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Fully electrified land transport in 100% renewable electricity networks dominated by variable generation

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A R T I C L E I N F O

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A B S T R A C T

Large greenhouse gas reductions are possible with a fully decarbonised grid and electric land transport. Additional electric load could pose a significant challenge to a grid with high levels of variable and non-dispatchable renewable energy sources. This scenario is not well-examined, nor is the use of pumped hydro energy storage for low-cost energy balancing. In this paper, we investigate the electrification of land transport within a photovoltaics and wind dominated 100% renewable electricity system. Only technologies that are deployed at scale and widely available globally are considered, namely photovoltaics, wind, battery electric vehicles, high voltage transmission, and pumped hydro. As a case study we present an hourly energy balance analysis of the Australian National Electricity Market with 100% renewables and 100% uptake of electric vehicles for land transport. The cost of the system is determined by occasional periods (days-weeks) of low renewable generation, and therefore only weakly dependent on the charging regime. The 40% increase in electricity demand due to electric land transport can be incorporated with a 4%–8% increase in the levelized cost of electricity. An exception occurs if most passenger vehicle charging occurs during the evening peak period, in which case the average price increases by about 18%.

1. Introduction

To limit global warming to well below 2 °C, and as close to 1.5 °C as possible [1], it is necessary to stop using fossil fuels, preferably while also providing an equitable energy supply to all of humanity. The stunning declines in the cost of solar photovoltaics (PV) and wind mean these technologies are now competitive with new-build coal- and gas-fired power, and it is expected that they will cost less than the operating costs of existing fossil plants within a decade [2]. In 2019, over 160 Gigawatt (GW) of net new wind and PV [3] was deployed, which is more than the sum of coal [4], gas, nuclear [5] and other renewables [3] combined. The decarbonisation of the current electricity system via PV and wind and sufficient storage is feasible at low net cost [6] but could be complicated by the inclusion of large new loads, such as the electrification of transport.

Renewable electrification of land transport via electric vehicles (EV) would reduce greenhouse emissions by 15–25% globally [7]. For example, Khalili et al. [8] showed that fuel switching in all modes of land, sea, and air transport could assist in limiting warming to 1.5 °C, although this work did not include the embodied carbon of the electrified fleet. Electrifying the land transport fleet would likely reduce total energy consumption, oil spills, oil-related conflict, and improve urban air pollution and local energy security. However, other problems remain: noise pollution, traffic accidents, reduced opportunities for walking and cycling, air pollution due to brake pad and tyre degradation, the assignment of a large fraction of city space to car parking and roads, and the consequent urban heat effect.

If the only problem were one of short term supply, the additional demand due to the electrification of land transport could be met relatively simply with fossil fuels and dispatchable hydro: more coal, gas, or hydro capacity could be added and managed to follow the load. This is, however, more complicated in an electricity system dominated (>90%) by variable PV and wind, as the additional demand would require not only more PV and wind capacity, but also more storage and dispatchable generation capacity. It is important to determine how much more (if any) this would be likely to cost.

In this paper we explore the renewable electrification of land

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transport within the Australian National Electricity Market (NEM). Australia is a pathfinder for the three quarters of humanity who live in the sunbelt (lower than 35° of latitude), where insolation is consistently high and winters are generally mild [9]. This is where most of the world's growth in population, energy use and greenhouse emissions is occurring. A successful transition to renewable energy in Australia would provide a useful model for other countries.

Australia is a useful case study for high wind and solar use because nearly all new generation capacity additions in Australia are PV and wind, and the annual deployment rate of new renewable capacity is 4 times larger per capita than in Europe, China, Japan or the United States of America (USA), and 10 times larger than the global average [10]. In Australia, 20% of the electricity generated came from PV and wind in 2020, and the country is on track for 100% renewable electricity by 2032 if current deployment rates continue. In the state of South Australia, PV and wind accounted for 59% of electricity generation in 2020 and more than 90% of the total load on 37 calendar days [11]. Australia is grappling with the problems and opportunities of incorporating large amounts of variable PV and wind sooner than most other countries. The Australian experience is highly replicable in many other countries because there are wind and or/solar resources available nearly everywhere.

This paper is structured as follows: Section 1.1. Provides a brief review of the literature; Section 2 introduces the methodologies used; Section 3 describes the characteristics of Australia as a case study; Section 4 summarises the modelling results; and Section 5 provides a discussion of findings and limitations.

1.1. Background

100% renewable electricity and 100% electrified land transport are major steps towards carbon neutrality. PV and wind are likely to dominate future installed generation capacity due to their falling costs and rapid deployment worldwide. However, the balancing costs (including storage, transmission, loss and spillage) of variable PV and wind increase exponentially with renewable energy penetration [6]. Thus, incorporating additional demand from electrified land transport may be more challenging in a 100% renewable grid. However, most existing studies that investigate the impact of EV integration on electricity systems focused on conventional fossil fuel powered grids (e.g. Refs. [12–14]) or grids that had moderate renewable energy penetration (e.g. 33%–80% renewable energy penetration in Refs. [15–24]). With more countries and regions expected to commit to carbon neutrality and the impending phase out of internal combustion engine vehicles following announcements from Europe, China, Japan and USA, these previous studies do not go far enough.

Several studies that modelled EV integration in grids with high renewable energy penetration (e.g. British Columbia [25] and Reykjavik, Iceland [26]) relied largely on dispatchable hydro power and biomass. However, most regions do not have sufficient hydro and biomass resources to balance variable generation and demand and the conclusions from these studies are therefore not widely applicable.

Only a limited number of recent studies attempted to investigate the impacts of EV integration on grids dominated by variable renewable energy. Dorotić et al. explored the feasibility of achieving carbon neutrality on an island (population 16,000 in 2011), with only PV and wind as energy sources and vehicle-to-grid (V2G) as a demand response mechanism [27]. All modes of transport were included, and wind and PV capacities were optimized based on pre-defined boundary conditions. This study found that a decrease in V2G deployment would result in an increase in electricity imports and exports, while the peak load remained unaffected. However, the electricity system modelled in this study was not a closed system in that it used imports and exports to balance energy, and so provides only limited information for those countries and regions that are unable to share electricity with neighbouring systems due to geopolitical constraints. It was also relatively small, and so conclusions cannot be directly drawn for grids serving larger populations, and which have higher reliability standards.

Li et al. modelled 100% electrified passenger vehicles in a 100% renewable Australian electricity system dominated by solar PV, wind, and concentrated solar power (CSP) [28]. Dispatchable resources such as hydro and biomass represented just 6% of the total capacity. They found that the levelized cost of electricity (LCOE) of 100% renewable electricity with controlled EV charging would be AU$147/MWh (US$103/MWh), which represented an AU$12/MWh (US$8/MWh) increase from the scenario without EVs and an AU$1,710 (US$1,197) per capita increase in annual expenditure for electricity and conventional vehicle fuel compared with current levels. However, this study did not include the energy requirements of other modes of land transport (e.g., light commercial vehicles, trucks, buses, etc.). Utilisation rates of commercial vehicles are generally much higher than passenger vehicles, and so charging profiles for these classes of vehicles are more difficult to control centrally, which may lead to reduced charging flexibility. Moreover, this study relied on heroic assumptions on future deployment of CSP for thermal storage, with over 80 GW CSP (with 15 h storage) required in the 100% EV penetration scenarios. However, only 6.3 GW of CSP was cumulatively installed globally as of 2019 [3], and it is unlikely to compete with pumped hydro and batteries in the near future. The exclusion of pumped hydro storage in this study would also lead to an increase in the estimated system costs. In contrast to CSP, pumped hydro represents 96% of global storage power capacity (GW) and 99% of global storage energy capacity (GWh). Off-river pumped hydro resources are well distributed across the globe [29] and available off-the-shelf with known costs. A global atlas of off-river pumped hydro found 616,000 good sites [29] with an enormous combined storage of 23 million GWh, which is about 100 times more than needed to support a global 100% renewable electricity system. Australia has 4000 good sites with combined storage potential of 177,000 GWh, which is hundreds of times more than required.

This study is a necessary extension of our previous work [6]. We filled a gap in the literature by presenting a long-term (5 years), hourly energy balance analysis that investigates the impact of a complete electrified land transport fleet (including motorcycles, passenger vehicles, light commercial vehicles, articulated trucks, rigid trucks, non-freight carrying trucks, rail and buses) on a 100% renewable electricity system with more than 90% variable PV and wind. The remaining electricity was sourced from existing hydro and bio energy. Sufficient pumped hydro energy storage (PHES), along with strong interconnections via high voltage transmission and occasional spillage were used to balance supply and demand on an hourly basis. This was enough to ride through calm windless periods, and was included in the calculated cost of energy. Various EV charging profiles were generated to represent a wide range of scenarios. We used Australia as a case study and a modified version of National Electricity Market Optimiser (NEMO) to find the least-cost electricity system configuration. We aimed to derive detailed characteristics of the optimized electricity system, including installed capacities of PV, wind, pumped hydro and transmission, hourly generation and demand profiles, the annual generation mix and total spillage, and a breakdown of the LCOE including the levelized cost of generation (LCOG) and the levelized cost of balancing (LCOB).

