed. These batteries were not economic on spot market revenues alone (energy arbitrage and FCAS). Their entry reflected the requirements of energy purchases and a likely regulatory requirement to have a limited amount of storage accompany VRE development.

The reduction in costs assumed in this scenario is unlikely to have a level of battery storage development exceed the battery storage assessed as required in the Base Scenario until late in the study period. However, the lower costs of battery storage may result in a potential regulatory requirement that increases the level of batteries to accompany new VRE.

Firming costs of VRE would be reduced by the availability of lower cost batteries, and this would assist in the economics of new VRE generation. Increased batteries installation would likely be accompanied by increased VRE development (although this may not be large).

Noting these uncertainties this scenario assumed the following:

- The additional Battery development (from that in the base Scenario) was close to 4000 MW by 2041;
- Individual traders were operating their respective batteries individually (i.e. they were not subject to central control);
- There were no other changes such as additional VRE entry. This assumption was made in order that the impact of additional batteries alone would be observed.

21.2 High Battery Scenario – NEM Outcomes

As a first comment the modelling observed the challenge in coordinating multiple battery operation. This recognised that batteries will be located in different regions and like generators will be managed by parties that may have different projections (over each day) of spot prices and that submit different bids and offers. They may be operated to assist in specific VRE production smoothing and high spot price risk management. A different outcome would likely be obtained if batteries were assumed to be subject to central control.

The figure below shows a selection of the modelling results from the High Battery Scenario. These are the standard set that are used in all the scenarios (and that were described in the Base Scenario).

The following observation are made:

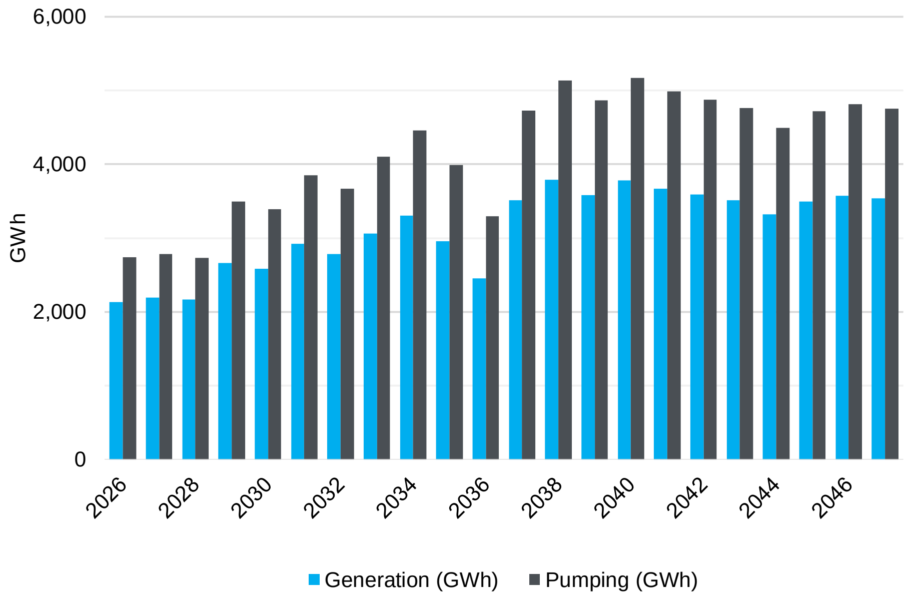
Installed Generation and storage capacity

There was no change as assumed for this scenario.

Carbon Emissions

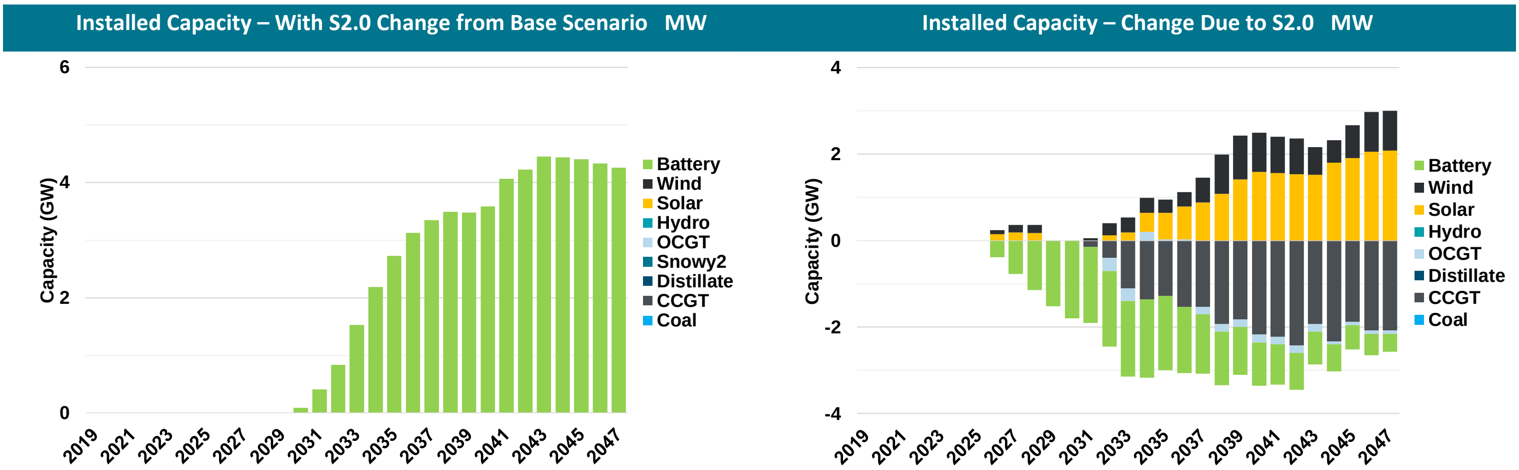
Very little change as no new VRE was assumed to entry. Emissions reduced slightly reflecting surplus VRE that was not captured by the storage in the Base Scenario.

Figure 59 High Battery Scenario Modelling Results – Snowy 2.0 Annual Generation and Pumping Volumes



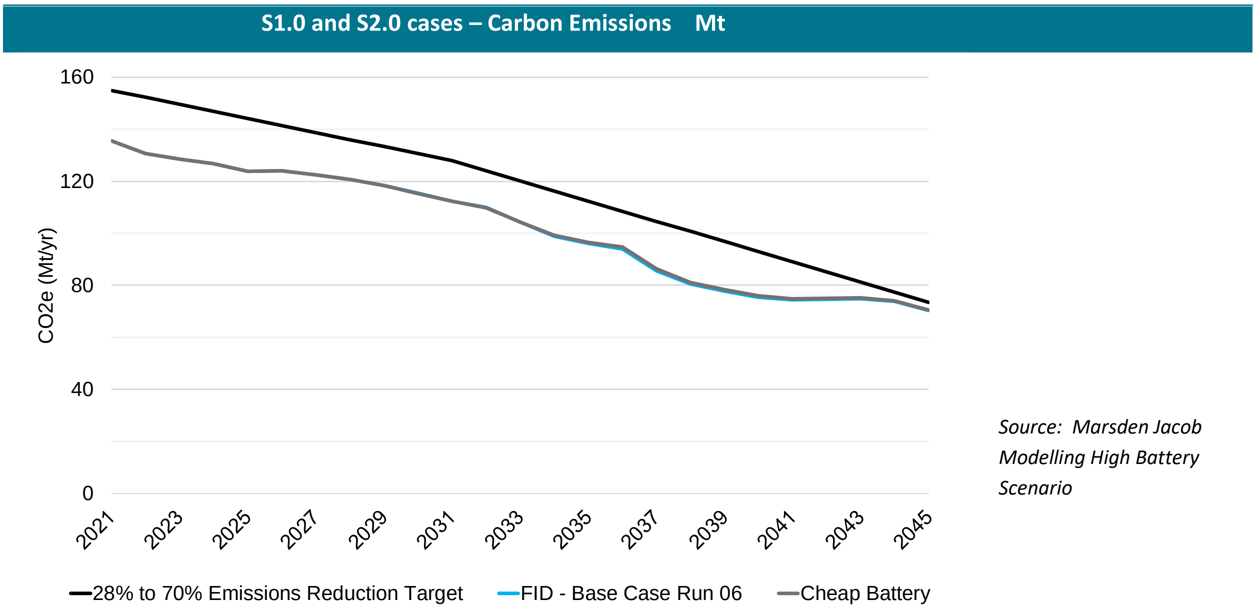
Source: Marsden Jacob Modelling High Battery Scenario

Figure 60 High Battery Scenario Modelling Results – Annual Installed Capacity Changes due to Snowy 2.0 MW



Source: Marsden Jacob Modelling High Battery Scenario

Figure 61 High Battery Scenario Modelling Results – NEM Carbon Emissions MT



Source: Marsden Jacob Modelling High Battery Scenario

22. Modelling Summary and Conclusions

This chapter summarises the finding of the study through a narrative description of the basis and risk for Snowy 2.0, followed by a graphical presentation of Snowy 2.0 generation and pumping.

22.1 Summary of Snowy 2.0 and Requirement

A summary of the study findings that relate to the basis for and economics of Snowy 2.0 is presented below. This is presented under the headings of:

- VRE Operation in the Current NEM;
- NEM Transformation – Capacity and Energy Requirements;
- Snowy 2.0 and Impact to NEM Development;
- Economic Modelling of Snowy 2.0.

22.1.1 VRE Operation in the Current NEM

The NEM

The NEM is undergoing a transformation associated with the rapidly changing economics of generation, a recognition of the need to reduce carbon emissions in the long-term, and aging coal generators of which a substantial number will close by the mid 2030's.

VRE Entry To date

Up until recently (i.e. 2018), VRE economics required additional revenues other than that provided by spot energy revenues. The RET and LRET schemes were designed to provide this additional revenue stream, and the VRET and QRET schemes have been respectively introduced by the Victorian and Queensland State governments to continue VRE developments post 2020.

VRE cost reductions and increasing spot price levels (reflecting less coal generation and high gas prices) now has VRE economic on spot energy sales alone, and new VRE is being planted on the basis of this new economic reality.

To date, except in SA, the accommodation of VRE in the NEM has not been difficult. This is because the NEM has had enough dispatchable and firm capacity to absorb the variability of VRE production. Expressed differently, the NEM has had sufficient firming capacity.

22.1.2 NEM Transformation – Capacity and Energy Requirements

New Generator Options and VRE Entry post 2025

From a supply reliability perspective, as the coal power stations close (which could see all existing coal generators close by the mid 2040's) it will be necessary to replace both the dispatchable and firm capacity (MW) and energy production (MWh) that was provided by these generators. The options to replace this capacity and energy production were identified as:

- VRE (solar and wind generation). This provides energy but only a relatively small amount of capacity that can be relied upon;
- Gas generation. This provides both firm capacity and energy but produces emissions, noting that emissions are about half that of black coal generation;

- Storage. Provides dispatchable and firm capacity noting that the latter would require a storage duration of 24 hours or more.

New coal power stations are not included in the above list. The reasons for this are that new coal generation is becoming increasingly unlikely (each year) due to factors that include cost, public and industry preference, the lending policies of banks regarding coal power stations, and global agreements on emissions.

However, the study did recognise that unlikely events can occur, and a scenario was modelled that had new coal generators developed.

Changing NEM and Transmission

The transformation to increased levels of VRE will result in changed locations of generators as well as associated changes in power flows across the grid. This will increase the need and value of transmission that provides for capacity support between regions.

This is understood as follows. In the absence of VRE, interconnection capacity is and has been used to capture both the diversity that results from regional maximum demands occurring at different times and generator failures in different regions occurring at different times. Increasing levels of VRE will result in increasing and more frequent periods where one region has a high level of VRE output and the neighbouring region has a low level of VRE output. The size of the VRE variations between regions will increase the value and need for upgraded transmission between regions to maximise the benefits of geographical diversification.

The AEMO ISP recognised the need for upgraded transmission between all regions. This study considered that upgraded transmission is required regardless of whether Snowy 2.0 is developed or not.

Firming - Dispatchable and Firm Capacity

As more VRE enters and coal generators close the ability of the power system to “absorb” the VRE energy will decrease (i.e. there will be insufficient “firming capacity”). Increasing VRE and reducing thermal generation will require increasing amounts of new dispatchable and firm capacity.

This study highlighted the need to distinguish between dispatchable capacity and firm capacity. Dispatchable capacity is that which is controllable (either up or down) and firm capacity is that capacity which is both dispatchable and which can be relied upon to be available. In relation to gas and storage generation:

- Gas generation provides firm capacity (the issue of firmness in a 5-minute energy settlement market is noted, and price risk may require some OCGT plant to have modifications made);
- Storage generation with limited hours of storage does not provide firm capacity as it may not be available to generate when needed. The study assessed that firm capacity from storage requires at least 24 hours of storage.

The table below summarises the provision of disputable capacity and firm capacity by the different generator types.

	Gas OCGT	Gas CCGT	Coal	Pumped Hydro > 24 hrs storage	Hydro (not run of river)	Wind	Solar	Batteries < 24 Hrs Storage	Batteries > 24 Hrs Storage	Demand Side < 2 Hours
Dispatchable	Y	Y	Y	Y	Y	N	N	Y	Y	Y
Firm	Y	Y	Y	Y	Y	N	N	N	Y	N

VRE Output Uncertainty

Modelling has shown that the uncertainty of VRE output is such that the total variation in energy production increases over increasing time periods (i.e. daily, weekly, monthly, seasonal, yearly). Capturing the variation in VRE energy output requires days of storage in order that periods of days to weeks of high VRE can be stored and periods of days to weeks of low VRE can be covered (and this relates to firm capacity).

22.1.3 Snowy 2.0 and Impact to NEM Development

"No Snowy 2.0" - Replacing the closing Coal Power Stations

In the absence of Snowy 2.0 the replacement of the closing coal power stations with VRE, gas generation and storage would occur as follows:

- Using VRE to replace the lost energy production from the closed coal generators;
- Using dispatchable generation (most notably gas) to fill in the gaps when VRE is not generating:
- Gas generation does not address the issue of capturing "spilt" VRE generation and thus has an economic limit on this nature of firming. Taken by itself, firming with gas generation can be viewed as gas generation using VRE to minimise gas use;
- Using battery storage to capture VRE generation that would spill and using it when needed. Not capturing this generation would mean VRE generators would increasingly provide less generation to the market resulting in increased costs of the usage energy from VRE. This would be reflected in decreasing prices VRE would receive from the spot energy market, which would be increasingly lower compared to average spot price levels. The substantial "discount" solar and wind generation receives on spot prices would present a significant hurdle to VRE economics;
- The cost and limited hours of batteries mean that they can only capture part of the daily variation in VRE and do not provide firm capacity;
- The outlook is that even with the projected reduced costs of batteries, the level of storage required means that gas generation will be required for firm capacity and to address the majority of the variations in VRE output.

Snowy 2.0 Quality and Value Provision

Snowy 2.0 is a long-life asset that provides 2,000 MW of dispatchable and firm capacity, conservatively 175 hours of storage and is centrally located. The quality and value relationships include:

- It's central location that provides for:
  - Maximum consumer access
  - NEM wide balancing of VRE
  - Security against critical transmission outages
  - Additional value to upgraded transmission between SA-VIC-NSW-QLD (the transmission developments identified in the AEMO 2018 ISP between NSW-VIC-SA are considered 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);
- It's large level of storage (175 hours) that provides for energy security and firm capacity against extreme market conditions, both of which will become of increasing value to risk mitigation in the future;
- It's flexible operating nature that provides for increased market stability and efficiency:
  - Providing pumping demand (of up to 2,000 MW) in response to the changing availability of surplus coal and surplus VRE, and generation operating in response to spot price signals and replacing gas plant and batteries that would have been developed and used
  - Such operation directly supports the development of new VRE and emissions reductions.

"With Snowy 2.0" - Replacing the closing Coal Power Stations

Snowy 2.0 would influence the operation of and asset mix that replaces the closing coal power stations as follows:

- Significantly more "spilt" VRE output would be captured thereby improving the economics of VRE entry. Additional VRE generation would be developed. The diversity of VRE output means that Snowy 2.0 would provide for significantly more than 2,000 MW of additional VRE to enter;
- The firm capacity provided by Snowy 2.0 would provide for about 2,000 MW less of gas generation (CCGT and OCGT) to be developed;
- Less battery storage would also be needed, although the reduction in battery storage would reduce as battery costs become lower late in the study period.

The net result is improved market efficiency, more reliable market operation, and lower emissions.

22.1.4 Economic Modelling of Snowy 2.0

Snowy 2.0 Risks and Economic Assessment

Like any investment there are risks associated with the Snowy 2.0 development. With the long-term need for Snowy 2.0 established, these risks relate to the transition period to high VRE and low coal generation and competitors to firming services. These risks were categorised as follows:

- Factors that delay the need for new storage:
  - Lower demand growth
  - Later retirement of coal power stations
  - Lower development of VRE
  - Higher development of gas generation;
- Factors that reduce the revenue received by storage:
  - Increased flexibility of existing coal generators
  - Lower gas costs
  - Increased battery uptake (in front and behind the meter)
  - Earlier development of Basslink II (Hydro Tasmania pumped hydro project);
- Factors pertinent to Snowy 2.0:
  - Delayed transmission development between NSW/Victoria/Queensland reduced the value of Snowy 2.0
  - Drought increases the value of Snowy 2.0.

The impact of Snowy 2.0 was undertaken through the development and modelling of the NEM under different development scenarios, and for each scenario under two cases, one that assumed Snowy 2.0 was not developed and one that assumed Snowy 2.0 was developed. The scenarios modelled were as follows:

- A Base (or central) Scenario that assumed the most likely outlooks of demand growth, capital and fuel costs, coal generator closures, and current policy;
- Changes to the Base Scenario (each modelled separately):
  - Higher level of demand growth
  - Lower and higher levels of hydro water inflows
  - Additional battery storage enters
  - New coal generation is developed, and existing coal generators increase the flexibility of their operation
  - Earlier retirement of some of the existing coal generators
  - Increased EVs projection.

From this modelling the impacts to the NEM associated with developing Snowy 2.0 were obtained.

Snowy 2.0 benefits to the NEM

On a NEM wide basis the modelling found that Snowy 2.0 would directly and substantially contribute to the trilemma issues of reliability, price, and emissions reduction as the existing coal fleet closes.

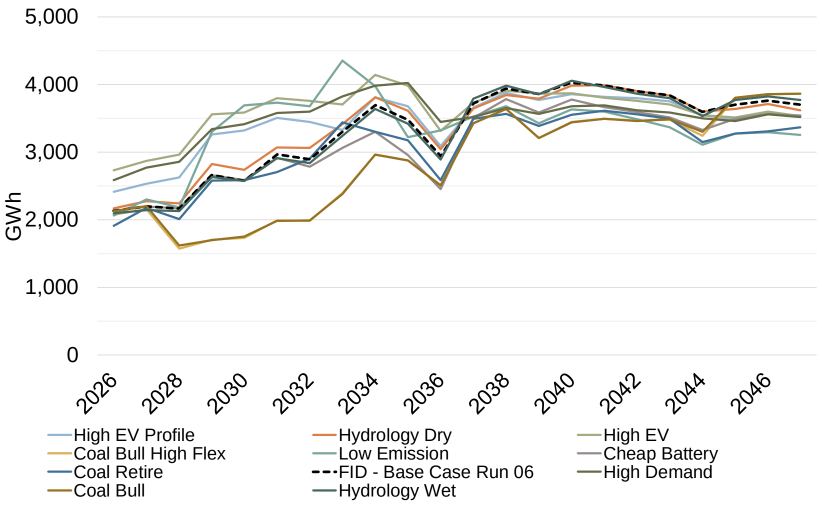
The dynamic of this involved:

- Snowy 2.0 providing replacement firm capacity and energy production;
- The replacement energy production initially uses spare coal generation as well as VRE generation, and this transitions to mostly spare VRE output as the coal plant closes;
- Snowy 2.0 results in additional VRE development and less gas generation development and use.

