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RESEARCH ARTICLE

Evaluation of Australia's Generation-Storage Requirements in a Fully Renewable Grid With Intermittent and Flexible Generation

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ABSTRACT Energy storage is crucial for grids with high renewable penetration to ensure reliable power supply during low renewable generation periods and address the intermittency associated with weather-dependent resources. However, sizing grid-scale storage presents challenges due to its interdependence on renewable generation and load profiles. This paper investigates the minimization of storage requirements for Australian grids as a case study in a fully renewable scenario and examines how inflexible generation (such as solar and wind) and flexible generation (such as hydro) affect the capacity requirements. Investigating the role of generation technology in sizing storage is paramount for a fully renewable grid and, therefore, sets this work apart from previous studies that primarily focused on grid capacity expansion planning. Moreover, unlike studies that rely on simulated profiles, our study distinguishes itself by utilizing high-resolution real-world generation data from existing generators. We extend our analysis to the economic trade-off between investing in increased storage versus intentional excess renewable generation. Subsequently, the optimum generation-storage requirement is analyzed, and regional requirements with and without interconnectors are estimated. Finally, we analyze storage annual utilization and present a sensitivity analysis to variations in technology costs. The quantitative results suggest that optimal storage size is contingent upon the renewable mix, and while solar generation is cost-competitive, higher contributions from wind generation and strategic dispatch of hydro generation are required to achieve an optimum generation-storage solution. We show that storage with a power capacity slightly lower than the mean annual demand with a duration of one day is required for Australia's National Electricity Market (NEM); in absolute terms, there exists a storage requirement of 18.5—21.5 GW and 400—770 GWh for a fully renewable grid. These findings underscore the importance of carefully balancing the renewable mix to achieve an efficient and cost-effective grid. Based on estimated future costs for long-duration storage and generation technology, the optimum generation-storage solution will translate into an investment of approximately 9.8% of the country's Gross Domestic Product (GDP)—this investment is achievable when amortized over 10–15 years for the transition to a near-100% renewable grid.

INDEX TERMS 100% renewable electricity grid, Australian energy transition, energy economics, long-duration energy storage, storage optimization.

NOMENCLATURE

Parameters

Δt	Sampling interval, $\Delta t = 1/12$ h.
η_c	Charging efficiency of the energy storage.
η_d	Discharging efficiency of the energy storage.
max	Superscript identifying maximum value over analyzed duration.
min	Superscript identifying minimum value over analyzed duration.
C^e_{ES}	Cost per unit of rated storage energy capacity.

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C^{p}_{ES}	Cost per unit of rated storage power capacity.
C_S	Cost per unit of rated utility-solar power capacity.
C_W	Cost per unit of rated wind power capacity.
N_T	Number of time points, $N_T = 366 \cdot 24/\Delta t = 105,408$.
P_S	Nameplate capacities of utility-solar PV generators.
P_W	Nameplate capacities of wind generators.
P^{0}_{gt}	Actual power from utility-solar and wind generators at time t.
r	Superscript for individual regions in the national electricity market.
t	Time, $t = k\Delta t, k = 1, 2, \ldots, N_T$.
Set	
$\mathcal{G}$	Set of set of all the solar and wind generators.
$\mathcal{I}$	Set of all the interconnectors.
$\mathcal{R}$	Set of all the regions of the NEM.
$\mathcal{S}$	Set of all the solar generators.
$\mathcal{T}$	Set of all time-samples.
$\mathcal{W}$	Set of all the wind generators.
Variables	
α	Percentage of allowable over-capacity.
β_g	Scaling factor for generator g output.
CF_S	Average capacity factor for utility-solar.
CF_W	Average capacity factor for wind.
E_G	Total electricity generated over analyzed period.
E_L	Total electricity consumed over analyzed period.
E_η	Total energy lost due to storage inefficiency.
$E_{\mathrm{ES}_{\max}}$	Peak assumed for the storage.
$E_{\mathrm{ES}_{\min}}$	Depth proposed for the storage.
E_{ES}	Energy to or from storage.
E_I	Total energy traded between regions over period.
E_X	Total energy curtailed over period.
EP_c	Energy to power ratio of storage.
$P_{\mathrm{SW}t}$	Power output for scaled generation.
P_{ct}	Charging power of ESS at time t.
P_{dt}	Discharging power of ESS at time t.
P_{Gt}	Total renewable power generated at time t.
P_{Ht}	Power output from hydro generators at time t.
P_{It}	Power from interconnector at time t.
P_{Lt}	Net Demand at time t.
P_{Xt}	Excess power output for curtailment or utilization at time t.

I. INTRODUCTION

Global renewable electricity generation capacity has surpassed 2,972 GW as of 2020, comprising 1,328 GW hydropower, 738 GW solar photovoltaic (PV), and 702 GW wind generation [1]. In 2020, renewables contributed approximately 29% of global electricity generation, representing a 1.7% increase from the previous year [2]. Furthermore, projections by the International Renewable Energy Agency (IRENA) suggest that renewables have the potential to fulfill more than 80% of global electricity demand by 2050, with solar and wind power alone comprising 52% of total generation [3]. Given that the power sector is responsible for over one-third of global annual emissions, decarbonization through renewable energy technologies becomes crucial in mitigating emissions across various sectors, including transportation, industry, and agriculture [4].

Numerous studies have emerged in the past decade advocating for the feasibility of a fully renewable-powered grid. Some of these studies focus on specific regions [5], [6], [7], [8], while others adopt a global perspective [9], [10], [11]. Most researchers agree that achieving near-zero carbon emissions is a challenging but attainable goal, emphasizing the importance of managing the integration of wind and solar energy, given their stochastic variability and status as predominant renewable sources worldwide [12], [13], [14]. However, the transition from low to higher renewable penetration presents significant technical challenges related to power adequacy—maintaining a balance between supply and demand, as well as addressing other network difficulties arising from the intermittent nature of inverter-connected renewable sources. Unlike conventional dispatchable generators, variable renewable energy (VRE) energy outputs cannot be increased to meet demand because they are generally operated to maximize output. However, the generation from renewables may be curtailed to reduce output to balance decreasing demand, which implies energy wastage and increased energy cost due to reduced utilization. Therefore, the demand-supply balancing challenge intensifies as the penetration of renewables increases together with the retirement of conventional generators. Nevertheless, renewable generation is expected to increase as renewable production costs are lower than for fossil-fuelled generation[1] and more countries are committing to net-zero CO_2(e) emissions by the year 2050 [15]. Thus, it is essential to integrate solutions that may provide needed dispatchability to ensure supply-demand balance at a reasonable cost.

Various solutions are available to ensure demand-supply balance, including dispatchable renewable generators such as hydro and biomass, demand-side management (DSM) [16], gas-fired power plants with carbon capture and storage (CCS) [17], increased interconnection to leverage geographic diversity of renewable sources, and energy storage systems (ESS). The introduction of ESS is expected to contribute significantly to the solution of the demand-supply balancing problem aggravated by variability in power from VRE sources such as wind and solar. By charging during periods of surplus renewable power and discharging during times of deficit, storage systems provide the flexibility needed to achieve a demand/supply balance. However, sizing optimal

[1] The relative costs of renewable and fossil-fuelled generation in terms of total system cost is less clear-cut when all of the additional infrastructure required to support renewable generation, is taken into account. However, renewable costs are on a downward trajectory.

storage energy and power capacities to match renewable generation while ensuring cost-effectiveness is challenging. To reliably provide 100% of electricity demand from renewable sources, even during seasonal cycles and unpredictable weather events, longer duration energy storage (LDES) and/or higher solar and wind power capacities are required compared to what is typically needed to enhance renewable dispatchability.

This paper focuses on assessing the storage requirements for the continental multi-gigawatt-scale grid called the National Electricity Market (NEM) of Australia, incorporating inter-regional transmission links in a 100% renewable energy (RE100) scenario.[2] The electricity sector in Australia contributes one-quarter of annual emissions, followed by transportation (17.3%) and agriculture (13.5%) [18]. Almost two-thirds of Australia's electricity was produced from fossil fuels by 2022, with coal (black and brown) generation plants accounting for over 65%, and the remainder being supplied by gas-fired power stations [18]. Many of these conventional generators will be replaced with renewable ones in the near future due to age and decreasing economic viability; this is evident from the recent announcement to decommission the largest coal-fired power plant (2.8 GW) in Australia by 2025, seven years earlier than its previously planned closure [19]. The remaining coal-fired generators will eventually be closed between 2035 and 2051. Additionally, the Australian government has recently committed to reducing greenhouse gas (GHG) emissions by 43% from 2005 levels and to achieve 82% of annual electricity generation through renewable sources by 2030; this emphasizes the importance of energy storage for grid flexibility. This puts Australia at the forefront of the global transition, making it a global test case for how intermittent renewables are integrated into the energy system.

While previous studies have examined the storage potential for energy adequacy and proposed necessary storage capacities for the RE100 scenario, this research addresses several limitations. Firstly, we examine the reciprocal relationship between generation and storage capacities, examining the impact of generation mix on storage requirements and determining the required wind/solar ratio for optimum storage. This two-dimensional analysis is important to understand generation technology's role in sizing storage and therefore sets this work apart from previous studies that have mainly focused on grid capacity expansion planning. Secondly, it demonstrates that providing generation capacity beyond the annual demand significantly reduces storage capacity requirements and costs. Additionally, the study highlights the potential of strategically dispatching flexible hydro generation to meet demand peaks in minimizing storage needs. In contrast to many studies that heavily rely on dispatchable generators, such as biomass, hydro, or gas, to reduce storage requirements, this research considers limited generation flexibility. Finally, this study not only proposes an optimal generation-storage mix for both isolated and interconnected NEM regions but also conducts a sensitivity analysis to analyze the implications of cost variations.

II. LITERATURE REVIEW

The importance of grid-scale energy storage is widely accepted, especially with the increased penetration of renewables. Various energy storage mechanisms have been developed with the global energy storage capacity amounting to 19.1 GW [2] and 9 TWh [20] as of 2020. It is forecasted to reach over 270 GW and 13.35 TWh by 2026 [21] and grow to about 2 TW and 110 TWh by 2040 with 10% of all generated electricity stored [22]. Pumped hydro energy storage (PHES) is by far the most widely deployed technology, accounting for approximately 90% of global storage power [2], followed by electrochemical batteries (7.5%), and thermal storage (1.8%) such as molten salt storage systems integrated with concentrated solar thermal (CST) power. Furthermore, other storage technologies under development offer complementary characteristics.