The major novelties of this study are listed below:

- In contrast to Refs. [12–26], this study modelled EV integration in a 100% renewable electricity system supplied by more than 90% variable PV and wind, which is yet to be well examined. A 100% renewable system such as this is more complicated because of the weather-dependent nature of PV and wind and the additional required balancing mechanisms.
- The use of pumped hydro energy storage to provide mature, large-scale, low-cost energy balancing services for an EV-integrated system such as this has also not been examined in the literature
- In contrast to the large deployment of V2G in Ref. [27] and CSP in Ref. [28], this study included only off-the-shelf technologies that have been deployed at large scale globally, namely solar PV, wind, battery electric vehicles (BEV), pumped hydro energy storage and high voltage direct-current/alternating-current transmission (HVDC/HVAC). Therefore, the cost for the integration of electrified land transport in a 100% renewable electricity system dominated by variable solar PV and wind energy estimated in this study represents a more reliable upper bound. Further technological and commercial developments (e.g., the wide deployment of V2G or significant cost reductions of other generation or storage technologies) would lead to lower costs, but were excluded from the scope of this study due to the philosophy of using proven, established technologies. This is discussed further in Section 5.3.
- In contrast to Refs. [13,15,19,21,25–27], this study used a closed electricity system in an industrialized, isolated country with a generally mild climate and the highest per capita renewable energy deployment rate as a case study, and therefore the findings presented in this study are widely applicable to the sunbelt (i.e. countries with latitude ±35°).

In addition, this study modelled 100% electrification of all modes of land transport, which represents the end point in the transition to a carbon neutral land transport sector. Aviation and shipping were excluded as direct electrification of these two transport modes is more difficult. Pumped hydro energy storage, which is often overlooked in the existing literature due to confusion with conventional large-scale hydroelectric dams, is used for storage, as off-river schemes can be located away from rivers, and are therefore widely available in most regions of the world and effectively dispel the social and environmental concerns associated with conventional hydroelectricity [29].

2. Methodology

2.1. Charging load profiles

Rather than synthesising future travel and electricity demand data, this study used historical data for both. Improved autonomous vehicle capability, the increased use of electronic meetings (whether due to the COVID-19 pandemic or for other reasons) and other factors might substantially affect future driving patterns in unpredictable ways. We have not attempted to model such changes. These historical data were used to develop representative hourly profiles for weekdays and non-weekdays (i.e., weekends and public holidays), which were applied throughout the modelled period.

2.1.1. Daily demand

The daily required electricity consumption for all modes of land transport except rail was calculated from the average daily travelling distance and the energy consumption per distance travelled, along with energy losses:

Equation 1

$$E_{daily} = c \times d_{daily} \times (1 + t_{loss})/\eta + v\_loss \times B$$

where:

- E_{daily} (in kWh) is the daily electricity consumption
- c (in kWh/km) is the average energy consumption per kilometre
- d_{daily} (in km) is the daily travel distance
- t_{loss} is the transmission & distribution loss
- η is the charging efficiency (85% according to Ref. [30])
- v_loss is the additional standing loss due to battery self-discharge plus the energy used to power on-board electronics (1% of nominal battery capacity per day according to Ref. [31])
- B is the nominal battery capacity

For rail, the historical liquid energy consumption and nominal diesel efficiency were used to determine the total required electrical energy consumption. This figure, together with the electric rail efficiency, was used to find the average daily electricity consumption (assuming no variations between weekdays and non-weekdays):

Equation 2

$$E_{rail,daily} = \frac{D_{rail,annual} \times \eta_{diesel}}{\eta_{electric}} \Big/ 365$$

where:

- $E_{rail,daily}$ (in kWh) is the daily electricity consumption for rail
- $D_{rail,annual}$ (in kWh) is the annual diesel consumption for rail
- η_{diesel} is the diesel efficiency (29% according to Ref. [32])
- $\eta_{electric}$ is the electric rail efficiency (76% according to Ref. [32])

The daily electricity consumption E_{daily} (or $E_{rail,daily}$ for rail) was then distributed evenly over the daily 24 h period, to account for private freight rail for which timetables could not be accessed.

2.1.2. Charging scenarios

For all modes of land transport except rail, an end-of-trip charging regime was developed for the baseline scenario, in which we assumed that drivers park, plug in, and start charging immediately after each trip. A typical weekday and weekend profile that was developed using travelling patterns from the Sydney Greater Metropolitan Region (discussed later in Section 3) is shown in Fig. 1. Profiles were produced for each financial year, for each State and Territory, and for each mode of transport. The electric load for rail was assumed to be constant throughout the modelling period.

Other scenarios were developed to test the impact that the additional load from the electrified land transport fleet had on the electricity system. Only passenger vehicle charging regimes were varied as they are more likely to have sufficient flexibility to be incorporated into centralised charging regimes. The modelled scenarios were:

1. End of trip charging (baseline) – described above
2. End-of-day charging during the historical peak period (worst-case) with high/low charging rates: two extreme scenarios where it was assumed that all passenger vehicle charging took place during the evening peaks (4–9pm) on weekdays. Charging during weekends was unaffected (identical to the end-of-trip scenario). These scenarios were developed to simulate an extreme case of daily commuting: all passenger cars arrived

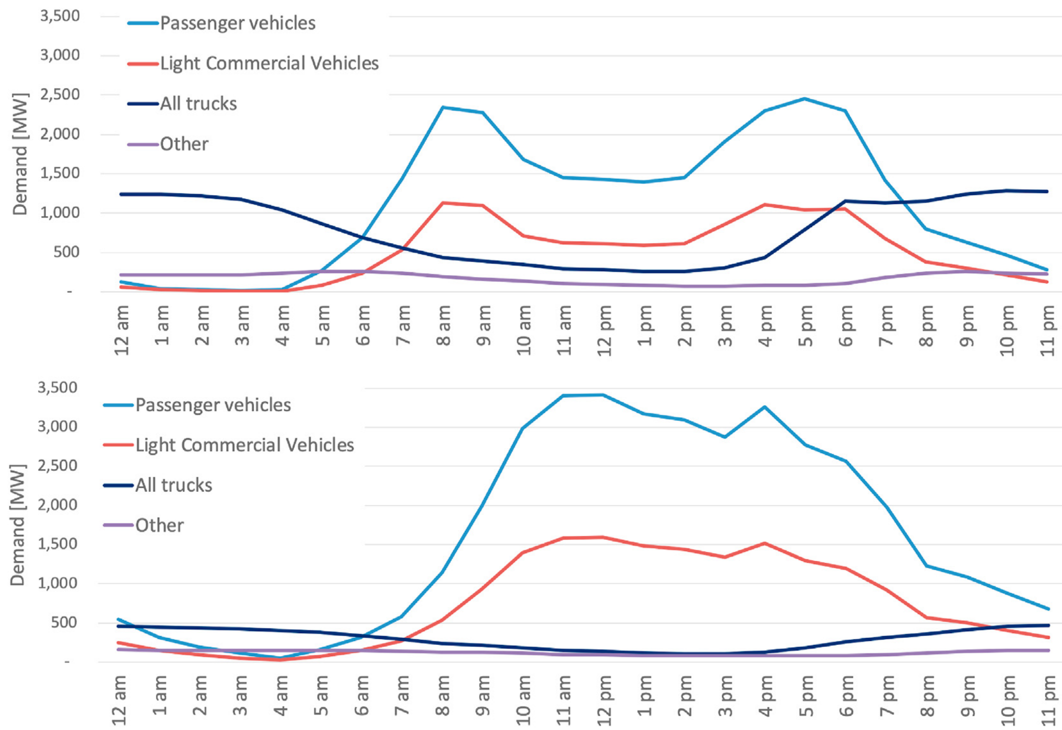

Fig. 1. The end-of-trip (baseline) charging profile for each mode for NSW financial year 2005/06 weekdays (top) and non-weekdays (bottom). The profile shown was used for the first six months of 2006. Trucks include articulated trucks, rigid trucks and non-freight carrying trucks. Others include buses, motorcycles and rail. Other States have similar profiles that are scaled to fit the daily electricity demand derived in the previous section — more detail can be found in Section 3 and in the Supplementary Information.

home at some point during 4–7pm, and started charging immediately with no control. For vehicles travelling an average daily distance and arriving home at 7pm, charging would finish at around 9pm with a Level 1 charger (the simplest and lowest cost charger, capable of delivering up to 3.6 kW [33]). The cost the owner pays to purchase and install a charger increases with decreasing charging time, and so in the low charging rate scenario, we assumed consumers would choose the lowest cost

