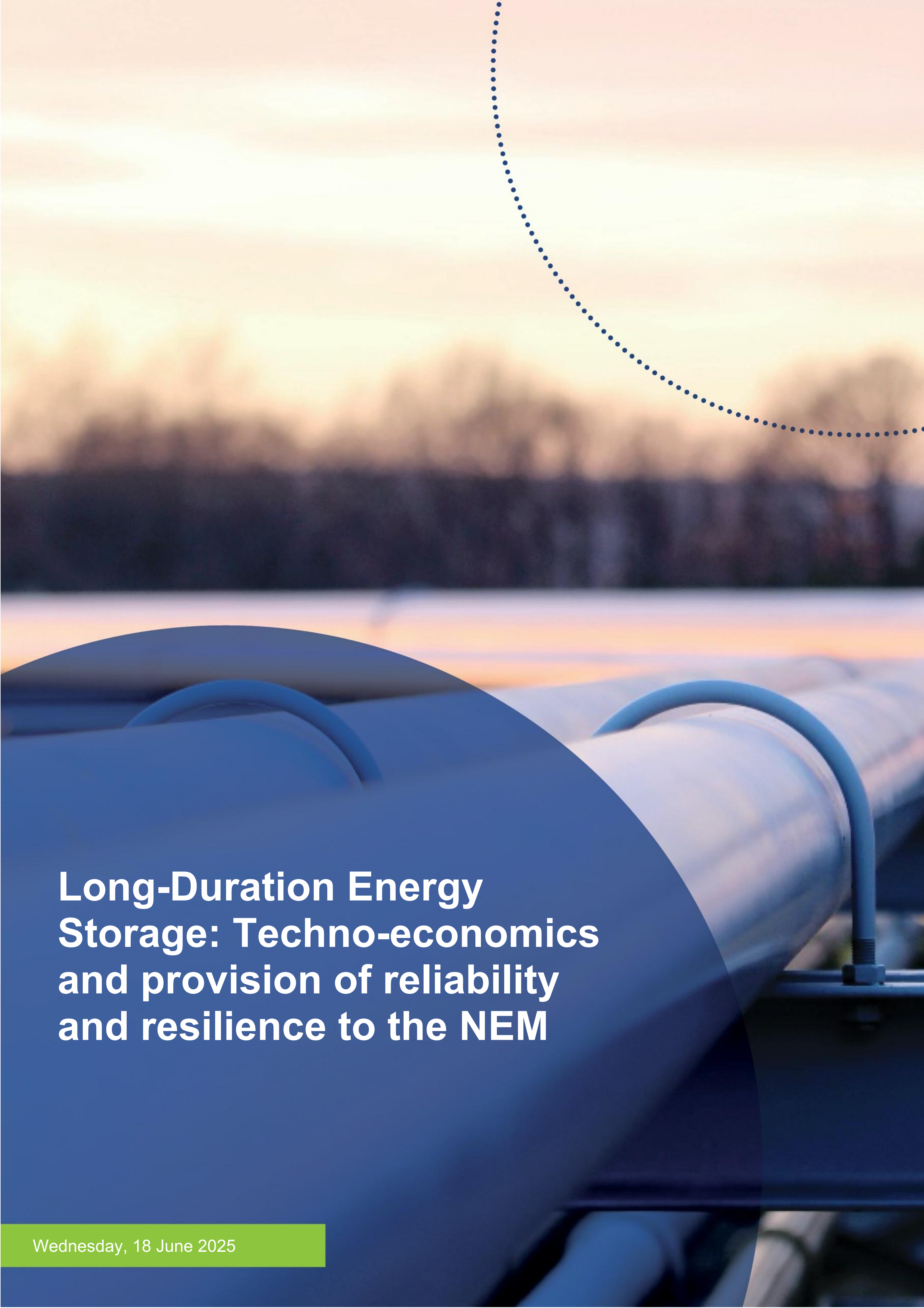

Long-Duration Energy Storage: Techno-economics and provision of reliability and resilience to the NEM

Wednesday, 18 June 2025

Project number: RP1.1-07

Integrated electricity-hydrogen: Future system and market interactions under different storage considerations

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Cooperative Research Centres Program

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

Important Disclaimer

Acknowledgement

This work is funded by the Future Fuels CRC, supported through the Australian Governments' Cooperative Research Centres Program. The cash and in-kind support from the industry participants is gratefully acknowledged.

Project Information	
Project number	RP1.1-07
Project title	Integrated electricity-hydrogen: Future system and market interactions under different storage considerations
Research Program	Research Program 1
Milestone Report Number	Deliverable 5
Description	Methodology and main results
Research Provider	The University of Melbourne
Project Team	Dr Sleiman Mhanna, The University of Melbourne Prof Pierluigi Mancarella, The University of Melbourne
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Project start/completion date	1 July 2023 to 18 June 2025
IP Access	**Public**
Approved by	Dr Dennis Van Puyvelde (ENA)
Date of approval	18 June 2025

Executive Summary

Long-duration energy storage (LDES) systems, such as pumped-hydro energy storage (PHES) and potentially hydrogen energy storage systems (HESSs), are essential for managing and maintaining reliability and resilience as the National Electricity Market (NEM) transitions to a renewables-dominated electricity system.

A new comprehensive techno-economic framework, founded on an optimisation-based market dispatch model, has been developed by the authors to provide valuable insights into the techno-economics of these LDES technologies and their contribution to reliability and resilience. The framework is informed by a set of well-defined engineering and economic assumptions derived from reputable and publicly accessible sources. A range of scenarios is modelled to evaluate the merits of different LDES options, including the anticipated Snowy 2.0 and Borumba PHES projects; a scenario with HESSs located in Victoria and southern Queensland; and combinations of these, as shown in Figure ES1.

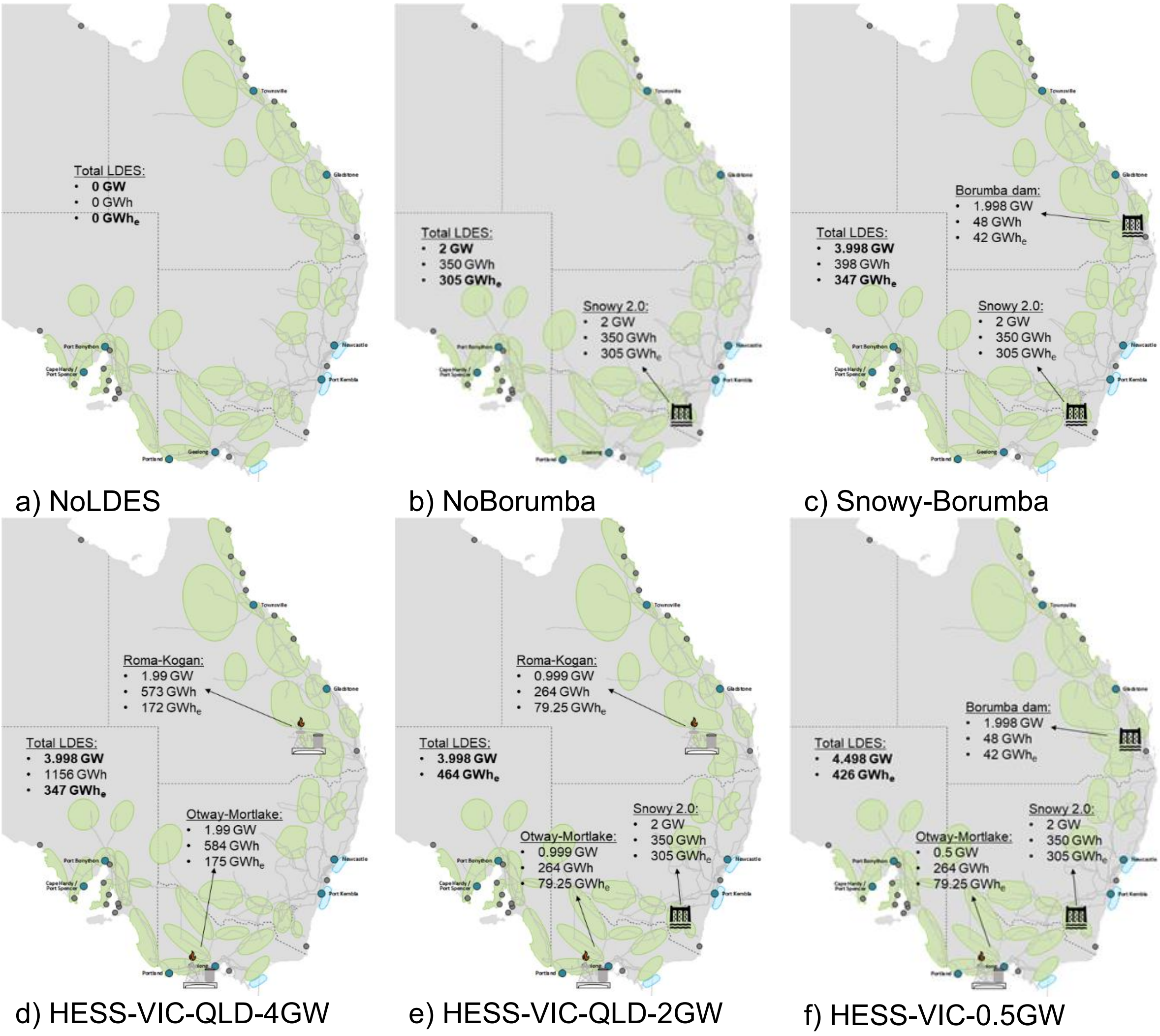

Figure ES1: Illustration of the proposed six LDES scenarios to assess the merits of Snowy 2.0, Borumba, and two HESSs in Victoria and southern Queensland.

The overarching aim of this work is to objectively assess the techno-economic merits of LDES technologies such as HESSs and PHES, depending on a variety of factors, including:

- location in the NEM,

- market conditions,
- weather conditions, and
- availability of suitable storage sites—be they depleted gas reservoirs, as in the case of HESSs, or rivers and dams in the case of PHES.

Although only the design of HESSs is optimised—along with the operation of the NEM by adjusting assumptions on Snowy 2.0, Borumba, and the proposed HESS designs—other assumptions, which are taken directly from the Step Change scenario in AEMO's 2024 ISP but could still influence outcomes, include (but are not limited to):

- network development (transmission expansion),
- forecast regional and sub-regional demand,
- uptake of VRE,
- uptake of utility-scale and distributed battery energy storage systems (BESSs),
- uptake of electric vehicles (EVs),
- degree of coordination of consumer energy resources (CERs),
- domestic and export hydrogen demand, and
- technology cost curves.

While the insights are not intended to serve as commercial recommendations on LDES options, the key findings include:

Suitable geology

- Australia has suitable underground geological formations—particularly *depleted gas reservoirs*—located near the high-voltage (HV) transmission network for large-scale HESS deployment.

Capex

- Large-scale HESSs may have a CapEx up to 30% lower than that of a PHES with equivalent power and energy storage capacities.

LCOE and LROE

- Compared to PHES, which has a capacity factor (CF) of approximately 38%, current HESS technology is expected to achieve a CF of around 10%, resulting in a levelised cost of energy (LCOE) up to three times higher than that of a PHES with equivalent power and energy storage capacities.
- The same low CF for HESSs that drives their high LCOE also results in a correspondingly high *levelised revenue of energy* (LROE), significantly strengthening the business case.
- Under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP, the LROE analysis in this report indicates that HESSs in strategic locations such as Victoria and Southern Queensland may be able recover their costs within the first 20 years of operation exclusively through participation in the wholesale NEM.
- The expected increase in price volatility as the NEM becomes more renewables-dominated presents greater opportunities for HESSs to maximise their revenue by capitalising on high prices that may occur when residual demand is high or during reliability events.

Reliability

- The projected generation, storage, and transmission capacities in AEMO's 2024 ISP may not be sufficient to maintain reliability in the NEM through to 2050.

- The 2 GW Borumba facility with 24 hours of storage may be insufficient to maintain reliability in Queensland; at least 86 hours of storage may be required instead.
- In a scenario where both Snowy 2.0 and Borumba are present, installing a HESS in Victoria with 500 MW and 158 hours of net storage may significantly enhance the reliability of the NEM, particularly in the southern states of Victoria, South Australia, and Tasmania.
- Together, the Otway-Mortlake HESS in Victoria and the Roma-Kogan HESS in southern Queensland, in the HESS-VIC-QLD-4GW scenario, are capable of maintaining reliability in New South Wales until 2043, under a counterfactual case in which Snowy 2.0 is delayed by five years.

Resilience

- In the process of selecting variable renewable energy (VRE) drought days for assessment, it is important to consider both residual demand *and* VRE CFs. Focusing solely on the latter may overlook instances with potential reliability risks.
- Due to their strategic locations, the Otway-Mortlake HESS in Victoria and the Roma-Kogan HESS in Southern Queensland (the HESS-VIC-QLD-4GW scenario) could significantly enhance resilience by maintaining reliability during extended VRE droughts.
- While the HESS-VIC-QLD-4GW scenario improves resilience, unplanned generator or interconnector outages beyond those modelled could still pose reliability risks. This is particularly critical in winter when residual demand is high, and the power system operates with low reserve margins. As a result, maintenance schedules for dispatchable generators must be carefully planned and coordinated during winter to mitigate reliability concerns arising from VRE droughts. These concerns are further compounded by the impact of weather forecast accuracy on the ability to anticipate unfavourable conditions, which affects the accumulation of sufficient energy in LDES to maintain resilience during periods of severe VRE drought.
- If a severe VRE drought event similar to that of May 2024 occurs during periods of high residual demand—such as in winter—the NEM, under both the HESS-VIC-QLD-4GW scenario and the projected generation, storage, and transmission expansion in AEMO’s 2024 ISP, may not be resilient. This suggests that additional firming and backup generation should be planned—particularly in Victoria and Queensland—beyond what is projected in AEMO’s 2024 ISP and in this report, to hedge against events like the one in May 2024.
- In resilience studies involving prolonged VRE droughts, optimisation-based market dispatch models with extended time horizons (spanning months rather than days or weeks) not only provide the necessary temporal granularity (e.g., 30 minutes) and foresight (e.g., 20 years) to rigorously assess such events, but they eliminate the need for strong assumptions about the state of energy (SoE) at the onset of such events. This helps avoid shortsighted assumptions that may compromise the accuracy of resilience assessments.

VRE curtailment

- The modelled HESSs in this report present opportunities to accommodate more VRE in the NEM that would otherwise be curtailed. This is due, among other factors, to the fact that HESSs typically have a capacity factor (CF) of up to 10.5%, while PHES options generally have a CF of up to 38%.
- An LDES system in Victoria can access VRE from *four* subregions: Central South Australia, Southeast South Australia, Tasmania, and South New South Wales. In contrast, an LDES system in South New South Wales has access to VRE from *three* subregions: Victoria, Central New South Wales, and Central South Australia.

- Higher LDES power and energy storage capacities in VIC, SA, and TAS, beyond what is projected in AEMO's 2024 ISP, contribute to a higher accommodation of VRE, in addition to a higher contribution to reliability.

Operational costs

- A 2 GW LDES in New South Wales can displace more generation from gas-fired generation (GFG) and coal-fired generation (CFG) compared to other states, resulting in a notable reduction in overall operational costs and emissions across the NEM. According to AEMO's 2024 ISP, 33% of the 14.44 GW of GFG across the NEM in 2035–36 is located in New South Wales. At the same time, New South Wales is forecast to still have around 1.42 GW of CFG in 2035–36—about 2.53% of the total dispatchable capacity.

Price volatility

- In general, LDES helps reduce price volatility by lowering the frequency and magnitude of both extremely low and extremely high prices.
- LDES in strategic locations like Victoria and southern Queensland can greatly reduce price volatility by enhancing reliability, leading to a decreased reliance on expensive demand-side programs (DSP) to mitigate unserved energy (USE).

Market dispatch modelling

- Long-horizon, optimisation-based market dispatch models can play an instrumental role in scheduling energy reserves in LDES systems over weeks and months, helping to hedge against forecasting errors, imperfect foresight, unplanned outages, and gas supply chain risks.
- While the market dispatch analysis in this report focuses on the wholesale energy market, HESSs can also offer regulation and contingency services in the frequency control ancillary services (FCAS) markets by leveraging the flexibility of proton-exchange membrane (PEM) electrolysers and hydrogen turbines, potentially increasing revenue opportunities even further.

In summary, this work stress-tests AEMO's 2024 ISP using comparable zero-emissions LDES technology case studies and advanced modelling techniques that not only replicate the 2024 ISP operational modelling but also introduce the additional granularity and foresight needed to evaluate both current NEM benefits and the enhanced reliability and resilience provided by LDES. This work also demonstrates that both HESSs and PHES, when deployed in strategic locations, have distinct merits and can coexist synergistically—particularly when assessed across a broad set of metrics, including reliability and resilience.

Overall, this research underscores the need for advanced optimisation-based market dispatch modelling frameworks that can adequately evaluate and quantify the potential benefits, as well as the challenges, risks, and opportunities that different types of LDES systems offer to the NEM or other electricity networks and markets. In general, such a framework can assist system planners in pre-emptively minimising the risk of investing in a suboptimal power system architecture today or being locked out of a more cost-effective one in the future. This is especially true since PHES projects are at risk of cost blowouts and delays, as such projects are generally specific to the geography in which they are envisaged to be built, along with many other factors, including availability of existing dams, distance between existing and/or new dams, terrain characteristic, access to nearby rivers, and proximity to existing electricity infrastructure, to name a few. This work also demonstrated that a system with higher energy efficiency may not necessarily lead to a more reliable, more resilient, and more cost-effective system.

Future work involves extending the developed long-horizon optimisation-based framework to *jointly optimise* the development of generation, transmission, and storage, alongside gas infrastructure development—resulting in a truly integrated model that simultaneously incorporates all three energy vectors: electricity, natural gas, and hydrogen.

Policy implications

The above findings have the potential to initiate new evidence-based policy discussions, from which specific market and policy settings may evolve to facilitate the deployment of alternative LDES technologies—such as HESSs—particularly when:

a) The maximum installed capacity of GFG is constrained by CO_2 emissions and PHES is limited to specific regions in the NEM;
b) Cost recovery is not limited to actual use (i.e., the value of reliability and resilience these technologies provide to the NEM), or extends beyond their participation in the NEM (i.e., using hydrogen directly as feedstock to decarbonise hard-to-abate industries such as steel, cement, and aluminium production); and
c) Energy system planning, initiated by a review of the ISP by the Energy and Climate Ministerial Council (ECMC), is now undergoing its most significant transformation since its inception in 2017. As a result, AEMO is establishing new processes to evaluate a range of gas infrastructure options to support planning for a resilient, cost-efficient, and decarbonised grid.

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Summary for policy makers and industry

Increasing uptake in variable renewable energy (VRE) will require a commensurate acceleration in the adoption of various forms of energy storage systems to support their variability and improve system reliability. Clean fuels such as green hydrogen (H_2) will also play a central role in the context of energy system decarbonisation, but, as of today, it is unclear to what extent they can competitively provide security, reliability, and resilience to the NEM in Australia.

An optimisation-based modelling framework is developed in this report for evaluating the technical and economic merits of hydrogen energy storage systems (HESS) in providing long-duration energy storage (LDES) to the NEM under the reliability standards stipulated by the Australian Energy Market Operator (AEMO) and stringent resilience requirements against prolonged periods of VRE droughts. This framework also paved the way for unprecedented insights into how the levelised cost of energy (LCOE) for HESS—enabled by underground hydrogen storage (UHS) systems in key locations in Australia—compares to that of PHES, such as Snowy 2.0 and Borumba. The report also examines the business case of the considered HESS and PHES by computing their estimated maximum levelised revenue of energy (LROE) that could be achieved from participating in the wholesale NEM over a 20-year period.

Research into HESS is well underway; however, most existing literature on the role of hydrogen as a storage medium focuses on siloed applications—such as reservoir simulations, the design of UHS facilities, generic build cost and/or LCOE analyses that consider HESS in isolation—or is limited in scope to molecule-based energy vectors. Understanding the role of HESS from a whole-system perspective requires frameworks for *integrated electricity and hydrogen systems* (IEHS) that can capture the synergies between the two energy vectors, and how they translate to improved energy security, reliability, resilience against extreme weather events, and system flexibility in a decarbonised energy system.

While many studies examine HESS in IEHS from the perspective of reliability and resilience, the IEHS modelling framework developed in this project is characterised by many key distinguishing features, including:

- A market dispatch modelling framework aimed at mimicking the operation and settlement of the NEM, including typical offering/bidding behaviour of all current and future market participants,
- A methodology—based on the revenue duration curve and rooted in concepts from game theory—for computing revenue opportunities for any market participant,
- A long-horizon outlook that maintains relatively high temporal and spatial resolution, and
- Consideration of the essential physics of electricity flow, as well as hydrogen flow, compression, and storage, in a computationally tractable way.

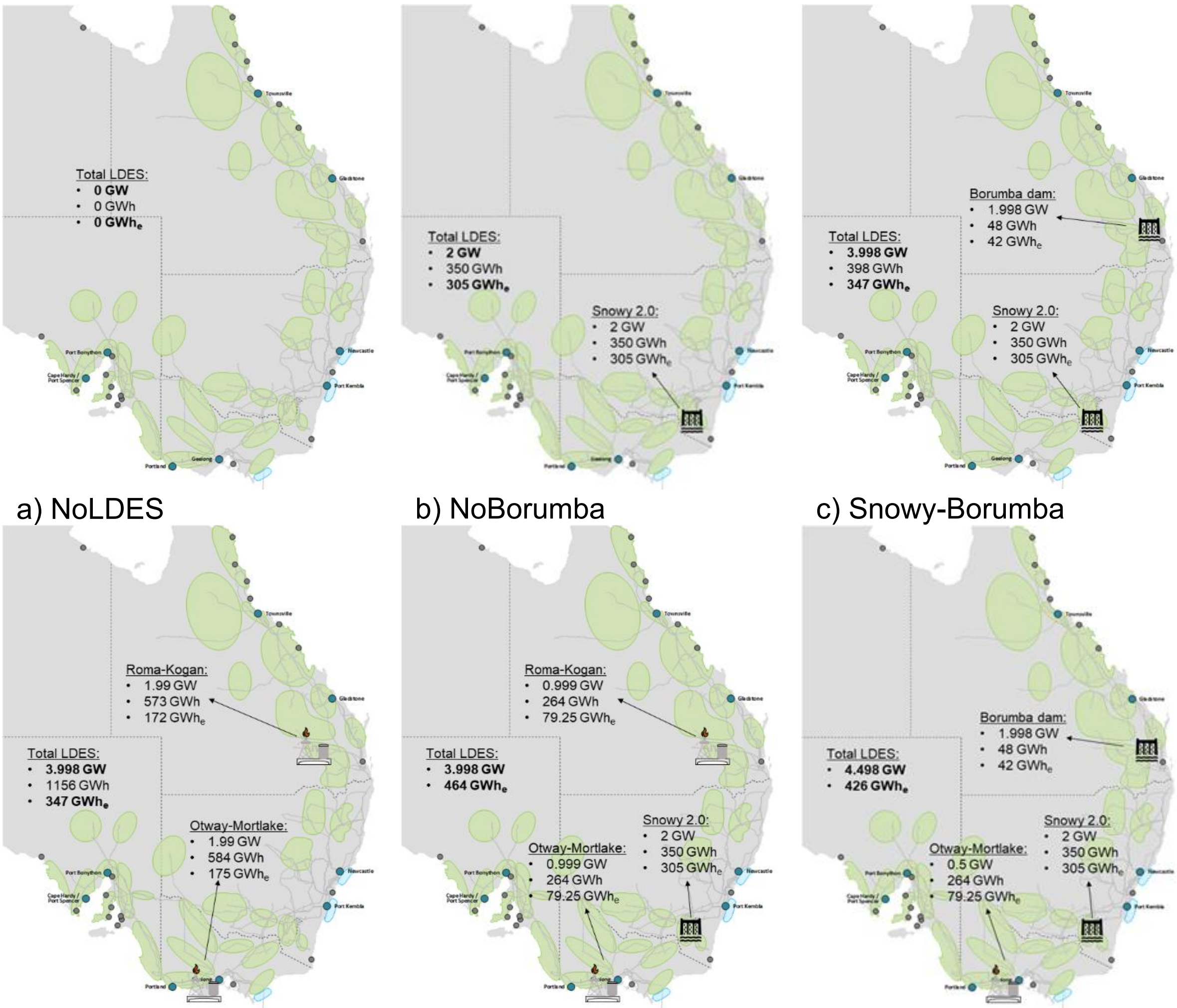
The core objectives and key outcomes of this project are summarised as follows:

A. **Identifying suitable reservoir locations** for UHS in Australia.

Hydrogen storage technologies can be broadly classified into three main categories: compression, liquefaction, and chemical. Compression storage is deemed as the cheapest option and the safest for storing large volumes of gaseous hydrogen due to its lower likelihood of gas leaks. A review of existing studies revealed that depleted gas reservoirs (DGRs) in key locations in Australia have suitable geological characteristics (e.g., porosity and permeability) for storing large volumes of pressurised hydrogen gas. This project focuses on the DGR in Otway in VIC and Roma in QLD in particular for UHS because of their relative proximity to high-voltage (HV) transmission lines, which makes them easier to connect to the NEM compared to other more remote DGR such as the ones in Moomba in SA and Ballera in QLD.

B. **Designing scenarios** for assessing the techno-economic merits of PHES and HESS at strategic locations in the NEM.

Six LDES scenarios, illustrated in Figure 1, are proposed in this project to evaluate the reliability and resilience of the NEM under different LDES options. NoLDES is a counterfactual scenario in which the NEM has no LDES systems, and NoBorumba is a hypothetical scenario in which only Snowy 2.0 will be present and Borumba PHES does not exist. Snowy-Borumba is a scenario in which both Snowy 2.0, located in SNSW, and Borumba, located in SQ, are considered for LDES. This scenario, which uses the same input and output assumptions in AEMO's 2024 Integrated System Plan (ISP), assumes that Snowy 2.0 and Borumba will be operational by 2028 and 2031, respectively.



a) NoLDES b) NoBorumba c) Snowy-Borumba

d) HESS-VIC-QLD-4GW e) HESS-VIC-QLD-2GW f) HESS-VIC-0.5GW

Figure 1: Illustration of the proposed six LDES scenarios to assess the merits of Snowy 2.0, Borumba, and two HESSs in VIC and SQ.

HESS-VIC-QLD-4GW is a hypothetical scenario in which Snowy 2.0 and Borumba PHES are replaced with two HESS, one in VIC (Otway-Mortlake) and another in SQ (Roma-Kogan), with combined power and energy storage capacities commensurate to that of Snowy 2.0 and Borumba combined. HESS-VIC-QLD-2GW is a hypothetical scenario in which *only* Borumba PHES is replaced with two HESS—one in VIC and one in SQ—with combined power and energy storage capacities commensurate to that of Borumba. The HESS-VIC-0.5GW is a hypothetical scenario where both Snowy 2.0 in SNSW and Borumba in SQ exist, and a HESS with 500 MW and 158 hours of storage is commissioned in VIC in 2031.

In addition to assessing reliability and resilience, the developed optimisation-based market dispatch model is used to derive the LCOE for each option in each scenario. As it is extremely challenging to model offering/bidding behaviour with high certainty, the developed optimisation-based market dispatch model is not used directly to compute the LROE for each option. Instead, three LROE basis scenarios are systematically designed to estimate annual revenue opportunities from the *revenue duration curve* (RDC), derived from the price duration curve (PDC). The LCOE and LROE basis scenarios are summarised in Table 1.

As different long-term market offering and bidding behaviours can influence the market clearing price, the LCOE and LROE of the considered LDES are assessed under four sensitivities, each based on different assumptions about the offer prices of renewable generators and the offer and bid prices of BESS.

Table 1: Basis scenarios for deriving the LCOE and LROE.

LDES option	LCOE basis scenario	LROE basis scenario
Snowy 2.0 (2000 MW)	Snowy-Borumba	NoLDES
Borumba (1998 MW)	Snowy-Borumba	
Otway-Mortlake HESS (1999 MW)	HESS-VIC-QLD-4GW	
Roma-Kogan HESS (1999 MW)	HESS-VIC-QLD-4GW	
Otway-Mortlake HESS (999 MW)	HESS-VIC-QLD-2GW	NoBorumba
Roma-Kogan HESS (999 MW)	HESS-VIC-QLD-2GW	
Otway-Mortlake HESS (500 MW)	HESS-VIC-QLD-0.5GW	Snowy-Borumba

C. **Developing a methodology for designing large-scale HESS** in VIC and SQ.

A review of existing literature on the modelling of DGRs and the design of UHS facilities suggest that around 48% of total storage volume, also known as *cushion gas*, needs to be injected into the DGR to displace the original gas, maintain reservoir pressure, and enable efficient injection and withdrawal of hydrogen at the desired purity throughout the lifespan of the facility. The cushion gas is generally unrecoverable. As the density of hydrogen gas is approximately 7 times lower than that of natural gas, higher pressures are required to store an equivalent amount of energy in a storage reservoir, despite the higher gravimetric energy density of hydrogen compared to that of natural gas. A generic design of a compression-based HESS, illustrated in Figure 2, is comprised of a UHS reservoir, a hydrogen production facility, compression stations, pressure regulation stations, a buffer system, purification membranes, wellbores for injection and withdrawal, an electricity generation facility, and an electricity substation connecting the HESS to the main electricity grid.

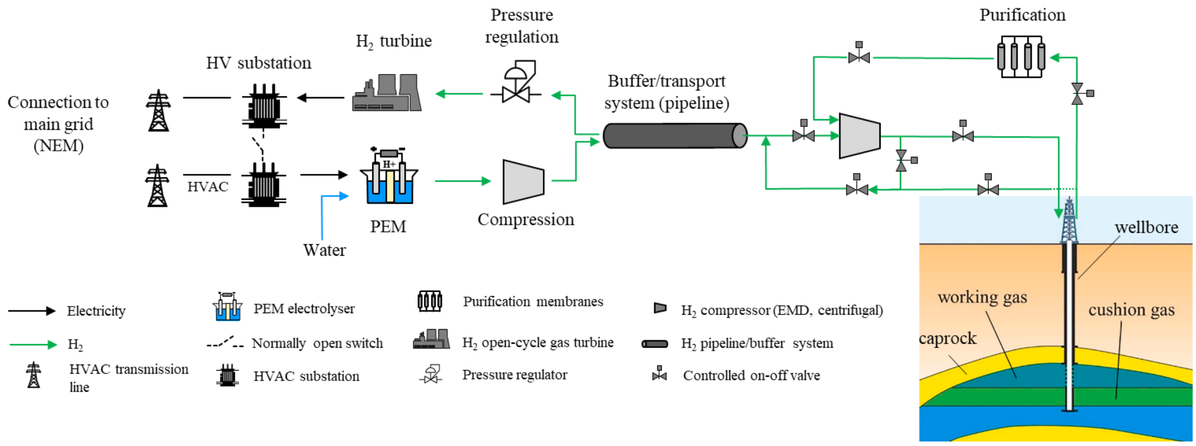
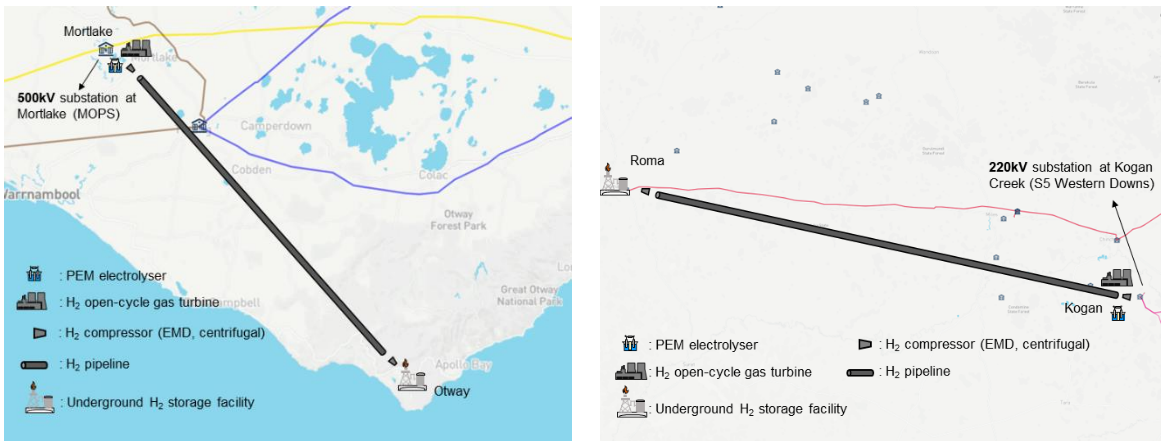


Figure 2: Generic HESS design.

In VIC, the closest HV substation to the DGRs in Otway is the 500 kV substation at Mortlake, approximately 110 km away. In SQ, the nearest HV substation to the DGRs in Roma is the 220 kV substation near the Kogan Creek power station, about 200 km away. Consequently, both the electrolysers and hydrogen turbines will be positioned near these substations, requiring hydrogen to be transported via a pipeline to and from the UHS facilities in Otway and Roma. Previous work within FF CRC found that transporting hydrogen via pipelines is generally more cost-effective than transporting electricity through HV electricity transmission lines in this context. The capacity, and therefore the flow rate requirements of the electrolysers and hydrogen turbines is determined based on the specific requirements of each LDES scenario illustrated in Figure 1 above. The required pipeline capacity is determined by finding the smallest feasible diameter that can accommodate the largest of the two peak flow rates required by the electrolysers and the hydrogen turbines. Compressor sizing is determined by the pipeline flow rate as well as the pressure requirements for transmission, injection into, and withdrawal from the UHS facility. The resulting hydrogen storage system designs are shown in Figure 3a for the Otway-Mortlake HESS in VIC and Figure 3b for the Roma-Kogan HESS in SQ.



a) Otway-Mortlake HESS. b) Roma-Kogan HESS.

Figure 3: High-level designs of the HESS in VIC (left) and SQ (right).

D. **Developing a methodology for determining the capital expenditure (CapEx) and fixed operation and maintenance (FOM) costs** of the proposed two HESSs and the two PHES projects, Snowy 2.0 and Borumba.

   Various reliable and publicly available sources—including AEMO's 2024 ISP and the peak body representing Australia's pipeline infrastructure—are consulted to estimate the CapEx and FOM costs of the proposed HESS. These cost estimates, which are used to determine the optimal design of the HESS based on the above criteria, consider the lead time for development and construction, the technical life of each component, and the cost of connection to the main grid. To ensure fairness in the comparison, connection costs are also added to the CapEx of Snowy 2.0 and Borumba.

E. **Developing an optimisation-based market dispatch modelling framework** that mimics the operation and settlement of the NEM Dispatch Engine.

   Underpinning the key insights in this report is a large-scale optimisation framework that simulates the operation and settlement of the NEM Dispatch Engine over twenty years with relatively high temporal and spatial resolution. Specifically, the framework incorporates a long-horizon, network-constrained unit commitment model, time-coupled through state-of-energy (SoE) constraints, ramp rates, and minimum up-time and down-time constraints for coal-fired generators (CFG) and gas-fired generators (GFG). The model adopts a twelve-node network representation of the NEM, a half-hourly temporal resolution, and a twenty-year planning horizon. The regional reference prices (RRP), also known as locational marginal prices (LMP), as well as the annual energy production for each assessed LDES option are obtained from the solution of this model. This optimisation-based market dispatch model, invoked for each one of the six scenarios in Figure 1, enables finding the LCOE and LROE for each LDES option, as well as assessing reliability, resilience, VRE curtailment, and operational costs under each scenario.

F. **Developing a methodology for deriving LCOE and LROE** for the considered HESS and PHES.

   The cost of purchasing electricity from the grid is also obtained from the solution of the developed optimisation-based market dispatch model, which, together with the RRP and the annual energy production, enables finding the LCOE for each assessed LDES option. Because modelling offering and bidding behaviour with high certainty is extremely challenging, this work instead uses the revenue duration curve (RDC), derived from the price duration curve (PDC), to estimate revenue opportunities for a potential market participant. The PDC is a graph that displays the distribution of wholesale energy prices in descending order over a full financial year, highlighting the percentage of time that prices could exceed a certain threshold. The RDC reflects the average price that occurs during the periods when prices could potentially exceed a specific level. In an ideal case, it represents the average spot market earnings a participant could generate by operating only when spot prices are at or above that level. The RDC is then used to compute the LROE for each assessed LDES option. In general, a project is deemed potentially commercially viable if the LROE is higher than the LCOE.

G. **Quantifying and assessing the reliability** of the NEM under six different scenarios with different LDES options.

   For the NEM to remain reliable, it must continuously balance electricity supply and demand while ensuring that the power system operates within its designated limits. Additionally, the NEM must be diligently managed throughout the year to ensure that electricity demand is met at least 99.998% of the time. The developed assessment framework in this report considers weather variability and generator reliability settings, in congruence with the reliability assessment in AEMO's Electricity Statement of Opportunities (ESOO). Weather variability is captured through VRE and demand traces sourced from AEMO's 2024 ISP, which are used directly as inputs to the optimisation-based market dispatch model, without any modifications. Hydro scheme inflows and domestic and export hydrogen demands in each year out to 2051 are obtained from AEMO's 2023 Inputs, Assumptions, and Scenarios (IASR) workbook. The reliability of the NEM is assessed under each one of the six scenarios in Figure 1.

H. **Quantifying and assessing the resilience** of the NEM under four different VRE drought events with varying duration and severity.

Extreme weather conditions culminating in minimal or no sunshine or wind for an extended period introduce major challenges to maintaining a reliable operation in a system dominated by VRE. A methodology is developed in this project to examine the resilience of the NEM under four different VRE drought events with varying duration and severity. Several important metrics are assessed during these events, including operability, residual demand and operational demand, reserves, SoE of all storage systems, RRP, and the amount of unserved energy (USE). Three of the four analysed VRE drought events are *conceptually* similar to the ones assessed in AEMO's 2024 ISP, which were co-developed (not by the authors of this report) in collaboration with climate scientists. The fourth VRE drought event replicates the severity of the eight-day VRE drought observed from 20–27 May 2024, which was characterised by extremely low NEM-wide wind and solar CFs of 11.6% and 17.9%, respectively.

I. **Quantifying and assessing the VRE curtailment** across the NEM in each assessed LDES case.

   VRE curtailment refers to instances where VRE generators reduce output due to low market prices or insufficient demand, resulting in economic "spill", or due to network curtailment where transmission or system strength constraints prevent these generators from producing electricity. Within the context of LDES, this report identifies the main factors influencing the amount of VRE curtailment in each LDES scenario, including geographical location, energy storage capacity, round-trip efficiency (RTE), and the CF of an LDES.

J. **Quantifying and assessing the operational costs** across the NEM in each assessed LDES case.

   In this report, operational costs refer to short-run marginal costs (SRMC) of CFG and GFG multiplied by the energy produced. These costs also incorporate the variable operation and maintenance (VOM) and fuel costs, i.e., cost of coal for CFG or cost of natural gas for GFG. This assessment explores the impact of geographical location, regional uptake in GFG, and regional retirements of CFG on the operational costs across the NEM under each LDES scenario in Figure 1.

CapEx and fixed O&M

Under the specific technical and financial assumptions in this report, the total NPV of CapEx and FOM costs shown in Table 2 suggest that the two HESSs are around 30% cheaper than their PHES counterparts. The forecast energy output for each LDES option, shown in Table 2 is obtained from the solution of the long-horizon optimisation-based market dispatch model. The energy NPV of Snowy 2.0 is approximately four times higher than that of the Otway-Mortlake HESS in VIC, and the energy NPV of Borumba is about three times higher than that of the Roma-Kogan HESS in QLD. This difference is mainly attributed to the lower RTE of HESSs compared to that of PHES. The RTE of HESSs is around 21%, whereas the RTE of PHES is approximately 3.58 times higher, at around 76%. These RTEs translate to CFs of at most 11% for HESSs and 38% for PHES.

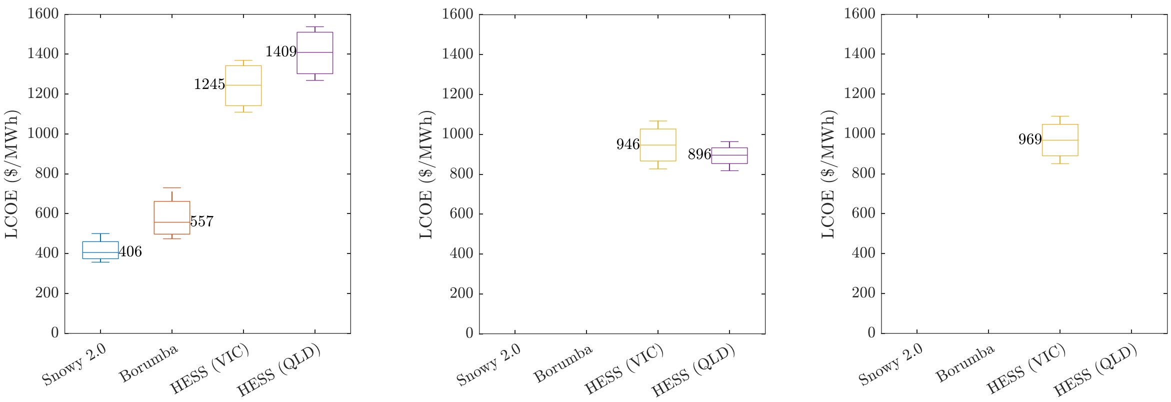
Table 2: NPV of CapEx, FOM cost, and energy across the considered 20 years of operation for each assessed LDES option.

Scenario	LDES option	Capacity (MW)	Storage capacity (GWh_e)	CapEx NPV ($B)	FOM cost NPV ($B)	Total NPV ($B)	Energy NPV (TWh)
Snowy-Borumba	Snowy 2.0	2000	305	10.63	2.35	12.98	27.11
	Borumba	1998	42	11.51	2.29	13.80	18.44
HESS-VIC-QLD-4GW	Otway-Mortlake HESS	1999	175	7.61	1.60	9.21	6.82
	Roma-Kogan HESS	1999	172	7.98	1.66	9.64	6.40
	Otway-Mortlake HESS	999	79	2.77	0.58	3.35	3.06

HESS-VIC-QLD-2GW	Roma-Kogan HESS	999	79	2.94	0.61	3.55	3.68
HESS-VIC-0.5GW	Otway-Mortlake HESS	500	79	1.50	0.32	1.82	1.60

LCOE and LROE

Viewed in isolation, the CapEx and FOM do not paint a complete picture of the full merits of providing cost-competitive LDES to the NEM. An important piece of the puzzle is the LCOE. Although the two HESSs have a CapEx NPV that is around 30% lower than their PHES counterparts, the maximum CFs of the PHES options are 3.58 times higher than their HESS counterparts, enabling them to generate significantly more energy. This corroborates why, in scenarios HESS-VIC-QLD-4GW and Snowy-Borumba (see Table 1), the LCOE of the 2 GW Otway-Mortlake HESS in VIC is around 3 times higher than that of Snowy 2.0 and the LCOE of the 2 GW Roma-Kogan HESS in QLD is 2.5 times higher than that of Borumba, as shown in Figure 4.

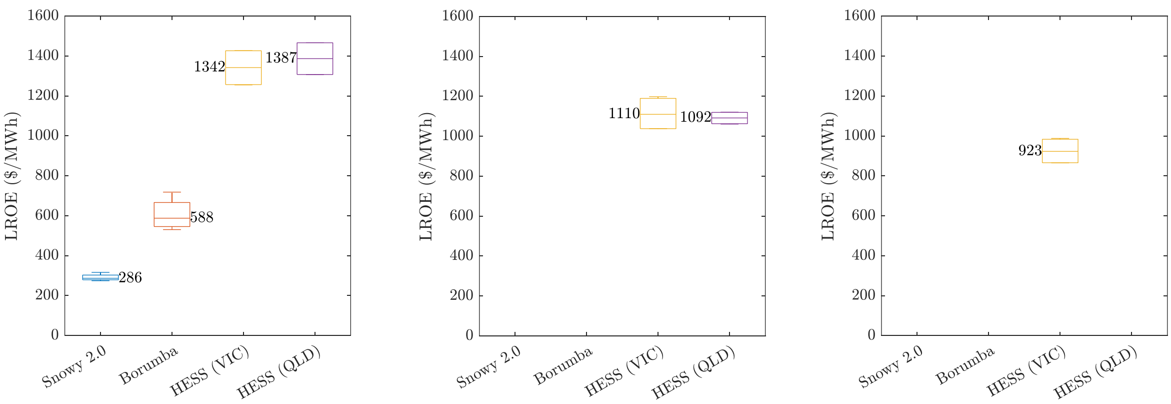


a) Scenarios Snowy-Borumba and HESS-VIC-QLD-4GW

b) Scenario HESS-VIC-QLD-2GW

c) Scenario HESS-VIC-0.5GW

Figure 4: LCOE for each assessed LDES option. The error bar represents the maximum and minimum across the assessed sensitivities, and the coloured bar indicates the mean.



a) Scenarios Snowy-Borumba and HESS-VIC-QLD-4GW

b) Scenario HESS-VIC-QLD-2GW

c) Scenario HESS-VIC-0.5GW

Figure 5: LROE for each assessed LDES option. The error bar represents the maximum and minimum across the assessed sensitivities, and the coloured bar indicates the mean.

The last piece of the puzzle in a business case analysis is the *LROE*. Under the specific technical and financial assumptions in this report, which reflect current technology cost predictions, the findings in Figure 5a and Figure 5b suggest that, by participating *only* in the wholesale market, the Otway-Mortlake HESS in VIC in scenarios HESS-VIC-QLD-4GW and HESS-VIC-QLD-2GW (see Table 1) may be able to recover all their costs within the first 20 years of operation. In other words, the Otway-Mortlake HESS in VIC in scenarios HESS-VIC-QLD-4GW and HESS-VIC-QLD-2GW may potentially be commercially viable under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP. On the other hand, as shown in Figure 5b, the Roma-Kogan HESS in QLD is only profitable in the HESS-VIC-QLD-2GW scenario, in which it has a capacity of 1 GW. Despite the higher LROE of the 2 GW Roma-Kogan HESS in QLD compared to the 2 GW Otway-Mortlake HESS in VIC, the former has a noticeably higher LCOE, mainly due to its higher CapEx (see Table 2), incurred by the longer pipeline connecting the UHS facility in Roma to the electrolysers and hydrogen turbines in Kogan (see Figure 3).

Despite its high CapEx, Borumba may also potentially be commercially viable under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP. This suggests that LDES options like Borumba and the Roma-Kogan HESS substantially improve reliability in QLD, and that without them, the RRP would be extremely high during periods of high residual demand. In the case of Snowy 2.0, the LROE being lower than the LCOE suggests that there is sufficient generation capacity in NSW to prevent Snowy 2.0 from being the marginal or inframarginal generator for long enough to recover its costs. Nonetheless, Snowy 2.0 substantially improves reliability and resilience in NSW, as will be discussed below.

The (relatively) high LROE of the Otway-Mortlake HESS in VIC and the Roma-Kogan HESS in QLD, compared to their PHES counterparts, can be explained by the low CF and, by association, the low energy output which results in a high LCOE but also in a (relatively) high LROE. In other words, the low CF of HESSs is unfavourable from an LCOE perspective but favourable from an LROE perspective. The opposite is true for Snowy 2.0 and Borumba, which are characterised by higher CFs and, by association, higher energy outputs, resulting in lower LCOE and LROE.

Moreover, the higher LROE of the Otway–Mortlake HESS in VIC and the Borumba PHES in QLD, compared to their LCOE, can be attributed to increased price volatility. Price volatility is expected to become more pronounced after 2034-35, when the market share of coal generation drops to only 2.53% of total dispatchable capacity and the NEM becomes dominated by renewables. This, therefore, presents more opportunities for the profitable LDES options (i.e., Borumba PHES and the Otway-Mortlake HESS in the HESS-VIC-QLD-4GW scenario, and the two HESSs in the HESS-VIC-QLD-2GW scenario) to maximise their revenue by tapping into the high prices that could arise when the residual demand is high and during reliability events.

Interestingly, although still greater than one, the ratio of LROE to LCOE is higher in this scenario than in the HESS-VIC-QLD-4GW scenario (see Figure 4b and Figure 5b). This is mainly because, despite the presence of Snowy 2.0, the 1 GW HESS in VIC and the 1 GW HESS in QLD under the HESS-VIC-QLD-2GW scenario do not provide sufficient capacity to maintain reliability in VIC and QLD, respectively, when compared to the 2 GW Otway-Mortlake HESS and the 2 GW Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario. As a result, the two smaller HESS units in the HESS-VIC-QLD-2GW scenario can remain inframarginal for a longer period, allowing them to generate more revenue relative to their LCOE than they would if they had 2 GW of capacity, as in the HESS-VIC-QLD-4GW scenario.

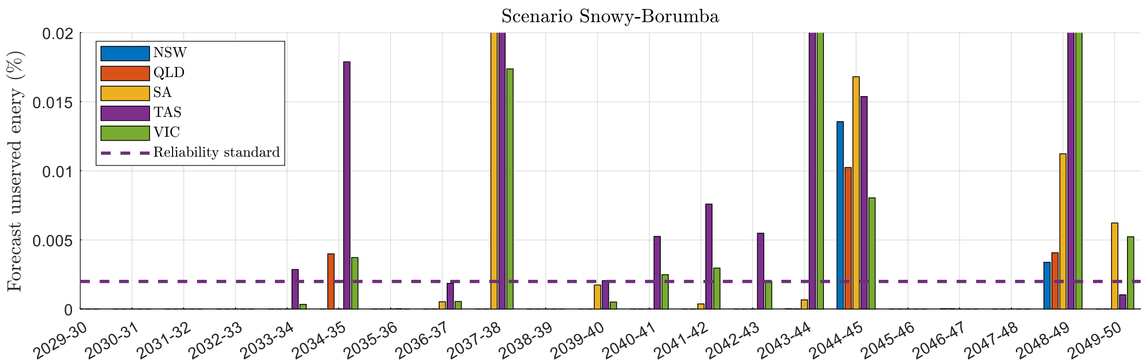
In the HESS-VIC-0.5GW scenario (see Table 1), the PDC and RDC are derived from the RRP computed in the Snowy-Borumba scenario, which includes both Snowy 2.0 and Borumba. The presence of Snowy 2.0 and Borumba significantly decreases price volatility across the NEM, which in turn reduces the maximum potential revenue opportunities for additional LDES in the market. This explains why the LROE is likely to be slightly lower than the LCOE for the HESS in VIC under the HESS-VIC-0.5GW scenario. Nevertheless, adding the 500 MW HESS in VIC also contributes significantly towards improving reliability and resilience in VIC, SA, and TAS, as discussed below.

Reliability

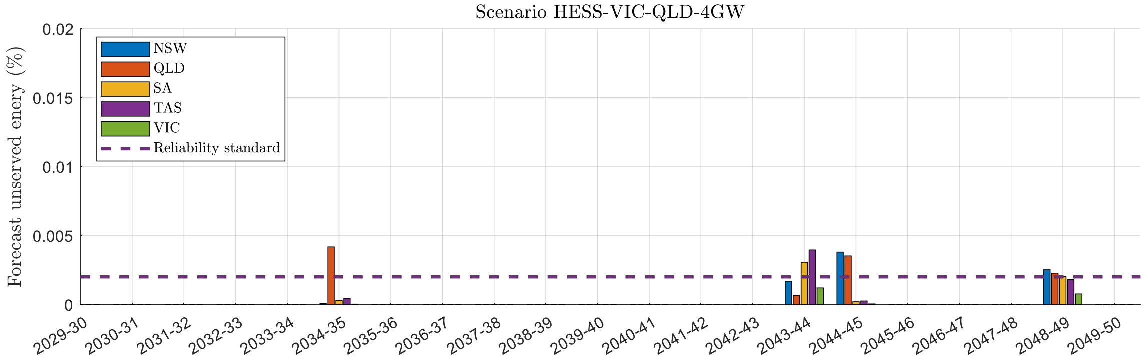
Reliability results in Figure 6a suggest that USE in the Snowy-Borumba scenario frequently exceeds 0.02% (10 times the specified reliability standard of 0.002%) in many years between 2028 and 2047, particularly in the southern states of VIC, SA, and TAS. In contrast, the HESS-VIC-QLD-4GW scenario has the lowest worst-case USE among the six scenarios. Figure 6b shows that the worst-case USE in the HESS-VIC-QLD-4GW scenario, which does not exceed 0.0042%, is witnessed in year 2034-35, where around 2.83 GWh of demand is unmet across the year in QLD. The second highest USE in the HESS-VIC-QLD-4GW scenario is around 0.004% in VIC in year 2043-44.

These findings suggest the following:

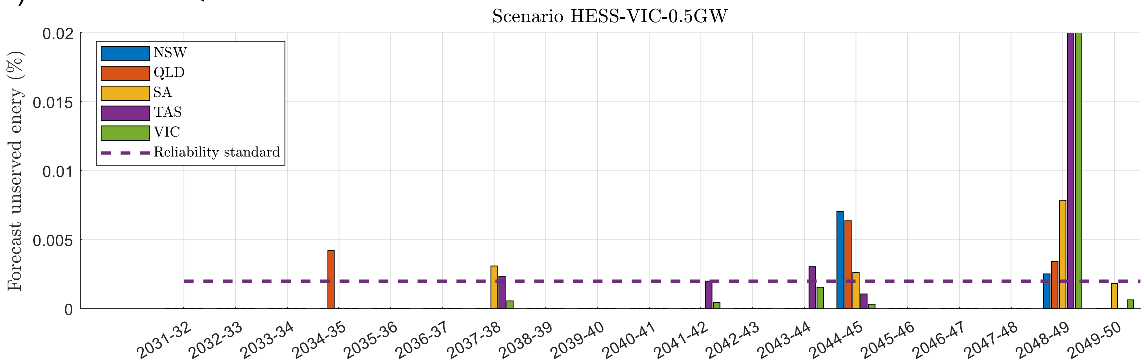
- The projected generation, storage, and transmission capacities in AEMO's 2024 ISP may not be sufficient to maintain reliability in the NEM through to 2050.
- Reliability is improved in QLD under the HESS-VIC-QLD-4GW scenario compared to the Snowy-Borumba scenario because the Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario can provide 172 GWh_e, i.e., 86 hours of net storage at 1.99 GW, compared to 42 GWh_e, i.e., 21 hours of net storage at 1.998 GW in the case of Borumba the Snowy-Borumba scenario. This suggests that 21 hours at 1.998 GW may not be sufficient to maintain reliability in QLD, and that at least 86 hours may be required instead.
- Together, the Otway-Mortlake HESS in VIC and the Roma-Kogan HESS in SQ, in the HESS-VIC-QLD-4GW scenario, are capable of maintaining reliability in NSW under a counterfactual case in which Snowy 2.0 does not exist.
- It is more beneficial to the reliability of NEM to have LDES in VIC than in SNSW. Despite HumeLink, VNI West, and Project EnergyConnect, which are envisaged to be commissioned by July 2030, July 2027, and July 2030, respectively (see Figure 79 and Table 50), Snowy 2.0 may not be enough to overcome interconnector constraints during periods of high residual demand to alleviate USE in the southern states of VIC, TAS, and SA in the Snowy-Borumba scenario. In contrast, the Otway-Mortlake, by virtue of being in VIC, is better positioned to overcome interconnector constraints between VIC and TAS, i.e., Marinus Link and Basslink, and between VIC and SA, i.e., Heywood interconnector and Murraylink.
- The above claims are further substantiated in Figure 6c, which shows that having a HESS with 500 MW and 158 hours of net storage in VIC, as in the HESS-VIC-0.5GW scenario, greatly improves reliability in the southern states of VIC, SA, and TAS.



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW



c) HESS-VIC-0.5GW

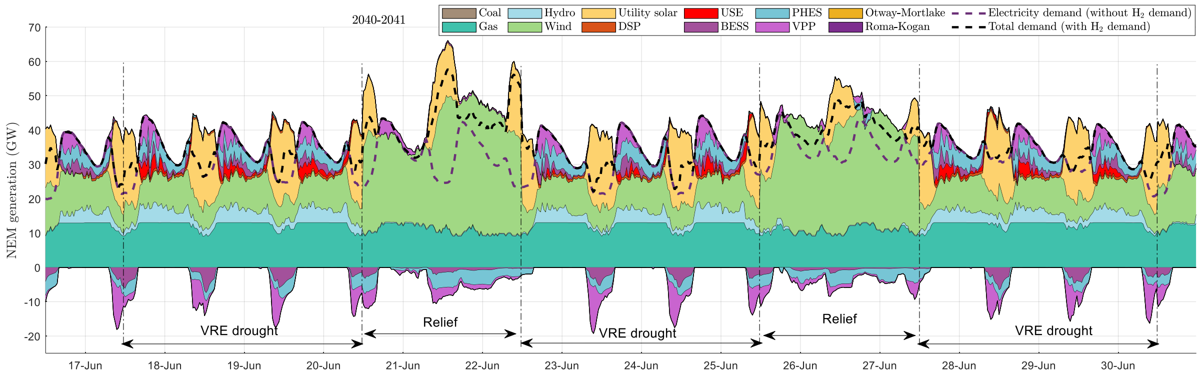
Figure 6: Forecast reliability outcomes by region from 2029-30 to 2049-50 under scenarios Snowy-Borumba, HESS-VIC-QLD-4GW, and HESS-VIC-0.5GW.

Resilience

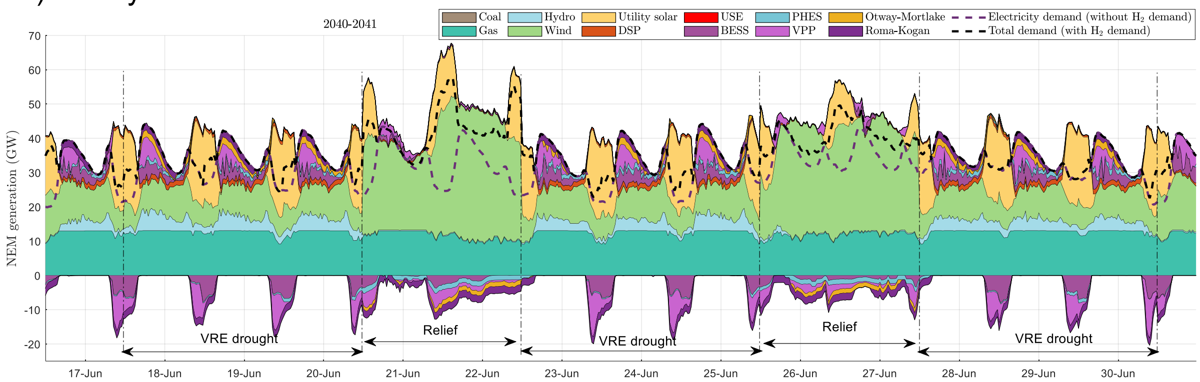
In the absence of reliable forecasts for future weather conditions, a severe VRE drought event—comprising multiple intermittent VRE droughts over two weeks in June 2041—is synthesised from the VRE traces in AEMO's 2024 ISP to evaluate the resilience of the NEM under extreme weather conditions. This prolonged VRE drought event is characterised by frequent periods of extremely high residual demand due to wind lulls coinciding with high heating demand in southern states, during which a VRE output of as low as 16% of operational demand is witnessed for several hours. The wind and solar CFs are 13.78% and 22.13%, respectively, across 9 of the 14 days.

Figure 7 shows that, despite hydro generators and GFG operating at (near) full capacity, the Snowy-Borumba scenario experiences substantially more USE compared to the HESS-VIC-QLD-4GW scenario. In fact, lost load under the Snowy-Borumba scenario frequently exceeds 1 GW in VIC, SA, and TAS across these two weeks. In contrast, the HESS-VIC-QLD-4GW scenario experiences minimal USE, which does not exceed 120 MW and occurs on far fewer occasions. Both scenarios experience extremely high regional prices, driven by a combination of costly demand-side program (DSP) activations and lost load priced at the market price cap of $17,500/MWh, as shown in Figure 8.

This report also assesses a severe VRE drought event that replicates the severity of the eight-day VRE drought observed from 20–27 May 2024, which was characterised by extremely low NEM-wide wind and solar CFs of 11.6% and 17.9%, respectively. In this case, both scenarios exhibit substantial USE; however, the severity is markedly reduced in the HESS-VIC-QLD-4GW scenario. This suggests that additional firming and backup generation should be planned accordingly—particularly in VIC and QLD—beyond what is projected in AEMO's 2024 ISP and in this report, to hedge against high-intensity, low-probability (HILP) events such as this one.