Storage becomes crucial to ensure supply reliability when renewable penetration exceeds 50% [23]. A number of studies suggest that with renewables contributing over 75–80% of energy, long-duration seasonal storage equalling one day of average demand will be required [24], [25], [26]. However, relying on wind and solar to meet 100% of demand may require storage that lasts several weeks [14], [27]. Additionally, researchers have attempted to quantify the requirements of grid-scale storage for countries and continents with different mixes of generation and storage technologies [28], [29], [30], [31]; many of the technologies and applications are reviewed in [32] and [33] and optimization methods employed for grid-scale ESS are discussed in [34].

The authors of [35] proposed a low-cost generation fleet considering a renewable technology mix for the NEM to fully meet demand, with wind energy as the primary contributor and CST with storage, but not including small or large-scale ESS to minimize overall costs. Blakers et al. [36] conducted an energy balance analysis for a 100% RE scenario and suggested that pumped hydro be used as the primary storage technology, proposing an optimum energy storage capacity of 17 GW and 450 GWh (± 30%) for Australia. Subsequently, the study was extended by considering High Voltage Direct Current (HVDC) transmission lines across Australia to manage double demand for future grid [37].

Lenzen et al. [38] conducted simulations similar to Elliston's model [35] and proposed biofuel and CST technologies as the dominant suppliers in the generation mix. However, we argue that the analysis needs to be revisited in light of the current higher penetrations of hydro and rooftop PV, which exceed the assumed capacities in that study. Furthermore, the study did not consider utility-scale batteries due to their high cost at the time of the study. Previous works by authors in [35], [38], and [39] substantially relied on increased capacities of dispatchable sources such as hydro, biomass, geothermal, and CST to propose a 100% renewable

[2]This study does not include the region of Western Australia (WA) as historically it has been independent of the NEM.

grid (RE100). However, many of these technologies are considerably more expensive than solar and wind, making their large-scale implementation impractical. Furthermore, the current lower cost of solar generation compared to wind generation contradicts the assumptions made in those studies. Therefore, it is necessary to reassess these assumptions and revisit the optimum generation capacities with storage.

The Australian Energy Market Operator (AEMO) projects a storage requirement of 45 GW and 620 GWh by 2050 [40]. This estimation includes 30 GW of power compensated by virtual power plants (VPPs) and Vehicle to Grid (V2G) systems, while 15 GW by utility-scale storage. These capacities aim to meet a doubling in demand with a 97% renewable penetration, complemented by 9 GW of gas-fired generators. Notably, AEMO considers VPPs and V2G as dispatchable storage sources with substantial power capacity. Moreover, the AEMO does not consider a zero-emission scenario or low-carbon generation resources, such as nuclear and biogas-fired thermal generation. In contrast, the authors in [41] explore the potential of bioenergy resources combined with CCS and examine prospects of nuclear small modular reactors (SMRs) in Australia to provide firm generation; however, the study did not consider the potential of power-to-gas-to-power (PtGtP), particularly the utilization of hydrogen (via PtH_2tP).

Various factors must be considered when selecting storage technology, including efficiency, response time, capital and operating cost, lifetime, and duration. Batteries are typically employed in short-term storage ($\leq$ 4 hrs) applications to primarily assist in ancillary services such as frequency and voltage control. Lithium-ion (Li-ion) batteries are becoming increasingly popular in Australia due to their proven technical and economic performance [42], with proposed projects exceeding 14 GW and 22 GWh in 2022. However, integrating Li-ion batteries to balance the intermittency of wind or solar generation over six (6) hours is not cost-effective [43]. Note that PHES provides a cost-effective option for medium (4–16 hrs) and long-duration ($>$ 16 hrs) storage (up to days), which is required to deliver power during extended periods of low VRE supply. Though limited geographically and environmentally, recent studies have highlighted technologies that can expand PHES potential locations [44], [45]. Currently, the NEM has roughly 810 MW and 15,380 MWh of PHES capacity, and the Snowy 2.0 project (due to be completed in 2028) will offer 2,000 MW capacity and seven days of storage at rated output [46]. Additionally, PHES projects with a combined capacity of over 4.2 GW and 37 GWh are proposed as of 2022 [47]. Furthermore, power-to-gas-to-power technology, particularly PtH_2tP, though currently expensive is expected to become more affordable in the future and may offer greater flexibility and scalability than PHES while offering seasonal storage capacity [48], [49].

For grid decarbonization with 100% renewable energy penetration, we need cost-effective long-duration storage solutions, including PHES, flow batteries (zinc-bromide), and hydrogen storage; which can be scaled with power and energy capacities decoupled. These technologies must provide electricity for prolonged periods of multiple hours, days, or even weeks [22].

A. STATEMENT OF CONTRIBUTION AND NOVELITY

Building upon previous research [50], our study presents an optimization-based approach to investigate the effects of increasing VRE penetration (solar and wind) on storage requirements in Australia. The novel features of the study include the following:

- Utilization of high-resolution (5-min) actual 2020 data from the 89 exiting generators installed across the Australian NEM in contrast to simulated data traces. This enables us to incorporate various factors that are not accurately represented in simulated data, such as geographic variability in generator capacity factors, generation losses, and sub-hourly changes in generation patterns.
- Investigation of the reciprocal relationship between generation mix and storage capacities to understand the optimum share of wind and solar capacities for lower storage needs and overall investments.
- Incorporation of limited flexibility through strategic hydropower dispatch to reduce storage requirements.
- Modeling excess generation and demonstrating its cost-competitiveness up to an optimum factor.
- Estimation of regional generation and storage capacities for the Australian NEM in isolated and interconnected scenarios, along with curtailed and traded power.
- Investigation into storage utilization and sensitivity analysis of variations in component costs and storage efficiency.

By complementing existing studies, this paper offers valuable insights into reducing generation and storage requirements while maintaining energy and power adequacy in a high-renewable future.

The remainder of this paper is structured as follows: We first briefly introduce the Australian electricity market with generation and load profiles in Section III. Then, we explain the formulation of the optimized problem and assumptions for our study and simulation cases in Section IV. Subsequently, Section V presents the results of three primary optimal solutions. We then present an in-depth discussion of the results and their implications (Section VI). Finally, we summarise our findings in Section VII.

III. THE AUSTRALIAN NATIONAL ELECTRICITY MARKET (NEM)

The Australian Energy Market Operator (AEMO) runs the South and East Australian regional power grid, the National Electricity Market (NEM). The NEM comprises the interconnection of the Queensland (QLD), Victorian (VIC), New South Wales (NSW), including the Australian Capital Territory (ACT), South Australian (SA), and Tasmanian (TAS) grids. The NEM has a total generation capacity of 57 GW as of December 2020, fueled by coal, gas, wind, utility-solar, hydro, and other sources, excluding rooftop-solar, which is estimated to be 10.6 GW. Renewable sources, including rooftop solar, supplied approximately 26.5% of the grid's total annual energy consumption of around 200 TWh in 2020, while fossil-fueled sources provided the remaining share.

A. RENEWABLE GENERATION

Wind provided the largest share of 36% of renewable energy generation and met around 10% of the annual energy demand in 2020 for the NEM. This was followed by hydro and rooftop-solar generation, with each meeting 6.9% and 6.4% of the annual energy demand, respectively [18]. The generator technology's capacities and energy contribution as of 2020 are provided in Table 1, while the power generation profiles of wind and utility-solar, along with the monthly mean generation, are depicted in Fig. 1. Wind and solar generation follow seasonal variations on top of daily variations, with the lowest generation in the winter (June to Aug) and the highest generation in the spring (Sept to Nov); this contrasts the demand profile. Furthermore, solar and wind generation exhibit a negative correlation ($r = -0.273$) across the NEM, indicating complementarity between solar and wind throughout the day [51]. This can be observed in Fig. 1c and Fig. 1d, where a decrease in wind generation coincides with an increase in solar generation during midday hours. Different wind and solar sources installed across Australia have varied annual capacity factors; the recorded average capacity factor (CF) for utility-solar and wind farms are 23.34% and 33.82%, respectively, based on actual generation data for 2020.

Furthermore, hydro generation operates as a dispatchable renewable source, primarily from reservoirs, with a small portion of generation from run-of-river (ROR) turbines. Installed hydro capacities in VIC, NSW, and TAS exceed 2 GW in each region, with relatively low capacity in QLD and no substantial hydro plants in SA. The regional existing peak and energy demand for the modeled year are provided in the Appendix in Table 8.

TABLE 1. Cumulative nameplate capacities [52] and energy contributions to total demand as of 2020 [18] for australia.

Renewable	Solar	Wind	Hydro	Rooftop	Total
Capacity (MW)	4,857	6,660	7,636	10,150	29,303
Energy (%)	3.3	9.7	6.9	6.4	26.3

B. ELECTRICITY CONSUMPTION

Australia's electricity demand has been relatively stable over the past decade but is expected to rise due to electric vehicle (EV) adoption and industrial electrification. On the other hand, the grid has observed lower minimum demands due to the growing rooftop-solar generation. Load data for 2016 through 2020 indicate average peaks of approximately 34.5 GW from January to February and average annual mean demand of 21.6 GW. The 5-min demand profile for 2020 with monthly mean is presented in Fig. 2a with a peak demand of approximately 38 GW, while the weekly mean demand for 2016–2020 is depicted in Fig. 2b. Seasonal variation in demand is evident, with high peaks and low troughs in winter/summer and spring/fall, respectively.

IV. SYSTEM MODELING AND OPTIMIZATION ALGORITHM

We have utilized the actual power generation data of utility-solar, rooftop-solar, hydro, and wind generators from all the regions of the NEM. The regions represented by the set $\mathcal{R}$, comprise SA, VIC, NSW, QLD, and TAS. For optimization, linear programming (LP) is implemented using a publicly available toolkit library named PuLP and solved using the Gurobi solver [53]; the overall model is depicted in Fig. 3. The modeling is carried out for the entire NEM with the following two separate assumptions to determine the storage capacity requirements for each case.