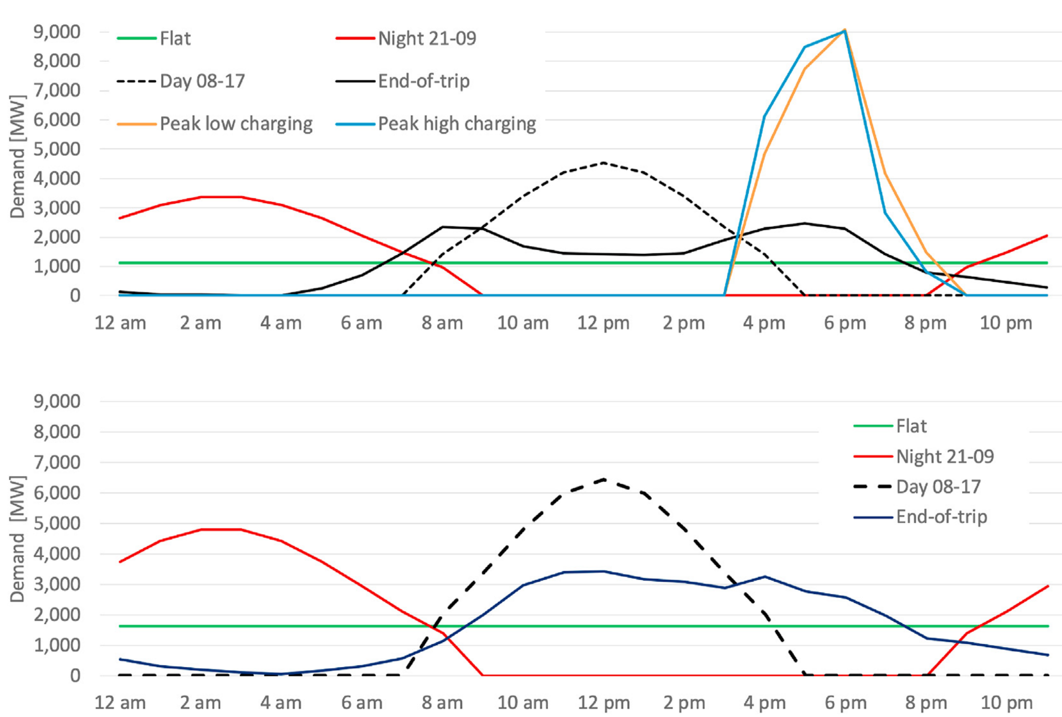

Fig. 2. Passenger EV charging profiles (weekday top, weekend bottom) by scenario for NSW in 2005–06 (MW). The end-of-day scenarios are not shown in the weekend profile as they are identical to the end-of-trip scenario.

option that would provide them with their required charging rate. Consumers may instead choose to purchase the most expensive option with faster charging at a higher power level “just in case”. The impact of this case was tested in the high charging rate scenario, where consumers installed home chargers with higher power capacity. A typical profile is shown in Fig. 2. The higher charging scenario led to greater demand for the first 2 h, and slightly lower demand for the final hours.

3. Utility-controlled charging: assumed that charge timing would be controlled by a central agent. This could be the energy market operator or an energy company providing aggregation services. Vehicles were expected to be connected to charging infrastructure during the specified charging window unless travelling. A central agent manages the state of charge of the vehicles and consumption across the network to best match the target profile. The vehicle owner plugs in upon arrival but does not need to manage the charging. The modelled utility controlled scenarios were: (i) a continuous, flat passenger EV scenario that spreads charging evenly throughout the night and day; (ii) daytime charging scenarios that took advantage of daytime PV availability; and (iii) night-time models that filled evening valleys in baseline demand. Sample profiles are shown in Figs. 2 and 3.

2.2. Hourly energy balance modelling

The method used in Ref. [6] was extended to balance the electricity supply and demand for these scenarios. Energy balance modelling was undertaken using historical data for wind, sun and grid demand for every hour of the years 2006–10, and the required generation mix to meet electricity demand for every hour was

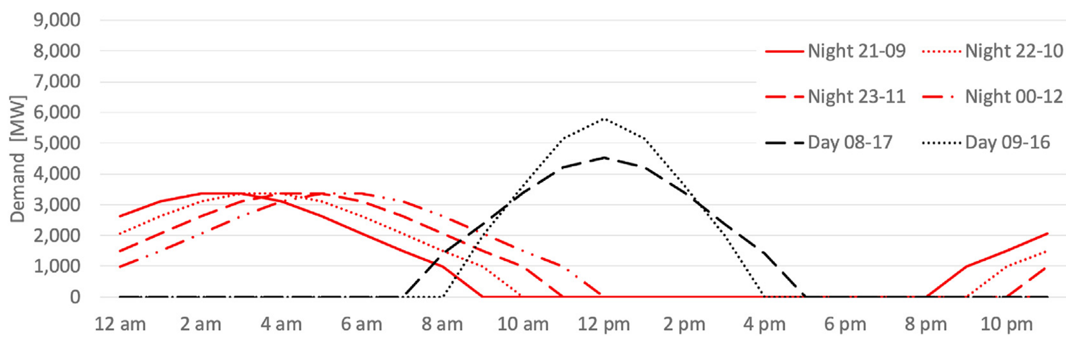

Fig. 3. Day (black) and Night (red) passenger vehicle charging profiles for NSW 2005-06 weekdays. Day 08–17 and Day 09–16 represent charging between 8am-5pm and 9am-4pm respectively. Night 21-09, 22-10, 23-11, and 00-12 represent overnight charging starting from 9pm, 10pm, 11pm and midnight respectively and lasting for 12 h.

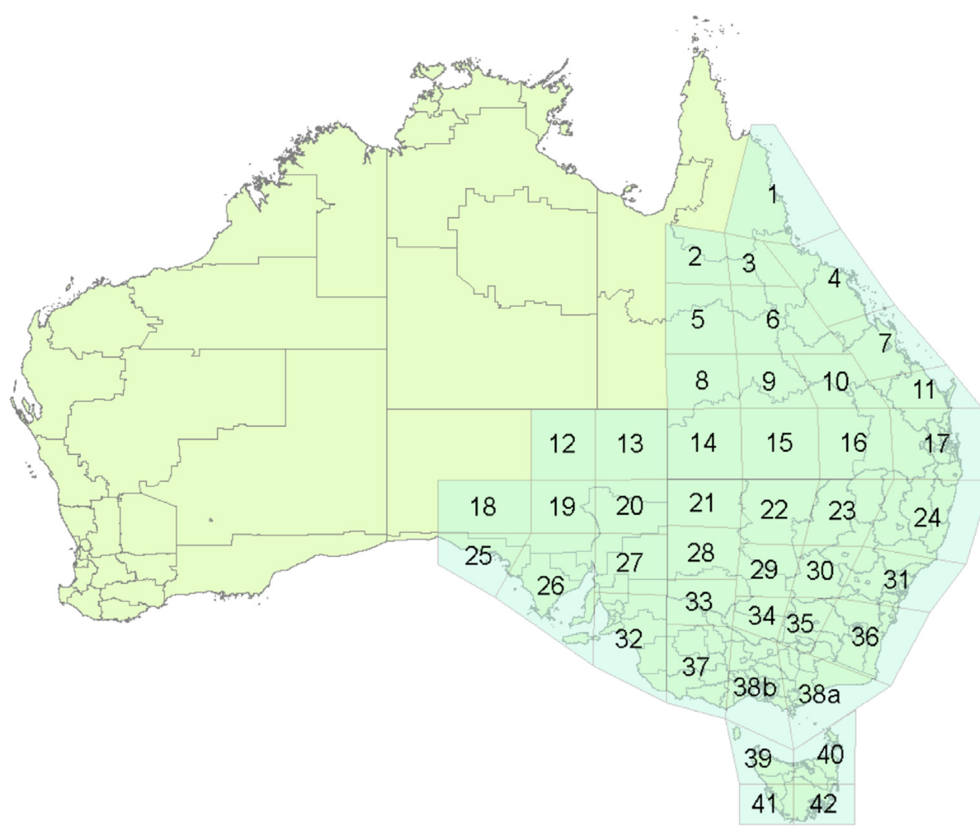

Fig. 4. Locational polygon map for renewable energy resources in the NEM [42].

Table 1
Assumed EV characteristics in Australia.