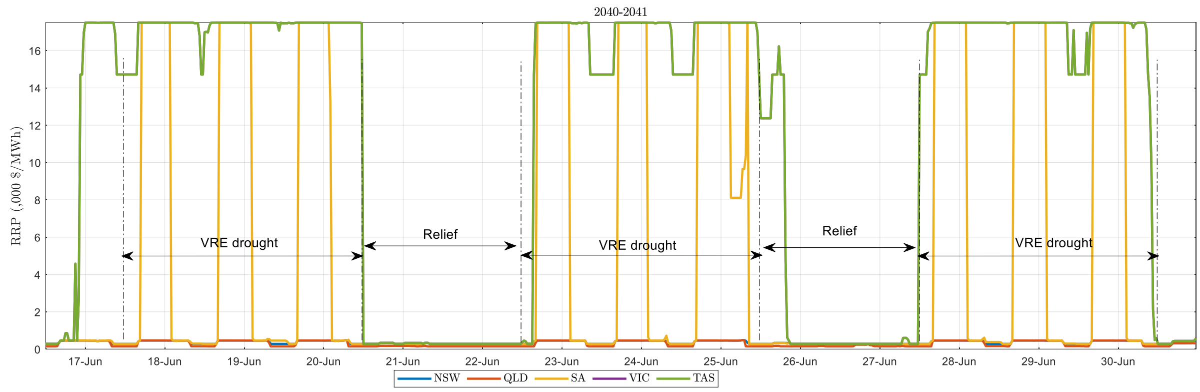


a) Snowy-Borumba

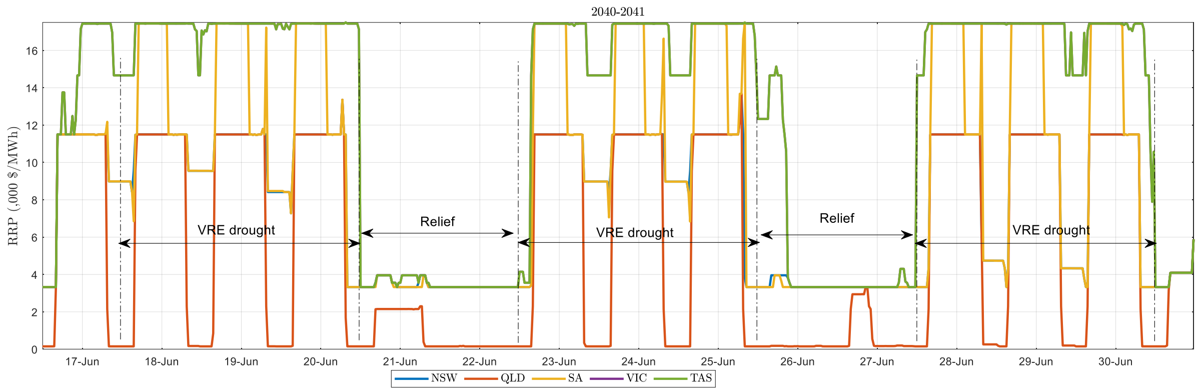


b) HESS-VIC-QLD-4GW

Figure 7: Forecast operability across the NEM experiencing two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 8: RRP across the NEM during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

VRE curtailment

Figure 9 shows that the HESS-VIC-QLD-4GW scenario witnesses consistently less VRE curtailment compared to the Snowy-Borumba scenario from 2031-32 out to 2050-51, with most of the curtailment emanating from economic spill as high solar generation in spring and summer is expected to create an energy oversupply. This decrease reaches as high as 38% in 2035-36. The main factors influencing this outcome are:

- HESSs have a lower charging efficiency compared to PHES, which enables them to accommodate more VRE that might otherwise be curtailed. This is because HESSs typically have a charging (electrolysis) efficiency of around 70% and a discharging (hydrogen turbine) efficiency of around 30%, whereas the PHES options typically have charging (pumping) and discharging (generating) efficiencies of around 87%. The RTE of HESSs is therefore around 21% compared to around 76% for PHES.
- The Otway-Mortlake HESS, by virtue of its strategic location in VIC, has access to VRE from *four* subregions, CSA, SESA, TAS, and SNSW. In contrast, Snowy 2.0, located in SNSW, has access to VRE from *three* subregions, VIC, CNSW, and CSA.
- Higher LDES power and energy storage capacities in VIC, SA, and TAS, beyond what is projected in AEMO's 2024 ISP, contribute to a higher accommodation of VRE, in addition to a higher contribution to reliability.

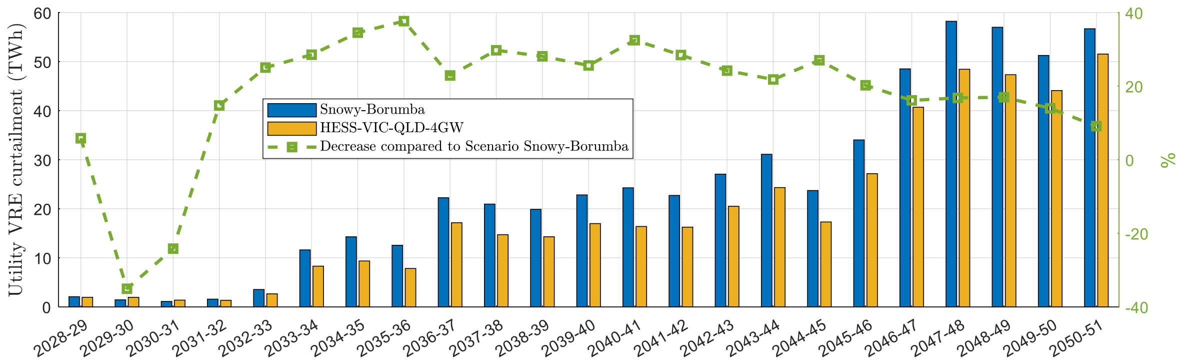


Figure 9: VRE curtailment across the NEM from 2028-29 to 2050-51 in the Snowy-Borumba and the HESS-VIC-QLD-4GW scenarios.

Operational costs

Figure 10 shows that the HESS-VIC-QLD-4GW scenario experiences consistently higher operational costs for CFG and GFG compared to the Snowy-Borumba scenario from 2028–

29 through to 2050–51, with the increase reaching as high as 43% in 2035–36. The primary reason for this increase is the absence of Snowy 2.0 in NSW under the HESS-VIC-QLD-4GW scenario, which results in a 2 GW shortfall in flexible capacity—requiring additional backup power in NSW, primarily from GFG, to compensate for the deficit.

According to the Step Change scenario in AEMO's 2024 ISP, NSW in 2035-36 is forecast to have 4.7 GW of GFG—around 33% of the 14.44 GW forecast for the whole NEM. At the same time, NSW in 2035-36 is forecast to still have around 1.42 GW of CFG—around 2.53% of the total dispatchable capacity, which is also relied upon to compensate for this deficit.

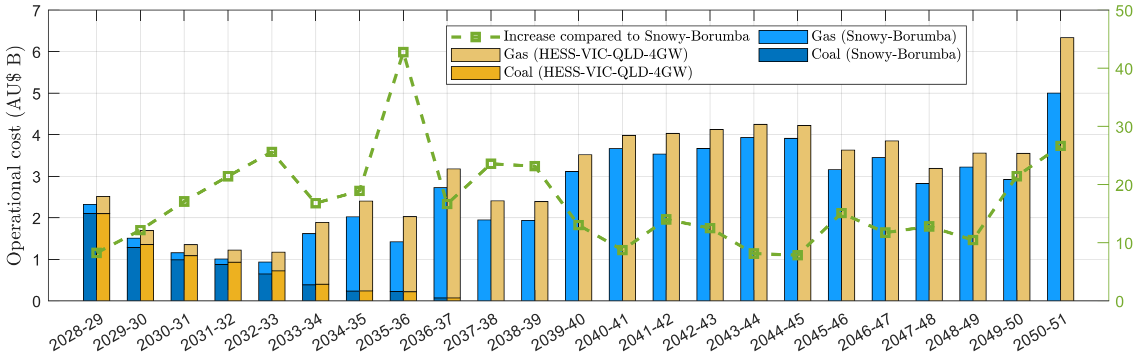


Figure 10: Operational costs of CFG and GFG from 2028-29 to 2050-51 in the Snowy-Borumba and the HESS-VIC-QLD-4GW scenarios.

Price volatility

Figure 11 shows that from 2034-35 onwards the forecast average NEM prices increase substantially in a scenario with no LDES (NoLDES) compared to scenarios HESS-VIC-QLD-4GW and Snowy-Borumba. Moreover, price volatility, represented by the error bars in Figure 11, is consistently improved in the presence of LDES. Figure 11 also shows that, due to an increased reliance on CFG and GFG in NSW, the average prices across the NEM in the HESS-VIC-QLD-4GW scenario are slightly higher than those in the Snowy-Borumba scenario for 9 out of the 20 years between 2028-29 and 2047-48. For the remaining 11 years, these *average* prices are lower than those in the Snowy-Borumba scenario. Additionally, price *volatility* is significantly reduced under the HESS-VIC-QLD-4GW scenario compared to the Snowy-Borumba scenario, especially from 2033-34 onwards. This is mainly due to the significant improvement in reliability under the HESS-VIC-QLD-4GW scenario, which manifests in less reliance on costly DSP to mitigate USE. Values higher than $1,000/MWh are predominantly at the market price cap (MPC) of $17,500/MWh across all LDES options.

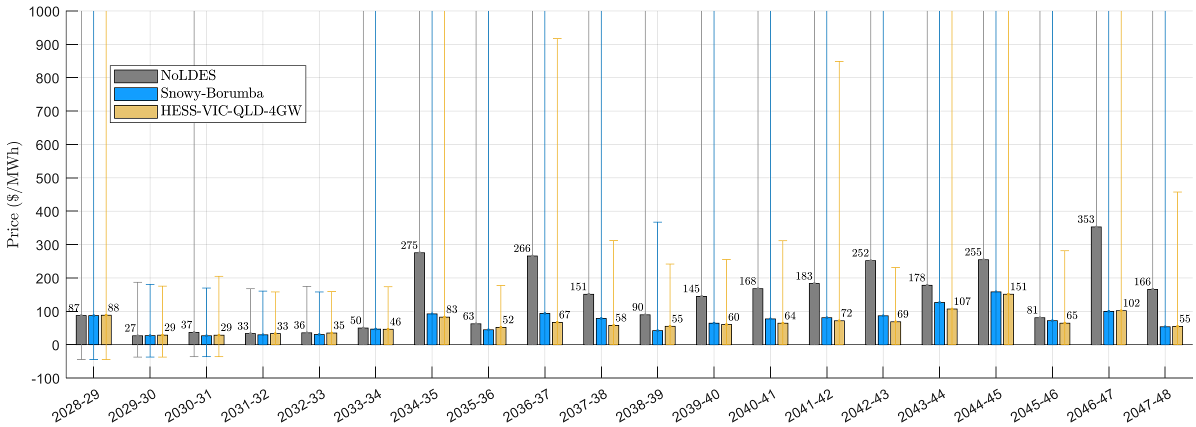


Figure 11: Average annual NEM prices in the NoLDES, Snowy-Borumba, and HESS-VIC-QLD-4GW scenarios from 2028-29 out to 2047-48. The error bars show the maximum and minimum prices in each year.

Glossary

AEMO	Australia Energy Market Operator
AUD	Australian Dollar
BESS	Battery energy storage system/systems
BoM	Bureau of Meteorology
CapEx	Capital expenditure
CCGT	Combined-cycle gas turbine/turbines
CDP	Candidate development path
CER	Consumer energy resources
CF	Capacity factor/factors
CFG	Coal-fired generator/generators/generation
CNSW	Central New South Wales
CSA	Central South Australia
CQ	Central Queensland
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DGR	Depleted gas reservoir/reservoirs
DSP	Demand-side programs
EMD	Electric motor drive
EV	Electric vehicle/vehicles
FOM	Fixed operation and maintenance
GFG	Gas-fired generator/generators/generation
GWh_e	GWh electrical equivalent
H_2	Hydrogen gas
HESS	Hydrogen energy storage system/systems
HHV	Higher heating value
HILP	High intensity low probability
HVAC	High voltage alternating current
HVDC	High voltage direct current
IASR	Inputs, assumptions, and scenarios
IEHS	Integrated electricity and hydrogen system/systems
ISP	Integrated system plan
GG	Gladstone
kV	Kilovolt
LCOE	Levelised cost of energy
LDES	Long-duration energy storage
LGC	Large-scale generation certificate/certificates
LHV	Lower heating value
LMP	Location marginal price/prices
LNG	Liquefied natural gas
LOR	Lack of reserve
LRMC	Long-run marginal cost/costs
LROE	Levelised revenue of energy
MERRA	Modern-Era Retrospective analysis for Research and Applications
MLF	Marginal loss factor/factors
MPa	Megapascales
Mt	Megatonne (or million metric tons)
NASA	National Aeronautics and Space Administration
NEM	National Electricity Market
NG	Natural gas
NNSW	Northern New South Wales
NPV	Net present value
NQ	Northern Queensland
NSW	New South Wales
OHL	Overhead line

O&M	Operation and maintenance
OpEx	Operating expenditure
PDC	Price duration curve/curves
PEM	Proton exchange membrane
PHES	Pumped-hydro energy storage system/systems/schemes
PPA	Power purchase agreement
PtG	Power-to-gas
PV	Photovoltaic
QLD	Queensland
QED	Quarterly Energy Dynamics
RDC	Revenue duration curve/curves
RES	Renewable energy sources
REZ	Renewable energy zones
RRP	Regional reference price/prices
RTE	Round-trip efficiency
SA	South Australia
SESA	Southeast South Australia
SMYS	Specified minimum yield strength
SNSW	South New South Wales
SNW	Sydney, Newcastle, Wollongong
SoC	State of charge
SoE	State of energy
SQ	Southern Queensland
SRMC	Short-run marginal cost/costs
TAS	Tasmania
UHS	Underground hydrogen storage
USD	United States Dollar
USE	Unserved energy
V	Volt
VALCOE	Value-adjusted levelised cost of energy
VCG	Vickrey-Clarke-Groves
VIC	Victoria
VoLL	Value of lost load
VOM	Variable operation and maintenance
VPP	Virtual power plant
VRE	Variable renewable energy
WACC	Weighted average cost of capital

1. Introduction

As a pathway to net zero emissions by 2050, a plethora of utility-scale energy storage systems of varying durations will unequivocally be required to support the reliability and resilience of an energy system that is dominated by variable renewable energy (VRE). State and federal governments are currently committing to considerable investments in pumped-hydro energy storage (PHES) systems [1], [2], and industry stakeholders are investing in growing Australia's fleet of battery energy storage systems (BESS). At the same time, commercial and government stakeholders envision an energy transition accompanied by large-scale hydrogen production (through electrolysis) for export and domestic use [3], which may create new opportunities for grid-connected hydrogen-based technologies to competitively participate in domestic energy markets, both as a source and a storage of energy. However, as of today, the extent to which hydrogen energy storage systems (HESSs) can competitively provide security, reliability, and resilience to the National Electricity Market (NEM) in Australia remains unclear.

The Australian Energy Market Operator (AEMO) envisions a three-fold increase in utility-scale wind and solar capacity by 2030, with a national target of 82%, increasing to six-fold by 2050, from 21 GW in 2024 to 127 GW. Compounded by a substantial increase in rooftop solar and other distributed solar, this monumental scale of VRE development will require a commensurate increase in *firming* technology in the form of dispatchable storage and backup technology in the form of gas-fired generation (GFG), as shown in Figure 12. AEMO forecasts 36 GW/522 GWh of storage capacity in 2034-35, increasing to 56 GW/660 GWh of storage capacity in 2049-50, as shown in Figure 13.

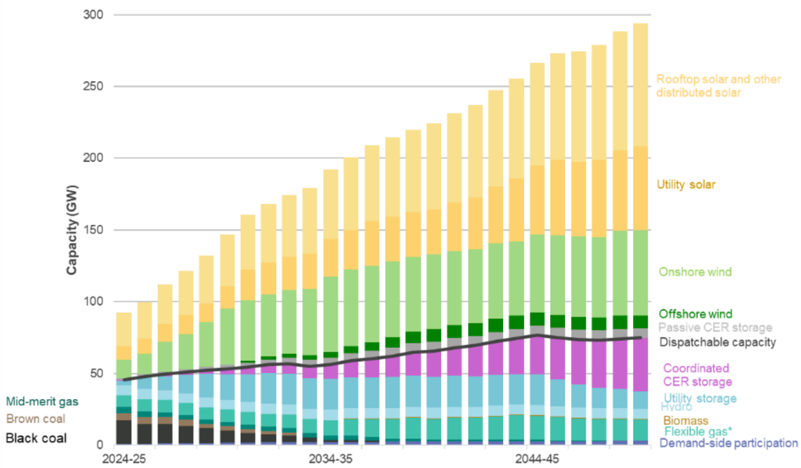
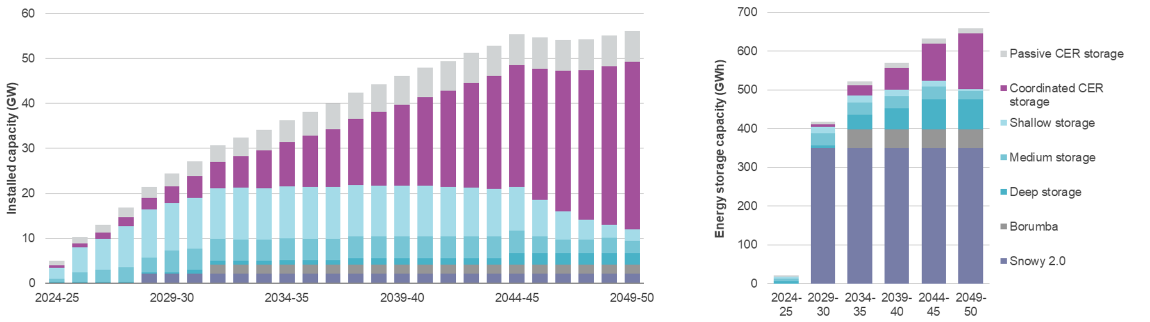


Figure 12: Forecast capacity in the NEM in AEMO's 2024 ISP [3].

The core value of energy storage lies in its ability to address supply and demand imbalances across various time scales and periods by shifting energy over time. When the cost of this shifting—encompassing production and storage—is lower than the cost of meeting demand through immediate production in the following period, energy storage delivers economic benefits.

Dispatchable storage systems of different depths and technologies will be required to buffer the variability of renewable energy by charging during periods of excess VRE generation and discharging during periods of shortfall in VRE generation, thereby shifting energy across time. In doing so, storage systems can *smooth* out the peaks and troughs in demand and supply and reduce VRE curtailment. Dispatchable storage systems can also provide services such as frequency control ancillary services (FCAS) that help balance out fast changes in supply and demand, maintain grid stability and inertia, and smooth out abrupt changes in grid frequency. By shifting energy across time, also known as *temporal energy arbitrage*, dispatchable storage systems are also able to *dampen* price volatility by raising operational demand when charging, thereby decreasing the magnitude of negative prices, and by discharging electricity at lower prices than expensive peaking units, thereby decreasing the magnitude of high prices. An illustration of the suitability of various energy storage technologies against duration of discharge and energy storage capacity is shown in Figure 14.



a) Installed storage capacity (GW)

b) Installed storage energy capacity (GWh)

Figure 13: Installed a) storage capacity and b) storage energy capacity in the NEM according to the Step Change scenario in AEMO's 2024 ISP [3].

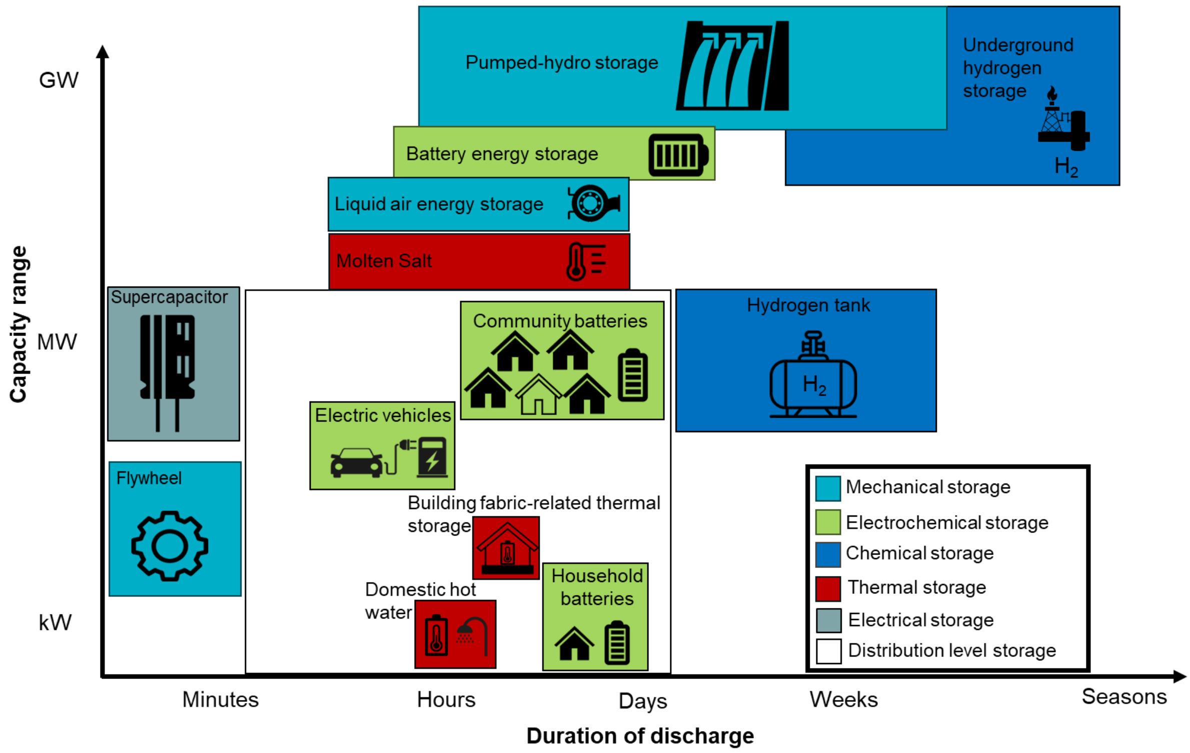


Figure 14: Suitability of various energy storage technologies against duration of discharge and energy storage capacity.

These storage technologies, which can be classified into five categories—consumer energy resources (CER), shallow, medium, deep, and long-duration—have different yet overlapping applications. An overview of the most common electricity storage applications is illustrated in Figure 15. These categories differ based on their "depth" of storage, meaning the duration over which electricity can be dispatched at maximum output before depleting the stored energy. Depending on the technology and storage depth, the duration of electricity storage can range from two hours to a week or more. These five categories are formally defined as:

- **CER storage**: Behind-the-meter household, business or industrial batteries, including electric vehicles (EV) that may be capable of sending electricity back to the grid. Coordinated CER storage is managed as part of a virtual power plant (VPP), whereas passive CER storage is not. This type of storage has a relatively small discharge duration of about two hours at full discharge. In addition to providing reliability and grid services, VPP could play a major role in distribution-level voltage control and transmission and distribution network investment deferral.
- **Shallow storage**: Utility-scale storage capable of dispatching electricity for less than 4 hours, valued for both their system services and their energy value.
- **Medium storage**: Utility-scale storage capable of dispatching electricity for 4 to 12 hours, also valued for both their system services and their energy value. These are predominantly BESS or small-scale PHES that can shift large quantities of electricity to meet evening or morning peaks.
- **Deep storage**: Strategic reserves capable of dispatching electricity for 12 to 24 hours to facilitate energy shifting over more than a day or to cover long periods of low solar and wind output (VRE droughts). These are predominantly BESS or medium-scale PHES.
- **Long-duration energy storage (LDES)**: Strategic reserves capable of dispatching electricity for more than 24 hours to facilitate energy shifting over days, weeks, or even months (seasonal shifting), or to sustain extended periods of low solar and wind output (VRE droughts). These are predominantly large-scale PHES, or potentially HESSs. According to AEMO's 2024 ISP [3], LDES in the NEM is expected to be provided by two large-scale PHES projects, Snowy 2.0 and Borumba, envisaged to be operational by 2028 and 2031, respectively, as shown in Figure 13.

LDES systems such as PHES and emerging technologies such as HESSs will play a pivotal role in enhancing *reliability* and *resilience* in a VRE-dominated energy system by shifting energy across days, weeks, or even seasons. As VRE becomes the dominant source of power generation following the retirement of all coal generation in 2037 [3], the NEM will be increasingly sensitive to weather variations. As a result, extreme weather conditions culminating in minimal or no sunshine or wind for an extended period pose unprecedented risks and challenges to maintaining reliability and resilience.

The analysis by Gilmore et al. 2022 [4] identifies, through backcasting techniques over the past 42 years using NASA's MERRA-2 reanalysis dataset, that, in the worst historical continuous time sequence, the future NEM VRE fleet will likely deliver 54% of its 42-year *average* output (not its nameplate output) over a two-week period and 32.6% on the worst winter day. The analysis in [4] also identifies credible scenarios in which the future NEM VRE fleet may experience a capacity factor (CF) as low as 1%, driven by low wind production across the mainland NEM coinciding with sunset, but only over a very small number of periods out to 2050. This reinforces the importance of strategic planning for LDES *capacity* and *ramping r*equirements in conjunction with energy storage capacity. In addition to providing *reserves* and ramping services, the applications of LDES, outlined within the red dashed squares in Figure 15, also extend to *congestion relief* and *transmission investment deferral* if planned alongside transmission developments.

PHES is a well-established technology that stores energy in the form of gravitational energy from the difference in height between two water reservoirs. As of today, PHES is the most widely deployed and largest form of storage technology, with nearly 200 GW of installed capacity, accounting for more than 90% of all LDES across the world with more than 400 projects in operation according to the International Hydropower Association (IHA) [5]. PHES is still one of the fastest growing stationary storage technologies, with deployments of around 5 GW each year worldwide [5]. On the other hand, HESS is an emerging technology that stores energy in chemical bonds, enabled by a technology that converts electricity into hydrogen, commonly known as “power-to-gas”. For LDES applications, hydrogen can be stored in underground reservoirs and later used to generate electricity in a fuel cell or a hydrogen turbine. The overall cycle is often referred to as “power-to-gas-to-power” [6].

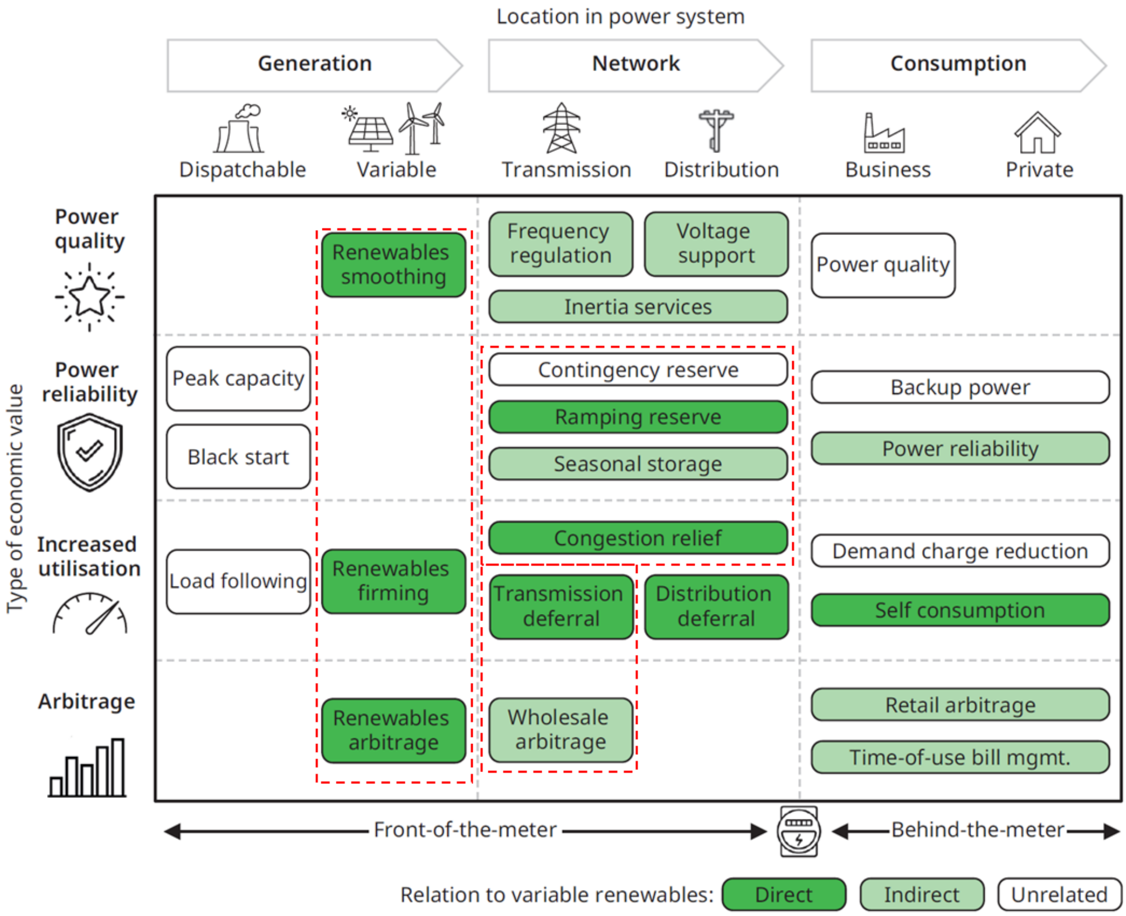


Figure 15: Illustration of the most common applications of electricity storage systems (figure adapted from Schmidt et al. 2023 [6]). The applications of LDES are outlined within the red dashed squares. The shade of green reflects the extent of the relation to VRE.

With PEM electrolysers and hydrogen turbines close to technological maturity, global efforts are currently focused on demonstrations of large-scale hydrogen storage in underground geological formations such as saline aquifers, depleted gas reservoirs (DGRs), salt caverns, and rock caverns [7]. The suitability of such geological formations hinges on many factors, including desired storage cycles, injection and withdrawal rates, storage capacity, hydrogen purity requirements, porosity and permeability, cap rock integrity, geochemical and biological reactions, reservoir stability, and proximity to existing electricity transmission infrastructure [8], [9].

Many HESS projects are currently under development around the globe. Underground Sun Storage 2030 [10] is a research project aimed at demonstrating seasonal storage of large volumes of hydrogen in a DGR in Austria. Laboratory testing suggests that hydrogen content can be increased to 100%, following predecessors of this project that already demonstrated 20% hydrogen storage in a well-tolerated manner. The Advanced Clean Energy Storage Project [11] in Utah, USA aims to convert 220 MW of VRE into 100 metric tonnes per day of green hydrogen, by way of alkaline electrolysis, and store it in two salt caverns, each with a capacity of 5500 metric tonnes, capable of providing 300 GWh of dispatchable clean energy. An 840 MW hydrogen-capable combined cycle gas turbine (CCGT) will then convert the hydrogen back to electricity, starting with a blend of green hydrogen and natural gas in 2025 and incrementally increasing to 100% green hydrogen by 2045. Project Hydrogen Pilot Cavern Krummhörn [12] aims to test the construction and operation of 100% hydrogen storage in a new salt cavern storage facility under real conditions. The new salt cavern, which is created using the process of leaching, is designed to provide 1.8 GWh. With the aim of investigating the suitability and integrity of a porous reservoir in the form of a DGR for storing hydrogen, project HyStorage [13] consists of gradually injecting hydrogen at 5%, 10% and 25% in three phases in a DGR, followed by withdrawal after a three-month holding period.

Other notable projects include Hydrogen Pilot Storage for large Ecosystem Replication (HyPSTER) [14] in France, aiming to store hydrogen produced from electrolysis in a salt cavern for industrial and mobility uses, and H2RESTORE [15] in Australia, investigating the commercial and technical viability of storing renewable hydrogen underground in existing DGRs in southwest Victoria.

In addition to their limited geographical availability, both PHES systems and HESSs have their distinct advantages and disadvantages. PHES systems are prone to high risks of long lead times for construction, which could result in cost blowouts. On the other hand, HESSs have a low round-trip efficiency (RTE) and require significant compression to reach sufficient energy density. Therefore, when considered as LDES options for supporting the reliability and resilience of the electricity system, the merits of each technology are case-specific and should be evaluated under many factors including, geographical and geological suitability, market conditions and externalities (e.g., extremely high gas prices), technology costs, reliability standards, energy security, transmission infrastructure development, and proximity to high-voltage (HV) transmission infrastructure, in addition to uncertainties around VRE uptake and demand growth.

More broadly, research into hydrogen storage systems can be divided into four umbrella categories: *siloed* assessments (including, geographical, technical, and economic) of different large-scale hydrogen storage technologies ([7], [8], [16], [17], [18], [19], [20], [21], [22]), reservoir simulations ([9], [15]), UHS design ([9], [15]), and integrated electricity and hydrogen system (IEHS) models and assessments (optimisation-based ([23], [24], [25], [26], [27], [28], [29]) and non-optimisation-based ([18], [19], [30], [31], [32], [33], [34])) . Informed by reservoir simulations and UHS design criteria from Salmachi et al. 2024 [9] and Lochard Energy [15] and by suitable UHS locations in Australia from Ennis-King et al 2021 [35] and Amirthan et al. 2023 [17] this project developed a first-of-their-kind optimisation-based market dispatch model capable of evaluating the role of HESSs in providing reliability and resilience to the electricity system, in this case the NEM, while informing on *levelised cost of energy* (LCOE) and *levelised revenue of energy* (LROE).

Unlike the siloed assessments that consider HESSs in isolation and disregard the electricity system, the developed optimisation-based modelling framework and methodologies can capture the synergies between the two energy vectors, and how they translate to improved energy security, reliability, resilience against extreme weather events, and system flexibility in an integrated fashion. Furthermore, although the optimisation-based models in [23], [24], [25], [26] can assess reliability and resilience, as well as optimise power generation mix in conjunction with storage, they can only inform on CapEx, as they are *cost-based* optimisation models that use generic build costs. Moreover, these methods resort to representative periods, typically a couple of weeks and a single year, to reduce computational burden of the underlying optimisation models. In contrast, the developed capability in this report:

- Provides detailed HESS designs, and therefore detailed CapEx,

- Includes an optimisation-based market dispatch modelling framework designed to mimic the operation and settlement of the NEM, including typical offering and bidding behaviour of all current and future market participants,
- Includes a methodology—based on the revenue duration curve and rooted in concepts from game theory—for computing revenue opportunities for any market participant; and
- Considers the essential physics of electricity flow, as well as hydrogen flow, compression, and storage, under a long-horizon outlook with relatively high temporal (30 minutes) and spatial (twelve subregions) resolution while maintaining computationally tractability.

The developed framework addresses two of the gaps identified by Zhang et al. 2025 [36]: *balance between spatial and temporal resolution*, and the *chicken and egg dilemma*. Because the developed optimisation-based market dispatch modelling framework has a 20-year planning horizon and adopts a relatively high temporal (30 minutes) and spatial (twelve-node network model) resolution, it avoids having to select *representative days, weeks, or years*, as is common practice in the literature, which has been repeatedly demonstrated to heavily influence results. By developing a methodology that quantifies *revenue opportunities* (from participating in the wholesale electricity market), the proposed framework equips investors with a decision-making support tool that weighs the risks and opportunities that inform business models and actionable investment decisions.

2. Large-scale hydrogen storage options for Australia

Hydrogen storage technologies can be broadly classified into three main types: *compression, liquefaction, and chemical* [37]—as illustrated in Figure 16. Compression consists of storing gaseous hydrogen at higher pressures to increase its volume. Line packing in gas pipelines is an example of a compression solution to store gaseous hydrogen. As of today, there are four viable options for storing compressed hydrogen gas at scale, namely, saline aquifers, depleted gas reservoirs (DGRs), salt caverns, and engineered rock caverns [7].

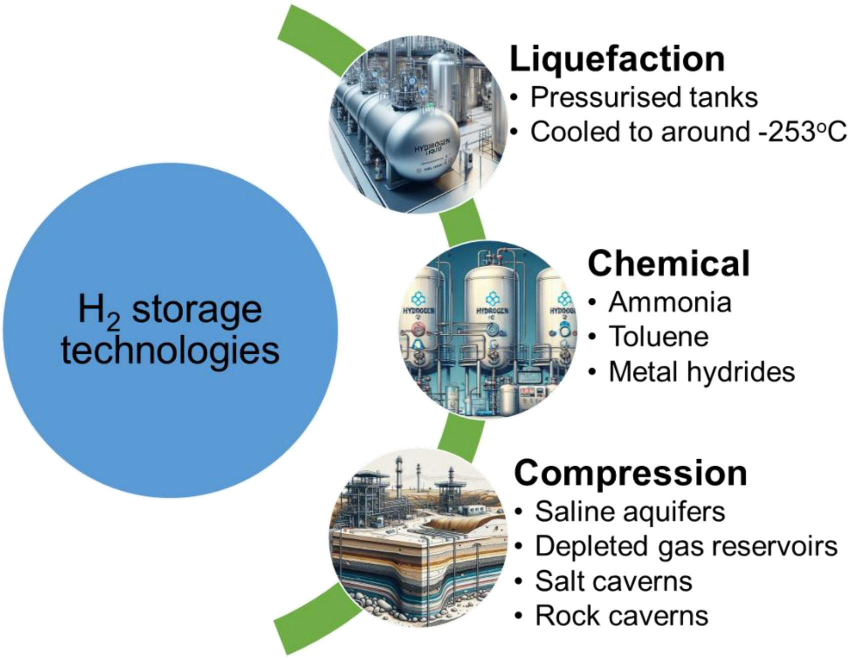


Figure 16: Illustration of the three main hydrogen storage technologies.

As illustrated in Figure 17, the first three options are naturally occurring porous structures in underground geological formations. Liquefaction consists of storing liquid hydrogen in tanks of fixed size by pressurising and cooling it to around -253˚C. Chemical storage uses material carriers such as ammonia, metal hydrides, and toluene as carriers for hydrogen. Both liquefaction and chemical storage technologies have superior volumetric densities but are generally much more costly than compression storage, which is a more attractive option predicated on the availability of suitable underground geological formations.

In addition to being the cheapest option for storing large volumes of gaseous hydrogen, compression storage is also deemed as the safest due to its lower likelihood of gas leaks [17], [35], [38], and is preferred in applications requiring high hydrogen purity and fast discharge [7], [8]. Equally important, although each one of these storage types and technologies could potentially offer a unique suite of benefits in specific applications, *technological readiness and maturity* will also play an important role in determining their potential deployment. A more comprehensive review of hydrogen storage options can be found in [7].

In Australia, studies have shown that DGRs in key locations have suitable geological characteristics (e.g., porosity and permeability) for storing large volumes of pressurised hydrogen gas [17], [35]. This project focuses on the DGRs in Otway in VIC and Roma in QLD for the following reasons. First, Table 2 in [35] and Table 5 in [17] show that the Otway reservoirs in VIC and the Surat reservoirs in QLD have large storage capacities at the scale required for electricity generation to support the reliability of the NEM. Second, a major advantage of the Otway and Surat reservoirs is their relative proximity to high-voltage (HV) transmission lines, which makes them easier to connect to the NEM compared to other more remote DGRs such as the ones in Moomba in SA and Ballera in QLD [39]. These potential large-scale hydrogen storage sites and the existing infrastructure facilities in Australia are illustrated in Figure 18.

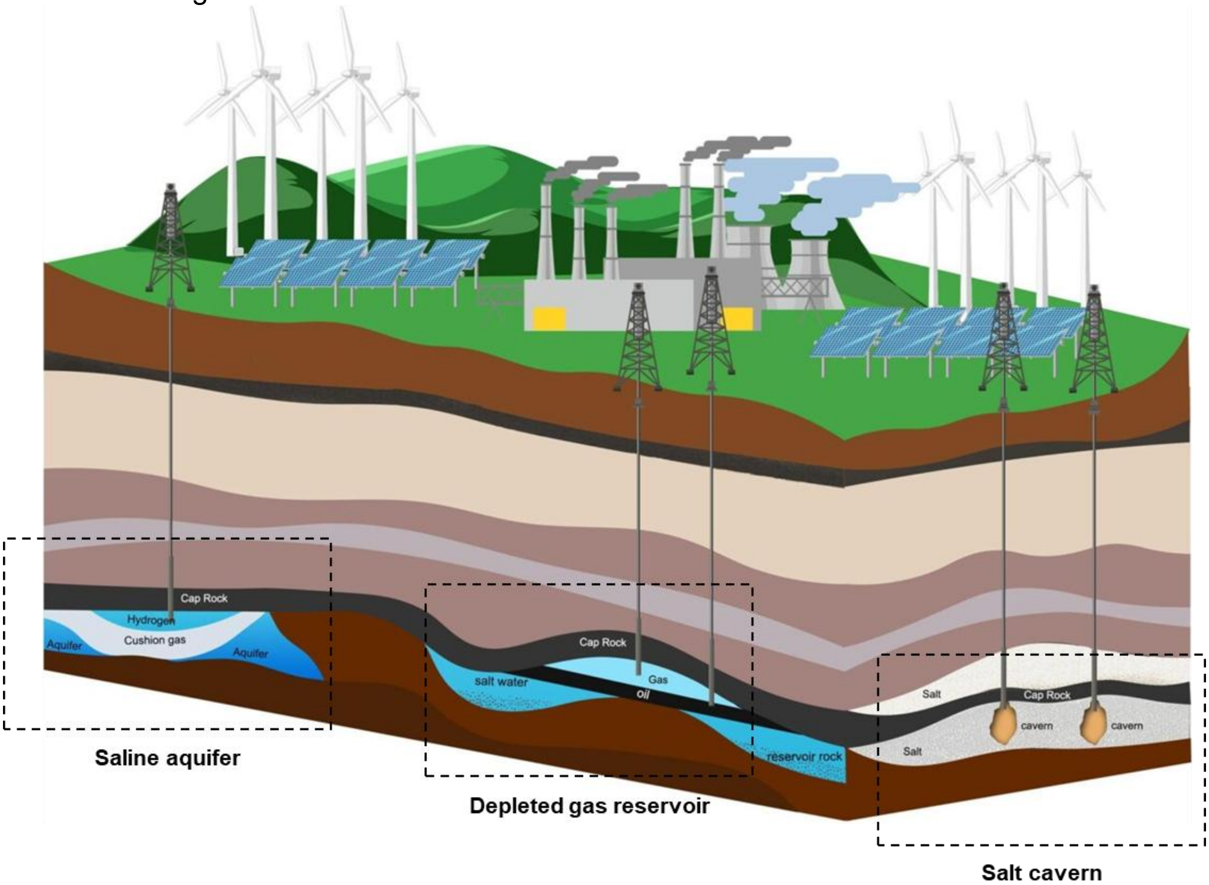


Figure 17: Three options for storing hydrogen gas at scale (image modified from [40]).

Table 5 in [17] specifies that the DGRs in Roma may have a combined UHS capacity of 122 kt of hydrogen whereas the DGRs in Otway may have a combined UHS capacity of 53 kt. For a higher heating value (HHV) of 142 MJ/kg, 122 kt of hydrogen is tantamount to 4810 GWh. If this hydrogen is used as fuel in a 2 GW hydrogen turbine with 30% efficiency (based on HHV) [41], and assuming 48% of that volume is for cushion gas[1], the UHS can potentially provide 375 h of storage for the NEM. To put things into perspective, PHES project Snowy 2.0 is expected to provide 168 h of storage at 2 GW. Recent findings in the H2RESTORE project [15] identify six DGRs in Otway that are viable for UHS with a combined hydrogen working storage volume of 14.8 kt and cushion volume of 13.17 kt.

[1] See next section for more information on cushion gas.

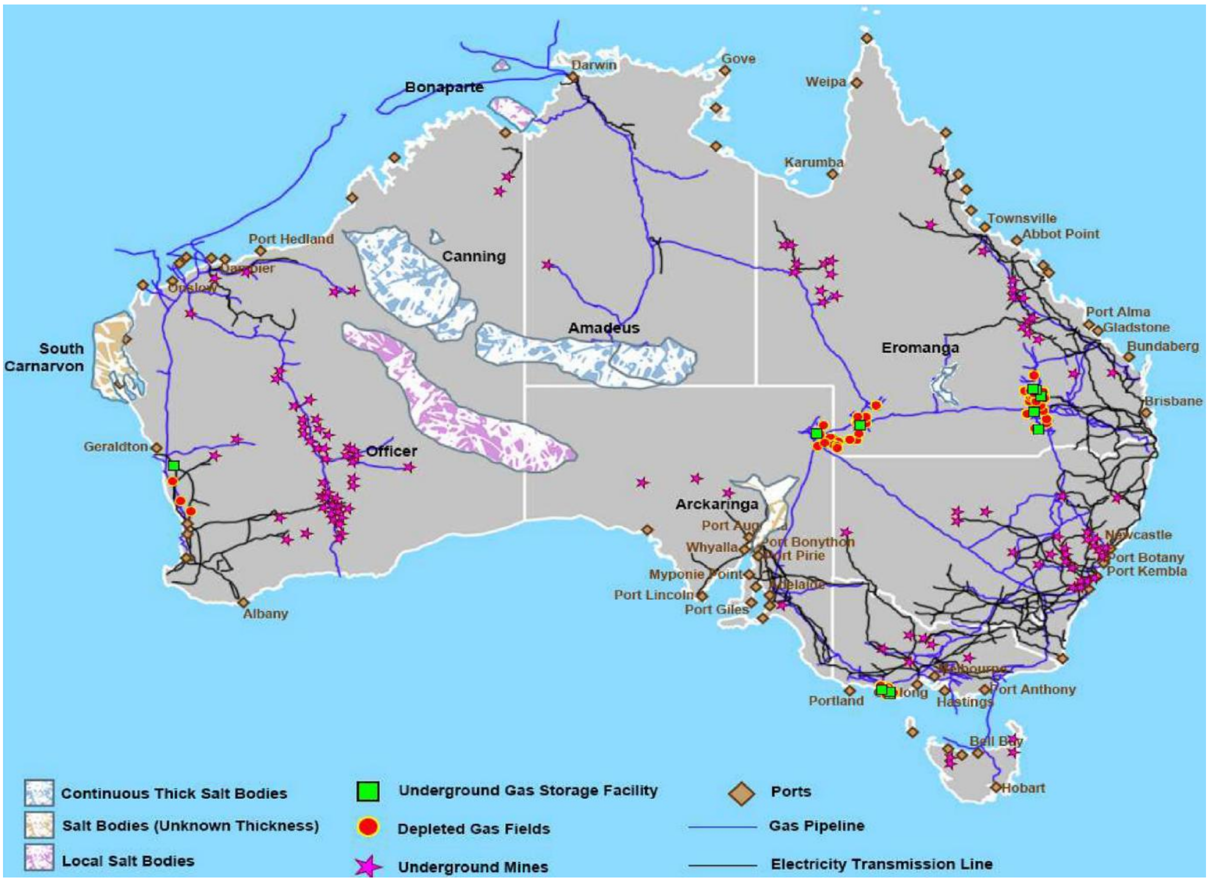


Figure 18: Existing energy production, transmission, and storage infrastructure and UHS options in Australia [17].

3. HESS design

This section describes the methodologies for designing the proposed hydrogen energy storage system (HESS) in VIC and SQ and for finding the CapEx and fixed O&M (FOM) of the HESSs and the two PHES projects Snowy 2.0 and Borumba. This section also details the optimisation-based market dispatch modelling underpinning the derivation of the LCOE and LROE for each long-duration energy storage (LDES) option. The main sources of data input for the modelling of the NEM in this project are AEMO's 2023 Inputs, Assumptions, and Scenarios (IASR) workbook [42] and the optimal development path (ODP), i.e., CDP 14, identified in the *Step Change scenario* in AEMO's 2024 Integrated System Plan (ISP) [3].

3.1. Hydrogen energy storage system design

As illustrated in Figure 19, a compression-based HESS is generally comprised of an underground hydrogen storage (UHS) reservoir, a hydrogen production facility, compression stations, pressure regulation stations, a buffer system, purification membranes, wellbores for injection and withdrawal, an electricity generation facility, and an electricity substation connecting the HESS to the main electricity grid. Hydrogen production is assumed to be enabled by proton exchange membrane (PEM) electrolysers due to their fast response capability and wider operating range [43], which may be a welcome source of additional flexibility for the NEM. Economies of scale are also expected to decrease the cost of PEM electrolysers to around a third of their current cost by 2035 and to converge to the cost of alkaline electrolysers by 2040 [44].

Electricity generation is assumed to be enabled by open-cycle hydrogen turbines, which are less expensive than fuel cells and have similar operating capabilities to open-cycle natural gas turbines [30]. Open-cycle hydrogen turbines can also provide system strength and inertia, giving them an additional advantage over fuel cells. At times of surplus electricity, hydrogen gas is produced from PEM electrolysers and then compressed and transported in a buffer system to another compression station before being injected at high pressure into a UHS reservoir. Then, at times of high electricity demand, pressurised hydrogen can be extracted from the UHS reservoir and transported via the same buffer system to a hydrogen turbine for electricity production. In addition to transporting gas and smoothing the inherent variability in upstream hydrogen production, the buffer system can also act as a short-duration to medium-duration storage.

In general, the buffer system can accommodate greater energy storage; however, this would require a larger pipeline, resulting in increased capital expenditure (CapEx) for the HESS. In this report, the pipeline is optimally sized as part of an integrated cost optimisation of the entire HESS, and is designed to provide short-duration storage—no more than four hours—during withdrawal from the underground hydrogen storage (UHS). During injection, however, the pipeline can support storage durations exceeding four hours, as the output flow rate from the PEM electrolyser is significantly lower than that of the input to the hydrogen turbine. While increasing the pipeline size could extend storage duration in the withdrawal direction, it would necessitate additional compression and lead to higher CapEx due to the larger infrastructure requirements.

Due to mixing with the existing natural gas in the DGR, purification may be necessary to ensure a specific level of hydrogen purity for the hydrogen turbines, especially during the first few years of operation. In this case, compression may be required to compensate for the pressure drop in the purification process, as shown in Figure 19. Another advantage of hydrogen turbines over fuel cells is their lower sensitivity to natural gas content, which reduces the cost of purification.

Because the UHS in this project is initially a DGR that used to contain natural gas, a certain minimum volume of hydrogen gas—called *cushion gas*—needs to be injected into the reservoir to raise the pressure to levels that enable extraction. More formally, cushion gas refers to the gas that remains unrecoverable after being injected into the reservoir to displace the original gas, maintain reservoir pressure, and enable efficient injection and withdrawal of hydrogen at the desired purity throughout the lifespan of the facility. The volume of hydrogen gas that can be used as *working* storage is an additional volume of gas on top of the cushion gas. The time it takes to inject the cushion gas can be up to 12 months or more, depending on various technical and economic factors [9]. As the density of hydrogen gas is approximately 7 times lower than that of natural gas, higher pressures are required to store an equivalent amount of energy in a storage reservoir, despite hydrogen's higher gravimetric energy density (~120 MJ/kg) compared to natural gas (~50 MJ/kg) [9].

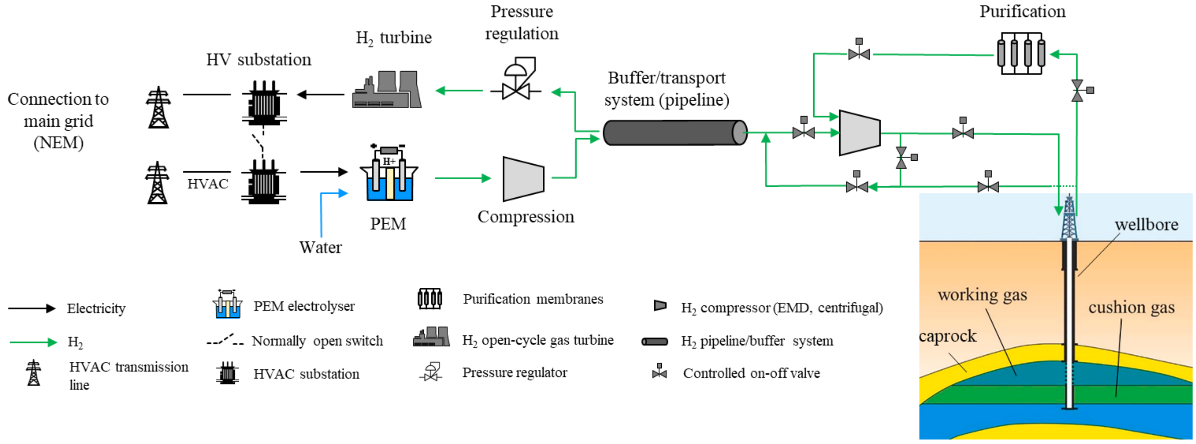
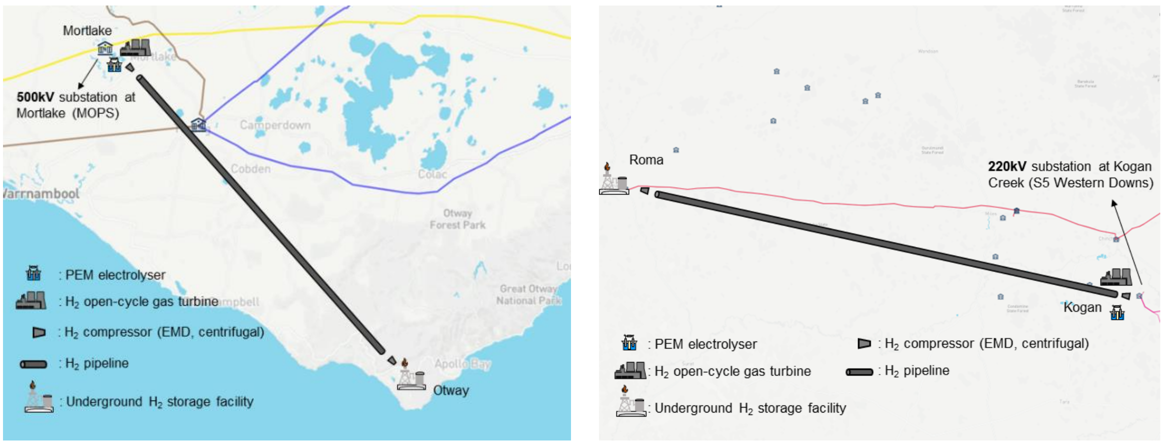


Figure 19: Generic HESS design.

In VIC, the nearest HV substation to the DGRs in Otway is the 500 kV substation at Mortlake, which is around 110 km away. In SQ, the nearest HV substation to the DGRs in Roma is the 220 kV substation (S5 Western Downs) near the Kogan Creek power station, which is around 200 km away. As a result, both the PEM electrolysers and hydrogen turbines are assumed to be located near these substations and the hydrogen will need to be transported via a pipeline to and from the UHS facilities in Otway and Roma. This design is more cost-effective than co-locating the electrolysers and hydrogen turbines with the UHS facilities and building electricity transmission lines to connect the HESS to the existing HV substations. This is in congruence with the findings in [45], [46] which showed that pipelines are generally more cost-effective than electricity transmission lines in such applications. The existing 500 kV substation in Mortlake and the 220 kV substation in Kogan will need to be expanded to include the new transformers and switchgear to *connect* the electrolysers and the hydrogen turbines to the NEM. The resulting hydrogen storage system designs are shown in Figure 20a for the Otway-Mortlake HESS in VIC and Figure 20b for the Roma-Kogan HESS in SQ.



a) Otway-Mortlake HESS. b) Roma-Kogan HESS.

Figure 20: High-level designs of the HESS in VIC (left) and SQ (right).

While hydrogen pipelines can be designed to operating under a pressure range between 3 MPa and 12 MPa [46], the bidirectional hydrogen pipelines in this project are sized under a smaller pressure range, between 5.8 MPa and 8 MPa [15]. This is because frequent pressure cycling at higher operating pressures can cause faster growth in fatigue cracks which requires greater inline inspection frequency and larger internal wall thickness that may fall outside of manufacturing range.

Since the output pressure of a typical PEM electrolyser is around 3 MPa [47], compressors are required to boost the pressure to 8 MPa before transmission to the UHS facilities. At the UHS facility, the injection pressure at the surface (tubing head pressure) is assumed to range between 12.5 MPa and 16 MPa. As the pressure at the outlet of the pipeline is designed to drop no further than 5.8 MPa at the outlet, compressors at the UHS facility are designed with the capability of boosting the pressure from as low as 5.8 MPa to as high as 16 MPa. The withdrawal pressure at the surface (tubing head pressure) is assumed to range between 8.5 MPa and 13 MPa. Since 8.5 MPa is higher than the pipeline maximum allowable operating pressure (MAOP) of 8 MPa, compression will only be needed to compensate for the pressure drop in the purification membranes if the purification process is activated. Thanks to controlled on-off valves, the same compressors can be used in the withdrawal process to enable transporting hydrogen to the hydrogen turbines, as shown in Figure 19. All compressors in this work are assumed to be electrically driven (i.e., EMD), and either centrifugal or reciprocating, depending on the required flow rate.

For the Otway-Mortlake HESS in VIC, water for the electrolysers is assumed to be transported from the Warrnambool treatment plant, about 42 km away. For the Roma-Kogan HESS in SQ, water for the electrolysers at Kogan is assumed to be sourced from a water treatment plant near the Kogan Creek coal mine around 6 km away. The considered pressure ranges for the proposed UHS sites, summarised in Table 3, are a result of detailed reservoir simulations conducted under the H2RESTORE project [15]. Generic parameters for the pipelines, compressors, and hydrogen turbines in the considered HESSs are provided in Table 4, Table 5, and Table 6, respectively. The marginal loss factors (MLF) and auxiliary loads are obtained from AEMO'S 2023 IASR workbook [42].

Table 3: Generic parameters of the considered UHS sites [15].

Sub-region	Basin	Site	Withdrawal pressure (MPa)	Injection pressure (MPa)	Reservoir pressure (MPa)
VIC	Otway	Otway	8.5 - 13	12.5 - 16	10 - 14.5
SQ	Surat	Roma	8.5 - 13	12.5 - 16	10 - 14.5

Table 4: Generic parameters of the pipelines in the considered HESSs.

Sub-region	From	To	Length (km)	Minimum pressure (MPa)	Maximum pressure (MPa)	Direction
VIC	Mortlake	Otway	110	5.8	8	Bi-directional
SQ	Kogan	Roma	200	5.8	8	Bi-directional

Table 5: Generic parameters of the compressors in the considered HESSs.

Sub-region	Site	Type	Adiabatic efficiency	Mechanical efficiency	Prime mover efficiency	Pressure range (MPa)	Power consumption (MW)
VIC	Mortlake	EMD	85%	98%	95%	7 - 8	See Appendix C
SQ	Kogan	EMD	85%	98%	95%	7 - 8	See Appendix C
VIC	Otway	EMD	85%	98%	95%	7 - 8	See Appendix C
SQ	Roma	EMD	85%	98%	95%	7 - 8	See Appendix C

Table 6: Technical parameters of the hydrogen turbines in the HESSs [41], [42].

Sub-region	Site	Region	Efficiency (HHV)	Ramp rate (MW/min)	MLF	Auxiliary load

VIC	Mortlake	VIC	30%	22	0.99	1.1%
SQ	Kogan	QLD	30%	22	0.97	1.1%

Additional cost and parameter assumptions for pipelines and compressors are listed in Table 49 in Appendix A. Appendix C, provides an overview of the main gas compressor technologies and the equations used for finding the power consumption of the considered EMD compressors. Pipelines and compressors are sized based on flow rate requirements for the hydrogen turbines and PEM electrolysers in each one of three HESS scenarios described in Section 4.

3.2. CapEx and FOM costs

All NPV values in this report use 2024 as reference year. A weighted average cost of capital (WACC) of 10% is used for all the financial computations of the HESSs and the PHES projects, whereas as a WACC of 7%, in line with AEMO's 2024 ISP [3], is used to compute LCOE of VRE, BESS, and other PHES as described below.

3.2.1 HESS

The CapEx and fixed operation and maintenance (FOM) of the HESSs are obtained by adding the CapEx and FOM costs of each component in the HESS, including the water lines required for electrolysis. General financial parameters for the UHS sites, pipelines, compressors, hydrogen turbines, and PEM electrolysers are tabulated in Table 7, Table 8, Table 9, Table 10, and Table 11, respectively. The CapEx includes the costs of all surface facilities and wellbores for each DGR. For example, there are six DGRs (fields) in Otway. The CapEx of each component in the considered HESSs depends on the capacity of that component, which in turn depends on the storage requirements and power capacity from the HESSs. Six different scenarios with different HESS storage and power requirements are analysed in this work. They are described in Section 4.

Once the capacities of the PEM electrolysers and hydrogen turbines are determined, the capacity, and therefore the diameter, of the pipeline is then optimised as in [45] by finding the smallest possible pipeline diameter that can transport the highest of the two maximum flow rates required by the PEM electrolysers and the hydrogen turbines. In addition to distance and operating pressure range, the sizing of the pipelines accounts for erosional velocity, specified minimum yield strength (SMYS), and design factor [45]. The design factor and the SMYS are used to find the internal pipe diameter, whereas the erosional velocity ratio (EVR) is used to find minimum pipeline size such that the outlet pressure is above the specified minimum pressure (5.8 MPa in this case) and the maximum gas velocity remains within the erosional velocity criteria. Table 49 in Appendix A shows the adopted values of these design parameters. Compressors are then sized based on the flow rate in the pipeline and the required pressures for transmission, injection into, and withdrawal from the UHS facility. Redundancy is achieved by installing two compressors in parallel.

Table 7: General financial parameters of the considered UHS sites [15].

Sub-region	Basin	Site	FOM cost (% of CapEx/year)	Lead time for development (years)	Lead time (years)	Construction time (years)	Technical Life (years)
VIC	Otway	Otway	3%	2	2	2	40
SQ	Surat	Roma	3%	2	2	2	40

Table 8: General financial parameters of the pipelines in the considered HESSs.

Sub-region	From	To	FOM cost (% of CapEx)	Lead time for development (years)	Lead time (years)	Construction time (years)	Technical Life (years)
VIC	Mortlake	Otway	See Table 49	2	2	2	40
SQ	Kogan	Roma	See Table 49	2	2	2	40

Table 9: *General financial parameters of the compressors in the considered HESSs.*

Sub-region	Site	Lead time for development (years)	Lead time (years)	Construction time (years)	Technical Life (years)
VIC	Mortlake	2	2	1	20
SQ	Kogan	2	2	1	20
VIC	Otway	2	2	1	20
SQ	Roma	2	2	1	20

Table 10: General financial parameters of the hydrogen turbines in the HESSs [48].

