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What cost for more renewables? The incremental cost of renewable generation – An Australian National Electricity Market case study

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ABSTRACT

This study evaluates the incremental costs of higher levels of renewable energy (RE) supply using an optimisation tool to find least cost electricity generation portfolios. The Australian National Electricity Market (NEM) in 2030 is used as a case study for exploring various generation portfolios from low to high shares of RE, low to high greenhouse gas emissions caps, and low to high carbon prices. Incremental costs are found to increase approximately linearly as the RE share grows from zero to 80%, and then demonstrate a small degree of non-linear escalation, related to the inclusion of more costly renewable technologies such as solar thermal electricity. Similarly, costs increase approximately linearly as a greenhouse gas emissions cap is lowered from 150 megatonnes (Mt) to 30 Mt, and then demonstrate a small degree of non-linear escalation for caps below 30 Mt. However, in both cases this escalation is moderate, and does not appear to provide a strong argument for long-term policies that aim for RE shares lower than 100%, or electricity sector emissions caps higher than zero as one option for rapid decarbonisation.

1. Introduction

It is clear that RE is becoming a mainstream electricity generation option. RE sources now provide almost 20% of global energy consumption, with more than half of that coming from sources other than traditional uses of biomass [20]. The rate of growth is substantial; in 2014, renewables accounted for more than 59% of net additions to global power capacity [20], with new wind and solar both exceeding new hydro capacity. This includes growth in developing countries; for example, in 2013, China's new renewable power capacity surpassed new fossil fuel and nuclear capacity [19]. While a number of countries have electricity industries with high levels of hydroelectric generation including Norway and Austria, these trends towards other forms of renewable energy suggest that a growing number of countries may have high penetrations of wind and solar power in coming decades.

Certainly, many countries and regions are accelerating the shift to renewable electricity through various policy mechanisms. For example, Denmark, Scotland, and the small-island state of Tuvalu have announced policies to derive 100% of their electricity from renewable sources [19]. Germany has a stated goal of 80% renewable electricity by 2050. Hawaii has the highest target of any state in the United States requiring 100% renewable electricity by 2045 [16]. These policies often involve setting a jurisdiction target for RE at one or more particular time horizons, as done by 164 countries as of early 2015 [20]. A range of mechanisms are available to drive deployment towards these RE targets. Other climate policy mechanisms such as carbon taxes and emissions trading schemes may not specifically target RE deployment, but can support it. When developing policies based on such mechanisms and determining the appropriate target, it is important to understand how the average cost of electricity might increase to achieve a particular target. It might be reasonable to expect that there could be diminishing returns from the higher levels of investment. For example, 90% renewable electricity may be significantly less expensive to achieve than 100%. This study explores this hypothesis.

Few studies have quantified how the incremental costs change as higher levels of renewable generation are approached. Most studies focus on moderate levels of RE, approximately 30–50% of energy. Some have explored 100% renewable energy scenarios on a variety of geographic scales [6]. For example, in the Australian

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National Electricity Market (NEM), analysis of 100% renewable scenarios has been conducted by the market operator [2] and others [9–11,25]. These studies are useful for understanding the limiting case and placing a potential upper bound on the costs. Less often, studies such as the National Renewable Energy Laboratory's Renewable Electricity Futures Study [17] explore pathways including high renewable penetrations. This analysis quantified costs for power systems with 30%–90% renewable energy, focusing on 80%. [17] quantified the change in retail electricity prices as the US power system was transformed over time to various levels of renewable penetration in 2050. The study found an additional cost of around $5 per MWh for each additional 10% in renewable generation, but did not explore the additional cost or the generating mix that would be involved in achieving 100% renewable electricity. [12] examined costs in the Portuguese electricity system associated with a small number of renewable penetration levels including 100%.