- *Copper plate*[3] grid with aggregate load and storage neglecting interconnector capacity constraints and transmission losses. This provides conceptual insights into storage requirements under various generation scenarios and serves as a benchmark for the study.
- Interconnected grid in which the five NEM regions with the existing inter-regional links and associated capacity constraints are represented.

To represent the grid network $\mathcal{N}$, let i be an interconnector in the set $\mathcal{I}$ and r be a region in $\mathcal{R}$, then $\mathcal{I}(r)$ is the set of interconnectors that are incident on region r. Furthermore, let g be a utility-solar or wind generator in set $\mathcal{G}$, then $\mathcal{G}(r)$ is the set of generators in region r of network $\mathcal{N}$. Finally, let $\mathcal{S} \in \mathcal{G}$ and $\mathcal{W} \in \mathcal{G}$ be the sets of utility-solar and wind generators, respectively, and $\mathcal{G} = \mathcal{S} \cup \mathcal{W}$, then $\mathcal{S}(r)$ and $\mathcal{W}(r)$ are the sets of utility-solar and wind generators in region r, respectively.

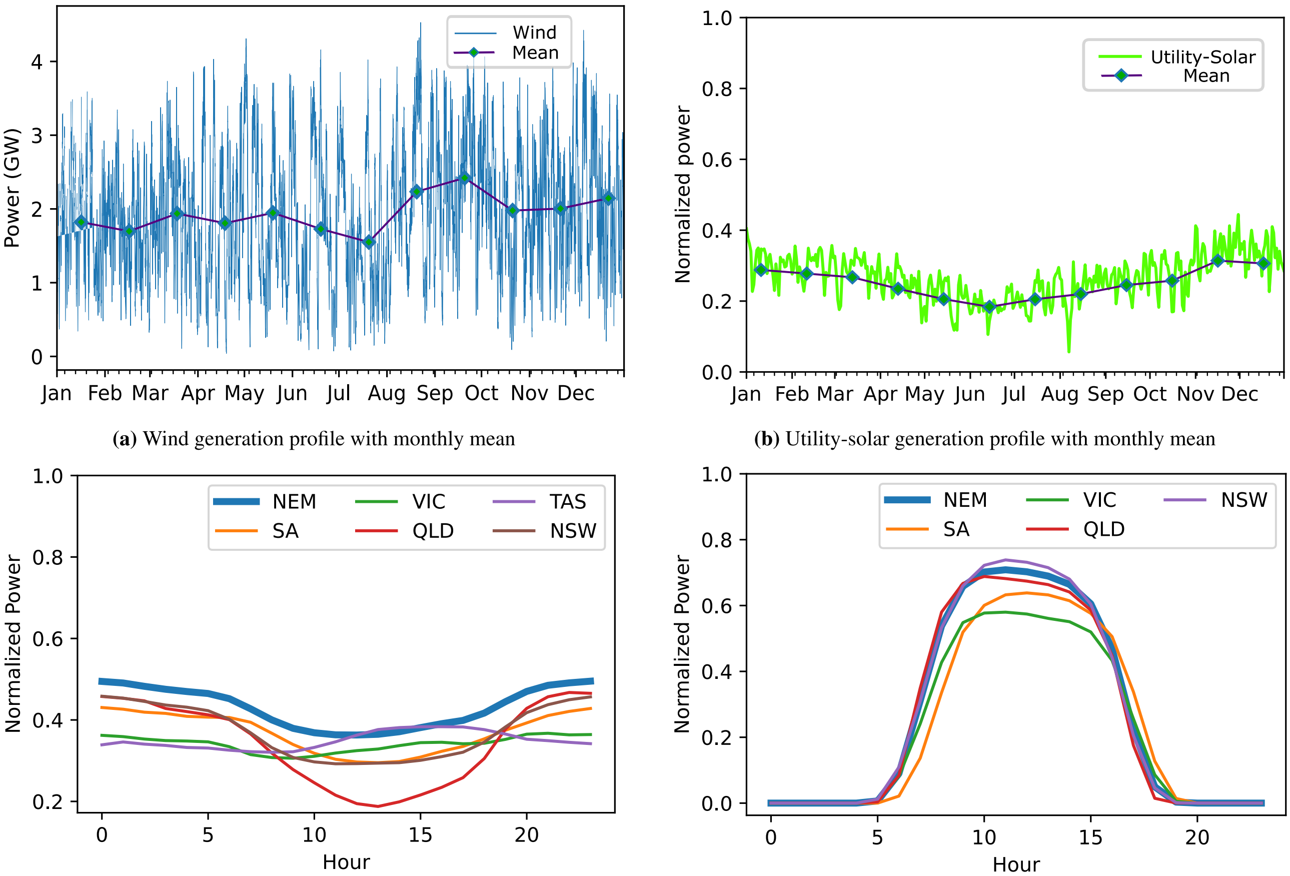
The actual power output from existing generator g, at time t is P^0_{gt}. This is scaled by the scaling factor (β_g) that is determined by an optimization algorithm to minimize the objective function while ensuring the constraints are met. The total utility-solar and wind generation $P^r_{\mathrm{SW_t}}$ in region r at time t is defined by Eq. 1,

$$P^r_{\mathrm{SW}t} = \sum_{g \in \mathcal{G}(r)} \beta_g P^0_{gt}, \tag{1}$$

where $\beta_g \geq 1$ to ensure that at least the actual existing generator capacity is utilized for model. Then,

$$P^r_{Gt} = P^r_{\mathrm{SW}t} + P^r_{Rt} + P^r_{Ht}, \tag{2}$$

[3]This is the idealization of the grid as a connection of all generators and loads by zero impedance conductors to a single node that provides a bound as a benchmark for comparison. The phrase *copper plate* is not used idiomatically in its usual English sense that alludes to printing plates. In this context, it is a literal translation of the German *Kupferplatte*, as it was the German literature that originally coined the term in this context. It is intended to evoke the mental picture of the grid as one ideal conducting plate to which all sources and loads are connected.



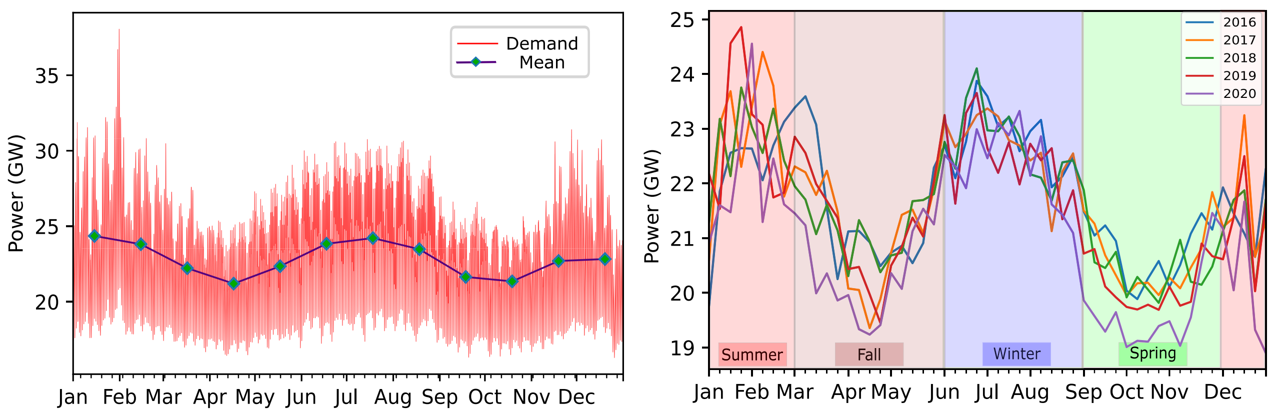
(a) Wind generation profile with monthly mean

(b) Utility-solar generation profile with monthly mean

(c) Wind daily mean generation

(d) Utility-solar daily mean generation

FIGURE 1. **Wind and utility-solar power generation profiles (a) and (b), with monthly mean for 2020. The normalized power (power at 5-min intervals divided by peak annual power) is plotted at 1-day intervals. The lowest mean generation for utility-solar and wind is recorded in the winter season (i.e., June and July, respectively). Figures (c) and (d) provide daily mean generation from wind and utility-solar across the NEM and its regions. Note that there is no existing utility-solar plant in TAS as of 2020.**



(a) Electricity consumption (5-min) profile with monthly mean

(b) Weekly mean demand for five years 2016–2020

FIGURE 2. **Electricity consumption profiles; the lowest monthly mean is recorded in fall and spring with peaks of maximum demand in summer and winter as in 2a, and similar behavior is evident in five previous years of demand as in 2b.**

is the total output from generating sources (excluding storage) within region r at time t, P^r_{Rt} is the total rooftop-solar generation, and P^r_{Ht} is the total hydro generation within region r at time t.

A. OBJECTIVE FUNCTION

In the mathematical model of optimization, the objective in Eq. 3 is to minimize the overall investment costs of generation (from solar and wind) and storage, considering power (GW)

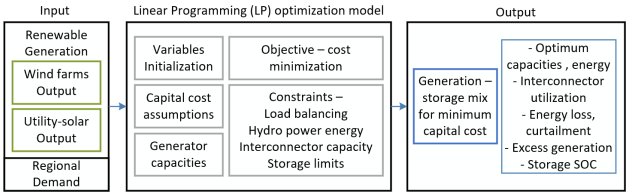


FIGURE 3. Linear Programming (LP) model with generation data from a total of 89 generators to minimize the overall cost of generation and storage.

and energy capacity (GWh), to meet system load in every 5-min interval.

$$\text{Min}\left(\sum_{r\in\mathcal{R}}(C_S P_S^r + C_W P_W^r + C_{\text{ES}}^e E_{\text{ES}}^r + C_{\text{ES}}^p P_{\text{ES}}^r)\right), \quad (3)$$

where C_S, C_W are the capital costs of solar and wind power plants (\$A/GW), C_{ES}^e is the investment cost of storage energy capacity (\$A/GWh), C_{ES}^p is the investment cost of storage power capacity (\$A/GW), P_S^r and P_W^r denote the nameplate capacities of additional generators required on top of that of the existing generators, while E_{ES}^r and P_{ES}^r are the storage energy and power capacity (rated) respectively for region $r \in \mathcal{R}$.