Sub-region	Site	FOM cost (% of CapEx/year)	Lead time for development (years)	Lead time (years)	Construction time (years)	Technical Life (years)
VIC	Mortlake	3%	2	2	1	20
SQ	Kogan	3%	2	2	1	20

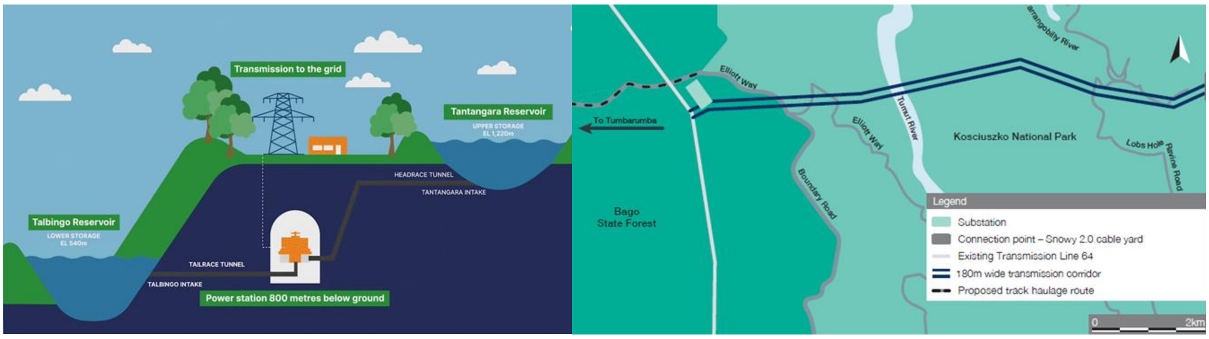
Table 11: General financial parameters of PEM electrolysers [42].

Sub-region	Basin	Site	FOM cost ($/kW/yr)	Lead time for development (years)	Lead time (years)	Construction time (years)	Technical Life (years)
VIC	Otway	Otway	See AEMO's 2024 IASR	2	2	1	20
SQ	Surat	Roma	See AEMO's 2024 IASR	2	2	1	20

3.2.2 PHES

PHES project Snowy 2.0 consists of connecting the existing Tantangara and Talbingo reservoirs through 27 km of underground tunnels, and the construction of an underground hydro-electric power station with pumping capabilities. As of December 2024, Snowy 2.0 has a revised total cost to completion of AU$12 B, with an estimated cost to complete of AU$7.7 B, and an envisaged commissioning date by December 2028 [49]. Connecting Snowy 2.0 to the NEM is a separate project consisting of 9 km of new HV transmission lines which will span the Tumut River, a switching station located in the Bago State Forest, and an upgrade of the access tracks to the new switching station and transmission line structures [50]. The cost of this connection is not included in the CapEx stipulated in [49].

To ensure a fair comparison with the CapEx of the HESSs which include the cost of connection to the NEM, a connection cost of 115.5 $/kW (see "Connection cost" in AEMO's IASR workbook [42]) is added to the current CapEx of Snowy 2.0. Distributing the remaining AU$7.7 B equally across the 4 years from 2025 and 2028 and discounting these cashflows back to 2024 results in a CapEx NPV of $AU10.42 B. The annual FOM cost is assumed to be 3% of the total CapEx. An overview of Snowy 2.0 and its connection to the NEM are shown in Figure 21.



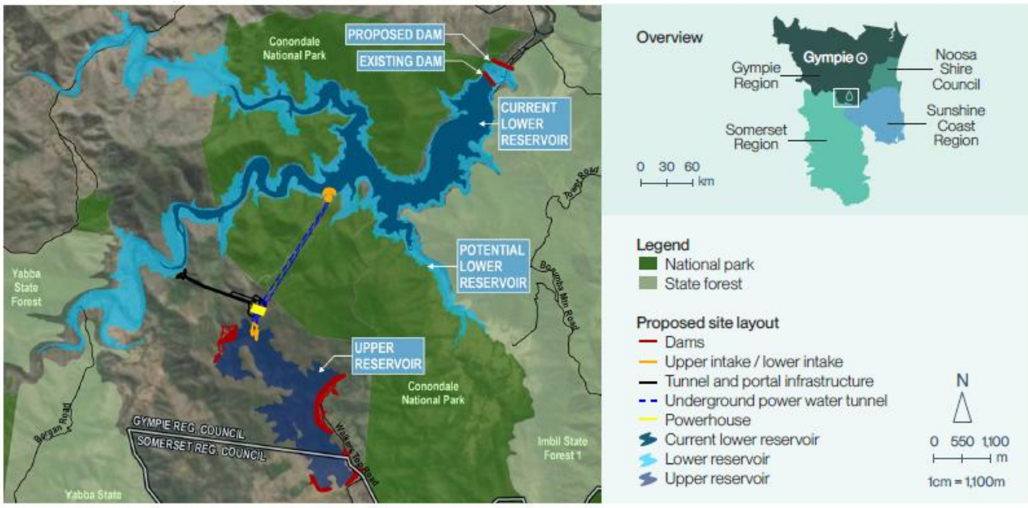
a) Illustration of Snowy 2.0 (image from [49])

b) Illustration of Snowy 2.0 connection to the NEM (image from [50])

Figure 21: An overview of Snowy 2.0 and its connection to the NEM.

The construction of the PHES project at Lake Borumba involves building a new high dam to expand the existing lower reservoir (Lake Borumba) and creating an upper reservoir by constructing a new dam at a higher elevation. An underground powerhouse will connect the two reservoirs, allowing water to be pumped from the lower to the upper reservoir or to be released from the upper reservoir to the lower reservoir to power the hydro turbines for electricity generation [51]. Borumba PHES is expected to cost AU$14.2 B by the time of its completion in 2030.

As this cost does not include the cost of connection, a connection cost of 110.5 $/kW (see “Connection cost” in AEMO’s IASR workbook [42]) is added to the current CapEx of Borumba to once again ensure a fair comparison with the CapEx of the HESSs which include the cost of connection to the NEM. Spreading the resulting AU$14.42 B equally across the 6 years from 2025 and 2030 and discounting these cashflows back to 2024 results in a CapEx NPV of $AU11.51 B. The annual FOM cost for Borumba is assumed to be 3% of the total CapEx. An overview of Borumba and its connection to the NEM are shown in Figure 22.



Proposed main works for Borumba Pumped Hydro Project

Figure 22: Overview of Borumba (image from [51]).

3.3. Market dispatch modelling

Central to all the key insights in this report is a large-scale optimisation framework that models the NEM over multiple years with relatively high temporal and spatial resolutions. More specifically, the framework consists of a long-horizon, network-constrained unit commitment model that is time-coupled through state-of-energy (SoE) constraints, ramp rates, and minimum up-time and down-time constraints for coal-fired generators (CFG) and gas-fired generators (GFG). The model adopts a twelve-node network representation of the NEM as shown in Figure 23. Mathematically, the objective of the optimisation model is to minimise operational costs, in the form of offers that reflect short-run marginal costs (SRMC) or long-run marginal costs (LRMC) where applicable,[2] subject to sub-regional electricity demands and sub-regional domestic hydrogen demands, as well as hydrogen export demands over the whole planning horizon as

$$\text{Minimise } Generation\ offers - bids + DSP\ offers + VoLL \tag{1}$$

subject to

$$Nodal\ power\ balance\ constraints: \tag{2}$$

[2] In the NEM, an “offer” represents the price at which a market participant is willing to *sell* electricity, whereas a “bid” is the price at which a market participant is willing to *buy* electricity.

$$
\begin{aligned}
&\quad\quad Electricity\ demand\ \text{(subregional, 30 min)}\\
&\quad\quad H_2\ domestic\ demand\ \text{(subregional, 30 min, flexible, monthly target)}\\
&\quad\quad H_2\ export\ demand\ \text{(export ports, 30 min, flexible, monthly target)}\\
&\quad\quad MLF
\end{aligned}
$$

$$
\begin{aligned}
&HESS\ constraints:\\
&\quad\quad Electrolyser\ operation\\
&\quad\quad H_2\ turbine\ operation\ \text{(including } ramp\ rates\text{)}\\
&\quad\quad Compressor\ power\ consumption\\
&\quad\quad Pipeline\ operation\\
&\quad\quad UHS\ SoE
\end{aligned}
\tag{3}
$$

$$
Coal - fired\ generation\ constraints\ \text{(including } ramp\ rates \text{ and } minimum\ up - time\ and\ down - time\text{)} \tag{4}
$$

$$
Gas - fired\ generation\ constraints\ \text{(including } ramp\ rates \text{ and } minimum\ up - time\ and\ down - time\text{)} \tag{5}
$$

$$
H_2\ reciprocating\ engine\ constraints\ \text{(including } ramp\ rates\text{)} \tag{6}
$$

$$
PHES\ constraints\ \text{(including } SoE\text{)} \tag{7}
$$

$$
Wind\ generation\ constraints \tag{8}
$$

$$
Solar\ generation\ constraints \tag{9}
$$

$$
BESS\ constraints\ \text{(including } SoE\text{, and } degradation\text{)} \tag{10}
$$

$$
Hydro\ generation\ constraints \tag{11}
$$

$$
Network\ constraints\ \text{(including } losses\text{)} \tag{12}
$$

$$
Reserve\ constraints\ \text{(regional)} \tag{13}
$$

$$
VPP\ constraints\ \text{(subregional)} \tag{14}
$$

$$
DSP\ constraints\ \text{(regional)} \tag{15}
$$

where $VoLL$ is the *value of lost load.*

The main sources of data input for the modelling of the NEM in this project are AEMO's 2023 IASR workbook [42] and the optimal development path (ODP) identified in the *Step Change scenario* in AEMO's 2024 ISP [3]. The model is agile and parametrised which allows it to support any other scenario and ODP in AEMO's 2024 ISP [3]. The Step Change scenario was chosen because it has the largest likelihood at 43%, compared to the *Progressive Change* scenario at 42% and the *Green Energy Exports* scenario at 15% [3].

The proposed model in (1)-(15) is, to the best knowledge of the authors, mathematically akin to the *time-sequential model* in AEMO's 2024 ISP which includes generator reliability settings. However, the following key assumptions and modelling choices characterise the proposed model in this work.

3.3.1 Temporal and spatial resolution

The proposed optimisation-based market dispatch model in (1)-(15) has a 20-year planning horizon and adopts a temporal resolution of 30 minutes and a twelve-node network representation of the NEM, as shown in Figure 23. Transmission projects in CDP 14 in AEMO's 2024 ISP [3] are shown in Figure 79 in Appendix A, and their transfer capability along the flow paths under different system conditions are listed in Table 50 in Appendix A.

3.3.2 HESS constraints

The proposed optimisation-based market dispatch model in (1)-(15) incorporates new HESS constraints delineated in (3). These constraints capture operational requirements of electrolyser and hydrogen turbines, compressor power consumption, pipeline operation (including linepack[3]), and UHS state of energy.

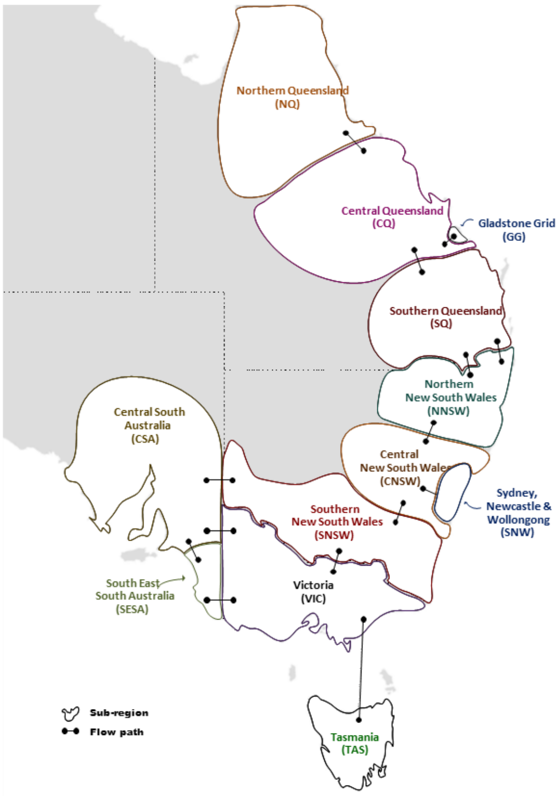


Figure 23: The twelve sub-regions in the NEM as stipulated in AEMO's 2024 ISP [3].

3.3.3 Offering behaviour: CFG, GFG, and hydro generators

All conventional synchronous generators (i.e., coal-fired, gas-fired, and hydro) submit two price bands, the first is their SRMC (obtained from AEMO's 2023 IASR workbook [42]), and the second is a value slightly lower than the market price cap of $17,500/MWh. The second price band is a small fraction of the capacity of the conventional synchronous generator, whose exact value is determined from the reliability response as a percentage of the regional demand in AEMO's 2023 IASR workbook [42], which typically ranges from 0.41% to 7.29% depending on the region and planning year.

These regional reliability response percentages are shown in Table 53 and Table 54 in Appendix A for winter and summer months, respectively. This behaviour of offering a small proportion of a generator's capacity at near the market price cap is common practice in the NEM, as it allows the participant to increase opportunities of maximising revenue without risking not being inframarginal or marginal. This reasoning is especially true if the *majority*, as opposed to only a small proportion, of typically marginal generators (e.g., GFG, and hydro) adopts such an offering behaviour, because it further increases the likelihood of clearing the market at near the market price cap during reliability events.

With the predicted increasing rate of retirement of coal generation coinciding with a growth in demand and an increasing share of flexible generation (especially storage systems) [3], the already rare occurrence of market prices that are close to the market floor price of -$1000/MWh, which are mainly a byproduct of the *inflexibility of coal-fired generators*, is expected to decrease as well. This observation was corroborated numerically by the

[3] The linepack refers to the amount of pressurised gas stored in a pipeline.

optimisation model in (1)-(15), which, when it incorporates the generator technical and economic constraints (opportunity cost versus cost of startup and shut down, and minimum up-time and down-time constraints) that engender such prices, did not reveal any instances where the clearing price is close to the market floor of -$1000/MWh.

This is because instead of clearing the market at around -$1000/MWh when the operational demand[4] is low (due to high rooftop PV generation for example), the model instead deems it more economical in the medium to long term to increase the operational demand by charging storage systems, thereby ensuring that the marginal generator is one with an offer that is much higher than the market floor price.

The SRMC of all hydro generators is assumed to be $8.58/MWh in this work, in line with AEMO's 2023 IASR workbook [42]. However, if considered as an offer, this SRMC is much lower than the actual offers witnessed in the NEM in 2024-25, as shown in Figure 24. The revenue opportunities computed in this work could potentially be higher if hydro generators are assumed to offer within the range $71/MWh to $111/MWh shown in Figure 24, especially if hydro remains the most frequent price setter beyond 2030. Similar trends are observed in quarters 1, 2, and 3 of 2024 as per as per AEMO's Quarterly Energy Dynamics (QED) [52]. This assumption therefore ensures both *conservatism* and strong *alignment* with AEMO's 2024 ISP [3].

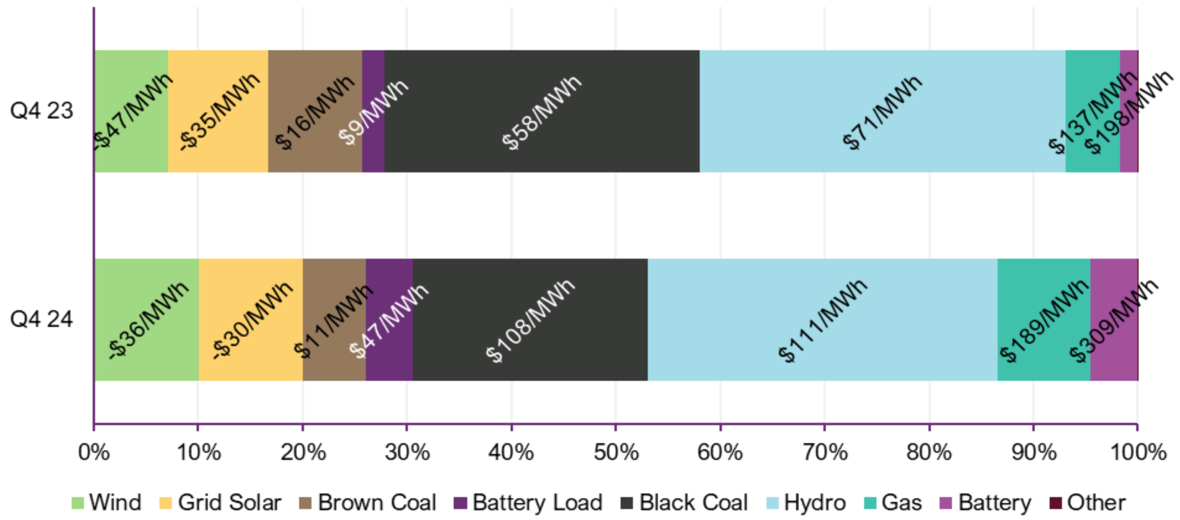


Figure 24: Price-setting frequency by fuel type in quarter 4 of 2023 and 2024 as per AEMO's Quarterly Energy Dynamics [52].

3.3.4 Offering/bidding behaviour: VPP

Virtual power plants (VPP), which represent the coordination of consumer energy resources (CER), offer to sell (discharge) and bid to buy (charge) energy based on optimised *opportunity cost*.[5]

3.3.5 Offering/bidding behaviour: BESS and VRE

To capture the long-term uncertainty around offering prices of VRE and bidding and offering prices of BESS in the market, a sensitivity analysis with four different sensitivities is developed in this work to assess the impact of these prices on estimates of LCOE and LROE of Snowy

[4] Operational (sent-out) demand refers to demand supplied from the NEM, consumers' rooftop PV and behind-the-meter BESS.
[5] The "opportunity cost" of a storage system refers to the potential profit that system could have earned by discharging its stored energy at a later time when electricity prices are higher.

2.0, Borumba, and the HESSs in VIC and QLD. These four sensitivities are summarised in Table 12 for offering prices of BESS and VRE and Table 13 for the bidding prices of BESS.

Under sensitivities 1 and 2, all BESS are assumed to offer and bid based on optimised opportunity cost. On the other hand, sensitivities 3 and 4 assume that all BESS offer to generate (discharging) at their LCOE, i.e., their long-run marginal cost (LRMC), and to bid based on optimised *opportunity cost*. This assumption is justified as follows. BESS currently (in 2024-25) make more than half of their revenue from participating in the frequency control and ancillary services (FCAS) market [53]. However, with an increasing uptake in BESS, coinciding with a decline in coal generation, the FCAS market in Australia is likely to become saturated, thereby prompting BESS to seek cost recovery predominantly from the wholesale market.

One way to capture this in the model is to assume that all BESS offer to sell electricity at their LCOE when generating. The LCOE values of BESS, listed in Table 55 in Appendix A, are computed based on sub-regional build costs, connection costs, CF, FOM costs, and lead times obtained from AEMO's 2024 ISP under the Step Change scenario [3]. These LCOE values, which range between $109/MWh and $300/MWh for BESS and $214/MWh and $65/MWh for PHES, are in congruence with the ones in Lazard's 2024 levelised cost of storage (LCOS) analysis [54]. This assumption is further substantiated in Figure 24 which shows NEM prices between $198/MWh and $309/MWh when BESS are the price setters in quarter 4 of 2023 and 2024. These two offering and bidding behaviours can be viewed as encompassing different energy arbitrage strategies and opportunity costs for BESS.

To generate more realistic wholesale prices that reflect the current operation and settlement of the NEM Dispatch Engine (NEMDE), all renewable generators are assumed to offer energy at prices close to the Large-scale Generation Certificates (LGCs) [55]. Rather than relying on specific historical LGC data, these values are derived from the long-run marginal cost (LRMC) of utility-scale wind and solar, to avoid bias. The LRMC (i.e., LCOE) of utility-scale wind and solar listed in Table 51 and Table 52 in Appendix A, are computed based on sub-regional build costs, connection costs, CF, FOM costs, and lead times obtained from AEMO's 2024 ISP under the Step Change scenario [3]. These LCOE values, which range between $66/MWh and $300/MWh for wind (including offshore) and between $37/MWh and $130/MWh for solar, are consistent with the ones in Lazard's 2024 LCOE analysis [54].

As LGCs are expected to cease in 2030, sensitivities 1 and 3 assume that all utility wind and solar generators offer to sell at prices close to the LGCs until 2030, and at $0/MWh beyond. On the other hand, sensitivities 2 and 4 assume that other long-term contracts such as Guarantee of Origin [56], or Power Purchase Agreements (PPAs) in general may, still incentivise utility wind and solar to offer to sell at negative prices beyond 2030. Due to transparency around PPAs, VRE generators are therefore assumed to offer to sell at prices close to the negative of the *current* LGC prices until 2050.

Table 12: Four sensitivities with different assumptions on offering prices of VRE and BESS.

Sensitivity	Generator offering price									
	CFG	**GFG**	**Hydro**	**Utility Wind**	**Utility solar**	**BESS**	**PHES**	**VPP**	**DSP**	**HESS**
1	SRMC			LGCs and PPAs cease in 2030	LGCs and PPAs cease in 2030	Opportunity cost	Opportunity cost	Opportunity cost	5 segments ($300MWh to $17,500/MWh)	Opportunity cost
2	SRMC			LGCs case in 2030. PPAs out to 2050	LGCs case in 2030. PPAs out to 2050	Opportunity cost	Opportunity cost	Opportunity cost	5 segments ($300MWh to $17,500/MWh)	Opportunity cost

3	SRMC	LGCs and PPAs cease in 2030	LGCs and PPAs cease in 2030	LRMC	Opportunity cost	Opportunity cost	5 segments ($300MWh to $17,500/MWh)	Opportunity cost
4	SRMC	LGCs case in 2030. PPAs out to 2050	LGCs case in 2030. PPAs out to 2050	LRMC	Opportunity cost	Opportunity cost	5 segments ($300MWh to $17,500/MWh)	Opportunity cost

Table 13: Assumptions on bidding prices of BESS under each sensitivity.

Sensitivity	Bidding price			
	BESS	**PHES**	**VPP**	**HESS**
1	Opportunity cost	Opportunity cost	Opportunity cost	Opportunity cost
2	Opportunity cost	Opportunity cost	Opportunity cost	Opportunity cost
3	Opportunity cost	Opportunity cost	Opportunity cost	Opportunity cost
4	Opportunity cost	Opportunity cost	Opportunity cost	Opportunity cost

3.3.6 Offering behaviour: DSP

Demand-side programs (DSP) are activated *only* during Lack of Reserve 2 (LOR2) and Lack of Reserve 3 (LOR3) events [57]. The anticipated voluntary reduction in operational demand, measured in MW, due to DSP, including wholesale demand response (WDR), is shown in Table 56 and Table 57 in Appendix A for winter months and summer months, respectively. The level of this reliability response accounts for responses driven by both price signals and network reliability programs, as expected during actual LOR2 or LOR3 events.

As an example, users participating in DSP under the Step Change scenario in NSW during the summer of 2028-29 would observe no response for prices below $1000/MWh, a reduction of 192 MW if prices are between $1000/MWh and $750/MWh, and a total reduction of 194 MW when prices exceed $750/MWh. In case of a reliability event, the combined response would be 668 MW, and the price would be close to the market cap of $17,500/MWh (see Table 57 in Appendix A). A detailed description of the different reserve levels, namely LOR1, LOR2, LOR3, are listed in Table 14.

Table 14: Definition of different reserve levels, namely LOR1, LOR2, LOR3 [57].

Terminology	Definition
LOR1	Is a notification that reserve levels are lower than the two largest supply resources in a state. At this stage, there is no impact on power system reliability and AEMO continues to monitor reserve levels to maintain adequate supply.
LOR2	Signals when reserve levels are lower than the single largest supply resource in a state, calling for a market response. At this le vel, there is no impact on the power system, but supply could be disrupted if a large contingency occurs. Once a forecast LOR2 is declared, AEMO has the ability to direct generators or activate reserve mechanisms to improve the supply-demand balance.
LOR3	Signals a deficit in electricity supply resulting in a system security condition. On a forecast LOR2, load shedding may be required, while for an actual LOR3, load shedding will be or is already activated.

Figure 25 illustrates another DSP example in which a DSP response of up to 20 MWh is offered at $400/MWh if reserves are between 0 and 20 MW lower than the single largest supply resource in a region. If reserves are between 20 MW and 60 MW lower than the single largest supply resource in a region, the commensurate DSP response is offered at $750/MWh. Following the same line of reasoning, if reserves are between 60 MW and 80 MW lower than the single largest supply resource in a region, the commensurate DSP response is offered at $4250/MWh, etc.

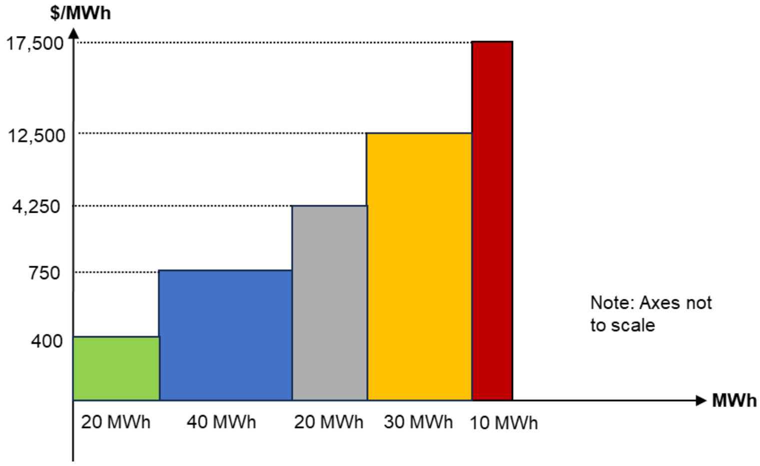


Figure 25: Example of DSP offering behaviour.

3.3.7 Summary

The optimisation-based market dispatch model in (1)-(15) is far less sensitive to short-term (e.g., intra-day) variations in offering and bidding prices than to *long-term trends in offering and bidding behaviour*. For example, the model is not sensitive to a GFG bidding at $200/MWh at 6 pm one day and then at $400/MWh another day when its actual production cost is $300/MWh, as long as in the long run its average offering price is $300/MWh. The same example can be made for hydro generators and coal generators.

As the NEM is based on the assumption of "perfectly competitive" market, which players are *price-takers*,[6] it incentivises participants to offer to sell at prices as close to their true production cost as possible. In summary, the considered *long-term trends in bidding behaviour* are:

- All BESS offer to sell and bid to buy based on optimised opportunity cost. This corresponds to sensitivities 1 and 2 in Table 12 and Table 13.
- All BESS offer to sell and their LRMC and bid to buy based on optimised opportunity cost. This corresponds to sensitivities 3 and 4 in Table 12 and Table 13.
- All utility wind and solar offer to sell at prices close to the negative of *current* LGC prices until 2030, and at $0/MWh from 2031 out to 2050. This corresponds to sensitivities 1 and 3 in Table 12 and Table 13.
- All utility wind and solar offer to sell at prices close to the current LGC prices until 2050. This corresponds to sensitivities 2 and 4 in Table 12 and Table 13.

3.4. LCOE and LROE

In general, the LCOE represents the average cost of generating electricity from a specific energy source over its lifetime. It includes expenses such as CapEx, fixed O&M (FOM), maintenance, variable O&M (VOM), and fuel, enabling a standardised metric for comparing *costs* different power generation technologies. For electricity storage technologies, the fuel cost is replaced with the cost of purchasing electricity. Because storage cannot continuously generate electricity, as it must recharge, its CF cannot exceed a 50%. Once the annual energy

[6] Under uniform pricing, a market is considered perfectly competitive if the number of players grows to infinity [74].

production and the RRP are obtained from solving Model (1)-(15), the cost of purchasing electricity from the NEM can be computed from the half-hourly wholesale energy prices as

$$Electricity\ Cost(\$) = Energy\ consumed\ (\mathrm{MWh}) \times\ clearing\ price\ \left(\frac{\$}{\mathrm{MWh}}\right),$$

and the LCOE [58] can be determined from

$$LCOE\ \left(\frac{\$}{\mathrm{MWh}}\right) = \frac{CapEx_{\mathrm{NPV}} + FOM\ cost_{\mathrm{NPV}} + VOM\ cost_{\mathrm{NPV}} + Electricity\ cost_{\mathrm{NPV}}}{Energy_{\mathrm{NPV}}}.$$

Knowing that the inframarginal generators[7] are paid the spot price adjusted by the MLF [58], the revenue from selling electricity in the wholesale market is given by

$$Revenue\ (\$) = Energy\ generated\ (\mathrm{MWh}) \times\ clearing\ price\ \left(\frac{\$}{\mathrm{MWh}}\right) \times MLF\ (\%),$$

and the levelised revenue of energy (LROE) is given by

$$LROE\ \left(\frac{\$}{\mathrm{MWh}}\right) = \frac{Revenue_{\mathrm{NPV}}}{Energy_{\mathrm{NPV}}}.$$

The LROE can also be thought of as a standardised metric for comparing the potential *revenue* of different power generation technologies over their lifetime. A project is deemed commercially viable if its LROE is higher than its LCOE.

Since it is extremely challenging to model offering/bidding behaviour with a high degree of certainty, this work proposes a methodology based on the revenue duration curve (RDC), which is derived from the *price duration curve* (PDC), to estimate revenue *opportunities* for a market participant [59]. The PDC is a graph that shows the distribution of wholesale energy prices in descending order across a full financial year. It illustrates the proportion of time in which prices could exceed a given level. In this report, the following steps are taken for computing the PDC:

1) Determine the regional reference price (RRP) for every 30-minute period by solving Model (1)-(15).
2) Sort the RRP in descending order (highest to lowest).
3) Plot the descending prices across the full financial year over a 0% to 100% time base.
4) Use this data set as a basis for computing the RDC.

The RDC indicates the average price that prevails during the proportion of time in which prices could exceed a given level. Ideally, it represents the average spot market earnings a participant could achieve (per MWh) by operating exclusively when spot prices are at, or above a specific level. In this report, the following steps are taken for computing the RDC:

1) Determine the RRP for every 30-minute period by solving Model (1)-(15).
2) Sort the RRP in descending order (highest to lowest).

[7] The term “inframarginal” refers to market participants who offer to sell electricity at a price that is lower than the market clearing price. These market participants are therefore *dispatched* by the market clearing engine. In contrast, market participants who offer to sell electricity at a price that is higher than the market clearing price are *not* dispatched.

3) Compute a running average of the descending prices by interval, i.e., $\left(\frac{\text{sum of descending prices}}{\text{Count of periods}}\right)$.

4) Plot the running average across the full financial year over a 0% to 100% time base.

An example PDC and RDC in VIC generated by the proposed model for year 2030-31 is shown in Figure 26. The forecast operability and the RRP behind these PDC and RDC are shown in Figure 95 and Figure 96 in Appendix B. Figure 96 shows more coal-fired and gas-fired generation in winter than in summer, contributing to more price volatility, as shown in Figure 95. The revenue opportunities derived from the RDC can also be thought of as the *theoretical maximum revenue* that can be obtained if offering/bidding behaviour is optimised over the whole year.

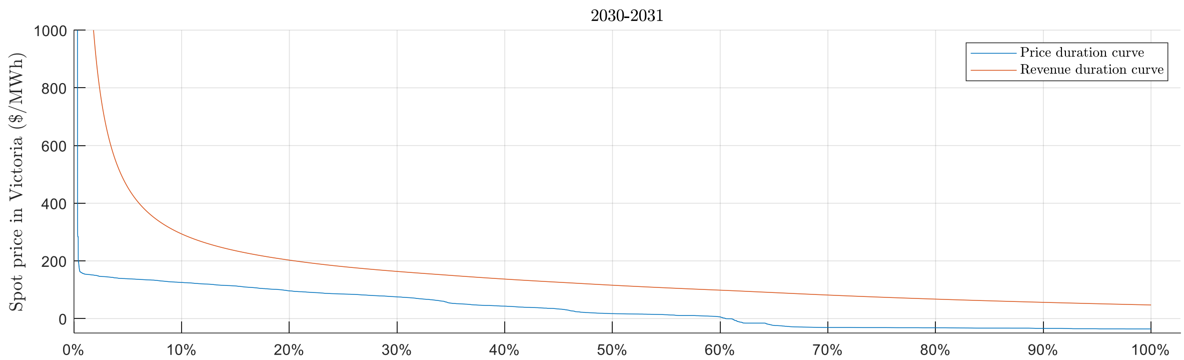


Figure 26: Example PDC and RDC in VIC generated by the proposed model for year 2030-31.

Formally, the methodology for computing the LCOE and LROE for any market player i is as follows:

1. **With** i ***included*** in the generation mix, invoke the optimisation-based market dispatch model in (1)-(15) to compute the half-hourly RRP, as well as half-hourly production (discharging) and consumption (charging) for i, which can be used to find the **LCOE** for player i.

2. **With** i ***excluded*** from the generation mix, invoke the optimisation-based market dispatch model in (1)-(15) to compute the half-hourly RRP.

3. **Compute the PDC and the RDC** for the region in which player i is located, using the RRP from Step 2.

4. **Find the intersection** between the CF of i (from Step 1), and the RDC to find the average clearing price that prevails during the proportion of time in a year that is no greater than its CF, and during which the prices are expected to be higher than the intersection between the CF and the PDC.

5. **Compute the annual maximum potential revenue** by multiplying the average clearing price (Step 4) by the annual energy production and the MLF.

6. **Compute the LROE** for player i.

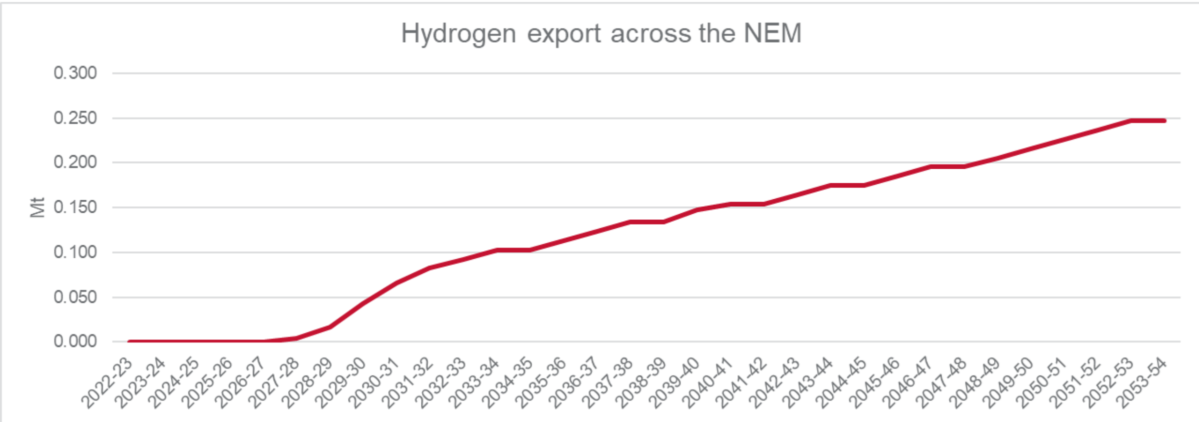
7. **Repeat** for each sensitivity case.

The idea of solving the optimisation model twice—once with player i included and once with player i excluded—is rooted in concepts from game theory, such as the Shapley value [60] and the Vickrey-Clarke-Groves mechanism [61], [62], [63]. The aim is to estimate the *maximum revenue opportunities*, which, under this methodology, is quantified for a market player i *before* it participates in the market. The rationale behind this methodology is that computing the RDC with the subject participant present in the market does not fully reflect these revenue opportunities, as their presence alters the market dynamics, and therefore the prices.

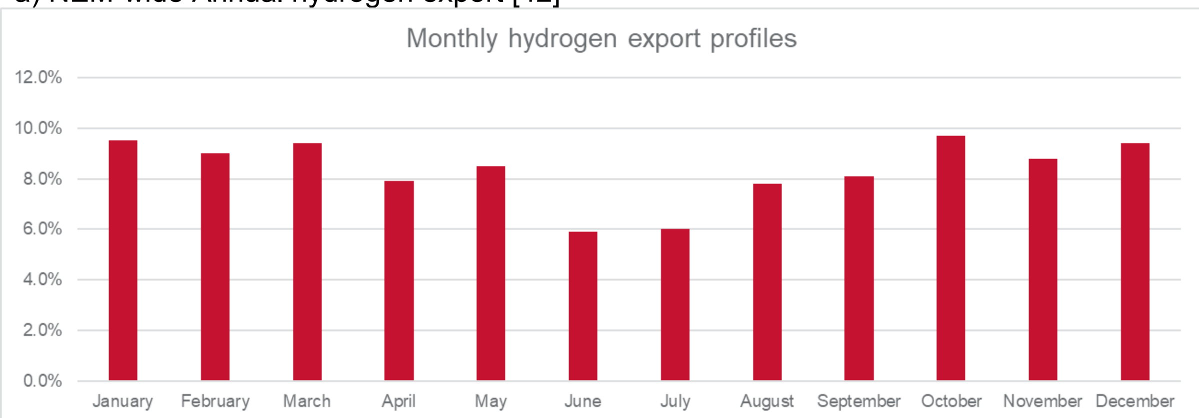
3.5. Hydrogen demand

Annual domestic and export hydrogen demand, shown in Figure 27a and Figure 80a in Appendix A, are obtained directly from AEMO's 2023 IASR workbook [42]. However, instead of adopting the same monthly targets for domestic hydrogen demand stipulated in AEMO's 2023 IASR workbook [42], monthly targets for hydrogen export demands are instead determined based on historical schedules of liquefied natural gas (LNG) ships in Australia [64] and pilot hydrogen export projects between Australia and Japan [65].

Annual hydrogen export targets under the Step Change scenario can be found in AEMO's 2023 IASR workbook [42]. These monthly hydrogen export profiles are shown in Figure 27b. Figure 27b shows that winter months, particularly June and July, witness less exports compared to the rest of the year. In contrast, typical monthly domestic hydrogen profiles, shown in Figure 80b in Appendix A, show higher demands in winter months compared to summer months.



a) NEM-wide Annual hydrogen export [42]



b) Monthly hydrogen export profiles developed in this work

Figure 27: Annual hydrogen exports and monthly hydrogen export profiles used in this report.

3.6. Framework architecture

The solution from the mathematical model in (1)-(15) enables generating regional and sub-regional wholesale prices, and annual energy production from every participant, from which the levelised cost of energy (LCOE) and the levelised revenue of energy (LROE) can be computed. State-of-the-art optimisation techniques including parallelised sparse Cholesky factorisation and rolling-horizon optimisation are used to solve this large-scale problem, which has around 480 million variables and 512 million constraints, in a tractable way. Despite these techniques, the model still takes around 11 hours to solve for each scenario in Table 15 (see Section 4) on a high-performance computer (HPC) with an Intel 13th Gen Intel(R) Core(TM) i9-13900KF at 3.00 GHz, 64 GB RAM, and 32 threads.

The overarching architecture of the developed modelling framework is shown in Figure 28. The methodology development was an iterative process alternating between model management and model evaluation. Model management involved a rigorous process of fine-tuning optimisation parameters and offering/bidding assumptions that best mimic how market participants behave in the NEM today and will behave in the future, while maintaining computational scalability.

The evaluation process was supported by consistent stakeholder engagement within FF CRC to validate model output against multiple benchmarks including existing reservoir simulations, build costs and LCOE in existing literature, general generation and transmission development trends in AEMO's 2024 ISP [3], and market insights such as AEMO's Quarterly Energy Dynamics [52].

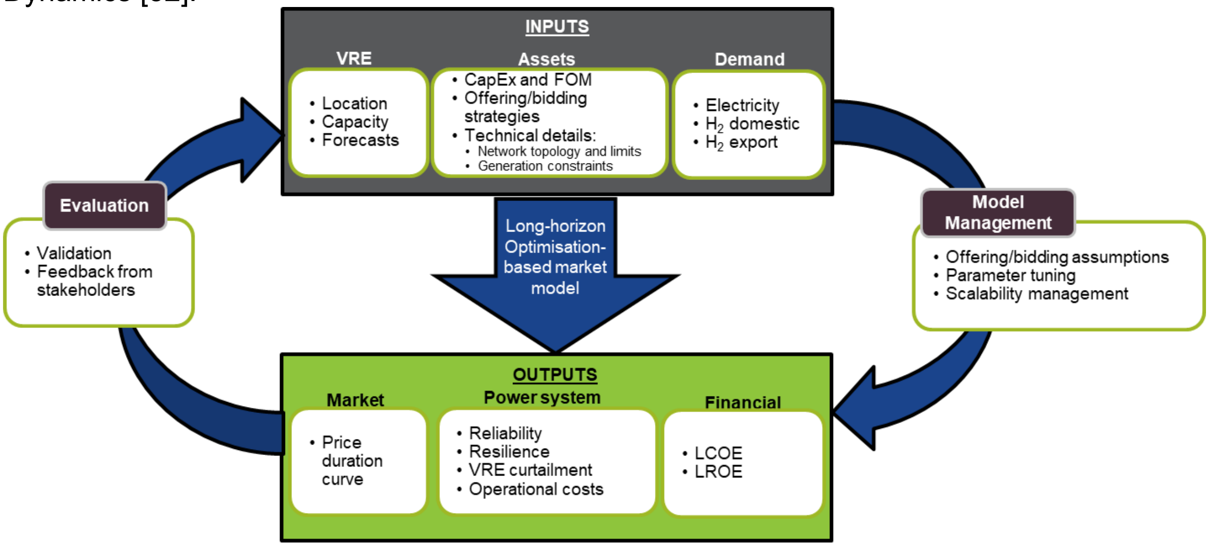


Figure 28: Framework architecture.

4. LDES scenarios

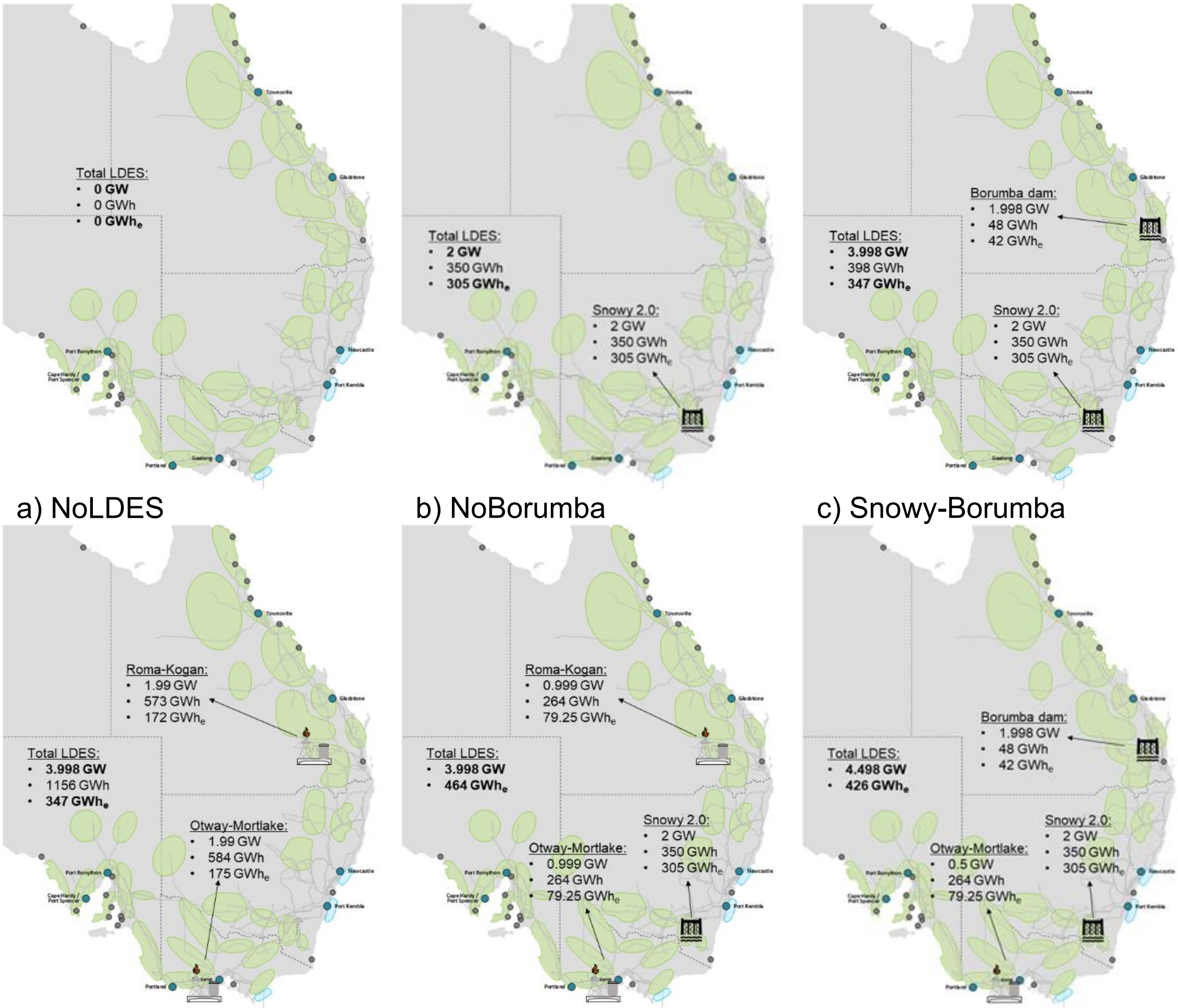
Six LDES scenarios are systematically designed to assess the merits of HESSs in VIC and SQ in providing LDES to the NEM, and how their LCOE and LROE compare to that of PHES, such as Snowy 2.0 and Borumba, under the reliability standards stipulated in AEMO's 2024 ISP [3] over a 20-year period, as well as stringent resilience requirements against prolonged VRE droughts. These six scenarios are described in Table 15 and illustrated in Figure 29.

The long-horizon optimisation-based market dispatch model in (1)-(15) is invoked for each scenario in Table 15, and for each sensitivity study described in Table 12 and Table 13. The basis scenarios for computing the LCOE and LROE are summarised in Table 16. Following the step outlined in the LCOE and LROE computation methodology, the LROE for Snowy 2.0, Borumba, and the two 2 GW HESS in the HESS-VIC-QLD-4GW scenario is obtained from the RRP under the NoLDES scenario in which all four LDES options are removed. Similarly, the LROE of the two 1 GW HESS in the HESS-VIC-QLD-2GW scenario is obtained from the RRP under the NoBorumba scenario in which *only* Borumba is removed. Finally, the LROE of the 500 MW HESS in the HESS-VIC-QLD-2GW scenario is obtained from the RRP under the Snowy-Borumba scenario in which *neither* Snowy 2.0 nor Borumba are removed.

A more elaborate description of each scenario is detailed in the six subsections below.

Table 15: Description of the six proposed LDES scenarios.

LDES Scenario	Description	Total deep storage power (GW)	Total deep storage capacity (GWh_e)
NoLDES	A counterfactual scenario in which no LDES options exist in the NEM. This scenario serves as the basis for computing the PDC and RDC for Snowy 2.0, Borumba, and the two 2 GW HESSs in the HESS-VIC-QLD-4GW scenario.	0	0
NoBorumba	A hypothetical scenario in which Borumba does not exist and Snowy 2.0 is the only LDES option. This scenario serves as the basis for computing the PDC and RDC for the two 1 GW HESSs in the HESS-VIC-QLD-2GW scenario.	2	305
Snowy-Borumba	Both Snowy 2.0, located in SNSW, and Borumba, located in SQ, are considered for LDES. This scenario, which uses the same input and output assumptions as the Step Change scenario in AEMO's 2024 ISP, assumes that Snowy 2.0 and Borumba will be operational by 2028 and 2031, respectively. This scenario serves as the basis for computing the PDC and RDC for the 500 MW HESS in the HESS-VIC-0.5GW scenario.	3.998	347
HESS-VIC-QLD-4GW	A hypothetical scenario in which Snowy 2.0 and Borumba are replaced with HESS in VIC and SQ. For both HESS projects, 1 GW is assumed to be commissioned by 2028 and another 1 GW by 2031.	3.998	347
HESS-VIC-QLD-2GW	A hypothetical scenario in which Borumba is replaced with 1 GW HESSs in VIC and SQ. Snowy 2.0 exists in this scenario. Both HESSs are assumed to be commissioned by 2031.	3.998	464
HESS-VIC-0.5GW	A hypothetical scenario in which both Snowy 2.0 in SNSW and Borumba in SQ exist, and a HESS with 500 MW and 158 hours of net storage is commissioned in VIC in 2031.	4.498	426



a) NoLDES b) NoBorumba c) Snowy-Borumba

d) HESS-VIC-QLD-4GW e) HESS-VIC-QLD-2GW f) HESS-VIC-0.5GW

Figure 29: Illustration of the six designed scenarios to assess the merits of Snowy 2.0, Borumba, and two HESSs in VIC and SQ. The conversion from GWh to GWh$_e$ involves the efficiencies of the generators for each LDES technology.

Table 16: Basis scenarios for deriving the LCOE and LROE.

LDES option	LCOE basis scenario	LROE basis scenario
Snowy 2.0 (2000 MW)	Snowy-Borumba	NoLDES
Borumba (1998 MW)	Snowy-Borumba	
Otway-Mortlake HESS (1999 MW)	HESS-VIC-QLD-4GW	
Roma-Kogan HESS (1999 MW)	HESS-VIC-QLD-4GW	
Otway-Mortlake HESS (999 MW)	HESS-VIC-QLD-2GW	NoBorumba
Roma-Kogan HESS (999 MW)	HESS-VIC-QLD-2GW	
Otway-Mortlake HESS (500 MW)	HESS-VIC-QLD-0.5GW	Snowy-Borumba

4.1. Scenario NoLDES

NoLDES is a counterfactual scenario in which no LDES options exist in the NEM. This case serves as the basis for computing the PDC and RDC for Snowy 2.0, Borumba, and the two 2 GW HESSs in the HESS-VIC-QLD-4GW scenario. This case is illustrated in Figure 29a.

4.2. Scenario NoBorumba

NoBorumba is a hypothetical scenario in which Borumba does not exist and Snowy 2.0 is the only LDES option. This scenario serves as the basis for computing the PDC and RDC for the two 1 GW HESSs in the HESS-VIC-QLD-2GW scenario. This case is illustrated in Figure 29b.

4.3. Scenario Snowy-Borumba

In this scenario, both Snowy 2.0, located in SNSW, and Borumba, located in SQ, are considered for LDES. This scenario, which uses the same input and output assumptions as the Step Change scenario in AEMO's 2024 ISP, assumes that Snowy 2.0 and Borumba will be operational by 2028 and 2031, respectively. This scenario serves as the basis for computing the PDC and RDC for the 500 MW HESS in the HESS-VIC-0.5GW scenario.

4.4. Scenario HESS-VIC-QLD-4GW: Swapping out Snowy 2.0 and Borumba

This is a hypothetical scenario in which both Snowy 2.0 and Borumba are replaced with two HESSs, one in VIC (Otway-Mortlake) and another in SQ (Roma-Kogan), with combined power capacity and storage capacity commensurate to that of Snowy 2.0 and Borumba combined. Specifically, the combined 3.998 GW power capacity of Snowy 2.0 and Borumba is divided equally across the Otway-Mortlake HESS and the Roma-Kogan HESS, as illustrated in Figure 30. The six DGRs in Otway, identified in [15] as suitable for UHS, have a combined hydrogen working storage volume of 14.8 kt and cushion volume of 13.17 kt. Knowing that the HHV of hydrogen is 142 MJ/kg, this 14.8 kt of hydrogen translates to 583.55 GWh of energy, which, when used as fuel for a hydrogen turbine with efficiency of 30%, can provide 175 GWh_e[8] (88 hours net of storage duration at 1.99 GW). The remaining 347-175=172 GWh_e is allocated to the Roma-Kogan HESS under the assumption of availability of suitable fields (see Table 5 in [17]). This 172 GWh_e translates to 573 GWh of working hydrogen energy or 14.5 kt of working hydrogen storage under an HHV=142 MJ/kg. A cushion gas volume of 48% of the total storage volume is assumed for the Roma-Kogan HESS, i.e., 13.5 kt (530.3 GWh). This allocation of storage energy is also shown in Figure 30.

Table 17 summarises the storage characteristics of the considered UHS. Indicative commissioning dates, also shown in Table 17, are meant to align with the 2028-29 commissioning date of Snowy 2.0. To match the combined 3.998 GW pumping capacity of Snowy 2.0 and Borumba which will be available by 2031-32, as viewed from the NEM, the two HESSs are each allocated 1.99 GW of electrolysers, each starting with 1000 MW in 2028-29 and another 999 MW in 2031-32, as shown in Table 18. The indicative commissioning dates in Table 18 are meant to align with those of Snowy 2.0 and Borumba [42], ensuring comparable total loads between the two sets of LDES technologies, as viewed from the NEM. Electrolyser efficiencies are obtained from AEMO'S 2023 IASR workbook [42]. By the same token, a total of 1.998 GW hydrogen turbines are installed 2031-32 in each HESS, as shown in Table 19. The MLF and auxiliary loads for the hydrogen turbines are obtained from AEMO'S 2023 IASR workbook [42].

The diameters of the pipelines connecting the UHS to the electrolysers and hydrogen turbines are determined by finding the smallest possible pipeline diameter that can transport the highest of the two maximum flow rates required by the PEM electrolysers and the hydrogen turbines. In this case, both pipelines (one in VIC and one in SQ) are sized to transport a maximum of 550.6 m^3/s (575.7 TJ/d) necessary to fuel the four hydrogen turbines. The

[8] GWh_e is used to distinguish a GWh of hydrogen energy or gravitational potential energy from the equivalent electrical GWh—i.e., GWh_e—that a HESS or PHES can deliver to the NEM after conversion from chemical or gravitational potential energy to electrical energy, respectively.

optimised diameters are listed in Table 20. Once the pipelines are sized, compressors are then sized based on the flow rate in the pipeline and the required pressures for transmission, injection into, and withdrawal from the UHS facility. The required power consumption of the EMD compressors is computed as detailed in Appendix C, and the findings are summarised in Table 21. Redundancy is achieved by installing two compressors in parallel as shown in column “Qty” in Table 21. A total of 4 compressor stations, each with 2 compressors, are therefore installed by 2031-32 in each HESS.

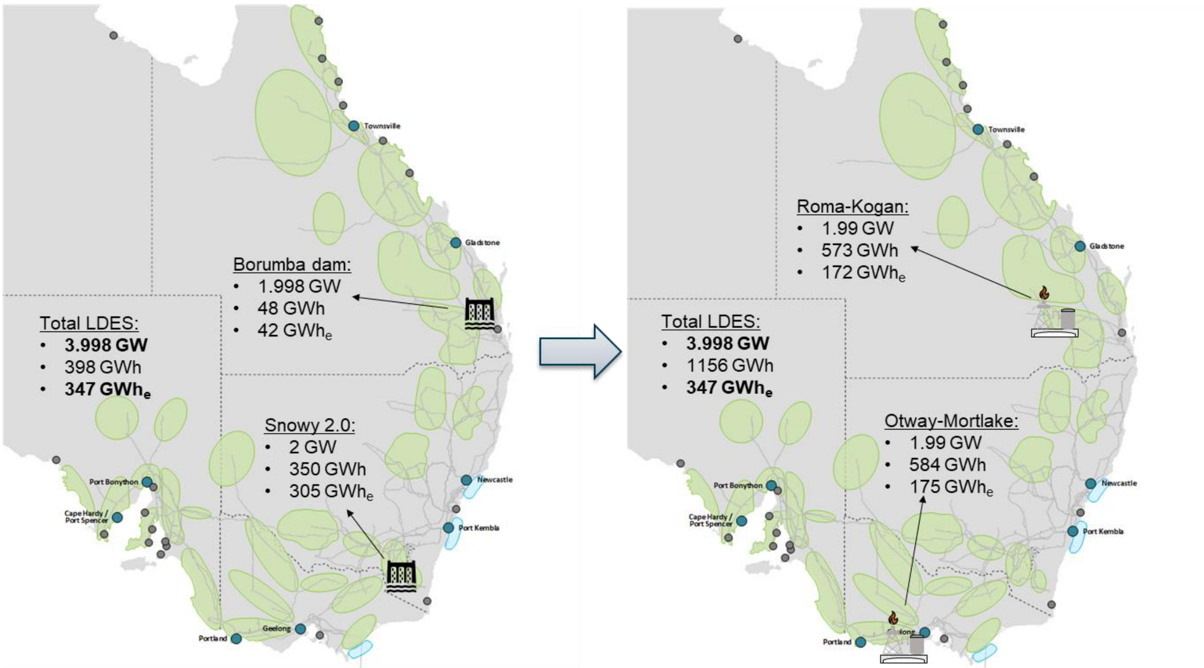


Figure 30: A hypothetical scenario where Snowy 2.0 and Borumba are replaced with HESSs in VIC and SQ.

Table 17: Characteristics and indicative commissioning dates of the UHS facilities in the HESS-VIC-QLD-4GW scenario.

Sub-region	Basin	Site	Cushion (kt)	Cushion (GWh)	Number of fields	Wellbores (per field)	Storage (GWh)	Storage (GWhe)	Storage (kt)	Indicative commissioning date
VIC	Otway	Otway	13.70	540.18	6	2	583.55	175.07	14.80	2028-29
SQ	Surat	Roma	13.45	530.29	6	2	572.87	171.86	14.53	2028-29

Table 18: Characteristics and indicative commissioning dates of the PEM electrolysers in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Capacity (MW)	Efficiency (kWh/kg H_2)	Efficiency	H_2 production (m^3/s)	H_2 production (TJ/d)	Water (kg/s)	Indicative commissioning date
1	VIC	Otway	1000	59.63	66.12%	54.63	57.13	46.58	2028-29
2	SQ	Roma	1000	59.63	66.12%	54.63	57.13	46.58	2028-29
3	VIC	Otway	999	55.73	70.75%	58.40	61.06	49.79	2031-32
4	SQ	Roma	999	55.73	70.75%	58.40	61.06	49.79	2031-32

Table 19: Characteristics and indicative commissioning dates of the hydrogen turbines in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Capacity (MW)	Efficiency (HHV)	H_2 input (m^3/s)	H_2 input (TJ/d)	MLF	Auxiliary load (%)	Connection cost ($/kW)	Indicative commissioning date
1	VIC	Otway	1000	30%	275.44	288.00	0.99	1.10	115.48	2028-29
2	SQ	Roma	1000	30%	275.44	288.00	0.97	1.10	110.49	2028-29

3	VIC	Otway	999	30%	275.16	287.71	0.99	1.10	115.48	2031-32
4	SQ	Roma	999	30%	275.16	287.71	0.97	1.10	110.49	2031-32

Table 20: Characteristics and indicative commissioning dates of the pipelines in the two HESSs in the HESS-VIC-QLD-4GW scenario.

Sub-region	From	To	Length (km)	Diameter (inch)	Capacity (m^3/s)	Capacity (TJ/d)	Minimum pressure (MPa)	Maximum pressure (MPa)	Direction	Indicative commissioning date
VIC	Mortlake	Otway	110	30	550.6	575.7	5.8	8	Bidirectional	2028-29
SQ	Kogan	Roma	200	34	550.6	575.7	5.8	8	Bidirectional	2028-29

Table 21: Characteristics and indicative commissioning dates of the compressors in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Inlet pressure (MPa)	Outlet pressure (MPa)	Throughput (m^3/s)	Throughput (TJ/d)	Throughput (kg/s)	Electricity consumption (MW)	Qty	Indicative commissioning date
1	VIC	Mortlake	3.0	8.0	54.63	57.13	2.44	8.81	2	2028-29
2	SQ	Kogan	3.0	8.0	54.63	57.13	2.44	8.81	2	2028-29
3	VIC	Mortlake	3.0	8.0	58.40	61.06	2.49	9.42	2	2031-32
4	SQ	Kogan	3.0	8.0	58.40	61.06	2.61	9.42	2	2031-32
5	VIC	Otway	6.8	16.0	275.44	288.00	2.44	46.21	2	2028-29
6	SQ	Roma	6.8	16.0	275.44	288.00	2.44	46.21	2	2028-29
7	VIC	Otway	6.8	16.0	275.16	287.71	2.49	46.16	2	2031-32
8	SQ	Roma	6.8	16.0	275.16	287.71	2.49	46.16	2	2031-32

4.5. Scenario HESS-VIC-QLD-2GW: Swapping out Borumba

This is a hypothetical scenario in which *only* Borumba PHES is replaced with two HESSs, one in VIC (Otway-Mortlake) and another in SQ (Roma-Kogan). Specifically, the 1.998 GW power capacity of Borumba PHES is divided equally across the Otway-Mortlake HESS and the Roma-Kogan HESS, as illustrated in Figure 31. In this case, the Otway-Mortlake HESS considers for UHS the largest DGR in Otway, which has a working storage volume of 6.7 kt and a cushion volume of 5.64 kt, as shown in Table 22. For a hydrogen turbine with an efficiency of 30%, the 6.7 kt working volume is equivalent to 79.25 GWh_e of electrical energy, or 79 hours of net storage duration at 999 MW. The Roma-Kogan HESS is assumed to have a DGR with similar capacity, as shown in Table 22. Consequently, the energy capacity in SQ has increased from 42 GWh_e to 79.25 GWh_e, which plays a significant role in improving reliability, as demonstrated in Section 5.3.

Technical and economic characteristics, and indicative commissioning dates of the PEM electrolysers, hydrogen turbines, pipelines, and compressors are shown in Table 23, Table 24, Table 25, and Table 26, respectively. The sizing of pipelines and compressors follows the reasoning described in the previous section. In this case, the indicative commissioning dates are meant to align with those of Borumba, according to AEMO's 2024 ISP [3].

