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When should you charge your EV?

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Introduction

As the uptake of Electric Vehicles (EVs) in Australia accelerates the impact of EV charging on the grid will become significant, possibly exceeding the total electricity demand in the residential sector. Hence the way in which EVs are charged will be a major factor in determining the optimal mix of generation technologies to meet that demand. One possible scenario is that a majority of EVs will be charged overnight in private garages, which would mean wind, hydro and energy storage will be required to meet that demand. However if the charging is done predominantly during the daytime at workplaces, public parking garages etc, then the EVs will be able to harness the plentiful and affordable solar PV energy.

In this study we have run an electricity grid capacity expansion model for the NEM using the Melbourne/Monash University Renewable Energy Integration Lab (MUREIL) with the two different charging options for the EVs. Comparing the output of the two simulations, the nighttime case results in an additional 7 GW of wind and 5 GW of PHES being installed in 2050, while for the daytime case, the model installs 7 GW of additional solar PV. The daytime case would see EV owners paying a LCOE of $47/MWh (4.7c/kWh) for the power to charge the EVs, while for the nighttime case the LCOE for the power to charge the EVs would be double, at $102/MWh. This conclusion suggests that there is a strong case for shifting the dominant form of charging to be where the EVs will be during the day, and not in private garages.

Model description

MUREIL (Wang et al 2018, Wang and Dargaville 2019) simultaneously optimises the transition pathways for the NEM by minimising the total system cost for electricity generation, transmission, and storage from 2020 to 2050. In particular, MUREIL aims to find least-cost configurations for the NEM generation mix that meets specified demand growth and emission abatement targets, subject to system inertia constraints, unit commitment, and economic dispatch with transmission power flow constraints. The model is technology agnostic and explores a range of generation options including large-scale solar photovoltaic (solar PV), concentrating solar thermal (CST), wind turbines, open (OCGT) and combined cycle (CCGT) gas turbines, largescale batteries, PHES, demand response, and coal with carbon capture storage, etc.

The transmission model used is a DC flow approximation with 21 nodes over the eastern states of Australia representing the major load centres (figure 1, AEMC 2013). The model is initialised with the existing transmission system capacities and a number of decision variables relating to augmentation and extension of the network to facilitate additional renewable generation in more remote parts of the grid (i.e. Northern Queensland or Tasmania).

The model simultaneously solves for additional capacity required at 5-year increments (2020-2050) and hourly economic dispatch to ensure supply and demand are always matched. Due to computational constraints, the model is run using one representative week from each season, resulting in a 28 day ‘year’.

Figure 1: The NEM transmission model. Blue arrows represent the AC transmission lines, while the orange arrows represent HVDC links.

Input data

Input data are taken from the AEMO Integrated System Plan 2022 (AEMO, 2021). These include the hourly demand trace for each state and the technology costs. The projected EV rollout numbers are taken from the "step change" scenario which shows 12 million EVs on the road by 2050 (figure 2). This represents around 50% of all vehicles and could be an underestimate if Australia adopts a 100% emission abatement target for 2050. We make the assumption that each vehicle is driven 50km per day, requiring 8kWh to recharge. For the daytime scenario this charging is restricted to 9am to 5pm, and for the overnight case restricted to 6pm to 6am.

To explore a larger geographic span (compared to the 33 ISP REZs) for renewable energy resources assessment, the model uses renewable resources capacity factor time series for the 43 RE polygons developed by the AEMO 100% Renewable Energy Study (AEMO, 2013). The total demand (not including EVs) increases from 198 TWh per year in 2020 to 283 TWh per year driven by electrification of industrial process and residential heat requirements (Ueckerdt et al. 2019) based on the Energy Transition Hubs Accelerated Scenario. The EV demand in addition to this is 35 TWh per year.

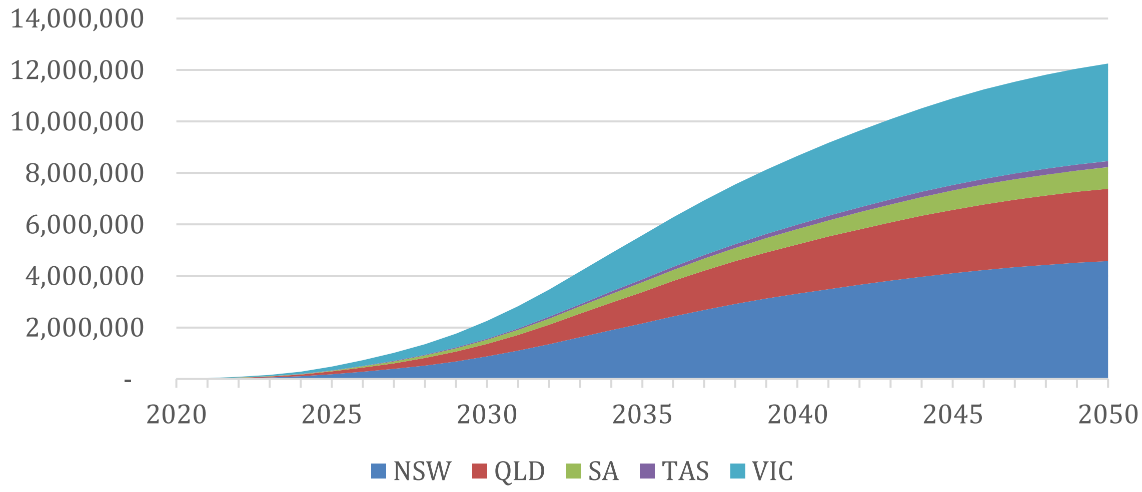

Figure 2: EV rollout by state to 2050 for the step change scenario from AEMO 2021.