22.2 Modelling Result Summary

The figure and tables below present for all scenarios the Snowy 2.0 generation and pumping volumes (Figure 62)

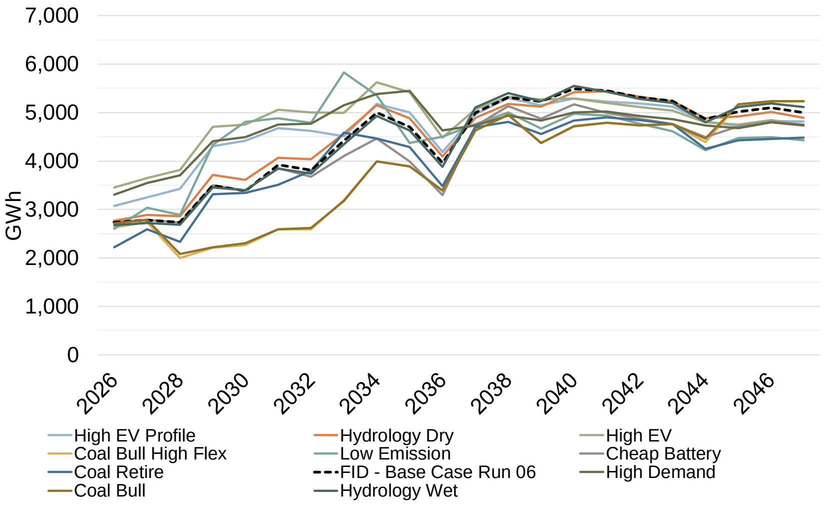
Figure 62 All Scenarios – Generation and Pumping Volumes



Snowy 2.0

Average Annual Generation Volume

GWh p.a.



Snowy 2.0

Average Annual Pumping Volume

GWh p.a.

Appendix 1 Variable Speed Machines

Snowy 2.0 will have six generators, all of which will be able to pump. Three of these six generators will be variable speed machines. This appendix characterises these variable speed machines.

A1.1 What Variable Speed Machines Provide

Variable speed machines provide the following when operating in generator and pump modes:

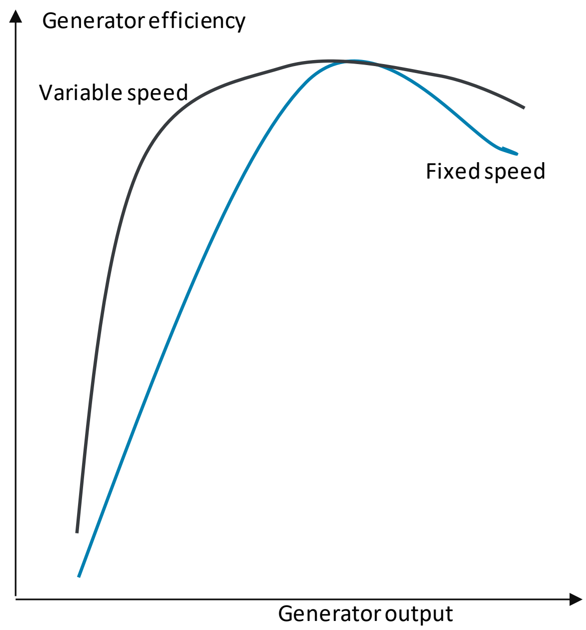
Generating

- Improved generating efficiency (providing a wider economic range) – see Figure 1 below.

Pumping

- No “all on or nothing” pumping level but a MW range over which pumping can occur;
- Improved pumping efficiency;
- Capability to provide the following FCAS when pumping:
    - Contingency Raise: 5 minute, 60 second
    - Contingency Lower: 5 minute, 60 second
    - Regulation: Raise and Lower.

Figure 63 Generating Efficiency – Fixed and Variable Speed Machines



The graph opposite shows the typical relationship of generator efficiency to generator output between fixed speed and variable speed generators.

Generator efficiency = MWh per unit of water.

Variable speed offers increased generator efficiency.

Source: Marsden Jacob Associates

A1.2 Economic Value

Variable speed machines provide for the following.

Improved operations:

- Smoother start-up and reduction in pumping providing:
  - less 'causer pays' payments (possibly),
  - more precision in economic operation through feedback of spot price response.

Arbitrage value:

- Pumping to occur that would not be otherwise economic,
- Additional pumping due to more efficient pumping operation,
- Additional generation due to more efficient operation.

Ancillary services:

- When not operating
  - Additional Raise 6 Second, 60 Second and 5-Minute provision
- When generating
  - Additional 6 Second provision
- When pumping
  - all FCAS services.

Appendix 2 Electric Vehicles

Electric Vehicles will influence future electricity demand in terms of both total energy and daily profile.

This appendix presents the issues, basis of, and assumptions of EV demand used in the modelling.

A2.1 Factors influencing Electric Vehicle take-up

Given the relative immaturity of the EV industry and the significant impact of government policy and incentives on EV up-take, there is material variability and uncertainty across industry EV forecasts, particularly regarding the timing and quantum of the 'tipping point' once EV's reach cost parity with combustion vehicles. The impact of EV's on total NEM grid demand is expected to be relatively small over the next 10-15 years (only ~2% increase in demand to 2030) but is expected to be material in the medium-to long-term (20-30% increase in grid demand by 2050-2070).

We estimate an average EV requires ~2,250 kWh of electricity each year. This assumes about 13,500km driven per annum (average of 37km per day) and an average EV gets 5.8 to 7.0km per kWh (14-17 kWh/100km). Although EV's can be charged slowly (trickle charge over 14 hours), or more quickly (Tesla 30min supercharge to 80%), a 'normal' charge is 5-7 hours.

EV consumption of 2,250kWh per year equates to about 6kWh per day and, according to AEMO, an average residential demand is about 17kWh per day. Hence, for an individual household, this can represent a material jump in daily demand. The impact on average and peak demand is likely to be smoother when aggregated across households and will depend on how households use behind-the-meter rooftop solar PV to charge, and how 'smart' controllers and/or tariff structures influence charging time. Overall, we would expect EV's to increase demand curve peaks and expect that the networks will face infrastructure challenges, especially in high EV penetration areas.

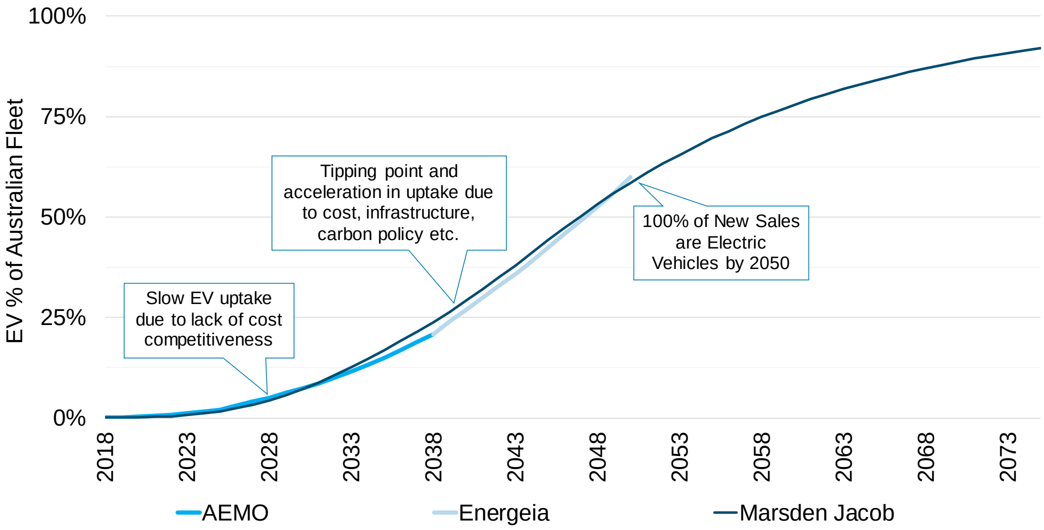
There are numerous ways the market operator and the energy companies can deal with the changing load profile caused by EV's, including:

- Time-of-use charging and perhaps completely new tariff structures that the energy companies can use to manage expected loads and influence customer behaviour;
- Use of 'smart' charging and home battery/solar management systems (such as Reposit or Sunverge) that can optimise when EV's are charged to reduce costs for consumers and manage load for energy companies.;
- Using a residential solar PV system to charge the EV during the day (behind-the-meter);
- Charging battery storage with excess solar production during the day, then using the stored energy at night to charge the EV as well as help power the home.

A2.2 Electric Vehicle Long-term Forecasts

AEMO's current ('neutral' scenario) expectations for EV penetration are for 2% of the fleet (440k vehicles) to be EV's by 2025, 7% (1.6m vehicles) by 2030 and 21% (5m vehicles) by 2038, and recent forecasts by Bloomberg New Energy Finance (BNEF) are similar to AEMO. Marsden Jacob forecasts out to 2075 are shown in the following figure.

Figure 64 EV Projection



Source: Marsden Jacob Associates, AEMO, Energeia

Marsden Jacob expects that take-up is likely to be slow out to the mid-2020's given the relatively higher cost of EV's compared to ICE vehicles, as well as factors including insufficient charging infrastructure, a low number of different models, and concerns about range and servicing. We then expect a strong acceleration in take-up as EV's become cost competitive, the technology is proven, and infrastructure is in place. We expect to see saturation by 2065-70 (which would equate to about 55-60 TWh of new demand), given EVs are expected to be considerably cheaper to buy and operate and zero (or very low) carbon emissions policies are likely to be in place. There will likely be only a small number of "vintage' ICE vehicles remaining in operation.

As part of the modelling, Marsden Jacob also ran a 'high EV uptake' scenario, which assumed that 50% of total passenger vehicles on the road by 2030 are electric vehicles, increasing to 80% by 2040. Given the forecast relative economics of EV's to ICE's, achieving this level of EV penetration would require government policy that very strongly pushed new car sales toward EV's. Further discussion and the results of that modelling are shown in Chapter 18 of the Main Report.

Appendix 3 Electricity Market Models

This appendix presents a review of the electricity market models used in the modelling. These are the PROPHET simulation model and the Firming Analysis Model (FAM).

A3.1 Market Simulation (PROPHET Simulation)

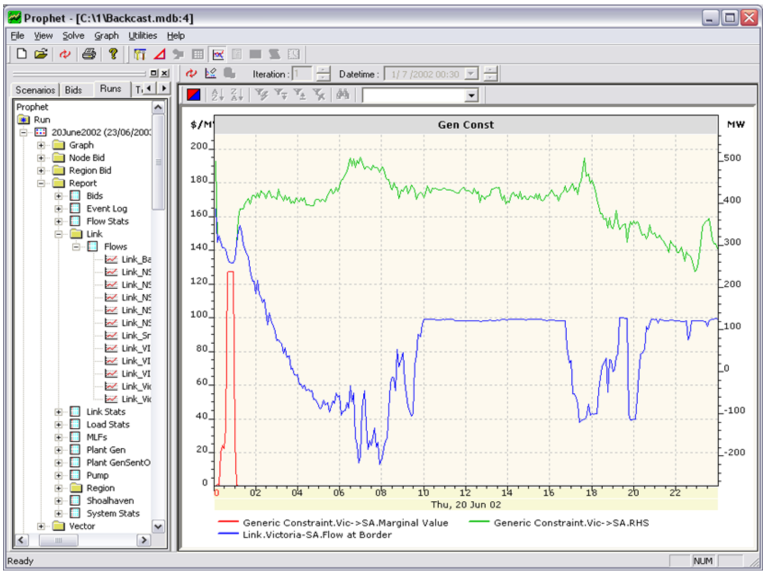
Introduction

The PROPHET Simulation Model is a commercially sold model. It is an advanced simulation model of common clearing price electricity markets. It has been used by many parties and in many major studies over the past 20 years.

PROPHET simulation simulates the half-hour by half-hour (or 5-minute by 5-minute) operation of competitive electricity markets ("Market Simulation Model"). This requires all the key processes in the market be simulated. Through each dispatch period this includes:

- Contracts in place,
- Generator breakdowns and planned outages,
- Demand (actual and forecast),
- Generator portfolios bid submission during each day (how these change due to conditions),
- Market Operator dispatch instructions and prices,
- Physical outcomes - generator dispatch, transmission line flows, energy not supplied etc,
- Settlements – revenues and payments.

Through the explicit representation of trading entities, contracts and other matters PROPHET can be benchmarked to the market being modelled (including observed spot price volatility). This can be done using game theoretic bidding and the representation of portfolio bids curves as impacted by costs and contract levels.



PROPHET Front End

Viewing results of a modelling run

Examples of the use of PROPHET include projecting future wholesale energy prices, impact of environmental schemes such as carbon pricing and the RET, transmission congestion and economics, competitive impacts of industry consolidation, assessment of market rule changes. It has also been used to quantify the operational and economic impact of technology changes such as smart grid, high wind penetration and geothermal.

Structure

PROPHET simulation consists of three main elements.

Physical system model:

- Customer electricity demand projections (shape, level),
- Generators (size, reliability etc),
- Transmission (configuration, limits);

Market arrangements model:

- Market processes (bidding rules etc),
- Market clearing engine,
- Market settlements;

Behavioural model:

- How generators bid (this is the key issue to prices).

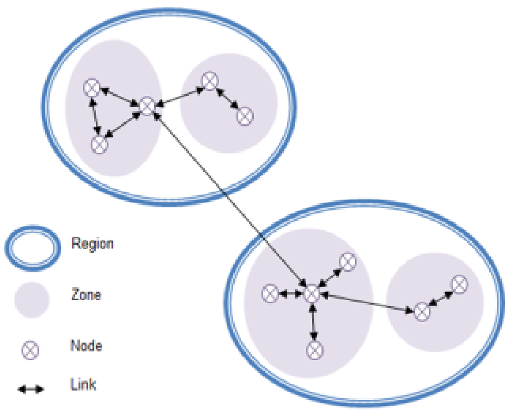
(Longer-term issues include contracting, investment, rules, industry policy)

NEM regional Structure

PROPHET provides for the NEM regional structure to be represented. This includes dynamic losses between regions and static losses within region.

PROPHET provides flexibility in the representation of the transmission network.

This provides for example Latrobe Valley to be a zone within the Victorian region

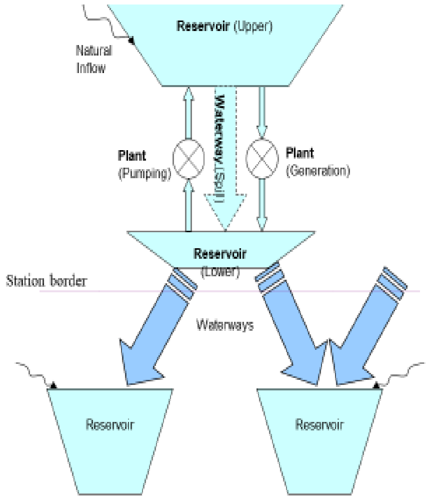


Source Intelligent Energy Systems

Generator / Hydro Physical representations

PROPHET provides for generators of all types to the represented in detail.

Two examples of this are hydro and the state of generator units. This is illustrated in the figures below:

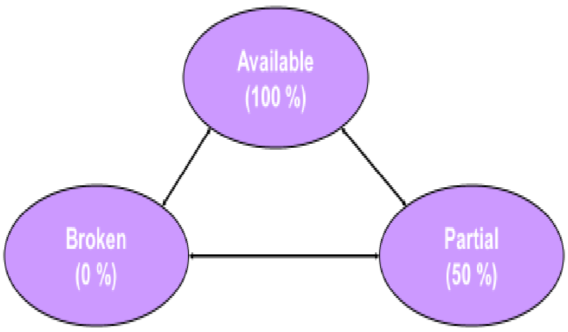


Representation of hydro systems

Source Intelligent Energy Systems

PROPHT provides for any number of plant outage states to be defined with transition probabilities between these.

An example of three possible states is shown below.



States of a generator units – full and partial failures

Source Intelligent Energy Systems

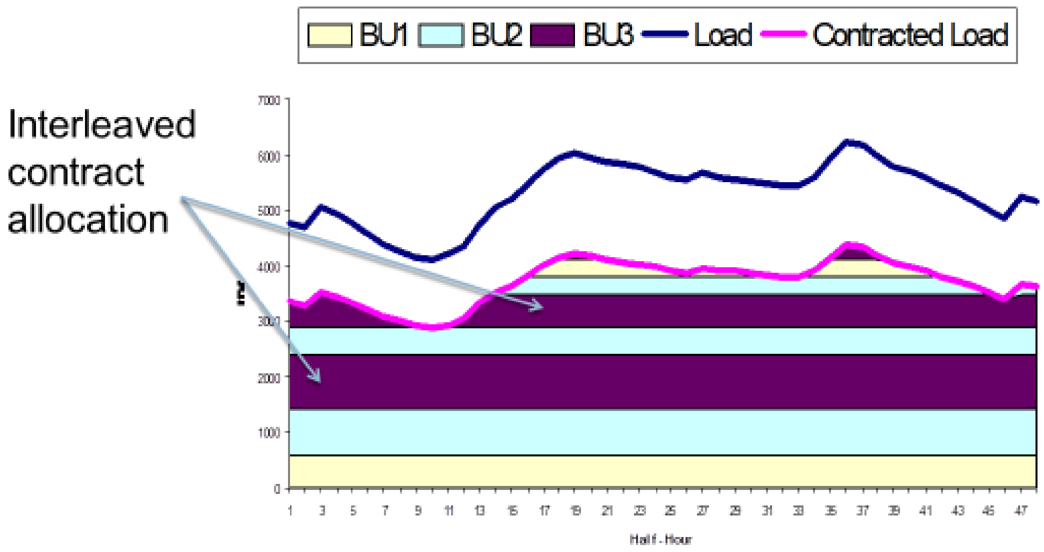
Generator Bidding

Generator bidding (offers) dynamics is fundamental to spot market operation and the spot prices that outturn.