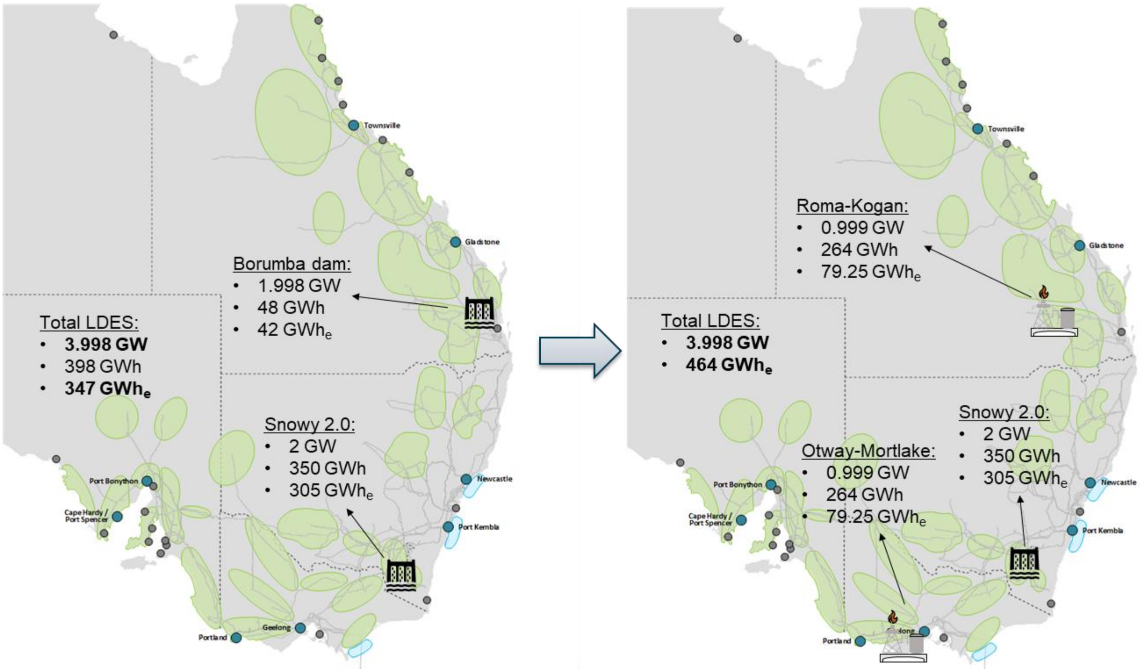


Figure 31: A hypothetical scenario where Borumba is replaced with HESSs in VIC and SQ.

Table 22: Characteristics and indicative commissioning dates of the UHS facilities in the two HESSs in the HESS-VIC-QLD-2GW scenario.

Sub-region	Basin	Site	Cushion (kt)	Cushion (GWh)	Number of fields	Wellbores (per field)	Storage (GWh)	Storage (GWh$_e$)	Storage (kt)	Indicative commissioning date
VIC	Otway	Otway	5.64	222.38	1	2	264.18	79.25	6.70	2031-32
SQ	Surat	Roma	5.64	222.38	1	2	264.18	79.25	6.70	2031-32

Table 23: Characteristics and indicative commissioning dates of the PEM electrolysers in the two HESSs in the HESS-VIC-QLD-2GW scenario.

ID	Sub-region	Site	Capacity (MW)	Efficiency (kWh/kg H_2)	Efficiency	H_2 production (m³/s)	H_2 production (TJ/d)	Water (kg/s)	Indicative commissioning date
1	VIC	Otway	999	55.73	70.75%	58.40	61.06	49.79	2031-32
2	SQ	Roma	999	55.73	70.75%	58.40	61.06	49.79	2031-32

Table 24: Characteristics and indicative commissioning dates of the hydrogen turbines in the two HESSs in the HESS-VIC-QLD-2GW scenario.

ID	Sub-region	Site	Capacity (MW)	Efficiency (HHV)	H_2 input (m³/s)	H_2 input (TJ/d)	MLF	Auxiliary load (%)	Connection cost ($/kW)	Indicative commissioning date
1	VIC	Otway	999	30%	275.16	287.71	0.99	1.10	115.48	2031-32
2	SQ	Roma	999	30%	275.16	287.71	0.97	1.10	110.49	2031-32

Table 25: Characteristics and indicative commissioning dates of the pipelines in the two HESSs in the HESS-VIC-QLD-2GW scenario.

Sub-region	From	To	Length (km)	Diameter (inch)	Capacity (m³/s)	Capacity (TJ/d)	Minimum pressure (MPa)	Maximum pressure (MPa)	Direction	Indicative commissioning date
VIC	Mortlake	Otway	110	24	275.16	287.71	5.8	8	Bidirectional	2031-32
SQ	Kogan	Roma	200	26	275.16	287.71	5.8	8	Bidirectional	2031-32

Table 26: Characteristics and indicative commissioning dates of the compressors in the two HESSs in the HESS-VIC-QLD-2GW scenario.

ID	Sub-region	Site	Inlet pressure (MPa)	Outlet pressure (MPa)	Throughput (m^3/s)	Throughput (TJ/d)	Throughput (kg/s)	Electricity consumption (MW)	Qty	Indicative commissioning date
1	VIC	Mortlake	3	8	58.40	61.06	5.21	9.42	2	2031-32
2	SQ	Kogan	3	8	58.40	61.06	5.21	9.42	2	2031-32
3	VIC	Otway	6.8	16	275.16	287.71	24.53	38.01	2	2031-32
4	SQ	Roma	6.8	16	275.16	287.71	24.53	38.01	2	2031-32

4.6. Scenario HESS-VIC-0.5GW: A 500 MW HESS in VIC

This scenario assumes that a 500 MW HESS is built in VIC (Otway-Mortlake) in 2031-32, as illustrated in Figure 32. This HESS also considers the largest DGR in Otway, which has a working storage volume of 6.7 kt and a cushion volume of 5.64 kt, as shown in Table 27. For a hydrogen turbine with an efficiency of 30%, the 6.7 kt working volume is equivalent to 79.25 GWh_e of electrical energy, or 158 hours of net storage duration at 500 MW. Technical and economic characteristics, and indicative commissioning dates of the PEM electrolysers, hydrogen turbines, pipelines, and compressors are shown in Table 28, Table 29, Table 30, and Table 31, respectively. Once again, the same reasoning described in the previous two sections applies to the sizing of pipelines and compressors.

The HESS-VIC-0.5GW scenario is based on the analysis in the H2RESTORE project [15].

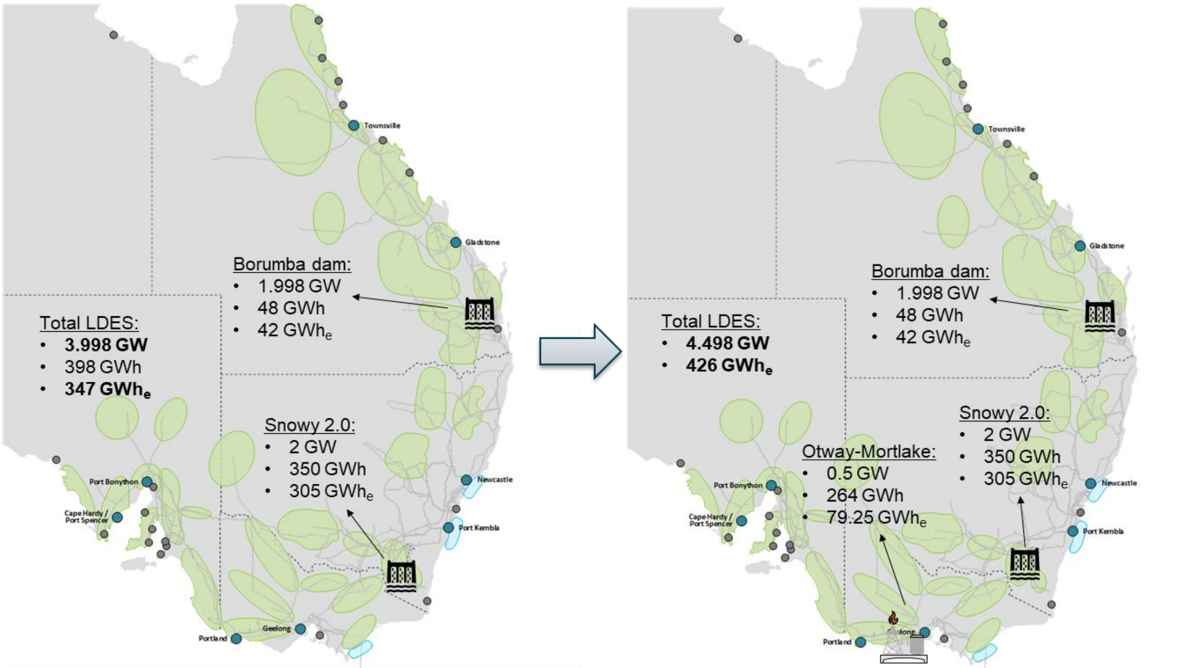


Figure 32: A scenario that considers a HESS with 500 MW and 158 hours of net storage in VIC.

Table 27: Characteristics and indicative commissioning dates of the UHS facilities in the HESS in the HESS-VIC-0.5GW scenario.

Sub-region	Basin	Site	Cushion (kt)	Cushion (GWh)	Number of fields	Wellbores (per field)	Storage (GWh)	Storage (GWh_e)	Storage (kt)	Indicative commissioning date
VIC	Otway	Otway	5.64	222.38	1	2	264.18	79.25	6.70	2031-32

Table 28: Characteristics and indicative commissioning dates of the PEM electrolysers in the HESS in the HESS-VIC-0.5GW scenario.

Sub-region	Site	Capacity (MW)	Efficiency (kWh/kg H_2)	Efficiency	H_2 production (m^3/s)	H_2 production (TJ/d)	Water (kg/s)	Indicative commissioning date
VIC	Otway	500	55.73	70.75%	29.23	30.56	24.92	2031-32

Table 29: Characteristics and indicative commissioning dates of the hydrogen turbines in the HESS in the HESS-VIC-0.5GW scenario.

Sub-region	Site	Capacity (MW)	Efficiency (HHV)	H_2 input (m^3/s)	H_2 input (TJ/d)	MLF	Auxiliary load (%)	Connection cost ($/kW)	Indicative commissioning date
VIC	Otway	500	30%	137.72	144.00	0.99	1.10	115.48	2031-32

Table 30: Characteristics and indicative commissioning dates of the pipelines in the HESS in the HESS-VIC-0.5GW scenario.

Sub-region	From	To	Length (km)	Diameter (inch)	Capacity (m^3/s)	Capacity (TJ/d)	Minimum pressure (MPa)	Maximum pressure (MPa)	Direction	Indicative commissioning date
VIC	Mortlake	Otway	110	18	137.7	144.0	5.8	8	Bidirectional	2031-32

Table 31: Characteristics and indicative commissioning dates of the compressors in the HESS in the HESS-VIC-0.5GW scenario.

ID	Sub-region	Site	Inlet pressure (MPa)	Outlet pressure (MPa)	Throughput (m^3/s)	Throughput (TJ/d)	Throughput (kg/s)	Electricity consumption (MW)	Qty	Indicative commissioning date
1	VIC	Mortlake	3	8	29.23	30.56	2.61	4.72	2	2031-32
2	VIC	Otway	6.8	16	137.72	144.00	12.28	19.02	2	2031-32

5. Findings

This section provides a rigorous examination of reliability, resilience, VRE curtailment, operational costs, and price volatility for each scenario in Table 15, and describes the main findings on CapEx and FOM, LCOE, and LROE.

5.1. CapEx and FOM

CapEx and FOM for each LDES option described in Section 4 can now be computed by following the design criteria stipulated in Section 3.1 and the CapEx and FOM methodology in Section 3.2. Table 32 shows that the Otway-Mortlake and Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario are each around 30% cheaper than Snowy 2.0 and Borumba, respectively. In the HESS-VIC-QLD-2GW scenario, the combined total NPV of the Otway-Mortlake and Roma-Kogan HESS (AU$3.35 B) (AU$3.35 B + AU$3.55 B = AU$ 6.9 B) is 50% lower than that of Borumba. A breakdown of CapEx and FOM costs for the UHS facilities, PEM electrolysers, hydrogen turbines, pipelines, and compressors in the two HESSs in the HESS-VIC-QLD-4GW scenario are listed in Table 33, Table 34, Table 35, Table 36, and Table 37, respectively.

The annual energy production for each LDES option over the 20 years following its indicative commissioning date is obtained from the solution of the long-horizon optimisation-based market dispatch model in (1)-(15). This then enables finding the energy NPV, shown in Table 32. Interestingly, the energy NPV of Snowy 2.0 is more than 4 times higher than that of the Otway-Mortlake HESS and the energy NPV of Borumba is more than 3 times higher than that of the Roma-Kogan HESS.

There are two main reasons behind this observation. The first is attributed to the RTE of each LDES option. It can be inferred from the efficiencies of the PEM electrolysers and hydrogen turbines in Table 18 and Table 19 that the RTE of the HESSs cannot exceed 21.22% (0.7075x0.3), whereas the RTE of their PHES counterparts is 76% (see AEMO’s 2023 IASR workbook [42]). This translates to a CF of at most 10.61% (0.5x0.7075x0.3) for the HESSs and 38% (0.5x0.76) for Snowy 2.0 and Borumba. The ratio of these CF is 3.58 (38/10.61), which corroborates why the PHES options can generate more than 3 times more energy than the HESSs.

The CFs from 2028-29 out to 2047-48 for the LDES options, are shown in Figure 33, and the associate forecast annual energy output in TWh are shown in Figure 81.[9] The higher CF of the PHES options is a sign of more frequent daily and monthly cycling, which can be seen by comparing the SoE in Figure 92 and Figure 93. It can also be seen from Figure 92 and Figure 93 that all four LDES options exhibit a seasonal behaviour whereby most of the charging occurs in summer and a lot more discharging occurs in winter.

The second reason is attributed to the cushion gas volume, which takes around one year to inject into the reservoir after commissioning for each HESS (see Table 17, Table 22, and Table 27). During this period, the HESSs does not generate any electricity.

[9] The CF and forecast energy output in the HESS-VIC-QLD-2GW scenario can be found in Figure 82 and Figure 83 Appendix B.

Table 32: NPV of CapEx, FOM cost, and energy across the considered 20 years of operation for each assessed LDES option.

Scenario	LDES option	Capacity (MW)	Storage capacity (GWh_e)	CapEx NPV ($B)	FOM cost NPV ($B)	Total NPV ($B)	Energy NPV (TWh)
Snowy-Borumba	Snowy 2.0	2000	305	10.63	2.35	12.98	27.11
	Borumba	1998	42	11.51	2.29	13.80	18.44
HESS-VIC-QLD-4GW	Otway-Mortlake HESS	1999	175	7.61	1.60	9.21	6.82
	Roma-Kogan HESS	1999	172	7.98	1.66	9.64	6.40
HESS-VIC-QLD-2GW	Otway-Mortlake HESS	999	79	2.77	0.58	3.35	3.06
	Roma-Kogan HESS	999	79	2.94	0.61	3.55	3.68
HESS-VIC-0.5GW	Otway-Mortlake HESS	500	79	1.50	0.32	1.82	1.60

Table 33: CapEx and FOM cost of the UHS facilities in the HESS-VIC-QLD-4GW scenario.

Sub-region	Basin	Site	Purification (M$)	Surface facilities (M$)	Wellbores (M$)	CapEx NPV (B$)	FOM NPV (B$)	NPV (B$)	Indicative commissioning date
VIC	Otway	Otway	244	240	216	0.70	0.15	0.85	2028-29
SQ	Surat	Roma	244	240	216	0.70	0.15	0.85	2028-29

Table 34: CapEx and FOM cost of the electrolysers in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Capacity (MW)	Build cost ($/kW)	FOM ($/kW/year)	CapEx (B$)	FOM (B$)	CapEx NPV (B$)	FOM NPV (B$)	NPV (B$)	Indicative commissioning date
1	VIC	Otway	1000	2259.4	62.8	2.05	0.40	2.05	0.20	2.46	2028-29
2	SQ	Roma	1000	2259.4	62.8	2.05	0.40	2.05	0.20	2.46	2028-29
3	VIC	Otway	999	1640.3	45.6	1.12	0.22	1.12	0.16	1.34	2031-32
4	SQ	Roma	999	1640.3	45.6	1.12	0.22	1.12	0.16	1.34	2031-32

Table 35: CapEx and FOM cost of the hydrogen turbines in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Capacity (MW)	Build cost ($/kW)	Connection cost (B$)	CapEx (B$)	FOM (B$)	CapEx NPV (B$)	FOM NPV (B$)	NPV (B$)	Indicative commissioning date
1	VIC	Otway	1000	1980.0	0.12	2.10	0.06	1.91	0.40	2.31	2028-29
2	SQ	Roma	1000	1980.0	0.11	2.09	0.06	1.90	0.40	2.30	2028-29
3	VIC	Otway	999	1546.6	0.12	1.66	0.05	1.13	0.24	1.37	2031-32
4	SQ	Roma	999	1546.6	0.11	1.66	0.05	1.13	0.24	1.37	2031-32

Table 36: CapEx and FOM cost of the pipelines in the two HESSs in the HESS-VIC-QLD-4GW scenario.

Sub-region	From	To	Length (km)	Diameter (inch)	CapEx (B$)	FOM (B$)	CapEx NPV (B$)	FOM NPV (B$)	NPV (B$)	Indicative commissioning date
VIC	Mortlake	Otway	110	30	0.32	0.01	0.32	0.05	0.37	2028-29
SQ	Kogan	Roma	200	34	0.69	0.02	0.69	0.11	0.81	2028-29

Table 37: CapEx and FOM cost of the compressors in the two HESSs in the HESS-VIC-QLD-4GW scenario.

ID	Sub-region	Site	Throughput (TJ/d)	Electricity consumption (MW)	CapEx (M$)	FOM (M$)	CapEx NPV (B$)	FOM NPV (B$)	NPV (B$)	Indicative commissioning date
1	VIC	Mortlake	57.1	8.8	40.03	2.00	0.036	0.013	0.049	2028-29
2	SQ	Kogan	57.1	8.8	40.03	2.00	0.036	0.013	0.049	2028-29
3	VIC	Mortlake	61.1	9.4	42.70	2.13	0.029	0.010	0.039	2031-32
4	SQ	Kogan	61.1	9.4	42.70	2.13	0.029	0.010	0.039	2031-32
5	VIC	Otway	288.0	46.2	196.51	9.83	0.179	0.063	0.241	2028-29
6	SQ	Roma	288.0	46.2	196.51	9.83	0.179	0.063	0.241	2028-29
7	VIC	Otway	287.7	46.2	196.32	9.82	0.134	0.047	0.181	2031-32
8	SQ	Roma	287.7	46.2	196.32	9.82	0.134	0.047	0.181	2031-32

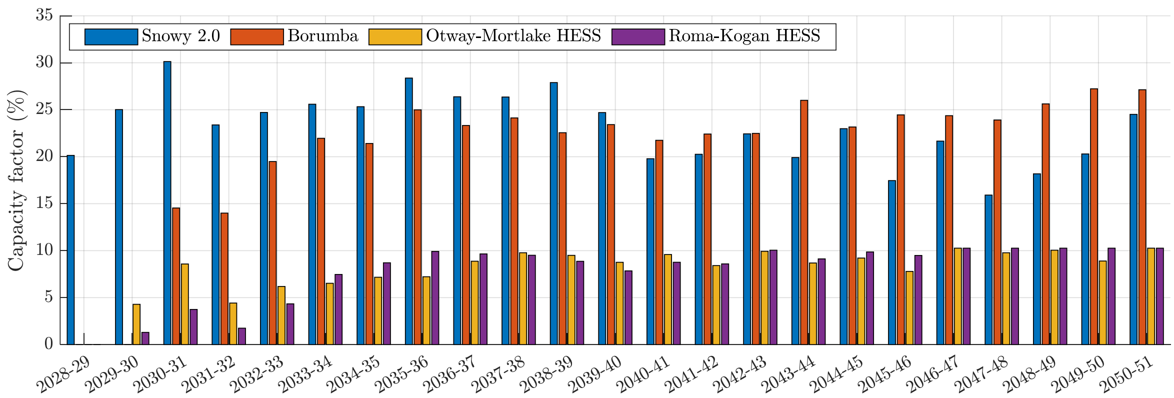


Figure 33: CF of each LDES option from 2028-29 to 2047-48 in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios and under Sensitivity 1.

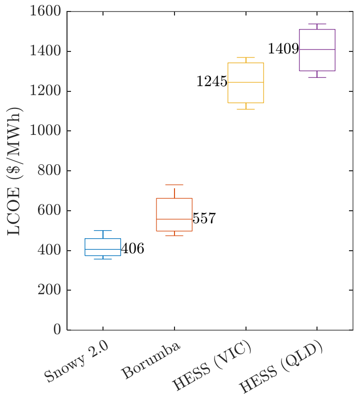
5.2. LCOE and LROE

Now that the CapEx and Energy NPVs are obtained, the last step towards finding the LCOE of each LDES consists of computing the cost of purchasing electricity from the NEM, as detailed in Section 3.4. As already established, the half-hourly regional wholesale energy prices, also referred to as RRPs, are also obtained from the long-horizon optimisation-based market dispatch model in (1)-(15). For reference, the basis scenarios for computing the LCOE and LROE are summarised in Table 16.

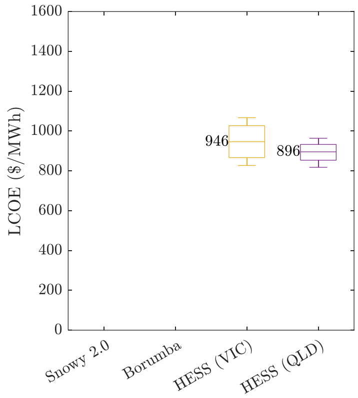
The LCOE for each assessed LDES option is shown in Figure 34 under the four sensitivities in Table 12 and Table 13 (see Section 3.3 for more details). In Figure 34, the error bars represent the maximum and minimum across the four sensitivities, and the values next to the horizontal bars indicate the median. While the two HESSs have a CapEx and FOM NPV that is around 30% lower than their PHES counterparts, the LCOE of the 2 GW Otway-Mortlake HESS in VIC is around 3 times higher than that of Snowy 2.0 and the LCOE of the 2 GW Roma-Kogan HESS in QLD is 2.5 times higher than that of Borumba, as shown in Figure 34. Among other factors, the CF is the most influential one behind this finding. The PHES options have maximum CFs up to 3.58 times higher than their HESS counterparts, enabling them to generate considerably more energy, as shown in Figure 33. It is important to note that these LCOE values are computed over a lifetime of 20 years starting from the (proposed) commissioning date, and not over the lifetime of each component in the project.

Another important factor is the cost of purchasing electricity from the NEM. This is shown in Figure 36 for each LDES option in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios under Sensitivity 1 (see Table 12), between 2028-29 and 2047-48. Figure 36 also shows that Snowy 2.0 and Borumba generally incur higher costs for purchasing electricity from the NEM compared to their HESS counterparts, due to several factors including the CF of each LDES option, as well as the total share of VRE, demand, and generation capacity in each state that hosts an LDES option.

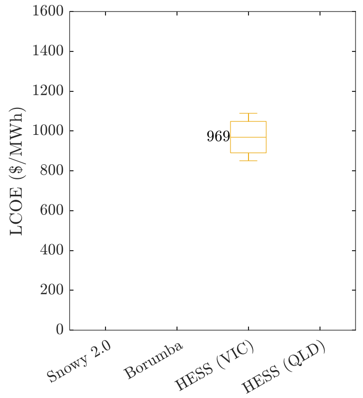
Interestingly, these costs are mostly negative for the two HESSs from 2028 to 2030, indicating that most of their charging occurs during periods of negative prices—effectively turning this cost into a source of revenue. The RRPs in 2030-31 are shown in Figure 95, which shows a prevalence of negative prices across the NEM, especially in spring and summer. Figure 95 also shows that the RRPs beyond 2030 no longer take negative values, as the LGCs are expected to cease by the end of 2030 under Sensitivity 1 (see Table 12). It should also be noted that the cost of electricity consumed by compressors in the HESS is included in the costs of purchasing electricity from the NEM, shown in Figure 36.



a) Scenarios Snowy-Borumba and HESS-VIC-QLD-4GW

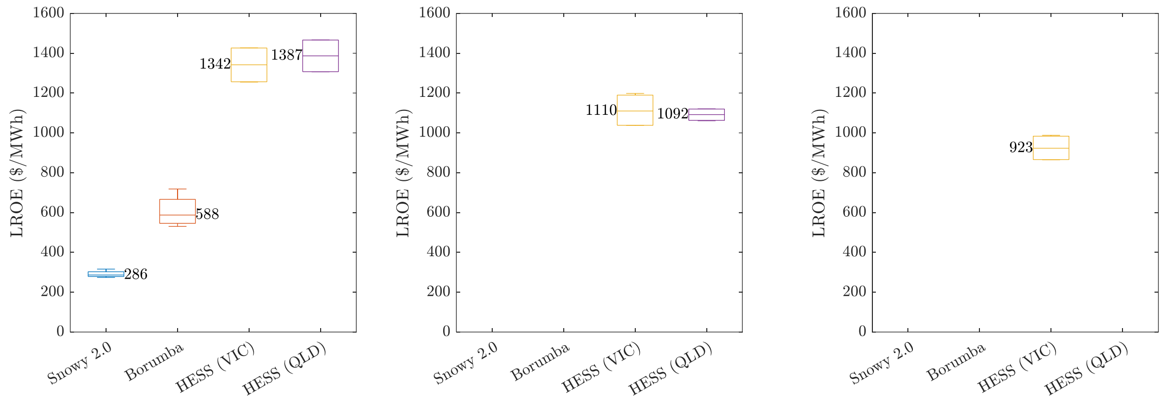


b) Scenario HESS-VIC-QLD-2GW



c) Scenario HESS-VIC-0.5GW

Figure 34: LCOE for each assessed LDES option under the four sensitivities in Table 12. The error bar represents the maximum and minimum across the four sensitivities, and the coloured bar indicates the mean.



a) Scenarios Snowy-Borumba and HESS-VIC-QLD-4GW

b) Scenario HESS-VIC-QLD-2GW

c) Scenario HESS-VIC-0.5GW

Figure 35: LROE for each assessed LDES option under the four sensitivities in Table 12. The error bar represents the maximum and minimum across the four sensitivities, and the coloured bar indicates the mean.

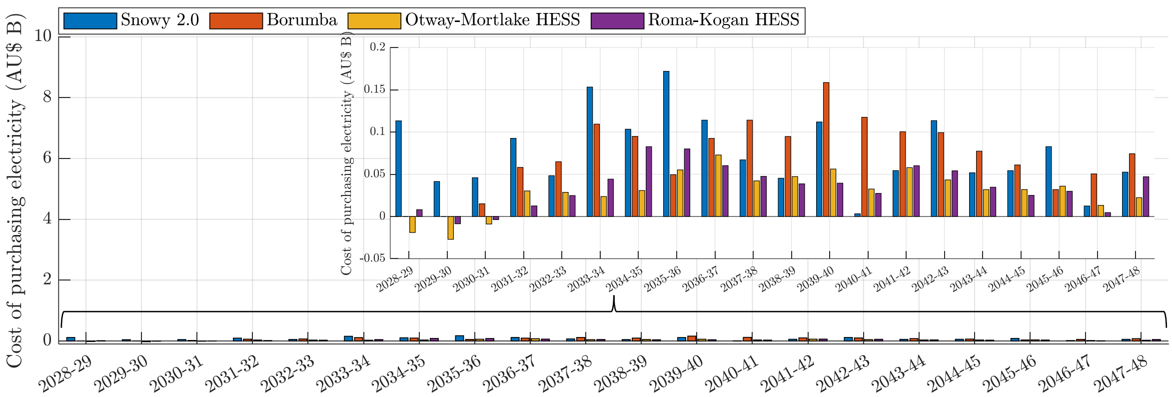


Figure 36: Cost of purchasing electricity from the NEM between 2028-29 and 2047-48 for each LDES option in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios and under Sensitivity 1.

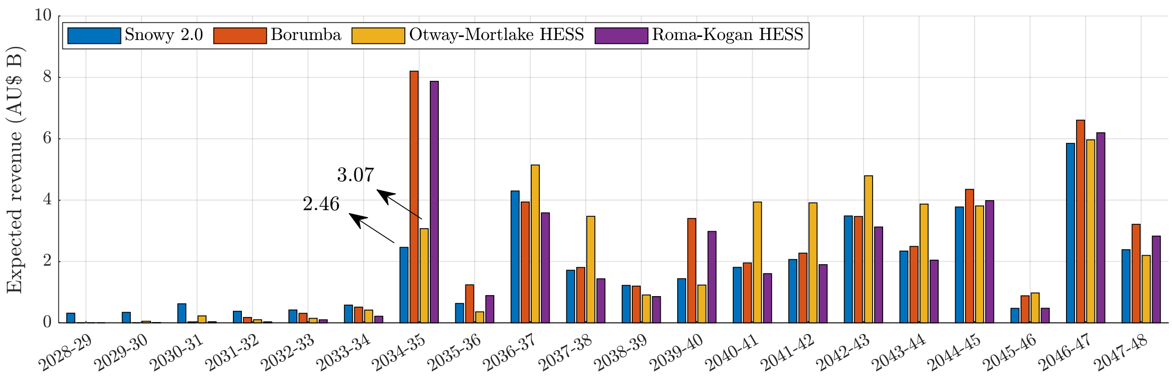


Figure 37: Potential maximum revenues from participating in the NEM between 2028-29 and 2047-48 for each LDES option in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios, and under Sensitivity 1.

While the LCOE is a key metric that enables the comparison of different energy sources on a consistent basis, an assessment of the business case of a project is not complete without the LROE. As described in Section 3.4, the first step towards computing the LROE is to find the price duration curve (PDC), from which the revenue duration curve (RDC) can be obtained by computing a running average of the descending price by interval. The revenue opportunities for a certain LDES option in a certain year can be found from the point where the CF and the RDC intersect, as shown in Figure 39. This intersection point represents the average spot market earnings a participant could achieve (per MWh) by selling electricity over a proportion of time in a year that is no greater than its CF, and during which the prices are expected to be higher than the intersection between the CF and the PDC (this point is not shown in Figure 39).

As an example, the Otway-Mortlake HESS in VIC has CF of around 7.16% (see Figure 33) and annual energy output of around 1.256 TWh (see Figure 81) in 2034-35. Looking at Figure 39, the intersection between the CF of 7.16% and the RDC for that year has a value of $2470/MWh. Multiplying 1.256 TWh by $2470/MWh by the MLF of 0.99 (see Table 19) yields a potential maximum revenue of around AU$3.07 B. Meanwhile, Snowy 2.0 PHES in NSW has a CF of around 25.32% and annual energy output of around 4.43 TWh (see Figure 81). The intersection between Snowy 2.0's CF of 25.32% and the RDC for that year has a value of $610/MWh (see Figure 86). Multiplying 4.43 TWh by $610/MWh by the MLF of 0.91 (see AEMO's 2023 IASR workbook [42]) yields a potential maximum revenue of around AU$2.46 B in 2034-35. Both values can be seen in Figure 37, which shows the estimated maximum revenue from participating in the NEM between 2028-29 and 2047-48 for each LDES option.

As expected, the revenue is generally much higher (by 1 to 3 orders of magnitude) than the cost of purchasing electricity from the NEM for all assessed LDES options, as can be seen by comparing Figure 36 and Figure 37. This aligns with the typical energy arbitrage behaviour of storage systems, which generally charge when prices are low and discharge when prices are high.

In essence, cost recovery can occur in the portion where the RDC exceeds the LCOE. In practice, a participant can maximise revenue in a year by offering all of its capacity in a way that ensures that it is inframarginal during specific periods during which the price is expected to be above the intersection between its CF and the simulated PDC for that year.[10] An example of such offering strategy during these periods is to, for example, offer 99% of its capacity at the market floor price (-$1000/MWh) and the remaining 1% at the market price cap ($17,500/MWh). These periods could be during winter when the residual demand is high, such as afternoon peaks and morning peaks. Such conditions are explored in more detail in Section 5.4.

The LROE can now be computed by dividing the NPV of the potential maximum revenue by the NPV of the energy produced in the first 20 years of operation. The LROE values for each LDES option are shown in Figure 35. Under the specific technical and financial assumptions in this report, which reflect current technology cost predictions, the findings in Figure 35 suggest that the Otway-Mortlake HESS in VIC in scenarios HESS-VIC-QLD-4GW and HESS-VIC-QLD-2GW (see Table 1) may be able to recover all their costs within the first 20 years of operation (i.e., the first 20 years of after the commissioning dates specified in Table 18 and Table 19). In other words, the Otway-Mortlake HESS in VIC in scenarios HESS-VIC-QLD-4GW and HESS-VIC-QLD-2GW can potentially be commercially viable under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP.

On the other hand, as shown in Figure 35b, the Roma-Kogan HESS in QLD is only profitable in the HESS-VIC-QLD-2GW scenario, in which it has a capacity of 1 GW. Despite the higher LROE of the 2 GW Roma-Kogan HESS in QLD compared to the 2 GW Otway-Mortlake HESS in VIC, the former has a noticeably higher LCOE, mainly due to its higher CapEx (see Table

[10] Note that these intersection points are not shown in Figure 39, which only shows the intersection points between the RDC and the CF and *not* the between the PDC and the CF.

32), incurred by the longer pipeline connecting the UHS facility in Roma to the electrolysers and hydrogen turbines in Kogan (see Figure 20).

Although Borumba has a high CapEx, it may potentially still be commercially viable under the generation, storage, and transmission expansion plan outlined in AEMO's 2024 ISP. This indicates that LDES options such as Borumba and the Roma-Kogan HESS play a significant role in enhancing reliability in QLD. Without them, the RRPs would likely spike during periods of high residual demand. For Snowy 2.0, the fact that its LROE is lower than its LCOE suggests that sufficient generation capacity exists in NSW, preventing Snowy 2.0 from operating as a marginal or inframarginal generator long enough to recover its costs. Nevertheless, Snowy 2.0 still provides substantial reliability and resilience benefits to the NSW power system, as discussed in the next two sections.

While the low CFs—and by association, the low energy output—of the Otway-Mortlake HESS and the Roma-Kogan HESS results in a (relatively) high LCOE, it also leads to a (relatively) high LROE. In other words, the low CFs of the HESS is unfavourable from an LCOE perspective but favourable from an LROE perspective. The opposite is true for Snowy 2.0 and Borumba, which are characterised by higher CFs and, by association, higher energy outputs, resulting in lower LCOE and LROE.

Additionally, the higher LROE of the Otway–Mortlake HESS in VIC and the Borumba PHES in QLD, compared to their LCOE, can be attributed to increased price volatility. Price volatility is shown in Figure 39 to become more pronounced after 2034-35 (see also Figure 76 in Section 5.6), when the market share of coal generation drops to only 2.53% of total dispatchable capacity and the NEM becomes dominated by renewables.[11] This, therefore, presents more opportunities for the profitable LDES options (i.e., Borumba PHES and the Otway-Mortlake HESS in the HESS-VIC-QLD-4GW scenario, and the two HESSs in the HESS-VIC-QLD-2GW scenario) to maximise their revenue by tapping into the high prices that could arise when the residual demand is high and during reliability events.

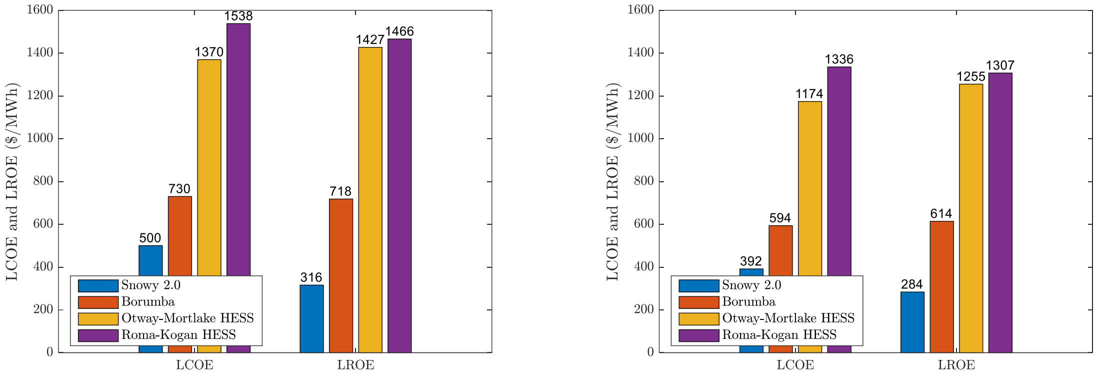
A comparison of Figure 34b and Figure 35b with Figure 34a and Figure 35a reveals that the LCOE and LROE of the 1 GW Otway-Mortlake HESS and the 1 GW Roma-Kogan HESS in the HESS-VIC-QLD-2GW scenario are lower than the 2 GW Otway-Mortlake HESS and the 2 GW Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario. This is partly due to lower power and energy storage capacities of the two HESSs in the HESS-VIC-QLD-2GW scenario compared to the ones in the HESS-VIC-QLD-4GW scenario (see Section 4), which decreases their CapEx NPV (see Table 32). Aside from their lower power and energy storage capacities, another contributor to their relative decrease in CapEx NPV is their later indicative commissioning dates, which coincide with projected decreases in the cost of major components in the HESS, such as PEM electrolysers and hydrogen turbines (see Section 4).

Interestingly, although still greater than one, the ratio of LROE to LCOE is higher in this scenario than in the HESS-VIC-QLD-4GW scenario (see Figure 34b and Figure 35b). This is mainly because, despite the presence of Snowy 2.0, the 1 GW HESS in VIC and the 1 GW HESS in QLD under the HESS-VIC-QLD-2GW scenario do not provide sufficient capacity to maintain reliability in VIC and QLD, respectively, when compared to the 2 GW Otway-Mortlake HESS and the 2 GW Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario. As a result, the two smaller HESS units in the HESS-VIC-QLD-2GW scenario can remain inframarginal for a longer period, allowing them to generate more revenue relative to their LCOE than they would if they had 2 GW of capacity, as in the HESS-VIC-QLD-4GW scenario.

In the HESS-VIC-0.5GW scenario, the PDC and RDC are obtained from the RRP computed in the Snowy-Borumba scenario (see Table 16), which includes *both* Snowy 2.0 and Borumba.

[11] For reference, the market share of coal generation is currently (in 2024-2025) at around 36%.

The presence of Snowy 2.0 and Borumba substantially reduces price volatility across the NEM after 2034-35, as can be seen in Figure 77 in Section 5.6, thereby diminishing the maximum potential revenue opportunities available to additional LDES entrants. This largely explains why the LROE for the HESS in VIC under the HESS-VIC-0.5GW scenario is likely to fall slightly below its LCOE, as can be seen by comparing Figure 34c and Figure 35c. Nonetheless, the addition of the 500 MW HESS in VIC still makes a meaningful contribution to improving reliability and resilience in VIC, SA, and TAS, as discussed in the next two sections.



a) LCOE and LROE under Sensitivity 1 b) LCOE and LROE under Sensitivity 3

Figure 38: LCOE and LROE for each assessed LDES option in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios under Sensitivity 1 (left) and Sensitivity 3 (right).

Notably, as shown in Figure 38, both the LCOE and LROE for all LDES in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios are lower under Sensitivity 3, where all BESS offer to sell at their LRMC, compared to Sensitivity 1, where BESS offer to sell based on their optimised opportunity cost. The reason for this is two-fold. First, because their RTE is much higher than those of PHES and HESS, BESS become inframarginal more often when they offer to sell based on their optimised opportunity cost (Sensitivity 1), compared to when they offer to sell at their LRMC (Sensitivity 3). This allows them to produce more energy as they are now dispatched more frequently. This comes at the expense of less frequent dispatch from the LDES systems, leading to a decrease in annual energy output from the LDES system and, by association, a decrease in CF, which increases the LCOE and LROE.

Furthermore, comparing the PDC in Figure 35 to the ones in Figure 89, shows that the downward slope of the PDC is amplified as a direct result of BESS offering to sell based on their optimised opportunity cost (Sensitivity 1). This means that the PDC *shifts* more to the left. Nonetheless, as already established, because of the decrease in CF, the vertical lines representing them also shift to the left in Figure 89. However, this left shift of the CF outweighs the left shift of the PDC, which means that the intersection between the CF and the PDC has a higher value compared to the case in which all BESS and PHES offer to sell at their LRMC (Figure 35). This, therefore, increases the potential maximum revenue, which, compounded by a decrease in energy output, leads to an increase in LROE.

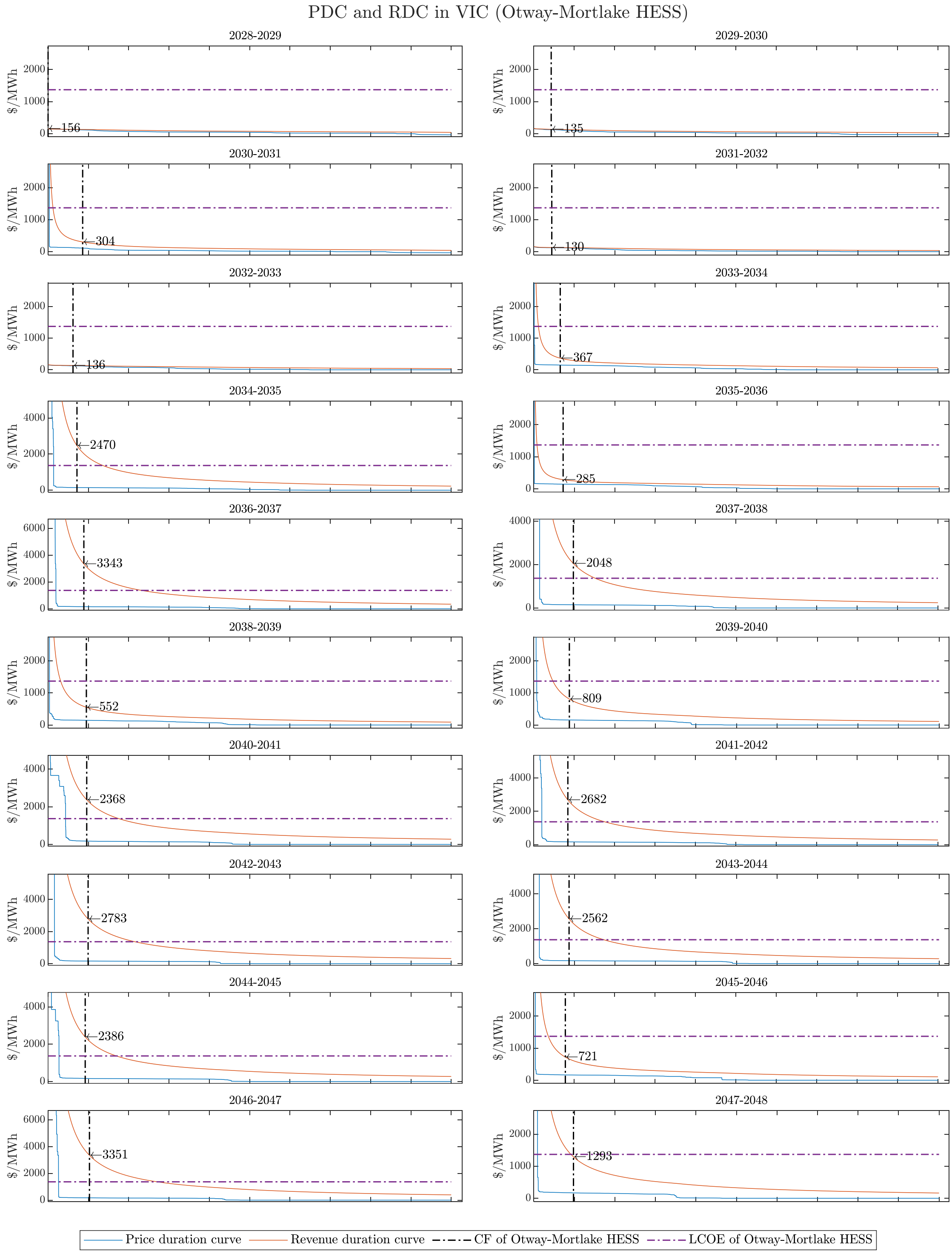


Figure 39: CF and LCOE of the Otway-Mortlake HESS in VIC in relation to the PDC and RDC in VIC from 2028-29 to 2047-48 obtained in the No LDES scenario, and under Sensitivity 1. The text arrows show the intersection points (prices) between the RDC and the CF.

5.3. Reliability

In the context of power systems, reliability refers to an electric power system's capability to supply electricity in the required quantity and quality to meet the demands of energy users. The reliability standard measures the expected Unserved Energy (USE) in each region, stipulating that no more than 0.002% of the total energy demand can remain unmet in any financial year. The approach in this report is consistent with the reliability assessment in

AEMO's 2024 Electricity Statement of Opportunities (ESOO) [66], which accounts for weather variability and generator reliability settings. Weather variability in this assessment is reflected in the VRE and demand traces obtained from AEMO's 2024 ISP [3], which are used *directly* as input to the optimisation model in (1)-(15). Annual hydro scheme inflows are obtained directly from AEMO's 2023 IASR workbook [42]. However, instead of simulating random generator outages, which would further increase the computational burden, the assessment in this section uses equivalent derating factors. Because the model uses a twelve-node network representation of the NEM (see Figure 23), regional USE is obtained by adding all the USE in the associated subregions.

The forecast reliability outcomes by region under each scenario are shown in Figure 40, which shows USE as a percentage of total energy demand, and Figure 90 in Appendix B, which shows USE is GWh for each region. Under the specific technical and financial assumptions in this report, the reliability results in Figure 40 show that the HESS-VIC-QLD-4GW scenario has the lowest worst-case and average USE among all six LDES scenarios. The worst-case USE in the HESS-VIC-QLD-4GW scenario, which does not exceed 0.0042%, is witnessed in year 2034-35, where around 2.83 GWh of demand is unmet across the year in QLD. The second highest USE in the HESS-VIC-QLD-4GW scenario is around 0.004% in VIC in year 2043-44. In contrast, USE in the Snowy-Borumba scenario frequently exceeds 0.02% (10 times the specified reliability standard of 0.002%) in many years between 2028 and 2047, and in many regions of the NEM, as shown in Figure 40c.

Unsurprisingly, as shown in Figure 40a, having no LDES in the NEM, as is the case in the NoLDES scenario, results in the worst USE between 2028-29 and 2049-50. Introducing Snowy 2.0, as in the NoBorumba scenario, greatly improves reliability not only in NSW but also in VIC, SA, and TAS compared to the NoLDES scenario, as shown in Figure 40b. However, Although the reliability in VIC, SA, and TAS is improved in the HESS-VIC-QLD-2GW scenario compared to the Snowy-Borumba scenario, it is worsened in QLD. This is suggesting that 1 GW from the HESS in SQ is not enough capacity in QLD to maintain higher reliability compared to the 2 GW from Borumba. Finally, Figure 40f suggests that having a HESS with 500 MW and 158 hours of storage in VIC, as in the HESS-VIC-0.5GW scenario, greatly improves reliability in the southern states of VIC, SA, and TAS.

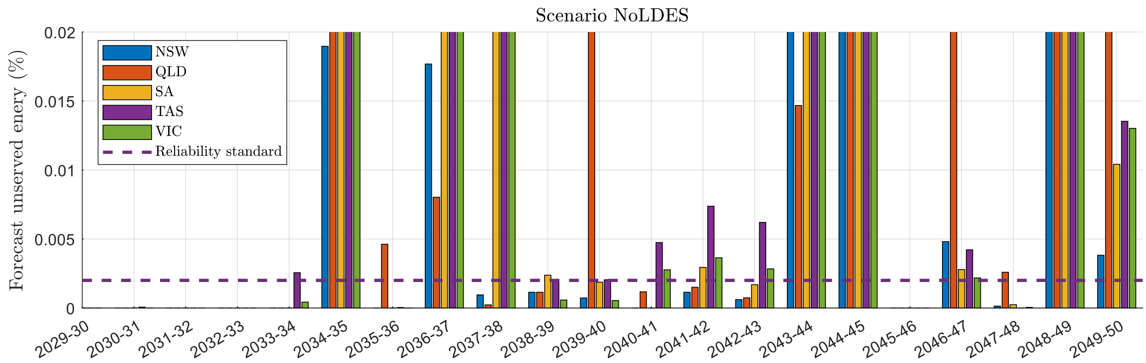
The following observations can be made from the findings in Figure 40 and Figure 90:

- Reliability is improved in QLD under the HESS-VIC-QLD-4GW scenario compared to the Snowy-Borumba scenario because the Roma-Kogan HESS in the HESS-VIC-QLD-4GW scenario can provide 172 GWh_e, i.e., 86 hours of net storage at 1.99 GW, compared to 42 GWh_e, i.e., 21 hours of net storage at 1.998 GW in the case of Borumba the Snowy-Borumba scenario. This suggests that 21 hours at 1.998 GW may not be sufficient to maintain reliability in QLD, and that at least 86 hours may be required instead.
- It is more beneficial to the reliability of NEM to have LDES in VIC than in SNSW. Despite the lower energy storage capacity of the Otway-Mortlake HESS in VIC, which can provide 172 GWh_e (86 hours of storage duration at 1.99 GW), compared to that of Snowy 2.0 with 153 hours at 2 GW, the Otway-Mortlake HESS greatly reduces USE to a value that does not exceed 0.004% in the southern states of VIC, TAS, and SA between 2028-29 and 2049-50.
- Despite HumeLink, VNI West, and Project EnergyConnect, which are envisaged to be commissioned by July 2030, July 2027, and July 2030, respectively (see Figure 79 and Table 50), Snowy 2.0 may not be enough to overcome interconnector constraints during periods of high residual demand to alleviate USE in the southern states of VIC, TAS, and SA in the Snowy-Borumba scenario. In contrast, the Otway-Mortlake, by virtue of being in VIC, is better positioned to overcome interconnector constraints between VIC and TAS,

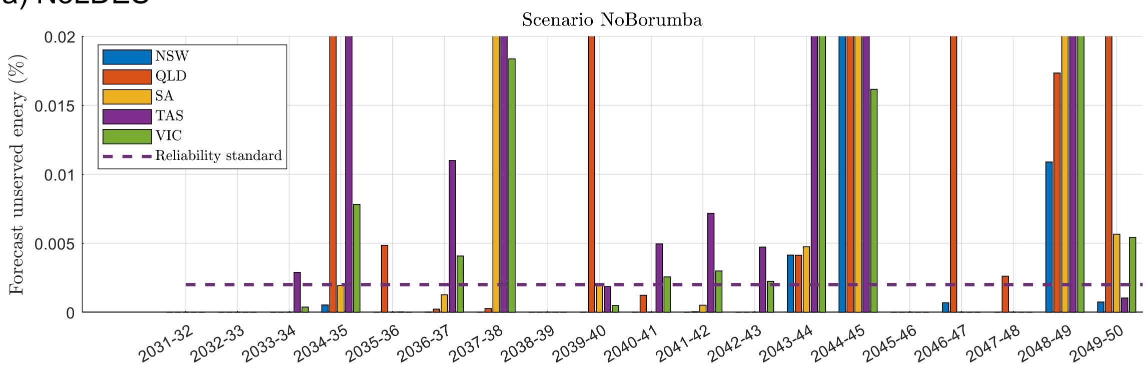
i.e., Marinus Link and Basslink, and between VIC and SA, i.e., Heywood interconnector and Murraylink.

- The above claims are further substantiated in Figure 40f, which shows that installing a HESS with 500 MW and 158 hours of net storage in VIC (79.25 GWh_e), i.e., the HESS-VIC-0.5GW scenario, greatly improves reliability in the southern states of VIC, SA, and TAS.
- Together, the Otway-Mortlake HESS in VIC and the Roma-Kogan HESS in SQ, in the HESS-VIC-QLD-4GW scenario, are capable of maintaining reliability in NSW under a counterfactual case in which Snowy 2.0 does not exist.

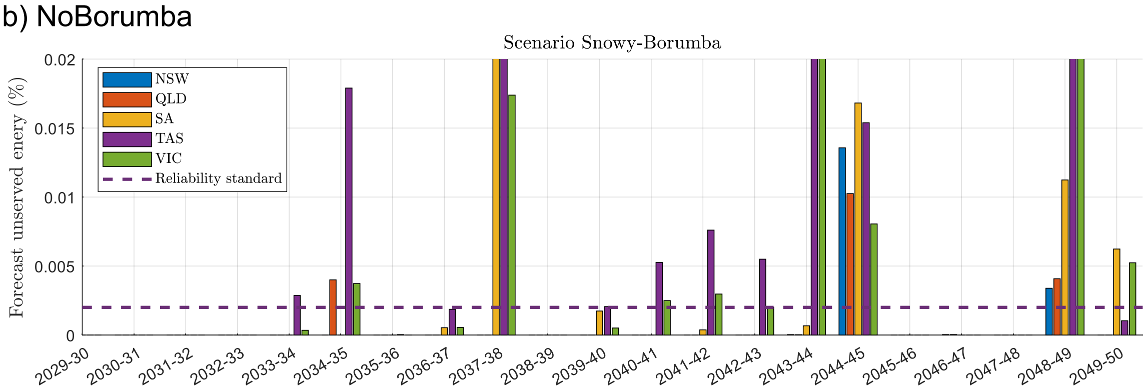
The impact on reliability of severe weather variability associated with prolonged VRE droughts will be assessed in Subsection: Resilience below.



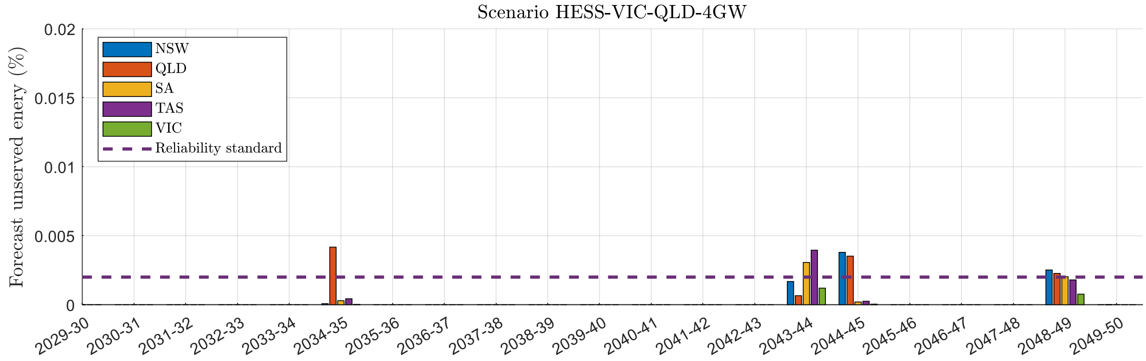
a) NoLDES



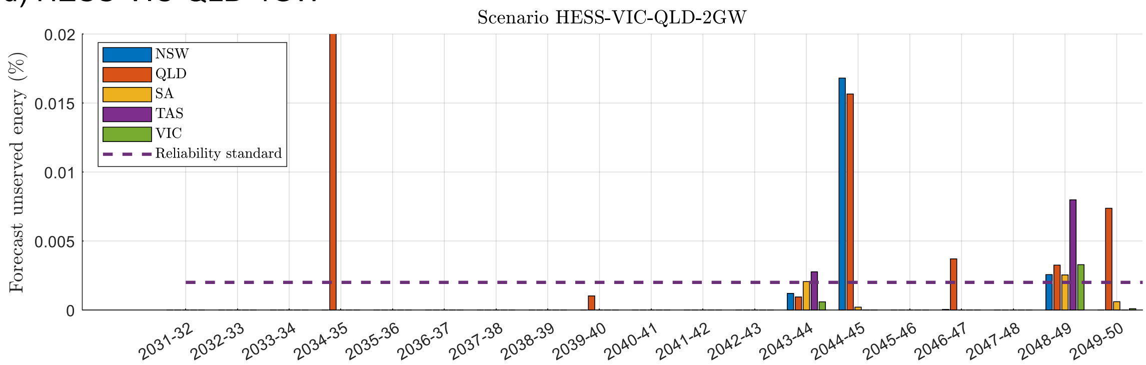
b) NoBorumba



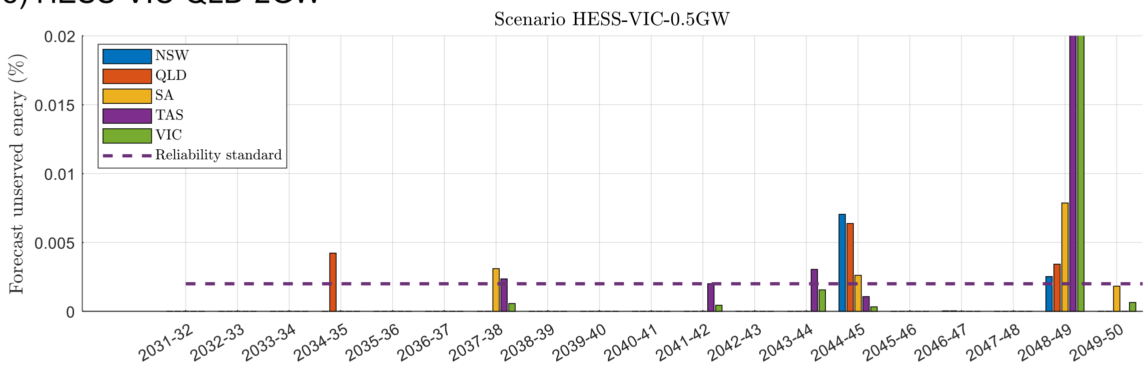
c) Snowy-Borumba



d) HESS-VIC-QLD-4GW



e) HESS-VIC-QLD-2GW



f) HESS-VIC-0.5GW

Figure 40: Forecast reliability outcomes by region from 2029-30 to 2049-50 under each scenario (see Figure 29).

5.4. Resilience

In the context of power systems, resilience refers to the capability of a power system to reduce the magnitude and/or duration of disruptive events and recover while maintaining the delivery of electricity to consumers. One critical type of disruptive event is prolonged periods of VRE droughts where unfavourable weather conditions lead to minimal or no sunshine or wind for an extended period, potentially compromising reliability. These events may become increasingly prominent as more VRE capacity is installed in the NEM, especially after all coal generation is retired, making it increasingly sensitive to weather variations. Several essential metrics are used to assess resilience, including:

- **Operability** across the NEM, which shows generation profiles, and in particular, contributions from key market participants such as GFG, hydro generators, storage systems, and DSP.
- **Residual demand and operational (sent-out) demand**. These two are formally defined in Table 38. Extended periods of VRE droughts are characterised by high residual

demand, especially in winter months when reduced solar generation coincides with wind lulls.

- Availability of **reserves** in each region. Regional reserve requirements as per the Step Change scenario in AEMO's 2024 ISP [3] are listed in Table 39. These reserve requirements represent the largest contingency in each state.
- **State of energy (SoE)** of all storage systems. Pertinent storage definitions are provided in Table 40. SoE of different types of storage systems, especially LDES, is a major indicator of how much reserves are available to complement GFG and hydro generators to maintain reliability during VRE droughts.
- **Regional reference prices (RRP)**. Operating under low reserves, as a result of extended periods of VRE droughts, is often associated with very high prices due to possible reliance on costly peaking generators, costly DSP (see Subsection: Market dispatch modelling), or in extreme cases, market cap prices due to lost load.
- Amount of **lost load**. When all available response from DSP is exhausted, a last resort to avoid blackouts is to resort to load shedding, which is measured as the amount of lost load in a region or subregion.

Table 38: Definition of the different types of demands in this report.

Terminology	Definition
Operational (sent-out) demand	Refers to the demand that is met by local scheduled and non-scheduled generating units such as consumers' rooftop PV and behind-the-meter BESS. It is therefore the demand seen from the perspective of, or satisfied by, the NEM.
Underlying demand	Encompasses all the electricity consumed by consumers, including electricity withdrawn from the grid and other sources including rooftop PV and behind-the-meter BESS.
Residual demand	Is the portion of demand that cannot be satisfied by VRE generation and must be supplied by other generators or storage systems.

Table 39: Regional reserve requirements in the Step Change scenario in AEMO's 2024 ISP [3].

Region	Initial regional reserve requirements (MW)
NSW	705
QLD	710
SA	195
VIC	550
TAS	140

Table 40: Definitions of the different types of storage used in this report.

Terminology	Definition
Consumer-owned storage (or distributed or CER storage)	Behind-the-meter household, business or industrial batteries, including electric vehicles (EV) that may be capable of sending electricity back to the grid. Coordinated CER storage is managed as part of a VPP, whereas passive CER storage is not. This type of storage has a relatively small discharge duration of about two hours at full discharge.
Shallow storage	Utility-scale storage capable of dispatching electricity for less than 4 hours, valued for both their system services and their energy value.
Medium storage	Utility-scale storage capable of dispatching electricity for 4 to 12 hours, also valued for both their system services and their energy value. These are predominantly BESS or small-scale PHES that can shift large quantities of electricity to meet evening or morning peaks.
Deep storage	Strategic reserves capable of dispatching electricity for 12 to 24 hours to facilitate energy shifting over more than a day or to cover long periods of low solar and wind output (VRE droughts). These are predominantly BESS or medium-scale PHES.

Long-duration energy storage (LDES)	Strategic reserves capable of dispatching electricity for more than 24 hours to facilitate energy shifting over days, weeks, or even months (seasonal shifting) or to sustain extended periods of low solar and wind output (VRE droughts). These are predominantly large-scale PHES or potentially HESS. Although it can be argued that this type can be lumped under deep storage, it is differentiated from deep storage to allow Snowy 2.0, Borumba, and the HESS assessed in this report to conveniently have their own category, referred to as LDES.

5.4.1 Selection of VRE drought periods

The analysis in this report starts by assessing the resilience of the NEM during a three-day low VRE period in June 2040. This three-day event, which spans 8-Jun-2040 to 11-Jun-2040, is characterised by a (relatively) low wind CF of 16.68% and a solar CF of 20.56%, as shown in Table 41. The NEM-wide residual demand profile over the duration of this event is shown in Figure 41 and the three highest residual demands are shown in Table 42. This is the same three-day low VRE period examined in Appendix 4 of AEMO's 2024 ISP [3]. The forecast NEM-wide generation dispatch profiles under the Snowy-Borumba scenario,[12] shown in Figure 42, confirm that the NEM remains resilient during this event, as no USE is observed. This aligns with the findings in Appendix 4 of AEMO's 2024 ISP.