B. CONSTRAINTS

For each region r and time t, demand and supply must be balanced as represented by Eq. 4. The regional demand at any time P_{Lt}^r is met with regional generation and the combination of supply from inter-connectors P_{It}^r and power discharged from storage P_{ct}^r. For times when the generation exceeds the demand power, the excess generation is managed by exporting the electricity to other regions, charging the storage P_{ct}^r, and curtailment P_{Xt}^r,

$$P_{Bt}^r = P_{Gt}^r + P_{It}^r + P_{ct}^r + P_{dt}^r - P_{Xt}^r - P_{Lt}^r = 0, \quad (4)$$

where

$$P_{Bt}^r = 0 \quad \forall t \in \mathcal{T}, \quad \forall r \in \mathcal{R}, \quad (5)$$

$$P_{ct}^r \leq 0, \quad (6)$$

$$P_{dt}^r \geq 0, \quad (7)$$

$$P_{Xt}^r \geq 0. \quad (8)$$

We consider the simulation of oversupply to the grid to minimize storage capacities, as represented in Eq. 9. The over-capacity factor (α) defines the excess generation capacity installed so as to exceed annual demand by the factor α. The simulation is then performed to find the optimum over-capacity factor (α_{opt}^r) as a variable to achieve the least cost generation-storage estimation while meeting the model constraints,

$$E_G^r = \alpha^r E_L^r \quad \forall r \in R. \quad (9)$$

The operation of the storage in any region requires that the energy in the storage at any interval t, i.e. its state of the charge (SOC), be determined by charge P_{ct}^r and discharge P_{dt}^r power and the energy stored at the previous interval as represented by Eq. 10. To account for the losses due to storage inefficiencies, round-trip efficiency (RTE) of 70% is assumed; with charging (η_c) and discharging efficiency (η_d) of 80% and 87%, respectively. The storage SOC is given as,

$$E_{\text{ESt}}^r = E_{\text{ES}(t-1)}^r - \eta_c P_{ct}^r \Delta t + P_{dt}^r \Delta t/\eta_d \quad \forall t \in \mathcal{T} \quad \forall r \in \mathcal{R}. \quad (10)$$

The model produces the summary of key results that include, the minimum capital costs, total generation capacities in the system for solar and wind, the energy production from each set of generators, storage power and capacity required, state of the charge (SOC), power curtailment, and others. The model is simulated with various scenarios to understand the behavior of renewable generators and their impact on storage capacity requirements translating to investment capital needed.

Each region is interconnected across the NEM with capacity limitations defined by transmission equipment ratings or interconnector capabilities. The total power flow into region r from its neighbouring regions across interconnector $i \in \mathcal{I}(r)$ is represented in Eq. 11 with capacity limitations in Eq. 12,

$$P_{It}^r = \sum_{i\in\mathcal{I}(r)} P_{it}, \quad (11)$$

$$P_i^{\min} \leq P_{it} \leq P_i^{\max}. \quad (12)$$

In the following, Eq. 13 represents the annual energy generated from all the sources for any region, while the Eq. 14 presents the regional annual energy consumption,

$$E_G^r = \sum_{t\in\mathcal{T}}(P_{\text{SW}t}^r + P_{Rt}^r + P_{Ht}^r)\Delta t \quad \forall t \in \mathcal{T}, \quad r \in \mathcal{R} \quad (13)$$

$$E_L^r = (\sum_{t\in\mathcal{T}} P_{Lt}^r)\Delta t \quad \forall t \in \mathcal{T}. \quad (14)$$

The storage capacity required for the region is determined by evaluating the total depth of the storage, i.e. minimum energy value of the storage response curve ($E_{\text{ES}}^{r,\min}$). We arbitrarily define the maximum capacity of the storage as a constant to allow the algorithm to stop charging should the storage be fully charged, i.e., SOC is 100%. Thus, the storage capacity required is determined by Eq. 16. The storage is arbitrarily considered charged up to the maximum capacity at the beginning of the simulation, i.e. $E_{\text{ES0}}^r = E_{\text{ES}}^{\max}$,

$$E_{\text{ES}}^{r,\min} \leq E_{\text{ES}t}^r \quad \forall t \in \mathcal{T} \quad \forall r \in \mathcal{R}, \quad (15)$$

$$E_{\text{ES}}^r = E_{\text{ES}}^{r,\max} - E_{\text{ES}}^{r,\min} \quad \forall r \in \mathcal{R}. \quad (16)$$

Similarly, the power capacity required for regional storage is the maximum power discharged from storage at any interval across the simulation year. A further constraint is that the charging power is capped at the maximum power discharge to ensure charging and discharging capacities of the storage system are equal,

$$P_d^{r,\max} \geq P_{dt}^r, \quad \forall t \in \mathcal{T} \quad \forall r \in \mathcal{R}, \quad (17)$$

$$P_{\text{ES}}^r = P_d^{r,\max} = P_c^{r,\max} \quad \forall r \in \mathcal{R}. \quad (18)$$

With over-capacity, the excess power at times is far higher than that required to meet the regional demand, to charge the storage, and to meet inter-regional demand; and in such a case, the power is curtailed, which can potentially be supplied to power a discretionary load such as hydrogen electrolyzers to form another revenue stream. The optimal power generation mix integrated with the ESS is specified to provide electricity without loss of supply.

One calendar year with sampling interval of 5-min comprises 105,408 sample points (= 12-time points per hour × 24 hrs per day × 366 days per year[4]). The optimal power generation mix integrated with the ESS supplies at least the demand within each sampling interval.

C. DATA SOURCES

The electricity demand is met through a mix of commercially available and cost-effective renewable technologies, including wind farms, grid-scale utility-solar farms, rooftop-solar installations, hydroelectric power stations, and energy storage systems. However, the study does not consider other renewable sources such as geothermal, biomass, and ocean energy due to their limited large-scale generation capacity in Australia, although their potential to contribute to the renewable energy future is acknowledged [54]. Additionally, we excluded fossil fuel-based generation to model a fully-renewable grid.

The real-world historical data is obtained from the publicly accessible AEMO data archives [55] for 2020 as the most recent year for the current study. Furthermore, custom Python code is developed to pre-process the data and extract the dispatch capacities for renewable generators and regional consumption. It is worth noting that AEMO archives all the market data for several years, providing a comprehensive dataset for analysis.

1) SUPPLY

We incorporate the historical 1-year data from 89 utility-solar and wind plants commissioned before August 2020 into our optimization model. This data includes average generation dispatch at 5-minute intervals. The regional breakdown of existing generators, their cumulative capacities, and average capacity factors used for modeling are presented in Table 2. Additionally, hydro generation is modeled as a dispatchable source with conservative existing capacities, assuming that not many hydropower plants will be commissioned. Details of regional generator capacities, annual energy from existing solar and wind plants, and constraints on hydro generation are provided in the Appendix Table 7.

2) DEMAND

Demand in the NEM is reported on a regional basis at 30-min intervals and is therefore interpolated to achieve the exact resolution as the supply data. Demand reported by the grid operator is typically front-of-the-meter (FTM) demand and

[4]2020 is a leap year.

TABLE 2. Generator breakdown based on technology and regions for the optimization model.

Technology	Number of plants						Capacity (MW)	CF (%)
	SA	NSW	QLD	VIC	TAS	NEM		
Utility-solar	3	14	20	5	0	42	3,492	16.6–36.3
Wind	16	9	2	17	3	47	6,140	20.6–45.4

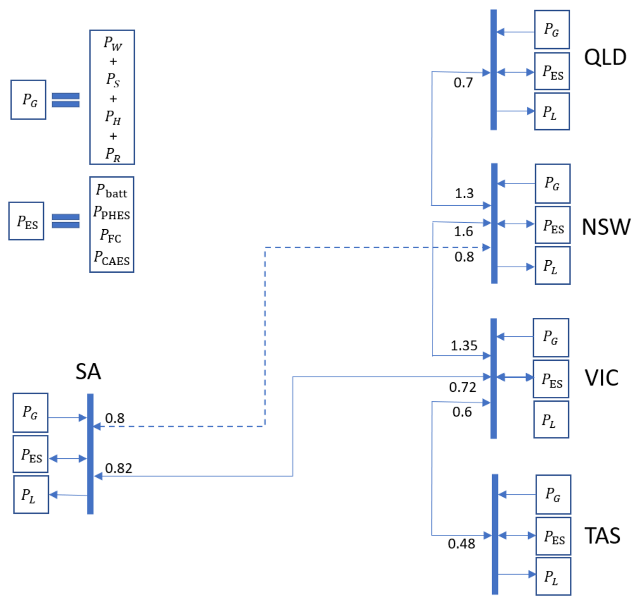


FIGURE 4. Schematic diagram of the NEM's regions with existing (represented by solid lines) and under-construction (represented by dashed line) interconnectors. For RE powered grid, the regional generation is represented by only renewable generators. In contrast, the storage is represented by aggregated regional storage that may combine different storage technologies such as batteries, PHES, PtH_2tP, and CAES. The indicated regions are South Australia (SA), Queensland (QLD), New South Wales (NSW), Victoria (VIC), and Tasmania (TAS).

does not include the demand satisfied by the rooftop-solar and battery installations. Therefore, in our simulation, we have aggregated the two demands to model the underlying demand of energy consumers. The regional peak and energy demand for the modeled year are provided in the Appendix in Table 8.

3) INTERCONNECTORS

The five regions of the NEM are interconnected via transmission lines as depicted in the schematic diagram in Fig. 4. The numbers on each inter-connector represent the assumed capacity limits in gigawatts (GW), which are the nominal physical limitations of these networks and are input to the simulation model. Two interconnectors exist between each region of QLD/NSW and SA/VIC; however, only one is shown for simplification with the capacities aggregated. The dashed line connecting SA and NSW represents a transmission line under construction at the time of research; hence, it is included in our model. The diagram also illustrates the regional generation and storage considered in the model to meet its demand.

