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Can high levels of renewable energy be cost effective using battery storage? Cost of renewable energy scenarios for an isolated electric grid in Western Australia

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Abstract. Many simulations of very high or 100% renewable energy electricity systems rely on existing or expanded capacity of utility scale power technologies with long construction lead times, such as hydro power or pumped hydro power. However, globally, the shorter lead time and more distributed technologies of wind power, solar PV, and batteries are expanding rapidly, and costs are falling. Can a grid get to high levels of renewable energy with these technologies alone, along with energy efficiency improvements, at reasonable cost? To address this question, scenarios of partial (<100%) renewable electricity supply were simulated for the South-West Interconnected System (SWIS) in the southwest of Western Australia. The SWIS is isolated from other grids, so power balance between supply and demand must be maintained completely within the grid, and there is no significant hydropower capacity to fall back on. Even with no improvement in cost and no carbon price, the partial renewable energy scenarios were found to be less expensive than a fossil fuel "business as usual" scenario up to about 70% renewable generation. With carbon prices of $24/tonne and $70/tonne, the same scenarios were less expensive up to around 80% and 96% renewable generation respectively. Hence at current costs, using solar PV, wind, energy efficiency and battery storage technologies are cost effective up to very high levels of renewable energy, but not 100%. However the cost of these technologies are falling rapidly. A simple way to include these continuous cost improvements into the levelised cost of energy calculation was developed, and it was found that if the costs of solar, wind and battery technologies continue to improve at current global rates, then the break even level with conventional generation increases significantly, up to 99% or above with a carbon price of $70/tonne and current Australian installed capacity growth rates. Hence a battery based system operating at almost 100% renewable energy which is no more expensive than a conventional fossil system is foreseeable for the SWIS grid, and perhaps other grids as well.

1 Introduction

Electricity systems with high levels of variable renewable energy generation are now widely considered able to operate effectively and reliably, although doubts remain [1]. Here renewable energy (or RE) is also taken to include energy efficiency measures and some form of storage. However, there is still a degree of uncertainty about the costs of such electricity systems, compared to the cost of using conventional fossil fuel or nuclear generation. On the one hand, many studies found the cost of RE systems favourable. For example, Mathiesen et al. [2] found that 100 percent RE systems for the country of Denmark may be economically beneficial compared to fossil fuel systems, particularly if externalities such as health costs are counted. Elliston et al. [3] found that the cost of a 100% renewable energy system for the national grid in Eastern Australia was competitive with fossil fuel based low carbon alternative systems. In the South West of Western Australia, Lu et al. [4] modelled costs for a 100% RE scenario using pumped hydro, and found that if 2030 capital prices are used, then the cost is similar to a conventional fossil generation scenario if there is a price on carbon of $25 per tonne. Sadiqa et al. [5] found a 100% renewable system for Pakistan using RE gas storage was less costly than a conventional fossil fuel system. Aghahosseini et al. [6] found that a renewable powered grid spanning the Americas would be less costly than conventional generation. Jacobson et al. [7] modelled a world wide 100% RE system containing 139 countries and found the overall cost to be less expensive than using

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conventional generation. A more recent similar study found the 100% RE system to have similar direct costs to the business as usual case [8]. If climate and health costs were included, the RE system was much cheaper.

In contrast, Zappa et al. [9] modelled seven renewable energy scenarios for Europe, and found them to be more expensive than the current system unless nuclear power or carbon capture and storage were used. Connolly et al. [10] modelled an RE system for Europe, including electricity, heat and transport, and found the cost of the system would be more expensive. Riesz et al. [11] found that the lowest cost renewable energy system scenarios for Australia had very high levels of wind power generation, but would be more expensive than the current conventional system. Rose et al. [12] found that an 85% renewable scenario for the South West of Western Australia would have a matching cost, but a 100% RE system would be more costly. Cochran et al. [13] conducted a meta study of large scale RE electricity system scenarios around the world, finding that some complete (100%) renewable energy scenarios were estimated to be more expensive than an equivalent conventional fossil fuel system, some on a par, and some less costly. A very recent meta study [14] found 100% RE scenarios to be the same or more expensive than an equivalent conventional system, unless externalities were included.

However, the costs of wind power and solar PV have fallen rapidly over the past decade, and are continuing to fall, to the point where new build wind power in particular could compete on a purely investment cost basis with new build fossil fuel power stations [15]. Benson and Magee [16] reported a cost improvement rate of around 3% per year for wind power, and around 9% per year for solar PV. More recent reports suggest these cost improvement rates are continuing [17,18]. Globally, installed capacity of wind and solar PV have also grown rapidly, by about 29% and 22% per year respectively [15]. There are some doubts over whether these growth rates can be maintained [19], although in Australia Baldwin et al. [20] forecast they will be exceeded in 2019.

Many of the most widely available sources of RE, such as wind and solar PV, are variable, and dependent on meteorological conditions. They cannot always generate according to the current level of demand, although there is often a correlation between availability and demand, for example extra air conditioning load on a hot sunny afternoon with high levels of solar radiation. There is also complementarity between different types of RE, such that the generation level of one type can be high when another is low. Hence using more than one type of RE, and also increasing the geographic spread of RE power plants, are options to more fully cover the demand if the availability of one RE source is low in one region. However this may mean there will be significant excess in generation availability when demand is low. Denholm et al. [21] investigated the effects of increasing levels of RE on an isolated electric grid, and found that costs would become prohibitive because of increasing levels of curtailment of the RE generators when demand was less than the available supply. Adding a form of energy storage decreased curtailment, although there were diminishing returns as the amount of storage increased. This is consistent with the findings of Elliston et al. [22] for the national grid in Eastern Australia. The cost incremented in a mostly linear fashion as the proportion of RE generation increased, with some cost acceleration above linear increase as the proportion of RE exceeded 80%.