Table 41: NEM-wide wind and solar energy across a three-day low VRE period in June 2040 and its relationship to operational demand. For reference, the last column shows these same variables but across the whole of 2039-40.

	Three-day low VRE period	2039-2040
	8-Jun-2040 12:00:00 PM to 11-Jun-2040 11:30:00 AM	
Demand (TWh)	2.25	269.23
Wind (TWh)	0.71	194.85
Solar (TWh)	0.45	56.11
VRE (% of demand)	51.32%	93.22%
Wind CF (%)	**16.68%**	35.80%
Solar CF (%)	**20.56%**	25.13%

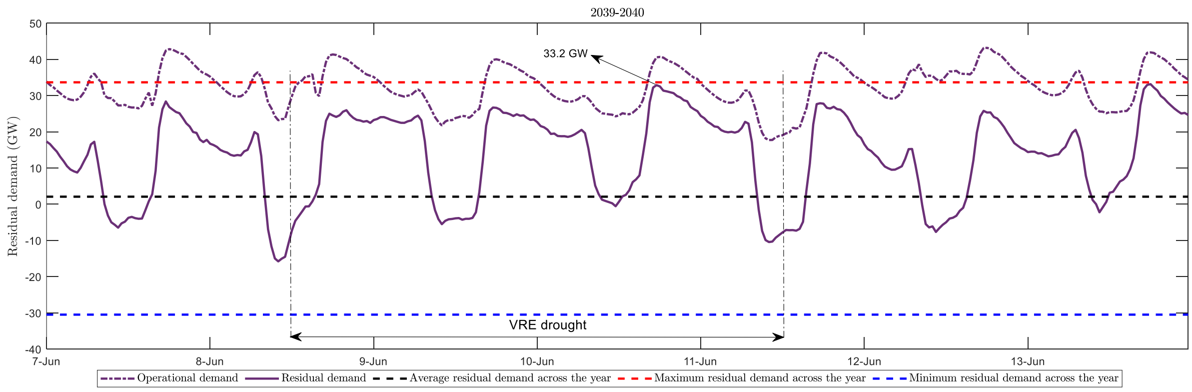


Figure 41: Residual demand across the NEM during a three-day low VRE period in June 2040.

Table 42: The three highest NEM-wide residual demands witnessed during a three-day low VRE period in June 2040.

Three-day low VRE period		
8-Jun-2040 12:00:00 PM to 11-Jun-2040 11:30:00 AM		
Residual demand (GW)	VRE (% of demand)	Date and time

[12] The Snowy-Borumba scenario in this report adopts the same input assumptions as the Step Change scenario of AEMO's ISP.

Highest	32.88	17.41	10-Jun-2040 17:00:00
Second highest	32.53	18.95	10-Jun-2040 17:30:00
Third highest	32.22	20.02	10-Jun-2040 18:00:00

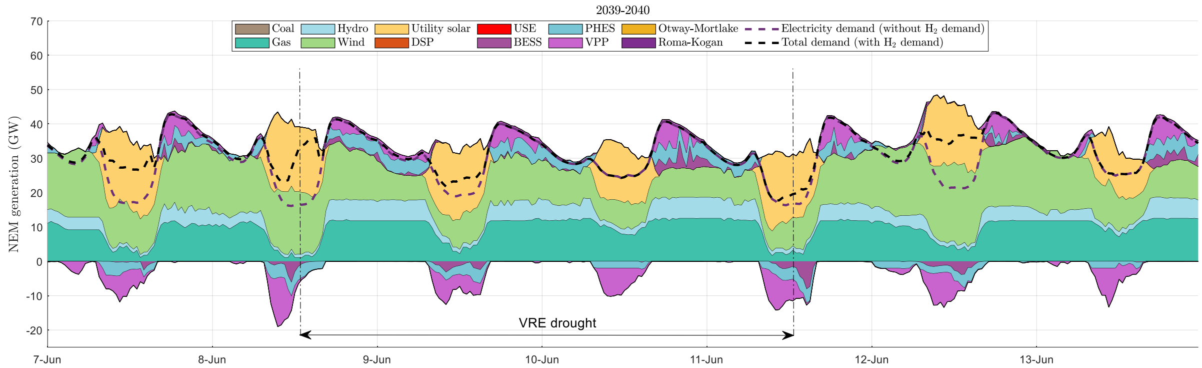


Figure 42: Forecast operability across the NEM experiencing a three-day low VRE period in June 2040 in the Snowy-Borumba scenario.

The assessment in this report extends the analysis to June 2041, which also experiences periods of high residual demand and low wind CF, although different observations were made in this case. The residual demand for the whole year of 2040-41 is shown in Figure 94 in Appendix B, clearly showing higher prevalence of high residual demand in winter months. Of particular interest is a 24-hour low VRE period between 23-Jun-2041 and 24-Jun-2041, during which the wind CF drops to 13.78% due to wind lulls coinciding with high heating demand in southern states (NSW, VIC, SA, and TAS), particularly during the evening peak of the 23rd of June when operational demand peaks and solar output dwindles, as shown in Table 43. Interestingly, the residual demand during these 24 hours reaches 34.8 GW during the evening peak of 23-Jun-2041—1.6 GW higher than that in June 2040 (see Figure 41), as shown in Figure 43 and Table 44.

Table 43: NEM-wide wind and solar energy across a 24-hour low VRE period in June 2041 and its relationship to operational demand. For reference, the last column shows these same variables but across the whole of 2040-41.

	24-hour low VRE period	2040-41
	23-Jun-2041 12:00:00 PM to 24-Jun-2041 11:30:00 AM	
Demand (TWh)	0.81	274.26
Wind (TWh)	0.20	194.34
Solar (TWh)	0.17	57.91
VRE (% of demand)	45.80%	91.97%
Wind CF (%)	**13.78%**	37.43%
Solar CF (%)	**22.13%**	20.26%

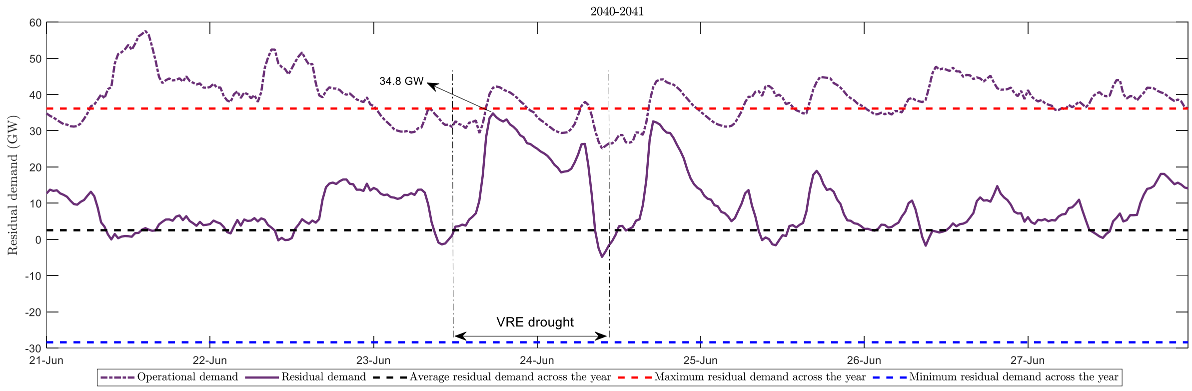


Figure 43: Residual demand across the NEM during a 24-hour low VRE period in June 2041.

Table 44: The three highest NEM-wide residual demands witnessed during a 24-hour low VRE period in June 2041.

	24-hour low VRE period		
	23-Jun-2041 12:00:00 PM to 24-Jun-2041 11:30:00 AM		
	Residual demand (GW)	VRE (% of demand)	Date and time
Highest	34.78	16.57	23-Jun-2041 17:00:00
Second highest	33.70	16.92	23-Jun-2041 17:30:00
Third highest	33.49	19.09	23-Jun-2041 19:30:00

During this event, the NEM experiences USE during the morning peak of 24-Jun-2041 under the Snowy-Borumba scenario, as evidenced in Figure 44 a). Most of the lost load in the Snowy-Borumba scenario occurs in VIC and TAS during the morning peak of the 24th of June, as shown in Figure 45. In contrast, the HESS-VIC-QLD-4GW scenario in Figure 44 b) does not witness any USE during that period. In both cases, GFG and hydro generators operate at (near) peak output between the evening peak of the 23rd of June until the morning peak of the 24th of June to compensate for VRE shortfalls during that time. At the same time, most storage systems across the NEM discharge at (near) peak output, as shown in Figure 46.

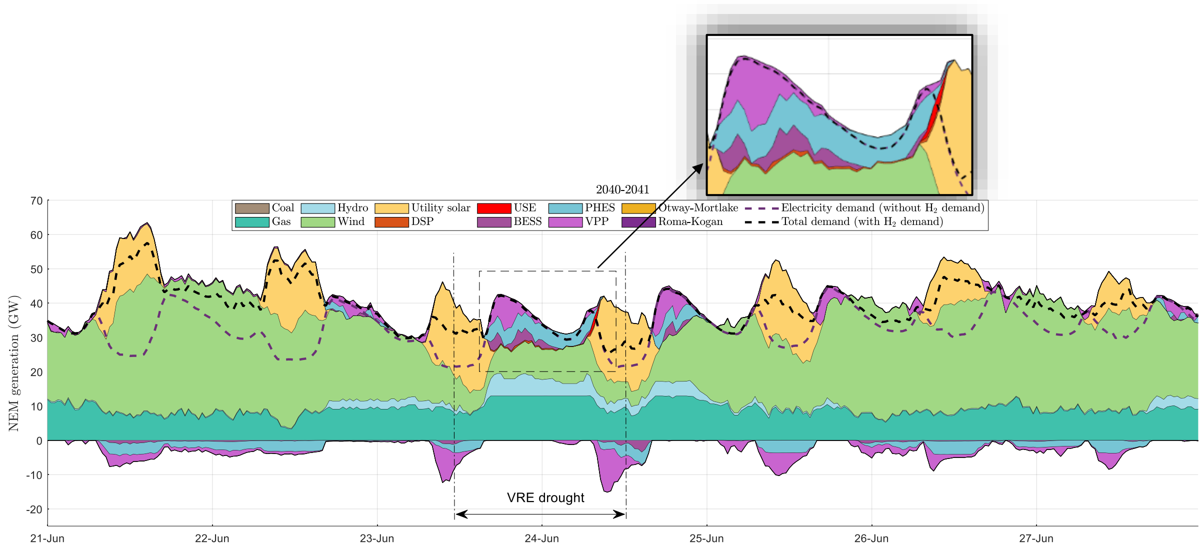
Interestingly, Figure 46 a) shows that shallow and medium storage systems under the Snowy-Borumba scenario enter the 24-hour low VRE period at around 60% SoE and are fully discharged by the morning peak of the 24th of June. In the HESS-VIC-QLD-4GW scenario, shallow and medium storage systems enter the event fully charged (i.e., 100% SoE), and then recharge to around 70% after the morning peak on the 24th, in anticipation for the evening peak and the morning peak of the next day. Figure 46 also shows that the Otway-Mortlake HESS and the Roma-Kogan HESS enter the event with around 91% and 40% SoE, respectively, whereas Snowy 2.0 and Borumba enter with around 42% and 72% respectively.

These SoE are determined by the optimisation model in (1)-(15) which minimises operational costs over a much greater horizon than the 7 days shown in Figure 46, and therefore leverages this foresight to balance the operating costs (see objective function in (1)) between multiple periods with high residual demand, in a way that eventuates in the lowest possible overall operational cost over 20 years. The half-hourly SoE profiles of Snowy 2.0, Borumba, Otway-Mortlake HESS, and the Roma-Kogan HESS over the first 20 years of their life can be found in Figure 92 and Figure 93 in Appendix B.

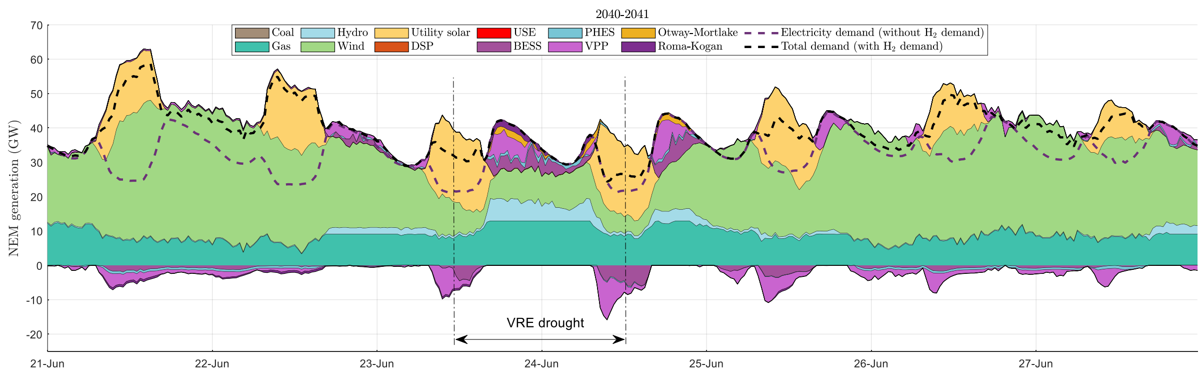
Although both cases resort to DSP to reduce the magnitude of the residual demand during this period, Figure 47 shows that the Snowy-Borumba scenario activates significantly more DSP than in the HESS-VIC-QLD-4GW scenario, particularly in VIC, SA, and TAS. This is confirmed in Figure 48 a), which shows that forecast reserve levels fall below the magnitude of the largest contingency (see Table 37) in VIC, SA, and TAS, enough to trigger a reliability response (LOR3) in VIC and TAS as load shedding is witnessed under the Snowy-Borumba scenario. Specifically, up to 0.6 GW and up to 1.6 GW of load are lost in VIC and TAS, respectively, as shown in Figure 45.

In contrast, Figure 48 b) shows a much smaller fall in reserves in these same states, which only triggers LOR2 that is fully alleviated by DSP under the HESS-VIC-QLD-4GW scenario. This reliance on DSP, which are costly (see Table 56 and Table 57 in Appendix A), is also evidenced in Figure 49 a) showing very high market prices, upwards of $17,500/MWh (i.e., market price cap) in VIC, SA, and TAS under the Snowy-Borumba scenario. In contrast, Figure 49 b) shows that RRP across the whole NEM do not exceed $500/MWh, as very minimal DSP is activated in the HESS-VIC-QLD-4GW scenario.

The substantial improvement in resilience under the HESS-VIC-QLD-4GW scenario, most notably in southern states, is attributed to the *location* of the Otway-Mortlake HESS. Being in VIC, it offers more strategic benefits to the southern states, despite its lower energy storage capacity compared to Snowy 2.0. This is discussed in more detail in Subsection: Reliability. Although no USE was forecast in the HESS-VIC-QLD-4GW scenario, any additional unplanned generator or interconnector outages beyond those modelled may cause reliability concerns.



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 44: Forecast operability across the NEM experiencing a 24-hour low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

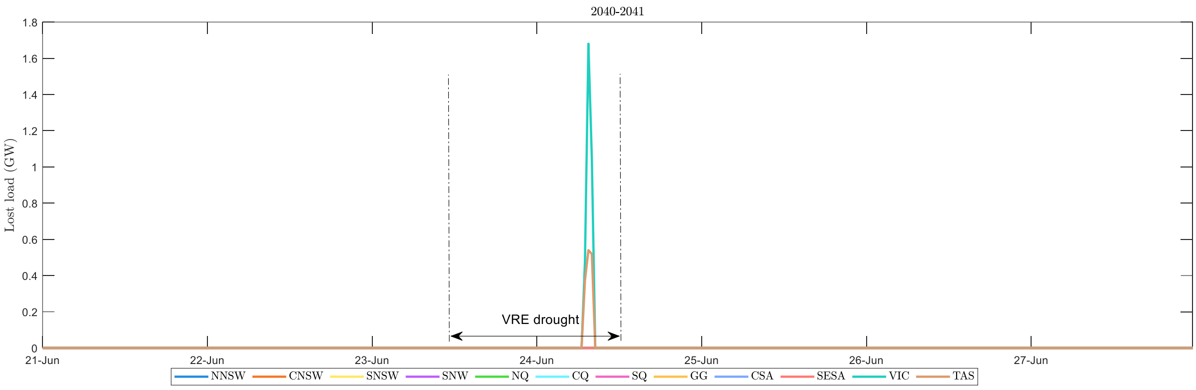
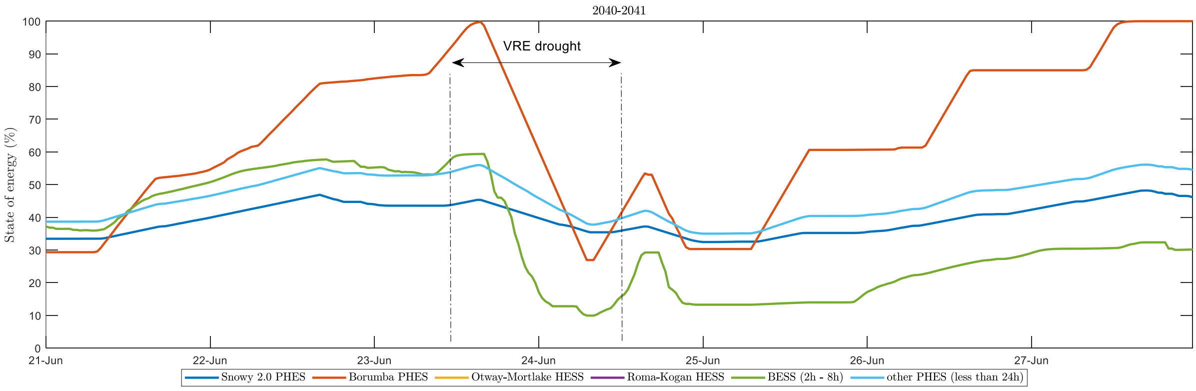
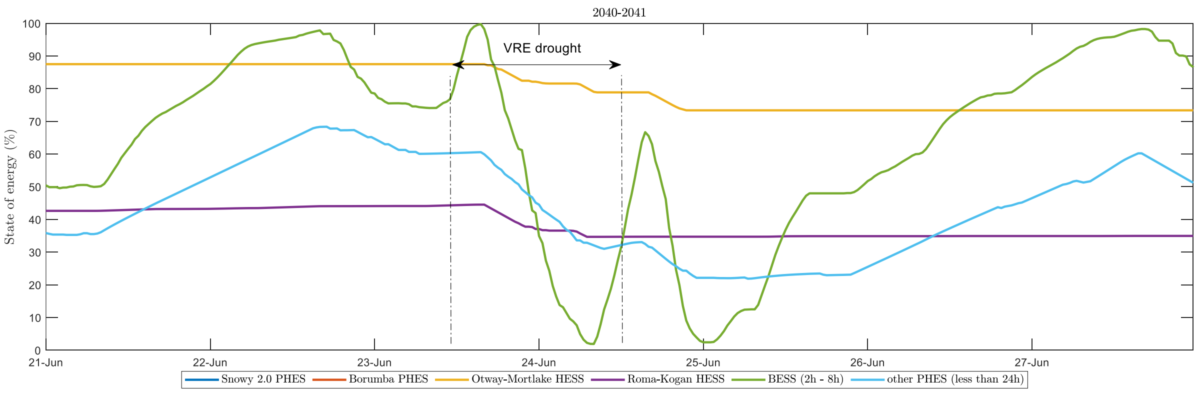


Figure 45: Lost load in each subregion during a 24-hour low VRE period in June 2041 under the Snowy-Borumba scenario.

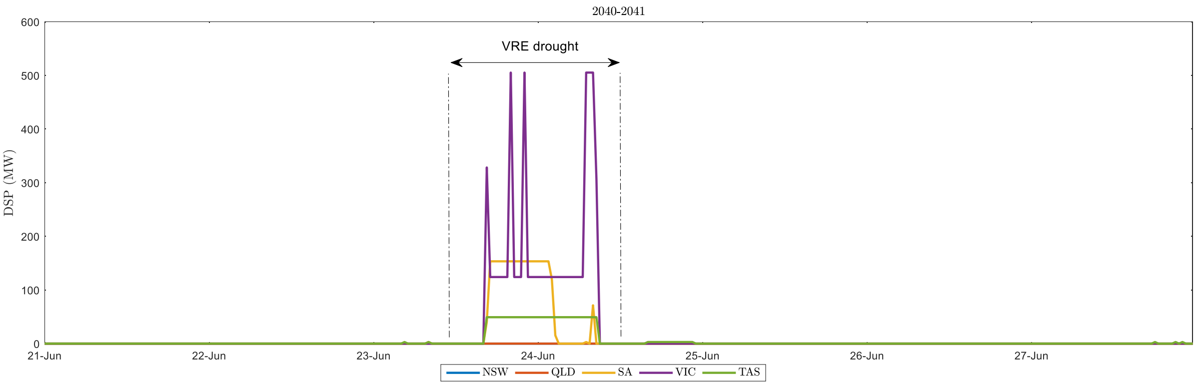


a) Snowy-Borumba

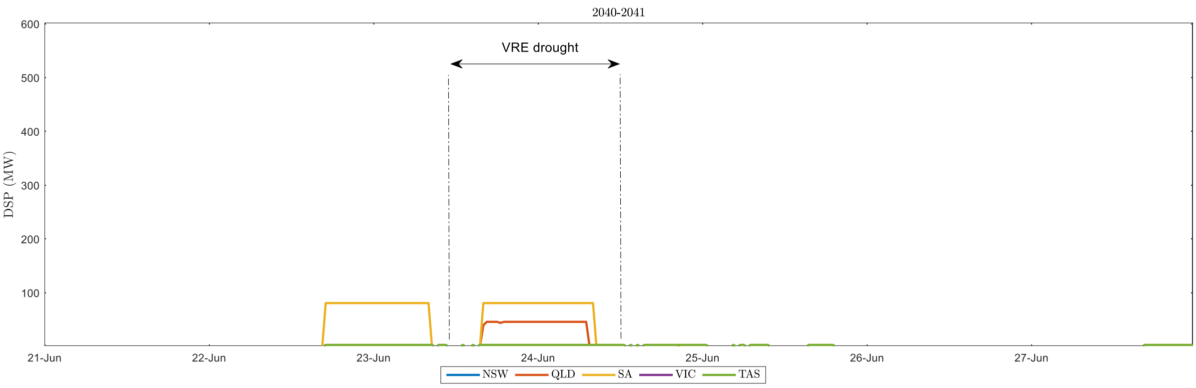


b) HESS-VIC-QLD-4GW

Figure 46: SoE of all storage systems (except hydro) across the NEM during a 24-hour low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

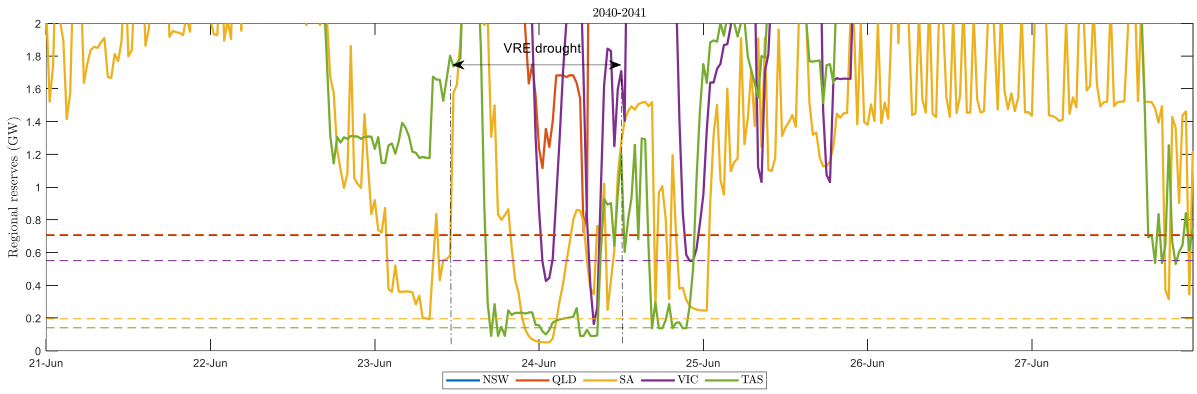


a) Snowy-Borumba

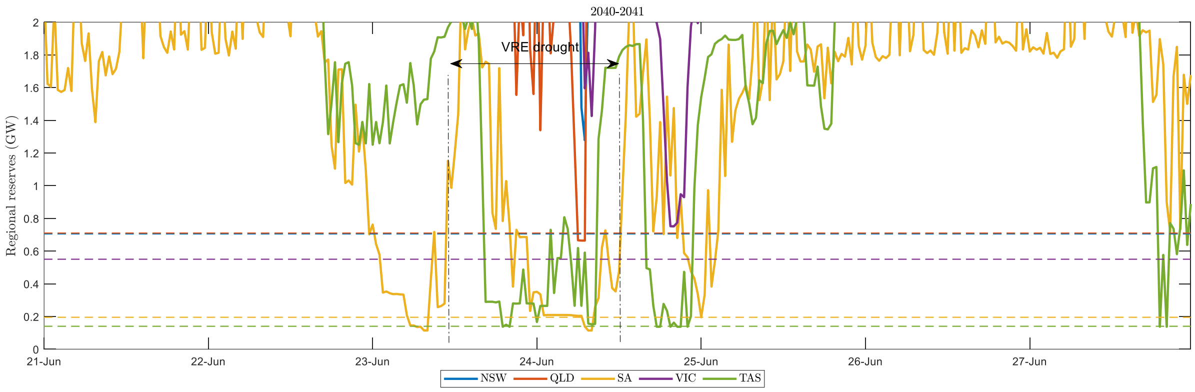


b) HESS-VIC-QLD-4GW

Figure 47: DSP activation during a 24-hour low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

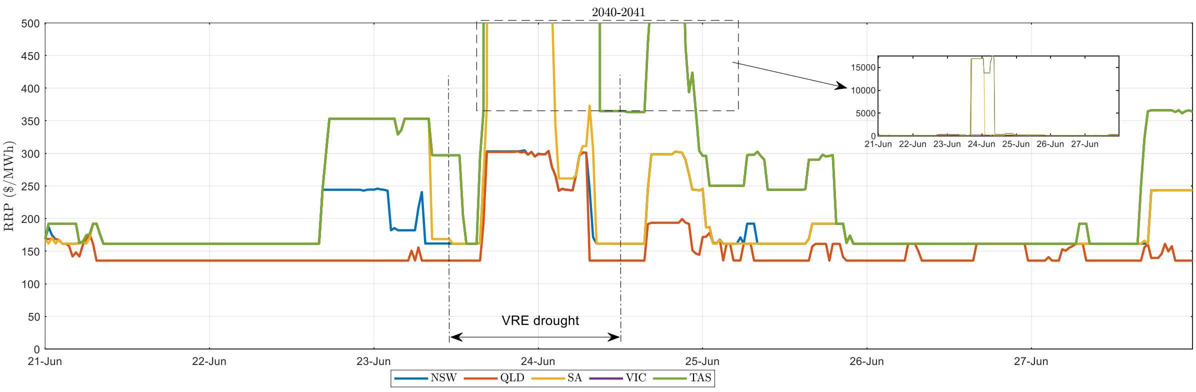


a) Snowy-Borumba

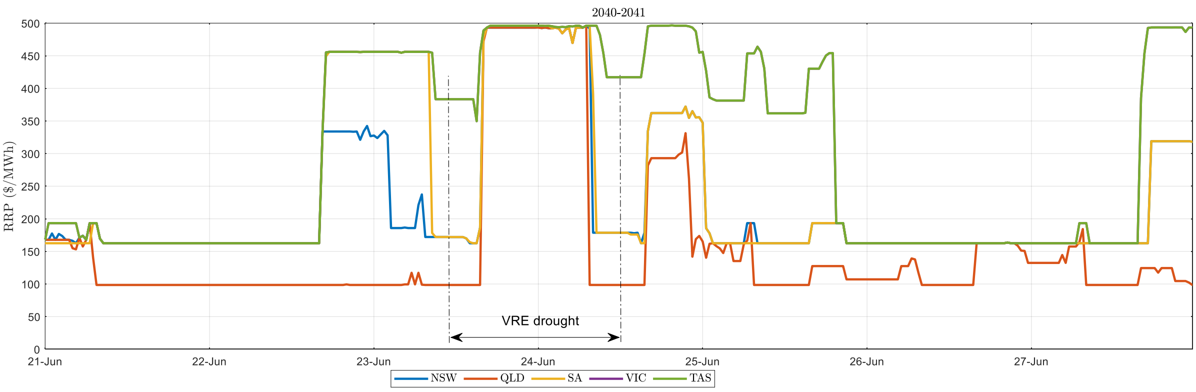


b) HESS-VIC-QLD-4GW

Figure 48: Regional reserves during a 24-hour low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom). The dashed lines represent the largest contingency in each state (see Table 39).



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 49: RRP across the NEM during a 24-hour low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

It should be re-emphasised that no assumptions on initial SoE are made at the beginning on any of the three considered VRE drought events assessed below because the long-horizon optimisation-based market dispatch model in (1)-(15) aligns the start of its operational horizon with the indicative commissioning dates of the four considered LDES (see Section 4), where they are, for obvious reasons, assumed to start at 0% SoE. This can be seen in Figure 92 and Figure 93 in Appendix B.

So far, no algorithms were used to synthesise the two events in June 2040 and June 2041 as they are intrinsic to the VRE traces obtained directly from AEMO's 2024 ISP [3]. The subsequent three subsections examine the resilience of the NEM under scenarios Snowy-Borumba and HESS-VIC-QLD-4GW during three synthetically generated, but plausible VRE drought events with varying duration and severity in 2040-41. One of those events mimics the recent eight-day severe VRE drought that occurred in May 2024, which witnessed a wind CF of around 11.6% and solar CF of 17.9%.

5.4.2 Three-day VRE drought period

As it is difficult to forecast timing, severity, and duration of prolonged VRE droughts, and knowing that climate conditions may change in unpredictable ways over coming decades across the different regions of the NEM, this section assesses a situation with more severe weather conditions, manifesting in a three-day VRE drought period in June of 2040-41. In the absence of reliable forecasts for future weather conditions, simulating such a three-day VRE drought is achieved by artificially extending the 24-hour low VRE period in the previous section to start on the 22nd of June and end on the 25th of June, i.e., repeating it three times over three days.[13]

The wind and solar CFs therefore remain unchanged at 13.78% and 22.13%, respectively, as shown in Table 45. For reference, 2040-41 is characterised by wind and solar CFs of 37% and 20.26%, respectively, and a VRE output of around 92% of operational demand. The highest residual demand reaches 36.61 GW during the afternoon peak of the 24th of June, with a VRE output as low as 16% of operational demand, as shown in Table 46 and Figure 50.

Unsurprisingly, the amount of USE under the Snowy-Borumba scenario is more pronounced during this event compared to the 24-hour one, as shown in Figure 51 a) and Figure 52. Nonetheless, the NEM remains resilient under the HESS-VIC-QLD-4GW scenario, which exhibits no USE, as shown in Figure 51 b). This extended period also witnesses a more consistent dispatch at peak output from GFG and hydro generators, and more frequent cycling of shallow and medium storage systems in an effort to shift energy from the middle of the day to meet afternoon peaks during this extended VRE drought period, as shown in Figure 53.

On the other hand, LDES systems allocate most of the discharging to the period starting shortly before the evening peak and ending shortly after the morning peak. Interestingly, as the southern states (VIC, SA, and TAS) experience colder temperatures and shorter days, and therefore higher residual demands compared to QLD, the LDES options in or closest to these states, i.e., Snowy 2.0 and the Otway-Mortlake HESS, experience more pronounced depletion and less cycling compared to Borumba and the Roma-Kogan HESS in SQ.

As shown in Figure 54, DSP is once again activated in both scenarios to reduce the magnitude of the residual demand during this period—albeit to a larger extent, particularly in VIC, SA, and TAS under the Snowy-Borumba scenario. This higher DSP activation the Snowy-Borumba scenario is accompanied by more frequent drops in reserve levels in VIC, SA, and TAS, enough to trigger a reliability response (LOR3), as shown in Figure 55 a). Consequently, the market price cap of $17,500/MWh is reached more frequently across the three-day VRE drought event compared to the 24-hour one, as shown in Figure 56 a).

In contrast, NEM-wide availability of reserves is improved under the HESS-VIC-QLD-4GW scenario, particularly in VIC and QLD. Corroborated by Figure 54 b), Figure 55 b) shows that reserve levels do not progress beyond LOR2, which also explains why the RRP shown in Figure 56 b) do not exceed $850/MWh.

[13] Only the VRE traces are repeated. Operational demand is not repeated.

Although no USE was forecast in the HESS-VIC-QLD-4GW scenario, any additional unplanned generator or interconnector outages beyond those modelled will likely cause reliability concerns, more so than in the case with the 24-hour low VRE period in the previous section. Therefore, maintenance schedules of dispatchable generators must be meticulously planned and coordinated during winter, when reliability concerns due to VRE droughts are high. This is further compounded by the impact that weather forecast accuracy has on the degree of foresight of unfavourable weather conditions to allow accumulation of sufficient energy in LDES to maintain resilience during periods of severe VRE droughts. Prudent scheduling of energy reserves in LDES systems may be essential to hedge against forecasting errors, imperfect foresight, unplanned outages, and gas supply chain risks.

Table 45: NEM-wide wind and solar energy across the three-day VRE drought event and its relationship to operational demand. For reference, the last column shows these same variables but across the whole of 2040-41.

	Three-day VRE drought 22-Jun-2041 12:00:00 PM to 25-Jun-2041 11:30:00 AM	2040-41
Demand (TWh)	2.43	274.26
Wind (TWh)	0.59	194.34
Solar (TWh)	0.52	57.91
VRE (% of demand)	45.56%	91.97%
Wind CF (%)	**13.78%**	37.43%
Solar CF (%)	**22.13%**	20.26%

Table 46: The three highest residual demands witnessed during the three-day VRE drought event.

	Three-day VRE drought		
	22-Jun-2041 12:00:00 PM to 25-Jun-2041 11:30:00 AM		
	Residual demand (GW)	VRE (% of demand)	Date and time
Highest	36.61	15.85	24-Jun-2041 17:00:00
Second highest	35.62	16.22	24-Jun-2041 17:30:00
Third highest	35.32	16.57	23-Jun-2041 17:00:00

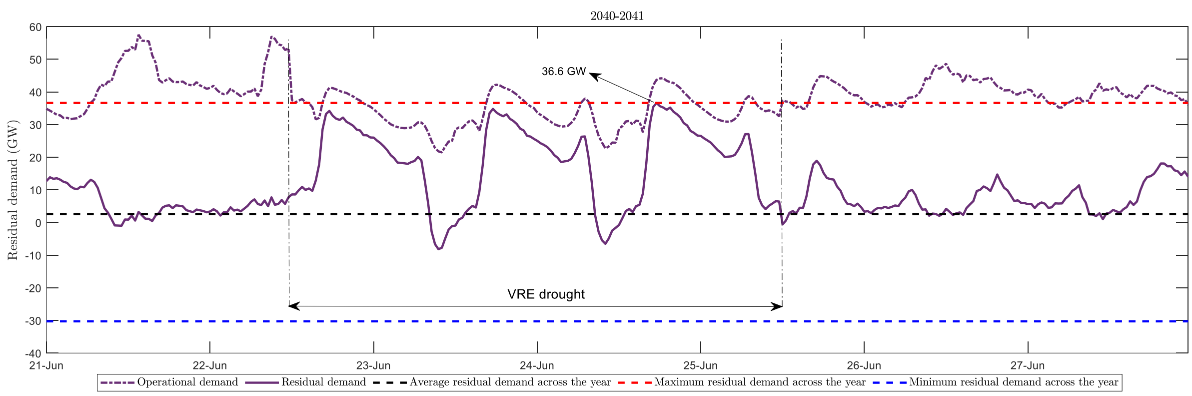
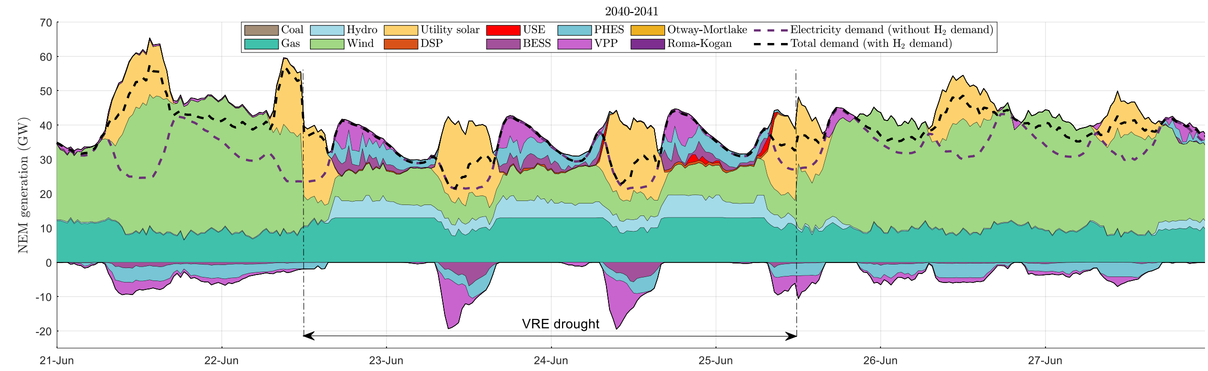
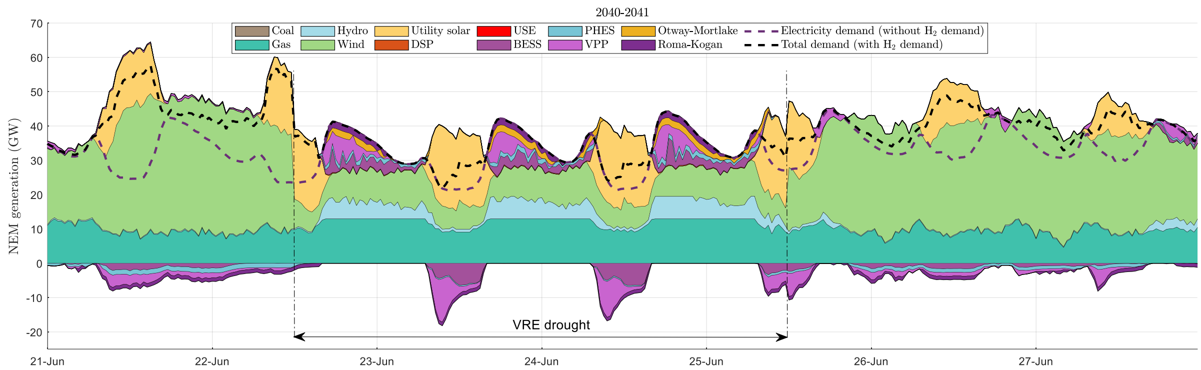


Figure 50: Residual demand across the NEM during a three-day VRE drought period in June 2041.



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 51: Forecast operability across the NEM experiencing a three-day low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

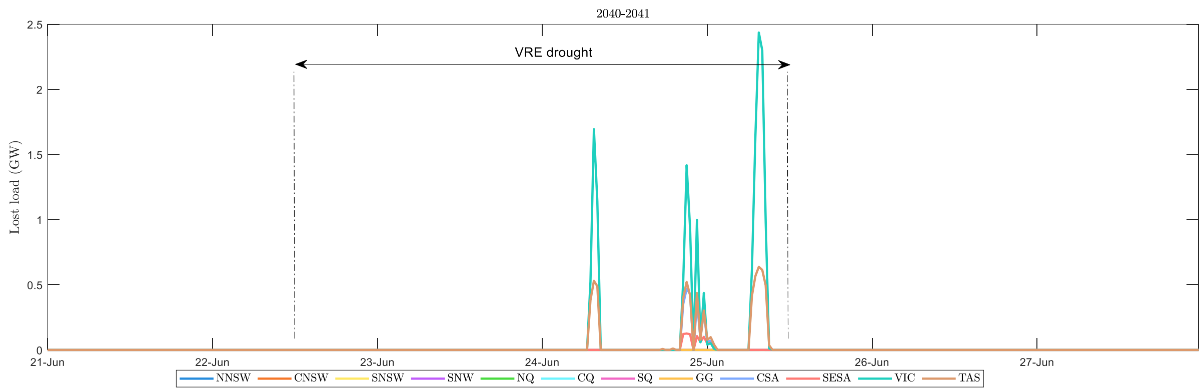
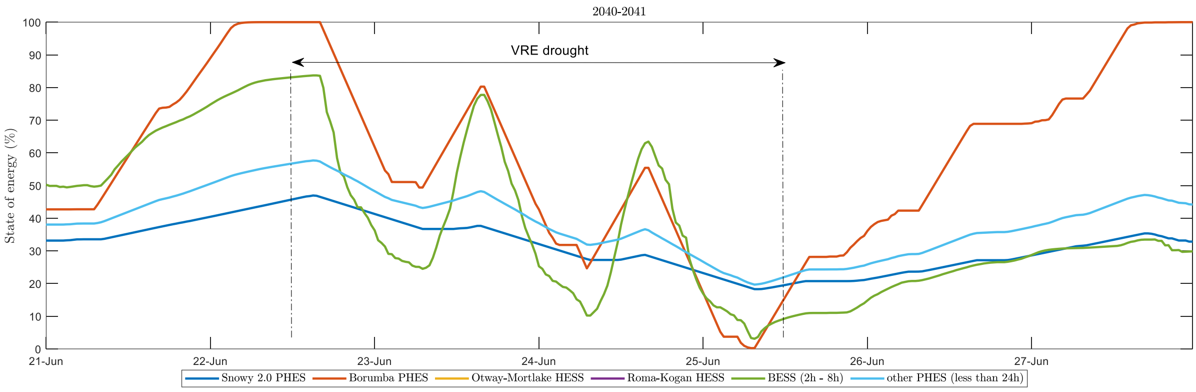
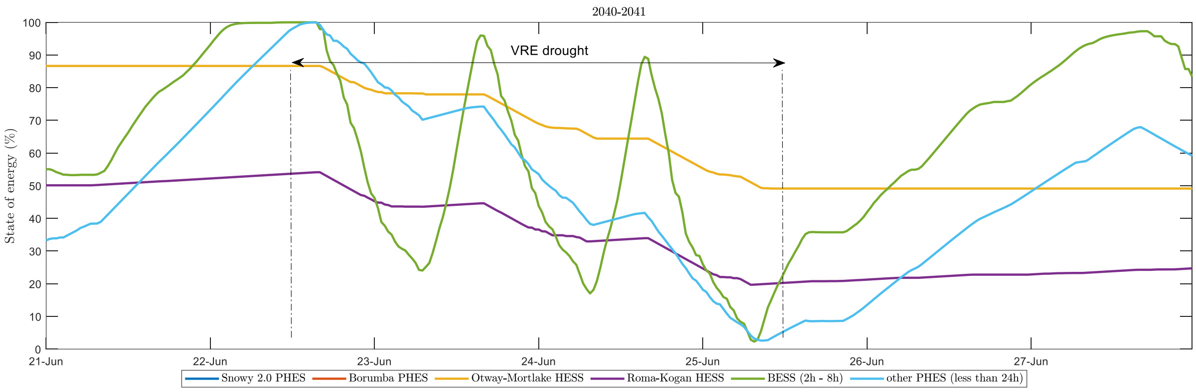


Figure 52: Lost load in each subregion during a three-day low VRE period in June 2041 under the Snowy-Borumba scenario.

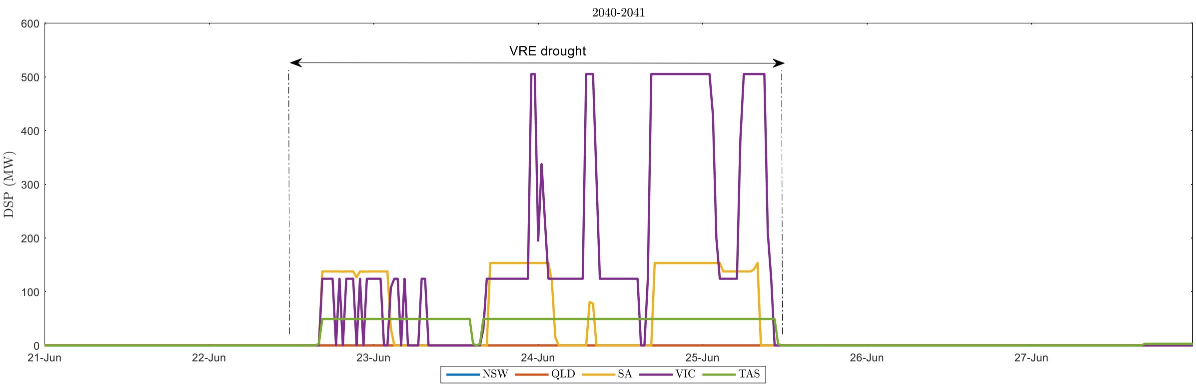


a) Snowy-Borumba

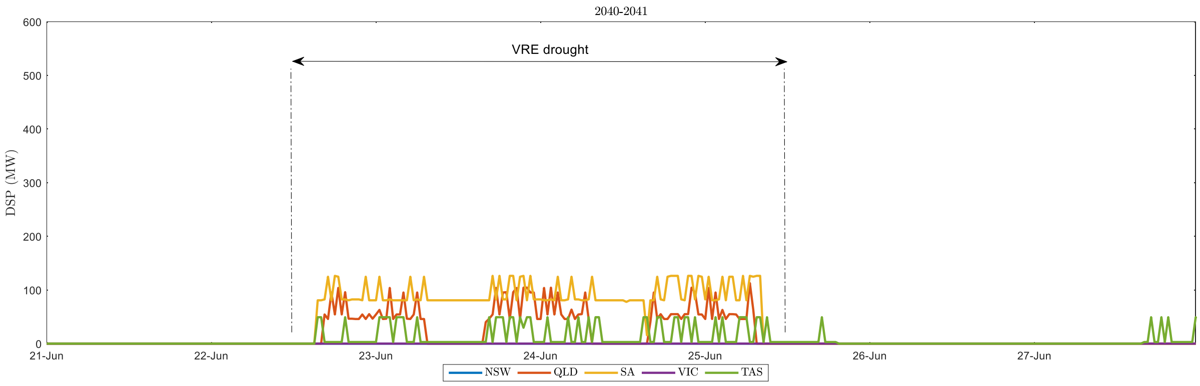


b) HESS-VIC-QLD-4GW

Figure 53: SoE of all storage systems (except hydro) across the NEM during a three-day low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

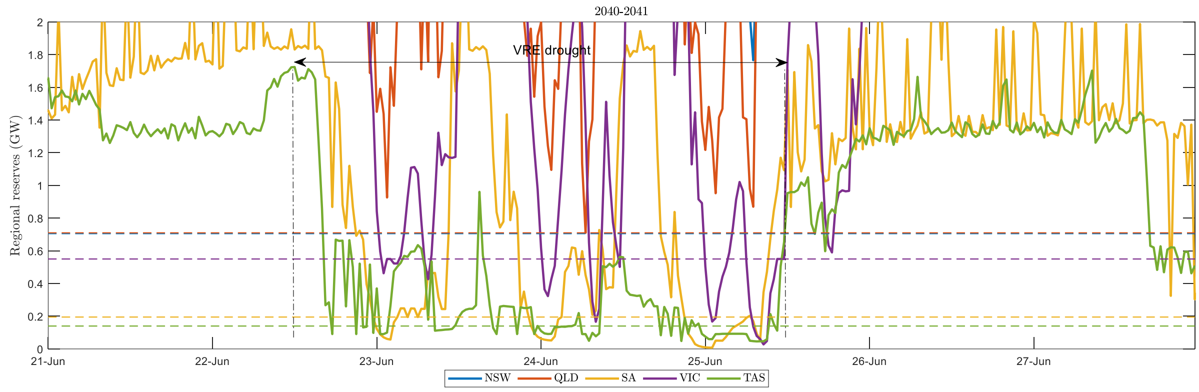


a) Snowy-Borumba

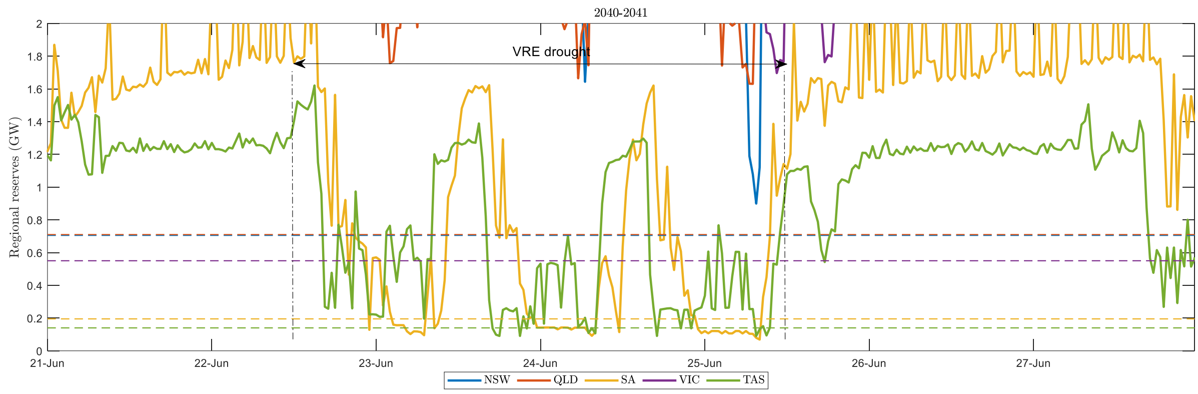


b) HESS-VIC-QLD-4GW

Figure 54: DSP activation during a three-day low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

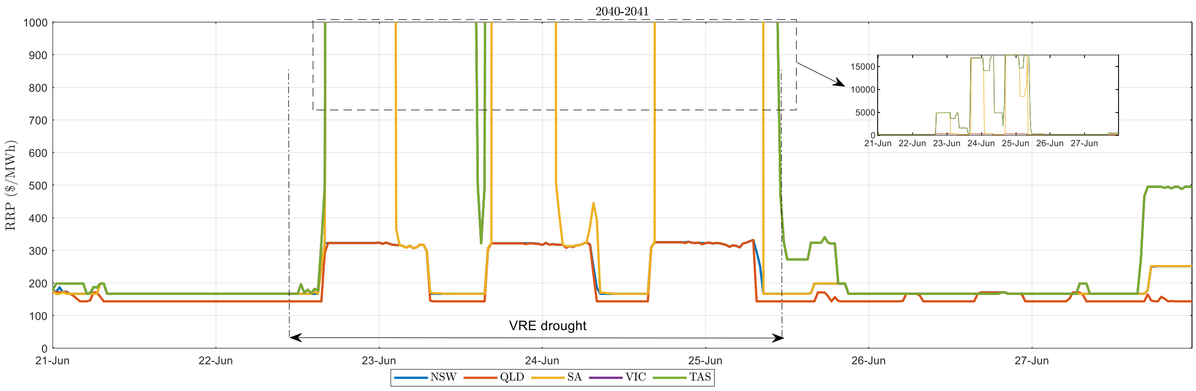


a) Snowy-Borumba

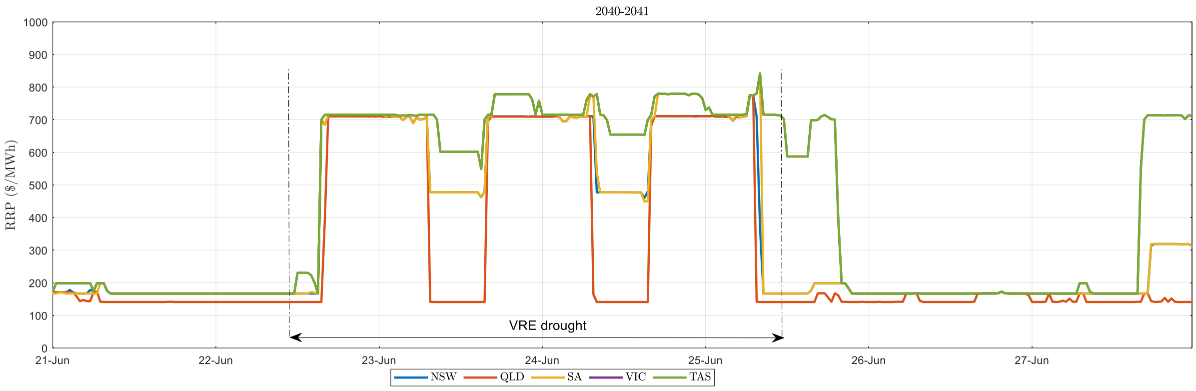


b) HESS-VIC-QLD-4GW

Figure 55: Regional reserves during a three-day low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom). The dashed lines represent the largest contingency in each state (see Table 39).



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 56: RRP across the NEM during a three-day low VRE period in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

5.4.3 Multiple intermittent VRE droughts

Extended periods of intermittent VRE volatility can stem from extreme intermittent weather patterns that give rise to several periods of fluctuating VRE output interspersed with short intervals of typical VRE generation. Such a situation is simulated by artificially extending the three-day low VRE period in the previous section to start on the 17th of June and end on the 30th of June, i.e., repeating it three times over fourteen days, punctuated by two two-day relief periods, as shown in Figure 57 and Figure 58. Figure 57 also shows that the highest residual demand of 36.6 GW now occurs on a different day (17th of June) compared to the previous case due to with different underlying and operational demand patterns.

This case is more severe than the three-day VRE drought event in the previous section as the two interspersed relief days are not long enough to allow most storage systems to replenish prior to the corresponding VRE drought periods. This engenders an increased amount USE in both scenarios compared to the three-day VRE drought event, as shown in Figure 59. During this event, LDES systems allocate most of the discharging to the period starting shortly before evening peak and ending shortly after the morning peak on during the VRE drought periods, as shown in Figure 60.

Unlike in the three-day low VRE period in the previous section, the HESS-VIC-QLD-4GW scenario experiences a small amount of USE (Figure 59b), albeit to a far lesser extent than in the Snowy-Borumba scenario (Figure 59a). Interestingly, Figure 61 shows that the HESS-VIC-QLD-4GW scenario activates more DSP compared to Snowy-Borumba, even during relief days. This activation of DSP allows some generation to be redirected towards recharging storage systems, particularly the slow-charging HESS in VIC and SQ. This, in turn minimises USE, which does not exceed 120 MW under the HESS-VIC-QLD-4GW scenario (Figure

59b).[14] In contrast, Figure 59a shows much more severe USE in VIC, SA, and TAS under the Snowy-Borumba scenario, frequently exceeding 1 GW.

Despite more DSP activation under the HESS-VIC-QLD-4GW scenario, Figure 62 shows that reserve availability is once again significantly improved compared to the Snowy-Borumba scenario, especially in the VIC and QLD. LOR3 is minimally activated in SA and TAS under the HESS-VIC-QLD-4GW scenario, as shown in Figure 62b (see Figure 91 in Appendix B). Figure 62a shows that the reserves under the Snowy-Borumba scenario dip well below the magnitude of the largest contingency in many southern states (VIC, SA, and TAS), reaching zero in SA on nine separate instances. This also explains the extremely high prices in Figure 63a. However, although it leads to a substantial decrease in USE, the higher DSP activation under the HESS-VIC-QLD-4GW scenario incurs higher average prices compared to the Snowy-Borumba scenario, particularly in NSW and QLD, as shown in Figure 63b.

Figure 58 also shows the total hydrogen demand for domestic use and export, whose intraday and inter-day flexibility offers some relief to reserves during this period by shifting the bulk of the hydrogen production to the middle of the day when there is surplus generation.

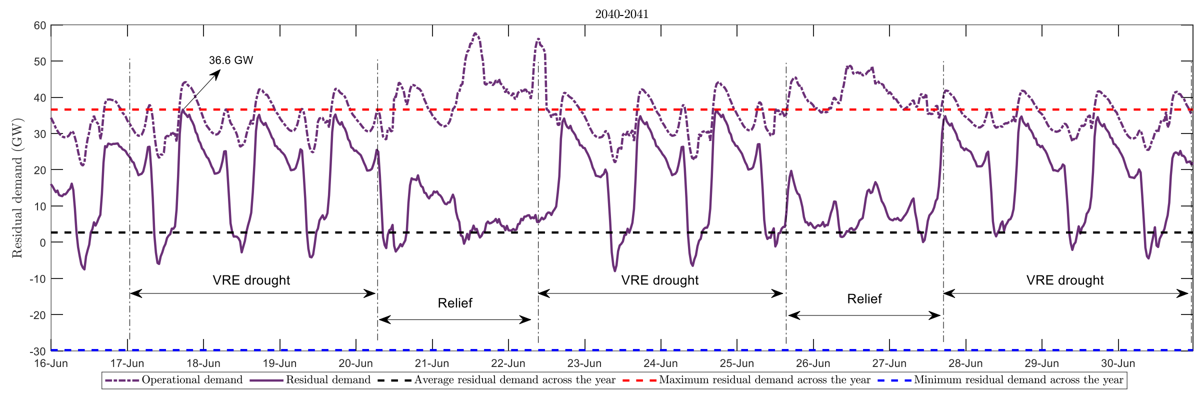
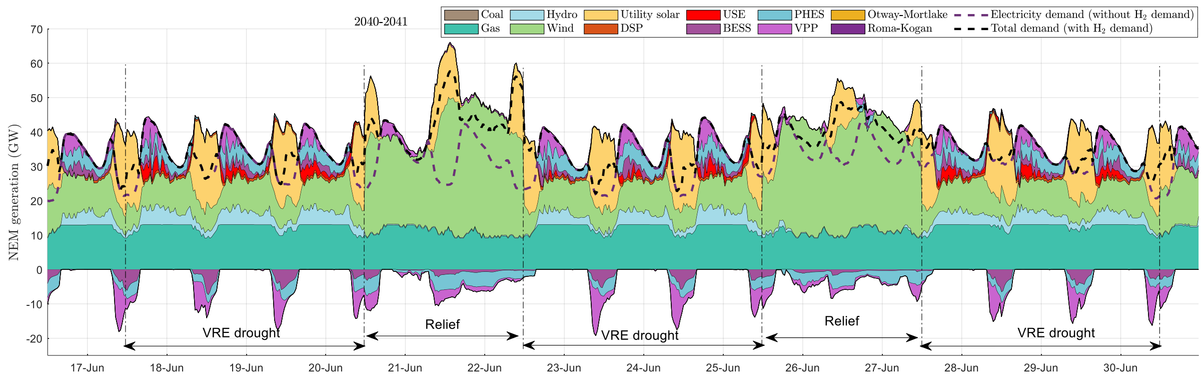
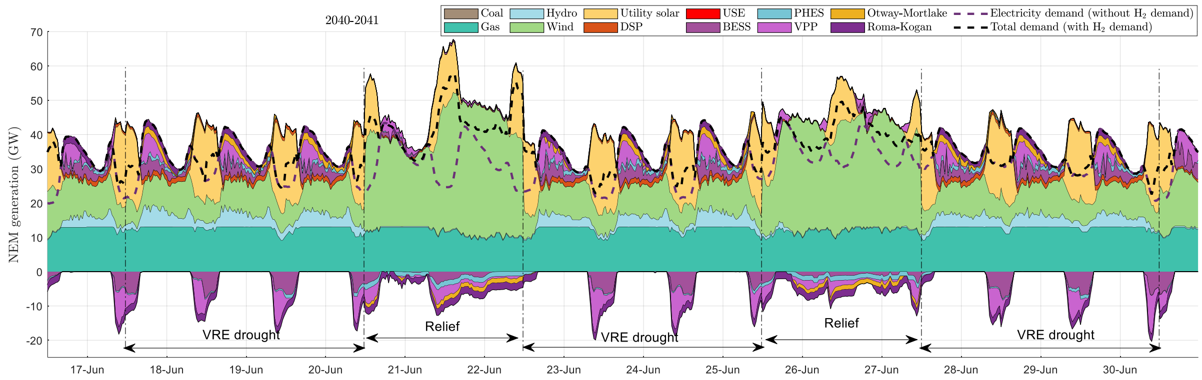


Figure 57: Residual demand across the NEM during two weeks with multiple VRE drought events in June 2041.



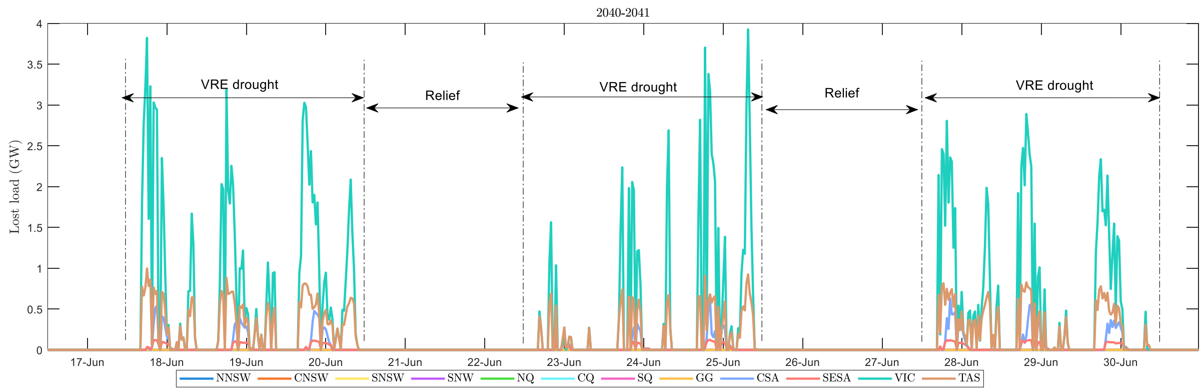
a) Snowy-Borumba

[14] A version with a different y-axis range can be found in Figure 91 in Appendix B.