D. ECONOMIC ASSUMPTIONS

The cost of storage in power systems is influenced by several factors, including round-trip efficiency, power and energy capacity, hours of operation, degradation over the lifespan, and the range of services it supports, such as ancillary and auxiliary services. For short-term storage solutions such as Li-ion batteries with durations of up to 4 hrs, the cost is primarily associated with power capacity rather than energy capacity. The energy capacity cost increases linearly with duration, while the power capacity cost decreases [22], [56]. Conversely, storing additional energy incurs low marginal costs in long-duration energy storage (LDES) technologies exceeding 8 hrs because energy and power capacities can be decoupled. This decoupling allows for scalable energy capacity without needing proportional power capacity expansion. In this paper, a techno-economic analysis for storage is excluded, and instead, an approximation based on the average costs of various LDES technologies is used. Cost estimates for utility-scale solar, wind, and storage systems in 2030 can be found in Table 3. Unless otherwise specified, the 'reference' costs are utilized in simulations, assuming an exchange rate of A\$1.00 = US\$0.75. The high and low-cost assumptions encompass the variability in future cost estimates for different LDES technologies, such as PHES, CAES, and PtH_2tP, which have the potential for significant cost reductions compared to generation technology costs. The high-cost scenario assumes lower technological developments, resulting in significantly higher storage power and energy costs. Conversely, the low-cost scenario reflects substantial cost reductions. Similarly, solar technology costs are anticipated to experience a more substantial reduction compared to wind. These cost scenarios are used to perform sensitivity analysis and assess the generation-storage requirements.

TABLE 3. Capital Expenditure (CAPEX) cost assumptions in australian dollars (AUD) for the year 2030 based on data from [22], [56], and [57].

Type	High	Low	Reference
Solar ($A/kW)	1,189	768	1,120
Wind ($A/kW)	1,910	1,746	1,828
Storage Power ($A/kW)[a]	3,359	800	1,200
Storage Energy ($A/kWh)[a]	140	6	30

[a] Cost of storage with the duration of 24 hrs is assumed.

E. STUDY LIMITATIONS

The analysis does not consider generation reserve for outages, assuming 100% reliability of all generation sources. However, downtime of generators necessitates additional generation capacity to compensate for supply loss. Similarly, additional storage facilities will be required to account for outage times. Additionally, the study's generation costs do not incorporate grid integration expenses and excess generation is assumed to be a cost instead of income that could be potentially derived from hydrogen production, for example. It is important to note that a comprehensive storage solution would involve a mix of multi-timescale storage technologies, but this paper does not determine this mix and is an open question for future research. Moreover, the feasibility of storage meeting the dP/dt requirement is not assessed.

Furthermore, the study does not include scaling of rooftop-solar, although it acknowledges rooftop-solar's potential for significant capacity expansion. Rooftop-solar installations have higher investment costs than utility-solar, and they currently benefit from government subsidies and feed-in tariffs. Moreover, the increasing deployment of distributed energy resources (DER) impacts grid stability by reducing operational demand in the daytime. Also, behind-the-meter (BTM) batteries are more expensive than utility storage. We assume that the additional rooftop-solar installations will offset additional demand resulting from EV adoption through smart charging and demand-side management (DSM).

The study is based on generation data from a single year, which limits the assessment of inter-year variability and may underestimate the storage requirements. Furthermore, the nominal capacities of interconnectors are considered secure, meaning that if one interconnector experiences an outage, the remaining interconnector can handle the load. In the rare event of an outage, interconnector flow would be reduced to ensure system security. However, the implications of such outages are not considered in this analysis due to their infrequency, short duration, and unpredictable occurrence.

V. RESULTS OF THE SIMULATIONS

To begin with, we simulate a *copper plate* grid with only solar and wind generation to understand the theoretical bound of this critical generation mix on storage requirements as described in Section V-A. Subsequently, in Section V-B, we simulate the same grid with excess generation capacity using existing hydro capacities to understand the cost benefits of hydro generation in reducing storage requirements.

This is followed (in Section V-C) by a simulation of the grid with regions connected by interconnectors to understand the regional optimum generation-storage. Finally, sensitivity analysis on the cost is carried out in Section V-E.

A. MORE WIND OR SOLAR?

We analyze the impact of renewable generation technology on storage power, energy capacity requirements, and overall cost using a *copper plate* grid with only solar and wind generators. Our model assumes a fully efficient storage system, ignoring storage inefficiencies. The modeling for storage power/energy capacity optimization (minimization) produces the following key results,

1) ENERGY CAPACITY OPTIMIZATION

To minimize energy storage capacity, the optimal wind and solar generation penetration is 52% and 48%, respectively, of the overall annual demand. Figure 5 shows variations in the optimal energy capacity, associated power capacity of storage, and the required storage investment capital for different wind and solar penetrations. If the Australian electricity demand were to be met entirely by additional utility-solar, the country would require $\approx$ 12.4 TWh storage capacity, whereas with additional wind generation alone, would require only around 4.5 TWh, a third of the previous case; due to wind's ability to blow at night when the sun does not shine. The optimum penetration mix (wind 52% and solar 48%) would need an estimated 4 TWh in storage capacity and approximately A$152 billion investment cost.

2) POWER CAPACITY OPTIMIZATION

The modeling results indicate that wind should contribute 91% and solar 9% to the overall annual demand. Storage power capacity varies from 30.8 GW for a solar-dominant to 22.5 GW for a wind-dominant grid. In a solar-dominant system, high power capacity storage is necessary to meet nighttime demand because of the diurnal generation pattern of solar power. Therefore, the power capacity at the optimum penetration mix (wind 91% and solar 9%) to minimize storage power is 22.25 GW; however, this costs approximately over A$250 billion due to the very high associated storage energy capacity.

For a 100% renewable electric system, the storage energy component appears to drive investment costs. Thus energy capacity optimization yields the least-cost solution with solar and wind penetration at 48% and 52%, respectively, and storage requirements of approximately 26.8 GW and 4 TWh. Fig. 5 demonstrates that storage costs vary minimally with wind penetration above 40%. This is important because it implies that as long as wind penetration is at least 40%, the total cost of the RE100 grid is near optimal. However, the costs are susceptible to the proportion of wind and solar below 40% of wind penetration and escalate considerably as the ratio of wind decreases. It is evident that optimum storage power and energy capacities will require different penetrations of solar and wind due to a reciprocal relationship between storage requirements and generation technology.

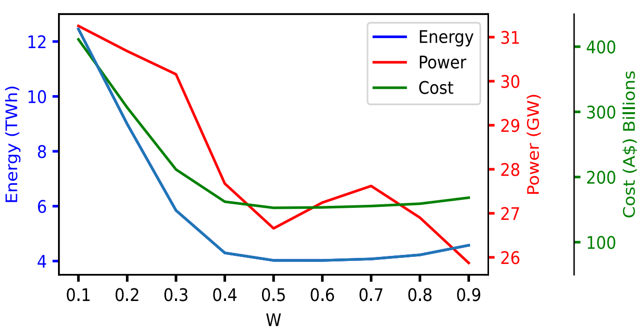


FIGURE 5. Energy capacity optimization - Storage energy and power capacity achieved for a renewable penetration of 100% with different proportions of wind (W). The proportion of solar is $S = 1 - W$. The associated storage costs are indicated as well.

3) STORAGE POWER AND ENERGY CAPACITY INTERRELATIONSHIP

We further analyze the relationship between generation and storage capacities by focusing on storage components. We model storage power capacity against constrained energy capacity and vice versa. In the process, we record the respective wind and solar generators' nominal capacity (GW) ratios (wind : solar). The results are plotted in Fig. 6 for energy-constrained simulation, where at point A, for example, the cumulative capacity of wind and solar is 42 GW and 32 GW, respectively, with a wind-to-solar ratio of 1.3, requiring storage of 4.6 TWh and 24.6 GW. The findings suggest that a high wind-to-solar ratio can lead to lower power capacity but higher energy capacity storage. However, the optimum values for power or energy optimization alone may not be practical or economical, so we consider investment costs to find the optimum capacities in subsequent modeling. Notably, generating 100% of electricity from wind and solar is not an effective way to reduce storage requirements. Instead, the scenario provides insights into the desirable wind and solar mix to minimize storage needs. Incorporating dispatchable RE generation significantly reduces the need for storage, as evident from studies and our simulations presented in V-B.

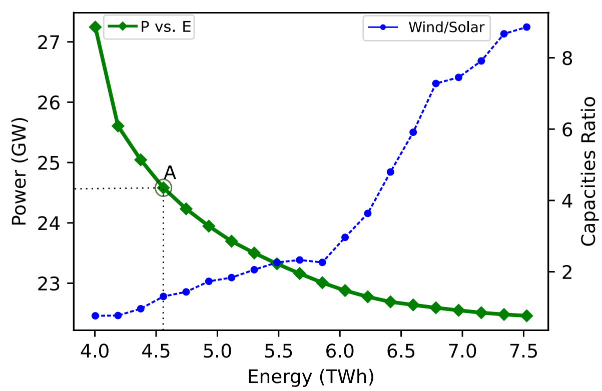


FIGURE 6. Storage power and energy capacity relationship for energy capacity-constrained optimization (green line) with installed wind and solar capacities ratio (blue line). The ratio of wind capacity divided by solar capacity is taken here. For example, at point A, the storage requirement is 4.6 TWh and 24.6 GW with cumulative capacities of wind to solar at the ratio of 1.3.

B. DISPATCHABLE AND EXCESS GENERATION'S IMPACT ON STORAGE REQUIREMENTS

This Section discusses the generation, storage, and total cost requirements with hydro generation in the *copper plate* grid model, considering excess generation capacity. It is assumed that storage with a round trip efficiency (RTE) of 70% provides all demand balancing needs. The study limits the scaling factor (β) of generator output in any one region to ensure that each region will have annual generation equal to at least its annual demand. The results show that as we increase the generation, the storage requirement tends to decrease with increased spilled energy. However, after a certain level of over-capacity, the overall investment costs increase. For each case, we find the optimum over-capacity factor (α_{opt}), which results in the least-cost generation-storage solution.

Two optimization scenarios are considered: the first scenario (A) utilizes the actual hydro generation dispatch for the modeled year, while in the second scenario (M), the hydro dispatch is optimized by using it as a peaker plant to meet peak demands and ultimately reduce the overall power capacity of storage. This latter scenario represents the minimum-cost optimal generator-storage solution incorporating copper plate assumptions and over-capacity modeling. It is important to note that practical constraints, such as duty cycles, seasonal water release obligations, etc., are not considered when optimizing the hydro dispatch in this scenario.

