An Emissions Consideration for Flexible Green Hydrogen Electrolysers in the NEM

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Hydrogen electrolyser loads are a pertinent technology not only in adding a tremendous foreseeable increase in demand to the Australian National Electricity Market (NEM) but also an opportunity for such demand to be flexible and price responsive. While existing literature explores the opportunity to produce green hydrogen as an export commodity in Australia (Palmer, 2018; Hydrogen Council, 2021), or contextual studies of integrating electrolyser loads in other power systems (Welder *et al.*, 2018; Bødal *et al.*, 2020), there are literature gaps in comparing contracting strategies a hydrogen participant may take with renewable generators in the NEM to both hedge the energy spot price, as well as assure hydrogen production is green.

Green certificate-based schemes are a common energy market policy implemented to facilitate the uptake of renewable energy. Within the NEM, Large-scale Generation Certificates (LGCs) form one aspect of the Renewable Energy Target policy framework whereby liable entities must purchase a proportion of certificates to cover their energy consumption, while participants who are not liable may also choose to purchase such certificates from a market pool (Clean Energy Regulator, 2018). One potential voluntary participant in such a scheme are hydrogen electrolysers seeking to assure their production as green hydrogen. However, current certificates schemes disregard any temporal matching of generation and consumption, rather banking of certificates is allowed in the current LGC scheme. IRENA further recognise temporal correlation, geographical correlation, a linkage to technology type and additionality of new capacity build as key factors for future green hydrogen certificate schemes (IRENA Coalition for Action, 2022).This paper therefore investigates the consequences of a flexible load operating within existing schemes as well as the outcomes of temporal matching through the use of bundled Power Purchase Agreements (PPAs) with hypothetical renewable generators.

A linear mixed-integer optimisation model is constructed to formulate the operational decisions of an electrolyser load seeking to produce green hydrogen in a counter-factual study using historical NEM data. For a defined case study, data is extracted and processed using python packages NEMOSIS (Gorman, 2021) and NEMED (Heim and Naderi, 2022). This data is input as variables to the optimisation model, aggregated to a half-hourly basis, providing adequate insight into price-responsive behaviour without excessive computational burden. The model considers the objective to minimise a cost function comprised of; the cost of energy from the spot market, the cost owing (or received) on the PPA contract(s) for difference and the negative cost (benefit) of producing hydrogen, assumed as $4/kg or equivalently $60/MWh. An additional cost implied is that of the shadow carbon price in one scenario, given an average grid emissions intensity trace.

Subsequently the model can be described in three components; the electrolyser load, PPA contracts and the generated emissions associated with load consumption that is assumed from the grid (not via PPAs). The electrolyser is defined with a rated capacity of 100MW and for consistency across scenarios is set to operate at approximately a 70% capacity factor, a requirement to be met daily reflecting a possible end-use demand for hydrogen production. The PPA contracts, detailed overleaf, are assumed as bundled PPAs that include green certificates. It is further assumed certificates may be banked as the load must cover its operation with acquired certificates over the entire simulation, but not per-interval. Finally, any consumption that does not temporally match contracted renewable generation has emissions associated with it based on average emissions intensity trace.

This paper presents six scenarios in evaluating the influence of PPA contracting strategies on load operation and associated emissions produced, considering the South Australian region of the NEM over the period of March 2020 for plotted results, and further over the CY2020 for tabulated results.

- Reference Case: Grid-connected Electrolyser only (no PPA).
- Case A: Contracting a PPA strike price of $30/MWh with a solar farm ('Bungala One' historical trace scaled to a rated capacity 2.5 times that of the load).
- Case B: Contracting arrangements of Case A, with a carbon price of $100/tCO2-e on the regional average emissions.
- Case C: Contracting a PPA strike price of $40/MWh with a wind farm ('Hornsdale 3' historical trace scaled to a rated capacity 2 times that of the load).
- Case D: Applying both contracts of Case A and C.
- Case E: Applying both contracts of Case A and C, without any excess energy via the spot market.

A comparison is initially drawn between Cases A and B in evaluating the effect of shadow carbon pricing against the reference case which purchases certificates from the spot market at $30/MWh. Figure 1 depicts a subsection of timeseries data for one week in the simulation period. Given the allowance of banking of certificates, the load is not always temporally matched to the contracted generation, and hence we quantify the emissions for energy consumed from the grid. A consideration for the average carbon emissions intensity for each dispatch interval with respect to South Australia in this case study yields a 25% reduction in emissions attributed to the load's grid consumption, yet only a 10% reduction in grid energy consumed as per Table 1. Although this load shifting does burden the cost of a 24% reduction in revenue.

