Emissions and prices are anti-correlated in Australia: what this means for the decarbonisation of our grid

Louise Bardwell
The Australian National University
Canberra, Australia

Lachlan Blackhall
The Australian National University
Canberra, Australia

Marnie Shaw
The Australian National University
Canberra, Australia

ABSTRACT

Recent work has shown that energy storage operating in a CO_2 intensive grid can increase greenhouse gas (GHG) emissions. In this paper we sought to characterise the emissions of Australia's electricity grid to inform the planning and operation of energy storage with the goal of minimising emissions associated with energy storage and supporting the rapid decarbonisation of Australia's energy system.

To do so, a marginal emissions factor (MEF), representative of the emissions intensity of the marginal generator (the generator with the highest bid price) in each time period, was calculated for the Australian National Electricity Market (NEM) across 2018 for each of the five NEM regions, SA, NSW, VIC, QLD, and TAS. Through analysis, significant variation was discovered in the MEF's intra-day variability, with high MEF values occurring overnight and during times of lower demand, and low MEF values occurring during the day during times of peak demand. Compared against the average 30-minute spot price across the day, a strong anti-correlation was calculated between the MEF and the spot price.

Using these results, the importance of energy storage operated to minimise both costs and emissions was highlighted. By taking the key finding of its anti-correlation with price, the MEF can be simply implemented in the real world, including through dynamic carbon incentives and market tariffs, to ensure emissions are being reduced both in the short-term and long-term. In doing so, this paper's findings can be used to ensure optimum energy storage operation for emissions reductions is not disadvantaged in an energy market operating under least cost dispatch. The authors of this paper suggest these findings be used in further work modelling how energy storage will operate under different cost and emission reduction objectives, dynamic carbon incentives, and market tariffs.

CCS CONCEPTS

• **Hardware** → **Power and energy**; **Energy generation and storage**; **Batteries**; *Energy distribution.*

KEYWORDS

batteries, neighbourhood scale batteries, energy storage, tariffs, solar PV, hosting capacity

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1 INTRODUCTION

In Australia, GHG emissions were 538 Mt CO_2e in 2020, only slightly down from their recent peak in 2018 of 559 Mt CO_2e. Of these emissions, electricity accounted for 32%, followed by emissions from other stationary on-site energy uses like industrial heat and household gas at 19.1%, and transport at 17.5% [2]. The decarbonisation of Australia's energy grid therefore has the potential to reduce over half of Australia's total CO_2e emissions. For this decarbonisation to occur, renewable energy generation supported by energy storage will be essential. The Australian Energy Market Operator (AEMO) has forecast the need for 6 to 19 GW of new flexible, dispatchable energy storage including pumped hydro, large-scale battery energy storage (BES), and distributed batteries [1].

Whilst the integration of energy storage will support decarbonisation long-term by increasing the integration of renewable generation in the grid, it is not however guaranteed to support decarbonisation in the short-term. This is because the type of energy storage and how it is operated will determine the degree to which it impacts a change in GHG emissions. For example in the case of BES, recent work has highlighted that operation to maximise revenue may be counter to that for minimising GHG emissions [13]. In such a situation, BES operated to minimise cost would result in a net increase in emissions, especially when taking into account the inherent inefficiencies of BES and its embedded emissions.

To properly manage this implementation of energy storage for rapid decarbonisation, in-depth understanding of the emissions profile of Australia's electricity grid, specifically emission trends, sources of emissions, and factors influencing emissions intensity at any period, is therefore needed. In doing so, comprehensive methodologies can be implemented to assess the impacts this small to large-scale energy storage will have on decarbonising the energy grid to appropriately inform energy users, energy networks, and energy policy. Without this insight, the operation of new energy storage, as well as the implementation of supporting policy and regulation, may fail to achieve its aims of rapid emissions reductions. In the context of the Paris Climate Agreement and increasing urgency to meet emission reduction targets, it is essential that countries like Australia consider both the long-term and immediate, short-term emission impacts of new technologies.

Whilst analysis of emissions intensity of electricity markets has been widely explored in literature, it has largely contained to electricity grids in Europe and North America. In these geographies, electricity generation is met by a considerably different mix to that in Australia, typically dominated by natural gas, nuclear and hydroelectric plants. The Australian electricity grid however has historically relied far more heavily on coal powered plants, with its recent decarbonisation being driven by DERs like rooftop solar PV, which contributed almost double that of utility scale solar to Australia's National Electricity Market (NEM) in 2021 (OpenNEM).

The Australian NEM therefore offers an important case study for other countries in showcasing the role energy storage can play in reaching 100% renewable electricity systems. As the NEM operates under a process of least cost dispatch, where the energy spot price is set by the generator with the highest bid price, analysis of the emissions intensity of the NEM reveals the impact least-cost dispatch has on achieving emissions reductions, and therefore the considerations that need to be taken to optimise energy storage integration. Unlike other electricity grids, the NEM publishes publicly available data on the results of its least-cost dispatch, including which generators had the highest bid price and set the market price in each time interval. With this time-wise data on marginal generators, a high degree of insight is possible on the short-term impact energy storage can have on decarbonisation.