The results for generation capacities (solar and wind) and storage capacities are tabulated in Table 4, while the cost is compared in Fig. 7. The results suggest that optimizing hydro generation dispatch reduces the storage requirement by a factor of about 0.53 (47% reduction). However, the wind and solar generation capacities are comparable for both scenarios with lower wind capacity required. The optimized hydro scenario only reduces the cost by a factor of 0.84 (16% decrease), with roughly 67% of the capital invested in generation. Moreover, a slight over-generation capacity of 105% results in a storage size reduction of more than half with an overall cost reduction of over 40%.

It is also evident that increasing the excess generation capacity above the optimum factor (α_{opt}) results in higher costs as the increase in the generation cost is not outweighed by the decrease in storage cost. With hydro dispatch optimization, hydro not only provides backup for peak demands, which reduces the required power capacity, but it also charges the storage system, allowing for a smaller required energy capacity.

TABLE 4. New generation capacities (nameplate) of renewable energy sources over existing capacities for various excess generation factor (α). The associated storage requirements and total system costs are shown. The results are provided for the actual and optimized hydro dispatch with bold values representing optimum over-capacity generation (α_{opt}), respectively. (Refer to Table 7 for regional hydro generation capacities).

Hydro Generation	α	Solar (GW)	Wind (GW)	Storage (GW)	Storage (GWh)	Cost (A$bn)
Actual (A)	1.00	13.8	37.4	23.4	8324	361
	1.05	15.3	39.3	23.5	3375	218
	1.10	16.8	38.6	22.0	877	142
	1.15	**20.6**	**36.6**	**21.7**	**725**	**138**
	1.20	23.4	38.4	21.6	564	139
	1.30	29.3	38.6	20.7	492	143
Optimized (M)	1.00	12.2	37.7	19.6	5839	281
	1.05	14.6	39.6	19.8	1454	156
	1.08	**21.0**	**31.8**	**18.6**	**382**	**116**
	1.10	20.3	33.9	18.5	367	118
	1.20	29.7	30.9	18.9	323	122
	1.30	36.0	34.3	18.3	239	132

C. REGION-BASED STORAGE WITH INTERCONNECTORS

Instead of relying on a single storage solution to meet the aggregate demand, the scenario involves using inter-regional interconnectors with dedicated storage in each region. The annual energy generation in each region must be sufficient to meet its annual energy demand. All regional storages solutions are 70% efficient, and interconnectors have constraints on power dispatch, as previously represented in Fig. 4. The simulations determine the optimum over-capacity factor (α_{opt}) for individual regions, with and without interconnectors to provide insight into the effect of inter-regional power flows in reducing storage requirements. The results are tabulated in Table 5.

The results reveal several important insights; key observations are as follows: (i) The optimum overcapacity generation for each region differs based on the share of generation and storage required to meet demand. (ii) Interconnectors provide a means for power exchange between regions, thus lowering VRE generation and storage capacities. Compared to an interconnected grid that requires an additional generation capacity of 57.4 GW and storage capacity of 19.3 GW and 455 GWh, the isolated regions will need an additional generation capacity of 68 GW and storage of roughly 25 GW and 650 GWh. (iii) In the extreme scenario of a system without interconnectors, the storage energy capacity required is about 1.4 times higher than that of the system with interconnectors. Moreover, an additional 18.5% generation capacity is needed to cater to isolated grids. (iv) Storage duration, energy curtailment (E_X), storage losses and average SOC of regional storage are lower for the interconnected system. (v) Finally the total cost saving of the interconnected system compared to the disconnected system is about $A26 billion. This provides insight into the potential benefit of interconnection.

With transmission lines represented, an average of 112% excess-generation across the NEM is required to have the optimum generation-storage solution with additional solar and wind capacities of around 27 GW and 30 GW, respectively. The highest excess generation is proposed for QLD at 123%, followed by VIC. Net energy transfer across regions (E_I) results in NSW importing up to 8% (6.14 TWh) of the region's annual demand, followed by SA importing upto 3% of SA's annual demand. Moreover, VIC exports roughly 9% of total generated energy, while TAS has net zero trade. Roughly 5.4% of the additional 12% generation is lost (E_η) due to storage inefficiency, and 6.5% is curtailed (E_X).

There is significant variation in capacity factors (CF) of existing generators, with solar (CF_S) ranging from 16.6% to 36.3% and wind (CF_W) from 20.6% to 45.4%. However, the average CF of the scaled generators is 21% and 39% for solar and wind generation, respectively. This means that as long as new installations have an average CF above the simulated ones, the generation-storage solution proposed will be valid. Finally, no storage is required for Tasmania (TAS) due to extensive hydro reserves and hydro generation capacities. The storage response (SOC) for each region is plotted in Fig. 8, showing the varied response for each regional storage across the year of operation and storage cycles, specifically lesser storage utilization is evident in spring and fall due to significant renewable generation.

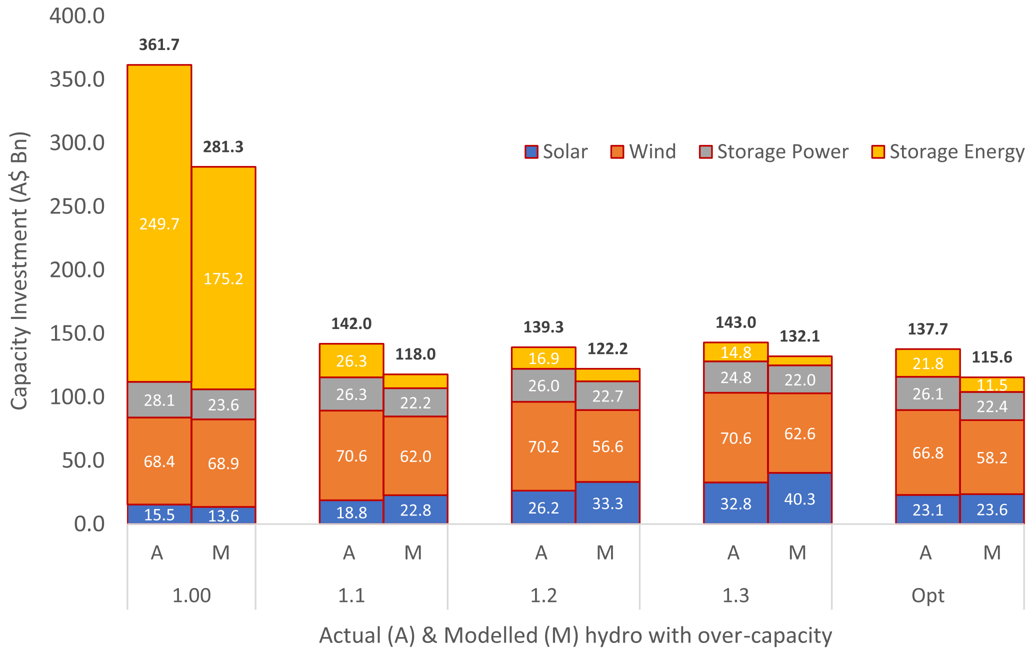


FIGURE 7. Stacked bar graph of new capacity investment costs. For actual hydro dispatch, the optimum over-capacity generation ($\alpha_{opt} = 1.145$) results in investment costs of A$137.7 billion compared to optimized hydro dispatch that requires lower over-capacity generation ($\alpha_{opt} = 1.078$) and lower investment costs of A$115.6 billion. The costs breakdown for storage and generation is also included for intentional over-capacity up to 130% ($\alpha = 1.3$).

TABLE 5. Optimal minimum-cost generation-storage requirement for the Australian regions without (A) and with (B) interconnectors.

(A) No Interconnector																
Region	α_{opt}	Solar (GW)[a]	Wind (GW)[a]	Storage (GW)	Storage (GWh)	EP_c (h)	Cost (A$bn)	Gen (TWh)	Wind [e] (TWh)	Solar [ee] (TWh)	SOC (%)	E_X (TWh)	E_η (TWh)	CF$_W$ (%)	CF$_S$ (%)	E_I (TWh)
SA	1.66	3.02	2.84	2.94	90.7	30.9	14.8	23	14.6	8.36	90.2	8.46	0.70	37	22	-
NSW	1.26	12.1	14.8	8.66	220	25.4	51.6	91.0	53.9	34.9	77.0	14.8	3.92	38	27	-
QLD	1.27	15.3	7.15	8.34	221	26.5	46.9	74.2	29.6	44.1	74.7	10.7	5.19	44	26	-
VIC	1.17	4.40	8.25	4.77	122	25.6	29.4	54.2	34.3	17.6	70.0	5.53	2.35	38	35	-
TAS	1.00	0.00	0.20	0.00	0.00	0.00	0.36	10.3	2.20	0.20	0.00	0.00	0.00	40	-	-
Total	1.26[b]	34.8	33.2	24.7	654	26.5[c]	149	252	135	105	78.0[d]	39.5	12.2	39[d]	22[d]	-
(B) With Interconnectors between regions																
Region	α_{opt}	Solar (GW)[a]	Wind (GW)[a]	Storage (GW)	Storage (GWh)	EP_c (h)	Cost (A$bn)	Gen (TWh)	Wind [e] (TWh)	Solar [ef] (TWh)	SOC (%)	E_X (TWh)	E_η (TWh)	CF$_W$ (%)	CF$_S$ (%)	E_I (TWh)
SA	1.00	0.00	1.93	1.15	33.6	29.3	5.91	13.81	11.3	2.51	69.1	0.00	0.386	35.8	21.7	0.39
NSW	1.03	11.1	10.8	6.38	140	22.0	44.0	74.2	40.1	31.9	65.7	4.37	3.55	38.0	26.5	6.04
QLD	1.23	13.0	7.60	7.64	169	22.1	42.6	71.9	31.2	40.1	65.0	7.10	5.10	44.5	31.3	-1.35
VIC	1.19	3.00	9.85	4.14	112.6	27.2	29.7	54.9	39.5	13.1	68.8	1.67	1.81	37.0	35.0	-5.08
TAS	1.00	0.00	0.20	0.00	0.00	0.00	0.36	10.3	2.20	0.20	0.00	0.00	0.00	40.0	-	0.0
Total	1.12[b]	27.0	30.4	19.3	455	23.6[c]	122.6	225.1	124.2	87.9	67.2[d]	13.2	10.8	38.1[d]	28.6[d]	0.00

[a] The new capacities required for utility-solar/wind. Existing capacities are provided in Table A-1
[b] Total NEM generation divided by total NEM demand
[c] Overall storage energy capacity divided by storage power capacity
[d] The number is an average
[e] Total energy generated from existing and new generators
[f] Total energy generated from utility-solar and existing utility-rooftop generators

D. STORAGE UTILIZATION CURVE

The regional residual load curves offer valuable insights into effective storage utilization. As the generated power is temporally shifted by charging storage, not all available power can be charged due to the limitations of charging capacities; consequently, some power needs to be curtailed. The duration curves in Figure 9 illustrate the storage utilization and the duration of excess available power. The solid curves represent the storage utilization, while the dashed curves represent the duration of excess available power, indicating the percentage of the year when power is charged, discharged, or curtailed. In QLD with the storage requirement of 7.6 GW, for example, the storage discharge must exceed 6 GW for roughly 4% of the year (equivalent to 14 days or 350 hrs) to meet demand, whereas it should exceed 4 GW for about 15% of the year. Additionally, QLD experiences excess generation potential for approximately 15% of the year, necessitating curtailment or alternative utilization. As excess generation increases, the positive residual load duration decreases, indicating a higher accumulation of yearly surplus and reduced reliance on storage or other dispatchable supply.