Class of vehicle	Average nominal battery capacity (kWh)	Average energy consumption (kWh/km)	Average maximum range (km)	References
Passenger EVs	77	0.17	450	[51–54]
Light commercial vehicles	60	0.4	150	[55–58]
Articulated trucks	800	1.4	570	[59]
Buses	100	1.1	91	[60–63]
Rigid trucks	100	1	100	[64–66]
Motorcycles	15	0.06	250	[67,68]
Non-freight carrying trucks	100	0.7	140	[69]

calculated. The generation mix was primarily composed of PV and wind, supported by off-river PHES and HVDC/HVAC. The existing bioenergy and hydroelectricity were assumed to be dispatchable but were not expanded. The model assumes perfect generation forecasts, as in Refs. [6,34]. It should be noted that Australia is a large country and weather systems take several days to pass across, which means that weather-related effects on solar and wind generation will rarely be a surprise to grid operators.

A modified and extended version of the National Electricity Market Optimiser (NEMO) model [35] was used to identify solutions which met the energy balance requirement. NEMO is an open source chronological dispatch model that was developed to generate an optimized portfolio of electricity generation technologies and has been used extensively [6,36–39]. The original algorithm and code are available in Ref. [35]. In this study, the NEM geographical region was divided into 43 cells, as shown in Fig. 4, and historical hourly data from the AEMO 100% renewables study [40] was used to calculate the wind and PV generation within each cell. The historical demand data from the same source was used. Existing bio and hydroelectricity (about 7% of annual electricity demand) was assumed to be dispatchable. The existing river-based PHES was utilized. The same constraints as those specified in Tables 2–4 of [41] were applied for the optimization.

In this study, several adjustments were made to the NEMO model to increase system resilience during occasional critical periods (cold, windless weeks in winter). The major changes were: pumped hydro facilities could be pre-charged using existing hydro and bio generators to manage occasional critical periods (a cold, windless week in winter – this could be enabled by advanced weather forecasting), and in critical periods existing hydro was utilized first to fill the gaps between energy supply and demand so that pumped hydro reservoirs were conserved for the most difficult periods. Further detailed information about the NEMO model, the adjustments made in this study, and the energy trace from the end-of-trip scenario, are available in the Supplementary Information.

For each solution, the LCOG and the LCOB were found. The LCOE is the sum of the LCOG and the LCOB. The LCOG is the weighted average cost of generation from each PV farm, windfarm, existing river-based hydro and existing bio power station. The LCOB, as described in Ref. [6], includes the costs of storage (PHES), transmission and spillage (curtailment), and is minimised by optimising the amount and location of generation and storage.

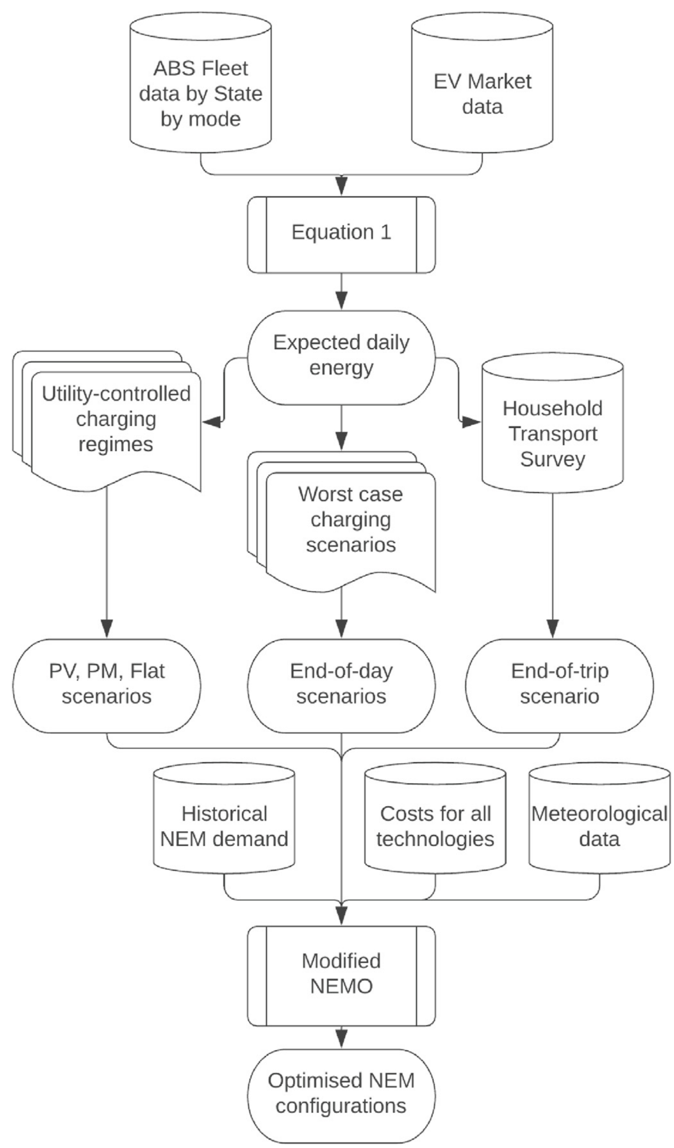

Fig. 5. Flowchart demonstrating the methodology used for the case study. The Optimized NEM configuration for each scenario includes the required generation capacity, storage capacity and transmission capacity.

3. Australian case study: 100% renewable electricity & electrified land transport

Australia is particularly interesting as an international renewable energy pathfinder. In the current Australian National Electricity

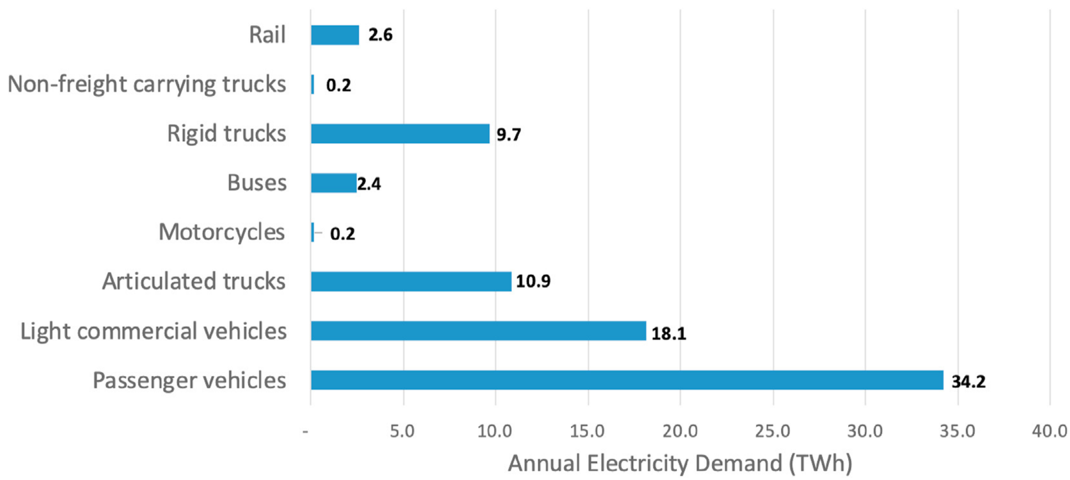

Fig. 6. Additional annual electric consumption added by each mode of transport.

Market, most generation capacity is coal-fired with support from gas (9% of generation). However, much of the coal fleet is approaching retirement age (nominally 50 years) [43] and will need to be replaced before 2040, and gas prices have risen dramatically over the past five years [44]. In 2018 and 2019, Australia installed wind and PV faster on a per capita basis than anywhere else in the world. New PV and wind now compete favourably with existing fossil fuel in the Australian electricity market and continued rapid deployment is expected in the next few decades.

In this study we modelled the Australian National Electricity Market, which services 22 million people [45], but excluded the much smaller systems that exist in Western Australia and the Northern Territory. Detailed information about the assumptions made when modelling the NEM and electrified land transport is available in Section 1 of the Supplementary Information.

3.1. Electrified land transport in Australia

A survey of the BEV models available in the market was carried out and the assumptions used in this paper are presented in Table 1.

Based upon information from the Australian Bureau of Statistics Survey of Motor Vehicle Use [46], hourly travel timetables for passenger vehicles, light commercial vehicles, motorcycles, buses, and all classes of trucks were modelled using historical data from the Sydney Greater Metropolitan Region Household Transport Survey [47], Public Transport Victoria bus timetables and geographic information datasets [48], and heavy vehicle traffic volume data from the New South Wales (NSW) Roads and Maritime Services for stations throughout NSW [49]. Travel timetables were then converted to electric load using the methodology described in Section 2, and pictured in Fig. 5. Transmission & distribution loss was assumed to be 7.5% in Australia, the midpoint of the range specified by the Australian Energy Market Operator [50]. Detailed information about data sources and the development of load profiles is available in Section 3 of the Supplementary Information.

Using the Australian data, the amount of additional electric load added by each mode is shown in Fig. 6. Over the modelled period the electrified fleet adds an average of 78 TWh p. a. additional electric consumption, which is around 38% of the historical electric load (205 TWh per year). Nearly half of the additional load is from passenger vehicles (34 TWh or 17% of the original grid consumption).