Hence most very high or 100% RE studies utilise storage, or a source of energy that can be generated flexibly according to demand, and can compensate for low availability of the variable sources of RE [14]. These include hydroelectricity, pumped hydroelectricity, bio energy, renewable hydrogen or methane conversion, geothermal energy and solar thermal generation and storage. The flexible generation technologies in effect utilise a form of stored energy. Demand side management, which is the controlled withdrawal of non-essential loads, can also be used when demand exceeds supply. Energy efficiency measures have the potential to reduce demand over all time scales.

A common feature of most high RE studies is the reliance on existing or expansion of hydro or pumped hydro capacity as one of the sources of flexible generation to achieve cost competitive 100% RE systems. All of the studies chosen by Deason [14] for in-depth analysis had this characteristic. Nine out of twelve of the studies assessed by Cochran et al. [13] also used hydro or pumped hydro. One of the exceptional studies, Kemp and Wexler [23], modelled Britain and relied on bio energy, tidal and wave power rather than significant levels of hydro power. The second exception, Lund and Mathieson [24], used biomass and hydrogen electrolysis for flexible generation. The third exception, Connolly et al. [25], relied heavily on bio energy. Another study, Pleβmann et al. [26], also simulated global 100% RE electricity relying on solar thermal and renewable power to gas storage rather than hydroelectricity.

Use of hydroelectricity or biomass on a large scale may not be feasible in many areas of the world due to topographical or environmental constraints. Even if feasible, these technologies could involve significant installation lead times. The average lead time for hydroelectric projects around the world has been about 8.6 years [27]. There can also be other barriers. For example, even though extensive pumped hydro capacity in the European Union is already available, Kougias and Szabó [28] found that rising levels of RE did not automatically lead to a rise in utilisation rates, and that this might inhibit the needed investment in new capacity. The authors suggested the use of proactive technological, policy and market measures to encourage utilisation and new investment.

However, in the absence of specific policies and planning to enable these large scale and long lead time projects, the use of another storage technology, batteries, is likely to grow. Usually considered for short term storage, battery systems are distributed, scalable from home or car size to utility scale, have short installation times, non dependence on suitable topography or geology, a growing installed base and a cost reduction trajectory. Benson and Magee [16] reported a cost improvement rate of around 3% per year. However, Nykvist and Benson [29] concluded that EV battery costs had improved at a faster rate of around

Table 1. Current installed capacity for the SWIS electrical grid (BAU) and renewable energy capacity for each partial renewable scenario (<100% RE) by technology type.

Scenario	RE generation (%)	Energy efficiency improvement	Solar PV	Wind	Distributed storage
BAU	17	5%	1000 MW	465 MW	–
1	42	25%	1000 MW	1033 MW	1000 MWh
2	47	30%	1000 MW	1033 MW	1140 MWh
3	52	30%	1710 MW	1033 MW	1140 MWh
4	56	30%	1710 MW	1433 MW	1140 MWh
5	69	30%	3420 MW	1947 MW	4560 MWh
6	72	30%	4000MW	1947 MW	7000 MWh
7	75	30%	3420 MW	2447 MW	10500 MWh
8	79	30%	4500 MW	2447 MW	10500 MWh
9	84	30%	6840 MW	2747 MW	10500 MWh
10	90	30%	6840 MW	3247 MW	16500 MWh
11	94	30%	6840 MW	3447 MW	22800 MWh
12	96	30%	6840 MW	4447 MW	22800 MWh
13	97	30%	9000 MW	4447 MW	22800 MWh
14	98	30%	9000 MW	4447 MW	25650 MWh
15	98.7	30%	9000 MW	4447 MW	33250 MWh
16	99.5	30%	14000 MW	4447 MW	33250 MWh
17	99.9	30%	18000 MW	4447 MW	38000 MWh

8%, and Schmidt et al. [30] predicted a faster cost improvement rate of around 7–9% per year between the years 2015 and 2030. Growth in global installed capacity has been about 33% per year [31].

Could a very high RE system be cost competitive using batteries alone as the storage system? This study will examine this question by making cost comparisons of different partial renewable energy scenarios using battery storage for the South West Interconnected System (SWIS). The SWIS is an electric grid that supplies the South-West region of Western Australia (SWWA). The present configuration of energy generation systems connected to the SWIS is dominated by conventional fossil fuel power stations. There is also about 460 MW of onshore wind capacity and more than 500 MW of roof top solar PV capacity connected to the SWIS.

Much of the conventional generation capacity is aging [32] and would be due for replacement within the next 15–30 years. Since it is not feasible to replace all the conventional power generation capacity overnight, the SWIS will continue to consist of a combination of conventional and RE generation, with the percentage of RE generation most probably increasing in line with the goal of reducing greenhouse emissions. A reason to model the SWIS is that it does not currently have any significant hydro power capacity. Also the SWIS has no connection with any other grid, and so must be entirely self reliant.