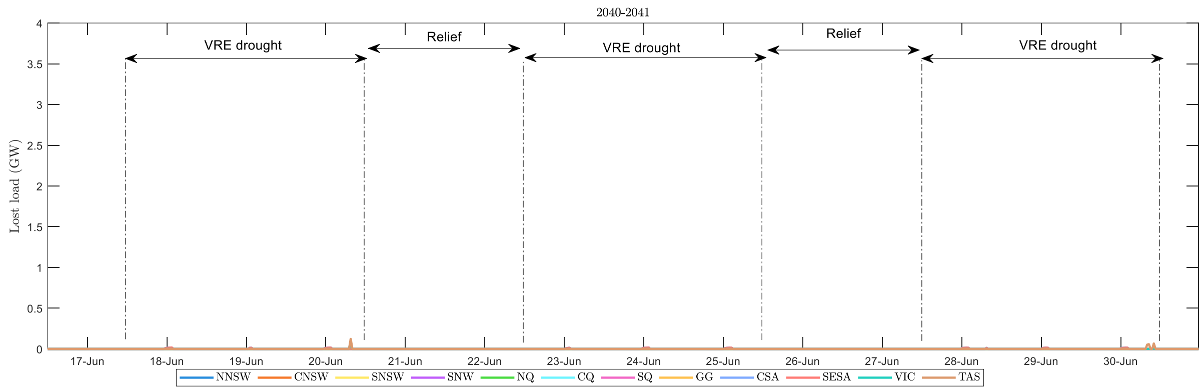


b) HESS-VIC-QLD-4GW

Figure 58: Forecast operability across the NEM experiencing two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

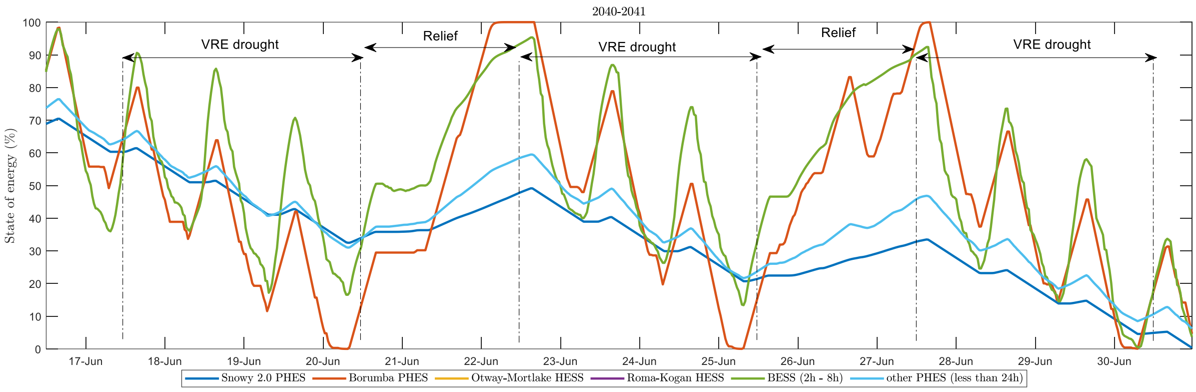


a) Snowy-Borumba

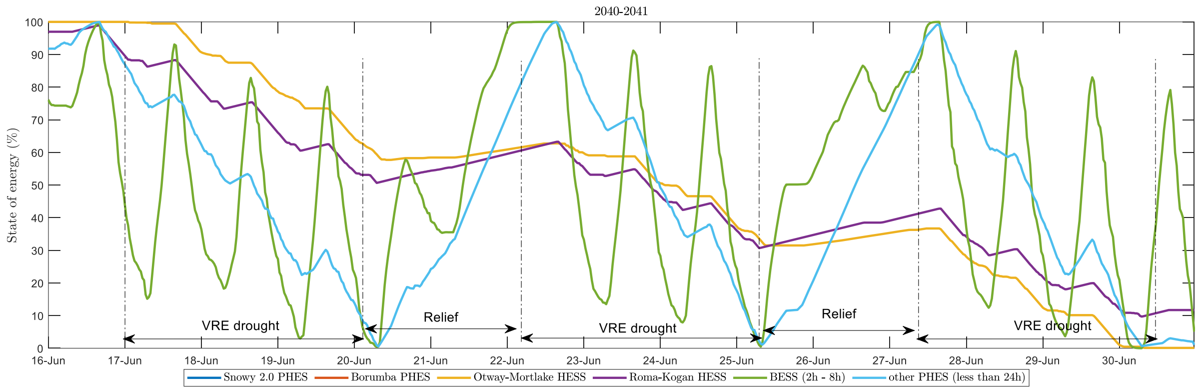


b) HESS-VIC-QLD-4GW

Figure 59: Lost load in each subregion during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

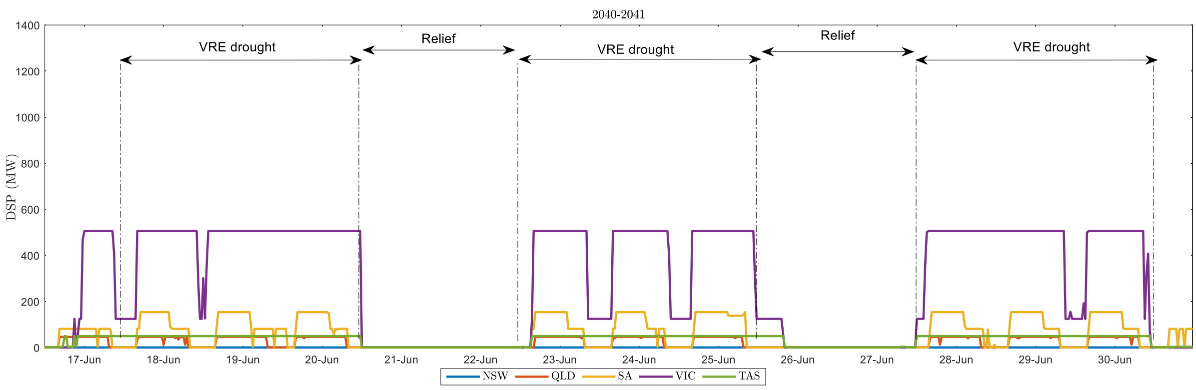


a) Snowy-Borumba

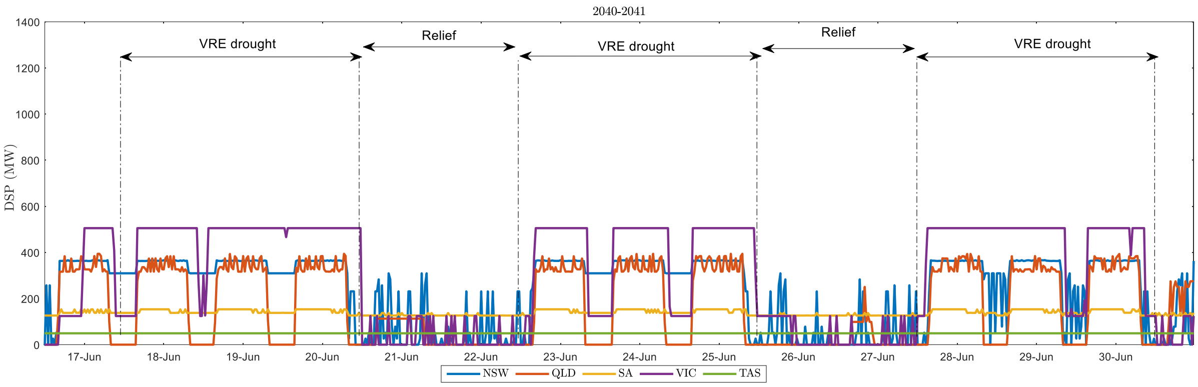


b) HESS-VIC-QLD-4GW

Figure 60: SoE of all storage systems (except hydro) across the NEM during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

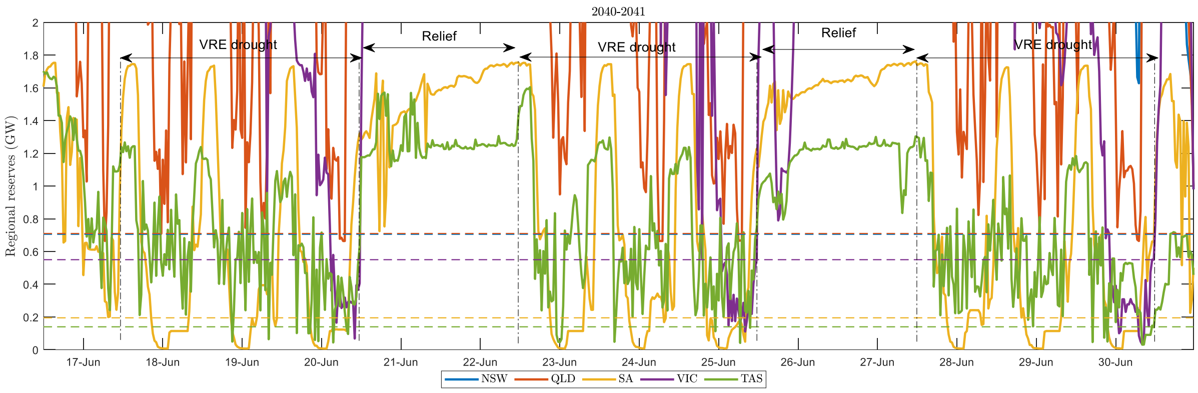


a) Snowy-Borumba

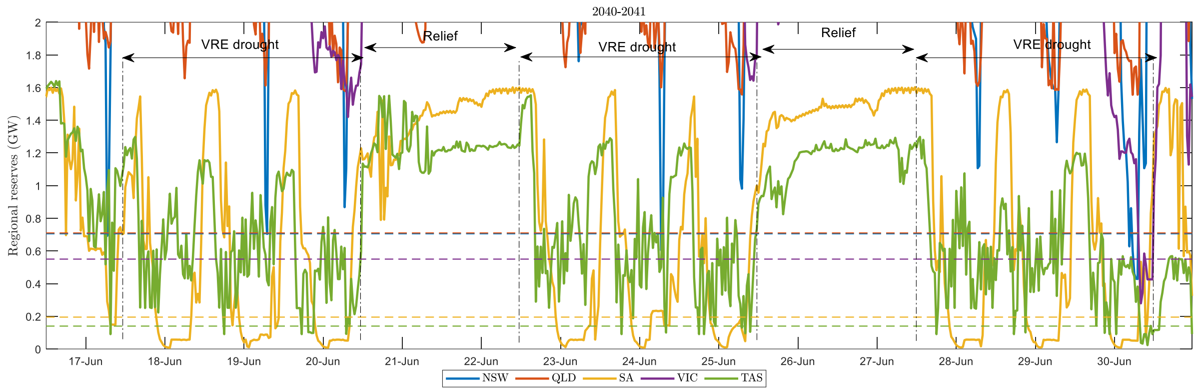


b) HESS-VIC-QLD-4GW

Figure 61: DSP activation during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

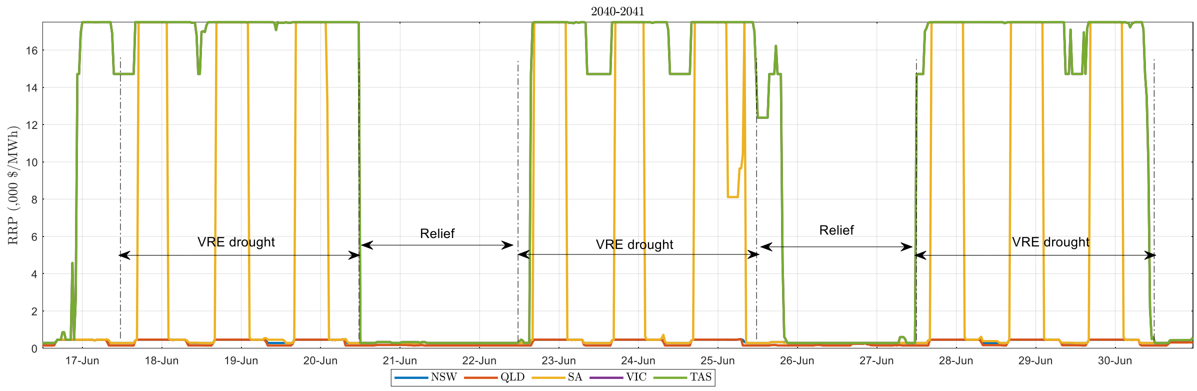


a) Snowy-Borumba

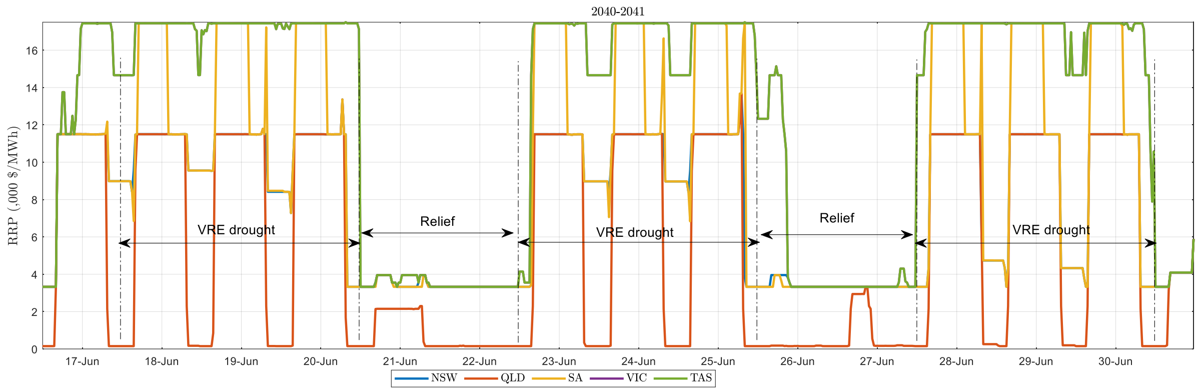


b) HESS-VIC-QLD-4GW

Figure 62: Regional reserves during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 63: RRP across the NEM during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

5.4.4 Eight-day VRE drought period: The May 2024 event

During May 2024 the NEM witnessed a rare yet severe prolonged VRE drought event that was characterised by wind CF as low as 11.6% over eight consecutive days. No reliability events were triggered during this event as the NEM had enough dispatchable synchronous generation in 2024 and the share of VRE had not reach a critical level that makes the NEM highly sensitive to such extreme weather events. However, the occurrence of such an event in 2041 when the NEM is envisaged to become VRE-dominated could have catastrophic repercussions unless generation and storage, including LDES, are planned accordingly to hedge against such extreme weather events and maintain resilience of the NEM. This section tests the generation, storage, and transmission plan in AEMO's 2024 ISP under such an extreme weather event, under the Snowy-Borumba and the HESS-VIC-QLD-4GW scenarios.

This event is modelled by extending the 24-hour VRE drought event to eight days, starting on the 20th of June, and then capping the wind and solar CFs to 11.6% and 17.9%, respectively, as shown in Table 47. The residual demand during this event reaches 38.44 GW during the afternoon peak of the 25th of June, with a VRE output as low as 13% of operational demand, as shown in Table 48 and Figure 64.

In this case, although both scenarios exhibit substantial USE, the severity is far lower in the HESS-VIC-QLD-4GW scenario, as shown in Figure 65 and Figure 66. This suggests that additional firming and backup generation should be planned accordingly—particularly in VIC and QLD—beyond what is projected in AEMO's 2024 ISP and in this report, to hedge against high-intensity, low-probability (HILP) events such as this one. This is also evident from Figure 67, which shows that all storage systems—including the LDES options—are fully depleted in both scenarios by the end of the eight-day VRE drought event, suggesting that more storage is needed.

Similar to the previous case, the HESS-VIC-QLD-4GW scenario activates more DSP compared to the Snowy-Borumba scenario, freeing up additional generation that can be redirected toward recharging all storage systems, as shown in Figure 68. Despite the observed improvement in reserves compared to the Snowy-Borumba scenario, the 2 GW HESS in VIC and SQ alone are insufficient to prevent LOR3—and, consequently, USE—as shown in Figure 67.

Finally, as expected, the consistent and extremely high prices shown in Figure 70 emanate from a combination of DSP and USE across both scenarios.

Table 47: Wind and solar energy across a severe eight-day VRE drought event and its relationship to operational demand. For reference, the last column shows these same variables but across the whole of 2040-41.

	Eight-day severe VRE drought 20-Jun-2041 12:00:00 PM to 28-Jun-2041 11:30:00 AM	2040-2041
Demand (TWh)	6.52	274.26
Wind (TWh)	1.35	190.41
Solar (TWh)	1.15	58.69
VRE (% of demand)	38.42%	90.83%
Wind CF (%)	**11.60%**	36.67%
Solar CF (%)	**17.90%**	21.02%

Table 48: The three highest residual demands witnessed during a severe eight-day VRE drought event.

	Eight-day severe VRE drought		
	20-Jun-2041 12:00:00 PM to 28-Jun-2041 11:30:00 AM		
	Residual demand (GW)	VRE (% of demand)	Date and time
Highest	38.44	13.00	25-Jun-2041 17:00:00
Second highest	37.73	13.27	20-Jun-2041 17:00:00
Third highest	37.39	13.30	24-Jun-2041 17:00:00

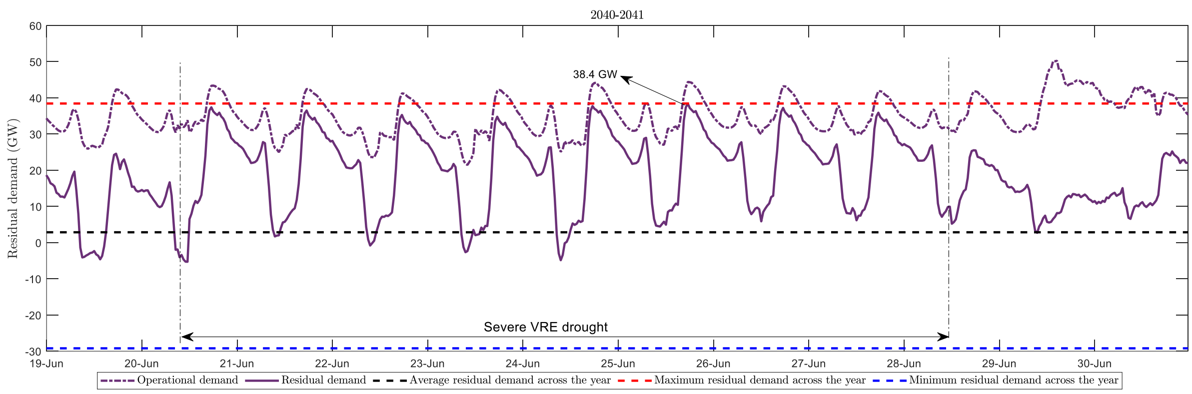
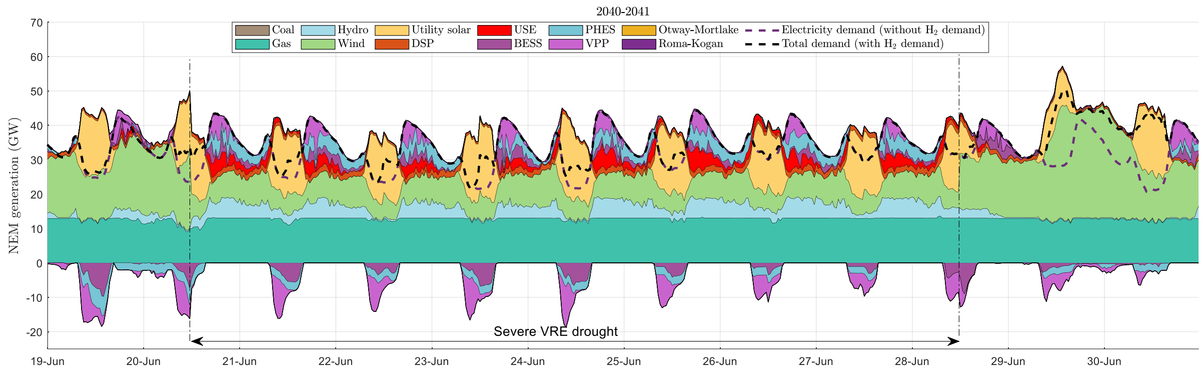
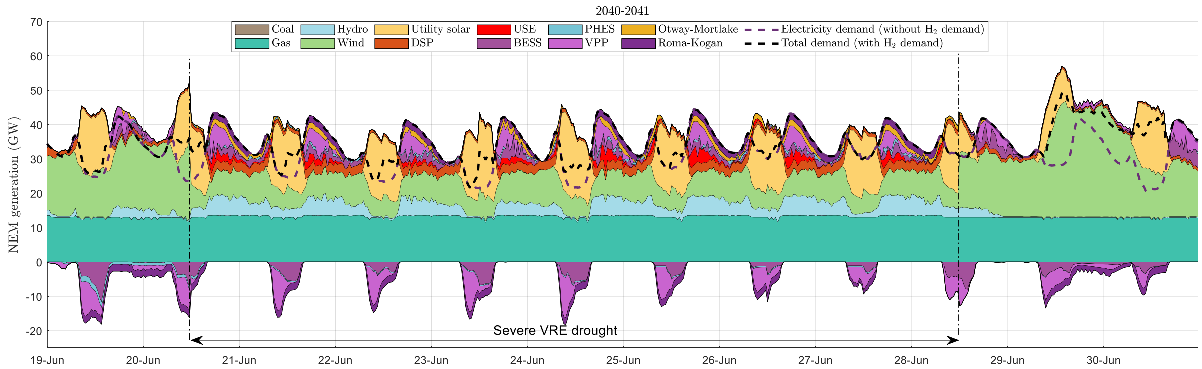


Figure 64: Residual demand across the NEM during a severe eight-day VRE drought period in June 2041.

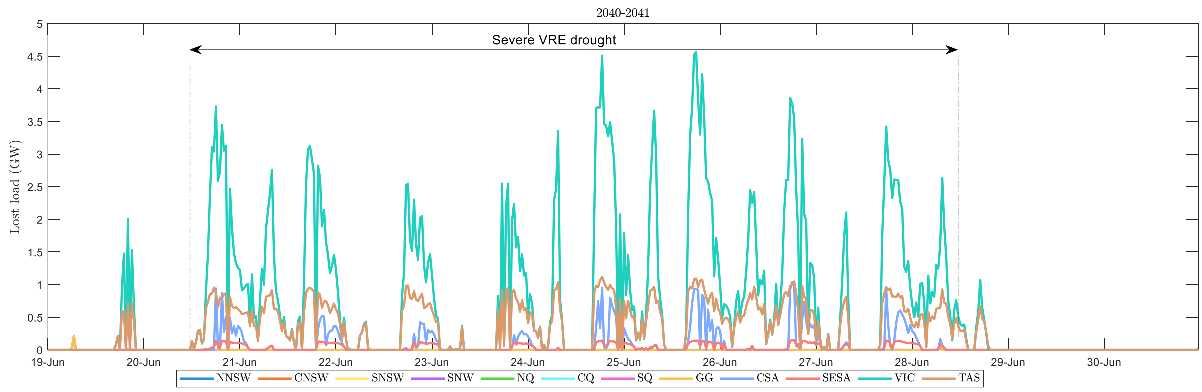


a) Snowy-Borumba

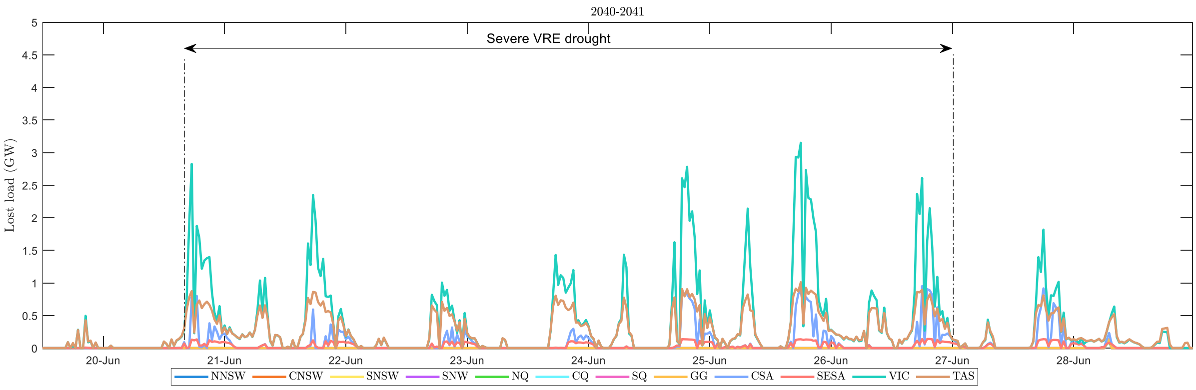


b) HESS-VIC-QLD-4GW

Figure 65: Forecast operability across the NEM experiencing a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

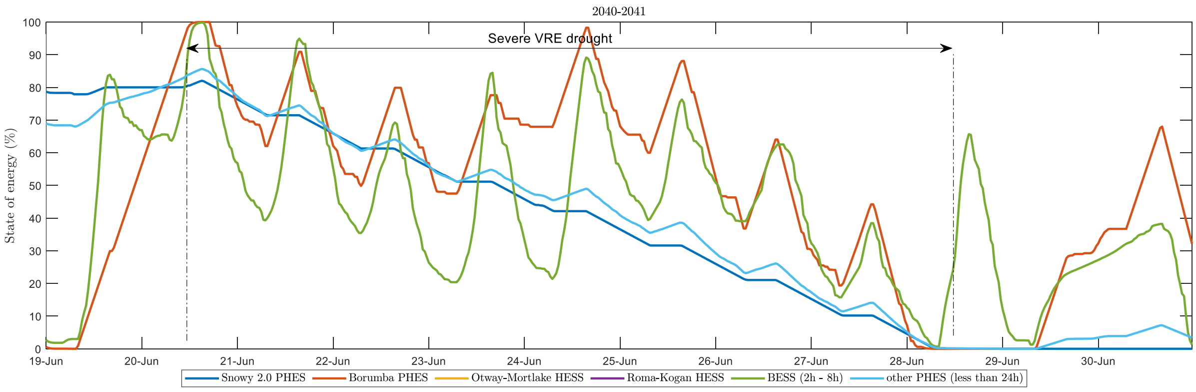


a) Snowy-Borumba

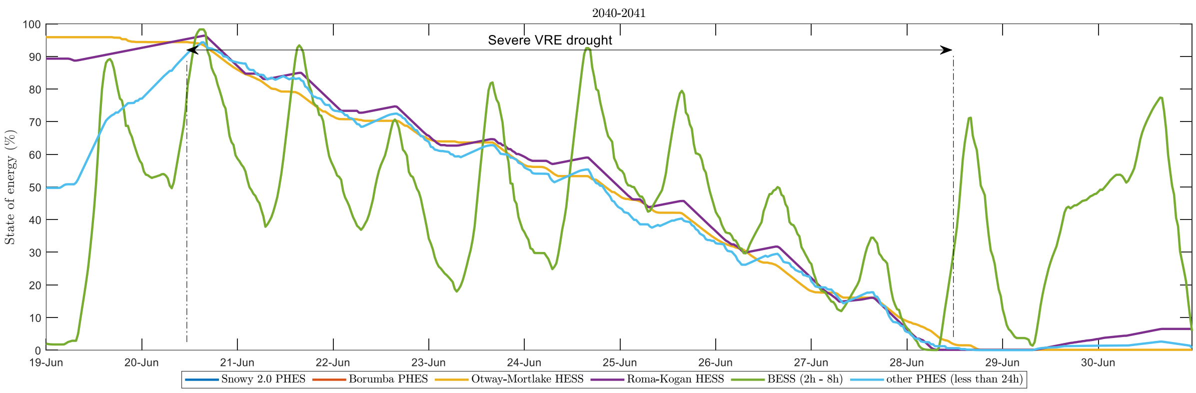


b) HESS-VIC-QLD-4GW

Figure 66: Lost load in each subregion during a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

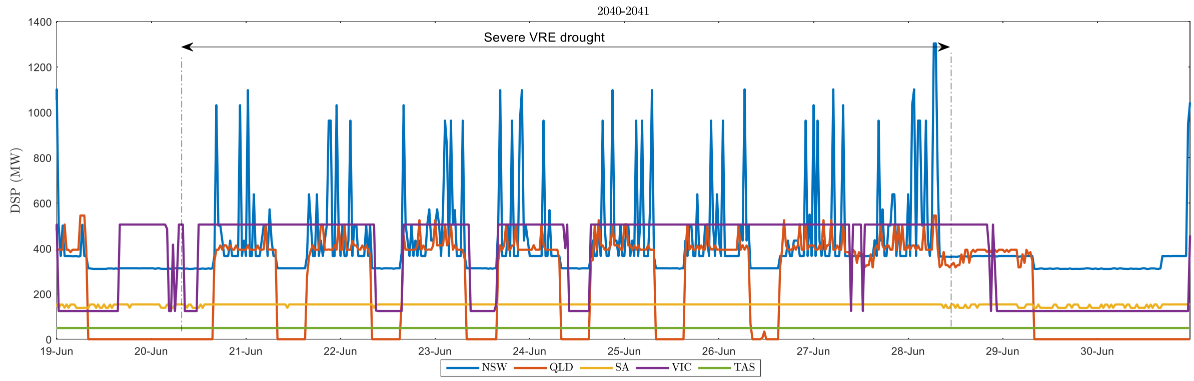


a) Snowy-Borumba

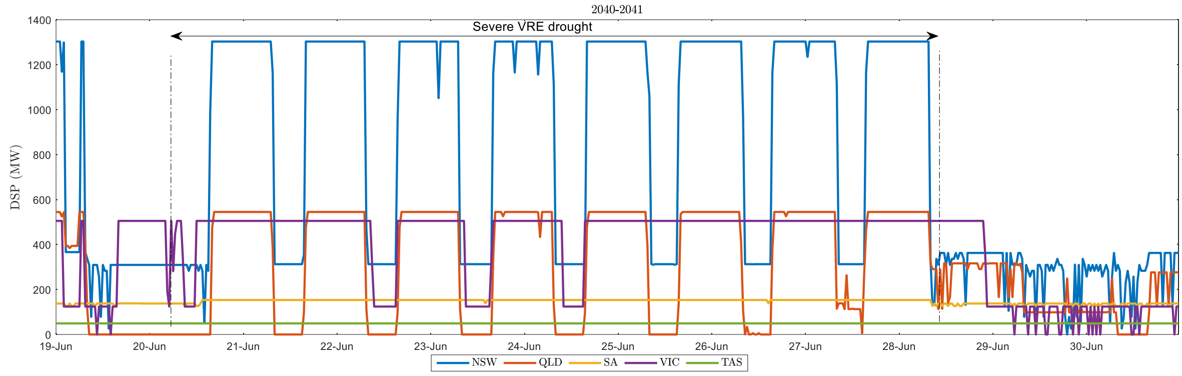


b) HESS-VIC-QLD-4GW

Figure 67: SoE of all storage systems (except hydro) across the NEM during a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

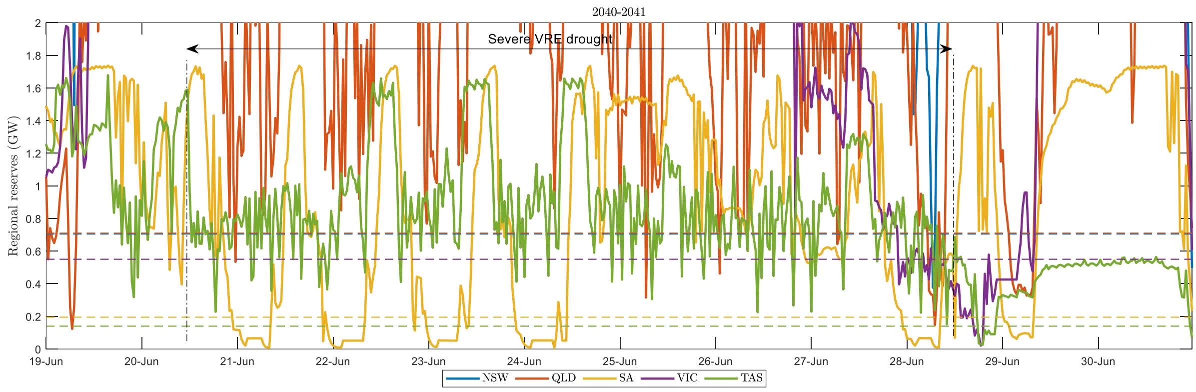


a) Snowy-Borumba

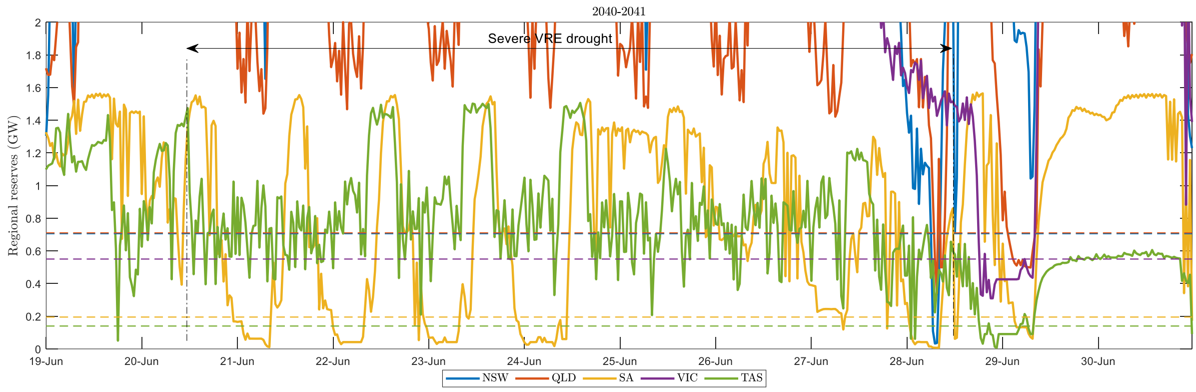


b) HESS-VIC-QLD-4GW

Figure 68: DSP activation in each region during a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

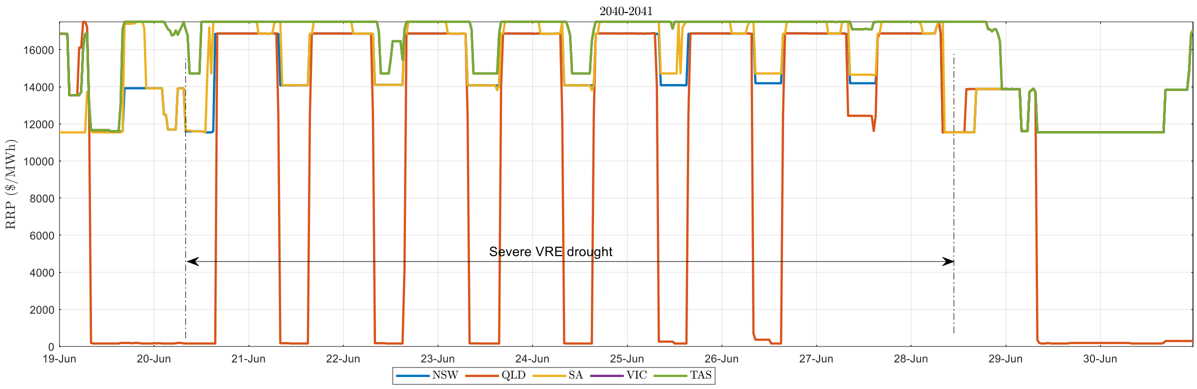


a) Snowy-Borumba

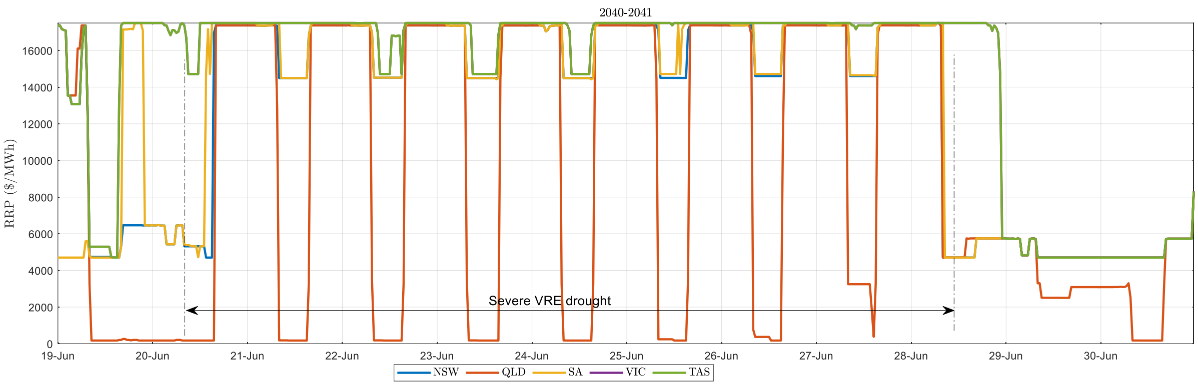


b) HESS-VIC-QLD-4GW

Figure 69: Regional reserves during a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 70: RRP across the NEM during a severe eight-day VRE drought period in June 2041 under cases Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

5.4.5 Summary

Several key takeaways can be drawn from the resilience assessment in this section, including:

- In the process of selecting VRE drought days for assessment, it is important to consider both residual demand *and* capacity factor (CF). Considering only CF may overlook instances with potential reliability risks, as demonstrated above.
- Due to their strategic locations, the Otway-Mortlake HESS in VIC and the Roma-Kogan HESS in SQ under the HESS-VIC-QLD-4GW scenario could significantly enhance resilience by maintaining reliability during extended periods of VRE droughts. The same reliability and resilience outcomes would have been observed if the two 2 GW HESS in

the HESS-VIC-QLD-4GW scenario were replaced with PHES of commensurate power (2 GW) and energy (~175 GWh_e) capacities in Victoria and Queensland. However, as of 2025, viable PHES locations with adequate energy capacities in VIC and QLD—at the scale required to maintain reliability and resilience as in the HESS-VIC-QLD-4GW scenario—have not yet been identified.

- While the HESS-VIC-QLD-4GW scenario substantially improves resilience, with no forecasted USE in three of the assessed cases, unplanned generator or interconnector outages beyond those modelled could still pose reliability risks. This is particularly critical in winter when residual demand is high, and the power system operates with low reserve margins. As a result, maintenance schedules for dispatchable generators must be carefully planned and coordinated during winter to mitigate reliability concerns arising from VRE droughts. This is further compounded by the impact that weather forecast accuracy has on the degree of foresight of unfavourable weather conditions which influences the accumulation of sufficient energy in LDES to maintain resilience during periods of severe VRE drought.
- If a severe VRE drought event similar to that of May 2024 occurs during periods of high residual demand—such as in winter—the NEM, under both the HESS-VIC-QLD-4GW scenario and the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP, may not be resilient. This suggests that additional firming and backup generation should be planned—particularly in VIC and QLD—beyond what is projected in AEMO's 2024 ISP and in this report, to hedge against events like the one in May 2024.
- In resilience studies involving prolonged VRE droughts, optimisation-based market dispatch models with extended time horizons (spanning months rather than days or weeks) not only provide the necessary temporal granularity (e.g., 30 minutes) and foresight (e.g., 20 years) to rigorously assess such events, but they eliminate the need for strong assumptions about the state of energy (SoE) at the onset of such events. This helps avoid shortsighted assumptions that may compromise the accuracy of resilience assessments.

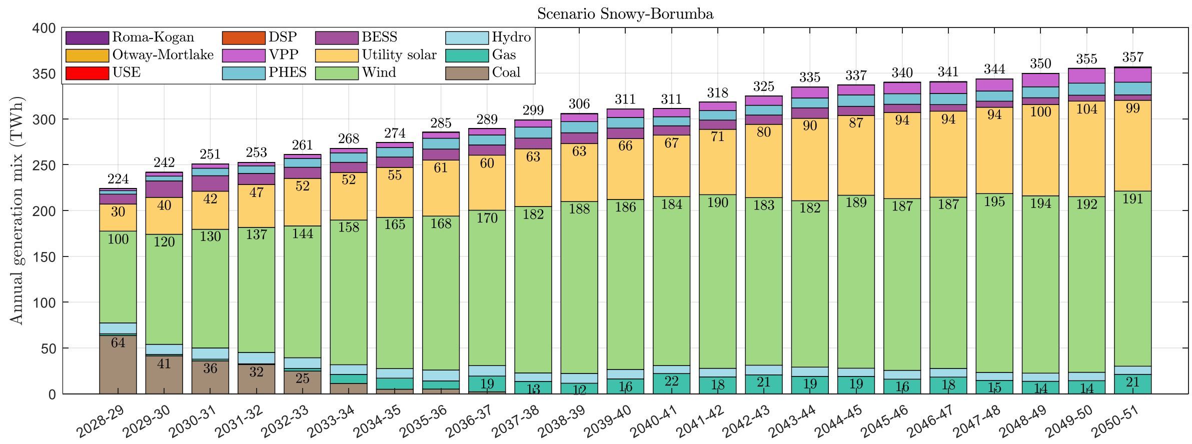
5.5. Generation mix

The annual generation mix from 2028-29 to 2050-51 for scenarios HESS-VIC-QLD-4GW and Snowy-Borumba is shown in Figure 71, and the difference in generation between these two scenarios is shown in Figure 72. The associated annual electricity demand under the Step Change scenario in AEMO's 2024 ISP [3] is shown in Figure 73. This section only shows the findings under Sensitivity 1 (see Table 12 and Table 13), in which the LGCs are assumed to cease in 2030 and all BESS are assumed to offer and bid based on optimisation opportunity costs.

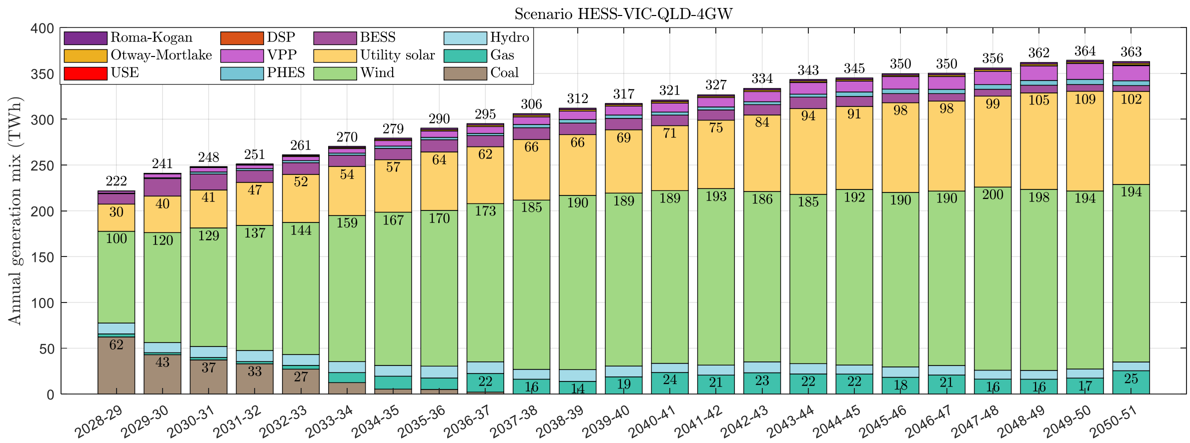
Many key observations can be made from these findings, including:

- Figure 71 and Figure 72 show that the HESS-VIC-QLD-4GW scenario witnesses consistently higher integration of solar and wind energy compared to the Snowy-Borumba scenario from 2031-32 out to 2050-51. This is another way of saying that less VRE curtailment is seen under the HESS-VIC-QLD-4GW scenario. The main reasons for this are described in Section 5.5.1.
- Figure 71 and Figure 72 show that, with the exception of year 2028-29, the HESS-VIC-QLD-4GW scenario witnesses consistently higher generation from CFG and GFG. The mains reasons for this are delineated in Section 5.5.2.
- The consistent increase in generation from VRE, CFG, and GFG in the HESS-VIC-QLD-4GW scenario from 2030–31 to 2050–51, also evident in Figure 72, stems from a combination of multiple factors, including the RTE of each LDES option, improvements in

reliability, and the total share of VRE, demand, and generation capacity in each state that hosts an LDES option.



a) Snowy-Borumba



b) HESS-VIC-QLD-4GW

Figure 71: Annual generation mix from 2028-30 to 2050-51 in the Snowy-Borumba and the HESS-VIC-QLD-4GW scenarios, and under Sensitivity 1.

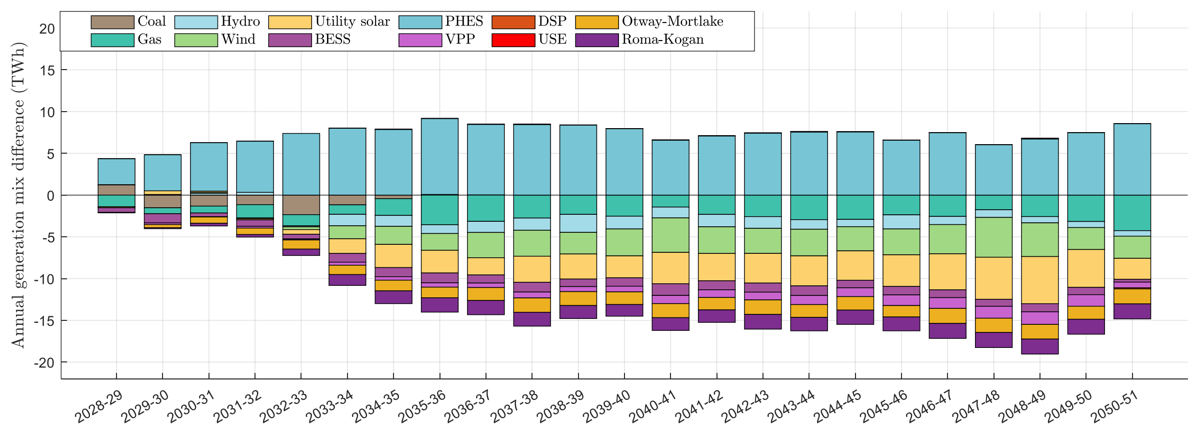


Figure 72: Annual difference in generation between the Snowy-Borumba scenario and the HESS-VIC-QLD-4GW scenario under Sensitivity 1.

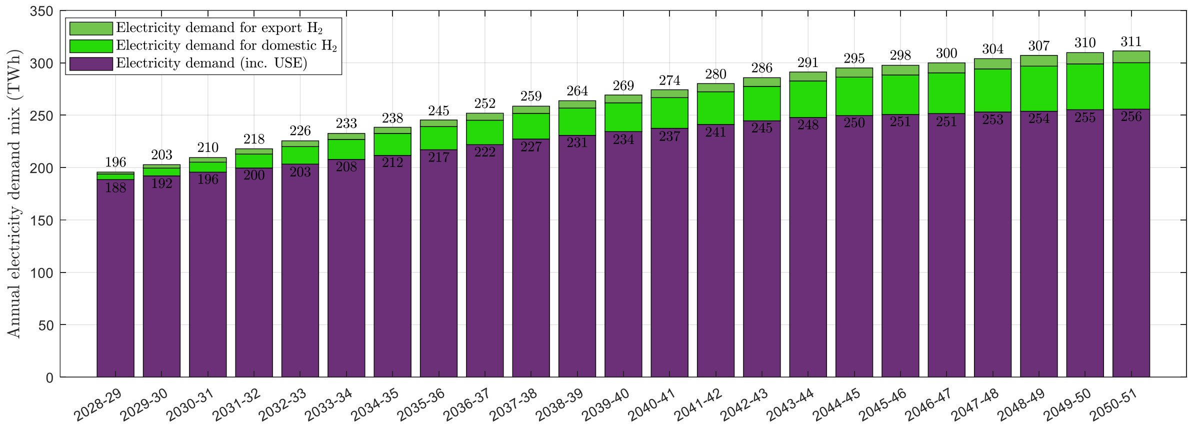


Figure 73: Annual electricity demand under the Step Change scenario in AEMO's 2024 ISP [3].

5.5.1 VRE curtailment

VRE curtailment refers to instances where utility-scale VRE generators do not operate at their maximum potential capacity. There many reasons for this phenomenon, including:

- Periods when utility-scale VRE potential exceeds operational demand.
- Constraints on transmission capacity that limit VRE transmission to demand centres.
- Network security or constraints related to system strength or security.
- Insufficient storage capacity to accommodate surplus VRE generation.

These conditions can result in economic "spill", where VRE generators reduce output due to low market prices or insufficient demand, or network curtailment, where transmission constraints prevent these generators from producing electricity.

Figure 74 shows the annual forecast VRE curtailment in Scenarios HESS-VIC-QLD-4GW and Snowy-Borumba to 2050-51. The majority of the curtailed VRE stems from economic spill rather than curtailment caused by transmission constraints. During spring and summer, high solar generation is expected to create an energy oversupply, with a portion of this surplus forecasted to be spilled. It can be seen from Figure 74 that the HESS-VIC-QLD-4GW scenario witnesses consistently less VRE curtailment compared to the Snowy-Borumba scenario from 2031-32 out to 2050-51. This decrease reaches as high as 38% in 2035-36. The main reasons for these observations are:

- Although both Scenarios, HESS-VIC-QLD-4GW and Snowy-Borumba, have the same total deep storage capacity, the HESS have a charging efficiency of at most 70.75% (see Table 18) whereas the PHES options have a charging (pumping) efficiency of 87.15%. This lower charging efficiency, which translates to slower charging, entails that the HESS can accommodate more VRE that might otherwise be curtailed.
- Being located in VIC grants the Otway-Mortlake HESS access to VRE from four subregions, CSA, SESA, TAS, and SNSW. In contrast, Snowy 2.0, located in SNSW, has access to VRE from three subregions, VIC, CNSW, and CSA.
- Higher LDES power and energy storage capacities in VIC, SA, and TAS, beyond what is projected in AEMO's 2024 ISP, contribute to a higher accommodation of VRE, in addition to a higher contribution to reliability.

This decrease in VRE curtailment is also evident from the annual generation mix shown in Figure 71 for scenarios HESS-VIC-QLD-4GW and Snowy-Borumba.

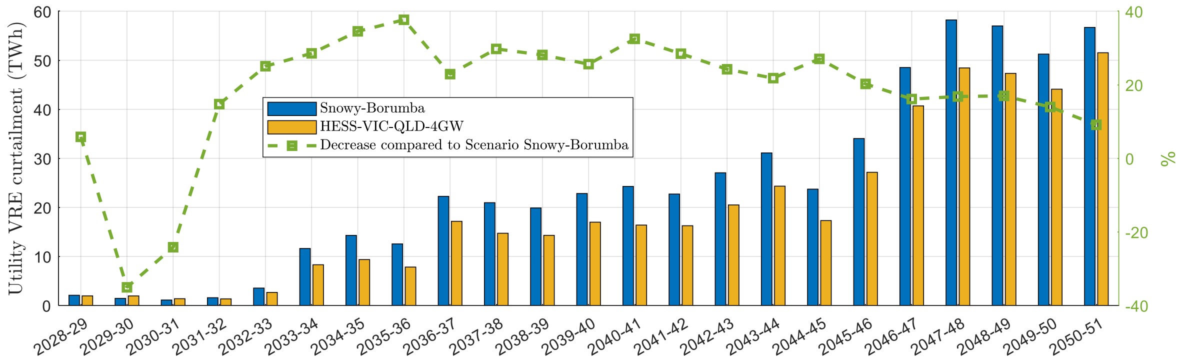


Figure 74: VRE curtailment across the NEM from 2028-29 to 2050-51 in the Snowy-Borumba and the HESS-VIC-QLD-4GW scenarios, and under Sensitivity 1.

5.5.2 Operational costs

The operational costs in this section refer to the SRMC of coal-fired and gas-fired generators multiplied by the energy produced, which are given by

$$Operational\ costs\ (\$) = SRMC\left(\frac{\$}{\mathrm{MWh}}\right) \times Energy\ generated\ (\mathrm{MWh}),$$

where

$$SRMC\left(\frac{\$}{\mathrm{MWh}}\right) = VOM\left(\frac{\$}{\mathrm{MWh}}\right) + Heat\ rate\left(\frac{\mathrm{GJ}}{\mathrm{MWh}}\right) \times fuel\ cost\left(\frac{\$}{\mathrm{GJ}}\right),$$

and VOM is the variable O&M cost of a unit. These operational costs are shown in Figure 75 for Scenarios Snowy-Borumba and HESS-VIC-QLD-4GW. Figure 75 shows that the HESS-VIC-QLD-4GW scenario witnesses consistently higher operational costs compared to the Snowy-Borumba scenario from 2028–29 through to 2050–51. This increase reaches as high as 43% in 2035-36. The main reason for this increase in operational cost of CFG and GFG in the HESS-VIC-QLD-4GW scenario is the absence of the 2 GW capacity from Snowy 2.0 in NSW, which necessitates more backup power, predominantly from GFG in NSW to compensate for this deficit in power.

As shown in Figure 12, the ODP in AEMO's 2024 ISP [3] forecasts around 14.44 GW of GFG by 2035-36, with 4.7 GW—around 33%—located in NSW. At the same time, NSW in 2035-36 is forecast to still have around 1.42 GW of CFG—around 2.53% of the total dispatchable capacity, which is also relied upon to compensate for this deficit. This increased reliance on CFG and GFG is also evident in Figure 71 and Figure 72 above.

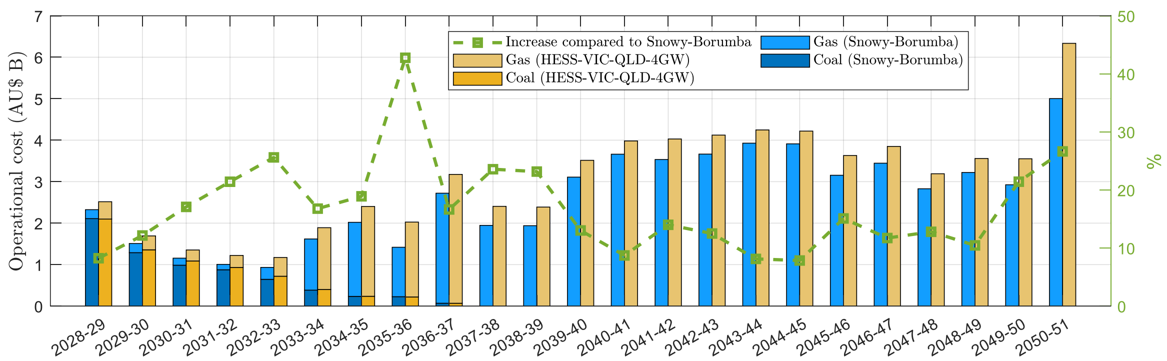


Figure 75: Operational costs of coal-fired and gas-fired generators from 2028-29 to 2050-51 in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios, and under Sensitivity 1.

5.6. Price volatility

In general, an increase in the share of VRE generation is typically accompanied by an increase in price volatility. However, installing more storage often goes a long way towards dampening this volatility. In the case of the NEM, more storage can contribute to a decrease in the magnitude and frequency of negative prices because, when charging, storage systems can raise the operational demand, and thereby the market clearing price.

At the same time, storage systems can decrease the frequency and magnitude of high prices by discharging electricity at lower prices than expensive peaking units and, in extreme cases, costly DSP (see Figure 25). This phenomenon can be seen in Figure 76, which shows the average annual NEM prices in each scenario from 2028-29 out to 2047-48. The error bars show the maximum and minimum prices in each year. Values higher than $1,000/MWh are predominantly at the market price cap (MPC) of $17,500/MWh across all LDES options.

Key insights include:

- From 2028-29 to 2033-34, the average NEM prices are relatively similar across the three scenarios. However, from 2034-35 out to 2047-48 the average NEM prices increase substantially in the NoLDES scenario compared to scenarios HESS-VIC-QLD-4GW and Snowy-Borumba. This is mainly due to a significant increase in USE and more frequent activation of costly DSP because of the low reliability in the NoLDES scenario (see Figure 40c).
- Due to an increased reliance on CFG and GFG in NSW under the HESS-VIC-QLD-4GW scenario, discussed in more detail in Section 5.5.2, the average prices across the NEM in the HESS-VIC-QLD-4GW scenario are slightly higher than those in the Snowy-Borumba scenario for 9 out of the 20 years between 2028-29 and 2047-48. For the remaining 11 years, these average prices are lower than those in the Snowy-Borumba scenario. This is mainly due to the significant improvement in reliability under the HESS-VIC-QLD-4GW scenario, discussed in more detail in Section 5.3, which manifests in less reliance on costly DSP to mitigate USE (see Section 5.4).
- Price volatility, illustrated by the error bars, is significantly reduced under the HESS-VIC-QLD-4GW scenario compared to the Snowy-Borumba scenario starting from 2033-34. This is also mainly due to the significant improvement in reliability under the HESS-VIC-QLD-4GW scenario.
- Figure 77 shows that the presence of a HESS with 500 MW and 158 hours of storage in VIC, as modelled in the HESS-VIC-0.5GW scenario, significantly reduces both average NEM prices and price volatility compared to the Snowy-Borumba scenario. This is again mainly due to a significant improvement in reliability brought about by the HESS-VIC-0.5GW scenario, as demonstrated in Section 5.3.

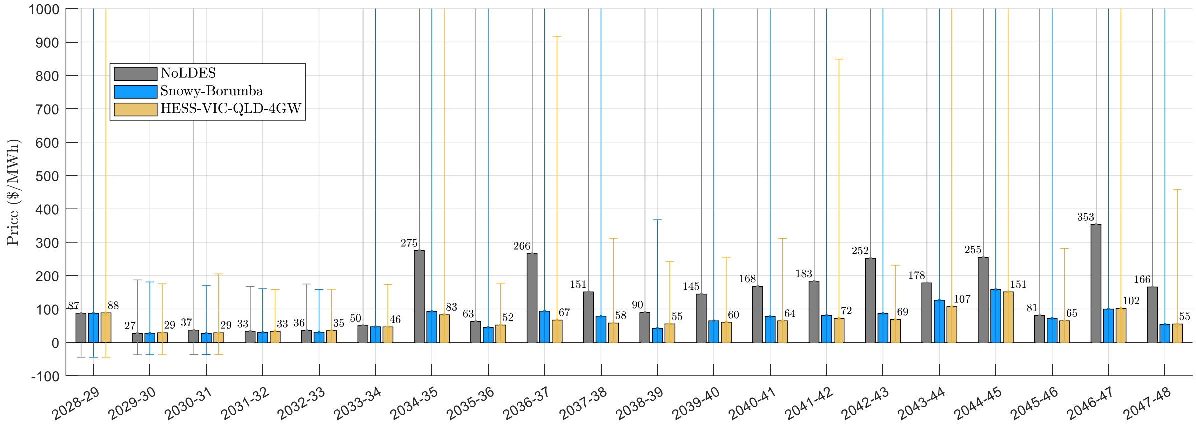


Figure 76: Average annual NEM prices in each scenario from 2028-29 out to 2047-48 in the Snowy-Borumba and HESS-VIC-QLD-4GW scenarios, and under Sensitivity 1. The error bars show the maximum and minimum prices in each year.

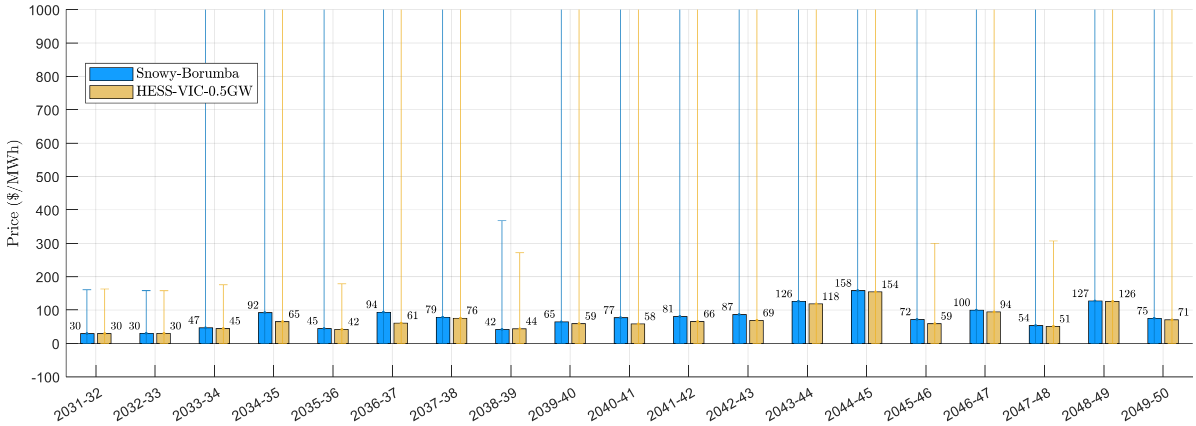


Figure 77: Average annual NEM prices in each scenario from 2030-31 out to 2049-50 in the HESS-VIC-0.5GW scenarios, and under Sensitivity 1. The error bars show the maximum and minimum prices in each year.

6. Conclusions

Under the vision of a future where whole-system decarbonisation is underpinned by large-scale deployment of variable renewable energy (VRE), ensuring reliable and resilient operation hinges on complementary deployment of storage systems of different durations. Strategically planned long-duration energy storage (LDES) systems such as pumped-hydro storage systems (PHES) and hydrogen energy storage systems (HESS), will be instrumental in providing long-term reserves and seasonal firming for VRE.