PROPHET has sophisticated logic that provides for:

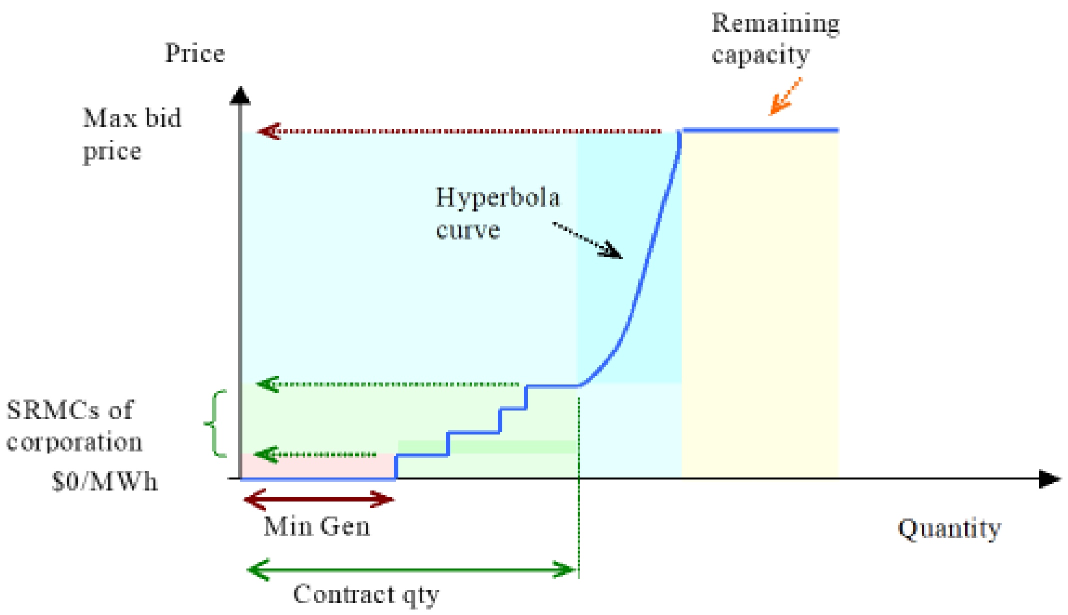
- The explicit representation of retail contract demand,
- Allocation of contracts to portfolios ,
- Generator operation within portfolios,
- Portfolio market power reflected in the manner generation is offered.

The figure below illustrates aspects of this logic.



Assignment of contracts to generators from the underlying consumer demand profiles

Source Intelligent Energy Systems



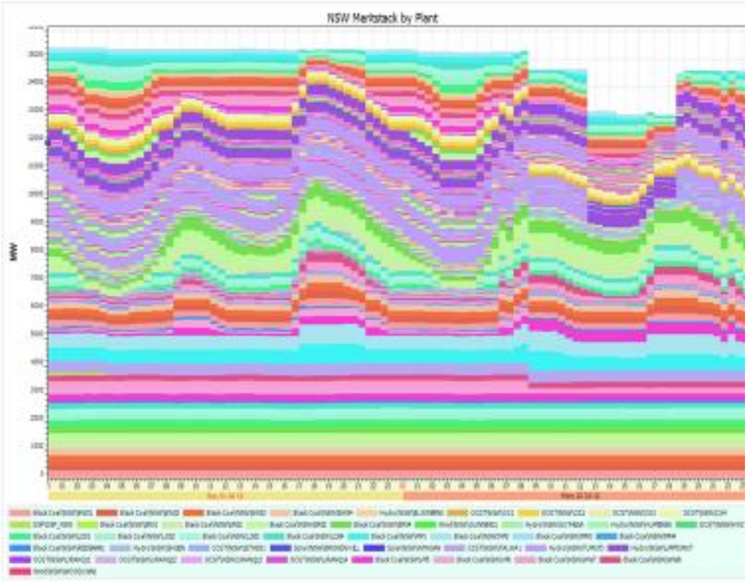
Generator unit and portfolio bid curves

Source Intelligent Energy Systems

The bids opposite represent generators bidding to contract as in the NEM (and other markets).

We see the interleaved and sculptured nature of bidding.

More complexity is introduced when generators make price / volume



Generator dispatch by price bands. Profile reflects bids and contracts.

Source Intelligent Energy Systems

A3.2 Economic least cost model (PROPHET Planning Model)

The PROPHET Planning Model is a sophisticated least cost model that has been used for many studies on Australian and overseas power systems. This model is used by the industry and as such is industry tested, robust and reliable. This is a major advantage compared to “in house” models used by other consultants.

Features of this model (and all least cost models) are the assumption of perfect competition and perfect foresight. This means that energy prices reflect short run marginal costs plus the marginal cost of capacity (if the market has no surplus capacity).

A3.3 Firming Analysis Model (FAM)

The FAM is a proprietary, Excel-based model, built internally by Marsden Jacob. It provides insight into the dynamics of Variable Renewable Energy (VRE) (wind and solar) and storage and assesses the value of storage in a high-VRE environment.

While it was developed to examine the NEM when VRE dominates (i.e. post-2050) it is also useful prior to that time and as a high level “check” on outcomes of the detailed market modelling.

The model is flexible, interactive and data driven. It simulates generation supply (MW) and customer demand (MW) at 30-minute intervals for a full year (to capture daily variation and seasonality of both VRE and demand). There is a separate version of the model that simulates 30-minute intervals for a single *month*, to remove the effects of intra-year seasonality.

The inputs are:

- Thermal 1 (coal) – represented as a capacity profile, ramp rate and Minimum Generation Load (mingen) over the year;
- Thermal 2 (gas) – represented as a capacity profile, ramp rate and mingen over the year;
- Solar – represented as a per unit trace (which can be both modified as needed, and enable scenarios to be run using different trace profiles) and a scaling factor defining the MW installed;
- Wind - represented as a per unit trace (which can be both modified as needed, and enable scenarios to be run using different trace profiles) and a scaling factor defining the MW installed;
- Storage – represented as a capacity (MW) and energy amount (MWh) (and hence, hours of storage), and starting level of energy in store;

- Demand – represented as a per unit trace and a scaling factor defining the maximum or average MW;
- Costs – annualised capital costs of each technology and annual operating costs based on LCOE.

The model works as follows:

Each consecutive 30-minute interval demand will be met by generation in the following order:

- Thermal 1 (coal) mingen
- Thermal 2 (gas) mingen
- Solar
- Wind
- Thermal 1 (coal) above mingen
- Thermal 2 (gas) above mingen
- Storage – charge or discharge; Storage will charge/pump when there is surplus VRE and storage will discharge/generate when generation has not met demand;

Data Driven

The model is totally data driven so it can represent the whole NEM, or any region or combination of regions within the NEM.

Our initial runs have focused on the combined 'super-region' of NSW + VIC + SA given the new interconnect capacity is likely to result in these three States/regions acting more like a single region. However, post 2050 it could be surmised that all states NEM mainland states (i.e. including Queensland and Tasmania) should be considered.

Being data driven the model is able to simulate many scenarios:

- Years of different demand outcomes;
- Years where there are periods of wind lulls;
- Loss of a thermal generator;
- Storage of different capacity and energy size.

Being data driven, the model can also represent different demand levels and profiles – such as incorporating the 'duck curve' over time as increasing installation of residential and corporate behind-the-meter rooftop solar PV erodes grid demand during daylight hours.

Finally, it can also represent different VRE profiles (for solar and wind), particularly different profiles of wind generation given its high variability. The model was initially run using the actual wind generation profiles from the NEM over the 2015, 2016 and 2017 years.

Outputs

Being Excel-based, the model is clearly flexible and so output can be easily created and modified by the user. However, initial charts included:

- The generation stack, including when storage is required to contribute to load or draw load to charge, for various periods over the year enabling comparison between seasons.
- Storage required (MW) as a percentage of Maximum Demand (MD)(MW) for the year, versus gas peaking required (MW) (as a percentage of MD),
- Cost versus energy in storage (where unserved demand is given a cost);
- The conditions under which large storage capacity (MWh) is required to meet NEM demand;
- Amount of time each plant type cleared the market;
- Instances when thermal generation is above the demand curve (when limited by mingen);
- Instances when VRE generation (GWh) is above the demand curve resulting in curtailment or spill;
- Storage required (MW) and (GWh) at different system levels of VRE and how the above issues change as the % VRE increases.

From this, the role and value of large-scale storage will be able to be examined across several scenarios very quickly. This will provide for a proper quantitative basis for the valuation of Snowy 2.0.

Appendix 4 Battery Economics and Entry

The study involved modelling the economics and entry of batteries over the study period. This appendix presents analysis on the cost of large-scale battery storage, the revenue streams from batteries, and their likely economics in the NEM.

The economics of storage is complex. Storage can be thought of as a generator with limited continuous operating hours (i.e. a level of firmness provided only by the hours of energy storage available) and with uncertain operating costs (that relate to the buy prices of energy - charging or pumping).

A4.1 Battery Revenue Streams and Economics

Table 16 presents the revenues potentially available to a battery (or other storage asset). This revenue structure and approach was used as the basis to assess the level of batteries that would enter.

Table 16 Battery Economics

Service	Assessment Approach	Importance
Spot market		
Energy arbitrage	Market modelling through buy and sell bids	The largest revenue stream
FCAS provision	Spreadsheet model to assess for each FCAS service supply and demand, and associated prices, volume and share.	Low Can be high as batteries can provide 24x7.
5-minute pricing	Ability to capture 5-minute prices. Limit of capturing 50% of the first 5-minute period.	Moderate Depends on OCGT response
Energy security		
Energy security	Ability to provide security / reliability contingent on storage volume and maintaining energy in reserve.	Low Difficult to monetise
Regulatory requirement	A level of storage to be required to accompany new solar and/or wind generation. May have usage guidelines.	High Maybe a key driver of development
Grid		
Support services Tariff for charging	Identification of l services and associated prices. This can be significant. For example, SA are known to be developing a tariff that recognises the time a battery charges.	Low
Retailer risk management		
Energy limited cap	Value in offsetting cap contract purchase Reduction in value due to limited storage.	High- Key revenue component
Firming product	Firms VRE profile on a daily basis.	Not suitable for energy limited storage
5-minute response	Firm capacity in a 5-minute market (noting 50% limit in first period)	Moderate 5-minute risk not fully understood
NEG	Mitigation against dispatchability requirement – question of how the NEG will value limited storage battery	Low NEG reliability requirement has low compliance requirement

The assumptions used were intended to be optimistic in relation to the volume of energy traded and the price spread obtained. However, even with these optimistic assumptions, a battery of 4 hours storage was not economic.

Table 17 presents an example of battery economics through a comparison of revenue streams and costs.

In relation to the provision of FCAS:

- The provision of FCAS contingency does not impede a battery from buying and selling energy (i.e. arbitraging spot price). Batteries can also provide multiple FCAS contingency services (6 Second, 30 Second, 5 Minute);
- Batteries will participate in FCAS, noting that the total amount of FCAS service quantity in the NEM is small (less than 500 MW per service).

The assumptions used were intended to be optimistic in relation to the volume of energy traded and the price spread obtained. However, even with these optimistic assumptions, a battery of 4 hours storage was not economic.

Table 17 Illustrative Example of Battery Economics (1)

Factor	Units	2025	2035	2045
Battery Cost (4 hours)	$/kW	1500	1180	1000
	$/kW$_{4\ hours}$/Year	$240	$189	$160
	$/MW$_{4\ hours}$/Year	$240,120	$188,894	$160,080
1 MW / 4 hours	$/Year	$240,119.56	$188,894.06	$160,079.71
Arbitrage Revenue				
Sale per day	MWh	3.5	3.5	3.5
Purchase per day	MWh	3.89	3.89	3.89
Price spread	$/MWh	$90	$100	$120
Buy price	$/MWh	$40	$30	$30
Ave spot prie	$/MWh	$85	$80	$90
% days	%	90%	90%	90%
Revenue	$ per day	$299.44	$338.33	$408.33
Revenue	$/year	$98,367.50	$111,142.50	$134,137.50
FCAS Revenue				
No FCAS services supplied		2	2	2
% time supplying		50%	40%	30%
FCAS price	$/MWh	$4.0	$2.5	$1.5
Revenue	$/year	$35,040	$17,520	$7,884
Total Revenue	$/year	$133,407.50	$128,662.50	$142,021.50
Loss	$/year	$106,712.06	$60,231.56	$18,058.21

Source Mrasden jacob Associates

Note (1): This utilises data assumptions different than presented in the assumptions chapter.

The study found that storage:

- Of limited hours cannot provide firming sufficient to support a cap contract; and
- Is not economic in the spot market based on the forward cost curves until past 2040 (for storage hours over 1 to 2 hours).

Battery storage development was required to be considered in the context of supporting VRE development. The table below presents the estimated new entry generation costs based on MJA assumptions.

Table 18 LCOE for Generation Options (2)

Plant Type	Capacity Factor	$/MWh
Coal plant (1)	70%	$112
CCGT	55%	$123
OCGT	25%	$212
Solar + 25% Battery (4 hours)	25%	$85
Solar + 50% Battery (4 hours)	25%	$115
Solar + 100% Battery (4 hours)	25%	$176

Source Marsden Jacob Associates

Note (1):

- WACC of 14% compared to other plant which have a WACC of 8%
- No carbon price.

Note (2): This utilises data assumptions different than presented in the assumptions chapter.

A4.2 Battery Development

The analysis has illustrated the following:

- A storage facility requires at least 24 hours storage to support the sale of a capacity type contract (refer also to Chapter 10 – Storage and Firm Capacity, in the Main Report);
- On the forward outlook of costs, batteries will not be economic at storage levels over 2 hours;
- Firming services will require a substantially higher amount of lower cost storage and/or gas or reciprocating fast start generation than offered by batteries.

The analysis has shown that batteries will likely enter through the following means:

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

Appendix 5 Firming Analysis Model (FAM)

This Appendix presents the development, assumptions and usage of the Marsden Jacob Firming Analysis Model (FAM).

A5.1 Model Background

With the increasing mix of VRE in the NEM in the foreseeable future, there is a need to encapsulate what this shift potentially means for Snowy 2.0 development. The areas that Marsden Jacob focused on for the purpose of modelling are:

- Thermal generation level;
- Storage requirement, both in terms of capacity and energy;
- Trade-off between percentage of VRE in the market and firming requirements;
- Trade-off between thermal and storage as a means of firming.

These areas will address questions for the period post-2047 (when PROPHET modelling is not optimised) on issues such as value of storage capacity, storage energy and market clearing by gas. This will also assist in quantifying the Snowy 2.0 value and revenue for 2047 onwards.

A5.2 Assumptions and Specifications

One of the FAM modelling main outputs will be what firming will potentially look like in the future. Marsden Jacob focuses on a definition of firming as follows.

Firming Definitions

Firming - Individual retailers: Provided by physical (dispatchable generation / storage) and contracts caps, load following).

Firming requirements and cost – NEM Wide: Refers to the amount of dispatchable generation and storage required as VRE increases.

Early observations indicate that:

- As VRE increases with no other changes (such as generation closures), the requirement for dispatchable generation reduces due to the additional supply from VRE;
- As VRE increases to high levels, if storage is not also increased there will be greater VRE spill.

To quantify these effects, two cases of VRE energy to demand energy are considered:

- VRE energy = demand energy (i.e. 100% renewable)
    - Required dispatchable generation and storage are all for firming;
- VRE energy = a lower percentage of demand energy:
    - Thermal generation is required to supply the demand energy not met by VRE, and thermal generation and storage are required for firming that component of demand energy that is supplied by VRE;
    - There is surplus thermal energy capability from that component supplying demand, which reduces the firming required to support the component of demand being supplied by VRE;
    - These two components are difficult to separate.

The “bottom line” is that there is an (optimum) cost of thermal and storage required when VRE is supplying a certain percentage of demand. Here we note that supplying 50% of demand by VRE may require VRE capable of generating 60% of the required energy (i.e. there is 10% spill).

A5.3 Methodology

The following section describes the FAM specifications.

Model Operation

FAM operates as follows:

- Simulates either a selected region in the NEM, group of regions, or the whole NEM, on a 30-minute basis for a year;
- A separate version of the model simulates 30-minute periods for a single month. This is to analyse month-to-month firming requirements given that the seasonality of VRE through the year is very significant and was found to be the dominant driver of firming requirements;
- Has as its inputs:
    - 30-minute trace of demand, that defines the profile of demand (MW) each 30 minutes that is to be supplied by VRE, thermal, and storage;
    - 30-minute trace of VRE, which is developed from individual solar and wind traces.;
    - Thermal plant MW (normally taken to be gas);
    - Storage MW and energy that can be stored (MWh storage).
- Model operation:
    - for each 30-minute period the demand less VRE is determined;
    - if VRE > demand then this surplus is stored to the extent that there is unfilled storage;
    - if VRE < demand then there are two modes of operation (selected by the user)
        - storage is used first to supply demand and then thermal;
        - thermal is used first to supply demand and then storage. This approach minimised the amount of storage required for a given level of thermal plant;
- Model outputs:
    - hours of the respective marginal suppliers – VRE, storage, gas;
    - VRE generation (MWh);
    - thermal plant generation (MWh);
    - storage required to meet capacity (MW) and energy (MWh) requirements.

Defining a Model Run

A model run is defined through 9 factors (that related to 7 different categories):

Table 19 Factors for FAM Model Run

Category	Factors
Demand	MWh of energy to be supplied over the year (equals the sum of 30-minute demands divided by 2) Trace – the profile of 30-minute demands (MW)
VRE	MWh of energy VRE can supply (equals the sum of 30-minute solar generation divided by 2) Trace – the profile of 30-minute VRE output (MW)
Storage MW	Capacity of storage specified
Storage hours	Storage size defined as hours of generation at maximum capacity
Storage efficiency	Storage cycle losses
Thermal	MW available to be used
Mode	Either thermal used before storage or storage used before gas to supply demand

The demand and VRE traces are developed to represent the region (or regions) in the NEM being modelled.

Table 20 FAM Model definition

Measure	Definition
Percentage of VRE	The annual energy (MWh) capable of being produced by all VRE as a percentage of the total demand energy (MWh)
Firming	The amount of thermal and generation required to support a defined level of VRE. This is expressed in terms of capacity (MW)
VRE %	We distinguish between the energy VRE can supply and what it does supply *VRE % = VRE % supplied + VRE spill*

Assumed percentage of solar in modelling

Percentage of solar as part of the overall VRE energy generation has been shown to affect the outcome of storage and gas requirement critically. Some of the observations and steps taken to derive the assumptions for solar are:

- A brief literature review of academic research and found that 25% solar/ 75% wind is generally the optimal mix between renewable generators for the whole system.
- Marsden Jacob separately modelled VRE and optimised the mix over a number of different regions, wind traces and demand profiles and found 25/75 solar/wind to be the optimal mix when seeking to minimise portfolio variability and match the demand profile.
- The example of the Kennedy Energy Park[24] in Queensland – the first combined wind, solar and battery storage project in Australia – is approximately 25%/75% solar/wind.
- Based on the AEMO ISP and AEMO[25] published data on proposed new generation, however, it appears that significantly more than 25% of proposed new projects are solar farms. Therefore, the actual mix of renewables in the NEM over the shorter-term (5-10 years) is more likely to be weighted toward solar. In the long term, it is expected that the mix to move more toward an optimal mix.
- Two cases are presented where the percentage of solar to VRE are:
  - 25%
  - 50%.

A5.4 Model Utilisation

The modelling has been used to estimate the cost of thermal and storage necessary to supply energy not supplied by VRE (when this is less than 100% of demand) and to provide the firming required.