The structure of this study is as follows: In the methods section scenarios are developed that push the level of RE used on the SWIS towards 100%, but hydroelectricity, pumped hydro, biomass or solar thermal technology are not used. Instead, differing mixes of wind, solar PV, energy efficiency improvement and distributed battery storage will be simulated, and the cost of energy (*COE*) for each scenario is estimated. A business as usual (BAU) scenario is also developed where the load demand of the SWIS grid was met with predominantly conventional fossil fuel generation capacity. The external cost of greenhouse emissions is incorporated into the cost model using a price on equivalent carbon emissions, and a simple method to incorporate cost improvement over the building duration of each scenario into the cost model is introduced. The results and discussion sections find that with no cost improvement of the RE technologies, the partial renewable energy scenarios with no carbon price are less costly than the BAU case for up to around 70% RE generation (the break even point). If the carbon price is increased or there is cost improvement, then the break even point is pushed higher. With a carbon price, cost improvement and current Australian installation growth rates, the break even point could reach above 99% RE generation. This result indicates that it is plausible a 100% RE grid using only batteries for storage will be cost effective compared to the fossil fuel BAU case. In the final section, the conclusions reached by this study are summarised.

2 Method

Seventeen partial renewable energy scenarios for the SWIS grid were considered in this study, each with a different level of renewable technologies used. The installed capacities of each of these technologies are given in Table 1. A business as usual (BAU) scenario was also developed whereby the load demand on the SWIS was met using mainly current conventional fossil fuel generation technologies. It was assumed that the cost of the BAU scenario does not change, although it may go up because of increasing fuel costs. The framework to model these scenarios has previously been developed to model 100% renewable energy (RE) scenarios for the SWIS on an hour-by-hour basis [33–35]. Hourly power generation profiles were synthesised for each scenario, based on the installed capacity of each renewable energy technology and statistical profiles of wind speed and solar radiation. These profiles were compared to the hourly load profile over a period of one year to estimate the percentage of RE generation.

In general terms, for each scenario the cost of energy (COE) was estimated by aggregating the cost of each power plant and new grid infrastructure within the scenario. The cost of an individual power plant itself has several components, each of which must be calculated (Fig. 1). To incorporate a price on carbon into the cost calculation, the greenhouse emission intensity was first calculated. A capital recovery factor, capital cost improvement factor and inflation ratio factor were also calculated to represent the monetary effects of time. All the cost components were then summed to obtain the cost of each power plant, and finally the cost of all power plants were aggregated and divided by the total energy generated by all plants to establish the COE of the scenario.

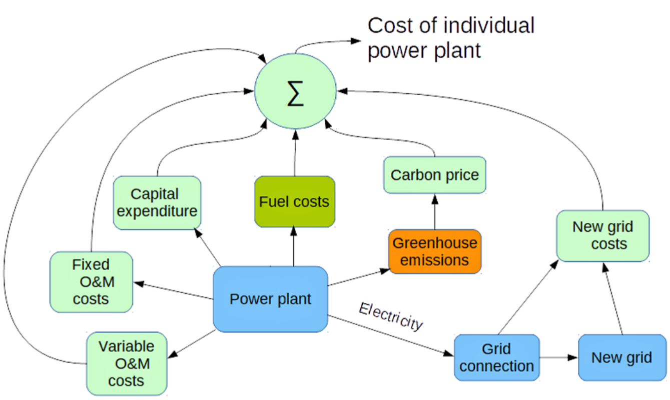

Fig. 1. Components of the cost of an individual power plant. O&M stands for operations and maintenance.

2.1 Calculation of emission intensity

Renewable energy power plants use no fossil fuels, so greenhouse emissions come from embodied emissions of construction and operation of the power plant. In contrast, for fossil fuel plants, the majority of the emissions come from combustion of the fuel [36]. Therefore the emissions from each type of power plant must be treated differently. The individual emissions intensity EI_n ($kgCO_2e/MWh$) for a renewable energy power plant n (one of a fleet of plants in a scenario) was estimated by pro-rating the embodied emissions over the lifetime of the plant:

$$EI_n = \frac{ERE_n cap_n}{lf_n e_n} \tag{1}$$

where cap_n is the capacity of the plant (MW), lf_n is the plant lifetime (y), ERE_n is the specific emission intensity per unit of capacity ($kgCO_2e/MW$), and e_n is the annual energy generated (MWh). The emissions of storage were calculated by defining ERE_n in terms of MWh of battery capacity instead of MW. The emissions from energy efficiency measures are uncertain but were set at zero, although some EE measures might have emissions from the embodied emissions of building materials. For fossil fuel plants, the individual emissions intensity was estimated using:

$$EI_n = EF_n \tag{2}$$

where EF_n is the specific emission intensity per unit of energy generated ($kgCO_2e/MWh$). The values for ERE_n, EF_n and lf_n used in this study are given in Tables 2 and 3.

The emissions from building new transmission lines to connect a power station was estimated using:

$$ET_n = \frac{TLF\, tlength_n + TCF}{lf_{tl}} \tag{3}$$

where TLF is the transmission line specific emissions intensity ($kgCO_2e/km$), TCF is the converter specific emissions intensity ($kgCO_2e$), $tlength_n$ is the length of new transmission line required (km), lf_{tl} is the lifetime of transmission lines (y), and ET_n is the total emissions from building new transmission lines to connect plant n to the grid ($kgCO_2e$). Transmission line greenhouse emissions were pro-rated over the lifetime of the lines. The values of transmission line emission parameters are given in Table 4.

Table 2. Specific emission intensities and plant lifetimes for different energy generation and storage technologies.

Technology	Specific emissions EI	Reference
Roof top solar PV	1.8424×10^6 kg/MW	Good et al. [37]
Utility scale solar PV	1.8424×10^6 kg/MW	Good et al. [37]
Wind	1.2749×10^6 kg/MW	Kumar et al. [38]
Storage	75000 $kgCO_2e/MWh$ capacity	Larcher and Tarascon [39]
Coal	950 $kgCO_2e/MWh$	Kelp and Dundas [40]
Gas	600 $kgCO_2e/MWh$	Kelp and Dundas [40]

Table 3. Plant lifetimes for different energy generation and storage technologies.