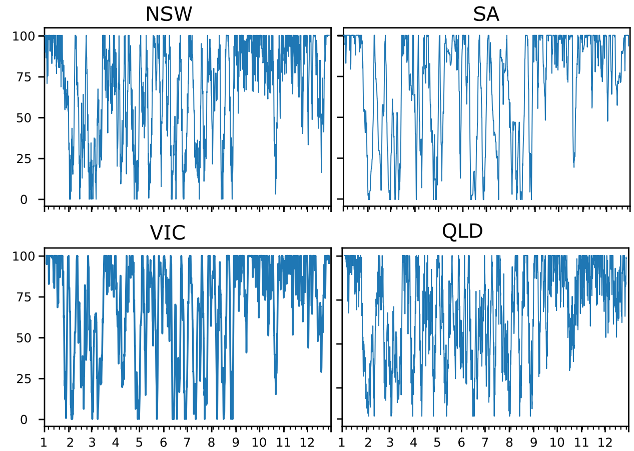


FIGURE 8. **SOC (%) of storage for NEM regions across the year of simulation. (Note: Tasmania (TAS) has no storage requirement due to sufficient dispatchable hydro generation capacity and imports during demand deficit).**

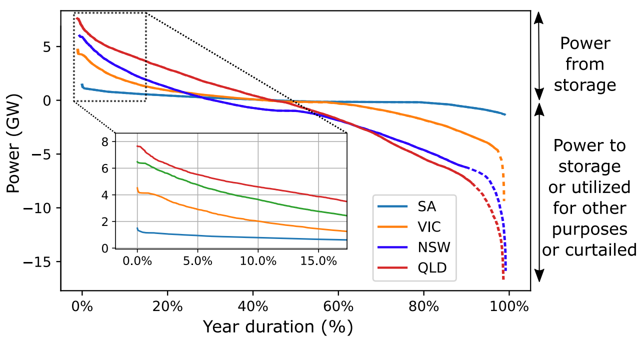


FIGURE 9. **Storage and curtailed power duration curve. Dashed lines indicate curtailment, whereas solid lines reflect the charging and discharging power of each regional storage and the respective duration of operation.**

E. SENSITIVITY ANALYSIS FOR COST ASSUMPTIONS

The study assumes future generation and storage costs for 2030, and while generation costs are more certain due to historical trends and rapid developments, storage costs, on the other hand, are more uncertain. Consequently, we analyse the influence of component costs on the generation-storage mix by simulating low and high-cost scenarios based on the data presented in Table 3. The results are graphically presented in Fig. 10 and compared with the reference cost analysis in Section V-C. Throughout all scenarios, storage power capacities remain relatively consistent. However, it becomes evident that the high-cost scenario necessitates higher generation capacities, particularly by including additional solar capacities, to reduce the storage energy capacity while maintaining existing wind capacities. This leads to solar and wind penetrations of 42% and 52%, respectively, resulting in investments of A$210 billion. These figures represent a significant increase of approximately 70% compared to the reference cost assumptions.

Conversely, in the low-cost scenario where a 30% reduction in solar cost is assumed, higher solar capacities are installed, while wind penetration is decreased to facilitate the integration of lower-cost storage. As a result, the initial investments for this scenario amount to A$89 billion, representing a reduction of approximately 30% compared to the reference cost assumptions. Notably, under the low-cost scenario, the optimal generation mix shifts from a prevailing reliance on wind (as observed in the reference and high-cost scenarios) to a predominance of solar at 46% and 48%, respectively.

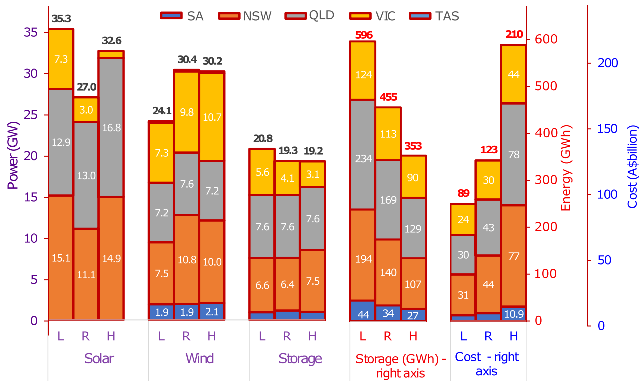


FIGURE 10. **Sensitivity analysis of the generation-storage mix to variations in component costs based on Table 3. The optimization is modeled using Low (L), and High (H) cost assumptions and compared with the Reference (R) costs. The figure depicts a dual secondary axis with storage energy capacity and overall system cost plotted together. It shows that, in general, for a minimum-cost solution, storage capacity requirements decrease with higher storage costs. Similarly, lower solar costs enable the integration of higher solar capacities.**

Furthermore, the local cost sensitivity analysis or One-At-a-Time (OAT) analysis is conducted with the results plotted in Fig. 11. For each technology (generation and storage), the optimum capacity mix was calculated for higher (technology_high) and lower (technology_low) cost assumptions. Furthermore, the sensitivity analysis is undertaken for the storage system at lower efficiencies than the reference case i.e. at 50% and 60%, respectively. The storage power requirement does not vary much in all scenarios, whereas the energy capacity fluctuates from 400–770 GWh due to changes in energy storage costs. The generation mix of solar and wind capacities aligns with our earlier findings in Section V-A, i.e. storage capacities are highly dependent on wind and solar generation mix. Based on various cost assumptions, the analysis suggests storage with a capacity of 80–90% of annual mean demand (22.8 GW) and a duration of 18–39 hrs for a fully renewable grid.

VI. DISCUSSION

Storage capacity requirements for the grid increase substantially with high penetration of solar and wind. Therefore, the study aimed to determine the optimal mix of renewable

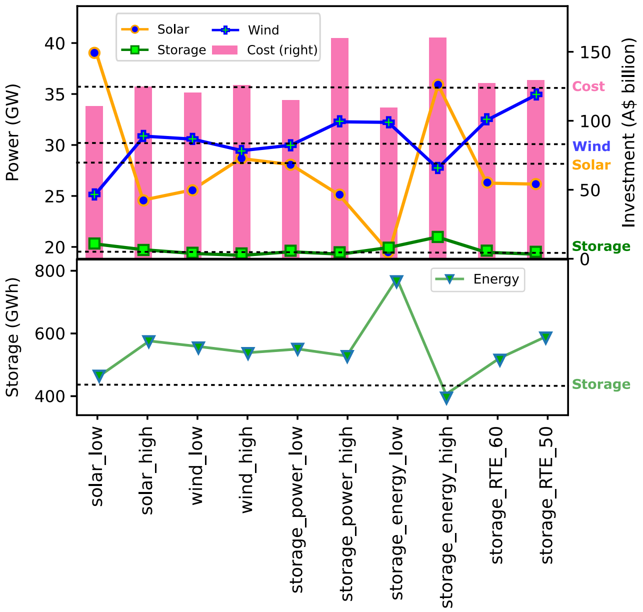


FIGURE 11. Sensitivity analysis for the generation-storage optimal mix to minimize overall investments due to variation in technology cost. The post-script 'low' highlights the lower cost assumption for technology and vice versa. The simulation at round-trip efficiency of 50% and 60% are plotted with post-script 'RTE_50' and 'RTE_60', respectively. The horizontal dashed lines represent the respective values for the reference case.

energy sources and storage technologies to achieve a 100% renewable electricity system for the National Electricity Market (NEM) in Australia. The findings indicate that to completely rely on renewable energy, a wind share of at least 40% and preferably 50% will tend to minimize storage energy and power capacity requirements and cost. Additionally, dispatchable renewable sources such as hydro or biomass may help to reduce the storage requirements even further. Importantly, by increasing renewable generation capacity to supply 8–10% more than the annual energy demand, the storage energy capacity requirement is reduced by a factor of about 10. However, beyond an optimum overcapacity factor, the additional generation capacity will not be economical unless the surplus electricity is used to produce green products such as hydrogen [58], ammonia, or other synthetic fuels to justify the costs of the extra generation capacity.

Relying on a very high share of solar and wind requires overbuilding total installed capacity (relative to peak demand) to produce sufficient energy when available wind or solar output is well below average. Prolonged calm periods lasting days or weeks during winter months with low solar insolation are particularly challenging for VRE-dominated systems. The residual demand with low solar and wind output cannot be met with shorter-duration batteries or demand side management (DSM) [13]. Moreover, interconnectors between regions provide power transfer and desirably reduce dependence on medium and long-duration storage as transmission line losses are typically lower than storage losses, i.e., 5–10% compared to 15–40%, respectively. The interconnectors also translate into reduced regional storage capacities, with an investment of around $A123 billion required for interconnected grids; about $A26 billion less than five isolated grid systems, emphasizing the benefit of sharing generation and storage resources between regions; the breakdown is provided in Table 6.

The cost estimate for the SA–NSW interconnector (including transmission lines, synchronous condensers, transformers, reactors, switchgear, etc.) is around $A2.6 billion. The incremental benefit of this interconnector based on our analysis is around A$ 1 billion. Nevertheless, the new interconnector is opening up massive renewable energy opportunities essential to meet renewable generation targets—the line passes through a sun-rich region, a region that would not be utilized if it were not for the interconnector.