The various scenarios are summarized in Table 2.

Table 2
Scenarios and descriptions for passenger vehicle charging regimes.

Scenario	Descriptor	Description
Baseline 2030	No BEVs	Historical demand with no synthesised transport electrification
Unmanaged	End-of-trip	Charges as soon as the trip finishes
End-of-day	Peak Low rate	Charges during the evening peak (4–9pm) at a low-power rate
End-of-day	Peak High rate	Charges during the evening peak (4–9pm) at a high-power rate
Utility controlled	Flat	Uniform charging load 24 h per day
Utility controlled	Daytime	Charges during daytime e.g. Day 08–17 charges from 8am to 5pm, and Day 09–16 charges from 9am to 4pm
Utility controlled	Night-time	Charges during the night after the evening peak period. Four scenarios were created – where a 12-h charging period begins at 9pm, 10pm, 11pm and 12am for Night 21-09, Night 22-10, Night 23-11 and Night 0-12 respectively.

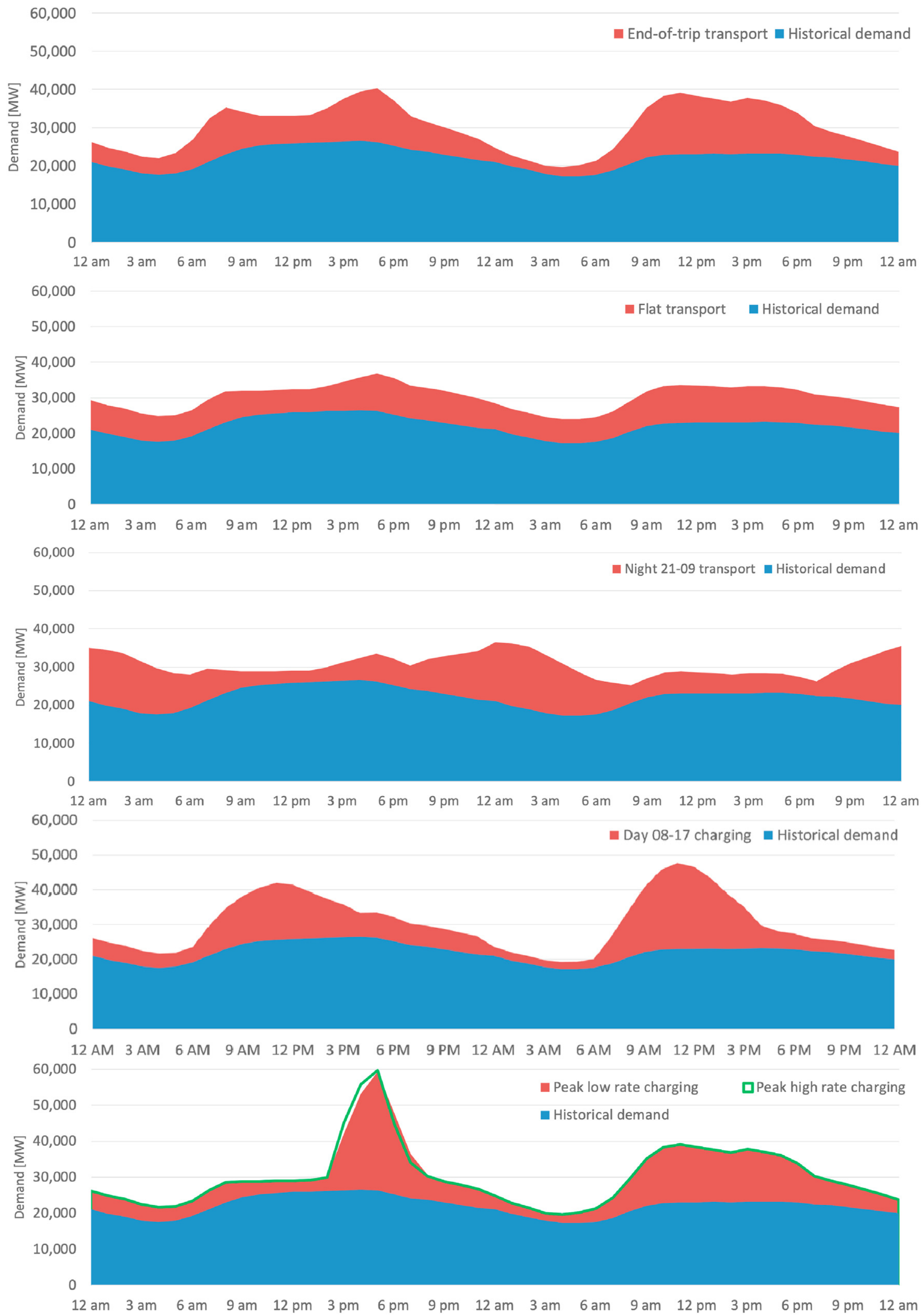

Fig. 7. Land transport charging demand (red) and historical NEM demand (blue) for a sample two-day (weekday left, weekend right) period. Horizontal axis represents GMT+10. Vertical axis represents electric load in MW. a. End-of-trip scenario b. Flat charging scenario c. Night 21-09 charging scenario (beginning at 9pm for 12 h) d. Day 08–17 charging scenario (charging from 8am to 5pm) e. Peak low rate charging scenario with predominantly Level 1 chargers, and peak high rate charging with higher rated chargers – the slight difference in evening peak is shown with the overlaid line.

The overall demand profiles for a sample two-day period (Friday and Saturday) are shown in Fig. 7:

3.2. Economic parameters in Australia

Our cost estimates for PV, wind, PHES and high voltage transmission are summarized in Table 3. United States dollars were used, with an exchange rate of AU$1.00 = US$0.70. The assumed capital costs and average capacity factors for PV and wind resulted in an LCOG of $35/MWh for both technologies. Typical capacity factors were 23% (DC) and 42% for PV and wind, respectively. There are numerous reports of such prices being achieved already in other regions which do not have markedly superior wind and solar resources compared to those available within Australia [70]. Our cost estimates do not include a carbon price or subsidies. PV and wind costs are very likely to continue to fall. Detailed information for data sources is available in Section 3 of the Supplementary Information.

4. Results

4.1. Modelling outcomes

The modelled results for 11 scenarios are shown in Table 4. The 3rd, 4th and 5th columns show both the optimized power capacity and annual energy generation for PV, wind and PHES. The scenarios detailed in Table 2 above are represented in Table 4.

The key conclusion of this study is that a wide variety of combinations of PV, wind, PHES and HVDC/HVAC capacity and location yield similar LCOE ($55-57/MWh). The only outlier is charging during the peak period at the end of the day ($63/MWh). It is trivial to manage EV charging to avoid this.

Fig. 8 illustrates typical 7-day periods of supply and demand for the end-of-trip scenario, along with the pumped storage level over the course of the period. The first shows a week in summer with excess generation capacity. In this week, generation from PV and wind exceeds electricity demand the majority of the time, and PHES is rarely used. The excess generation is spilled. The second shows a period in spring where PHES operates in daily cycles. Excess generation is used to pump water into the reservoirs during the daytime, and this stored electricity is recovered at night to meet demand. The third shows the most difficult week in winter, which had a period of unmet energy at 6pm, when the demand from the electrified transport increased the historical evening peak, but there was no available generation capacity from the PHES or any other generation technology. The existing conventional hydro, which is absent from the first two periods, is largely used during this and other difficult weeks to meet evening demand and charge the PHES. A period of unmet energy occurred because the existing NEM reliability constraint was used. This could have been set to zero, which would have increased the LCOE.

The summer energy profiles generally feature much higher rooftop and large-scale PV generation, and consequent energy spillage. The calm, windless weeks, and the unmet energy events, occur in winter rather than summer.

4.2. Sensitivity analysis

A sensitivity analysis was performed on the end-of-trip charging scenario (LCOE = $57/MWh) by varying the following components by ± 20%: charging loss, energy consumption per kilometre, standing losses, PV costs, wind costs, the cost of PHES power and storage, the cost of hydro and bioenergy, the cost of HVDC terminal and line, HVAC costs and the discount rate. The effect on LCOE of varying parameters was minimal except for the wind cost and the discount rate, with a cost difference of -$4/+$4 per MWh and -$5/+$5 per MWh respectively. These results are shown in Fig. 9.

Table 3
Cost assumptions for power generation technologies.

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Technical lifetime (years)
1-axis tracking PV	840[a]	10[b]	0	0	25
Wind turbines	1260[c]	25[b]	2[b]	0	25
Pumped hydro	560/50[d]	7	0	0	50
Hydro (existing)[e]	–	34	7	0	50
Bio (existing)[e]	–	32	1	1–8	30
Transmission	As can be found in [6]				

[a] Source [71–73]:
[b] Source [73]:
[c] Source [73–76]:
[d] $560/kW for power components including turbines, generators, pipes and transformers; $50/kWh for storage components such as dams, reservoirs and water. Sources: private model.
[e] Purchase prices for existing hydro and bio are assumed to be $35/MWh.