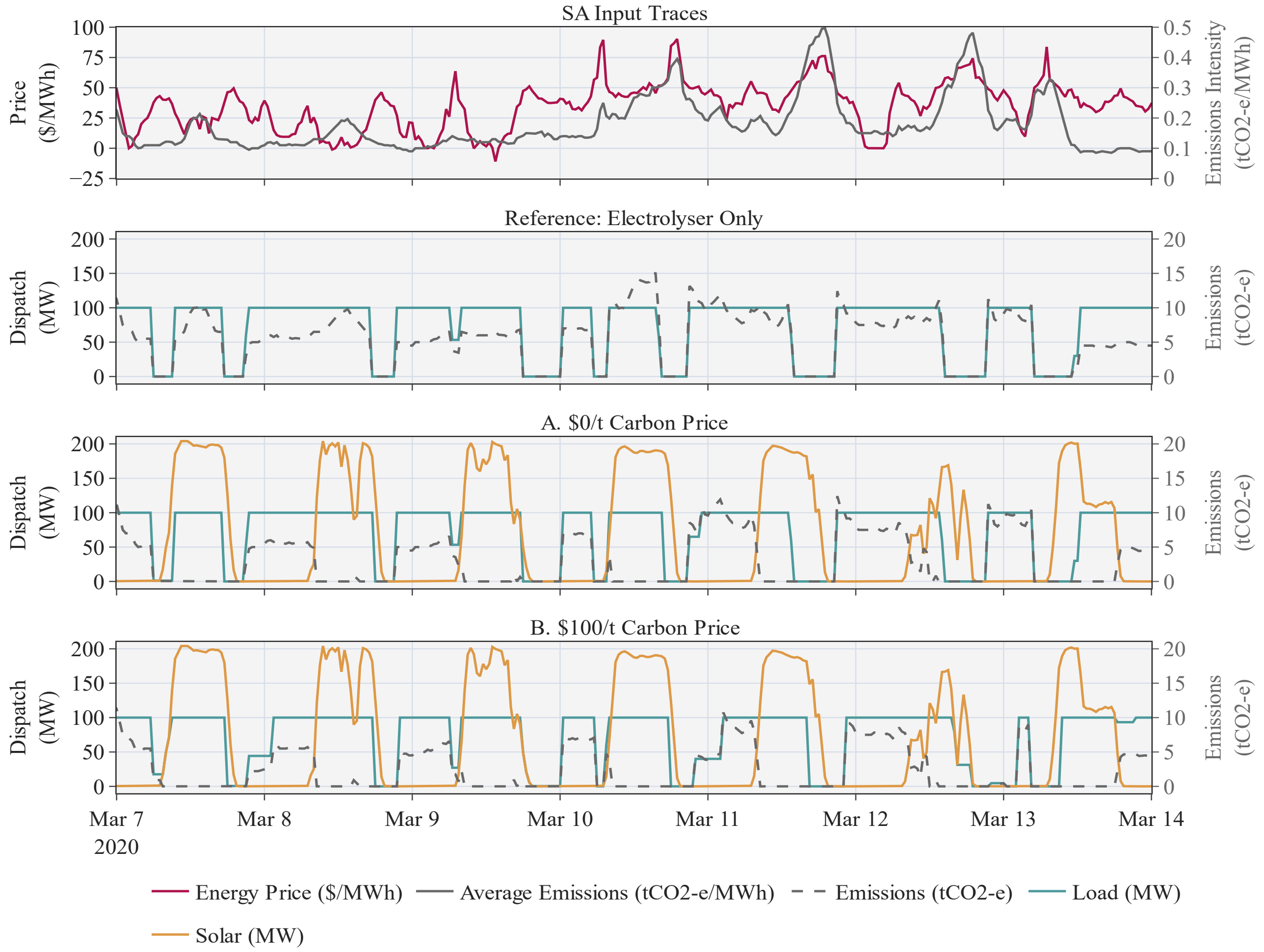

Figure 1 Impact of shadow carbon pricing on electrolyser operation.

A subsequent comparison of varying contracting arrangements considering solar, wind and a dual strategy with both solar and wind PPAs is shown in Figure 2. Here there is a clear distinction between solar and wind generation diurnally. In particular, Hornsdale which has a stronger production output in early morning periods, combining with the solar trace of Bungala, results in the load requiring much less energy from the grid to sustain the 70% capacity factor. There is minimal difference in revenue outcomes between Cases D and E since the load without any consumption from the grid (Case E) is able to increase operation at times covered by contracted renewable generation, with a negligible cost increment given oversizing of both contracted generators providing a financial hedge in addition to received green certificates.