Globally, the Australian NEM is also unique in the diversity in electricity generation it experiences between different regions. With the NEM split between South Australia (SA), New South Wales (NSW), Queensland (QLD), Victoria (VIC), and Tasmania (TAS), renewable integration and therefore emissions intensity in regions like TAS is far more progressed than that in QLD. As a result, the Australian NEM provides an interesting case study on the stages of renewable integration in electricity networks, and therefore the impact energy storage will have on emissions intensity as decarbonisation occurs.

With these unique attributes of the Australian NEM in mind, this paper provides novelty (to the authors' knowledge) in its deeper analysis of marginal emissions in the NEM, its state-wise comparison of marginal emissions, and in its discussion on how these will impact energy storage operation.

The remainder of this paper is organised as follows: Section II outlines related work. Section III describes the data to be analysed in this paper. Section IV analyses the data, and Section V discusses its impact on energy storage operation and emissions reductions. Section VI concludes the paper.

2 RELATED WORK

The emissions intensity of energy storage is dependent on the energy used or displaced by the storage when it charges and discharges. Recent work has highlighted the fact that, due to internal losses, if high carbon energy like coal or gas is used to charge energy storage and low carbon energy like solar PV and wind are reduced as a consequence of the energy storage discharging, emissions can actually be increased [11].

To calculate the emissions intensity of energy storage and its operation, the emissions intensity of generation in the electricity grid needs to be known. This is often determined through the use of an emissions factor that quantifies the emissions associated with generating one unit of energy, often measured in tonnes of CO_2 equivalent per MWh, for a specific energy generator or fuel technology type. Using this emissions factor alongside data on market price and dispatched generation, emissions intensity of an electricity grid can be calculated. Depending on the data available and focus of the analysis, the calculation of this emissions factor can differ significantly with varying degrees of adequacy. Two of the most common calculation methods used in literature are what are known as the average emissions factor (AEF) and the marginal emissions factor (MEF).

The AEF is a simplified calculation, taken as the total direct CO_2 emissions of the electricity generation sector divided by the total electricity generation over a certain period. Databases like eGRID use monthly emissions data to estimate hourly AEFs, and have been used by works like [9] and [5]. AEFs however are limited by their assumption that generation and emissions in the electricity network are static, taking a change in demand to affect the aggregate generation in that time period rather than just a marginal portion of it. [13] rather use the MEF, which reflects the emissions intensity of the marginal generators in the system in a particular time period. Here, the MEF acknowledges that a change in demand will only affect the dispatch of generators operating at the margin. For assessing the impact of BES, the MEF has been acknowledged as the more appropriate calculation method [12].

Both the AEF and MEF rely on the use of historical dispatch data to calculate the emissions intensity of that energy system in a future time period. [8] argues most works focus on this short-run MEF (SR-MEF) based on historical data that doesn't capture long-term changes to the electricity market. Rather, [8] propose long-run MEFs (LR-MEF), which represent the long-term change in CO_2 emissions per unit change in demand across the lifetime of a specific intervention. Complexity in determining a LR-MEF however arises due to uncertainty regarding the decommissioning of old power plants and rate of growth of new power plants, as well as broader changes to the energy grid that may influence future dispatch.

Calculating the MEF for the Australian National Electricity Market (NEM) in 2019, [10] found that emissions intensity and price were anti-correlated. In an industry report, [6] extended these findings to calculate the MEF by time-of-day for South Australia across the last decade. For a battery operating to maximise profits with perfect foresight of prices, which caused it to charge during the early hours of the morning and discharge during the evening peak, they found the net effect of the battery was to increase emissions. When the battery was operated to reduce emissions, they found it operated almost in stark contrast, charging during the peak and discharging during the early morning. As such, it was suggested that without any price on emissions, BES had no incentive to minimise emissions. The broader applicability of these results, including how the MEF varied across the year and between NEM regions, however was not covered, nor was analysis on what fuel technology type across the day represented the marginal generator.

With similar findings on the trade-offs between costs and emissions reductions, [13] use the Pareto frontier to show that costs and GHG emissions can simultaneously be reduced across a range of scenarios compared to the reference cases of no battery or a battery focused only on increasing PV self-consumption. A similar trade-off between revenue and emissions reduction for BES operation has

Table 1: Data Sources

Data type	Source
NEM CDEII	NEM market operations
NEM available generators	NEM market operations
NEM price setter	NEMDE market data
NEM spot price	NEM trading price - public

also been explored in [3], where they show that including just a small consideration for CO_2 emissions in the objective function can result in storage-related emissions that are greatly reduced at minimal expense to the owner.

3 THE DATA

3.1 The Australian NEM

The NEM operates across one of the world's longest interconnected power systems, connecting five of Australia's states and territories, SA, NSW, QLD, VIC, and TAS. It is a wholesale market where electricity in Australia is traded between generators and retailers, who buy and sell on electricity to businesses and households. Each of the five NEM regions act as separate price regions, with differing market prices and mixes of generation.