Technology	Lifetime *lf* (years)	Reference
Roof top solar PV	30	Good et al. [37]
Utility scale solar PV	30	Good et al. [37]
Wind	25	Kumar et al. [38]
Storage	15	Nicholls et al. [41]
Energy efficiency	15	Hoffman et al. [42]
Coal	30	EPRI [43]
Gas	30	EPRI [43]

Table 4. Transmission line emission parameters.

Parameter	Value	Reference
TLF	7000 $kgCO_2e/km$	Turconi et al. [44]
TCF	100,000 $kgCO_2e$	Turconi et al. [44]
lf_{tl}	40 years	Hauan [45]

The overall emissions intensity for each scenario, *EI*, in $kgCO_2e/MWh$, was calculated using:

$$EI = \frac{\sum_{n=1}^{NPRE} \frac{ERE_n cap_n}{lf_n} + \sum_{n=1}^{NPF} EF_n e_n + \sum_{n=1}^{NP} ET_n}{\sum_{n=1}^{NP} e_n} \quad (4)$$

where $NPRE$ is the number of renewable energy power plants, NPF is the number of fossil plants, and NP is the number of power plants in the scenario ($NP = NPRE + NPF$).

2.2 Calculation of the cost of each power plant

To represent the monetary effects of time, the cost for each individual power plant was estimated in a similar fashion to the simple levelised cost of energy calculator at NREL [46]. A capital recovery factor (CRF_n) was calculated, so that the annual required capital investment could be quantified:

$$CRF_n = \frac{d(1+d)^{lf_n}}{(1+d)^{lf_n} - 1} CIF_n \quad (5)$$

where d is the fractional discount rate (often set to the cost of finance or interest rate to reflect the opportunity cost of financing the power plant rather than earning interest), and lf_n is the plant lifetime (y). Since the cost of RE technologies are currently decreasing at a significant rate each year, an approach was developed to incorporate this change into the estimation of COE over the duration of building the entire RE system. Therefore a capital cost improvement factor for each power plant n (CIF_n) was introduced, and calculated based on yearly cost improvement and installation growth rate over a set duration:

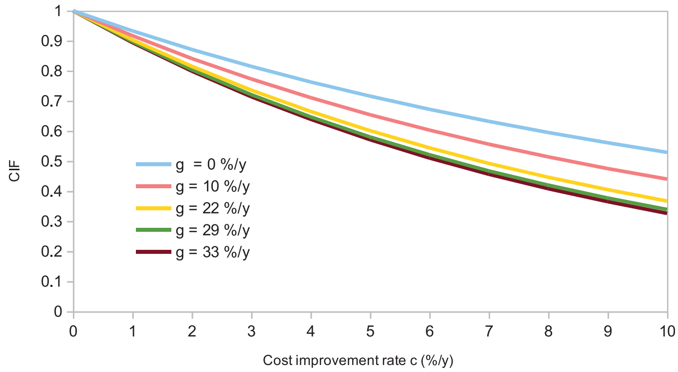

Fig. 2. Capital cost improvement factor (CIF) versus cost improvement rate for different installation growth rates (g). The effect of cost improvement on the overall capital cost of a wind, solar PV or battery system increases with higher installation growth rates.

$$CIF_n = \frac{\sum_{i=0}^{t_{bd}-1} (1-c_n)^i (1+g_n)^i}{\sum_{i=0}^{t_{bd}-1} (1+g_n)^i} \quad (6)$$

where c_n is the yearly fractional cost improvement for plant n, and g_n the yearly fractional increase in installation rate for plant n, and t_{bd} the system building duration (y). A higher g_n magnifies the effect of cost improvement (Fig. 2). If there is no cost improvement, CIF_n is set to a value of 1.

An inflation ratio factor (IRF_n) was also calculated so that inflation could be accounted for:

$$IRF_n = \frac{(1+i)^{lf_n} - 1}{i\, lf_n} \quad (7)$$

where i is the fractional inflation rate. It can be expected that some portion of the plant capacity is off line at any one time for troubleshooting or routine maintenance. This was assumed to be a constant percentage of the total capacity. The online fraction olf_n was defined as:

$$olf_n = 1 - \frac{capcdown_n}{100} \quad (8)$$

where $capcdown_n$ is the average percentage of the capacity that is off line at any one time. The total capital cost of a power plant was then calculated as:

$$capcost_n = \frac{CC_n cap_n}{olf_n} \quad (9)$$

where for plant n, $capcost_n$ is the capital cost of the plant, and CC_n is the capital cost factor (cost/MW). The capital cost of storage was calculated by defining cap_n and CC_n in terms of MWh of battery capacity instead of MW. Although these formulae can be applied to any currency, in this study any dollar value given is Australian dollars.

The capital cost of new transmission line and connection infrastructure for utility scale power plants was estimated using:

$$gridcost_n = TLC\, tlength_n + CCC \tag{10}$$

Table 5. New grid costs.

Parameter	Value	Reference
TLC	\$1 million per km	Krieg [47]
CCC	\$105,340	ERA [48]
GCC for rooftop PV	\$170 per kW	CEC [49]
GCC for distributed storage	\$25 per kWh	CEC [49]

All costs are in Australian dollars.

Table 6. Down time for different energy generation or storage technologies.