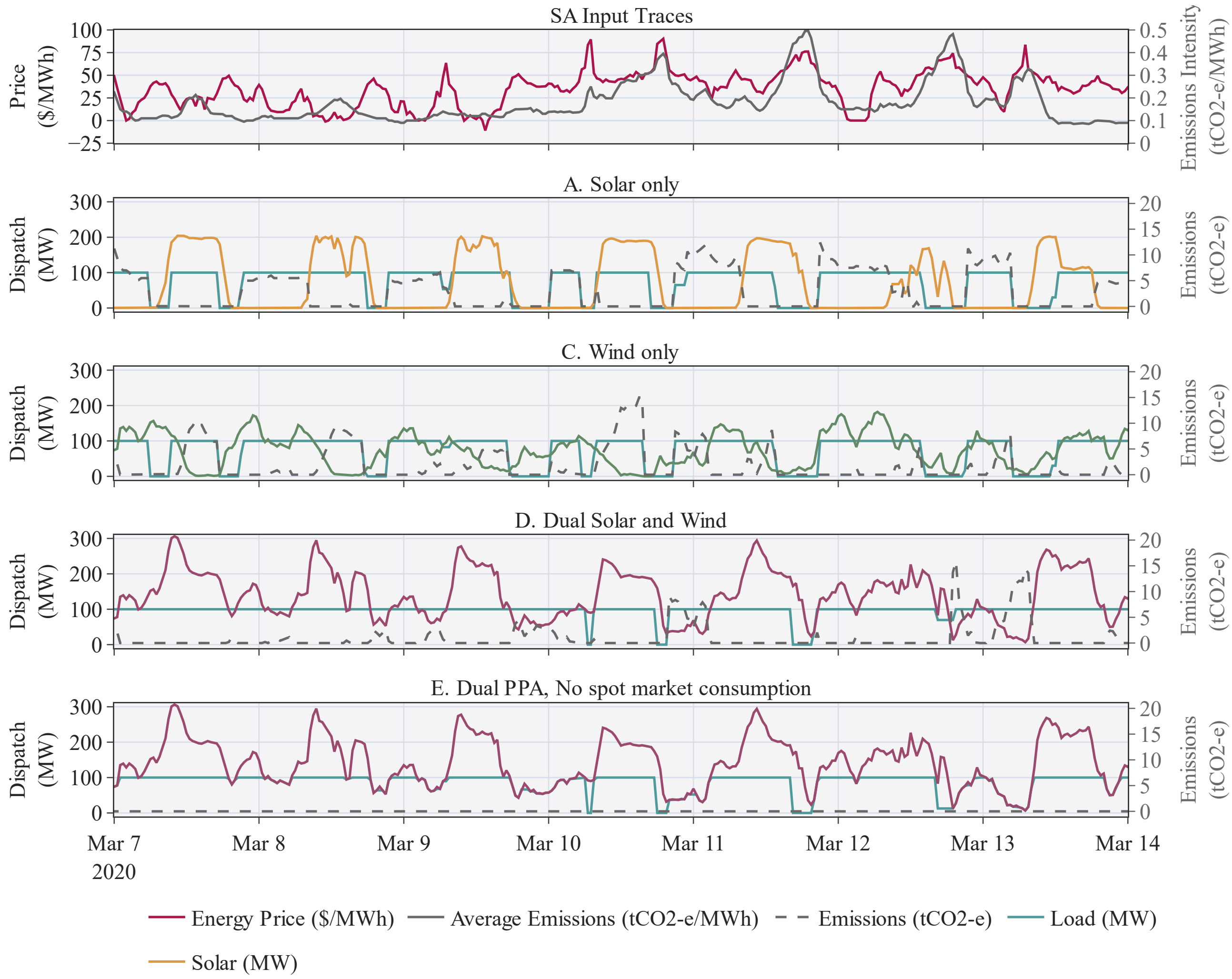

Figure 2 Impact of PPA contracting arrangements on electrolyser operation.

A distinctive feature of this case study is the poor performance of the wind PPA, which achieves an emissions reduction of approximately 20% with respect to the solar PPA however with a revenue reduction of 52%. This outcome cannot be generalised and is attributed to earlier price volatility in the simulation period which correlates with significant wind generation leading to a large tradable difference on the PPA contract.

Table 1 Summary of results for all scenarios over the period Mar – Apr 2020.

Case	Load Capacity Factor (%)	Proportion of Grid Energy (%)	Impact Emissions (tCO2-e)	Emissions Reduction wrt. Case A (%)	Total Revenue ($k)	Revenue Reduction wrt. Case A (%)
A	70	57.8	6,382	-	2,180.9	-
B	70	47.2	4,763	25.4	1,655.6	24.1
C	70	34.9	5,059	20.7	1,030.9	52.7
D	71	14.0	2,218	65.2	1,638.8	24.9
E	72	0	0	100.0	1,638.1	24.9

All in all, this particular case study reveals advantages in implementing a dual PPA strategy incorporating both solar and wind generators that not only achieves a significant reduction in emissions associated with the load consuming energy from the grid but further advantageous financial outcomes due to the hedge provided by both PPAs against the energy spot price. It also raises key questions for future work such as the implications of energy storage to be able to temporally match to renewable energy generation, without consuming from an emissions intensive grid, while also sustaining high load capacity factors for hydrogen production demand.

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