The NEM operates as a spot market, where supply and demand is matched instantaneously through a centrally coordinated dispatch process. AEMO's dispatch for generation in the NEM follows a least-cost dispatch model, where operation is designed to meet electricity demand in the most cost-efficient way. To do so, a spot price is used, which represents the incremental (marginal) cost of supplying one further unit of demand (1 MW). This price is set by the NEM Dispatch Engine (NEMDE), which takes input data on energy bids, energy availability, forecast load and generation, and generator's daily energy constraint.

In the dispatch process, generators must place bid offers with specified electricity amounts at specific prices for set time periods. These bids are then created into a bid stack that is overlaid with the forecast load so the cumulative volume of dispatched offers just equals the demand to be supplied at the end of each dispatch interval. This dispatch model is solved by the NEMDE solver algorithm that will schedule generation and load to meet forecast non-dispatchable demand in each region. The NEM data used in this paper is summarised in Table 1.

3.2 AEMO Emissions intensity data

As defined in the Australian Government's National Greenhouse Accounts (NGA) factors, emissions for carbon accounting of electricity generators are considered across three different emissions types [4]:

- Scope 1: emissions associated with combustion of fuels on-site or other emissions associated with the power station facility
- Scope 2: indirect emissions from any electricity purchased from the grid
- Scope 3: indirect emissions associated with extraction, production and transport of the fuel to the power station

Since a National Electricity Rules amendment in 2010, AEMO has been required to publish a carbon dioxide equivalent intensity index (CDEII) for the NEM for all scheduled generating units and market generating units in a time interval. The CDEII is calculated from dispatch data and publicly-available generator emission and efficiency data, which is then published on a daily basis as a NEM-wide CDEII. The key inputs to the CDEII are therefore emission factor data and available generators data. Both can be sourced from AEMO's NEMweb database and from AEMO's Integrated System Plan (ISP) database. Emission factors provided in this database were calculated using the following formula:

$$EF_i = \frac{3.6}{TE_i} \times \frac{ef_i}{(1 - A_i)} \tag{1}$$

where i is the energy generator, TE_i is the thermal efficiency of the generator, ef_i is the emission factor for the generator derived by summing the Scope 1 and Scope 3 emissions (in kgCO2e/GJ of fuel), A is auxiliaries, a loss factor for energy consumed by other equipment at the generating system, and 3.6 is the conversion factor (1 MWh = 3.6 GJ). Figure 1 shows the average of the emissions factors for each of the fuel technology types in the NEM as of 2020. As the EF_i is specific to each generator, the emissions factor associated with different fuel types will differ slightly.

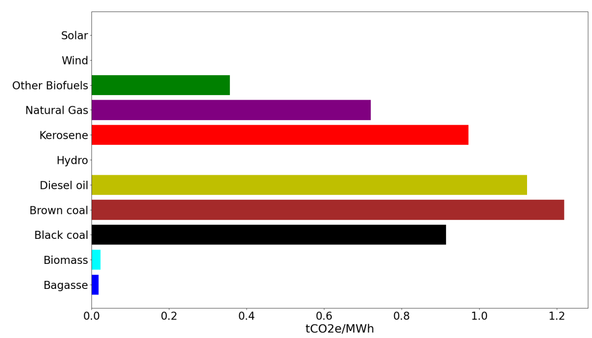


Figure 1: Average of emissions factors of generators in NEM by fuel tech type (averaged from NEM available generators)

The carbon dioxide equivalent emissions (CDE) is then calculated by multiplying the EF_i times the sent out generation (MWh). This is then summed for all generation that was sent out in a time period to find the total CDE (CDE_{total}) for the NEM. The CDEII is then this CDE_{total} divided by the total sent out generation. Figure 2 shows how the CDEII for the NEM regions has changed over the last decade since 2012. From 2012 to 2014, emissions steadied thanks to the introduction of a carbon pricing scheme in July 2012 by the Gillard Labor government. After the scheme was repealed in July 2014, emissions increased from 2015 to 2017, before decreasing again from 2018 as a result of the decommissioning of some of Australia's old brown coal power plants, including Hazelwood Power Station in Victoria that was decommissioned in March 2017. Comparing between the regions, SA and VIC has experienced much greater fluctuation in emissions intensity, with values in the last decade ranging from as low as 0.1 up to 0.8 tCO_2e/MWh, whilst

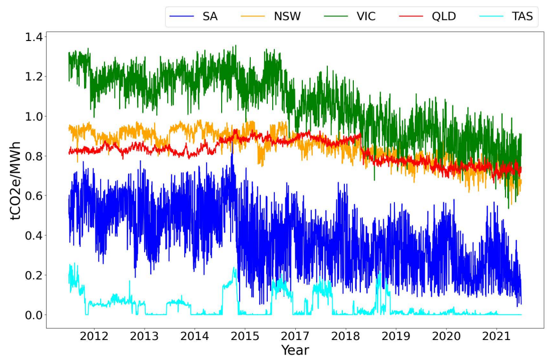


Figure 2: CDEII comparison between NEM regions from 2012 to 2021 (taken from NEM CDEII market operations data)