Technology	Down time *capcdown* (%)	Reference
Roof top solar PV	1.5	Jacobson et al. [50]
Utility scale solar PV	1.5	Jacobson et al. [50]
Wind	3	Faulstich et al. [51]
Storage	10	Dubarry et. al. [52]
Energy efficiency	0*	
Coal	16.83	Cochran et al. [53]
Gas	15	Gouveia et al. [54]

* Energy efficiency measures chosen to involve intrinsic or passive design improvements with no down time, or active systems with equivalent or better reliability than those they replace.

where *TLC* is the capital cost factor for new transmission lines (cost/km), *CCC* is the capital cost factor for new converter equipment, and $gridcost_n$ is the capital cost of the required new grid infrastructure for plant n. For distributed rooftop PV and storage, the grid connection cost was estimated using:

$$gridcost_n = 10^3 GCC \times cap_n \tag{11}$$

where *GCC* is the grid connection cost factor (cost/kW capacity for rooftop PV and cost/kWh capacity for storage). The values used for these parameters are given in Table 5.

The annual cost of each individual power plant ($cost_n$) could then be estimated:

$$\begin{aligned} cost_n = {} & CRF_n(capcost_n + gridcost_n) + IRF_n\big(OMC_{fn}cap_n \\ & + e_n\big(OMC_{vn} + FC_n + 10^{-3}CPEI_n\big)\big) \end{aligned} \tag{12}$$

where *CP* is the carbon price (cost/tonne CO_2e), OMC_{fn} is the annual fixed operation and maintenance cost (cost/MW), OMC_{vn} is the annual variable operation and maintenance cost (cost/MWh), FC_n is the fuel cost (cost/MWh), and EI_n is the emissions intensity for the technology (kgCO_2e/MWh). The fuel cost only applies to fossil fuel plants. The annual fixed operation and maintenance cost of storage was calculated by defining OMC_{fn} in terms of MWh of battery capacity instead of MW. The values for $capcdown_n$, CC_n, OMC_{fn}, OMC_{vn} and FC_n for each technology are given in Tables 6 to 10. Energy efficiency measures were assumed to have no down time.

2.3 Calculation of the cost of energy for each scenario

The overall *COE* for each scenario in terms of cost per unit of energy used (cost/MWh) was estimated by summing the annual cost for each plant and dividing by the sum of the annual energy generated by each power plant:

$$COE = \frac{\sum_{n=1}^{NP} cost_n}{\sum_{n=1}^{NP} e_n} \tag{13}$$

Table 7. Capital cost factors for different energy generation, storage or efficiency technologies.

Technology	Capital cost factor *CC* (\$million/MW)	Reference
Roof top solar PV	1.7	Blakers et al. [55]
Utility scale solar PV	1.7	Blakers et al. [55]
Wind	2.3	Blakers et al. [55]
Storage	0.265 \$million/MWh	Field [56]
Energy efficiency	\$350 per (MWh saved per year)	Jacobs [57]
Coal	3	EPRI [43]
Gas	1.45	EPRI [43]

All costs are in Australian dollars.

Table 8. Fixed annual operating and maintenance costs for different energy generation or storage technologies.

Technology	Fixed annual operating and maintenance cost OMC_f (\$/MW)	Reference
Roof top solar PV	0	EPRI [43]
Utility scale solar PV	25,000	EPRI [43]
Wind	35,000	Blakers et al. [55]
Storage	2000 \$/MWh	Brinsmead et al. [58]
Energy efficiency	0*	
Coal	45,000	EPRI [43]
Gas	2000	EPRI [43]

* The annual operating and maintenance cost of energy efficiency measures is often zero or even negative (the operating and maintenance cost of the building, appliance or process is reduced). All costs are in Australian dollars.

Table 9. Variable annual operating and maintenance costs for different energy generation and storage technologies.

Technology	Variable annual operating and maintenance cost OMC_v (\$/MWh)	Reference
Roof top solar PV	0	EPRI [43]
Utility scale solar PV	0	EPRI [43]
Wind	10	Blakers et al. [55]
Storage	3.1	Brinsmead et al. [58]
Energy efficiency	0*	
Coal	2.5	EPRI [43]
Gas	1.5	EPRI [43]

* The annual operating and maintenance cost of energy efficiency measures is often zero or even negative (the operating and maintenance cost of the building, appliance or process is reduced). All costs are in Australian dollars.

Table 10. Fuel costs for different fossil energy generation technologies.

Technology	Fuel cost FC (\$/MWh)	Reference
Coal	27	EPRI [43]
Gas	54.5	Lu and Hyland [59]

All costs are in Australian dollars.

To compare the model used in this study to the findings of Rose et al. [12], a discount rate of 8% and an inflation rate of 2% were used to broadly match the discount rates used in that study. Otherwise a discount rate of 5% and an inflation rate of 2% were used to reflect currently low interest rate levels in Australia [4].

To explore the effect of variation in the cost parameters, the Sensitivity, S_i, of the COE to each cost parameter was estimated using:

$$S_i = \frac{\Delta COE}{COE}\frac{P_i}{\Delta P_i} \tag{14}$$

where P_i is any one of the cost parameters in the above tables. P_i was varied ±5% from its nominal value and COE recalculated, such that $\Delta P_i = 0.1 P_i$ and $\Delta \mathrm{COE} = \mathrm{COE}_{+5\%} - \mathrm{COE}_{-5\%}$.

Initially, no cost improvement or growth in installation rate was set ($c = 0$, $g = 0$). The effect on the COE for each scenario of cost improvement and growth in installation rates was investigated by setting the c parameter for solar PV, wind and battery storage to the currently observed global trends, and the g parameter to both a moderate installation growth rate setting and a more rapid growth rate setting, reflecting current Australian trends (Tab. 11). The building duration t_{bd} was set to 15 years to reflect the short construction time frame needed to ramp up RE generation quickly and reduce greenhouse emissions fast enough to limit global temperature rise to 1.5 °C and forestall dangerous climate change [60].