Table 4
Modelling results by scenario – see text for details.

Scenarios	Sub-scenarios	Capacities, energy generation and spillage				Costs ($/MWh)		
		PV (GW/TWh)	Wind (GW/TWh)	PHES (GWh/GW/h)	Spillage	LCOB	LCOG	LCOE
Baseline 2030 (No BEVS)		30/49	43/159	430/17/26	9%	18	35	53
End-of-trip		54/98	57/212	761/30/26	15%	22	35	57
Daytime charging	Day 09–16	71/130	49/185	662/24/27	15%	21	35	56
	Day 08–17	61/111	55/208	572/23/25	17%	20	35	55
Night-time charging	Night 21-09	43/74	66/248	624/22/29	17%	21	35	56
	Night 22-10	47/82	66/244	574/21/27	19%	21	35	56
	Night 23-11	37/62	68/253	684/22/32	17%	21	35	56
	Night 00-12	56/102	58/217	636/22/30	16%	21	35	56
Flat		55/100	57/213	692/26/26	14%	21	35	56
End-of-day	Low charging rate	54/99	56/210	886/49/18	15%	27	35	62
	High charging rate	50/90	64/241	702/49/14	20%	28	35	63

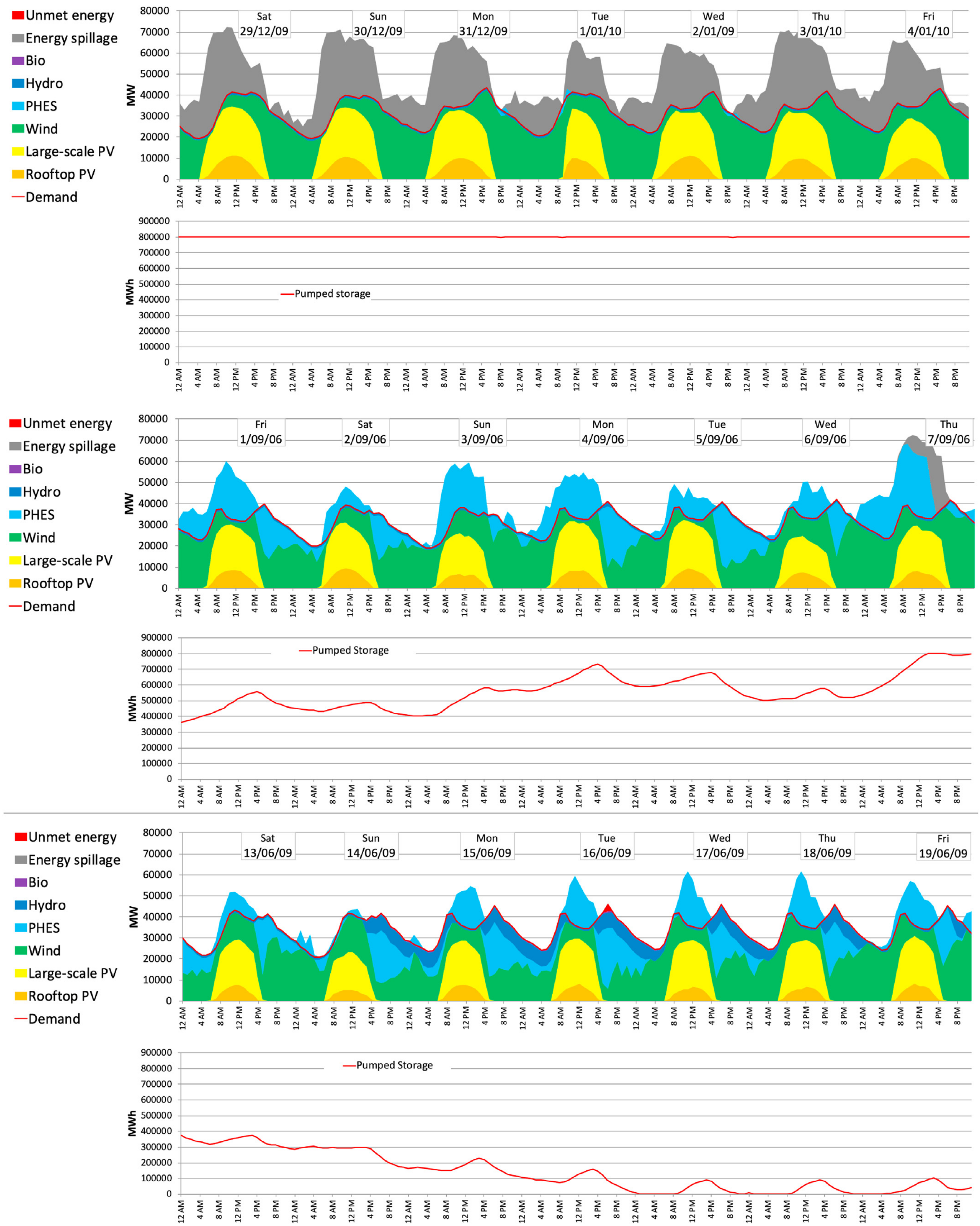

Fig. 8. Example demand and supply curves over the course of 7 days for the end-of-trip scenario – excess generation and consequent spillage is shown at the top, active and consistent pumping is shown in the middle, and an energy shortfall in winter in the lower graph. PV energy (yellow and gold) is supplied during the day. Wind energy (green) is available at most times. PHES (light blue) generates energy when demand (red line) exceeds the available supply from PV, wind, hydro and biomass.

Fig. 9. Sensitivity analysis (±20%) results for the end-of-trip charging scenario.

5. Discussion

5.1. Cost premium to incorporate electrified land transport with unmanaged charging

In our modelling, we optimized for a range of constraints, such as differing combinations of and locations for PV, wind and PHES, to supply historical demand together with synthesised demand for land transport electrification in the NEM. In the unmanaged end-of-trip scenario, we estimate that the average LCOE for the balanced renewable electricity and transport scenario is $57/MWh, consisting of wind and PV costs of $35/MWh and a balancing cost of $22/MWh. This lies within the range of the 2018 average spot price for wholesale electricity in Australia, which was about $61/MWh [77], and the future cost calculated in Ref. [6] of $53/MWh for a 100% renewable grid. This also compares favourably with the estimated LCOE for a new supercritical black coal power station in Australia, which is $56/MWh, derived from a major “whole-of-Government” report [78]. The current NEM generation is mostly met by coal generators that are several decades old and have sunk capital costs. Most of Australia's coal power stations will reach the end of their economic life over the next 15 years [79], if not sooner [80].

For most charging scenarios, there was a slight increase in cost ($2-4/MWh or 4%–8% increase) relative to the scenario without electric vehicles. This is due to the dependence upon existing conventional hydro and (to a small extent) existing biomass resources for managing extended periods of low generation such as a cloudy, low wind week in winter. These dispatchable sources are critical for managing the occasional periods of low generation. Since the total amount of energy from these sources is capped, their scale is diluted in the larger generation mix required for the electrified transport scenarios and the amount of storage relative to total demand increases to ensure demand is met. The dependence upon hydro also highlights the impact that drought years could have on the generation and balancing costs of the network.

The results presented in this study rely on several assumptions, some of which may change significantly in the future (PV/wind costs, battery capacity etc.). The impact of these assumptions was tested in the sensitivity analysis, which found that the effect on the LCOE of varying parameters was minimal, except for the cost of wind and the discount rate. The cost of wind is expected to continue to fall, and so it is likely that a lower overall LCOE will be achievable in the future.

The relatively low LCOE that we calculate for the balanced supply of 100% renewable electricity based upon wind and PV, coupled with their expected continued cost reductions, suggests that (without significant changes in policy) in the future wind and PV will dominate the Australian grid. Wind and/or PV will also dominate the grids of other countries within the sunbelt. PHES and HVDC/HVAC offer an off-the-shelf and low-cost solution to managing the variability of wind and PV.

Climate change leading to additional climate extremes may require additional provision over and above what one would expect from the historical records [81,82]. This is, however, not included in the scope of this study.