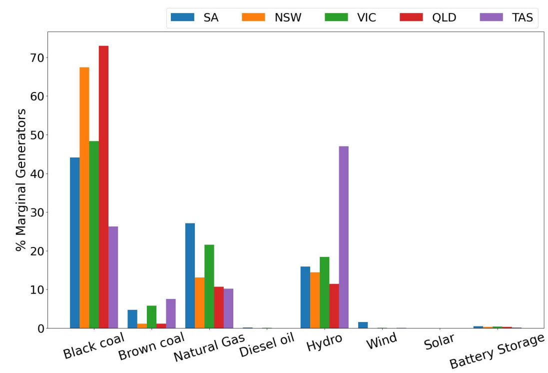


Figure 3: Frequency of different fuel technology types that were the marginal generator in the NEM

Table 2: MEF Regional Comparison

	avg	max	min	std	% MEF=0
SA	0.572	1.491	0	0.386	26.2
NSW	0.625	1.492	0	0.384	24.4
VIC	0.567	1.492	0	0.401	28.7
QLD	0.677	1.492	0	0.360	18.9
TAS	0.229	1.491	0	0.340	65.1

emissions intensity in QLD and NSW have remained more consistently high at around 0.8 to 0.9 tCO_2e/MWh due to their stronger reliance on coal-powered generation.

3.3 AEMO marginal generator data

The AEMO marginal generator data was taken from the NEMDE database that contains publicly available historical data on the results of the NEMDE algorithm from 2009 to present for the least-cost dispatch in each five-minute time interval. The data shows the most expensive generator, referred to as the marginal generator, and provides the predicted increase amount for which generators will change their dispatch in response to a 1MW change in demand in each region. In numerous cases, there may be multiple marginal generators caused by generating units bidding at the same price, meaning that with a change in demand, each of these units will change their output by an equal amount. Often, these multiple generating units are from the one plant, however, there are also time intervals when the marginal generators may come from different plants and potentially even different regions.

To just analyse the marginal generators with significant influence and output change in response to a change in demand, the data was filtered for only units changing their dispatch by greater than 0.05MW. Whilst energy storage like BES can operate in both the energy arbitrage and FCAS markets, only the energy arbitrage market was focused on.

The frequency of which each fuel technology type was the marginal generator across all 5-minute time intervals in 2018 is shown in Figure 3. As can be seen, black coal is the most frequent marginal generator, followed by hydro, natural gas, and brown coal. Compared to the other NEM regions, the high penetration of hydro power in Tasmania is evident, with almost 50% of the marginal generators in Tasmania being hydro plants.

To calculate the MEF for each time period, the emissions factor (EF_i) for the relevant marginal generator, i, was used. In time periods where more than one generator was operating at the margin, the average of the generators' emissions factors was used.