The modelling was used to:

- Provide a clearer picture of what moving to high levels of VRE entails in the NEM;
- At various levels of VRE (and at different solar/wind combination) quantify what would be required in place of Snowy 2.0 if it were removed. This is the fundamental opportunity value to Snowy 2.0;
- Determine the hours cleared by gas and VRE/storage. This will determine the trend in price spread and the revenue/value derivable through buy/sell of energy;
- The economic limits to the amount of energy that can be supplied by VRE;
- The role of large energy storage in energy regulation, the need to maintain thermal support for energy security and what maintaining such generation would mean.

[24] https://kennedyenergypark.com.au/
[25] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Appendix 6 FAM Results - Annual

This Appendix presents the modelling undertaken by the Firming Analysis Model (FAM) to investigate the amount, nature and economics of firming VRE in the NEM as the level of VRE increases to high levels.

The results of this modelling were used to support the storage requirements and Snowy 2.0 revenues post-2047 when most of, or all, the coal plant are expected to have closed.

The appendix presents the results of modelling that used the Firming Analysis Model (FAM)[26] over a year. By modelling over a year, the modelling incorporated VRE energy production variability between seasons.

A6.1 Specified Annual Runs

The following are the assumptions specified for the FAM modelling runs:

- The region modelled was the combined SA-VIC-NSW regions (on the assumption by 2047 there is strong interconnection between them)
- The demand was the sum of the SA, VIC and NSW demand traces (this provides some smoothing of these traces due to the non-coincident nature of their respective maximum demands)
- The VRE trace was developed by a combination of solar and wind traces from SA, VIC, and NSW (considering location diversification). The assumed proportion of solar to wind was as specified.
- The mode has thermal used before storage to minimise the amount of storage needed.
- For simplicity:
    - Capacity is expressed as a percentage of demand MD,
    - Energy is expressed as a percentage of demand energy (MWh).

Based on the above, three modelling run sets were performed based on the percentage of energy produced by VRE:

- Run set 1:
    - VRE energy equals 50% of demand energy;
    - Storage hours equal to 4 hours, 12 hours, and 24 hours;
    - Solar equal to 25% and 50% of VRE installed capacity;
    - Three different VRE production profiles (traces) we used (2015, 2016 and 2017).
- Run set 2:
    - VER energy equals 70% of demand energy;
    - Storage hours equal to 4 hours, 12 hours, and 24 hours;
    - Solar equal to 25% and 50% of VRE installed capacity;
    - Three different VRE production profiles (traces) we used (2015, 2016 and 2017).
- Run set 3:
    - VER energy equals 100% of demand energy;
    - Storage hours equal to 4 hours, 12 hours, and 24 hours;
    - Solar equal to 25% and 50% of VRE installed capacity
    - Three different VRE production profiles (traces) we used (2015, 2016 and 2017).

[26] 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.

For each run set the model solved for the minimum combinations of energy storage (MWh) and Thermal MW that provided for demand to be met. The firming required for the VRE component as described in section 13.2.1 of this note was not separately identified.

In all cases we have expressed the amount of storage capacity required (MW), based on hours of storage of 4, 12 and 24 hours, as a percentage of Maximum Demand (MW) – this is shown on the x-axis.

The y-axis shows the amount of gas capacity (MW) required, also expressed as a percentage of maximum demand (MW), for each level of storage. The more gas generation introduced, the lower the amount of storage required.

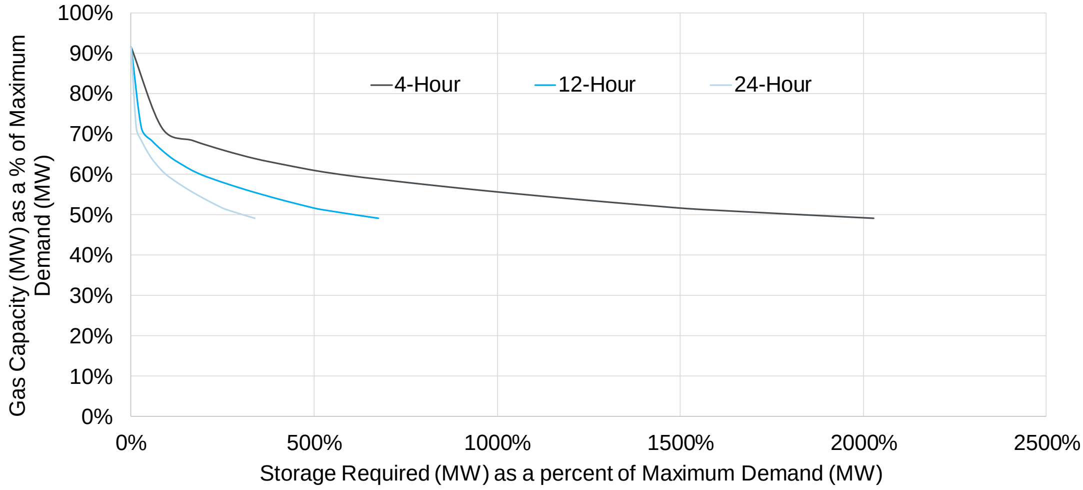
A6.2 Modelling Results

The following section presents the results based on the three run sets described above.

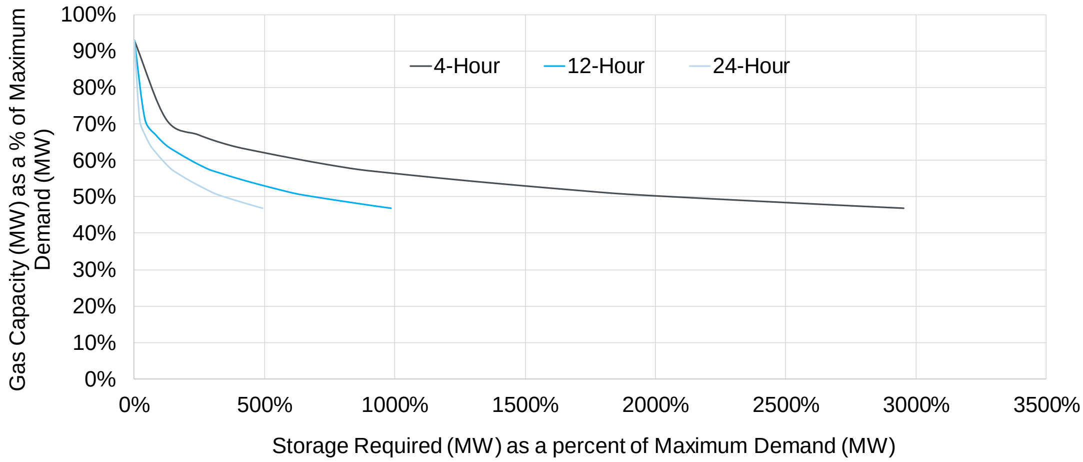
Annual Run Set 1

Run set 1 is VRE Energy equal 50% of Demand Energy.

Figure 65 FAM results run set 1



50% VRE Scenario (25% solar/75% wind mix) for 4, 12 & 24-Hour Storage

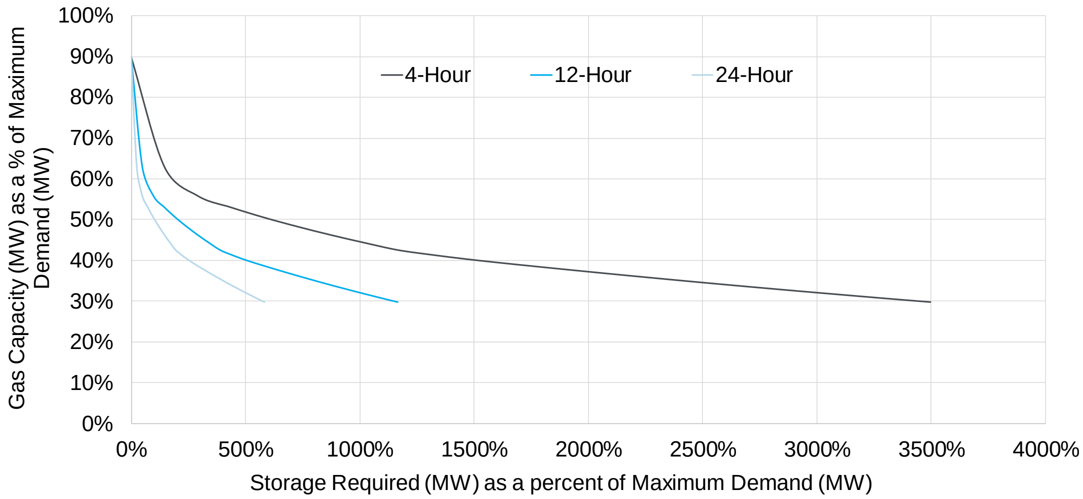


50% VRE Scenario (50% solar/50% wind mix) for 4, 12 & 24-Hour Storage

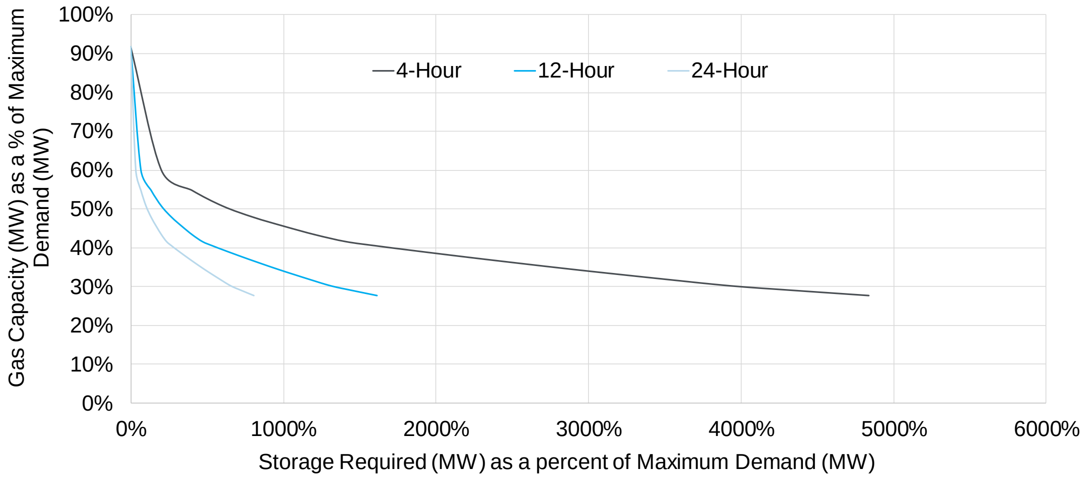
Annual Run Set 2

Run set 2 is VRE Energy equal 70% of Demand Energy.

Figure 66 FAM results run set 2



70% VRE Scenario (25% solar/75% wind mix) for 4, 12 & 24-Hour Storage

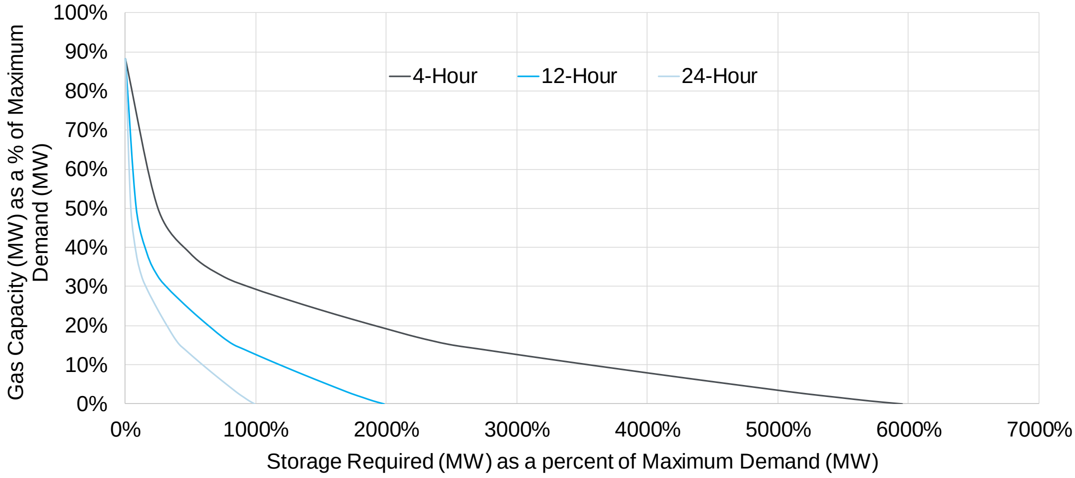


70% VRE Scenario (50% solar/50% wind mix) for 4, 12 & 24-Hour Storage

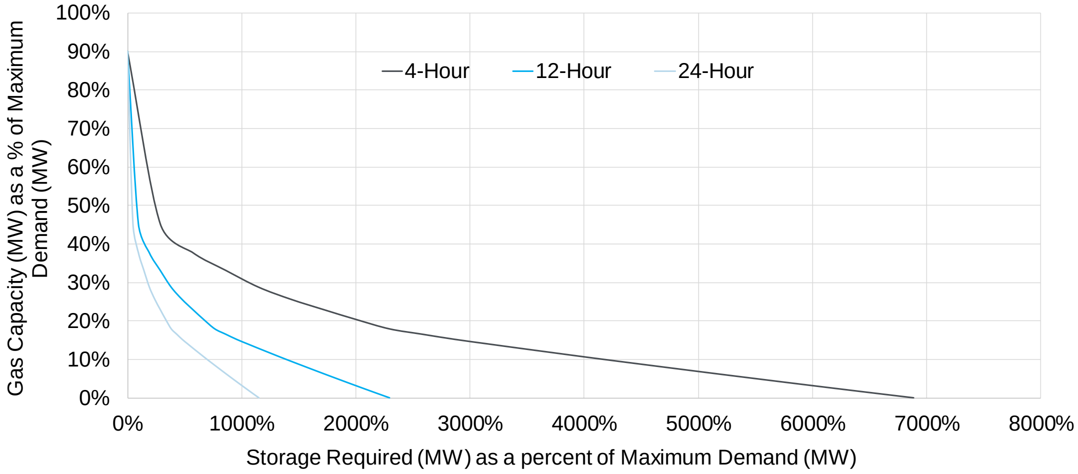
Annual Run Set 3

Run set 3 is VRE Energy equal 100% of Demand Energy.

Figure 67 FAM results run set 3



100% VRE Scenario (25% solar/75% wind mix) for 4, 12 & 24-Hour Storage



100% VRE Scenario (50% solar/50% wind mix) for 4, 12 & 24-Hour Storage

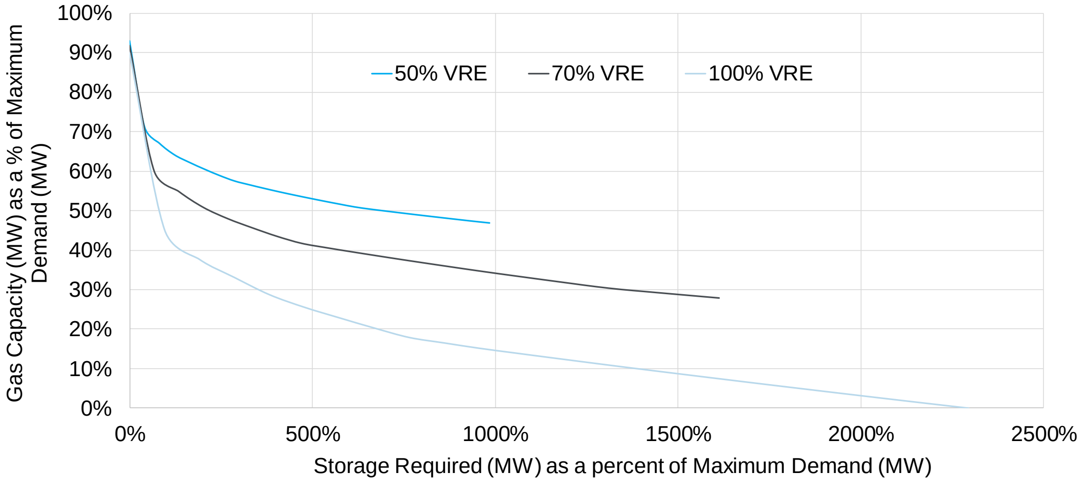
A6.3 Observations

Summarised below are the key observations from the three FAM runs described above.

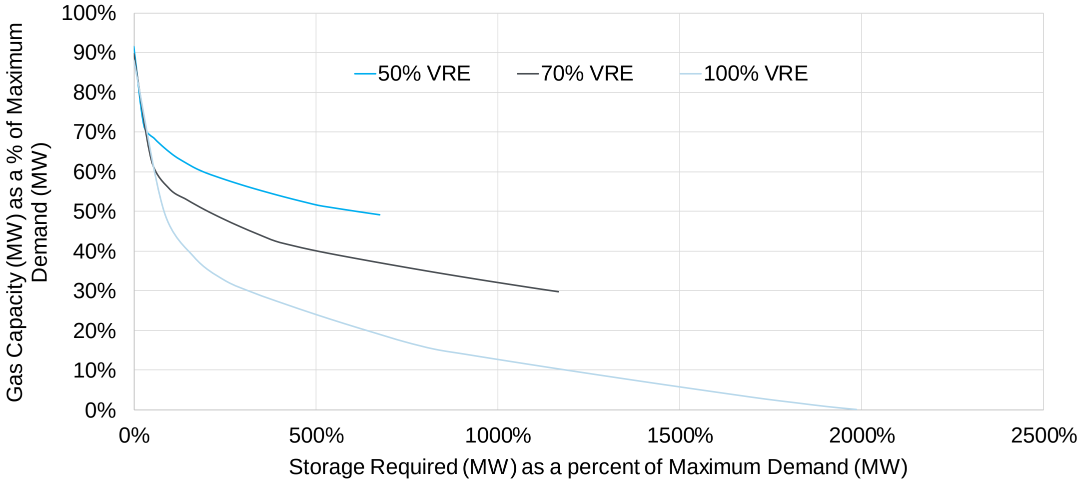
Firming requirement as VRE Energy % Increases

The firming requirement comparisons with different levels of VRE Energy percentage using 12-hour storage is summarised below.

Figure 68 Firming requirement comparisons



12-hour storage required between 50%, 70% and 100% VRE systems where VRE is split 50/50 between solar and wind.

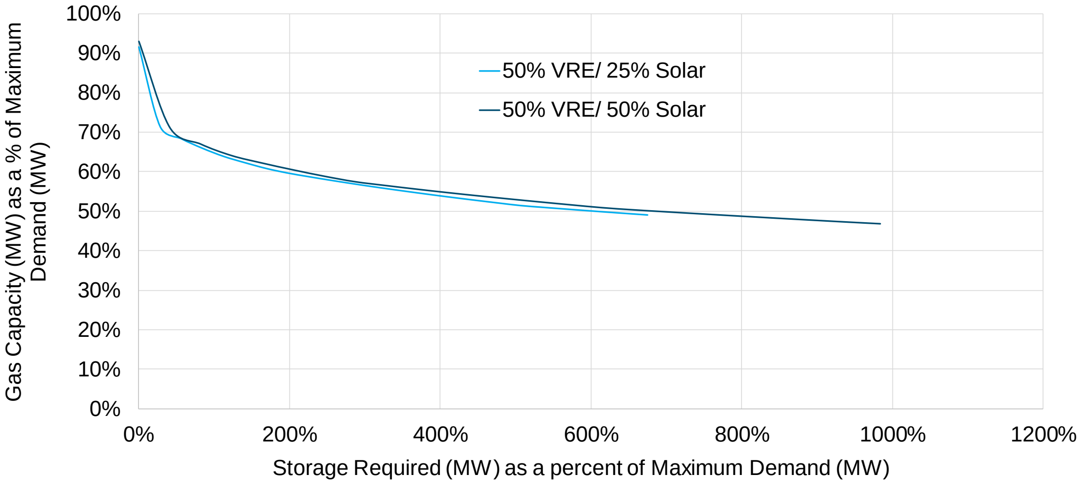


12-hour storage required between 50%, 70% and 100% VRE systems where VRE is split 25/75 solar/wind.