5.2. Impact of charging regimes on the balancing costs

While the LCOG is the same for all scenarios, the LCOB varies between $20-28/MWh. The three key requirements for a low cost of hourly balancing are the inclusion of widely dispersed PV and wind over large areas (100 million hectares in this case) with connections through HVDC and HVAC interconnectors to smooth local weather and demand; the use of off-river PHES storage; and sensible EV charging regimes. This was highlighted by the large increase in modelled LCOB with the unfavourable end-of-day charging scenarios, which were extreme cases. As can be seen in Fig. 7, these scenarios resulted in very large evening peaks due to the assumption that all passenger vehicles were plugged in during the historical evening peak. These scenarios therefore required significant increases in the power of the pumped hydro storage from 17 GW (baseline without electric vehicles) to 49 GW for the end-of-day charging scenarios, and 20% spillage of generation in the high charging scenario. It is possible that such a large increase in the peak demand could be partially managed by household batteries, which are cheaper than PHES in terms of power for short periods. However, household batteries are typically much smaller than EV batteries, and management of uncontrolled EV charging in this way would likely be quite expensive because of the charging and discharging losses. It is interesting to note the magnitude of the impact on LCOE of this relatively small increase in charging capacity for private vehicles. This has important implications for urban policy development.

There is a small reduction in LCOE for the utility-controlled scenarios compared with the end-of-trip scenario. This was due to the small decreases in the morning and evening electricity demand peaks (when solar generation is not available) and smaller storage requirement. The end-of-trip scenario required 4 GW more PHES capacity than any of the managed charging scenarios, compared with 23 GW more PHES for the end-of-day scenarios.

The lowest LCOE was found when daytime PV is relied upon to charge the passenger EV fleet during the period 0800-1700. This is due to the relative consistency of daytime solar averaged over the entire network – even cloudy days can result in reasonable PV generation. This combined with the availability of wind energy over the shoulder periods meant additional costs for vehicle charging were relatively low. Of all the utility-controlled charging scenarios, Day 08–17 had an average capacity of PHES with the shortest duration of storage needed. In comparison, constraining charging for the Day 09–16 scenario meant an increase in the LCOE, an increase in installed solar, and the lowest wind capacity. The increase in PHES capacity and duration resulted in an increase in the LCOB, and therefore the LCOE. However, in order for these scenarios to come to fruition, sufficient charging infrastructure at workplaces and other public facilities would be required.

Apart from this daytime charging scenario, the other controlled charging scenarios resulted in similar values for the LCOE at around \$56/MWh, although the installed generation ranged from 25 to 53 GW for PV and 49–66 GW for wind, and 21–29 GW for PHES with 25–37 h of storage. Thus, it is possible to model many scenarios that have a similar overall LCOE.

In fact, all scenarios other than the extreme end-of-day scenario (end-of-trip, night-time charging, daytime charging and flat scenarios) resulted in a similar balancing cost of \$20-22/MWh. The average cost premium to incorporate EV demand is around 6%. In other words, the charging scenario does not matter very much except that charging during the evening peak period should be avoided. This is due to the system cost largely being driven by the low generation stress period as described earlier in section 5.1. This important finding enables large flexibility when implementing these charging regimes in practice, as system costs will not be largely affected as long as there is a certain degree of load distribution and not all electric vehicles are charged within the peak hours.

5.3. Storage requirements and V2G

The cost of PHES is the largest LCOB component (\$12/MWh for the end-of-trip scenario, compared with \$5/MWh for transmission and \$5/MWh for spillage), demonstrating that the need for storage is a critical factor of the overall system cost. The scenario with no electrified transport required 17 GW and 26 h of PHES. The PHES contribution for the managed and the end-of-trip scenarios ranged from 21 to 30 GW of power capacity with 25–32 h of energy storage. This increased further in the low end-of-day case to 47 GW and 18 h, and in the high end-of-day case to 49 GW and 14 h. Total storage of 675 GWh $\pm$ 20% is optimum for all the scenarios, excluding the end-of-day scenario with the lower charging rate. This is slightly less than the average electricity consumed in the NEM (including transport) over the course of a single day. The incorporation of low-cost, mature PHES resulted in a lower LCOE than those in the papers discussed in section 1.1 (e.g. Refs. [19,25,28]). Unlike the case of molten salt energy storage or biomass energy balancing, excess wind or PV energy can be stored in a PHES system to reduce spillage with a round trip efficiency of 80%. A global survey of potential off-river PHES sites has recently been carried out and 616,000 well-distributed promising sites with a combined storage capacity of 23 million GWh have been identified. This is 100 times more than required to support a 100% global renewable electricity system [29].

Most of Australia's pumped hydro sites are in the Great Dividing Range, which runs 2000 km down the east coast, and this is also close to where most people live. There was no constraint that the off-river pumped hydro systems in this study were to be co-located with wind and PV farms. Instead, NEMO balanced the costs for transmission with the benefits of the best sites for each type of facility and found the optimum arrangement, assuming that wind and PV were connected to the grid using HVAC. This means new high voltage transmission was required, which is included in the calculated cost of energy. The dependence on the cost of transmission was tested in the sensitivity analysis, which found that increases in the cost of transmission did not lead to large increases in the LCOE.

In order to ensure that pumped hydro was always available for the occasional critical windless week in winter, the pumped hydro was pre-charged using the existing hydro and bio to ensure there would be sufficient energy stored. The hydro and bio were then dispatched ahead of the pumped hydro to minimise the chance of a shortfall. Apart from these critical periods, the pumped hydro typically operates in daily cycles because of the availability of PV, as shown in Fig. 8.

NEMO uses the historical solar and wind data to find an energy system with sufficient generation, according to the NEM constraint on unmet energy. As such, in the end-of-trip scenario, there are only 16 h (over the five-year period) where there is an energy shortfall. In order to reduce this figure to zero, the unmet energy constraint would need to be increased. The LCOE would likely increase as more generation or storage capacity was deployed. This is shown in Fig. 10, which shows that the generation capacity from the PHES, hydro and bio is generally sufficient to balance the shortfall from PV and wind.

Alternatively, demand response could be used to avoid the shortfall. The highest daily shortfall was 3,059 MWh over the course of two consecutive hours. If 125,000 car owners were paid not to consume 25 kWh each at that time, the energy deficit would have been avoided, probably with a lower cost than if new energy infrastructure were built [6].

The LCOB calculated in this work is an upper bound, given the conditions for grid reliability from the energy market operator. A large fraction of the LCOB relates to periods of several days of overcast and windless weather in winter that occur once every few years. Substantial reductions in storage requirements and LCOB are possible through contractual load shedding, household battery storage and advanced smart charging, such as V2G. Improving energy efficiency in the built environment would also depress energy demand in winter. However, while V2G offers potential for reducing the amount of short term storage required in electricity systems, it is not yet an established technology. The use of V2G in most jurisdictions would require the consumer, car and charger manufacturer, local electrician, electricity market operator and regulator to act in concert. Currently, most EV manufactures do not have V2G capabilities, with Nissan the main exception, while most EV chargers are only capable of one-direction operation. Tesla, one of the world's largest EV manufacturers, reports that it sees little value in V2G [83]. The cost of V2G in terms of battery degradation is an important factor given that battery costs dominate electric vehicle costs. There has also been little work undertaken to address the social science of V2G, which will affect its acceptance and uptake [84]. We are optimistic about the future potential of V2G in reducing balancing costs, but have excluded it from the scope of this study due to the philosophy of using proven, established technologies.

5.4. On system strength and renewables

The system strength of a power grid, i.e. the measure of how resilient the grid is to a disturbance [85], has traditionally been associated with the inertia provided from large spinning masses [86]. More renewable electricity connected to the grid through inverters has led to a decrease in inertia in countries around the world, with the largest falls seen in Denmark, Lithuania and Germany [87]. Although it was originally postulated that this loss in traditional inertia would limit the technical penetration of renewables [88], the adoption of changes in operations at solar and wind farms (i.e. use of de-loading techniques such as pitch angle control

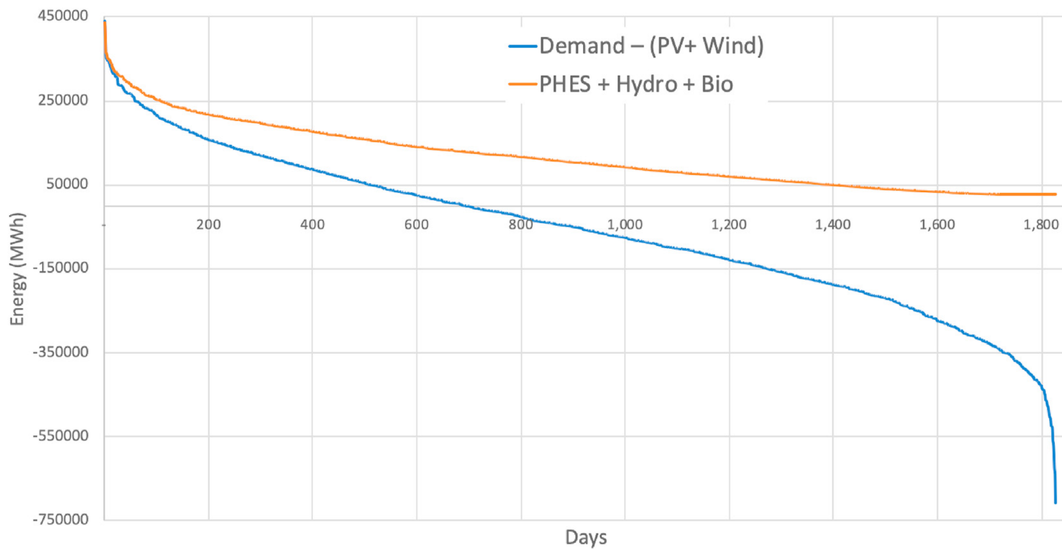

Fig. 10. Load duration curves for net load (demand minus generation from PV and wind) and combined generation from PHES, hydro and bio. Negative net load means that PV and wind generate excess electricity while positive net load means generation from PV and wind was not sufficient to meet the demand. At these times, PHES, hydro or bio were required to fill the gap.

etc. [87]), and the use of grid-forming inverters [89–91], have led to improvements in control. Batteries have played an integral part in this control improvement, and have been instrumental in preventing cascading losses in several instances in Australia, such as during the recent explosion of a coal-fired power plant [92]. It is also possible to convert end-of-life synchronous generation to synchronous condensers [93].