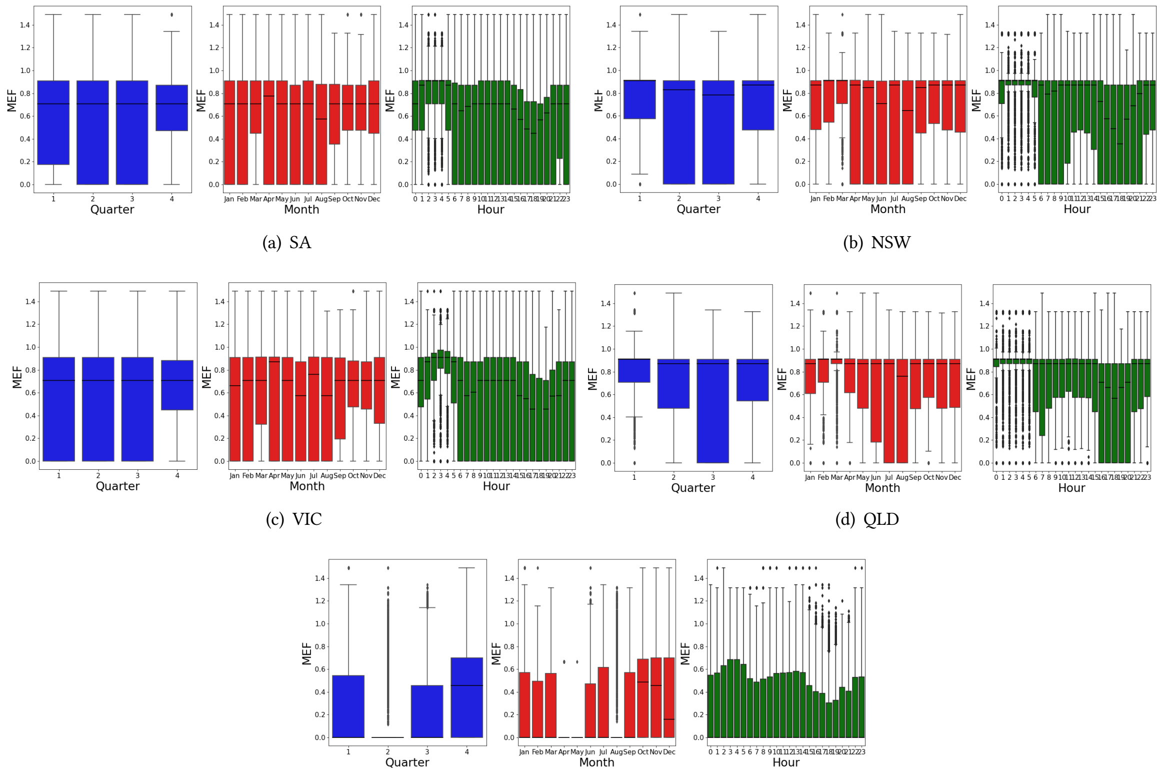
4 ANALYSIS

4.1 Trends

4.1.1 Range of the MEF data. Table 2 shows the average, maximum, minimum, standard deviation, and percentage of intervals where the MEF was zero for each of the NEM regions across 2018. As can be seen, QLD followed by NSW had the highest average MEF, followed by SA, VIC, and TAS. From these average MEFs, the greater percentage of coal-powered plants in the generation mix in QLD and NSW is evident, with both states also having the lowest percentage of time periods with a MEF of zero of 18.9% and 24.4% compared to 26.2% and 28.7% for SA and VIC. TAS as a distinct outlier to the other NEM regions saw 65.1% of time intervals in 2018 having a zero MEF, resulting in its average MEF of 0.229 and highlighting the impact high penetration of renewable hydro power generation has had on driving down its average MEF.

On an average day in South Australia in 2018, the difference between charging at maximum versus minimum grid marginal emissions was found to be 1.23tCO2e/MWh. For every 1 GW of distributed storage, charging during a period of high versus low marginal grid emissions would therefore result in approximately 0.45$MtCO_2e$ extra emissions per year, or 0.1% of Australia's total GHG emissions in 2020 (which reached 538 $MtCO_2e$). Likewise, charging battery storage from renewable energy and discharging at the time of highest grid emissions could reduce emissions to the same degree.

4.1.2 Quarter-wise distribution. Figure 4 shows the distribution of MEF values per 5-minute time period across the year of 2018 for SA, NSW, VIC, and QLD. Quarterly results suggest distribution of the



(a) SA (b) NSW

(c) VIC (d) QLD

(e) TAS

Figure 4: Results of MEF calculation, sorted by quarter of the year, month of the year, and hour of the day for NEM regions in 2018. Shows the variance of MEF across different time periods and between the different NEM regions

MEF is least during Q1 and Q4 for SA, NSW, and QLD, and greatest during Q3 for all of SA, NSW, QLD, and VIC, and also in Q2 for SA, NSW, and VIC. Both SA and VIC have a consistent median MEF across all four quarters, suggesting no seasonal variation across the year. NSW and QLD appear to have slight variation, with NSW seeing the lowest median MEF in Q3 and the highest in Q1, and QLD having a slightly higher median MEF in Q1. In TAS, the MEF is zero throughout Q2 except for a number of outliers, with the median MEF in Q1 and Q3 also being zero, and highest in Q4 at close to 0.4 tCO_2e/MWh.

4.1.3 Month-wise distribution. Monthly SA and VIC had lower monthly median MEF values around 0.7 tCO_2e/MWh, whilst NSW and QLD had higher monthly median MEF values closer to 0.8 tCO_2e/MWh. QLD, specifically in March, had the lowest range of MEF values, suggesting the price was consistently being set by the same fuel type. In all regions, August had the lowest median MEF ranging from about 0.6 to 0.7 tCO_2e/MWh. In TAS, all months but October, November, and December had a median MEF of zero.

4.1.4 Hour-wise distribution. All regions except for TAS show a trend of experiencing a small range of high MEF values during the early morning. In SA and VIC, the hours in the middle of the day, from around 6am to 3pm, have the greatest range, and median values of around 0.7 tCO_2e/MWh. NSW has similar range from 6am to 10am, from which the hours in the middle of the day until 3 pm are more concentrated in the range of 0.5 to 0.9 tCO_2e/MWh. QLD rather has a much stricter range between higher MEF valyes of 0.5 to 0. 9tCO_2e/MWh until the early afternoon. In all states, a drop of the median MEF is experienced from 3pm to 6pm, which then rises again approaching midnight. TAS, as an outlier,has a median MEF of zero for each hour of the day, with a much more consistent range of values throughout the day, including a similar dip at around 6pm.

4.1.5 Stationarity and seasonal variation. A stationary time series is one in which the properties are independent on the time at which the series is observed, meaning that there is no seasonal variation or time dependent trends in the series. Generally, a stationary time series will have no predictable patterns in the long-term, with plots roughly horizontal with constant variance between series. The time series data for the MEF across 2018 for each NEM region was therefore tested for stationarity to determine the existence or not of seasonal or time-dependent trends in the data. A Dickey-Fuller (DF) test was performed on the data, which was resampled to 30-minute time periods to reduce the noise in the 5-minute interval data. In all tests, the MEF time series were found to be stationary, with extremely low p-values of 7.60e-21, 2.57e-14, 1.13e-19, 6.58e-17, and 8.05e-12 for SA, NSW, VIC, QLD, and TAS respectively. Through this, the importance of focusing on the intra-day variability rather than the inter-day variability was further enforced.