For this analysis, we use the Australian NEM as a case study. The NEM supplies approximately 80% of the electrical load in Australia, with a peak demand of 30–35 GW in summer, and annual energy consumption of around 200 TWh [3]. The NEM provides a useful and relevant case study for several reasons. First, Australia has abundant and diverse renewable resources including solar radiation, wind, biomass, deep geothermal, wave, and hydro [13]. This makes scenarios with very high renewable generation technically and economically feasible using a potentially wide range of RE technologies [2]. Second, the NEM is currently operated predominantly on fossil fuels, with 75% of electricity generation coming from coal [18]. This means that high renewable scenarios are far from the present situation, and therefore of interest when considering the full spectrum of renewable penetration levels, and in setting intermediate and long-term RE targets. Third, the NEM is a moderately sized but significant electric power system, therefore having relevance to the many other similarly sized power systems around the world.

This paper is structured as follows. In Section 2, we provide a brief summary of the modelling tool used for the scenarios presented in this paper, including a number of recent enhancements to the tool. Section 3 describes the scenarios that were modelled. Section 4 presents and discusses the results. Section 5 addresses the policy relevance of the results and concludes the paper.

2. The model

The scenarios presented in this paper are simulated using a techno-economic optimisation model known as the National Electricity Market Optimiser (NEMO[1]). NEMO couples an evolutionary program to a chronological hourly dispatch model[2] using realistic renewable generation data and measured demand from the same period. The evolutionary program searches for the least cost system subject to a small number of constraints: limiting bioenergy consumption, limiting hydroelectricity generation to the NEM long-term average, and ensuring that the NEM reliability standard of 0.002% unserved energy is met over the modelled period. Optionally, a limit on CO_2 emissions and a minimum share of renewable generation can be included as constraints. NEMO has previously been used to find least cost future 100% renewable electricity systems in the NEM [9,10] and to compare the costs of these with lower emissions fossil fuel systems based on combined cycle gas turbines(CCGTs), coal with carbon capture and storage (CCS), and CCGT with CCS [11]. A number of improvements have recently been made to the model. These enhancements include revising some assumptions, using superior renewable energy resource data, and incorporating revised technology costs. Each of these will be discussed in the following subsections.

2.1. Revised O&M costs

The [5] released an update for the Australian Energy Technology Assessment (AETA) in December 2013. The update contains revised cost and performance data for the 40 different electricity generation technologies covered after consultation with industry and other parties. These revisions have reduced the operating and maintenance (O&M) costs of some renewable technologies including two of interest in this study: concentrating solar thermal (CST) and wind power. Capital costs for all technologies are unchanged. In some cases, O&M costs have been redistributed between fixed and variable O&M, and we acknowledge the difficulty in accurately assigning such costs. The first edition of AETA was met with some criticism [4,23], however the most recent set of RE costs are now comparable to costs reported from other parts of the world; for example, wind power in the United States [24] and other RE technologies elsewhere [15].

2.2. Mid-point capital costs

In earlier work, two sets of capital costs were taken from AETA data to perform sensitivity testing on the annual system cost [10]. For the low end costs, the lowest capital cost in the range was selected for each technology. Similarly, for the high end costs, the highest costs were selected. For this work, where the focus is the change in costs, mid-point values are used ("Capital cost" column of Table 1).

2.3. Renewable generation data

The model incorporates improved renewable generation data. The Australian Energy Market Operator (AEMO) contracted the CSIRO and an Australian consulting firm, ROAM Consulting, to produce input data to support its 100% Renewable Electricity study [2]. These data cover the years 2003–2011 and span almost all of the geographic area of the NEM (Fig. 1). The NEM is divided into 43 polygons which provides a higher spatial resolution than previously available data. Importantly, the data set provides synthetic wind power data for regions where wind power is weakly cross-correlated with existing wind farms in the NEM. The improved data set includes:

- Wind – Hourly traces of wind generation obtained from the ROAM Wind Energy Simulation Tool based on the Bureau of Meteorology ACCESS-A numerical weather prediction model [21]. The wind resource data for a number of sites in each polygon are fed through a power curve function, normalised to 1 MW, and a weighted average is calculated for the polygon based on capacity limits at each site and the total capacity limit for the polygon.
- PV – Hourly traces of electrical power from a nominal 1 MW single-axis tracking solar photovoltaic (PV) system based on the average of four to six sites in each polygon; and
- CST – Hourly traces of electrical power obtained using a reference central receiver system (100 MW power block, solar multiple of 2.5, and a small amount of thermal storage) sited in four to six locations in each polygon. At each site, the heliostat field was optimised in System Advisor Model (SAM). The reference

[1] NEMO is free software licensed under the GNU General Public License so that others can use and modify the model. The project website is at https://nemo.ozlabs.org. Suggestions, enhancements, and bug reports from other users are welcome.

[2] The model allows the time step to be any duration but 1 h is used for this work.

Table 1
Projected costs (mid-point for capital costs) in 2030 for selected generating technologies (2012 Australian dollars). Fuel not included in O&M costs. Consistent with AETA methodology, operating and maintenance costs are inflated by 17.1% over the period to 2030.

Technology	Heat rate GJ/MWh	Capital cost $/kW	Fixed O&M $/kW/y	Variable O&M $/MWh
Black coal	8.57	3038	59	8
Black coal w/CCS	11.46	4590	86	18
CCGT	6.92	1118	12	5
CCGT w/CCS	8.35	2250	20	11
OCGT	11.61	752	5	12
Central receiver CST		4778	84	7
Wind on-shore		1809	38	12
EGS geothermal		11,071	199	0
HSA geothermal		7234	234	0
PV (1-axis tracking)		2278	35	0

Source: [5].

traces were then normalised to a 1 MW plant with a solar multiple of 1.0 and then averaged to produce one trace per polygon [21]. The electrical power time series ($\vec{p}_e$) for a 1 MW plant with a solar multiple of 1.0 and no storage can be scaled to any plant configuration using the formula:

$$\vec{p}_{e'} = c \cdot m \cdot \vec{p}_e \tag{1}$$

where c is the desired capacity in MW and m is the desired solar multiple. Storage can be adequately simulated by diverting electrical energy, as required, from the power block to a buffer using a similar technique for modelling hydroelectric storage in power system models such as PLEXOS [7].

The ROAM data set includes the maximum allowable capacity of each technology in each polygon and the required land area subject to this limit. The limit was calculated using a GIS study that excludes regions such as high population areas, land with unsuitable gradients, marine protected zones and natural conservation areas [21]. The model ensures that no polygon hosts generating capacity in excess of its capacity limit.

For the scenarios described in this paper, five polygons were chosen with the highest average wind capacity factor from each Australian state in the NEM. Table 2 shows the capacity factor and build limit for each polygon, and the cross-correlation with polygon 38b in Victoria. All polygons have weak cross-correlation, particularly polygon 1 in far north Queensland which has a negative cross-correlation (see Fig. 1). The simple approach of choosing one polygon in each state balances the choice of high yielding wind sites with wide dispersion while minimising the number of additional parameters in the search space (one per polygon). Wind generation is known to be well correlated over relatively short distances and on short timescales [22], so nearby polygons can be practically omitted to reduce the number of parameters in the search space.