Results

Figures 3 and 4 show the change source of electricity between the daytime and nighttime scenarios, and the time series of output for the 28-day period that the model solves for. The figure shows, not surprisingly that for the daytime case there is a larger reliance on solar PV, while the nighttime case requires more wind and storage (PHES) to meet the additional load.

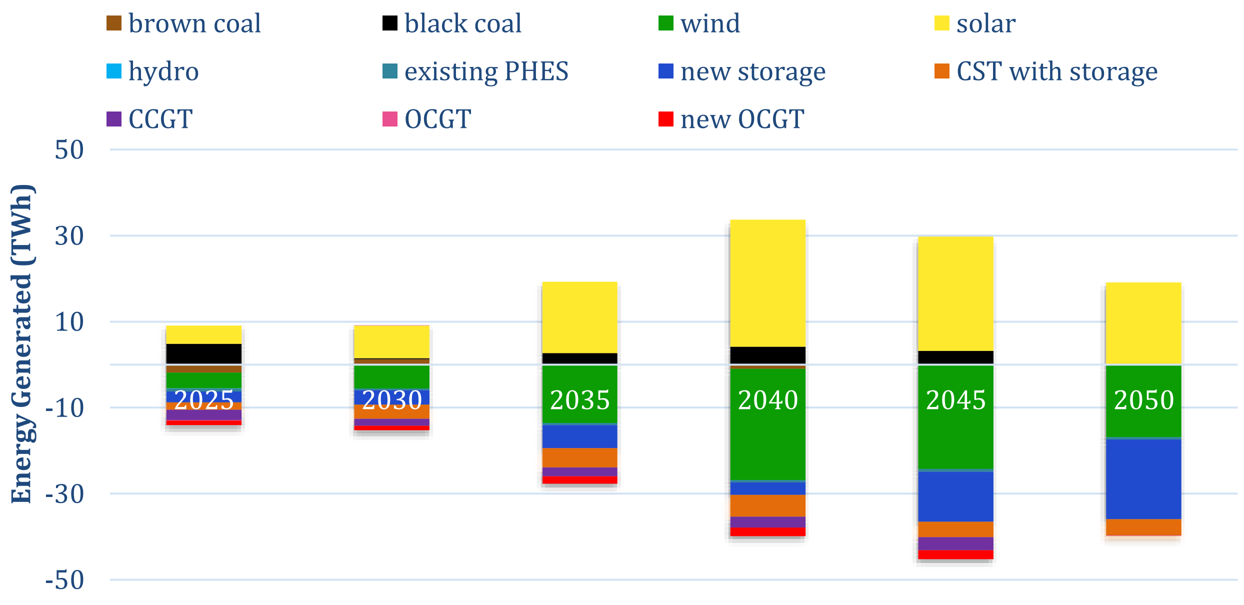

Figure 3: Difference in energy requirements for the daytime and nightime EV scenarios

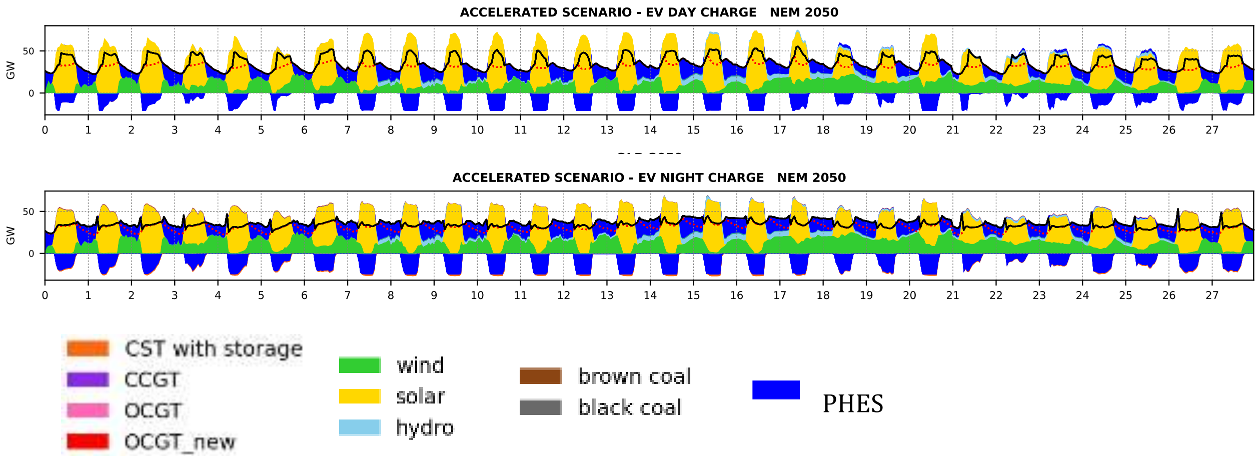

Figure 4: Time series of generation for the daytime and nighttime EV charging scenarios

The time series plot show that the overall impact of the difference in EV charging strategies is relatively small. However, an analysis of the inferred market prices from the model shows that the nighttime charging results in double the energy costs for EV owners (10c/kWh compared to 5c/kWh for daytime) resulting in an annual impact of approximately $150 per car per year.

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