4.2 Energy price versus emissions intensity

Figure 5 plots the MEF (shown in red) for each NEM region against the energy market spot price (shown in blue), averaged across 2018 for each 30-minute period in the day. Error bars showing the standard error of the mean have been added to both plots. The annual average MEF for each region has also been plotted. As can be seen in all plots, there is a significant anti-correlation between the average MEF in a 30-minute time period and the average energy spot price, as was found in [10]. The anti-correlation is most distinct in the early hours of the day, up to 6am, where the spot price is at its minimum values and the MEF is at its maximum values. Similarly, from early afternoon to evening, around 3pm to 9pm, the MEF is at its lowest, with its minimum value occurring around 6pm, whilst the spot price peaks, reaching its maximum value at 6pm. The standard error of the mean for the MEF in SA, NSW, VIC, and QLD are all small, suggesting there is low inter-day variability across the year and therefore high predictability.

For SA and VIC, and to a lesser extent NSW and then QLD, the anti-correlation between MEF and spot price is at its minimum during the middle of the day, from around 9am to 3pm. Incentivising battery operation to charge or discharge during this period is therefore likely to offer the best trade-off between cost and emissions reduction. There are also times at approximately 7am, 3pm, and 9pm where the spot price and MEF converge, which may offer opportunity for a fast response BES to further optimise the trade-off between costs and emissions.

Table 3: Spearman rank correlation coefficients for MEF versus market price by NEM region

Region	r-value	p-value
SA	-0.84	8.1e-14
NSW	-0.94	2.5e-23
VIC	-0.90	5.2e-18
QLD	-0.95	7.7e-26
TAS	-0.51	2.1e-4

As in the work of [14] and [7], the Spearman rank correlation coefficient r was used to analyse the relationship between the MEF and market price given the non-linearity of the relationship between the two datasets seen. Table 2 shows the results of the analysis. As observed, there was a strong anti-correlation between the average 30-minute MEF and market energy price for the year of 2018 for all NEM regions but TAS, with a Spearman r coefficient of -0.84 for SA, -0.90 for VIC, -0.94 for NSW, -0.95 for QLD, and -0.51 for TAS. In all cases the p-value was less than 0.05, meaning the null hypothesis of no anti-correlation was rejected for all.

4.3 Frequency of different fuel technology types as the marginal generator

Figure 6 shows the distribution of marginal generators by fuel technology type for each of the NEM regions across the day in 2018. All plots show the same trend for the percentage of marginal generators across the year that were black coal plants, highest overnight and with two significant dips during the periods of around 5 to 8am and 3 to 7pm. Throughout the day, peaking during the same time periods that black coal dips, hydro steadily increases in occurrence as the marginal generator, whilst natural gas represents a more consistent percentage of marginal generators. As was found previously, the distribution plots are similar between SA and VIC and between NSW and QLD. The key difference between SA and VIC to that of NSW and QLD, is the higher percentage of marginal generators that were natural gas or hydro throughout the day, which corresponds with the higher MEFs calculated for NSW and QLD.

5 DISCUSSION

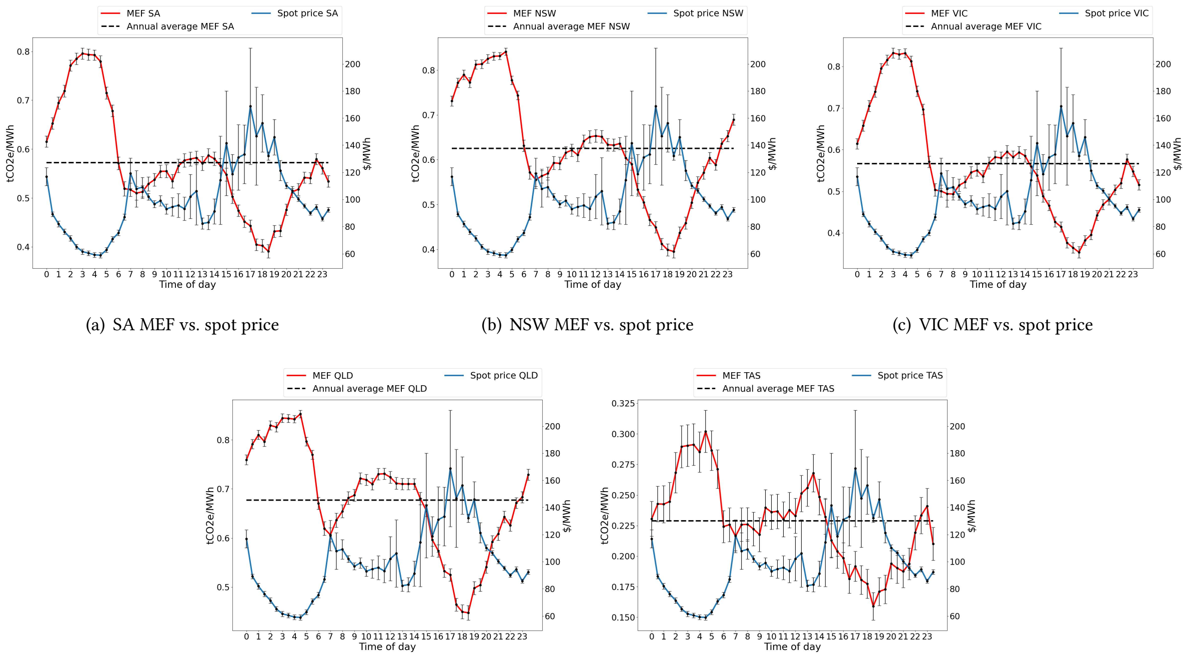
5.1 Impact of MEF on energy storage operation in a least cost dispatch market