TABLE 6. Investment costs breakdown in A$bn.

Regions	Generation	Storage	Overall
Disconnected	99.80	49.3	149
Interconnected	85.7	36.8	123

A. GENERATION REQUIREMENT

In terms of addressing the seasonal mismatch between supply and demand, we examine the output of the generators and show solar has a strong negative correlation with the load during winter, and wind tends to produce large amounts of energy in spring. It is, therefore, difficult to meet a very large fraction of the demand without the ability to move energy over longer time scales, while correlation can be improved by increasing the wind-to-solar capacities ratio [59]. An optimum over-generation of 112% will result in lower storage requirements for the NEM, with NSW having the highest generation requirements of 22 GW, closely followed by QLD at 20.6 GW. There is an additional requirement of roughly 27 GW solar and 30 GW wind in the NEM, each contributing 38% and 55% of total generation, with an estimated 70% of total cost invested in generation capacities. Furthermore, with a storage power capacity of around 19 GW, the NEM requires a total of 76 GW in capacity to support mean and peak demand of 22 GW and 38 GW, respectively.

Spreading the total capital required over, for example, 15 years would result in an annual investment cost of around $A8.2 billion. In comparison, the Reserve Bank of Australia (RBA) reported that investment in renewable energy was about $A7 billion in 2019 [60], while the Australian Energy Council (AEC) estimates that Australia currently spends approximately $A12 billion per year on electricity transmission and distribution infrastructure.

B. STORAGE REQUIREMENT

The optimum generation-storage solution presented in this paper demonstrates the storage requirements for each region of the NEM, with cumulative storage of 19.3 GW and 455 GWh implying a duration of around 24 hrs (1 day), to address intra-day, intra-week and inter-season fluctuations.

While the storage power requirements remain consistent, the energy requirements vary in the range of 350–600 GWh, depending on the costs associated with generation and storage technologies. The highest storage requirements exist in QLD and NSW, having the highest regional demand, followed by VIC. These findings are in line with other studies, such as Blakers et al. proposing storage capacities of over 17 GW and 450 GWh [36], the latest AEMO ISP recommending storage capacities of over 45 GW and 600 GWh to supply double the current consumption of approximately 205 TWh [40], and Lu et al. proposing storage capacities of 47 GW and 533 GWh to meet a consumption of 350 TWh in the energy sector [37]. Despite the challenges in comparing studies due to varying assumptions, the consistency among these findings mutually assures and validates our work.

Furthermore, our research provides a detailed methodology and valuable insights into the impact of inflexible generation, dispatchable generation, and interconnectors on storage requirements and infrastructure costs. Additionally, we analyze a crucial aspect of storage utilization, as lower utilization rates can result in reduced storage revenues and higher levelized storage costs (LCOS). We demonstrate that storage discharge at rated capacities for a very short duration of the year and therefore sizing storage to cater for demand peaks will have less marginal benefits. One effective strategy to optimize storage utilization is utilizing green hydrogen produced from excess generation as fuel in retrofitted gas generators. This approach, though not included in this study, can help meet peak demands for 1-2% of the year, resulting in lower storage energy and power capacities. By effectively managing storage utilization and leveraging alternative low-cost solutions, the overall performance of storage systems can be significantly enhanced, leading to improved economic feasibility and cost-effectiveness.

C. SELECTION OF STORAGE MIX

Short-term storage devices with fast response rates and high power-to-energy ratios may participate in ancillary services to address issues, for example, frequency regulation and contingency to address immediate shortfalls, and therefore will play an important role in the transition to a 100% RE grid [24]. Moreover, longer duration energy storage (LDES) solutions such as PHES, hydrogen storage, CAES, etc., will be needed to act as intra-day and intra-week storage for VRE penetration exceeding 80%, while ensuring the economic feasibility of storage systems [61]. Note that PHES and batteries have demonstrated round-trip efficiencies of 70–80% and 80–90% respectively, whereas hydrogen electricity generation has only achieved 30–40% [62]. Each technology provides distinct solutions for short, medium, and long-duration storage with varying costs and characteristics. Short-term storage is very responsive and can rapidly reverse the direction of power flow. This contrasts markedly with pumped-storage hydro schemes where the power range during charging (pumping) is low and uncontrollable for synchronously driven pumps and with a limited power range for asynchronously driven pumps; power reversal is relatively complex and time-consuming. Thus, the optimum portfolio will comprise diverse utility-scale storage systems complemented by consumer-driven battery systems [63], which will be investigated in future research.

D. PROSPECTS OF HYDROGEN STORAGE

Hydrogen generation and storage has received significant attention recently due to the potential of hydrogen to provide the means of decarbonization in sectors such as high-temperature process industries, e.g., steel and cement making, long-haul transportation, and production of ammonia utilized in agriculture, providing additional revenue streams to hydrogen storage systems [64], [65]. It also enables long-distance energy transportation in the form of liquid hydrogen or ammonia, from locations with abundant solar and wind resources, such as Australia, to energy-hungry countries at a much lower cost than battery storage [66]. As such, it is envisaged that PtH_2tP will provide for discharge durations of two days or more due to expected cost reduction in electrolyzer technologies and lower energy capacity capital cost compared to CAES and PHES [48]. Also, hydrogen requires less storage volume than compressed air or pumped hydro. The option to sell hydrogen to sectors outside of power generation provides an additional potential revenue stream for hydrogen technology systems.

Lastly, for penetration levels of up to 80% of annual demand, minimizing curtailment to less than 10% requires storage to shift the load [25]. In the Australian electricity grid with a 25% renewable penetration, the system experienced a curtailment of nearly 0.7% of total demand in 2020, equivalent to 1.3 TWh, with a maximum instantaneous power curtailment of nearly 3 GW. Higher penetration levels are expected to increase curtailments, particularly during spring and autumn. While storage can help reduce curtailment, our modeling, in line with prior research, suggests that over-capacity, rather than expensive storage, is the preferred cost-effective approach. Moreover, the additional generation helps offset storage losses and the degree of over-capacity required depends on the round-trip efficiencies of the storage system [24].

VII. CONCLUSION

This paper presents an optimization-based methodology to determine the minimum-cost generation-storage mix for achieving 100% renewable energy in the Australian NEM grid. By utilizing high-resolution (5-minute) actual data from existing generators installed across the NEM, the study incorporates real-world factors that are often overlooked in simulated data. The optimal generation-storage mix is determined by minimizing the total capital cost of the generation and storage components.

The optimum storage requirement depends significantly on the generation portfolio, especially the wind/solar mix. The study demonstrates that storage costs vary minimally with wind penetration above 40%. This is important because it implies that as long as wind penetration is at least 40%, the total cost of the RE100 grid is near optimal. However, the costs are susceptible to the proportion of wind and solar below 40% of wind penetration and escalate considerably as the ratio of wind decreases. It is evident that optimum storage power and energy capacities will require different penetrations of solar and wind due to a reciprocal relationship between storage requirements and generation technology. Furthermore, our study explores the potential of strategically dispatching flexible hydro generation to meet demand peaks, further mitigating the need for additional storage. By strategically utilizing hydro resources during peak demand periods, the study demonstrates the effectiveness of this approach in minimizing storage needs and optimizing the use of renewable energy sources.

For a 100% Australian renewable electricity grid, the optimum generation mix comprises 46–55% wind generation, 38–48% solar (utility and rooftop) generation, and 6–7% hydro generation, depending on component costs. An over-capacity of an average of 110–120% across the NEM is also recommended, with a storage requirement of 18.5–21.5 GW and 400–770 GWh for an interconnected grid. This implies energy curtailment of 6–10% and storage losses of 5–6% of total generated energy.

The findings of this research contribute significantly to the understanding of the relationship between generation and storage capacities. The study also investigates the sensitivity of storage utilization to component costs and efficiency, considering the uncertainties associated with future technology advancements. While storage costs are less certain than renewable generation costs, there is an expectation of substantial cost decrease for some storage technologies as they mature, potentially leading to higher storage deployment in the optimal generation-storage mix. Lastly, we demonstrate the storage utilization in a fully renewable grid, which can be improved by utilizing hydrogen-based peaking generators for a short duration of the year. These findings have important policy implications for policymakers designing and implementing renewable energy policies, as they can avoid over-investment in under-utilized storage and stranded assets by considering the optimal generation-storage mix.

A. FUTURE WORK

In this work, we have focused on the existing electricity system. We suggest future work addresses storage requirements due to electrification in other sectors, such as transportation, industry, and agriculture as well as exploring the hydrogen need for high-temperature industrial applications. With growing interest in electric vehicles (EVs), the future fleet of electric cars, assuming even half of the 20 million currently registered cars, may offer a storage capacity of roughly 600 GWh (at average storage of 60 kWh per car). Moreover, the charging requirements of EVs may increase the demand peaks and grid congestion and thus will require load shifting to day-time to fully exploit solar generation and smooth the demand curve. It is also noted that demand management can reduce load during hours of insufficient capacity and thus reduce the peak generation and storage power capacities.

TABLE 7. Existing regional generation capacities and annual energy output for each technology in 2020, retrieved from AEMO.

Technology		SA	NSW	VIC	QLD	TAS	**NEM**
Utility-solar	GW	0.35	1.08	1.63	0.43	0	3.49
	TWh	0.57	2.03	0.8	3.07	0	6.47
Wind	GW	1.67	1.22	0.51	2.32	0.42	6.14
	TWh	4.9	4.11	4.95	1.34	1.05	16.34
Hydro [a]	GW	–	2.3	2.1	0.6	2	7
	TWh	–	2.21	0.58	2.28	7.93	13
Rooftop-solar	TWh	1.83	3.76	2.69	4.56	0.2	13.04

[a] Power and energy capacities are input to the optimization as constraints

TABLE 8. Region-based peak power and annual energy demand for the modeled year (2020).

Demand	SA	NSW	QLD	VIC	TAS	NEM
Power (GW_p)	3.3	14.5	10.6	10.1	1.7	38
Energy (TWh_a)	13.8	72.3	58.3	46.3	10.3	201

APPENDIX
EXISTING GENERATION AND DEMAND

See Tables 7 and 8.

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