Understanding the role of HESS from a whole-system perspective requires modelling frameworks for integrated electricity and hydrogen systems (IEHS) that can quantify the benefits to energy security, reliability, resilience against extreme weather events, and system flexibility. Towards this aim, this report developed an optimisation-based IEHS techno-economic framework for evaluating the role of HESS in providing LDES to the National Electricity Market (NEM) under the reliability standards stipulated by the Australian Energy Market Operator (AEMO) and stringent resilience requirements against prolonged periods of VRE droughts. Supported by optimisation-based IEHS modelling frameworks and methodologies, this report also provides unprecedented insights into how the levelised cost of energy (LCOE) for HESS—enabled by underground hydrogen storage (UHS) systems in key locations in Australia—compares to that of PHES, such as Snowy 2.0 and Borumba.

This study finds that both Borumba PHES and the assessed HESS in Victoria and Queensland may be able to recover their costs under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP. However, the analysis also reveals that the projected LDES capacity in the ISP may be insufficient to maintain system reliability—particularly under severe and prolonged renewable energy droughts like the one experienced in May 2024. Both PHES and HESS offer distinct advantages depending on their location within the NEM, with HESS and Borumba showing strong revenue potential under AEMO's 2024 ISP projections for generation, storage, and transmission expansion.

The findings underscore the need for integrated capacity expansion planning that uses long-horizon models and explicitly accounts for high-impact, low-probability (HILP) events such as prolonged periods of severe renewable drought. Enhancing LDES capacity beyond current ISP projections is not only critical for maintaining reliability but could also prevent billions of dollars in electricity costs that would otherwise result from market volatility during extreme events. Investment in technologies like HESS in strategic locations could therefore deliver both economic and reliability benefits to the NEM.

The overarching aim of this work is to objectively assess the techno-economic merits of LDES technologies such as HESSs and PHES, depending on a variety of factors, including:

- location in the NEM,
- market conditions,
- weather conditions, and
- availability of suitable storage sites—be they depleted gas reservoirs, as in the case of HESSs, or rivers and dams in the case of PHES.

Although only the design of HESSs is optimised—along with the operation of the NEM by adjusting assumptions on Snowy 2.0, Borumba, and the proposed HESS designs—other assumptions, which are taken directly from the Step Change scenario in AEMO's 2024 ISP but could still influence outcomes, include (but are not limited to):

- network development (transmission expansion),

- forecast regional and sub-regional demand,
- uptake of VRE,
- uptake of utility-scale and distributed battery energy storage systems (BESSs),
- uptake of electric vehicles (EVs),
- degree of coordination of consumer energy resources (CERs),
- domestic and export hydrogen demand, and
- technology cost curves.

The specific numbers presented as part of the findings in this project are only applicable to the Australian context and may not be generalisable to other countries. Nonetheless, the IEHS modelling framework developed in this project, which leverages advanced numerical optimisation and computational methods, is designed with a focus on flexibility and modularity to rapidly incorporate and explore stakeholder insights or applications in different contexts. By extension, the developed techno-economic framework can also be applied to Western Australia's Wholesale Electricity Market (WEM) where PHES may not be a feasible LDES option.

Finally, although the specific numbers should be considered and viewed from the lens of the technical and financial assumptions made in this report, the developed optimisation-based market dispatch model can be used directly to make informed decisions on the commercial viability for *any* project or new participant by seamlessly changing input parameters to suit the desired application.

7. Implications and recommendations for industry and policymakers

Fostering the adoption of large-scale HESS in key locations in Australia will require new *evidence-based* policy and commercial interventions, from which specific market and policy settings may evolve. This is particularly relevant if their cost recovery is not limited to actual use or extends beyond their participation in the NEM. Cost recovery for HESS could include the *value* of reliability and resilience they provide to the NEM or the opportunities for using hydrogen directly as feedstock to decarbonise hard-to-abate industries such as steel, cement, and aluminium production, as well as the agricultural sector.

The developed optimisation-based IEHS techno-economic framework and the generated insights in this report have the potential to support informed decision-making for investors, as well as the development of business models for close-to-mature large-scale hydrogen storage technologies and LDES systems in general. Specifically, the developed methodology that informs on *revenue opportunities* can be used to quantify the *risks and opportunities* that are essential for business models and actionable investment and commercialisation decisions. The methodology underlying the LROE analysis in this report already captures important price signals such as the Market Price Cap (MPC) of $17,500/MWh, which acts as a strong incentive for investing in LDES. Other important price signals are the Cumulative Price Threshold (CPT) and Administered Price Cap (APC), could also greatly influence these incentives.

Business models for HESS may also benefit from policy and commercial interventions that consider market externalities such as spikes in natural gas prices because of sociopolitical turmoil or supply chain risks. Unlike natural gas, hydrogen produced for storage will primarily come from domestic renewable energy sources, making its production price determined endogenously rather than exogenously, which naturally helps hedge against price externalities.

Overall, this project underscores the need for advanced optimisation-based IEHS market dispatch modelling frameworks that can adequately evaluate and quantify the potential benefits, as well as the challenges, risks, and opportunities that different types of LDES systems offer to electricity networks and markets. Such a framework can assist system planners in pre-emptively minimising the risk of investing in a suboptimal power system architecture today or being locked out of a more cost-effective one in the future. This work also demonstrated that a system with higher energy efficiency may not necessarily lead to a more reliable, more resilient, and more cost-effective system.

The key findings in this report can be summarised as follows:

Suitable geology

- Australia has suitable underground geological formations—particularly *depleted gas reservoirs*—located near the high-voltage (HV) transmission network for large-scale HESS deployment.

Capex

- Large-scale HESS may have a CapEx that is 30% lower than a PHES of commensurate power and energy storage capacities.

LCOE and LROE

- Compared to PHES, which have a CF of around 38%, HESS under current technology can be expected to have a CF of around 10%, which manifests in an LCOE that could be up to three times as high as that of a PHES of equivalent power and energy storage capacities.

- The same low CF for HESS that drives their high LCOE also results in a correspondingly high LROE, significantly strengthening their business case.
- Under the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP, the LROE analysis in this report indicates that HESS in strategic locations such as VIC and SQ may be able recover their costs within the first 20 years of operation solely through participation in the wholesale NEM.
- The expected increase in price volatility as the NEM becomes more renewables-dominated presents greater opportunities for HESS to maximise revenue by capitalising on high prices that may occur when residual demand is high or during reliability events.

Reliability

- The projected generation, storage, and transmission capacities in AEMO's 2024 ISP may not be sufficient to maintain reliability in the NEM through to 2050.
- The 2 GW Borumba facility with 24 hours of storage may be insufficient to maintain reliability in Queensland; at least 86 hours of storage may be required instead.
- In a scenario where both Snowy 2.0 and Borumba are present, installing a HESS in VIC with 500 MW and 158 hours of net storage may significantly enhance the reliability of the NEM, particularly in the southern states of VIC, SA, and TAS.
- Together, the Otway-Mortlake HESS in Victoria and the Roma-Kogan HESS in southern Queensland, in the HESS-VIC-QLD-4GW scenario, are capable of maintaining reliability in New South Wales until 2043, under a counterfactual case in which Snowy 2.0 is delayed by five years.

Resilience

- In the process of selecting VRE drought days for assessment, it is important to consider both residual demand *and* capacity factor (CF). Considering only CF may overlook instances with potential reliability risks, as demonstrated above.
- Due to their strategic locations, the Otway-Mortlake HESS in VIC and the Roma-Kogan HESS in SQ (the HESS-VIC-QLD-4GW scenario) could significantly enhance resilience by maintaining reliability during extended VRE droughts.
- While the HESS-VIC-QLD-4GW scenario improves resilience, unplanned generator or interconnector outages beyond those modelled could still pose reliability risks. This is particularly critical in winter when residual demand is high, and the power system operates with low reserve margins. As a result, maintenance schedules for dispatchable generators must be carefully planned and coordinated during winter to mitigate reliability concerns arising from VRE droughts. This is further compounded by the impact that weather forecast accuracy has on the degree of foresight of unfavourable weather conditions, which influences the accumulation of sufficient energy in LDES to maintain resilience during periods of severe VRE drought.
- If a severe VRE drought event similar to that of May 2024 occurs during periods of high residual demand—such as in winter—the NEM, under both the HESS-VIC-QLD-4GW scenario and the projected generation, storage, and transmission expansion plan in AEMO's 2024 ISP, may not be resilient. This suggests that additional firming and backup generation should be planned—particularly in VIC and QLD—beyond what is projected in AEMO's 2024 ISP and in this report, to hedge against events like the one in May 2024.
- In resilience studies involving prolonged VRE droughts, optimisation-based market dispatch models with extended time horizons (spanning months rather than days or weeks) not only provide the necessary temporal granularity (e.g., 30 minutes) and foresight (e.g., 20 years) to rigorously assess such events, but they eliminate the need for strong assumptions about the state of energy (SoE) at the onset of such events. This helps

avoid shortsighted assumptions that may compromise the accuracy of resilience assessments.

VRE curtailment

- The modelled HESS in this report present opportunities to accommodate more VRE in the NEM that would otherwise be curtailed. This is due, among other factors, to the fact that HESS typically have a capacity factor (CF) of up to 10.5%, while PHES options generally have a CF of up to 38%.
- An LDES system in VIC has access to VRE from *four* subregions, CSA, SESA, TAS, and SNSW. In contrast, an LDES system in SNSW, has access to VRE from *three* subregions, VIC, CNSW, and CSA.
- Higher LDES power and energy storage capacities in VIC, SA, and TAS, beyond what is projected in AEMO's 2024 ISP, contribute to a higher accommodation of VRE, in addition to a higher contribution to reliability.

Operational costs

- A 2 GW LDES in New South Wales can displace more generation from gas-fired generation (GFG) and coal-fired generation (CFG) compared to other states, resulting in a notable reduction in overall operational costs and emissions across the NEM. According to AEMO's 2024 ISP, 33% of the 14.44 GW of GFG across the NEM in 2035–36 is located in New South Wales. At the same time, New South Wales is forecast to still have around 1.42 GW of CFG in 2035–36—about 2.53% of the total dispatchable capacity.

Price volatility

- In general, LDES contributes to a reduction in price volatility by decreasing the frequency and magnitude of extremely low and extremely high prices.
- LDES in strategic locations such as VIC and SQ can significantly reduce price volatility by improving reliability, which manifests in lower reliance on costly DSP to mitigate USE.

Market dispatch modelling

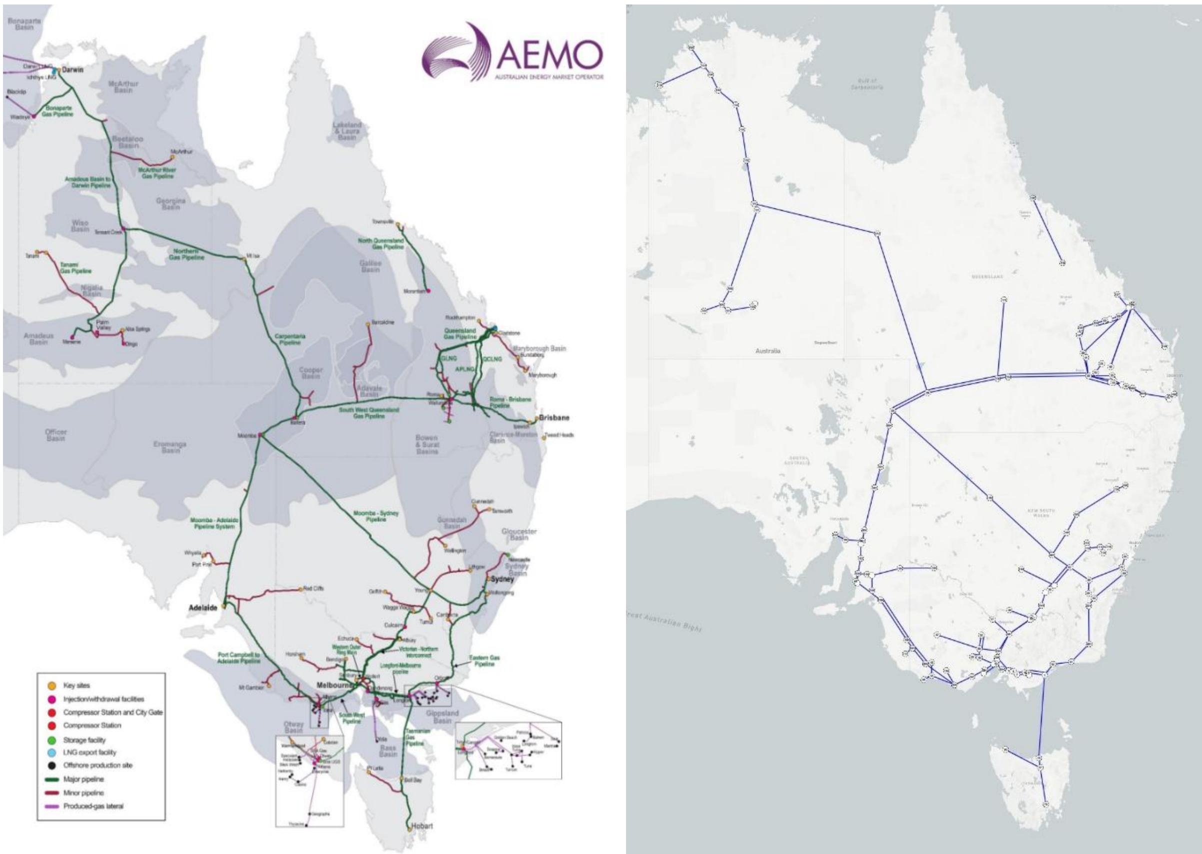
- Long-horizon, optimisation-based market dispatch models may be instrumental in the scheduling of energy reserves over weeks and months in LDES systems to hedge against forecasting errors, imperfect foresight, unplanned outages, and gas supply chain risks.
- Although the market analysis in this report is confined to the wholesale energy market, HESS can provide regulation and contingency services in the FCAS markets through the flexibility of PEM electrolysers and the hydrogen turbines, potentially increasing revenue opportunities even further.

8. Next steps and future work

The developed optimisation-based framework is currently being extended to *jointly optimise* the *development* of generation, transmission, and storage. In addition to informing on the required LDES power and energy storage capacities in each subregion in the NEM to ensure a desired level of reliability and resilience, this joint planning can also quantify the degree to which LDES can displace or defer investments in transmission. It will also enable comparing the value of *temporal energy arbitrage*, offered by storage systems, to the value of *geographic energy arbitrage*, offered by building more transmission.

At the same time, the model is currently being extended to also include *gas network constraints* [67], [68], making it a truly integrated model that simultaneously incorporates all three energy vectors, electricity, natural gas, and hydrogen. Doing so bestows the now integrated model with the capability to quantify and forecast the capacity and flexibility of the gas network to deliver gas to the 15 GW of GFG envisaged to be installed in the NEM by 2050 (see AEMO's 2024 ISP [3]). For reference, AEMO's 2024 ISP [3] only includes *daily* limits on total GFG gas consumption in each subregion. Figure 78 compares the East Coast Australian gas network from AEMO's Gas Statement of Opportunities (GSOO) to the model developed by the authors of this report at The University of Melbourne (UoM).

Finally, the rapidly changing energy system landscape introduces short-term and *long-term uncertainties* around energy policy, technology uptake and costs, evolving business models, and environmental and sociopolitical factors, all of which should be appropriately considered in planning studies. AEMO's 2024 ISP [3] captures these uncertainties by proposing three different cases, *Progressive Change* at 42% likelihood, *Step Change* at 43% likelihood, and *Green Energy Exports* at 15% likelihood, each reflecting a different pathway of how the future could unfold. The ISP then reflects these case probabilities in a *deterministic* methodology that determines the development path that produces the *least-worst weighted regret* (LWWR). In contrast, future work at UoM will capture this *uncertainty* through *stochastic integrated multistage planning* that considers all three cases and their probabilities *concurrently* to find *flexible* and adaptive generation, transmission, and storage investment portfolios that are *robust* to case uncertainty [69], [70].



a) GSOO 2024 b) UoM model

Figure 78: East Coast Australian gas network from AEMO's GSOO (left) and how it compares to the model developed by the authors of this report at UoM (right).

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Appendix A

Additional financial and technical information

These cost estimates for pipelines and compressors are obtained from the peak body representing Australian pipeline infrastructure [46]. These cost estimates, detailed in Table 49, fall under Class 4 of the Association for Advancement of Cost Engineering (AACE) classification system with a CapEx accuracy of -30%/+50%.

Table 49: Cost and parameter assumptions of pipelines and compressors [46].

Parameter		Option			
Diameter (inch)		4	6	…	46
Minimum pressure (MPa)		5.8	5.8	…	5.8
Maximum allowable operating pressure (MPa)		8	8	…	8
Specified minimum yield strength (psi)		52000	52000	…	52000
Design factor		0.5	0.5	…	0.5
Erosional velocity ratio		0.8	0.8	…	0.8
Manufacturing cost (USD/Tonne)		2649	2649	…	2649
Insurance and freight (USD/Tonne)[15]		218	218	…	218
Installation cost (kAUD/ inch/km)[16]	<100 km	70	70	…	70
	<250 km	50	50	…	50
	<500 km	40	40	…	40
	>500 km	37.8	37.8	…	37.8
Engineering costs (% of procurement and installation costs)	≤100 km	10	10	…	10
	>100 km	5	5	…	5
FOM cost (% of CapEx)	≤50 km	3.75	3.75	…	3.75
	≤100 km	3.25	3.25	…	3.25
	≤200 km	2.25	2.25	…	2.25
	≤500 km	2.11	2.11	…	2.11
	>500 km	1.875	1.875	…	1.875
Compressors		See Tables 6, 26, and 27 in [46].			

[15] Insurance and freight costs are from the supplier (Welspun) to Port Hedland, Western Australia [46].
[16] The reader is referred to [46] for a full list of factors that installation costs include.

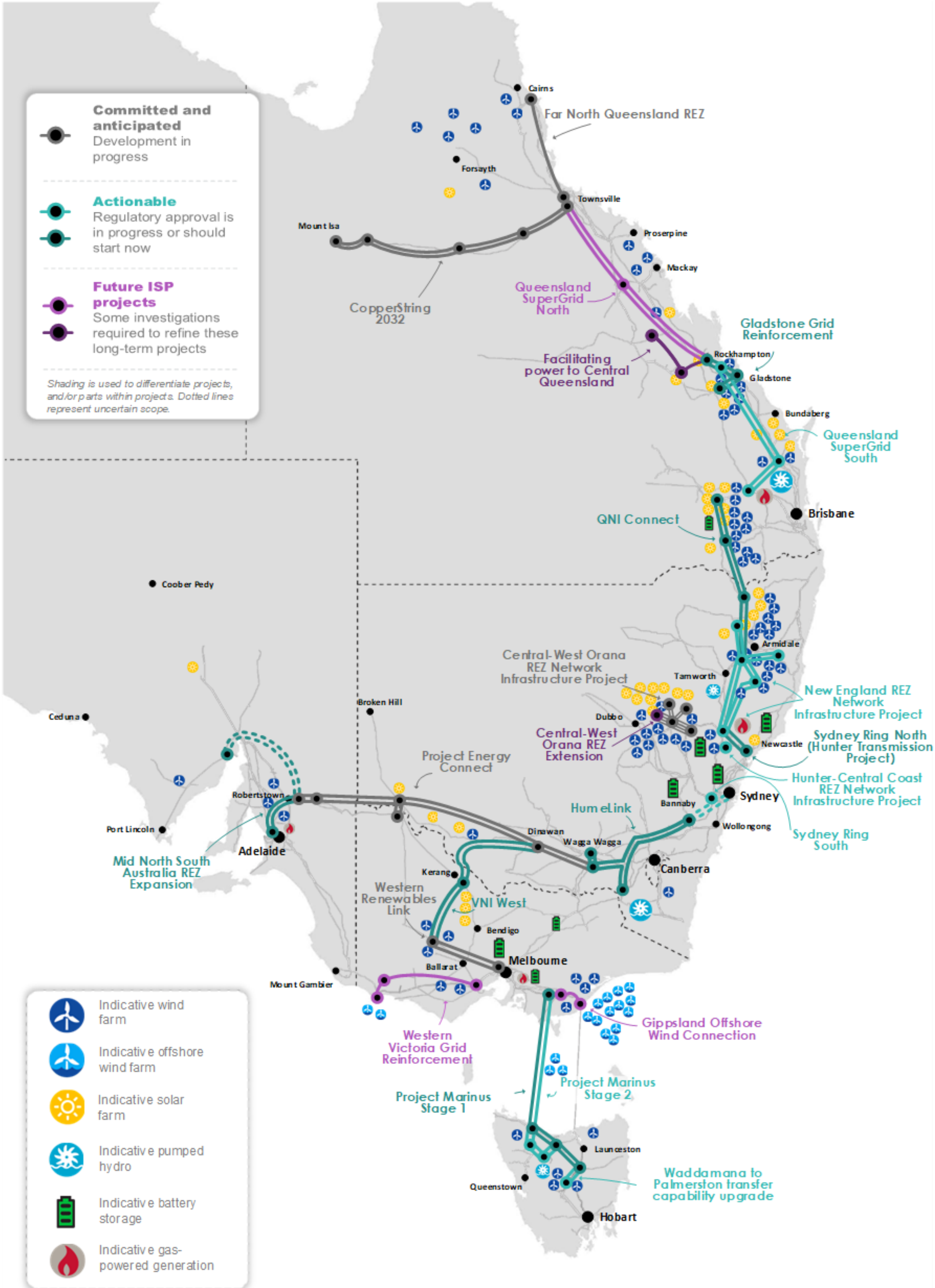


Figure 79: Transmission projects in the optimal development path (CDP 14) in AEMO's 2024 ISP [3].

Table 50: Transmission projects in the optimal development path (CDP 14) in AEMO's 2024 ISP [3] and their transfer capability along the flow paths, under different system conditions [42].

Flow paths (Forward power flow direction)	From	To	Forward-Summer (MW)	Forward-Winter (MW)	Reverse-Summer (MW)	Reverse-Winter (MW)	Indicative commissioning date
CQ - NQ	CQ	NQ	1,200	1,400	1,200	1,400	Existing
CQ - GG	CQ	GG	700	1,050	750	1,100	Existing
SQ - CQ	SQ	CQ	1,100	1,100	2,100	2,100	Existing
NNSW - SQ (Northern part of "QNI")	NNSW	SQ	745	745	1,165	1,170	Existing
NNSW - SQ ("Terranora")	NNSW	SQ	50	50	150	200	Existing
CNSW - NNSW (Southern part of "QNI")	CNSW	NNSW	910	910	930	1,025	Existing
CNSW - SNW Northern limit	CNSW	SNW	4,490	4,730	4,490	4,730	Existing
CNSW - SNW Southern limit	CNSW	SNW	2540	2,720	2,540	2,720	Existing
SNSW - CNSW (Northern part of "VNI")	SNSW	CNSW	2,700	2,950	2,320	2,590	Existing
VIC - SNSW (Southern part of "VNI")	VIC	SNSW	1000	1,000	400	400	Existing
VIC - SESA ("Heywood")	VIC	SESA	650	650	650	650	Existing
SESA-CSA	SESA	CSA	650	650	650	650	Existing
VIC - CSA (Murraylink)	VIC	CSA	220	220	200	200	Existing
TAS - VIC	TAS	VIC	462	462	462	462	Existing
Project EnergyConnect - Stage 1	SNSW	CSA	150	150	150	150	Dec-24
Project EnergyConnect - Stage 1	VIC	SNSW	150	150	150	150	Dec-24
Project EnergyConnect - Stage 2	SNSW	CSA	800	800	800	800	Jul-27
Project EnergyConnect - Stage 2	VIC	SNSW	100	100	100	100	Jul-27
New England REZ Transmission Link 1	CNSW	NNSW	3,000	3,000	3,000	3,000	Jul-29
Hunter Transmission Project	CNSW	SNW	5000	5,000	0	0	Jul-29
HumeLink	SNSW	CNSW	2,200	2,200	2,200	2,200	Jul-30
GG Grid Reinforcement	CQ	GG	2600	2,600	500	500	Jul-31
QLD SuperGrid South Option 5	CQ	SQ	3,150	3,150	3,150	3,150	Jul-32
QNI Connect Option 2	NNSW	SQ	1260	1,260	1,700	1,700	Jul-35
Project Marinus Stage 1	TAS	VIC	750	750	750	750	Jul-31
Project Marinus Stage 2	TAS	VIC	750	750	750	750	Jul-38
VNI West	VIC	SNSW	1,935	1,935	1,669	1,669	Jul-30

Table 51: LCOE of wind generation across the NEM. Sub-regional build costs, connection costs, capacity factors, FOM costs, and lead times are obtained from AEMO's 2024 ISP under the Step Change scenario [3].

Technology type	Fuel type	Region	Sub-region	REZ	REZ location	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50	2050-51
Wind	Wind	QLD	NQ	Q1	Far North QLD	86.9	83.4	80.1	76.9	73.8	70.9	69.0	67.9	67.8	67.6	67.4	67.3	67.2	67.0	66.9	66.7	66.6	66.4	66.3	66.2	66.1	66.0	66.0	65.9	65.9	65.8	65.7
Wind	Wind	QLD	NQ	Q2	North Qld Clean Energy Hub	113.6	109.1	104.8	100.7	96.7	93.0	90.5	89.2	89.0	88.7	88.5	88.3	88.2	88.0	87.8	87.6	87.4	87.2	87.0	86.9	86.8	86.6	86.6	86.5	86.5	86.4	86.3
Wind	Wind	QLD	NQ	Q3	Northern Qld	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	QLD	CQ	Q4	Isaac	121.0	116.2	111.6	107.1	102.8	98.8	96.1	94.7	94.5	94.2	93.9	93.7	93.6	93.4	93.2	93.0	92.8	92.6	92.3	92.2	92.1	91.9	91.9	91.8	91.8	91.6	91.6
Wind	Wind	QLD	CQ	Q5	Barcaldine	127.4	122.1	117.1	112.3	107.6	103.3	100.4	98.8	98.6	98.3	98.0	97.8	97.6	97.4	97.2	96.9	96.7	96.5	96.2	96.1	95.9	95.8	95.8	95.7	95.6	95.5	95.4
Wind	Wind	QLD	CQ	Q6	Fitzroy	115.9	111.3	106.9	102.6	98.5	94.6	92.1	90.7	90.5	90.2	90.0	89.8	89.6	89.5	89.3	89.0	88.9	88.7	88.4	88.3	88.2	88.0	88.0	87.9	87.9	87.8	87.7
Wind	Wind	QLD	SQ	Q7	Wide Bay	122.9	117.7	112.9	108.1	103.6	99.3	96.4	94.9	94.7	94.4	94.1	93.9	93.8	93.6	93.4	93.1	92.9	92.7	92.4	92.3	92.1	92.0	92.0	91.9	91.8	91.7	91.6
Wind	Wind	QLD	SQ	Q8	Darling Downs	108.5	103.9	99.6	95.4	91.4	87.7	85.1	83.8	83.6	83.3	83.1	82.9	82.8	82.6	82.4	82.2	82.0	81.8	81.6	81.4	81.3	81.2	81.2	81.1	81.1	81.0	80.9
Wind	Wind	QLD	CQ	Q9	Banana	160.0	153.8	147.9	142.2	136.7	131.6	128.1	126.3	126.0	125.7	125.4	125.1	124.9	124.7	124.4	124.1	123.9	123.6	123.3	123.1	122.9	122.8	122.7	122.6	122.6	122.4	122.3
Wind	Wind	NSW	NNSW	N1	North West NSW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	NSW	NNSW	N2	New England	95.7	91.7	87.9	84.2	80.7	77.4	75.2	74.0	73.9	73.6	73.4	73.3	73.1	73.0	72.8	72.6	72.5	72.3	72.1	72.0	71.9	71.8	71.8	71.7	71.7	71.6	71.5
Wind	Wind	NSW	CNSW	N3	Central-West Orana	112.2	107.5	103.1	98.8	94.6	90.8	88.2	86.8	86.6	86.3	86.1	85.9	85.7	85.6	85.4	85.2	85.0	84.8	84.5	84.4	84.3	84.1	84.1	84.0	84.0	83.9	83.8
Wind	Wind	NSW	SNSW	N4	Broken Hill	135.9	130.3	125.0	119.9	115.0	110.3	107.2	105.6	105.3	105.0	104.7	104.5	104.3	104.1	103.9	103.6	103.4	103.1	102.9	102.7	102.5	102.4	102.4	102.3	102.2	102.1	102.0
Wind	Wind	NSW	SNSW	N5	South West NSW	134.1	128.5	123.2	118.1	113.2	108.5	105.4	103.8	103.5	103.2	102.9	102.7	102.5	102.3	102.1	101.8	101.6	101.4	101.1	100.9	100.8	100.6	100.6	100.5	100.4	100.3	100.2
Wind	Wind	NSW	SNSW	N6	Wagga Wagga	149.5	143.5	137.8	132.3	127.1	122.1	118.8	117.0	116.8	116.4	116.1	115.9	115.7	115.5	115.3	115.0	114.7	114.5	114.2	114.0	113.8	113.7	113.6	113.5	113.5	113.3	113.2
Wind	Wind	NSW	SNSW	N7	Tumut	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	NSW	SNSW	N8	Cooma-Monaro	95.9	91.8	88.0	84.3	80.8	77.4	75.2	74.0	73.8	73.6	73.4	73.2	73.1	72.9	72.8	72.6	72.4	72.2	72.0	71.9	71.8	71.7	71.7	71.6	71.6	71.5	71.4
Wind	Wind	NSW	CNSW	N9	Hunter-Central Coast	111.4	106.7	102.3	98.0	93.8	89.9	87.3	85.9	85.7	85.5	85.2	85.0	84.9	84.7	84.5	84.3	84.1	83.9	83.7	83.5	83.4	83.3	83.3	83.2	83.1	83.0	82.9
Wind	Wind	NSW	SNW	N12	Illawarra	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	VIC	VIC	V1	Ovens Murray	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	VIC	VIC	V2	Murray River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	VIC	VIC	V3	Western VIC	105.8	101.6	97.6	93.7	90.0	86.5	84.2	82.9	82.7	82.5	82.3	82.1	82.0	81.8	81.6	81.4	81.3	81.1	80.9	80.7	80.6	80.5	80.5	80.4	80.4	80.3	80.2
Wind	Wind	VIC	VIC	V4	South West VIC	99.1	95.1	91.4	87.7	84.3	81.0	78.8	77.6	77.5	77.2	77.0	76.9	76.7	76.6	76.4	76.2	76.1	75.9	75.7	75.6	75.5	75.4	75.4	75.3	75.3	75.2	75.1
Wind	Wind	VIC	VIC	V5	Gippsland	104.0	99.7	95.7	91.8	88.1	84.6	82.2	80.9	80.8	80.5	80.3	80.1	80.0	79.8	79.7	79.5	79.3	79.1	78.9	78.7	78.6	78.5	78.5	78.4	78.4	78.3	78.2
Wind	Wind	VIC	VIC	V6	Central North Vic	125.8	120.8	116.1	111.6	107.2	103.1	100.4	98.9	98.7	98.4	98.2	98.0	97.8	97.6	97.4	97.2	97.0	96.8	96.5	96.4	96.2	96.1	96.1	96.0	96.0	95.8	95.7
Wind	Wind	SA	SESA	S1	South East SA	104.6	100.4	96.5	92.7	89.1	85.6	83.3	82.1	81.9	81.7	81.4	81.3	81.1	81.0	80.8	80.6	80.4	80.3	80.1	79.9	79.8	79.7	79.7	79.6	79.6	79.5	79.4
Wind	Wind	SA	CSA	S2	Riverland	127.2	121.9	117.0	112.1	107.5	103.2	100.3	98.7	98.5	98.2	97.9	97.7	97.5	97.4	97.2	96.9	96.7	96.5	96.2	96.0	95.9	95.8	95.7	95.6	95.6	95.5	95.4
Wind	Wind	SA	CSA	S3	Mid-North SA	103.3	99.2	95.3	91.5	87.8	84.4	82.1	80.9	80.7	80.4	80.2	80.1	79.9	79.8	79.6	79.4	79.2	79.1	78.9	78.7	78.6	78.5	78.5	78.4	78.4	78.3	78.2
Wind	Wind	SA	CSA	S4	Yorke Peninsula	103.8	99.4	95.3	91.3	87.5	83.9	81.5	80.2	80.0	79.7	79.5	79.4	79.2	79.1	78.9	78.7	78.5	78.3	78.1	77.9	77.8	77.7	77.7	77.6	77.6	77.5	77.4
Wind	Wind	SA	CSA	S5	Northern SA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	SA	CSA	S6	Leigh Creek	102.5	98.2	94.2	90.3	86.6	83.1	80.8	79.5	79.3	79.1	78.9	78.7	78.5	78.4	78.2	78.0	77.8	77.7	77.5	77.3	77.2	77.1	77.1	77.0	77.0	76.9	76.8
Wind	Wind	SA	CSA	S7	Roxby Downs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	SA	CSA	S8	Eastern Eyre Peninsula	108.9	104.5	100.4	96.5	92.7	89.1	86.7	85.4	85.2	85.0	84.7	84.6	84.4	84.3	84.1	83.9	83.7	83.5	83.3	83.2	83.1	82.9	82.9	82.8	82.8	82.7	82.6
Wind	Wind	SA	CSA	S9	Western Eyre Peninsula	102.3	98.1	94.1	90.2	86.5	83.0	80.6	79.3	79.2	78.9	78.7	78.5	78.4	78.2	78.1	77.9	77.7	77.5	77.3	77.2	77.1	76.9	76.9	76.8	76.8	76.7	76.6
Wind	Wind	TAS	TAS	T1	North East TAS	95.0	91.4	88.0	84.6	81.4	78.4	76.4	75.3	75.2	74.9	74.8	74.6	74.5	74.4	74.2	74.0	73.9	73.7	73.6	73.4	73.4	73.3	73.2	73.2	73.1	73.0	73.0
Wind	Wind	TAS	TAS	T2	North West TAS	89.2	85.7	82.5	79.3	76.3	73.4	71.5	70.5	70.3	70.1	69.9	69.8	69.7	69.6	69.4	69.2	69.1	69.0	68.8	68.7	68.6	68.5	68.5	68.4	68.4	68.3	68.2
Wind	Wind	TAS	TAS	T3	Central Highlands	76.7	73.7	70.9	68.2	65.5	63.1	61.4	60.5	60.4	60.2	60.1	60.0	59.9	59.8	59.6	59.5	59.4	59.2	59.1	59.0	58.9	58.9	58.8	58.8	58.8	58.7	58.6
Wind	Wind	NSW	CNSW	N0	NSW Non-REZ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Wind	VIC	VIC	V0	VIC Non-REZ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind - offshore (fixed)	Wind	NSW	SNW	N10	Hunter Coast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind - offshore (fixed)	Wind	NSW	SNW	N11	Illawarra Coast	301.9	293.0	284.3	276.3	268.7	261.8	256.8	253.5	251.5	249.2	247.1	245.4	244.6	243.3	242.3	240.7	239.3	237.4	236.1	234.8	233.7	232.5	231.4	230.2	229.3	228.4	227.8
Wind - offshore (fixed)	Wind	VIC	VIC	V7	Gippsland Coast	264.6	256.8	249.2	242.1	235.5	229.5	225.0	222.2	220.4	218.4	216.5	215.0	214.4	213.2	212.3	210.9	209.7	208.1	206.9	205.8	204.8	203.7	202.8	201.8	200.9	200.1	199.7
Wind - offshore (fixed)	Wind	VIC	VIC	V8	Portland Coast	275.1	267.0	259.1	251.7	244.9	238.6	234.0	231.0	229.2	227.1	225.1	223.6	222.9	221.7	220.8	219.3	218.0	216.4	215.1	213.9	212.9	211.8	210.8	209.8	208.9	208.1	207.6
Wind - offshore (fixed)	Wind	SA	SESA	S10	South East SA Coast	275.3	267.1	259.3	251.9	245.0	238.8	234.1	231.2	229.4	227.2	225.3	223.7	223.0	221.8	220.9	219.4	218.2	216.5	215.3	214.1	213.1	212.0	211.0	209.9	209.1	208.2	207.7
Wind - offshore (fixed)	Wind	TAS	TAS	T4	North West TAS Coast	255.3	247.8	240.5	233.6	227.3	221.5	217.2	214.4	212.7	210.7	209.0	207.5	206.9	205.7	204.9	203.5	202.4	200.8	199.7	198.6	197.6	196.6	195.7	194.7	193.9	193.1	192.7
Wind - offshore (fixed)	Wind	TAS	TAS	T5	North East TAS Coast	253.8	246.3	239.0	232.2	225.9	220.1	215.9	213.1	211.4	209.5	207.7	206.3	205.6	204.5	203.7	202.3	201.1	199.6	198.4	197.4	196.4	195.4	194.5	193.5	192.7	192.0	191.5

Table 52: LCOE of utility-scale PV generation across the NEM. Sub-regional build costs, connection costs, capacity factors, FOM costs, and lead times are obtained from AEMO's 2024 ISP under the Step Change scenario [3].

Technology type	Fuel type	Region	Sub-region	REZ	REZ location	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50	2050-51
Large scale Solar PV	Solar	QLD	NQ	Q1	Far North QLD	83.9	80.5	77.6	74.9	72.2	69.7	67.7	66.0	65.1	63.9	63.0	60.9	58.2	55.0	52.5	50.9	50.1	49.6	49.0	48.4	47.8	47.2	46.7	46.2	45.9	45.6	45.4
Large scale Solar PV	Solar	QLD	NQ	Q2	North Qld Clean Energy Hub	76.8	73.6	71.1	68.7	66.3	64.0	62.2	60.7	59.9	58.9	58.0	56.2	53.8	50.9	48.6	47.2	46.4	46.0	45.5	45.0	44.5	43.9	43.4	43.0	42.7	42.5	42.3
Large scale Solar PV	Solar	QLD	NQ	Q3	Northern Qld	80.8	77.4	74.7	72.1	69.5	67.1	65.2	63.5	62.6	61.5	60.6	58.6	56.1	53.0	50.5	49.0	48.2	47.7	47.1	46.6	46.1	45.4	44.9	44.5	44.1	43.9	43.7
Large scale Solar PV	Solar	QLD	CQ	Q4	Isaac	79.5	76.2	73.5	70.9	68.4	66.0	64.1	62.5	61.6	60.5	59.6	57.6	55.1	52.1	49.7	48.2	47.3	46.9	46.3	45.8	45.2	44.6	44.1	43.7	43.4	43.2	42.9
Large scale Solar PV	Solar	QLD	CQ	Q5	Barcaldine	71.9	68.7	66.2	63.7	61.3	59.0	57.2	55.7	54.9	53.8	53.0	51.1	48.7	45.8	43.5	42.1	41.3	40.8	40.3	39.9	39.3	38.7	38.2	37.9	37.5	37.3	37.1
Large scale Solar PV	Solar	QLD	CQ	Q6	Fitzroy	80.5	77.1	74.5	71.8	69.2	66.8	64.9	63.3	62.4	61.3	60.4	58.4	55.8	52.7	50.3	48.8	47.9	47.5	46.9	46.4	45.8	45.2	44.7	44.3	43.9	43.7	43.5
Large scale Solar PV	Solar	QLD	SQ	Q7	Wide Bay	79.5	76.0	73.1	70.3	67.6	65.0	63.0	61.2	60.3	59.1	58.1	56.0	53.3	50.0	47.4	45.8	45.0	44.4	43.8	43.3	42.7	42.0	41.5	41.1	40.7	40.5	40.2
Large scale Solar PV	Solar	QLD	SQ	Q8	Darling Downs	76.6	73.2	70.4	67.7	65.1	62.6	60.7	59.0	58.1	57.0	56.0	54.0	51.4	48.2	45.7	44.2	43.4	42.9	42.3	41.8	41.2	40.6	40.0	39.6	39.3	39.0	38.8
Large scale Solar PV	Solar	QLD	CQ	Q9	Banana	87.1	83.6	80.9	78.2	75.5	73.1	71.1	69.4	68.5	67.4	66.4	64.4	61.8	58.6	56.1	54.6	53.7	53.2	52.6	52.1	51.5	50.9	50.4	50.0	49.6	49.4	49.1
Large scale Solar PV	Solar	NSW	NNSW	N1	North West NSW	77.9	74.5	71.7	69.0	66.3	63.8	61.9	60.2	59.3	58.2	57.2	55.2	52.5	49.3	46.8	45.3	44.4	43.9	43.3	42.8	42.2	41.6	41.1	40.6	40.3	40.1	39.8
Large scale Solar PV	Solar	NSW	NNSW	N2	New England	82.5	78.8	75.9	73.0	70.2	67.6	65.5	63.7	62.8	61.6	60.5	58.4	55.6	52.2	49.6	48.0	47.0	46.5	45.9	45.4	44.7	44.1	43.5	43.1	42.7	42.4	42.2
Large scale Solar PV	Solar	NSW	CNSW	N3	Central-West Orana	82.2	78.5	75.6	72.7	69.9	67.3	65.2	63.5	62.5	61.3	60.3	58.1	55.4	52.0	49.4	47.7	46.8	46.3	45.7	45.1	44.5	43.9	43.3	42.8	42.5	42.2	42.0
Large scale Solar PV	Solar	NSW	SNSW	N4	Broken Hill	79.0	75.6	72.9	70.2	67.6	65.1	63.1	61.5	60.6	59.4	58.5	56.5	53.9	50.7	48.2	46.7	45.8	45.3	44.8	44.3	43.7	43.0	42.5	42.1	41.7	41.5	41.3
Large scale Solar PV	Solar	NSW	SNSW	N5	South West NSW	84.9	81.1	78.1	75.1	72.3	69.6	67.4	65.6	64.6	63.4	62.4	60.1	57.3	53.8	51.1	49.4	48.5	47.9	47.3	46.8	46.1	45.4	44.8	44.4	44.0	43.7	43.5
Large scale Solar PV	Solar	NSW	SNSW	N6	Wagga Wagga	92.1	88.3	85.2	82.2	79.3	76.5	74.4	72.5	71.5	70.3	69.2	66.9	64.0	60.5	57.8	56.0	55.1	54.5	53.9	53.3	52.7	52.0	51.4	50.9	50.5	50.3	50.0
Large scale Solar PV	Solar	NSW	SNSW	N7	Tumut	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	NSW	SNSW	N8	Cooma-Monaro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	NSW	CNSW	N9	Hunter-Central Coast	83.9	80.1	77.1	74.1	71.2	68.5	66.3	64.5	63.5	62.2	61.2	58.9	56.1	52.6	49.8	48.1	47.2	46.6	46.0	45.4	44.8	44.1	43.5	43.0	42.6	42.4	42.1
Large scale Solar PV	Solar	NSW	SNW	N12	Illawarra	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	VIC	VIC	V1	Ovens Murray	91.4	87.4	84.1	80.9	77.9	74.9	72.6	70.7	69.6	68.3	67.2	64.8	61.7	58.0	55.0	53.2	52.2	51.6	50.9	50.4	49.7	48.9	48.3	47.8	47.4	47.1	46.8
Large scale Solar PV	Solar	VIC	VIC	V2	Murray River	84.9	81.4	78.6	75.8	73.1	70.6	68.6	66.9	66.0	64.8	63.9	61.8	59.1	55.9	53.3	51.8	50.9	50.4	49.8	49.3	48.7	48.0	47.5	47.1	46.7	46.5	46.2
Large scale Solar PV	Solar	VIC	VIC	V3	Western VIC	101.3	97.1	93.7	90.5	87.3	84.3	81.9	79.9	78.8	77.4	76.3	73.8	70.6	66.8	63.8	61.9	60.9	60.3	59.6	59.0	58.2	57.5	56.8	56.3	55.9	55.6	55.3
Large scale Solar PV	Solar	VIC	VIC	V4	South West VIC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	VIC	VIC	V5	Gippsland	102.4	98.0	94.4	91.0	87.6	84.5	82.0	79.8	78.7	77.2	76.0	73.4	70.1	66.0	62.9	60.9	59.8	59.2	58.4	57.8	57.0	56.2	55.5	55.0	54.5	54.2	54.0
Large scale Solar PV	Solar	VIC	VIC	V6	Central North Vic	92.9	89.2	86.2	83.3	80.4	77.7	75.6	73.8	72.8	71.6	70.5	68.3	65.5	62.0	59.3	57.7	56.7	56.2	55.6	55.0	54.4	53.7	53.1	52.7	52.3	52.0	51.8
Large scale Solar PV	Solar	SA	SESA	S1	South East SA	97.9	93.9	90.7	87.5	84.5	81.6	79.3	77.3	76.3	75.0	73.9	71.5	68.4	64.7	61.8	60.0	59.0	58.5	57.8	57.2	56.5	55.8	55.1	54.7	54.2	54.0	53.7
Large scale Solar PV	Solar	SA	CSA	S2	Riverland	79.7	76.2	73.5	70.7	68.1	65.6	63.6	61.9	61.0	59.8	58.9	56.8	54.2	51.0	48.5	46.9	46.0	45.5	44.9	44.4	43.9	43.2	42.7	42.3	41.9	41.7	41.4
Large scale Solar PV	Solar	SA	CSA	S3	Mid-North SA	88.1	84.4	81.5	78.6	75.8	73.2	71.1	69.3	68.3	67.1	66.1	64.0	61.2	57.8	55.1	53.5	52.6	52.1	51.4	50.9	50.3	49.6	49.0	48.6	48.2	48.0	47.7
Large scale Solar PV	Solar	SA	CSA	S4	Yorke Peninsula	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	SA	CSA	S5	Northern SA	85.0	81.4	78.6	75.8	73.1	70.5	68.5	66.8	65.9	64.7	63.7	61.6	58.9	55.7	53.1	51.5	50.7	50.1	49.5	49.0	48.4	47.8	47.2	46.8	46.4	46.2	45.9
Large scale Solar PV	Solar	SA	CSA	S6	Leigh Creek	75.6	72.3	69.6	67.0	64.5	62.1	60.3	58.6	57.8	56.7	55.8	53.8	51.3	48.2	45.9	44.4	43.6	43.1	42.5	42.0	41.5	40.9	40.3	39.9	39.6	39.4	39.2
Large scale Solar PV	Solar	SA	CSA	S7	Roxby Downs	78.6	75.3	72.8	70.2	67.8	65.4	63.6	62.0	61.2	60.1	59.2	57.3	54.9	51.9	49.6	48.1	47.3	46.9	46.3	45.9	45.3	44.7	44.2	43.8	43.5	43.3	43.1
Large scale Solar PV	Solar	SA	CSA	S8	Eastern Eyre Peninsula	97.6	93.6	90.4	87.2	84.2	81.3	79.0	77.1	76.0	74.7	73.6	71.2	68.2	64.5	61.6	59.8	58.8	58.2	57.5	57.0	56.3	55.5	54.9	54.4	54.0	53.7	53.5
Large scale Solar PV	Solar	SA	CSA	S9	Western Eyre Peninsula	82.1	78.5	75.6	72.7	70.0	67.4	65.4	63.6	62.7	61.5	60.5	58.3	55.6	52.3	49.7	48.1	47.2	46.6	46.0	45.5	44.9	44.2	43.7	43.2	42.9	42.6	42.4
Large scale Solar PV	Solar	TAS	TAS	T1	North East TAS	111.3	107.0	103.6	100.2	96.9	93.8	91.4	89.3	88.1	86.7	85.5	83.0	79.7	75.8	72.7	70.7	69.7	69.0	68.3	67.7	67.0	66.2	65.5	65.0	64.5	64.2	64.0
Large scale Solar PV	Solar	TAS	TAS	T2	North West TAS	129.4	124.3	120.2	116.2	112.3	108.6	105.7	103.2	101.9	100.2	98.8	95.8	91.9	87.2	83.5	81.3	80.0	79.2	78.4	77.6	76.8	75.8	75.0	74.4	73.9	73.5	73.2
Large scale Solar PV	Solar	TAS	TAS	T3	Central Highlands	115.9	111.4	107.7	104.1	100.6	97.2	94.6	92.4	91.2	89.7	88.4	85.7	82.2	78.0	74.7	72.6	71.5	70.8	70.0	69.4	68.6	67.7	67.0	66.5	66.0	65.7	65.4
Large scale Solar PV	Solar	NSW	CNSW	N0	NSW Non-REZ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large scale Solar PV	Solar	VIC	VIC	V0	VIC Non-REZ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 53: Reliability response in percent of regional peak demand in winter months [3].

Price band	Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50	2050-51
Reliability response in % of peak demand	NSW	2.51%	2.58%	2.65%	3.35%	4.49%	5.45%	6.07%	6.68%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%	7.29%
Reliability response in % of peak demand	QLD	2.59%	2.65%	2.72%	2.79%	2.85%	2.92%	2.99%	3.05%	3.12%	3.19%	3.25%	3.32%	3.39%	3.45%	3.52%	3.59%	3.65%	3.72%	3.78%	3.85%	3.92%	3.98%	4.05%	4.12%	4.18%	4.25%	4.25%
Reliability response in % of peak demand	SA	1.57%	1.68%	1.79%	1.89%	2.00%	2.11%	2.21%	2.32%	2.43%	2.54%	2.64%	2.75%	2.86%	2.96%	3.07%	3.18%	3.29%	3.39%	3.50%	3.61%	3.71%	3.82%	3.93%	4.04%	4.14%	4.25%	4.25%
Reliability response in % of peak demand	TAS	0.56%	0.71%	0.86%	1.00%	1.15%	1.30%	1.45%	1.59%	1.74%	1.89%	2.04%	2.18%	2.33%	2.48%	2.63%	2.77%	2.92%	3.07%	3.22%	3.36%	3.51%	3.66%	3.81%	3.95%	4.10%	4.25%	4.25%
Reliability response in % of peak demand	VIC	2.59%	2.66%	2.73%	2.79%	2.86%	2.92%	2.99%	3.06%	3.12%	3.19%	3.26%	3.32%	3.39%	3.45%	3.52%	3.59%	3.65%	3.72%	3.79%	3.85%	3.92%	3.98%	4.05%	4.12%	4.18%	4.25%	4.25%

Table 54: Reliability response in percent of regional peak demand in summer months [3].

Price band	Region	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Reliability response in % of peak demand	NSW	2.61%	2.67%	2.73%	2.80%	2.86%	2.92%	2.99%	3.05%	3.11%	3.18%	3.24%	3.30%	3.36%	3.43%	3.49%	3.55%	3.62%	3.68%	3.74%	3.81%	3.87%	3.93%	4.00%	4.06%	4.12%	4.19%	4.25%
Reliability response in % of peak demand	QLD	2.21%	2.29%	2.37%	2.45%	2.52%	2.60%	2.68%	2.76%	2.84%	2.92%	3.00%	3.07%	3.15%	3.23%	3.31%	3.39%	3.47%	3.54%	3.62%	3.70%	3.78%	3.86%	3.94%	4.01%	4.09%	4.17%	4.25%
Reliability response in % of peak demand	SA	1.82%	1.91%	2.01%	2.10%	2.19%	2.29%	2.38%	2.47%	2.57%	2.66%	2.76%	2.85%	2.94%	3.04%	3.13%	3.22%	3.32%	3.41%	3.50%	3.60%	3.69%	3.78%	3.88%	3.97%	4.06%	4.16%	4.25%
Reliability response in % of peak demand	TAS	0.33%	0.48%	0.63%	0.78%	0.94%	1.09%	1.24%	1.39%	1.54%	1.69%	1.84%	1.99%	2.14%	2.29%	2.44%	2.59%	2.74%	2.89%	3.04%	3.20%	3.35%	3.50%	3.65%	3.80%	3.95%	4.10%	4.25%
Reliability response in % of peak demand	VIC	2.63%	2.69%	2.75%	2.82%	2.88%	2.94%	3.00%	3.06%	3.13%	3.19%	3.25%	3.31%	3.38%	3.44%	3.50%	3.56%	3.63%	3.69%	3.75%	3.81%	3.88%	3.94%	4.00%	4.06%	4.13%	4.19%	4.25%

Table 55: LCOE of shallow and medium-duration storage systems across the NEM. Sub-regional build costs, connection costs, capacity factors, FOM costs, and lead times are obtained from AEMO's 2024 ISP under the Step Change scenario [3].

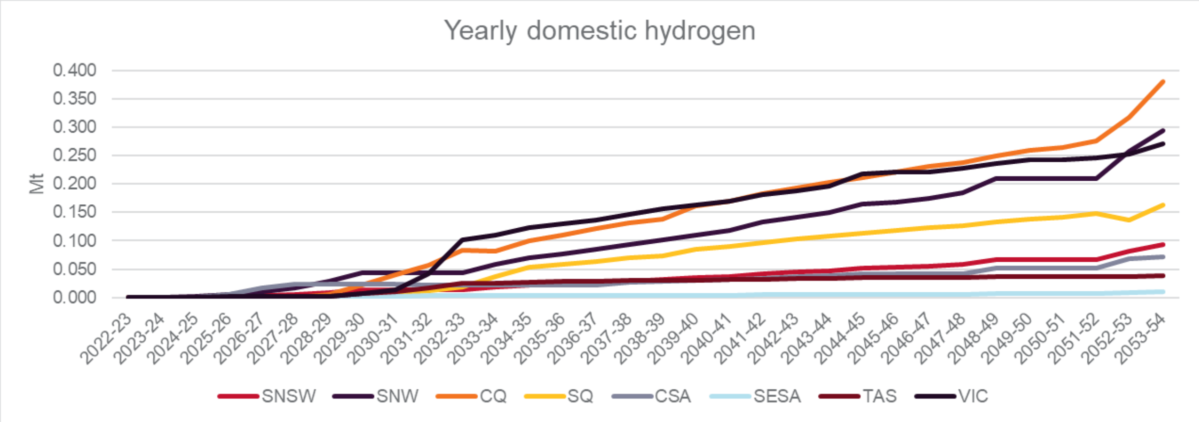
Technology type	Region	Sub-region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50	2050-51
Battery Storage (2hrs storage)	QLD	NQ	213.0	199.1	186.4	175.1	164.8	155.6	147.6	140.6	138.5	136.4	134.3	132.6	130.8	129.0	127.2	125.8	124.3	122.8	121.6	120.7	119.3	118.1	116.9	116.0	114.8	113.9	113.1
Battery Storage (2hrs storage)	QLD	CQ	213.0	199.1	186.4	175.1	164.8	155.6	147.6	140.6	138.5	136.4	134.3	132.6	130.8	129.0	127.2	125.8	124.3	122.8	121.6	120.7	119.3	118.1	116.9	116.0	114.8	113.9	113.1
Battery Storage (2hrs storage)	QLD	GG	213.0	199.1	186.4	175.1	164.8	155.6	147.6	140.6	138.5	136.4	134.3	132.6	130.8	129.0	127.2	125.8	124.3	122.8	121.6	120.7	119.3	118.1	116.9	116.0	114.8	113.9	113.1
Battery Storage (2hrs storage)	QLD	SQ	213.0	199.1	186.4	175.1	164.8	155.6	147.6	140.6	138.5	136.4	134.3	132.6	130.8	129.0	127.2	125.8	124.3	122.8	121.6	120.7	119.3	118.1	116.9	116.0	114.8	113.9	113.1
Battery Storage (2hrs storage)	NSW	NNSW	209.4	195.5	182.8	171.6	161.2	152.1	144.1	137.0	134.9	132.8	130.8	129.0	127.2	125.4	123.7	122.2	120.7	119.2	118.1	117.2	115.7	114.5	113.3	112.4	111.3	110.4	109.5
Battery Storage (2hrs storage)	NSW	CNSW	209.4	195.5	182.8	171.6	161.2	152.1	144.1	137.0	134.9	132.8	130.8	129.0	127.2	125.4	123.7	122.2	120.7	119.2	118.1	117.2	115.7	114.5	113.3	112.4	111.3	110.4	109.5
Battery Storage (2hrs storage)	NSW	SNW	209.4	195.5	182.8	171.6	161.2	152.1	144.1	137.0	134.9	132.8	130.8	129.0	127.2	125.4	123.7	122.2	120.7	119.2	118.1	117.2	115.7	114.5	113.3	112.4	111.3	110.4	109.5
Battery Storage (2hrs storage)	NSW	SNSW	219.1	204.5	191.2	179.5	168.7	159.1	150.7	143.3	141.1	139.0	136.8	134.9	133.1	131.2	129.4	127.8	126.3	124.7	123.5	122.6	121.0	119.8	118.6	117.6	116.4	115.5	114.5
Battery Storage (2hrs storage)	VIC	VIC	213.5	199.6	186.9	175.6	165.3	156.1	148.1	141.0	139.0	136.9	134.8	133.1	131.3	129.5	127.7	126.3	124.8	123.3	122.1	121.2	119.8	118.6	117.4	116.5	115.3	114.4	113.5
Battery Storage (2hrs storage)	SA	CSA	213.0	199.1	186.4	175.1	164.8	155.6	147.6	140.6	138.5	136.4	134.3	132.6	130.8	129.0	127.2	125.8	124.3	122.8	121.6	120.7	119.3	118.1	116.9	116.0	114.8	113.9	113.1
Battery Storage (2hrs storage)	SA	SESA	221.1	206.7	193.5	181.9	171.2	161.7	153.5	146.1	144.0	141.9	139.7	137.9	136.0	134.2	132.4	130.8	129.3	127.8	126.6	125.7	124.1	122.9	121.7	120.8	119.5	118.6	117.7
Battery Storage (2hrs storage)	TAS	TAS	213.5	199.6	186.9	175.6	165.3	156.1	148.1	141.0	139.0	136.9	134.8	133.1	131.3	129.5	127.7	126.3	124.8	123.3	122.1	121.2	119.8	118.6	117.4	116.5	115.3	114.4	113.5
Battery Storage (8hrs storage)	QLD	NQ	303.0	275.5	251.0	229.1	214.7	197.2	181.5	168.4	165.2	162.7	160.2	157.7	155.2	153.3	150.8	148.9	147.1	145.8	144.5	143.9	142.0	141.4	140.2	138.9	138.3	137.7	136.4
Battery Storage (8hrs storage)	QLD	CQ	303.0	275.5	251.0	229.1	214.7	197.2	181.5	168.4	165.2	162.7	160.2	157.7	155.2	153.3	150.8	148.9	147.1	145.8	144.5	143.9	142.0	141.4	140.2	138.9	138.3	137.7	136.4
Battery Storage (8hrs storage)	QLD	GG	303.0	275.5	251.0	229.1	214.7	197.2	181.5	168.4	165.2	162.7	160.2	157.7	155.2	153.3	150.8	148.9	147.1	145.8	144.5	143.9	142.0	141.4	140.2	138.9	138.3	137.7	136.4
Battery Storage (8hrs storage)	QLD	SQ	303.0	275.5	251.0	229.1	214.7	197.2	181.5	168.4	165.2	162.7	160.2	157.7	155.2	153.3	150.8	148.9	147.1	145.8	144.5	143.9	142.0	141.4	140.2	138.9	138.3	137.7	136.4
Battery Storage (8hrs storage)	NSW	NNSW	301.1	273.6	249.1	227.2	212.8	195.3	179.6	166.4	163.3	160.8	158.3	155.8	153.3	151.4	148.9	147.0	145.1	143.9	142.6	142.0	140.1	139.5	138.2	137.0	136.4	135.7	134.5
Battery Storage (8hrs storage)	NSW	CNSW	301.1	273.6	249.1	227.2	212.8	195.3	179.6	166.4	163.3	160.8	158.3	155.8	153.3	151.4	148.9	147.0	145.1	143.9	142.6	142.0	140.1	139.5	138.2	137.0	136.4	135.7	134.5
Battery Storage (8hrs storage)	NSW	SNW	301.1	273.6	249.1	227.2	212.8	195.3	179.6	166.4	163.3	160.8	158.3	155.8	153.3	151.4	148.9	147.0	145.1	143.9	142.6	142.0	140.1	139.5	138.2	137.0	136.4	135.7	134.5
Battery Storage (8hrs storage)	NSW	SNSW	317.6	288.6	262.8	239.7	224.5	206.0	189.5	175.7	172.4	169.7	167.1	164.4	161.8	159.8	157.2	155.2	153.2	151.9	150.6	149.9	147.9	147.3	145.9	144.6	144.0	143.3	142.0
Battery Storage (8hrs storage)	VIC	VIC	303.3	275.7	251.3	229.4	215.0	197.4	181.8	168.6	165.5	163.0	160.5	158.0	155.5	153.6	151.1	149.2	147.3	146.1	144.8	144.2	142.3	141.7	140.4	139.2	138.5	137.9	136.7
Battery Storage (8hrs storage)	SA	CSA	303.0	275.5	251.0	229.1	214.7	197.2	181.5	168.4	165.2	162.7	160.2	157.7	155.2	153.3	150.8	148.9	147.1	145.8	144.5	143.9	142.0	141.4	140.2	138.9	138.3	137.7	136.4
Battery Storage (8hrs storage)	SA	SESA	320.9	291.8	266.0	242.8	227.6	209.1	192.6	178.7	175.4	172.7	170.1	167.4	164.8	162.8	160.2	158.2	156.2	154.9	153.5	152.9	150.9	150.2	148.9	147.6	146.9	146.3	144.9
Battery Storage (8hrs storage)	TAS	TAS	303.3	275.7	251.3	229.4	215.0	197.4	181.8	168.6	165.5	163.0	160.5	158.0	155.5	153.6	151.1	149.2	147.3	146.1	144.8	144.2	142.3	141.7	140.4	139.2	138.5	137.9	136.7
Pumped Hydro (24hrs storage)	QLD	NQ	349.2	342.6	336.1	329.3	322.4	315.6	308.7	308.3	308.0	307.6	307.3	307.0	306.6	306.3	305.9	305.6	305.3	304.8	304.4	304.0	303.5	303.1	302.6	302.2	301.7	301.3	300.9
Pumped Hydro (24hrs storage)	QLD	CQ	349.2	342.6	336.1	329.3	322.4	315.6	308.7	308.3	308.0	307.6	307.3	307.0	306.6	306.3	305.9	305.6	305.3	304.8	304.4	304.0	303.5	303.1	302.6	302.2	301.7	301.3	300.9
Pumped Hydro (24hrs storage)	QLD	GG	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Pumped Hydro (24hrs storage)	QLD	SQ	381.4	374.2	367.0	359.5	352.0	344.5	337.0	336.6	336.3	335.8	335.5	335.1	334.7	334.3	334.0	333.6	333.3	332.8	332.3	331.8	331.3	330.9	330.3	329.9	329.4	328.9	328.4
Pumped Hydro (24hrs storage)	NSW	NNSW	327.0	320.9	314.8	308.4	302.0	295.6	289.2	288.8	288.5	288.1	287.9	287.6	287.2	286.9	286.6	286.3	286.0	285.5	285.2	284.7	284.3	283.9	283.5	283.1	282.6	282.3	281.8
Pumped Hydro (24hrs storage)	NSW	CNSW	425.8	417.7	409.7	401.3	392.9	384.5	376.1	375.6	375.2	374.8	374.4	374.0	373.5	373.1	372.7	372.3	371.9	371.3	370.9	370.3	369.7	369.2	368.6	368.1	367.5	367.0	366.5
Pumped Hydro (24hrs storage)	NSW	SNW	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Pumped Hydro (24hrs storage)	NSW	SNSW	396.7	389.2	381.8	373.9	366.1	358.3	350.5	350.1	349.7	349.2	348.9	348.5	348.1	347.7	347.3	347.0	346.6	346.1	345.6	345.1	344.5	344.1	343.5	343.1	342.5	342.1	341.5
Pumped Hydro (24hrs storage)	VIC	VIC	395.2	387.7	380.3	372.5	364.7	356.9	349.2	348.7	348.4	347.9	347.5	347.2	346.7	346.4	346.0	345.6	345.3	344.7	344.3	343.7	343.2	342.7	342.2	341.8	341.2	340.8	340.2
Pumped Hydro (24hrs storage)	SA	CSA	650.7	638.2	625.8	612.8	599.9	586.9	573.9	573.2	572.6	571.8	571.2	570.6	569.9	569.3	568.7	568.1	567.5	566.5	565.8	564.9	564.0	563.2	562.3	561.6	560.7	559.9	559.0
Pumped Hydro (24hrs storage)	SA	SESA	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Pumped Hydro (24hrs storage)	TAS	TAS	248.9	244.3	239.7	234.9	230.1	225.3	220.4	220.2	219.9	219.7	219.4	219.2	218.9	218.7	218.5	218.3	218.0	217.7	217.4	217.1	216.8	216.5	216.1	215.9	215.5	215.2	214.9

Table 56: DSP in MW between 2024 and 2050 for winter months [3].