From analysis, it is clear there is significant intra-day variability and insignificant inter-day variability in the MEF across all NEM regions. As a result, operation of energy storage need only focus on the intra-day optimisation of its operation. With the current state of Australia's least cost dispatch market, the MEF during the day is strongly anti-correlated with that of the spot price. Due to this, in the short-term, it is evident that energy storage operated to reduce costs will operate opposite to that operated to reduce emissions. The importance of multi-objective optimisation of energy storage, where both cost and emission reductions are used as operational objectives, has therefore been shown in this paper's analysis on the MEF.

5.1.1 Carbon incentives and market tariffs. Due to the anti-correlation between MEF and energy market price, carbon incentives could therefore play a critical role in improving the trade-off between emissions and costs. As there is no guarantee that energy storage operating in the NEM will be optimised to reduce emissions, system-wide carbon incentives to encourage energy storage to charge and discharge during particular time periods can serve to ensure that energy storage does not contribute in the short-term to an increase in emissions. As the anti-correlation between MEF and spot price is greatest during times when the MEF is highest, and smallest when the MEF is at its lowest, a flat carbon price may not necessarily be capable of achieving this. Dynamic carbon costs or market tariffs, incentivising operation to occur at particular times of the day, will therefore more likely be needed. Before such a carbon incentive or market tariff is introduced, however, greater understanding and modelling of how energy storage like BES will operate under different objectives with foresight on MEF and spot price trends, is needed.

5.2 Role of MEF and emissions-based operation as rapid decarbonisation occurs

In the coming decade, the anti-correlation between the MEF and market price will decline. This is because, as can be seen in the comparison of marginal generators between QLD and TAS, as renewable energy technologies and energy storage increase, as has



(a) SA MEF vs. spot price

(b) NSW MEF vs. spot price

(c) VIC MEF vs. spot price

(d) QLD MEF vs. spot price

(e) TAS MEF vs. spot price

Figure 5: 30-minute period MEF and spot price averaged across 2018 for all NEM regions with standard mean of error bars. In all regions, an anti-correlation between MEF and spot price can be seen

been achieved in TAS with its high penetration of hydro, the intensity of the MEF throughout the day will decline. Included in this comparison can be seen the decreasing dominance of black coal plants that are the marginal generator during the early morning and late night time periods.

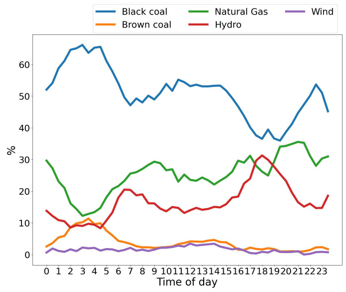
One of the main reasons for black coal often being the marginal generator during these times of lower demand and therefore market price is due to its low short run marginal cost (SRMC), whereby black coal plants will make low market bids to ensure they don't have to endure the more expensive alternative of shut down and start up costs. As shown in TAS, this occurrence will change as renewable penetration and storage in the NEM increases. During times when generation from wind and solar plants is highest, such as in the middle of the day, renewable generators will often make bid offers at the NEM's market floor price of -\$1,000/MWh to ensure that their generation is dispatched. The ability for renewable generators to bid and generate at these market floor prices comes from both their very low SRMC, as well as incentives via supplemental revenue streams, such as renewable energy certificates based off every MWh they produce, that encourage them to generate even at times of negative prices.

As the penetration of energy storage in the grid increases, technologies like BES that have charged off excess solar generation during the day will then also be able to discharge to meet demand overnight. As this will entail very low SRMCs for the energy storage technologies, they will also be able to significantly compete with the low bid prices made by black coal plants during these times. In doing so, black coal plants will continuingly be pushed to the margin, with their bids being the last to be accepted for dispatch. A point will then be reached when all overnight demand can be met by energy storage technologies alone and no black coal generation will be needed. Once this occurs, black coal plants will no longer be economically viable and will be forced to decommission early. Evidence for this has already begun to occur, with Origin Energy recently announcing the early decommissioning of Eraring Power Station, one of NSW's largest black-coal fired power plants, due to projections of it reaching non-competitiveness with other generation technologies past approximately 2035.