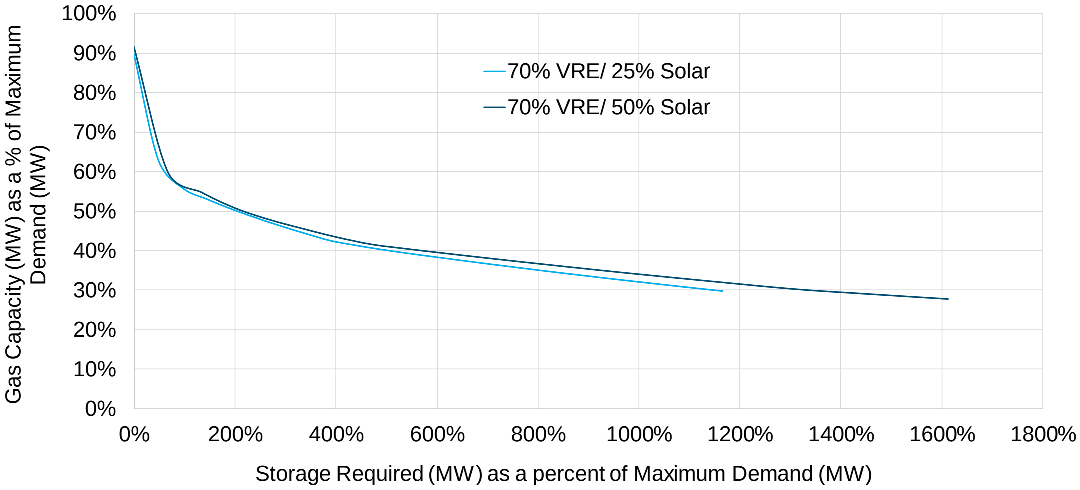
Firming change as Solar % of VRE changes

As noted earlier, the solar generation percentage affects the outcome of storage capacity.

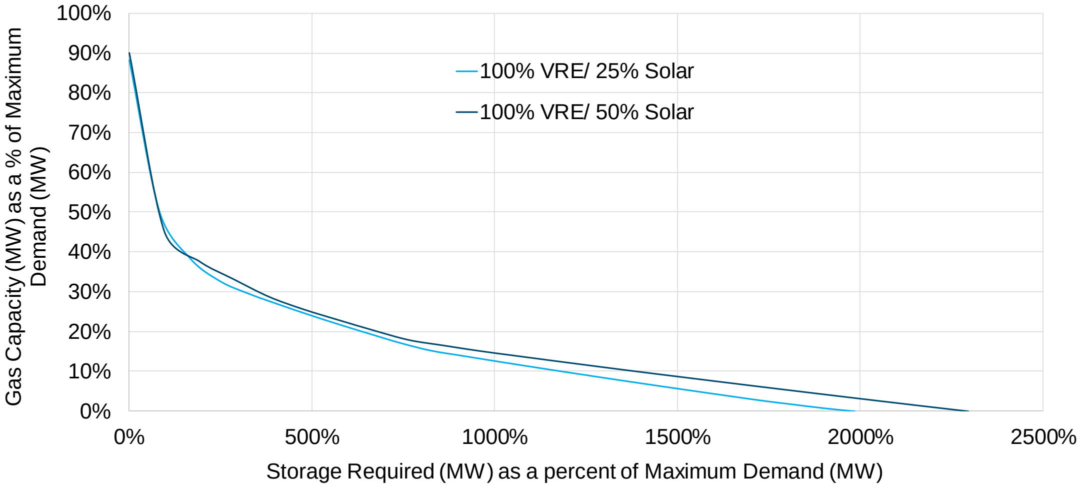
Figure 69 Solar percentage and storage comparison



50% VRE - Comparing 25% Solar versus 50% Solar Mix



70% VRE - Comparing 25% Solar versus 50% Solar Mix

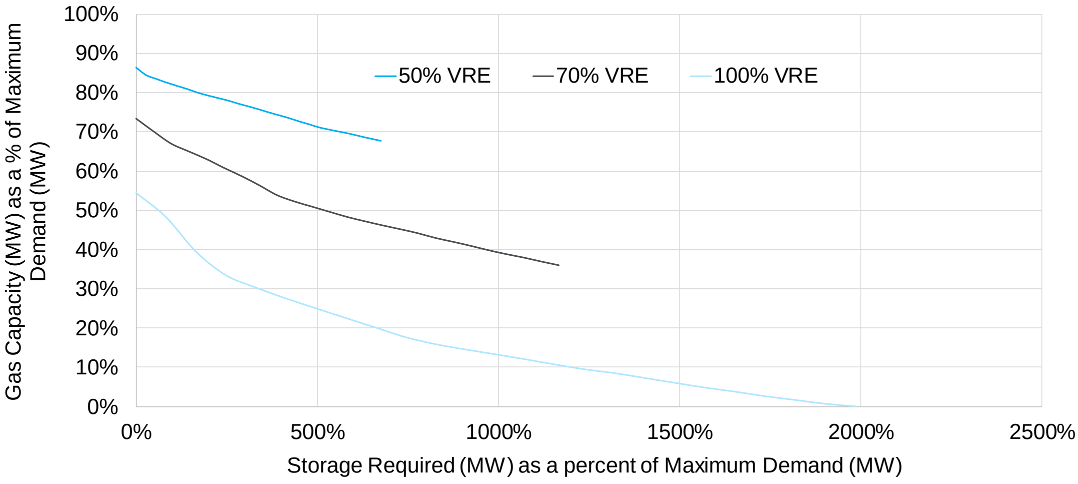


100% VRE - Comparing 25% Solar versus 50% Solar Mix

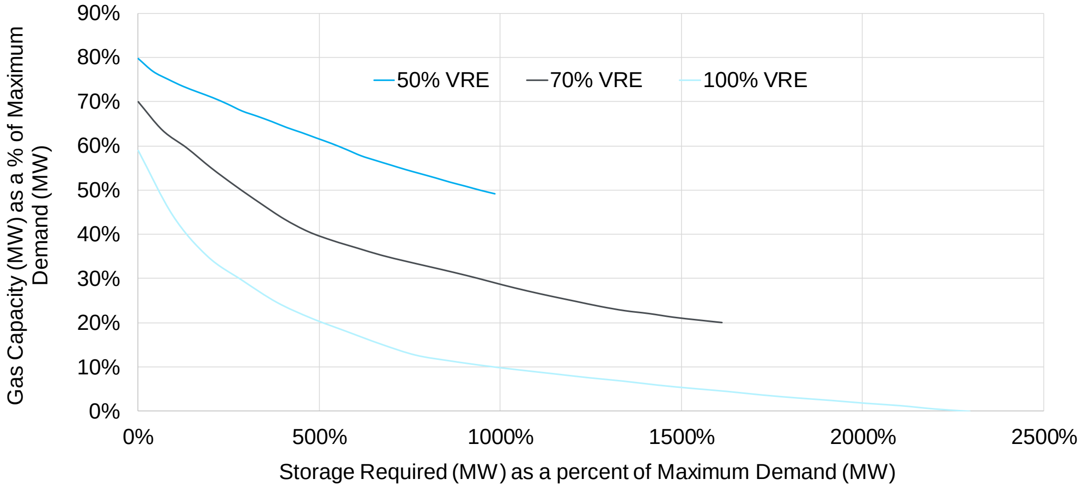
Percentage of Time Gas Generation is Marginal

The following charts show the percent of time that gas clears the market (is the last generator to dispatch) at different levels of storage for 25% solar and 50% solar VRE mixes. This is significant because gas will set the price.

Figure 70 Gas generation market clearing



Percent of time that gas clears the market for 50%, 70% and 100% VRE – 25% Solar

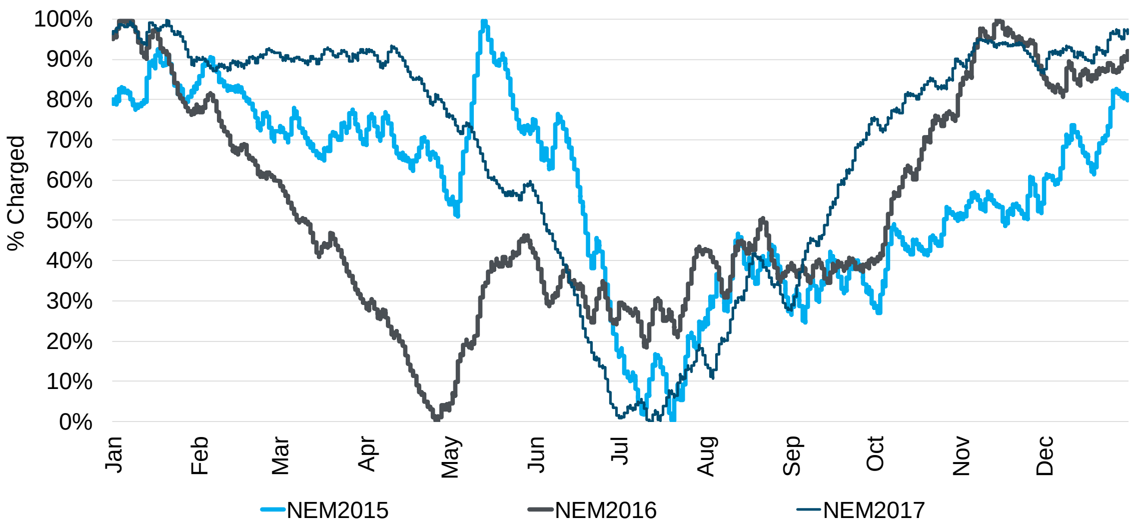


Percent of time that gas clears the market for 50%, 70% & 100% VRE - 50% Solar

Storage - Level of "charge" through a year

The level of storage for the battery varies depending on the VRE mix and thermal capacities as shown below.

Figure 71 Level of Energy in Storage over a Year – Three example profiles



Summary of Observations

Some of the main observations are:

- The graphs above quantify the amount of thermal generation and storage required as VRE % increases;
- The results show that the trade-off between storage and gas increases as the amount of thermal decreases;
- Very large storage is required. This relates to energy regulation on a daily, weekly, monthly and seasonal basis.

The table below presents the modelling of the SA-VIC-NSW region for a year under stated assumptions of % VRE and VRE generation pattern (i.e. historical year used). The modelling identified the gas MW and storage (MW and hours of storage) required. The amount of storage capacity (MW) was based on meeting maximum demand and maintaining system reliability. It shows the hours/days of storage required, i.e. 11 to 20 days of storage under a 100% VRE scenario.

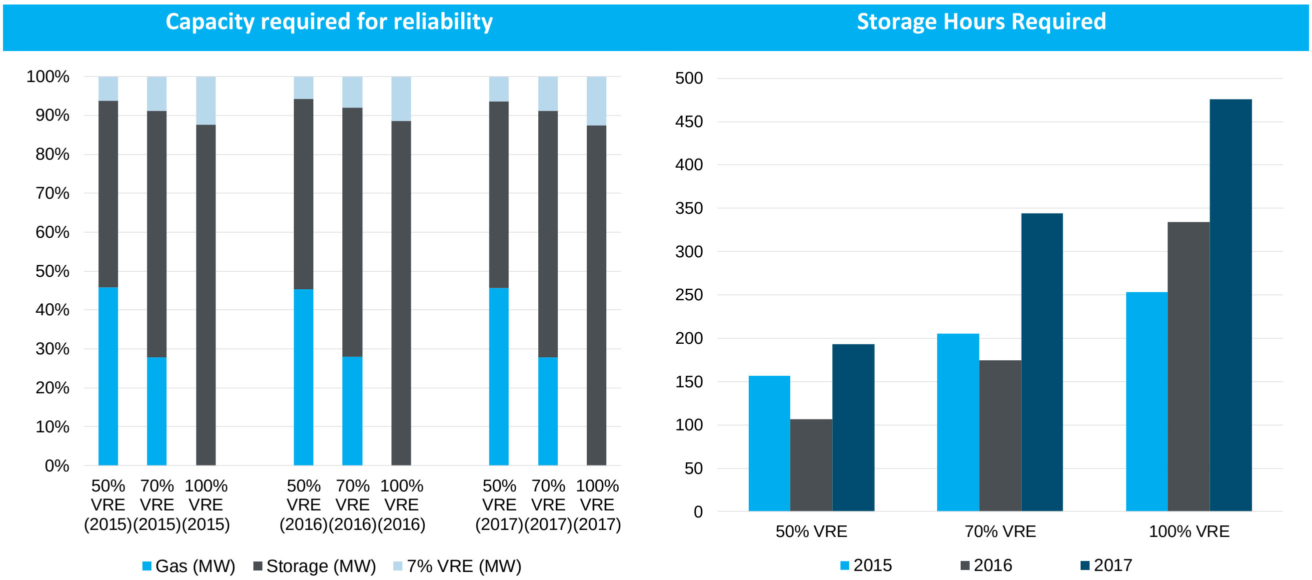
We note that this "yearly modelling" assumed a completely closed system with no alternative means to balance supply and demand other than through firming. It assumes no interconnectors, no demand side management, and no other temporary generation supply sources. Given the dominant impact of seasonality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

Table 21 FAM Annual Modelling Results Summary

	Max Demand	Reserve (MW)	=	7% VRE (MW)	Gas (MW)	Storage (MW)	GWh	Hours	Days
50% VRE (2015)	26,451	1,980	=	1,770	13,000	13,661	2,145	157	7
70% VRE (2015)	26,451	1,980	=	2,492	7,900	18,039	3,700	205	9
100% VRE (2015)	26,451	1,980	=	3,535	0	24,896	6,300	253	11
50% VRE (2016)	26,451	1,980	=	1,621	12,900	13,910	1,485	107	4
70% VRE (2016)	26,451	1,980	=	2,268	7,950	18,213	3,176	174	7
100% VRE (2016)	26,451	1,980	=	3,241	0	25,190	8,425	334	14
50% VRE (2017)	26,451	1,980	=	1,788	12,970	13,673	2,645	193	8
70% VRE (2017)	26,451	1,980	=	2,502	7,900	18,029	6,202	344	14
100% VRE (2017)	26,451	1,980	=	3,573	0	24,858	11,830	476	20

	Max Demand	Reserve (MW)	=	7% VRE (MW)	Gas (MW)	Storage (MW)	GWh
2015 Trace							
50% VRE	93%	7%	=	6%	46%	48%	1.6%
70% VRE	93%	7%	=	9%	28%	63%	2.8%
100% VRE	93%	7%	=	12%	0%	88%	4.8%
2016 Trace							
50% VRE	93%	7%	=	6%	45%	49%	1.1%
70% VRE	93%	7%	=	8%	28%	64%	2.4%
100% VRE	93%	7%	=	11%	0%	89%	6.4%
2017 Trace							
50% VRE	93%	7%	=	6%	46%	48%	2.0%
70% VRE	93%	7%	=	9%	28%	63%	4.7%
100% VRE	93%	7%	=	13%	0%	87%	8.9%

Figure 72   Minimum Storage to Capture VRE Variability over a Year



Source: Marsden Jacob

Appendix 7 FAM Results – Monthly

This appendix presents the modelling undertaken and results to assess the storage needs in the NEM under high VRE when inter-seasonal energy variation from VRE is removed.

Additional modelling was undertaken to remove the inter-seasonal requirements of storage.

The Model Background, Assumptions and Specifications, and Methodology for the monthly runs are ultimately the same as for the yearly runs described in Appendix 6. The only difference is that the model looks at 30-minute intervals over a selected *month* rather than for a full year.

A7.1 Specified Monthly Runs

Three additional run sets were performed looking at monthly firming requirements. There were:

- Monthly Run 1:
    - VRE energy equals 50% of demand energy;
    - Solar equals 25% of VRE installed capacity and wind 75%;
    - The months of February and October were modelled as our analysis showed they are more 'typical' or 'average' months with respect to VRE production.
- Monthly Run 2:
    - VRE energy equals 70% of demand energy;
    - Solar equals 25% of VRE installed capacity and wind 75%;
    - Again, the months of February and October were used.
- Monthly Run 3:
    - VRE energy equals 100% of demand energy;
    - Solar equals 25% of VRE installed capacity and wind 75%;
    - Again, the months of February and October were used.

For each run the model solved for the minimum combination of energy storage (MWh) and thermal MW that provided for demand to be met.

Given the calculated minimum thermal (MW) capacity required, the amount of dispatchable storage capacity (MW) was estimated, such that market Maximum Demand (plus a reserve) was met to ensure system reliability. 7% of total installed VRE capacity (MW) was assumed to be 'dispatchable' for the purposes of this modelling.

The energy storage (MWh) requirement could then be expressed as hours of storage relative to the level of dispatchable storage capacity (MW) calculated above.

A7.2 Modelling Results

The following section presents the results based on the three run sets described above.

Monthly Run 1

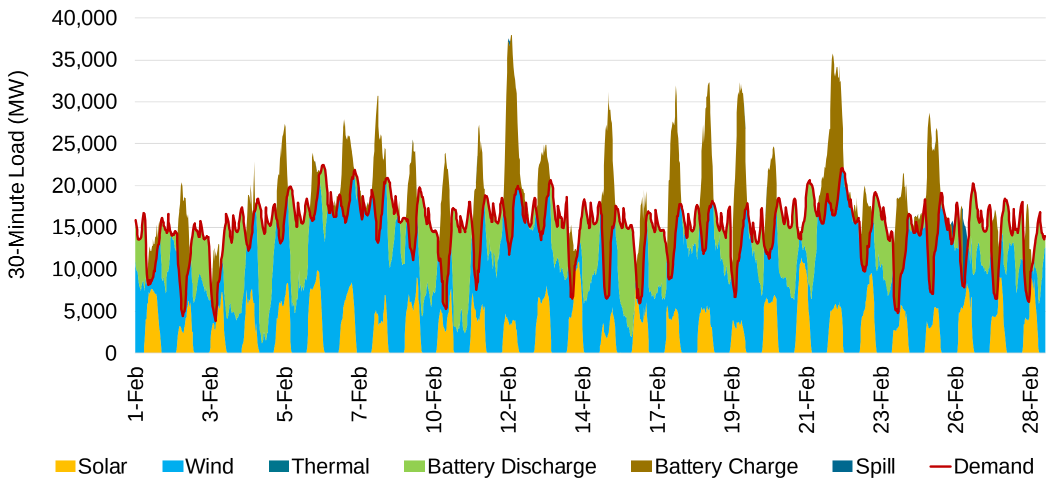
Monthly Run 1 is VRE Energy equal to 100% of Demand Energy.