System control and regulation is crucial for stability – in 2018 (when PV and wind met just 5% each of demand in Australia [94]), the NEM had the poorest frequency regulation in the developed world [95], due in part to large-scale generators switching off frequency control equipment as a result of market rules, which have since been rewritten with commensurate improvements in frequency control [96].

In this study, conventional hydro, bioenergy, and pumped hydro energy storage (when both generating and pumping) are all able to provide inertia when in use. In addition, hydro and pumped hydro can be operated in synchronous condenser mode to provide inertia even when not needed to provide energy. Conventional hydro is currently used in this way [97,98]. In the modelled system, the hydro, bioenergy and pumped hydro make up 37 GW of synchronous generation, which is 73% of the maximum demand. On average, there is 8.8 GW of operational synchronous plant, which is 27% of the average demand. Several 100% renewable studies performed using the NEM, including one by AEMO, have deemed a non-synchronous penetration limit of 85% realistic [99]. However, these were all undertaken before the widespread use of grid-forming inverters. In July 2021, the CEO of AEMO announced that the NEM would be capable of 100% instantaneous renewables penetration by 2025 [100].

Many studies in the literature have found that it will be possible for future grids with high penetrations of variable renewables to successfully operate despite lower levels of inertia. Decentralised charging BEVs can be used for frequency control, with or without V2G, e.g. in DeForest et al. [101], or Shokri Gazafroudi et al. [102]. Industrial demand management is also expected to provide system flexibility in the future [103,104].

5.5. Environmental and social considerations

As long as grid electricity is also decarbonised, transitioning land transport entirely to EVs would eliminate 15% of Australia's greenhouse gas (GHG) emissions [105]. In the absence of clean grid electricity, EVs would still result in a net decrease in Australian GHG emissions. The fleet-wide average emissions for new light vehicles in Australia in 2017 was 0.181 kg CO_2-e/km [106], while the emissions from electrified passenger vehicles assuming current emission intensity for purchased grid electricity range from 0.02 to 0.18 kg CO_2-e/km for NEM states. As more renewables enter the grid, these values will drop [107].

Electrification of land transport would also be beneficial for local air quality. Nitrous oxides, sulphur oxides and particulate matter could all be significantly reduced. Pollution from tyres and, to a reduced extent, from brake pads would still be present. EVs would result in lower noise pollution for suburban and urban areas [108] but would not strongly impact highway noise because noise from air resistance and tyres dominates at higher speeds [109].

The environmental impact of decarbonising grid electricity through the use of PV, wind, PHES, and HVDC/HVAC has been discussed in Ref. [6]. Electrifying transport will require more generation plant and likely more grid-scale storage.

Finally, this paper has not considered the environmental and social problems inherent in the transport system in Australia and many other countries. These include but are not limited to the construction of new motorways etc. inducing demand [110], the loss of public space for parking and subsequent urban heating, and poor health outcomes from the lack of active transport [111]. Health outcomes in Australia would be improved by increasing public and active transport [93]. If transport was shifted from private cars to active and public transport, integrating the charging of electric vehicles into the grid could be quite a simple undertaking. This study has also not investigated the material requirements for full electrification, nor the embodied emissions of the fleet change.

5.6. Implications for other countries

The key finding from this study is that charging of electric vehicles and all other forms of land transport can be incorporated into a 100% renewable electricity system with >90% variable PV and wind at low net cost, without any heroic assumptions about future technology development. This finding applies to all countries and regions with good wind or solar resources, sufficient off-river PHES sites and strong interconnection over large areas. A key requirement is to avoid charging during the evening peak demand period.

This study on the Australian NEM demonstrates that PV, wind, off-river PHES and large-scale interconnection offer a low-cost viable solution to supply both underlying grid demand and demand from a 100% electrified land transport fleet in an isolated electricity market. With PV and wind costs in the range of $35/MWh, the LCOE of a balanced 100% renewable electricity system is around $56/MWh. This is below the LCOE of any alternative supply option and is below the 2018 NEM pool price. A future carbon price would tip the balance further in favour of an all-renewable energy system. Future studies that refine costs and uncover improved solutions are likely to find an even lower LCOB.

The proposed Australian pathway is transferrable to other countries, especially those in the Sunbelt ($\pm 35^{\circ}$ of latitude) where the seasonality of both the solar irradiation and electricity demand is low. There are much more off-river PHES sites than are required to balance the supply and demand within most regions of the world [112].

6. Conclusion

Transport is the second largest source of emissions, following the electricity sector, in many regions around the world, with the land transport fleet producing the great majority of emissions in this sector. The electrification of land transport could remove a significant portion of global carbon dioxide emissions, if the electrified fleet is powered by renewable electricity.

In this study we demonstrate that solar photovoltaics, wind, off-river pumped hydro energy storage and high voltage transmission together offer a low-cost solution to integrating the additional load from electric vehicles into a 100% renewable electricity system dominated by variable PV and wind. We present an hourly energy balance analysis of the Australian National Electricity Market and find that without any heroic assumptions about future technology development, charging of electric vehicles and all other forms of land transport could be incorporated into the electricity system with only a 4%–8% increase in the levelized costs of electricity. The impact of various charging regimes on the levelized cost of electricity is minimal so long as mass charging during the evening peak period is avoided. This is because costs are largely determined by managing occasional periods (days-weeks) of low renewable generation.

This study contributes to the literature by presenting a detailed analysis of the impacts of the electrification of the land transport fleet on an electricity system dominated by variable renewable generation, which is yet to be well-studied. The inclusion of only off-the-shelf technologies with known costs, in particular pumped hydro energy storage which is often overlooked in the existing literature, allows a reliable upper bound of the system costs to be estimated.

The proposed Australian pathway is transferrable to other countries, especially those with good wind and solar resources, sufficient off-river pumped hydro energy storage sites and the potential for strong interconnection over large areas.

CRediT authorship contribution statement

Anna Nadolny: Conceptualization, Methodology, Formal analysis, Writing – original draft. **Cheng Cheng:** Methodology, Formal analysis, Writing – original draft. **Bin Lu:** Software, Writing – review & editing. **Andrew Blakers:** Conceptualization, Writing – review & editing, Supervision. **Matthew Stocks:** Investigation, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2021.10.039.

Abbreviations list

BEV	Battery Electric Vehicle
CO_2(-e)	Carbon dioxide (equivalent)
CSP	Concentrated solar power
EV	Electric Vehicle
GHG	Greenhouse Gas
GW	Gigawatt
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LCOB	Levelized Cost of Balancing
LCOE	Levelized Cost of Electricity
LCOG	Levelized Cost of Generation
NEM	National Electricity Market
NEMO	National Electricity Market Optimiser
NSW	New South Wales
PHES	Pumped Hydro Energy Storage
PV	Solar Photovoltaics
USA:	United States of America
V2G	Vehicle-to-grid

Variables

E_{daily}	(in kWh) is the daily electricity consumption
c	(in kWh/km) is the unit energy consumption
d_{daily}	(in km) is the daily travel distance
t_{loss}	is the transmission loss
η	is the charging efficiency (85% according to Ref. [30])
v_loss	is the additional standing loss due to battery self-discharge plus the energy used to power on-board electronics (1% of nominal battery capacity per day according to Ref. [31])
B	is the nominal battery capacity
$E_{rail,daily}$	(in kWh) is the daily electricity consumption for rail
$D_{rail,annual}$	(in PJ) is the annual diesel consumption for rail
η_{diesel}	is the diesel efficiency (29% according to Ref. [32])
$\eta_{electric}$	is the electric rail efficiency (76% according to Ref. [32])

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