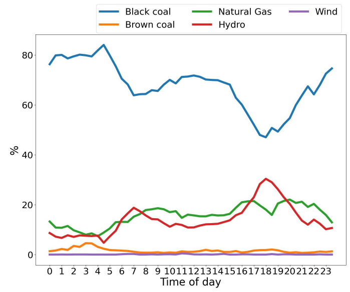
As this occurs, the significance of the MEF will decline as the emissions intensity of marginal generation throughout the day and night will continue to approach zero and all demand is met by renewable generation and storage. Once it reaches zero, the impact of operation of energy storage on emissions will be irrelevant. The time period for which this occurs is dependent on how quickly energy storage and renewable generation is implemented in the NEM, but under AEMO's 2022 ISP projections is likely to occur over the next decade.

6 CONCLUSION

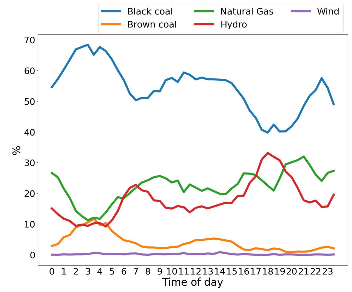
This paper has analysed the emissions intensity of the Australian NEM to understand how energy storage and its operation will contribute to rapid decarbonisation. To do so, a marginal emissions factor (MEF), representative of the emissions intensity of the marginal generator (the generator with the highest bid price) in each



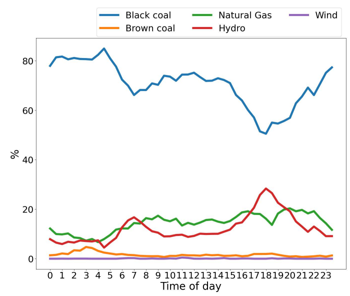
(a) SA



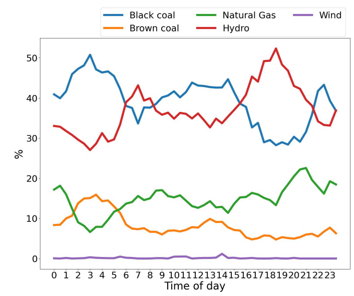
(b) NSW



(c) VIC



(d) QLD



(e) TAS

Figure 6: Percentage of different fuel technology types that were the marginal generator by time of the day for 2018 across all NEM regions (obtained from analysis of the NEM price setter data and its market data results for the NEM dispatch engine)

time period, was calculated by 5-minute time intervals using NEM price setter data for 2018 for each of the five NEM regions, SA, NSW, VIC, QLD, and TAS. The average MEF across the year for the regions was calculated to be 0.572, 0.625, 0.567, 0.677, and 0.229 tCO_2e/MWh respectively, with 26.2%, 24.4%, 28.7%, 18.9%, and 65.1% of 5-minute time intervals respectively having a zero MEF. All time series were found to be stationary, with insignificant inter-day variability and therefore high predictability across the year. When considering the intra-day variability however, significant variation was discovered, with high MEF values occurring overnight and during times of lower demand, and low MEF values occurring during the day during times of peak demand. Compared against the average 30-minute spot price across the day, a strong anti-correlation was calculated between the MEF and the spot price, with Spearman correlation coefficient r-values of -0.84, -0.94, -0.90, -0.95, and -0.51 calculated respectively for five regions. Using these results, the importance of energy storage operated to minimise both costs and emissions was discussed, highlighting how, if energy storage is to contribute to emissions reductions in the short-term, both costs and emissions need to be considered. Energy policy and regulation therefore need to be carefully considered to ensure they are having the desired decarbonisation impact, with the authors suggesting the possibility of dynamic carbon incentives or market tariffs to encourage storage to charge and discharge during particular time periods.

Analysing the distribution of fuel technology types that represented the marginal generators across the day, 50% to 80% of marginal generators in NSW and QLD, compared to 40% to 65% of marginal generators in SA and VIC, and 30% to 50% in TAS, were black coal plants. In SA, VIC, and most significantly TAS, this difference in percentage of marginal generators was made up by hydro and natural gas plants. In all regions, the percentage of black coal plants as marginal generators peaked in the early morning and were at minimum at 6pm. This comparison across NEM regions, specifically QLD and TAS, was finally argued in this paper as representing a case study on how increasing renewable energy storage in the NEM can compete with the historical dominance of coal powered generation in Australia, providing market competitive energy generation during times of low and peak demand.

Under this logic the MEF will therefore decline in significance, approaching a value of zero with the decarbonisation of the NEM. At this point, how energy storage operates on an emissions basis will be irrelevant. While this transition occurs however, the MEF will be an important indicator of the impact energy storage is having on decarbonisation, revealing the impact changes in demand resulting from new energy storage is having on generation at the margin. In doing so, it can ensure reliance on fossil-fuel powered generation is being replaced with renewable generation and storage at all times of the day, and therefore that rapid decarbonisation to meet net zero targets minimises emissions both in the short-term and long-term.

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