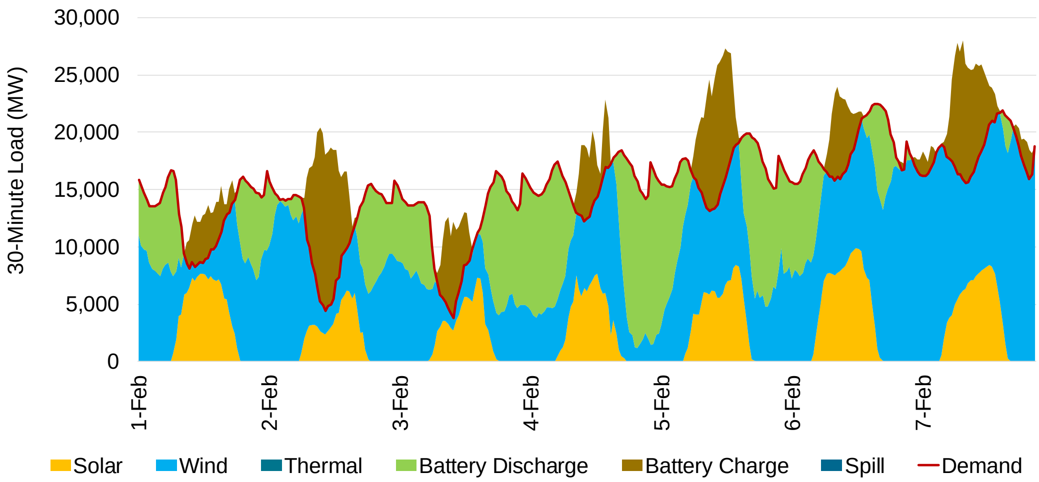
Table 22 FAM Monthly Results Summary – 100% VRE February

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	-	-			
Solar	12,600	2,569	30.3%		
Wind	37,800	7,468	29.4%		
Storage (MW)	24,903	2,267	1.0%	549,000	22
Totals (Net of Storage)	**50,400**	**10,037**	**2.3%**		
Spill/ Curtailment		24	0.2%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	3,528			
Non-VRE Dispatchable (MW)	24,903	VRE	20%	82%
Maximum Demand (MW)	28,431	Thermal (Gas)	0%	0%
Dispatchable % MD	100%	Storage	80%	18%
% Renewables	**100.0%**	**Totals**	**100%**	**100%**

Figure 73 FAM Monthly Results Charts – 100% VRE February





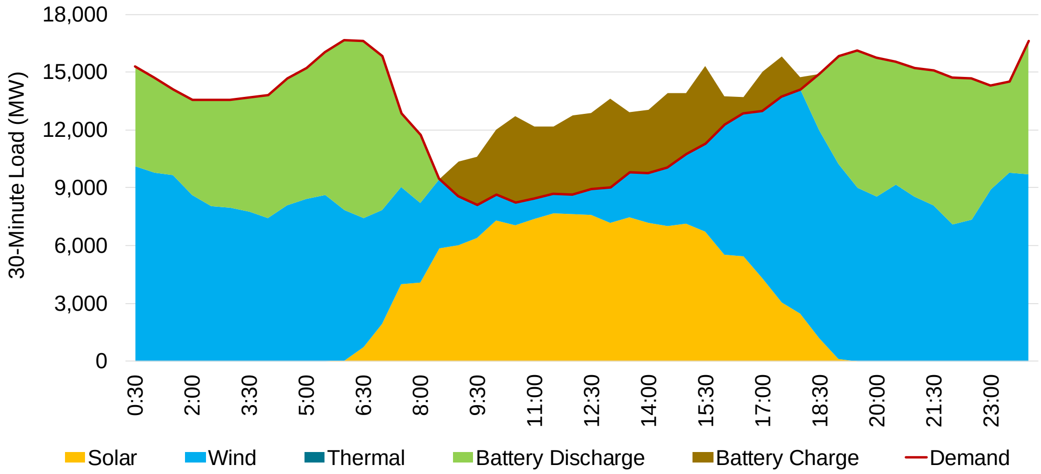


Figure 74 FAM Monthly Results – 100% VRE February – Storage Levels over Month

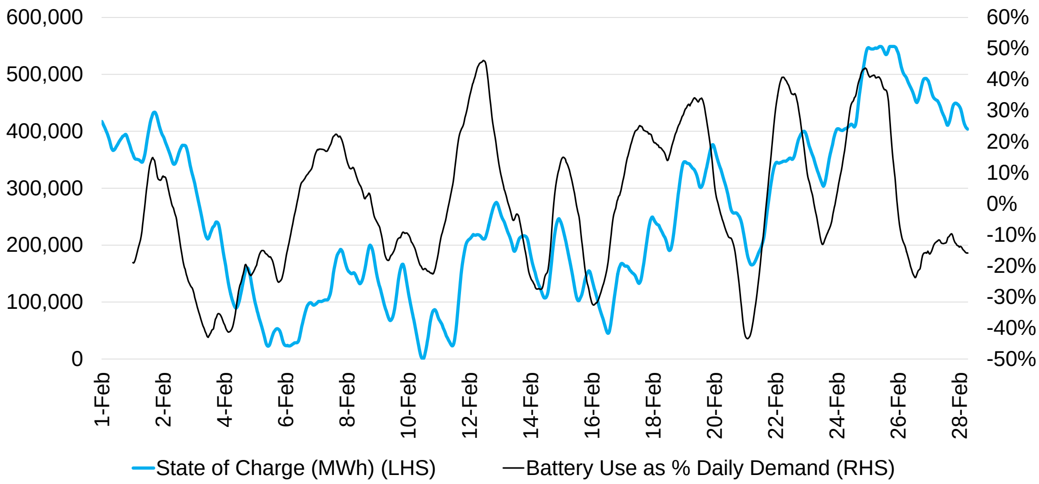


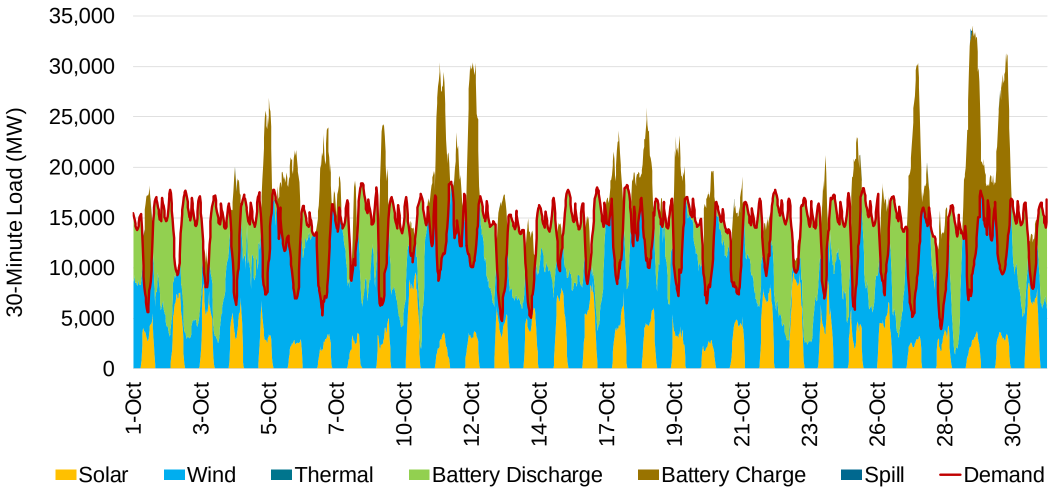
Figure 74 above shows the level of charge of the battery (in MWh) over the month. The % of Daily Demand (right hand axis) is the rolling 24-hour net storage used (negative means a net discharge over the day, and positive means the battery charged (net) over the day) as a percent of the rolling 24-hour total demand.

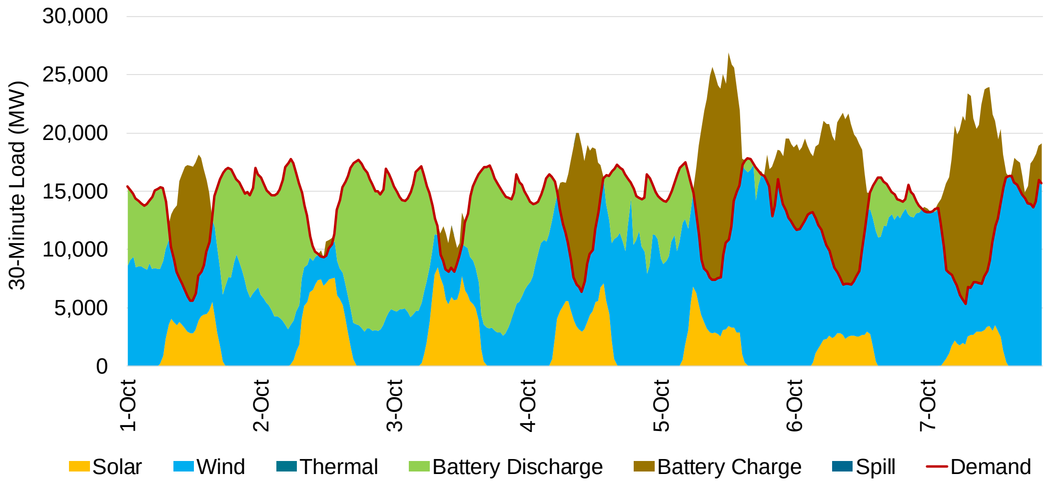
Table 23 FAM Monthly Results Summary – 100% VRE October

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	-	-			
Solar	10,910	2,335	31.8%		
Wind	32,730	7,640	34.7%		
Storage (MW)	25,376	2,676	1.2%	650,000	26
Totals (Net of Storage)	**43,640**	**9,975**	**2.6%**		
Spill/ Curtailment		1	0.0%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	3,055			
Non-VRE Dispatchable (MW)	25,376	VRE	19%	79%
Maximum Demand (MW)	28,431	Thermal (Gas)	0%	0%
Dispatchable % MD	100%	Storage	81%	21%
% Renewables	**100.0%**	**Totals**	**100%**	**100%**

Figure 75 FAM Monthly Results Charts – 100% VRE October





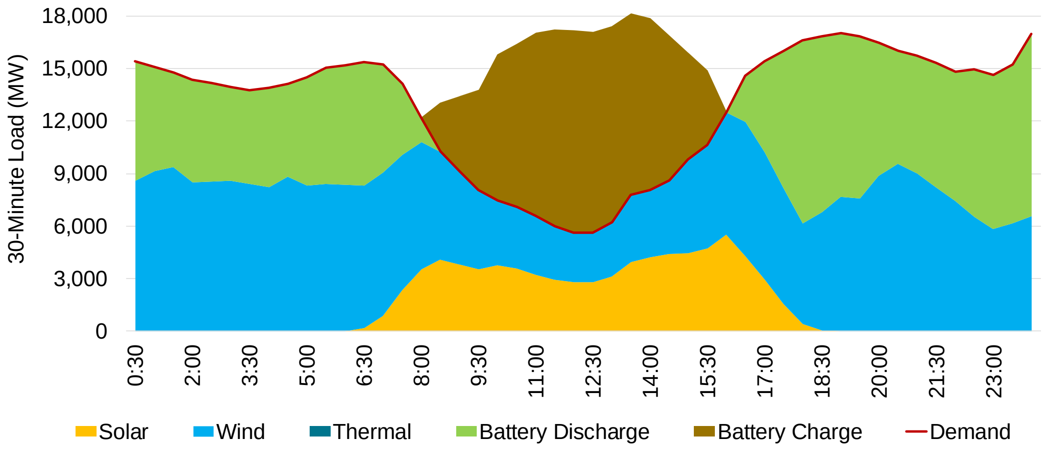
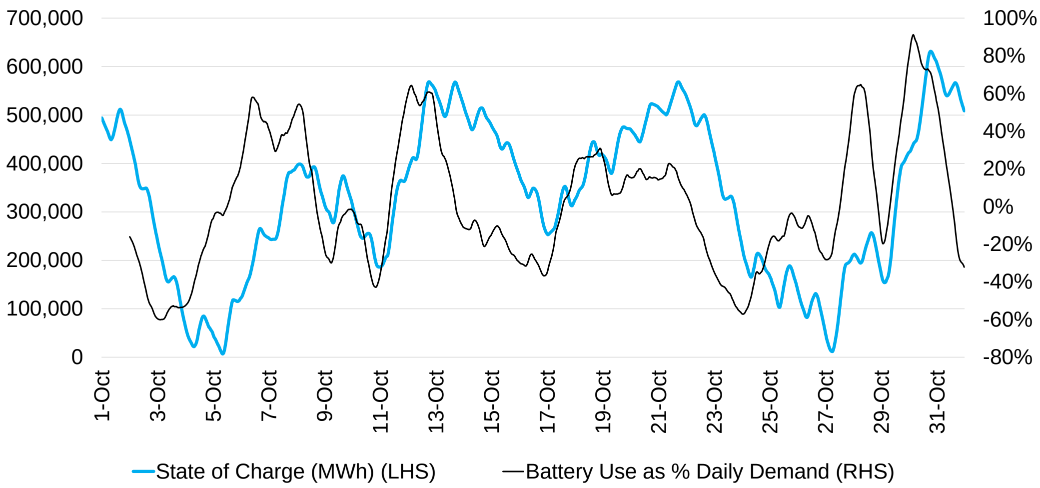


Figure 76 FAM Monthly Results – 100% VRE October – Storage Levels over Month



Monthly Run 2

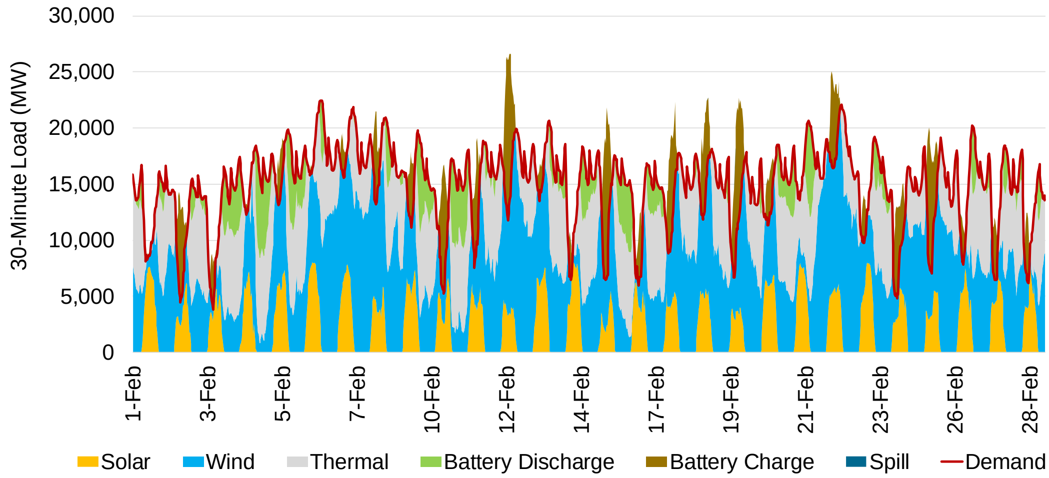
Monthly Run 2 is VRE Energy equal 70% of Demand Energy.

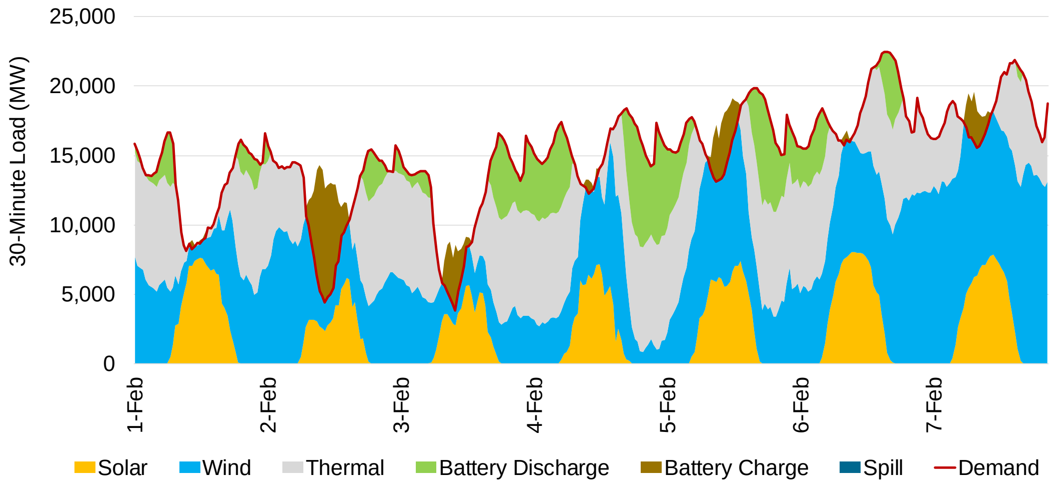
Table 24 FAM Monthly Results Summary – 70% VRE February

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	7,550	3,013	59.4%		
Solar	8,825	1,799	30.3%		
Wind	26,475	5,230	29.4%		
Storage (MW)	18,410	771	0.5%	288,000	16
Totals (Net of Storage)	**42,850**	**10,043**	**2.7%**		
Spill/ Curtailment		0	0.0%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	2,471			
Non-VRE Dispatchable (MW)	25,960	VRE	8%	65%
Maximum Demand (MW)	28,431	Thermal (Gas)	45%	28%
Dispatchable % MD	100%	Storage	47%	7%
% Renewables	**70.0%**	**Totals**	**100%**	**100%**