3 Results

In this section the cost of energy (COE) of scenarios with increasing levels of RE generation are compared to the COE of the fossil fuel business as usual (BAU) case. In previous studies it was found that the cost of renewable

Table 11. Cost improvement and installation growth rates for wind, solar PV and battery storage.

Technology	Global cost improvement rate (% per year)	Moderate installation growth rate (% per year)	Rapid installation growth rate (% per year)
Wind	3	10	22
Solar PV	9	10	29
Batteries	8	10	33

Table 12. Estimated emission intensity and provisional energy cost in $/MWh for each partial renewable scenario for the SWIS electrical grid under different carbon pricing schemes (20 runs).

Scenario	% RE generation	Emission intensity ($kgCO_2e/MWh$)	Cost ($/MWh) no carbon price	Cost ($/MWh) $24/tonne	Cost ($/MWh) $70/tonne
BAU	17	667	95.7	111	142
1	42	444	88.4	99.2	119
2	47	394	84.6	94.2	112
3	52	301	86.1	93.0	107
4	56	273	86.2	92.7	105
5	69	199	93.9	98.2	108
6	72	187	97.7	102	111
7	75	165	100	104	111
8	79	145	104	107	114
9	85	124	119	122	127
10	90	85.7	125	127	132
11	94	61.4	132	134	137
12	96	53.4	141	143	145
13	97.4	50.8	153	155	157
14	97.8	47.6	156	158	159
15	98.8	45.3	164	165	168
16	99.5	51.9	192	193	196
17	99.9	59.5	219	222	223

BAU is the business as usual case of using mostly conventional fossil generation. All costs and prices are in Australian dollars.

energy systems was competitive with fossil fuel systems, but rose sharply at very high levels of RE. So it is initially expected that the RE *COE* will be lower, but as RE levels rise, there will be a "break even" point where the two *COE*s are the same. At even higher levels of RE, the *COE* will be higher than the BAU case. The effect of carbon price and RE cost improvement rate on the break even point is explored, and a sensitivity analysis of the parameters used to estimate the *COE* for each scenario is also carried out.

Firstly, to confirm the model calibration, the BAU scenario of this study was compared to the BAU scenario presented by Rose et al. [12] for the SWIS grid. The *COE* of the BAU scenario with a discount rate of 8% and a carbon price of $30/tonne was 129 $/MWh, which matched the *COE* for business as usual of $129/MWh given by Rose et al. [12] with the same carbon price. For this study, the *COE* for the BAU case and the partial renewable energy scenarios was estimated with a discount rate of 5% (to better reflect current financial conditions) and three different carbon prices: none, $24/tonne and $70/tonne (Tab. 12). The *COE* for the BAU case with these carbon prices was estimated to be $95.7/MWh, $111/MWh and $142/MWh respectively.

Figures 3–5 show cost curves of the partial renewable energy scenarios compared to the BAU case as the level of RE rises. The break-even point occurs where the curves cross the dotted BAU line. The *COE* for the scenarios with no carbon price were less than the BAU for up to around 70% RE generation (Fig. 3 , black line). For a carbon price of $24/tonne, the *COE* for the scenarios was less than BAU for up to around 80% renewable energy generation (Fig. 4, black line). For a carbon price of $70/tonne, the break even COE occurred around 96% RE generation (Fig. 5, black line). Hence increasing the carbon price tended to flatten the cost curve, increasing the break-even level of renewable generation (Tab. 14). The lowest *COE* occurred at around

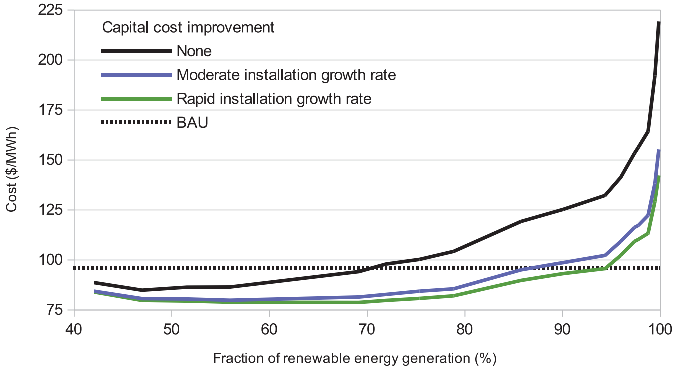

Fig. 3. Cost of partial renewable energy generation scenarios compared to business as usual (BAU) case (dashed line) with no carbon price. Renewable technologies used are wind, solar photovoltaic and distributed battery storage. Black line is no cost improvement over time, blue line is global cost improvement rates and moderate installation growth rates. Green line is global cost improvement rates and rapid installation growth rates. Cost is in Australian dollars.

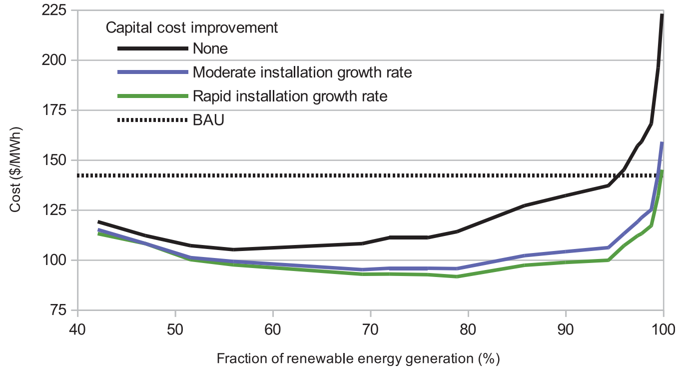

Fig. 5. Cost of partial renewable energy generation scenarios compared to business as usual (BAU) case (dashed line) with a $70 per tonne carbon price. Renewable technologies used are wind, solar photovoltaic and distributed battery storage. Black line is no cost improvement over time, blue line is global cost improvement rates and moderate installation growth rates. Green line is global cost improvement rates and rapid installation growth rates. Cost is in Australian dollars.