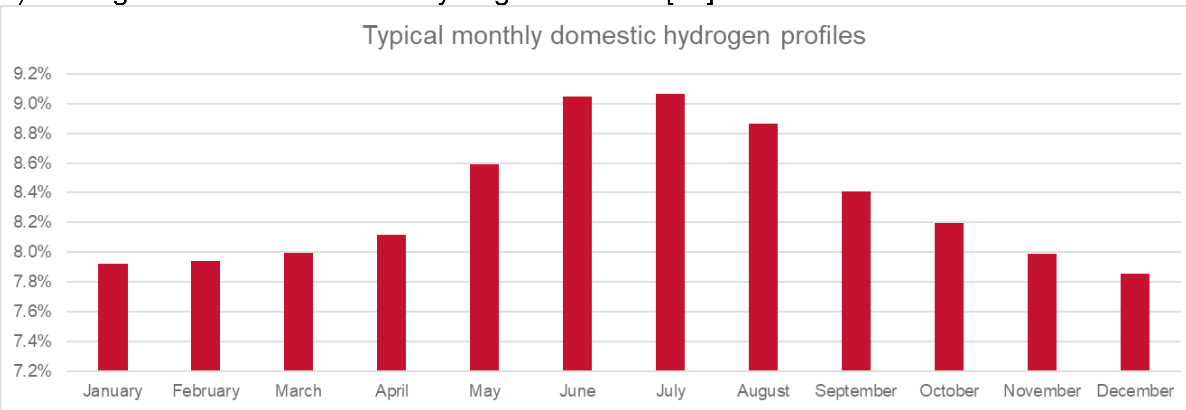
Price band	Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50	2050-51
$300 - $500	NSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$500 - $1,000	NSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$1,000 - $7,500	NSW	98	102	108	139	192	238	270	302	334	337	341	345	350	354	357	359	363	365	368	370	370	370	370	370	372	373	376
$7,500 +	NSW	99	104	109	141	194	241	273	305	337	341	345	348	353	358	361	363	367	369	372	374	374	374	374	374	376	377	380
Reliability Response	NSW	352	368	387	501	688	855	970	1,084	1,199	1,212	1,226	1,239	1,256	1,272	1,283	1,290	1,303	1,310	1,321	1,330	1,328	1,330	1,328	1,328	1,336	1,339	1,350
$300 - $500	QLD	23	24	26	27	28	29	31	32	34	35	36	38	40	41	43	44	46	47	49	50	51	53	54	56	57	58	59
$500 - $1,000	QLD	57	60	63	65	69	72	76	79	83	86	89	93	98	102	105	109	113	117	120	124	127	130	133	137	140	143	144
$1,000 - $7,500	QLD	160	167	176	184	193	203	212	222	232	241	251	262	274	286	295	305	316	327	338	347	355	364	374	383	392	401	405
$7,500 +	QLD	199	208	219	229	240	252	265	276	288	301	312	326	341	356	368	380	394	408	420	432	442	453	466	477	489	499	504
Reliability Response	QLD	275	288	303	316	332	349	366	382	399	416	432	451	471	492	509	526	545	564	581	598	612	627	644	660	676	690	697
$300 - $500	SA	28	30	33	36	39	42	45	48	51	55	58	62	66	70	74	77	81	84	88	91	94	97	100	103	105	108	109
$500 - $1,000	SA	44	47	52	56	61	66	71	75	80	86	91	97	104	110	115	121	126	132	138	143	148	152	156	160	165	169	170
$1,000 - $7,500	SA	47	52	56	62	66	71	77	82	88	93	99	106	113	120	126	132	138	144	150	156	161	166	170	175	180	184	186
$7,500 +	SA	53	58	63	69	74	80	86	92	97	104	111	118	126	133	140	147	153	160	167	173	179	185	190	195	200	205	207
Reliability Response	SA	53	58	63	69	74	80	86	92	97	104	111	118	126	133	140	147	153	160	167	173	179	185	190	195	200	205	207
$300 - $500	TAS	1	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3	3	4	4	4	4	4	4	4
$500 - $1,000	TAS	8	10	13	15	17	20	22	25	28	31	34	36	39	42	45	47	49	52	55	58	60	63	65	67	69	71	70
$1,000 - $7,500	TAS	8	10	13	15	17	20	22	25	28	31	34	36	39	42	45	47	49	52	55	58	60	63	65	67	69	71	70
$7,500 +	TAS	8	10	13	15	17	20	22	25	28	31	34	36	39	42	45	47	49	52	55	58	60	63	65	67	69	71	70
Reliability Response	TAS	8	10	13	15	17	20	22	25	28	31	34	36	39	42	45	47	49	52	55	58	60	63	65	67	69	71	70
$300 - $500	VIC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$500 - $1,000	VIC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$1,000 - $7,500	VIC	65	68	71	74	78	82	86	90	94	99	102	106	110	114	117	121	124	127	130	133	136	138	140	143	145	147	148
$7,500 +	VIC	65	68	71	74	78	82	86	90	94	99	102	106	110	114	117	121	124	127	130	133	136	138	140	143	145	147	148
Reliability Response	VIC	266	277	290	303	318	333	349	366	383	401	417	433	448	463	477	491	505	517	530	542	552	563	571	582	590	599	603

Table 57: DSP in MW between 2024 and 2050 for summer months [3].

Price band	Region	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
$300 - $500	NSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$500 - $1,000	NSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$1,000 - $7,500	NSW	94	97	102	107	113	118	123	128	133	137	141	145	150	155	159	163	166	171	176	180	183	186	189	192	196	199	203
$7,500 +	NSW	95	98	103	109	114	119	125	130	134	138	142	147	152	156	161	164	168	173	178	182	185	188	191	195	198	201	205
Reliability Response	NSW	337	350	367	386	405	424	443	460	476	491	506	521	539	555	571	584	598	614	632	647	658	667	678	691	705	716	728
$300 - $500	QLD	22	23	25	26	28	29	31	33	35	36	38	40	42	44	46	48	49	52	54	56	57	59	60	62	64	66	67
$500 - $1,000	QLD	54	58	61	64	68	72	76	81	85	89	93	97	103	108	113	117	122	127	132	137	141	144	148	153	157	161	165
$1,000 - $7,500	QLD	152	161	171	181	191	202	214	227	238	250	262	273	289	303	318	329	341	355	370	383	394	404	415	429	441	453	463
$7,500 +	QLD	189	201	213	225	237	251	267	282	297	312	326	340	359	377	396	410	425	442	461	477	491	503	517	534	549	564	577
Reliability Response	QLD	189	201	213	225	237	251	267	282	297	312	326	340	359	377	396	410	425	442	461	477	491	503	517	534	549	564	577
$300 - $500	SA	26	27	29	32	34	37	39	42	44	47	49	53	56	59	62	65	68	71	74	76	79	81	83	86	87	89	92
$500 - $1,000	SA	40	43	46	50	54	57	61	65	69	73	77	82	87	93	97	101	106	110	115	119	123	127	130	134	137	140	143
$1,000 - $7,500	SA	44	47	50	54	58	63	67	71	76	80	84	90	95	101	106	111	115	121	125	130	134	138	142	146	149	153	156
$7,500 +	SA	49	52	56	61	65	70	74	79	84	89	94	100	106	112	118	123	128	134	140	145	149	154	158	163	166	170	174
Reliability Response	SA	49	52	56	61	65	70	74	79	84	89	94	100	106	112	118	123	128	134	140	145	149	154	158	163	166	170	174
$300 - $500	TAS	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	4	4	5	5	5	5	5
$500 - $1,000	TAS	6	9	12	15	17	20	23	26	30	34	37	41	44	47	51	54	57	60	63	67	70	73	76	79	82	85	88
$1,000 - $7,500	TAS	6	9	12	15	17	20	23	26	30	34	37	41	44	47	51	54	57	60	63	67	70	73	76	79	82	85	88
$7,500 +	TAS	6	9	12	15	17	20	23	26	30	34	37	41	44	47	51	54	57	60	63	67	70	73	76	79	82	85	88
Reliability Response	TAS	6	9	12	15	17	20	23	26	30	34	37	41	44	47	51	54	57	60	63	67	70	73	76	79	82	85	88
$300 - $500	VIC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$500 - $1,000	VIC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
$1,000 - $7,500	VIC	63	66	69	73	78	83	88	92	98	103	107	112	117	123	127	132	135	140	145	149	153	156	159	163	167	170	173
$7,500 +	VIC	63	66	69	73	78	83	88	92	98	103	107	112	117	123	127	132	135	140	145	149	153	156	159	163	167	170	173
Reliability Response	VIC	212	220	233	246	262	278	294	310	328	344	360	376	395	412	428	442	455	470	486	501	513	522	534	548	560	571	581



a) Subregional annual domestic hydrogen demand [42]



b) *Typical* monthly domestic hydrogen profiles [42]

Figure 80: Annual domestic hydrogen demand and typical monthly domestic hydrogen profiles.

Appendix B

Supporting material

8.1. Energy output and capacity factors

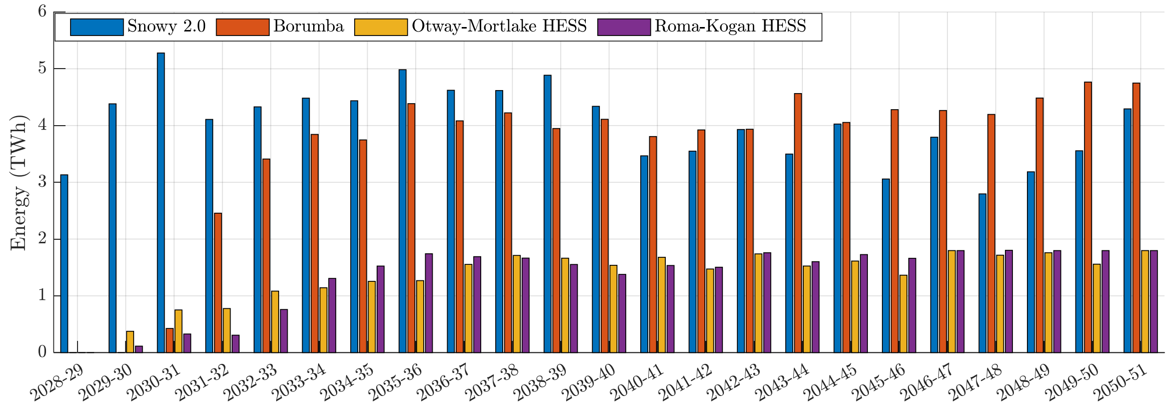


Figure 81: Forecast energy produced by each LDES option from 2028-29 to 2047-48 in the HESS-VIC-QLD-4GW scenario, and under Sensitivity 1.

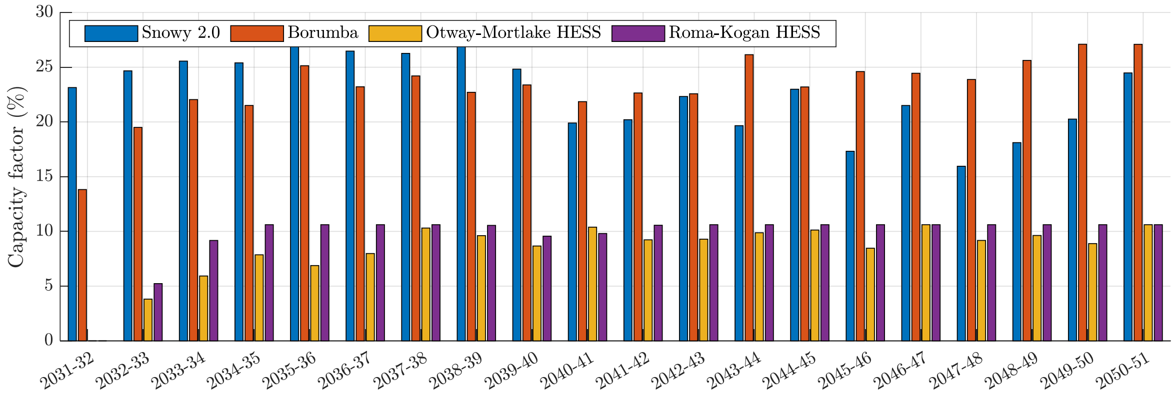


Figure 82: CF of each LDES option from 2031-32 to 2050-51 in the HESS-VIC-QLD-2GW scenario, and under Sensitivity 1.

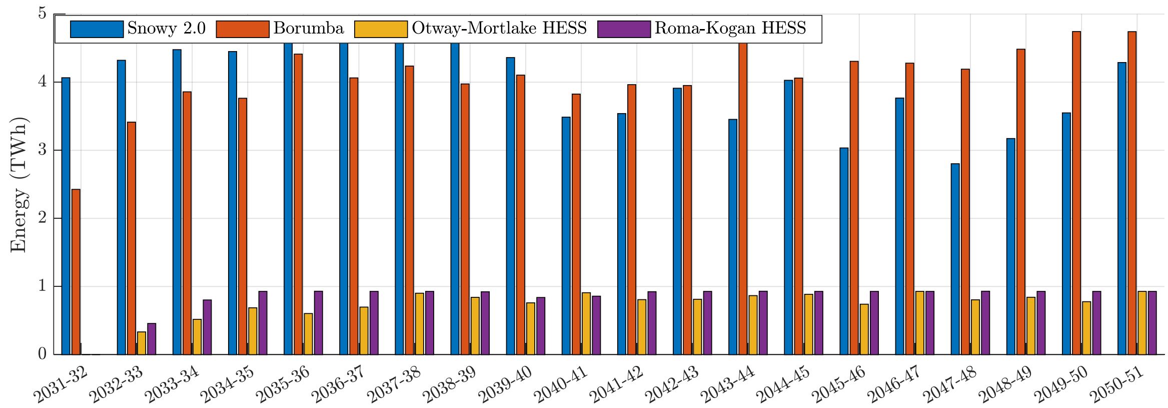


Figure 83: Forecast energy produced by each LDES option from 2031-32 to 2050-51 in the HESS-VIC-QLD-2GW scenario, and under Sensitivity 1.

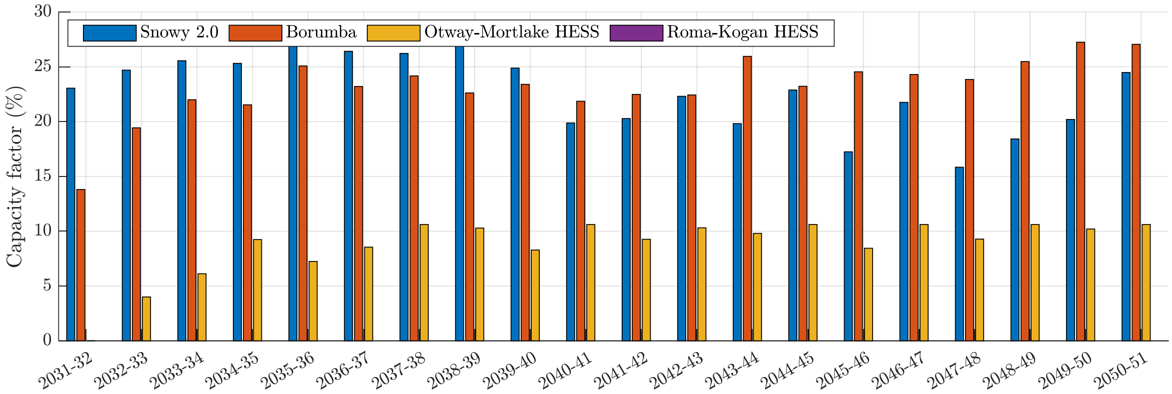


Figure 84: CF of each LDES option from 2031-32 to 2050-51 in the HESS-VIC-0.5GW scenario, and under Sensitivity 1.

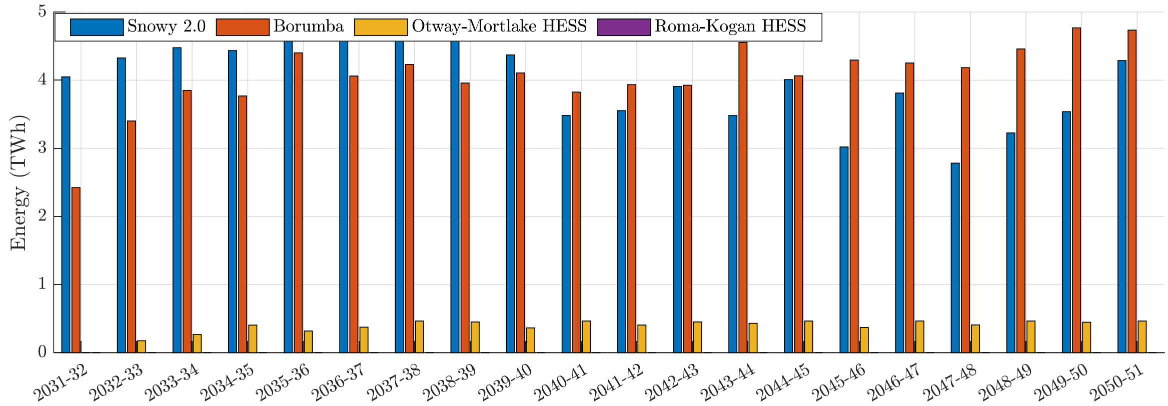


Figure 85: Forecast energy produced by each LDES option from 2031-32 to 2050-51 in the HESS-VIC-0.5GW scenario, and under Sensitivity 1.

8.2. PDC and RDC

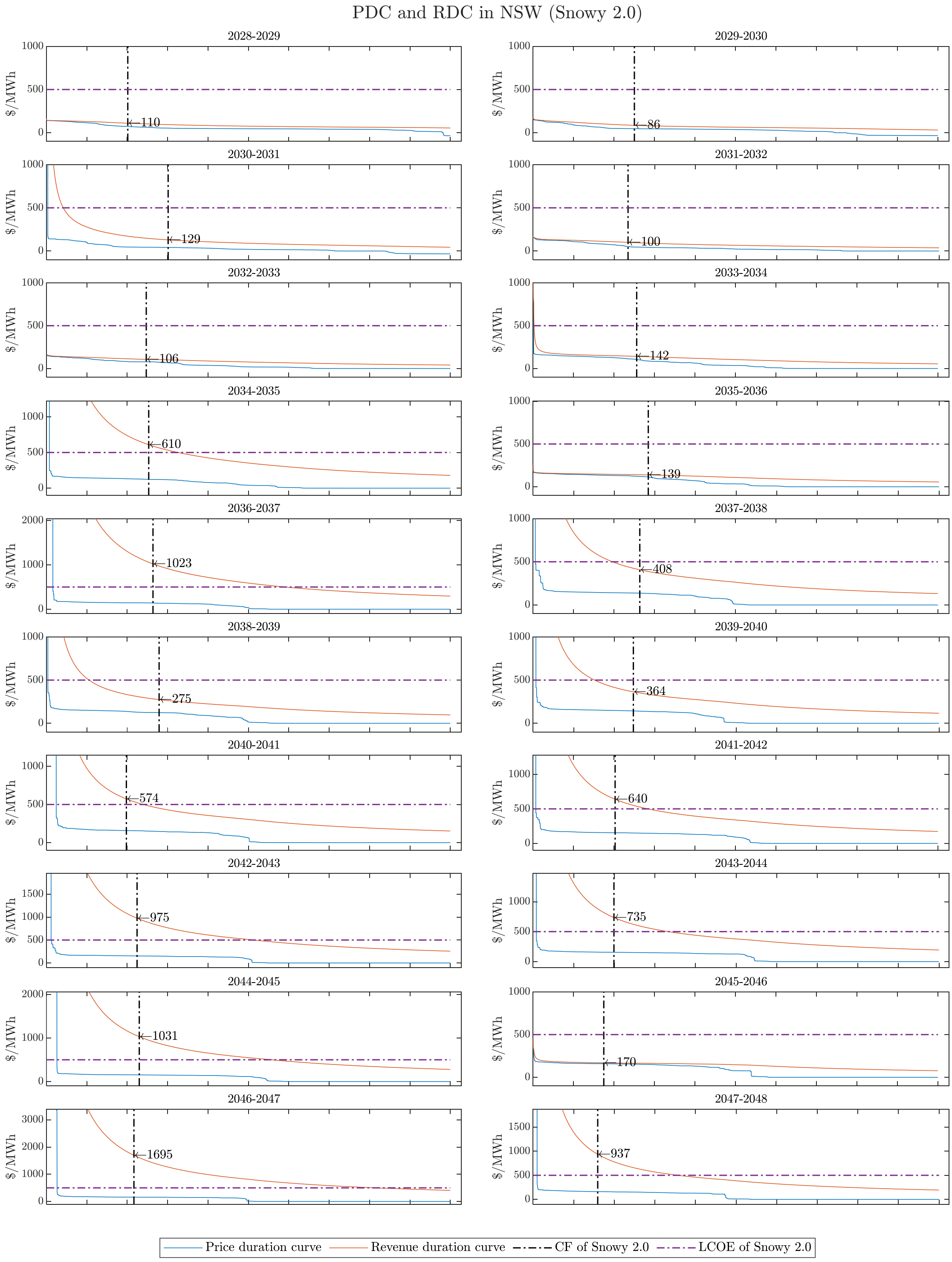


Figure 86: CF and LCOE of Snowy 2.0 in relation to the PDC and RDC in NSW from 2028 to 2048 obtained in the NoLDES scenario, and under Sensitivity 1. The text arrows show the intersection points (prices) between the RDC and the CF.

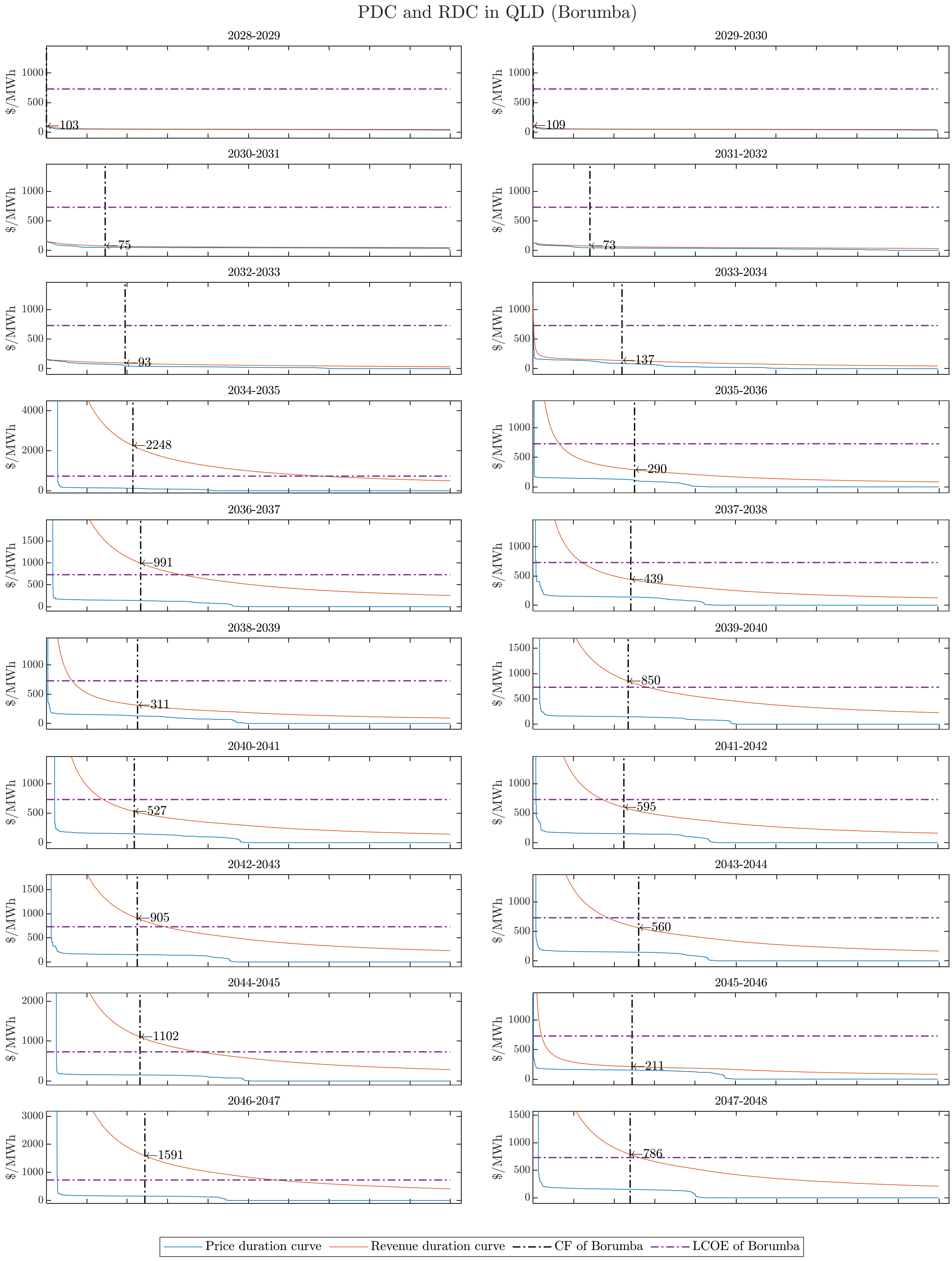


Figure 87: CF and LCOE of Borumba in relation to the PDC and RDC in QLD from 2028-29 to 2047-48 obtained in the NoLDES scenario, and under Sensitivity 1. The text arrows show the intersection points (prices) between the RDC and the CF.

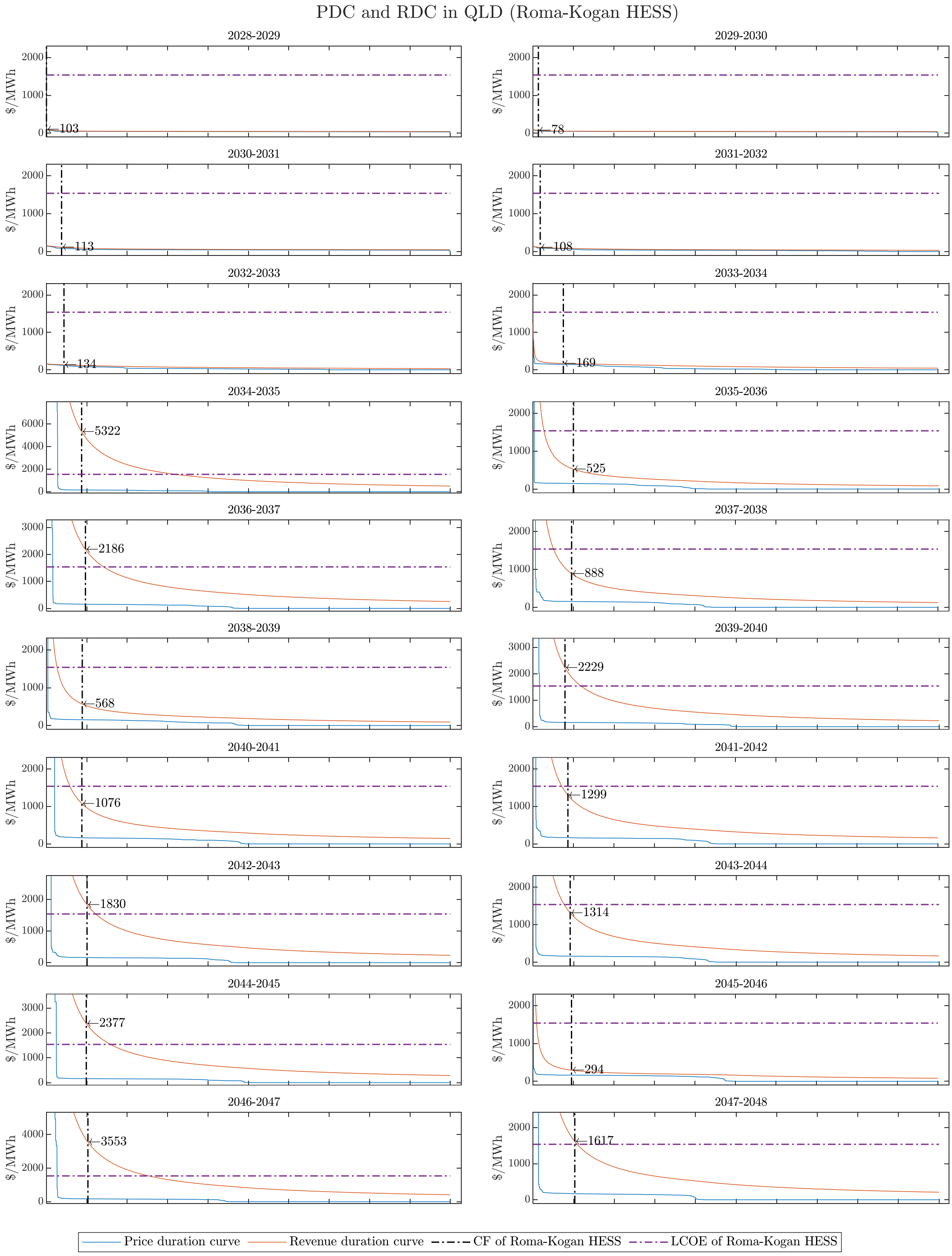


Figure 88: CF and LCOE of the Roma-Kogan HESS in relation to the PDC and RDC in QLD from 2028-29 to 2047-48 obtained in the NoLDES scenario, and under Sensitivity 1. The text arrows show the intersection points (prices) between the RDC and the CF.

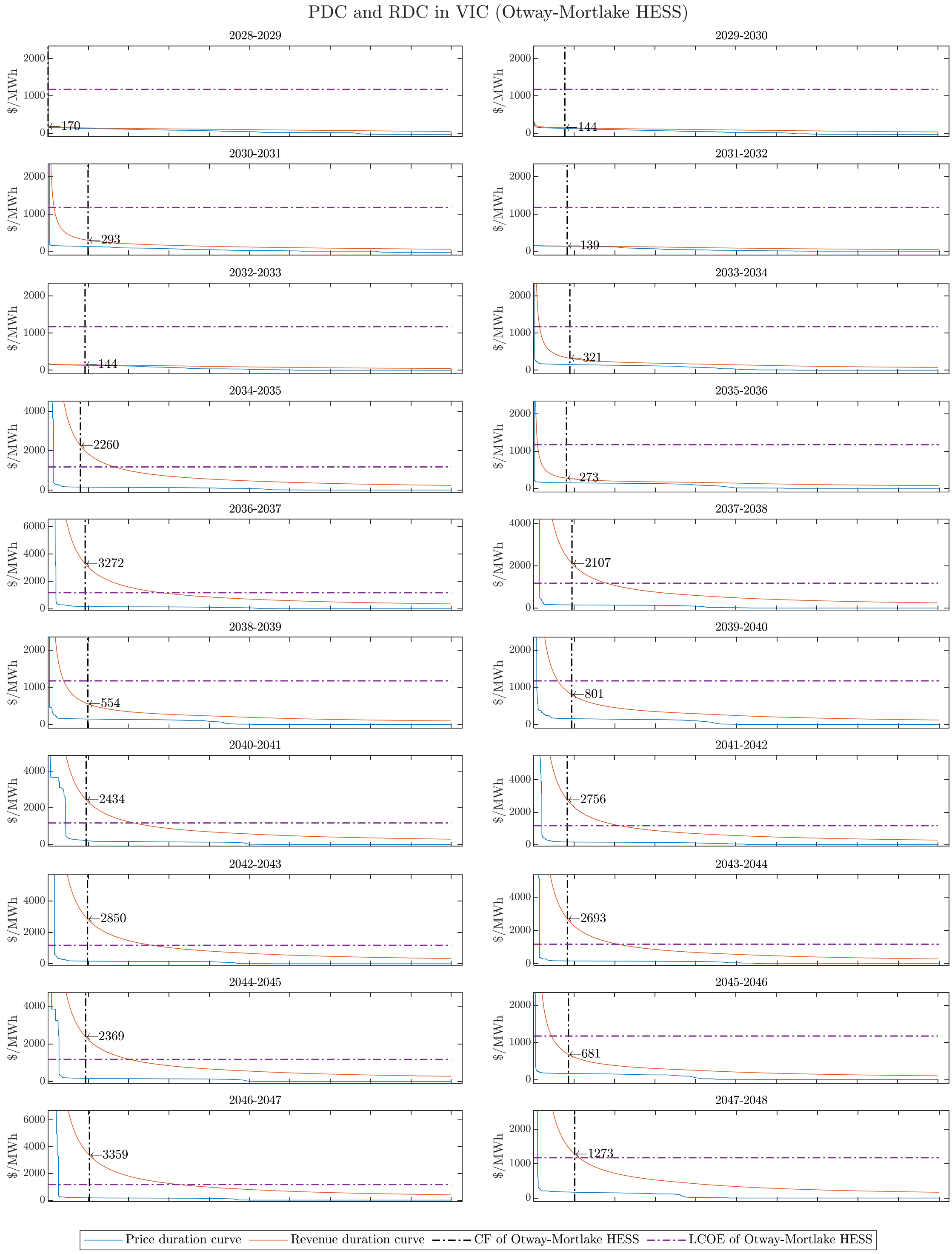
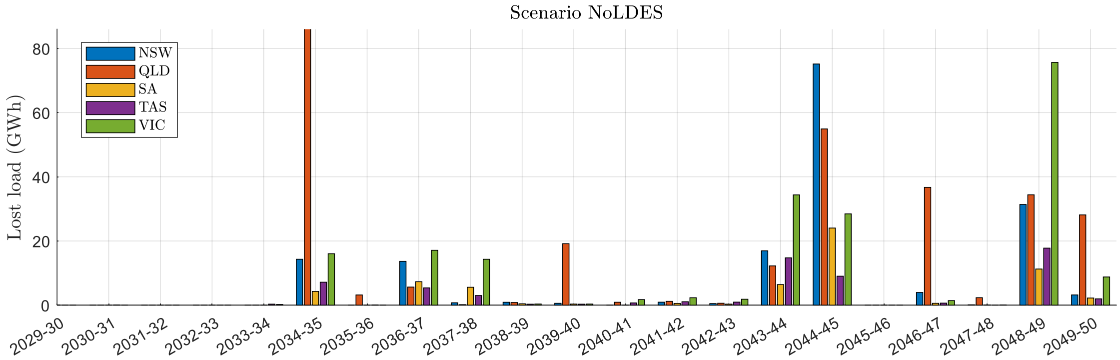
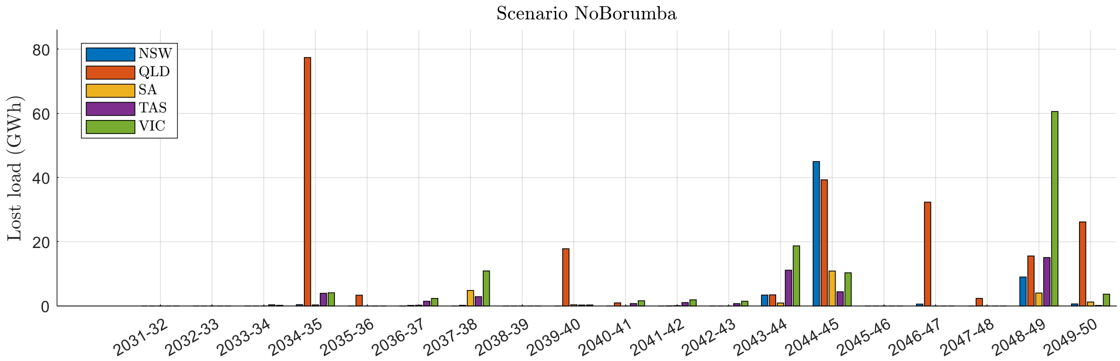


Figure 89: CF and LCOE of the Otway-Mortlake HESS in VIC in relation to the PDC and RDC in VIC from 2028-29 to 2047-48 obtained in the NoLDES scenario, and under Sensitivity 3. The text arrows show the intersection points (prices) between the RDC and the CF.

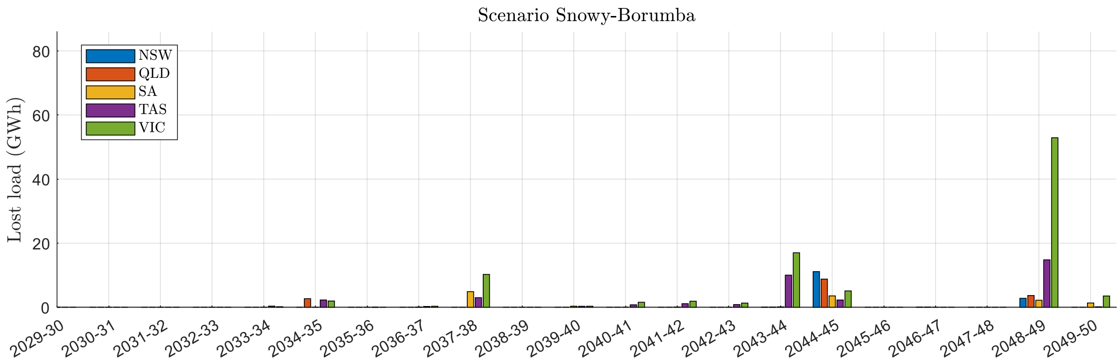
8.3. Unserved energy



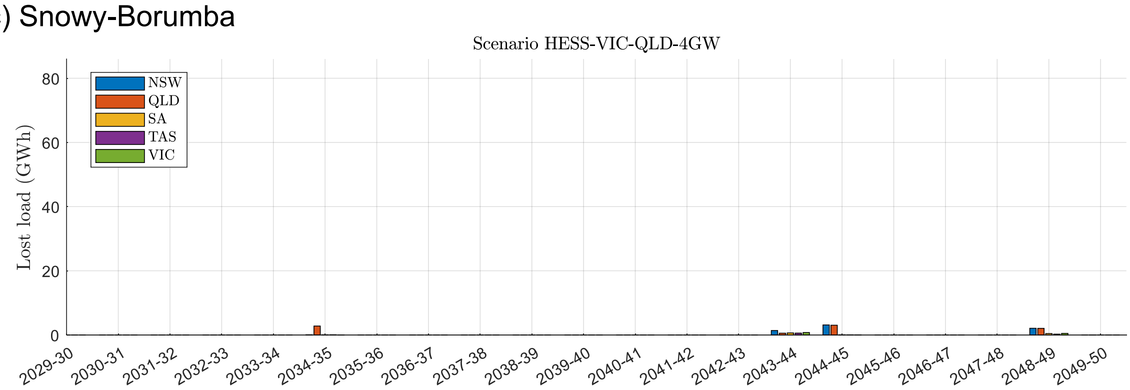
a) NoLDES



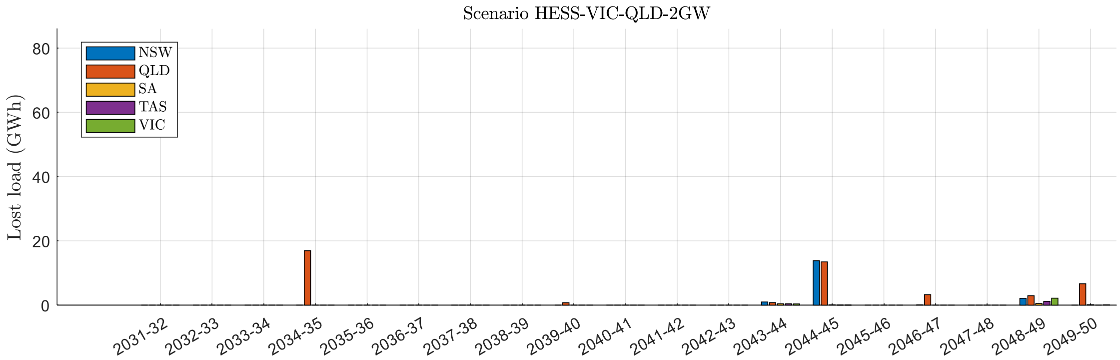
b) NoBorumba



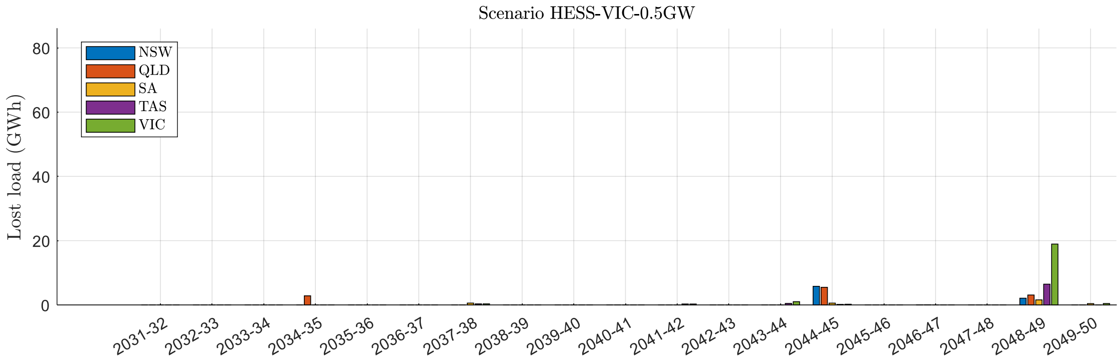
c) Snowy-Borumba



d) HESS-VIC-QLD-4GW



e) HESS-VIC-QLD-2GW



f) HESS-VIC-0.5GW

Figure 90: Forecast lost load (in GWh) by region from 2029-30 to 2049-50 under each scenario (see Figure 29).

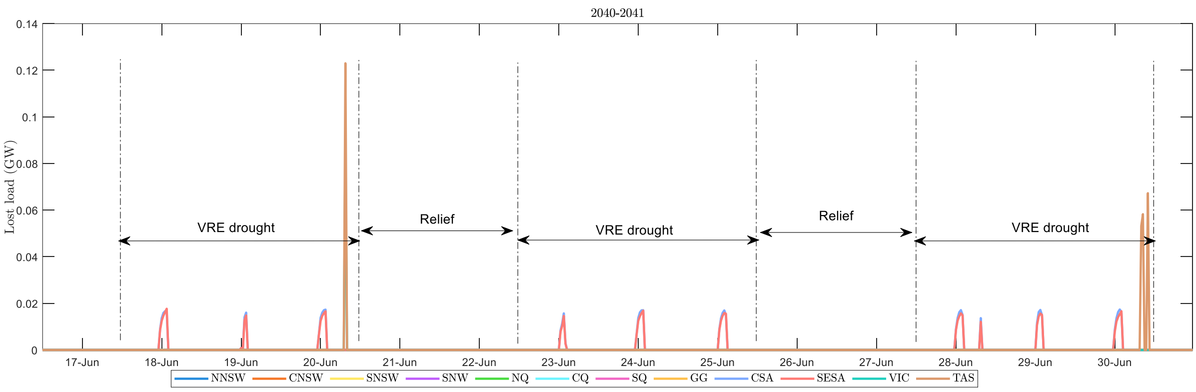


Figure 91: Lost load in each subregion during two weeks with multiple VRE drought events in June 2041 under scenarios Snowy-Borumba (top) and HESS-VIC-QLD-4GW (bottom).

8.4. State of energy

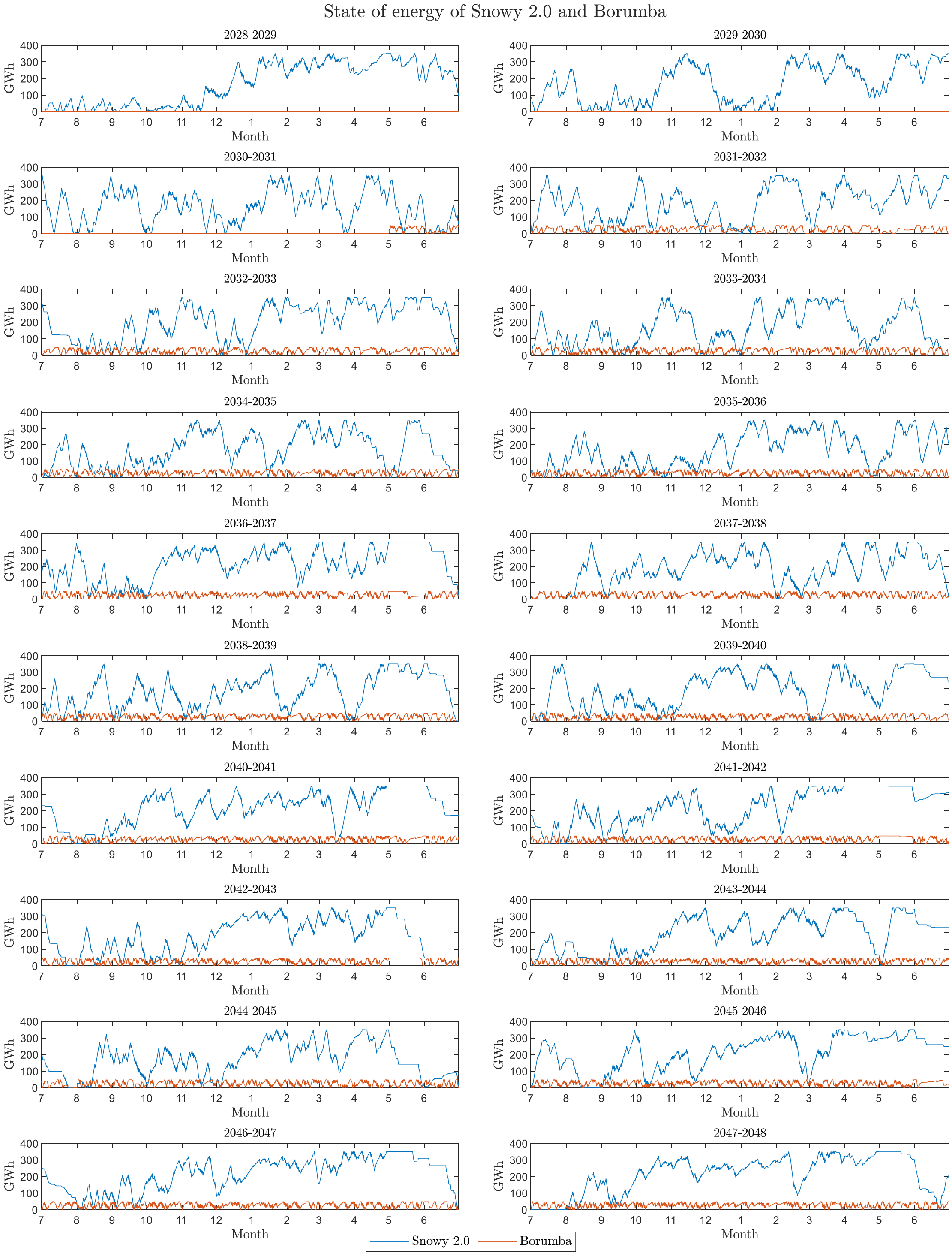


Figure 92: Forecast SoE of Snowy 2.0 and Borumba from 2028-29 to 2047-48 in the Snowy-Borumba scenario.

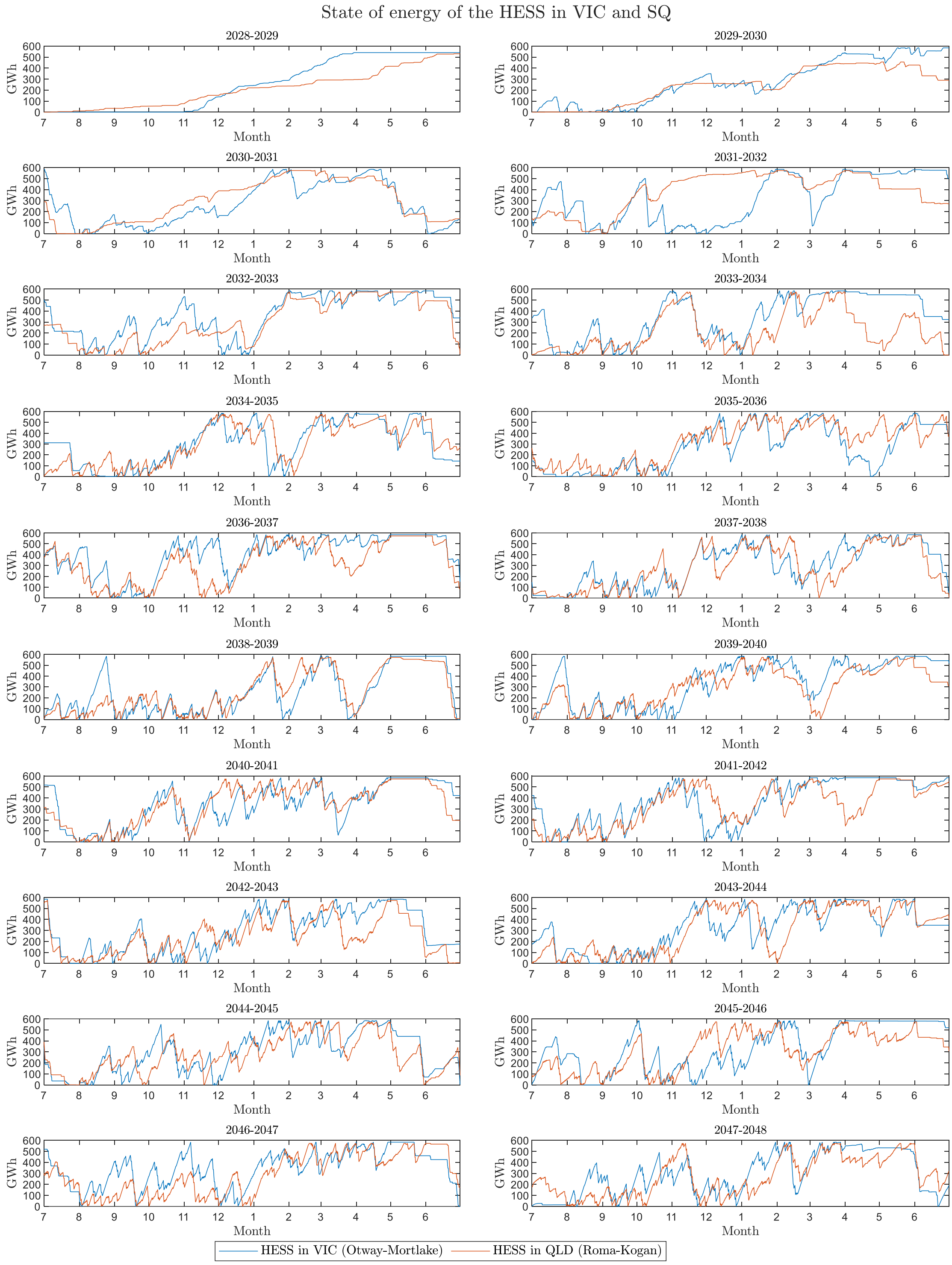


Figure 93: Forecast SoE of the considered HESS from 2028-29 to 2047-48 in the HESS-VIC-QLD-4GW scenario.

8.5. Residual demand

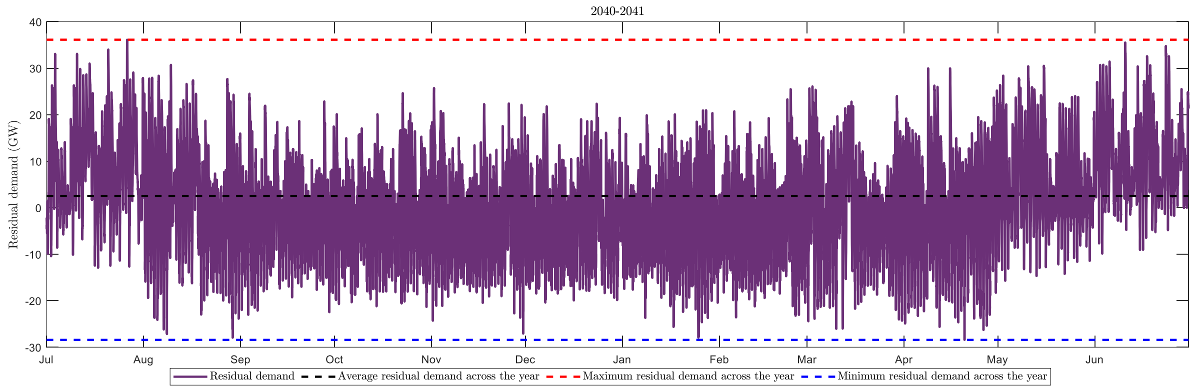


Figure 94: Residual demand across the NEM in financial year 2040-2041.

8.6. Locational marginal prices

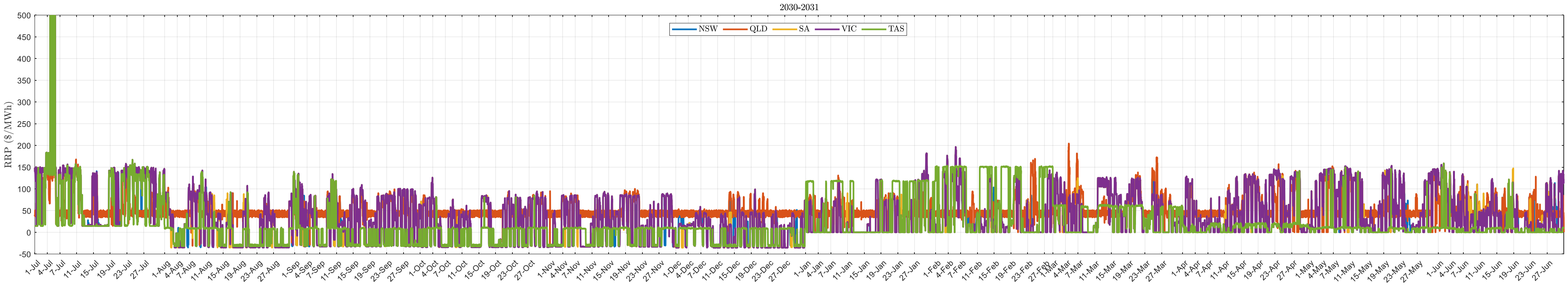


Figure 95: Example RRPs across the NEM in 2030-31 generated by the optimisation market dispatch model in (1)-(15).

8.7. Generation profiles

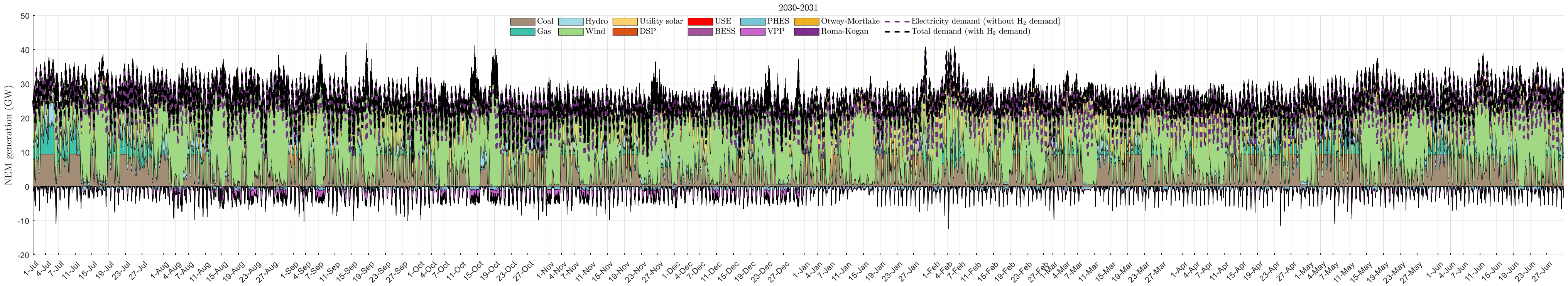


Figure 96: Example forecast operability across the NEM in 2030-31 generated by the optimisation-based market dispatch model in (1)-(15).

Appendix C

Compressor modelling

8.8. Overview

Compressors in the gas industry can be divided into three main types: rotary (rotary blowers, centrifugal), reciprocating (single acting, double acting), and jet, with centrifugal and reciprocating compressors being the most widely used [71]. A key technical difference between centrifugal and reciprocating compressors is the way that a compressor boosts the discharge pressure. In centrifugal compressors, the energy added to the gas to boost its pressure by adding kinetic energy to air particles using the centrifugal force and abruptly slowing them down, thereby build up pressure. By doing this in several stages, pressure can be increase to 13 MPa in lower compression machinery and as high as 20.5 MPa in 4-8 stage high compression turbomachinery, also known as multi-stage centrifugal compressors. Reciprocating compressors are positive displacement devices that utilise pistons powered by a crankshaft to compress gases. They are versatile, capable of handling a wide range of gas densities, and can rapidly adapt to changing pressure conditions. Discharge pressures in reciprocating compressors can be as high as 82.8 MPa for a typical compressor [72]. Various prime movers can be used to drive compressors, including gas turbines, steam turbines, electric motors, and gas engines. The choice of technology is primarily determined by economic factors [71].

8.9. Compression power

To find the total power input required for a compressor starts by finding the brake power P_b (MW), the adiabatic power P_a (MW), and the mechanical losses. Figure 97 illustrates a simplified compressor package along with its associated power.

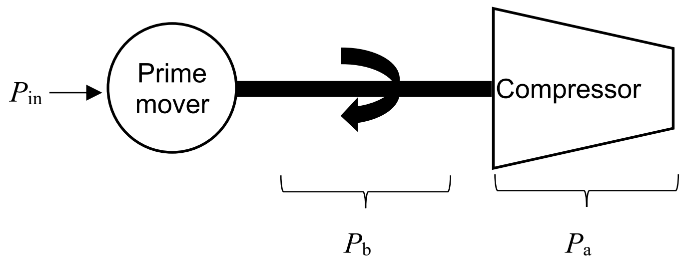


Figure 97: Generic diagram of a compressor.

The power required to compress gas with mass flow rate m_c (kg/s) under an adiabatic process is given by [73]

$$P_a = \frac{m_c R_s T Z_i \gamma}{\eta_a(\gamma - 1)}\left[\left(\frac{\mathcal{P}_j}{\mathcal{P}_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]. \tag{16}$$

The adiabatic efficiency can range from 0.75 to 0.85 [72], whereas the mechanical efficiency of the driver, given by

$$P_b = \frac{P_a}{\eta_m}, \tag{17}$$

can range from 0.95 to 0.98 [72]. Combining (16) and (17), the brake power can be written as

$$P_b = \frac{m_c R_s T Z_i \gamma}{\eta_o(\gamma - 1)}\left[\left(\frac{\mathcal{P}_j}{\mathcal{P}_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right], \tag{18}$$

where $\eta_o = \eta_a \eta_m$ is the overall compressor efficiency (excluding prime mover efficiency). Since $m_c = \rho_\circ q_c$ and $\rho_\circ = \mathcal{P}_{\text{st}}/Z R_s T_{\text{st}}$, the brake power can be written as a function of the volumetric flow rate as follows:

$$P_b = \frac{q_c T Z_i \gamma \mathcal{P}_{\text{st}}}{\eta_o(\gamma - 1) T_{\text{st}}}\left[\left(\frac{\mathcal{P}_j}{\mathcal{P}_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]. \tag{19}$$

Equations (18) and (19) can now be used to find the brake power of both reciprocating and centrifugal compressors.

8.10. Fuel or energy consumed by the prime mover

For electrically driven compressors (EMD), the power P_{in} (MW) consumed by the prime mover can be written as

$$P_{\text{in}} = \frac{P_b}{\eta_p}, \tag{20}$$

where η_p is the prime mover efficiency. On the other hand, in the case of gas turbines as prime movers, the fuel (m^3/s) consumed by the turbine is described by

$$q_f = \frac{P_{\text{in}}}{LHV}, \tag{21}$$

where LHV (MJ/m^3) is the lower heating value of the gas.

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