Figure 77   FAM Monthly Results Charts – 70% VRE February





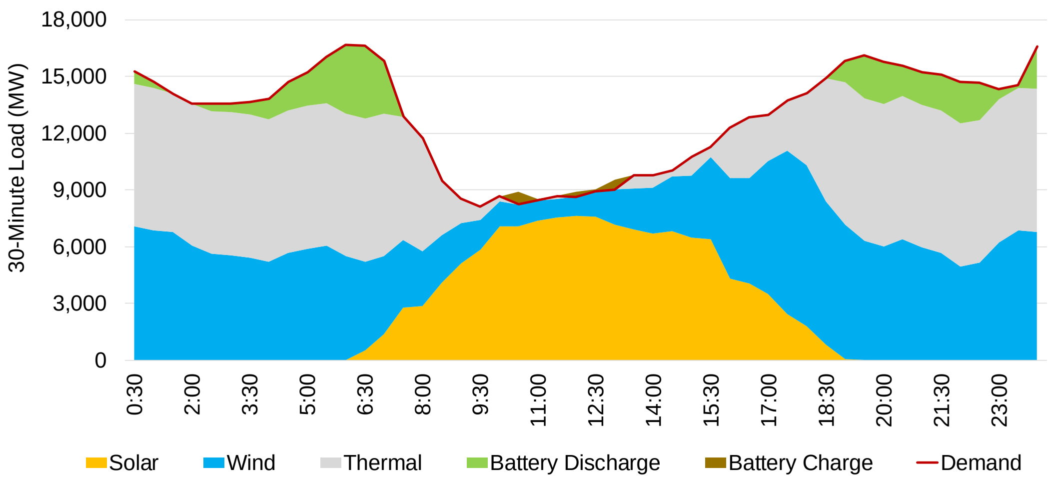


Figure 78 FAM Monthly Results – 70% VRE February – Storage Levels over Month

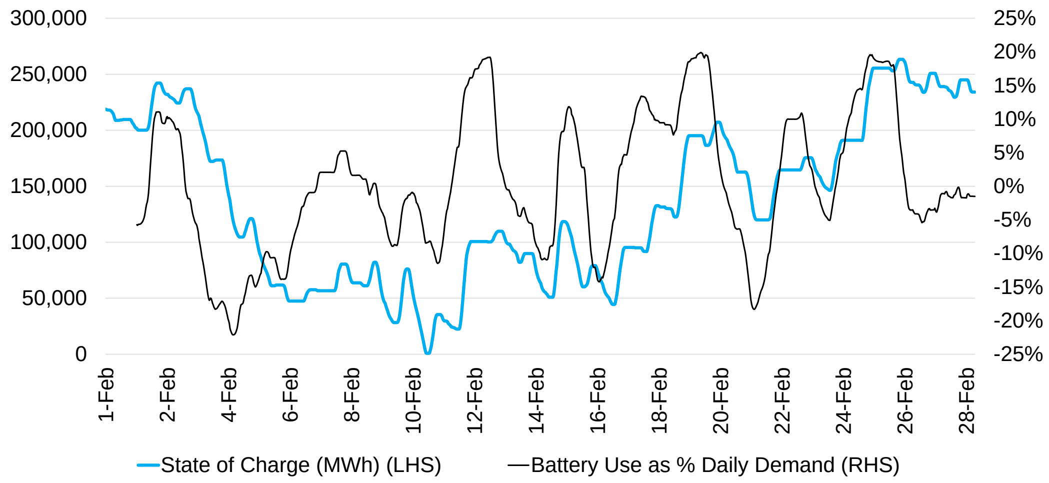


Table 25 FAM Monthly Results Summary – 70% VRE October

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	6,945	2,997	64.2%		
Solar	7,650	1,637	31.8%		
Wind	22,950	5,357	34.7%		
Storage (MW)	19,344	1,038	0.6%	290,000	15
Totals (Net of Storage)	**37,545**	**9,992**	**3.0%**		
Spill/ Curtailment		**10**	0.1%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	2,142			
Non-VRE Dispatchable (MW)	26,289	VRE	10%	63%
Maximum Demand (MW)	28,431	Thermal (Gas)	39%	27%
Dispatchable % MD	100%	Storage	51%	9%
% Renewables	**70.0%**	**Totals**	**100%**	**100%**

Figure 79 FAM Monthly Results Charts – 70% VRE October

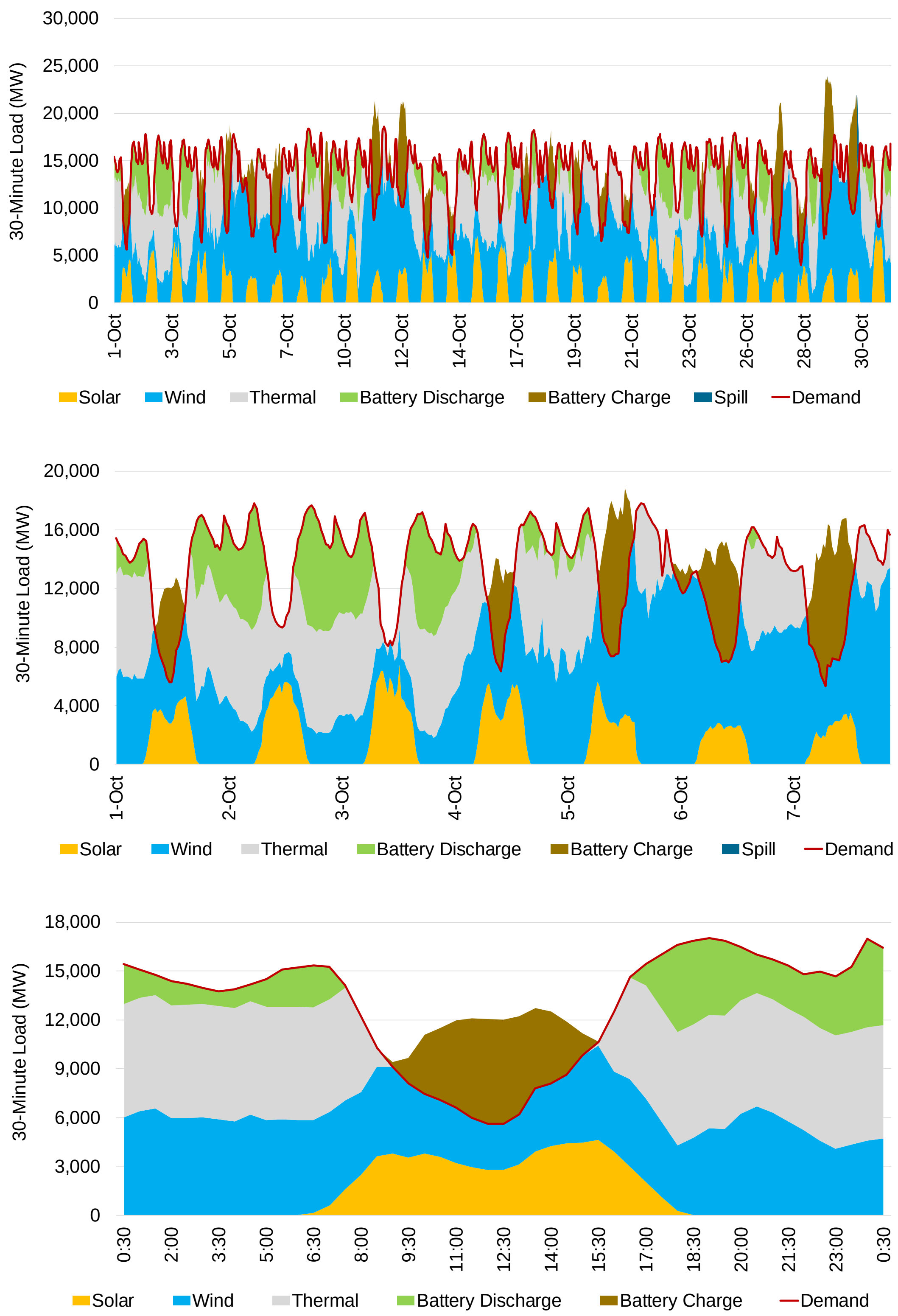
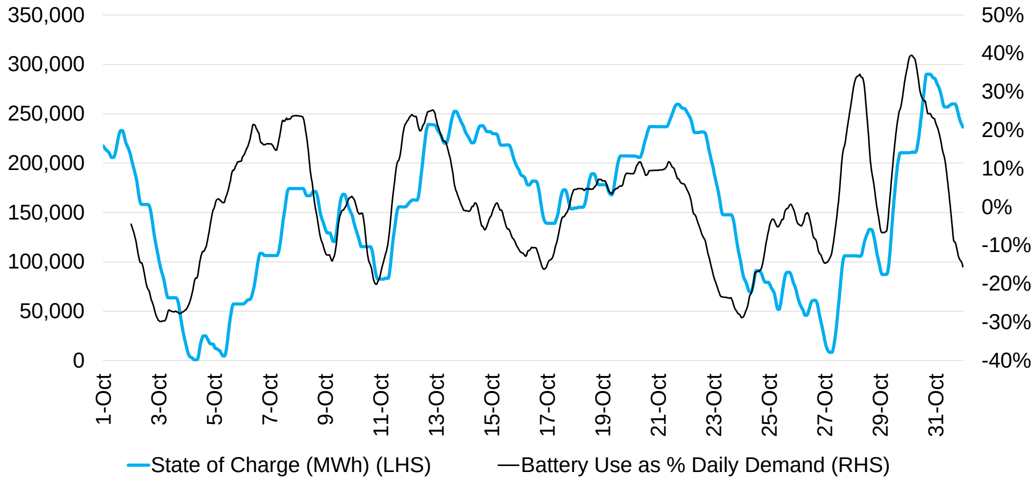


Figure 80   FAM Monthly Results – 70% VRE October – Storage Levels over Month



Monthly Run 3

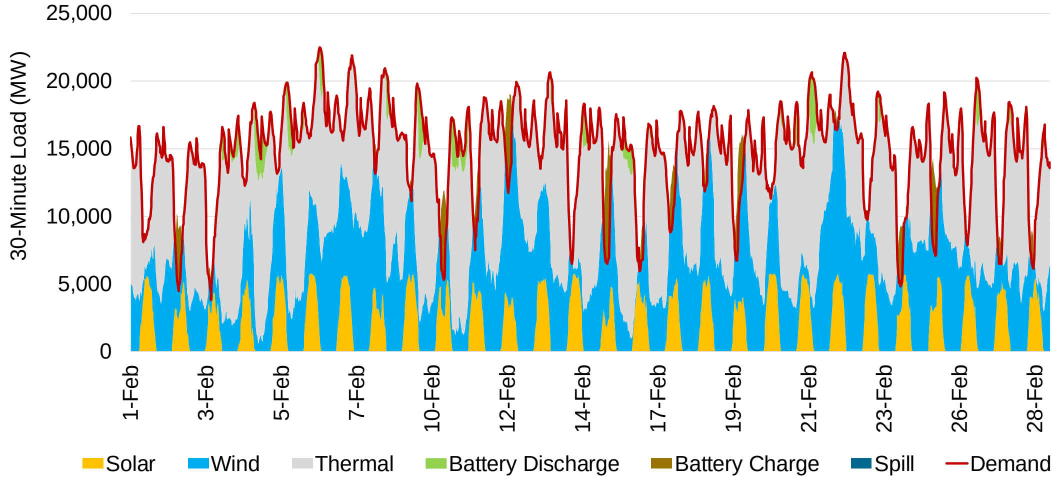
Monthly Run 3 is VRE Energy equal 50% of Demand Energy.

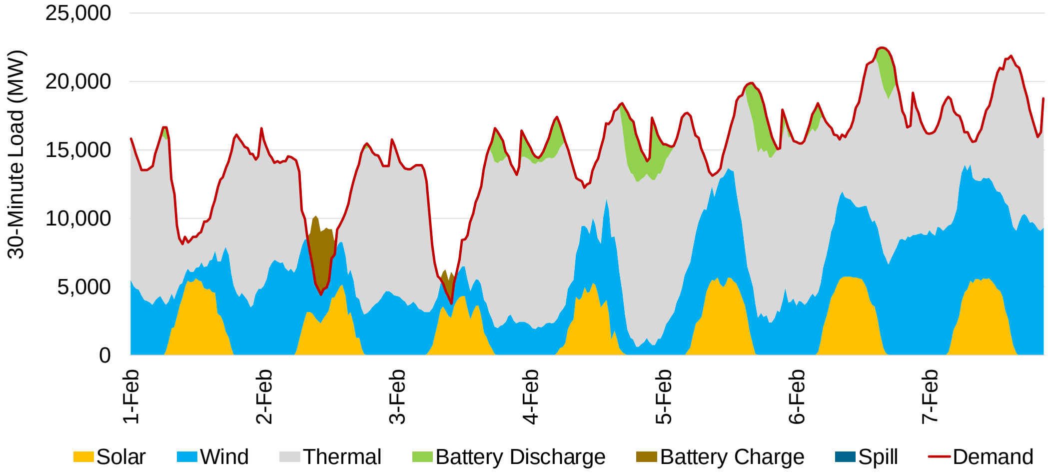
Table 26   FAM Monthly Results Summary – 50% VRE February

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	12,050	5,013	61.9%		
Solar	6,300	1,284	30.3%		
Wind	18,900	3,734	29.4%		
Storage (MW)	14,617	205	0.2%	100,000	7
Totals (Net of Storage)	**37,250**	**10,031**	**3.1%**		
Spill/ Curtailment		0	0.0%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	1,764			
Non-VRE Dispatchable (MW)	26,667	VRE	2%	49%
Maximum Demand (MW)	28,431	Thermal (Gas)	77%	49%
Dispatchable % MD	100%	Storage	21%	2%
% Renewables	**50.0%**	**Totals**	**100%**	**100%**

Figure 81 FAM Monthly Results Charts – 50% VRE February





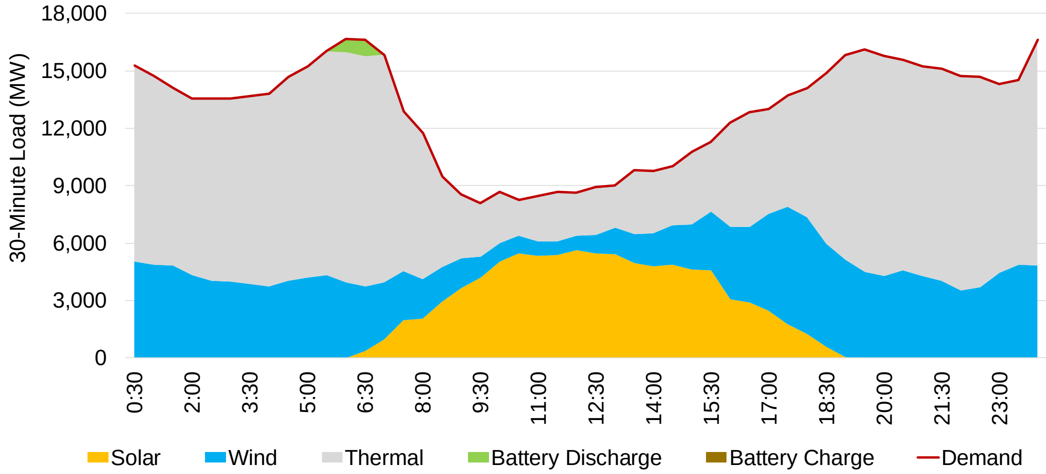


Figure 82 FAM Monthly Results – 50% VRE February – Storage Levels over Month

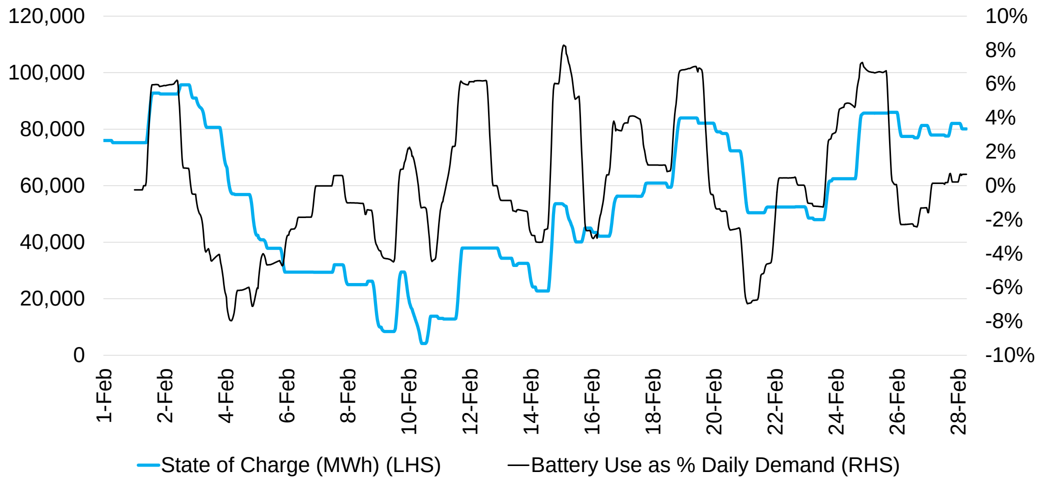
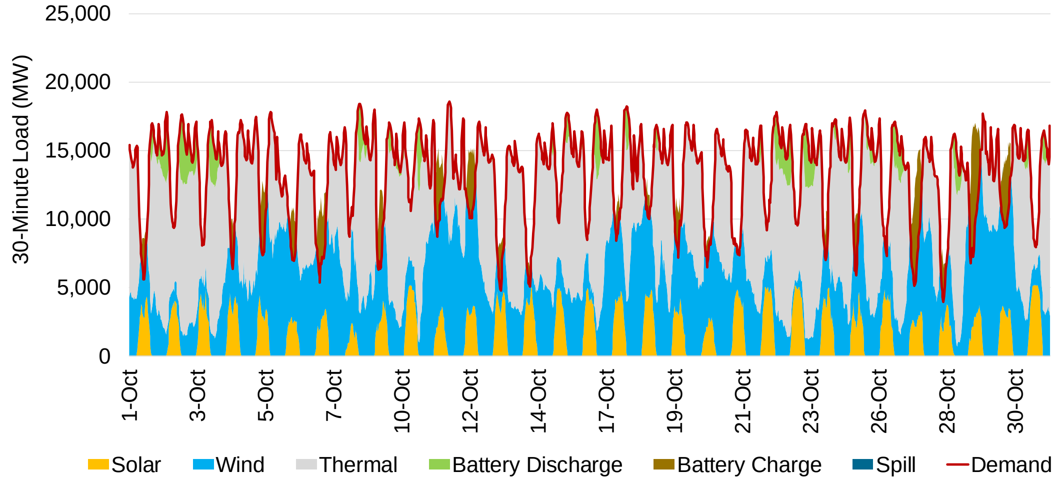


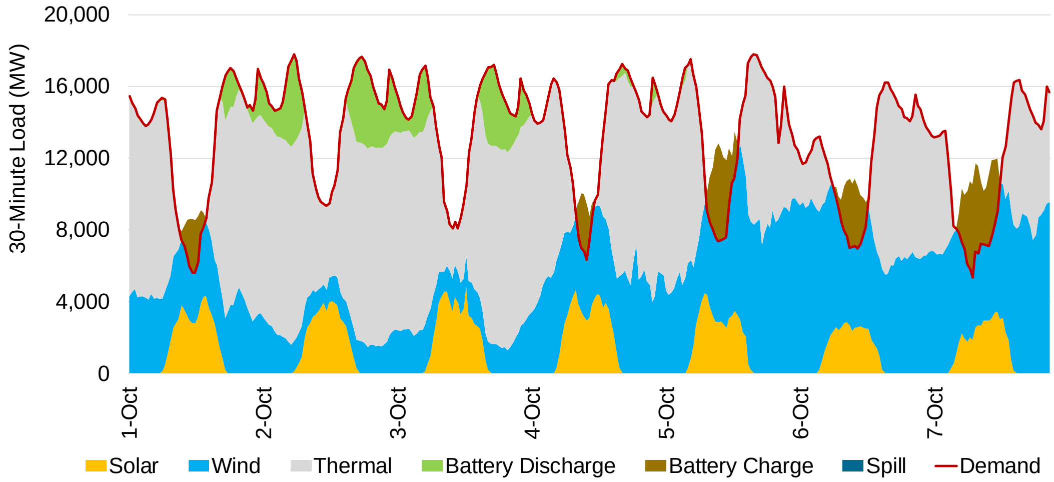
Table 27 FAM Monthly Results Summary – 50% VRE October

	Capacity (MW)	Generation (GWh)	CF%	Storage (MWh)	Hours of Storage
Thermal (Gas)	11,050	4,988	67.2%		
Solar	5,455	1,167	31.8%		
Wind	16,365	3,820	34.7%		
Storage (MW)	15,854	345	0.2%	135,000	9
Totals (Net of Storage)	**32,870**	**9,975**	**3.5%**		
Spill/ Curtailment	-	0	0.0%		