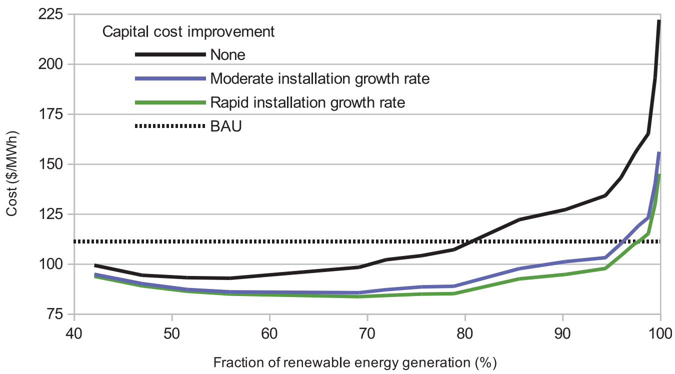

Fig. 4. Cost of partial renewable energy generation scenarios compared to business as usual (BAU) case (dashed line) with a $24 per tonne carbon price. Renewable technologies used are wind, solar photovoltaic and distributed battery storage. Black line is no cost improvement over time, blue line is global cost improvement rates and moderate installation growth rates. Green line is global cost improvement rates and rapid installation growth rates. Cost is in Australian dollars.

45–55% RE generation with no carbon price, and around 50–60% RE generation for carbon prices at $24/tonne and $70/tonne. For very high levels of renewable energy generation (>95%), the *COE* rose sharply, almost in an exponential like manner.

Sensitivity analysis of the parameters used to estimate the *COE* for each scenario revealed that the cost was most sensitive to investment parameters (discount rate, inflation rate and carbon price), capital cost parameters, fixed and variable O+M costs and plant lifetime. The most sensitive parameter was discount rate (Tab. 13), and the sensitivity to this parameter increased with the level of RE. Therefore, decreasing the discount rate would increase the break-even level of RE and vice versa. In contrast, sensitivity to the inflation rate decreased with increasing RE. These effects could be due to the higher required capital expenditure and absence of fuel costs of the RE technologies. Inclusion of a carbon price generally decreased the sensitivity to other parameters, and not surprisingly, the BAU scenario was most sensitive to the carbon price.

These sensitivity estimates were consistent with improvements in the capital cost of RE technologies reducing the *COE* of the high RE scenarios the most. If current global improvement rates in wind, solar PV and battery costs were implemented, along with installation growth rates consistent with current Australian trends (Tab. 11), then the break even cost points for the RE scenarios compared to the BAU scenario were increased (Tab. 14 and Figs. 3–5). With no carbon price, the break even point rose to around 95% RE, and with a carbon price of $70 per tonne, the break even point was above 99%. Even with more moderate installation growth rates, the break even point with no carbon price rose to 85%, and with a $70 per tonne carbon price was at 99%.

4 Discussion

Based on current technology costs, as RE generation increased from low levels, the cost dropped, reaching a minimum around 45–60% RE generation. The cost then rose again in a roughly linear fashion as RE increased up to about 80% RE generation, similar to the findings of Elliston et al. [22]. The cost increased more sharply up to around 95% RE generation, which was also noticed by Elliston et al. [22], and then increased steeply, almost in an exponential like way, at very high levels of RE generation above 95%. Hence the vanishing returns found by Denholm et al. [21] from adding capacity to cover increasingly

Table 13. Sensitivity of scenario cost to parameters.

Parameter class	Parameter	Scenarios No carbon price			Scenarios $70 per tonne carbon price		
		BAU	52% RE	99.9% RE	BAU	52% RE	99.9% RE
Investment environment	Discount rate	22.4	23.3	39.0	14.8	18.6	38.3
	Inflation rate	18.7	16.8	5.52	12.6	13.5	5.46
	Carbon price	–	–	–	33.0	19.9	1.87
Capital cost	Rooftop solar PV	4.49	8.50	35.0	3.06	6.74	33.8
	Wind	3.08	7.58	12.8	2.10	6.01	12.3
	Storage		1.31	17.2	–	1.04	16.5
	Efficiency	1.45	9.80	3.83	0.99	7.77	3.70
	Coal	12.7	–	–	8.64	–	–
	Gas	17.8	16.2	4.01	11.4	13.0	4.92
Fixed annual operation and maintenance costs	Rooftop solar PV	1.37	2.60	10.7	0.94	2.06	10.3
	Wind	0.85	2.08	3.51	0.58	1.65	3.39
	Storage	–	0.12	1.54	–	0.09	1.49
	Coal	3.95	–	–	2.69	–	–
	Gas	5.12	4.65	1.15	3.26	3.74	1.41
Variable operation and maintenance costs	Wind	0.56	1.52	2.52	0.41	1.10	2.46
	Storage	–	0.04	0.18	–	0.03	0.17
	Coal	1.66	–	–	1.13	–	–
	Gas	0.76	1.16	0.00	0.52	0.93	0.003
	Coal fuel cost	17.9	–	–	12.2	–	–
	Gas fuel cost	27.7	42.2	0.04	18.8	34.1	0.10
Plant lifetime	Roof-top solar PV	–1.81	–3.43	–14.1	–1.35	–2.98	–15.1
	Wind	–1.24	–3.19	–5.49	–0.87	–2.72	–5.63
	Storage	–	–0.73	–9.42		–0.59	–9.41
	Efficiency	–0.86	–5.80	–2.27	–0.59	–4.60	–2.21
	Coal	2.06	–	–	1.39	–	–
	Gas	3.07	8.64	–1.44	2.33	7.01	–1.54

Table 14. Carbon price and level of renewable energy generation for break-even cost with BAU with cost improvement and installation growth.

Carbon price ($/tonne)	Cost of BAU scenario ($/MWh)	Break even RE generation with no cost improvement or installation rate growth (%)	Break even RE generation with cost improvement and moderate installation rate growth (%)	Break even RE generation with cost improvement and rapid installation rate growth (%)
0	95.7	70	85	95
24	111	80	96	98
70	142	96	99	99.5

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infrequent meteorological conditions of prolonged low wind speed and solar irradiance were also indicated by this study. Most of the time, generation from this capacity is not needed and hence curtailed.

Therefore a 100% RE system for the SWIS based on wind, solar PV and battery storage would be more costly than a conventional system based on current technology costs. However, it can clearly be seen that replacing conventional fossil generation with renewable energy rather than more conventional plants will be the least cost option up to high levels of RE generation, with a cost break even point of around 70% even without a price on carbon. Any policy system that results in a price on carbon will make the break even point higher.

Denholm et al. [21] and other studies have suggested that interconnection with another grid, or a form of renewable energy that is capable of being stored for longer time scales, such as biomass, renewable power to gas, or pumped hydro, combined with the use of demand management, might be a more cost effective way to cover the final 5–10% of RE generation capacity to achieve a low emission 100% renewable electricity system. However, the cost of wind power has been falling in the last few years, and the cost of solar and battery storage is also currently falling rapidly. The results of this study show that if costs continue to improve on the same trajectory as currently observed, and installation rates grow even at a moderate rate of 10%, then the break even point with BAU will increase significantly, up to 85% RE with no carbon price. With a carbon price of $24 per tonne, the break even point reaches 96% RE. With a higher carbon price and/or faster cost improvement and installation growth rates, the cost advantage of using a conventional fossil generation system begins to vanish altogether, and a cost effective 100% RE system based on batteries is foreseeable.

5 Conclusions

In this study the cost effectiveness of using high levels of distributed renewable energy, and batteries as the only major storage technology, to supply the energy needs of a wide scale electrical grid was investigated. A number of conclusions can be drawn from the findings:

– *It is cost effective to pursue the approach of using battery storage now*: Even with no carbon price or cost improvement, the cost was less than using a business as usual fossil fuel approach up to a break even level of 70% RE. With a price on carbon or cost improvement of the RE technologies, the break even level was pushed higher, and could reach above 99%. However the costs of RE technologies play out in the real world, increasing the level of renewable energy generation on the SWIS from the current low levels using batteries will reduce costs as well as reducing greenhouse emissions for many years to come, even without the benefit of hydroelectricity, pumped hydro storage, bio energy or solar thermal storage.
– *Yearly cost improvements in RE technologies can be incorporated into levelised COE estimations.* This study developed a simple method to incorporate the continuously improving capital costs of RE technologies over the build duration of the system into the estimation of COE. This approach can be widely adopted, as there is urgency to build these low emission systems now, in order to avoid dangerous climate change, and not wait until some point in the future. It is perhaps more realistic to use this approach rather than estimating projected costs at some point in the future and then calculating the cost of building the entire system based on these costs.
– *These findings are applicable to other regions.* The finding of this study have positive implications for other regions in the world with variable renewable energy resources and also having to rely on battery storage, or coming to rely on battery storage by default in the absence of policies designed to enable the implementation of other technologies. A cost effective 100% RE system for these regions seems to be in reach even if there are geographical or policy challenges.

Nomenclature

BAU	Business as usual
c	Fractional yearly cost improvement
cap	Plant capacity (MW)
$capcdown$	Capacity that is off line at any one time (%)
$capcost$	Capital cost ($million)
CC	Capital cost factor ($million/MW)
CCC	Capital cost factor for new converter equipment ($million)
CIF	Capital cost improvement factor
CP	Carbon price ($/tonne)
COE	Cost of energy ($/MWh)
$cost_n$	Annual cost of power plant n
CRF	Capital recovery factor
d	Discount (investment) rate
EE	Energy efficiency
EF	Specific emission intensity of fossil fuel generators ($kgCO_2e$/MWh)
EI	Emission intensity ($kgCO_2e$/MWh)
ERE	Specific emission intensity of renewable energy generators ($kgCO_2e$/MW)
ET	Emissions from new transmission lines ($kgCO_2e$)
e_y	Annual energy generated (MWh)
FC	Fuel cost ($million/MWh)
g	Fractional installation growth rate
GCC	Distributed PV or storage grid connection cost factor ($/kW or $/kWh)
$gridcost$	Capital cost of new grid infrastructure ($million)
i	Inflation rate (%)
IRF	Inflation ratio factor
lf	Plant lifetime (y)
olf	Online fraction
OMC_f	Fixed annual operations and maintenance cost ($million/MW)
OMC_v	Variable annual operations and maintenance cost ($million/MWh)
P_i	One of the parameters used in the calculation of COE
RE	Renewable energy (includes energy efficiency measures and storage)
SWIS	South west interconnected system
SWWA	South west region of Western Australia
t_{bd}	System building duration

TCF	Converter specific emissions intensity ($kgCO_2e$)
TLC	Capital cost factor for new transmission lines ($million/km)
tlength	Length of new transmission line (km)
TLF	Transmission line specific emissions intensity ($kgCO_2e$/km)

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