			% Last Plant Loaded	% Total Gen (GWh)
7% of VRE Capacity (MW)	1,527			
Non-VRE Dispatchable (MW)	26,904	VRE	5%	48%
Maximum Demand (MW)	28,431	Thermal (Gas)	66%	48%
Dispatchable % MD	100%	Storage	29%	3%
% Renewables	**50.0%**	**Totals**	**100%**	**100%**

Figure 83   FAM Monthly Results Charts – 50% VRE October





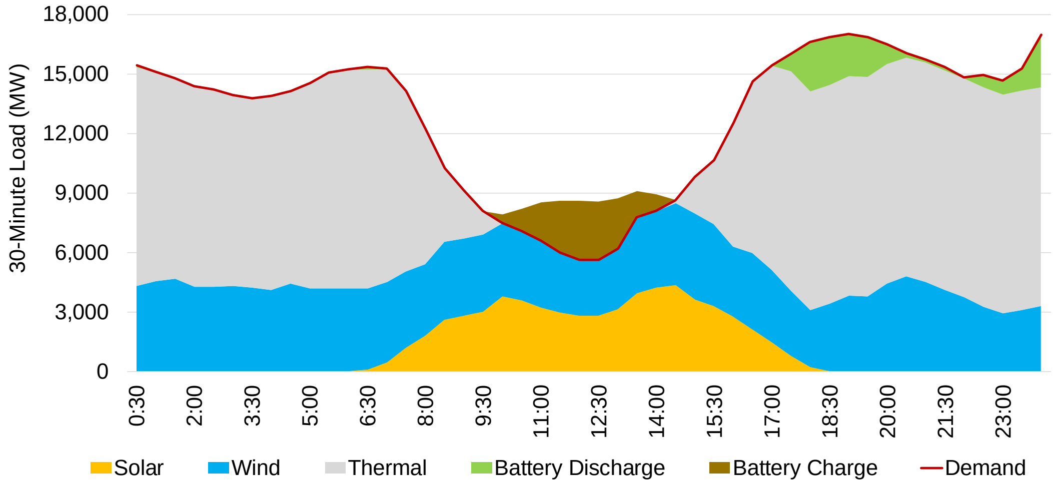
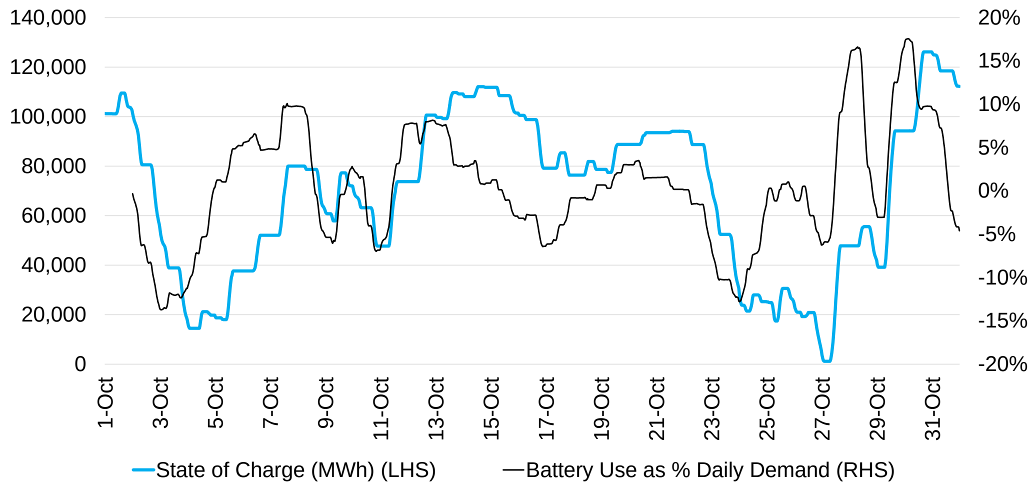


Figure 84 FAM Monthly Results – 50% VRE October – Storage Levels over Month



A7.3 Observations

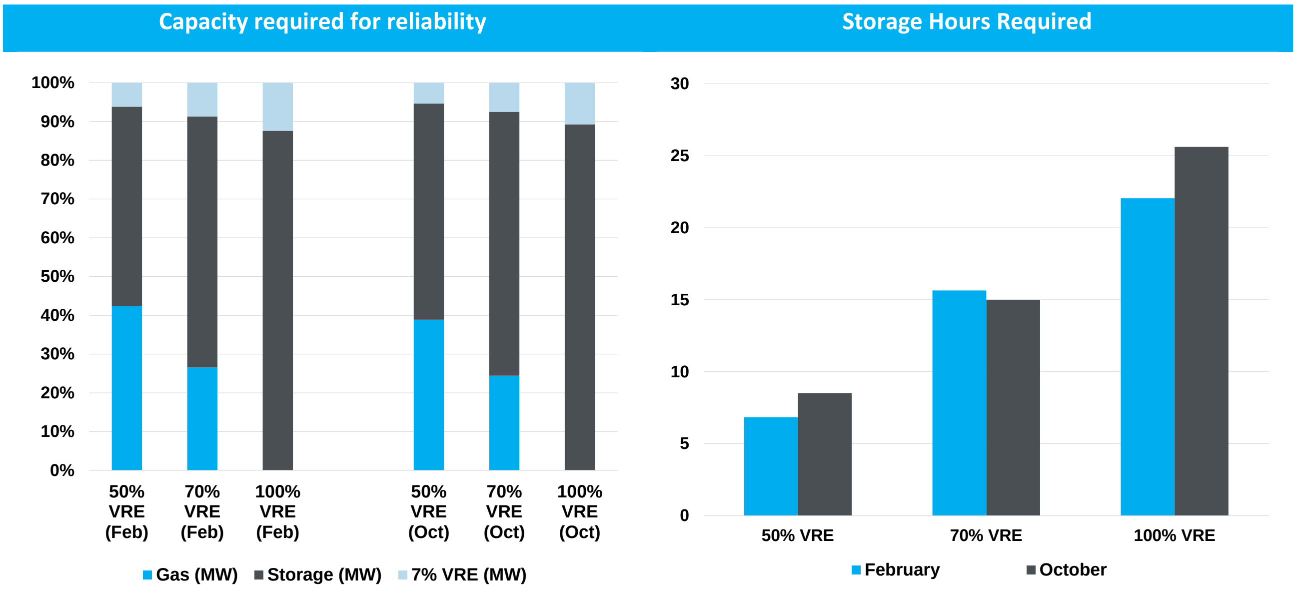
The following table presents the results of modelling over a month, which removes the interseason variability issues. The results show substantially less, but still unrealistic requirements for storage.

Table 28 Summary of Monthly Modelling Results – Firming Required

	Max Demand	Reserve (MW)	=	7% VRE (MW)	Gas (MW)	Storage (MW)	MWh	Hours
50% VRE (Feb)	26,451	1,980	=	1,764	12,050	14,617	100,000	7
70% VRE (Feb)	26,451	1,980	=	2,471	7,550	18,410	288,000	16
100% VRE (Feb)	26,451	1,980	=	3,528	0	24,903	549,000	22
50% VRE (Oct)	26,451	1,980	=	1,527	11,050	15,854	135,000	9
70% VRE (Oct)	26,451	1,980	=	2,142	6,945	19,344	290,000	15
100% VRE (Oct)	26,451	1,980	=	3,055	0	25,376	650,000	26

	Max Demand	Reserve (MW)	=	7% VRE (MW)	Gas (MW)	Storage (MW)	GWh
2015 Trace							
50% VRE	93%	7%	=	6%	42%	51%	1.0%
70% VRE	93%	7%	=	9%	27%	65%	2.9%
100% VRE	93%	7%	=	12%	0%	88%	5.5%
2016 Trace							
50% VRE	93%	7%	=	5%	39%	56%	1.4%
70% VRE	93%	7%	=	8%	24%	68%	2.9%
100% VRE	93%	7%	=	11%	0%	89%	6.5%

Figure 85 Minimum Storage to Capture VRE Variability within a month



Source: Marsden Jacob

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.

Appendix 8 Review of South Australia

The "South Australian situation" provides a window into the NEM as the level of VRE increases to high levels.

A review of SA was undertaken for the purpose of observing the issues that have emerged and as a means of comparing to the outcomes of the modelling undertaken for when VRE levels become high.

A8.1 South Australia is a High VRE Market

South Australia (SA) currently generates a high percentage of its energy (GWh) from wind, however, it does not yet have significant battery storage. Currently, SA only has the 100MW/129MWh Hornsdale Power Reserve (since late 2017) and ElectraNet's 30MW/8MWh Dalrymple Battery Project (ESCRI) has been commissioned very recently.

Given our modelling and findings on the likely requirements for energy storage under high VRE scenarios, SA can act as a useful case study to analyse what is currently happening in the NEM with regard to high VRE regions. Importantly, this appendix seeks to answer the question: does the SA situation support our analysis on storage requirements as the NEM increasingly transitions to high levels of VRE?

The following table shows installed capacity and generation in SA over the 2017 calendar year.

Table 29 Actual Capacity (MW) and Generation (GWh) for South Australia – CY2017

	Installed Capacity (MW)*	Annual Generation (CY2017)	Capacity Factor %
CCGT/Steam	1,938		
OCGT	915		
Reciprocating Engine	128		
Total Gas/Thermal	**2,981**	**7,253**	**27.8%**
Wind	1,225	3,936	36.7%
Storage (Battery)	8	1	1.7%
Totals	**4,214**	**11,190**	**30.3%**

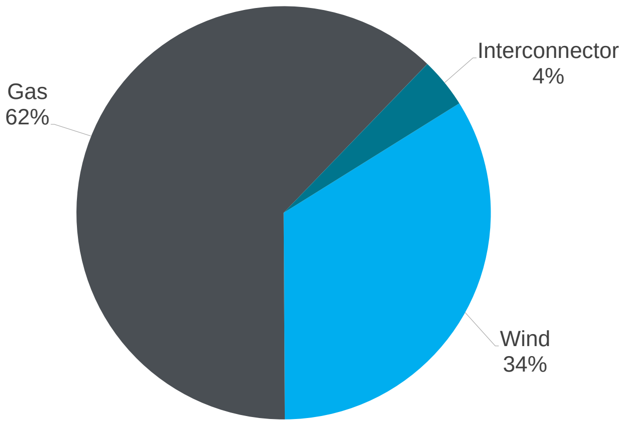
* Average over the year (i.e. the Hornsdale Battery was only commissioned at the end of the year

A8.2 Key Findings:

- SA does not currently have as much battery storage (MW or MWh) as our modelling would suggest it needs based on its level of VRE penetration. The primary reason SA is able to 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 1,200GWh in 2017. If this was 4.2 hour storage similar to the Tesla's batteries used as Hornsdale, this would have required over 285,700MW of installed capacity – versus the mere 100MW of Hornsdale.
- For calendar year 2017 SA generated 34% of total GWh from wind (refer Figure 86). 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 (i.e. exported 10% and imported 14%).

- Maximum Operational Demand in SA was 3,046MW over the year, and it had (still has) about 3,000MW 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 (but with reduced capacity factors) then the storage requirement does come down.

Figure 86 South Australian Share of Energy Generation (GWh) – CY2017

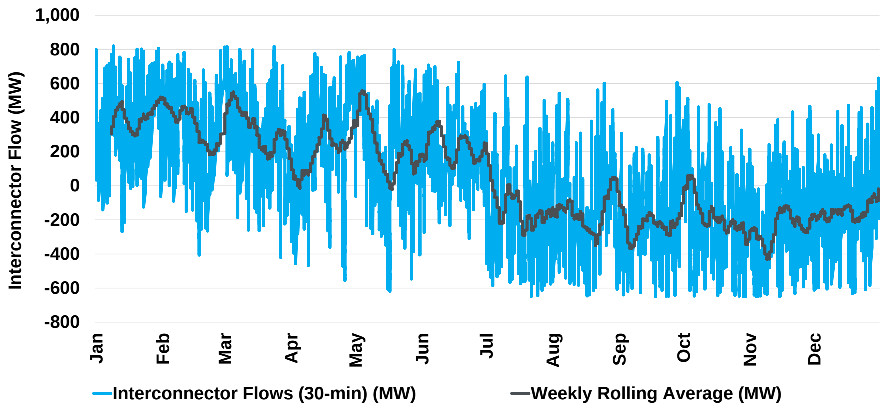


Source: AEMO/ NEOexpress

A8.3 Modelling Results

The following figure shows 30-minute interconnector flows (Heywood and MurrayLink) between SA and Victoria during 2017. Included is a weekly rolling average to smooth the data and highlight the trend.

Figure 87 South Australian Interconnector Flows – CY2017

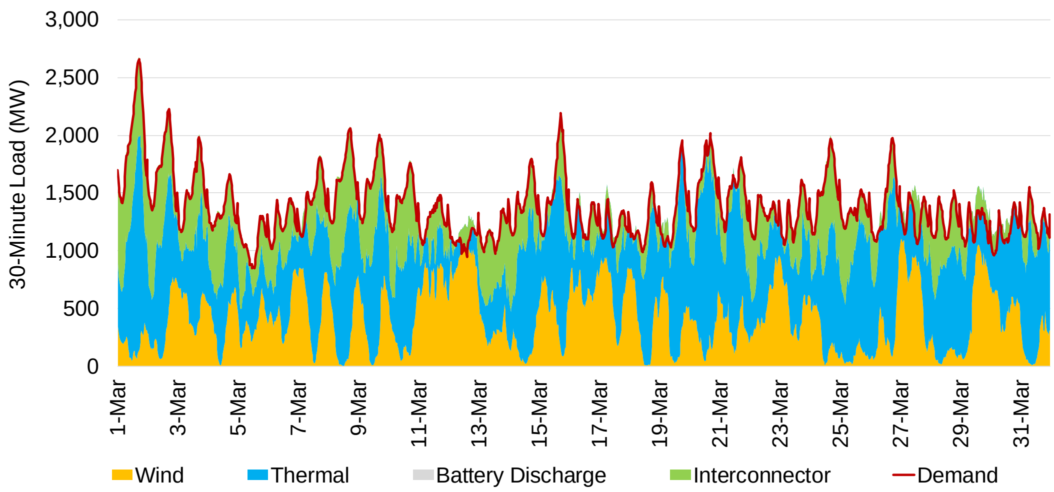


Source: Marsden Jacob

Over the year, 1,594 GWh was imported over the interconnectors from Victoria, and 1,139 GWh was exported.

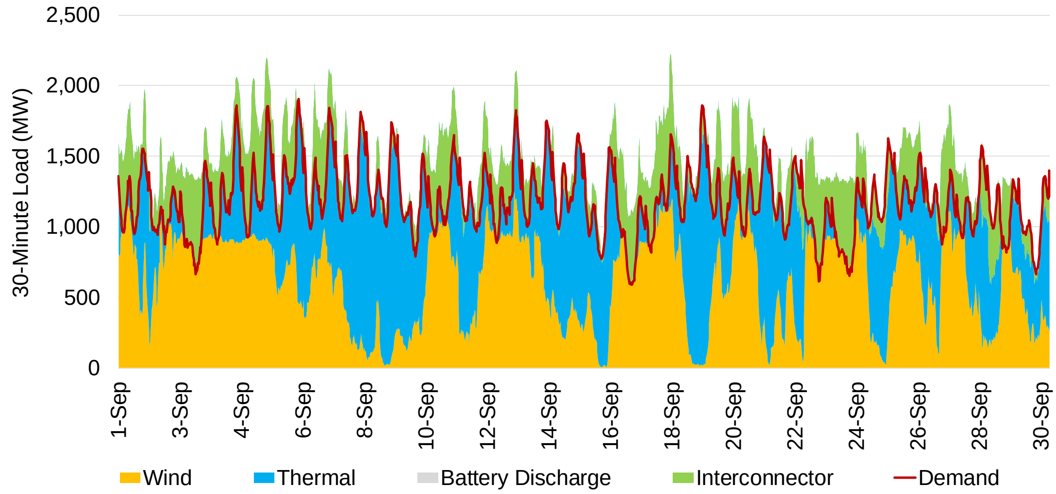
We modelled the full-year (2017) at 30-minute intervals to look at the generation type used for each period. We charted a month for each quarter (March, June, September and December) to look at seasonal variation. The following figures show the months of March and September 2017.

Figure 88 Generation Technology Filling Each 30-Minute Demand Interval – March



March saw significant net imports (the green areas under the red demand curve) from Victoria. Despite good wind generation, a greater proportion of SA's energy needs were met from gas generation and imports via the interconnectors.

Figure 89 Generation Technology Filling Each 30-Minute Demand Interval – September



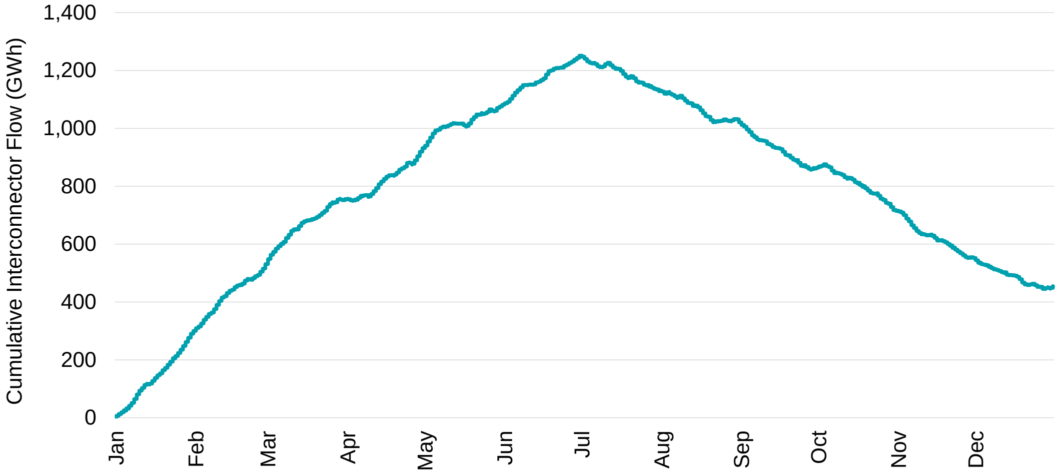
September experienced stronger wind generation and so the State had a lesser reliance on gas generation. During periods of particularly strong wind generation there was significant energy exported to Victoria. The green areas at the top of the figure (above demand) show the interconnector exports.

Through 2017, SA drew heavily on imports from Victoria over the first half of the year (similar to discharging battery storage), and then exported back about 2/3 of this in the second half of the year.

This overall trend in SA was similar to the trend we found in our other analysis on the more general variability of VRE production. Solar generation is clearly weaker in the winter months, but wind also appears to have a seasonally weaker period in the first half of the year, and a stronger second-half, the third quarter particularly.

The trend in annual interconnector flows in SA over 2017 is very apparent in the following figure, which looks at the cumulative interconnector flows over the year.

Figure 90 South Australian Cumulative Use of the Interconnectors



This is analogous to a large battery. The 'battery' discharged about 1,200GWh of energy in the first half and then recharged by about 800GWh in the second half. As highlighted above, it is largely the interconnectors, therefore, that has enabled SA to avoid significant physical battery capacity at this stage.