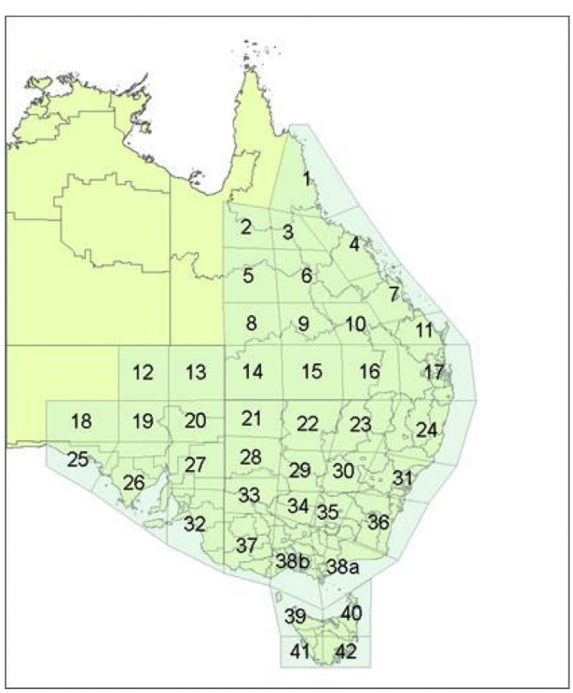


Fig. 1. Geographic polygons defined within the NEM.
Source: [2].

2.4. Use of utility-scale PV

The hourly traces for solar PV generation in each polygon are modelled on single-axis tracking (ie, utility-scale systems) rather than small-scale systems attached to rooftops. This is advantageous because the tracking PV produces a flatter generation profile throughout the daylight hours and yields more energy for comparable capital costs. The four polygons with the highest yield were selected from the states of Queensland, South Australia, New South Wales and Victoria. No PV was included for Tasmania due to the relatively lower solar insolation in that state, although it is notable that Tasmania has higher annual insolation than some European countries. Table 3 shows the build limits for the four polygons and the cross-correlation between the hourly generation time series of each polygon and polygon 13 in remote South Australia. Polygons 13, 14 and 21 all share a corner (see Fig. 1), hence the very high correlation coefficients shown in column 3. The larger distance between polygon 13 and polygon 37 in Victoria produces a lower cross-correlation coefficient, but these two time series are still well correlated.

2.5. Use of concentrating solar power technology

When the research program to explore 100% RE scenarios was commenced at the University of New South Wales in 2010,

Table 2
Selected polygons for wind power deployment. Build limits are taken for AEMO scenario 1. These are larger than for scenario 2 as they assume larger turbines are available [2].

Polygon	Capacity factor (%)	Build limit (GW)	Cross-corr. w/polygon 38b
1	42.2	80.3	−0.151
20	49.1	49.1	0.315
24	43.5	116.3	0.111
38b	40.3	15.6	1
42	47.3	29.1	0.335

Table 3
Polygons for PV deployment. Build limits are taken for AEMO 'scenario 1' [2].

Polygon	Build limit (GW)	Correlation coeff. with polygon 13
13	749	1
14	1338	0.962
21	921	0.966
37	670	0.875

parabolic trough CST technology with molten salt storage was selected due to its maturity. The Solar Electric Generating Station (SEGS) systems in California, for example, have been in continuous operation since the early 1980s, although without thermal storage. After several years of observing developments in solar thermal electricity, central receiver systems such as Gemasolar in Andalusia, Spain, and the Ivanpah SEGS in California are now sufficiently mature that they can be conservatively included in energy system scenarios in the 2030–2050 timeframe. Including central receiver systems in the scenarios offers the advantage of higher capacity factors and lower costs. Indeed, central receiver systems are projected to have lower capital and operating costs in 2030 than parabolic troughs due to the greater potential for cost reductions in this newer technology [5].

Previous experience with dispatching CST generators in simulated 100% renewable electricity systems has shown that the likely role of CST with storage in 100% RE systems is as dispatchable power available during critical demand periods, not as a supplier of bulk energy [10]. Hence, our previous assumption that CST plants might be required to have 15 h of thermal energy storage now appears misplaced. Instead, the central receiver systems are modelled with 6 h of storage, which further reduces the capital cost of CST (see Table 1).

2.6. System non-synchronous penetration limits

Detailed simulations of high renewable power system operation may include limits on the instantaneous penetration of non-synchronous generation sources such as wind and PV. Modern wind turbines do not contribute significant rotational inertia to the system and PV contributes none. When the system has insufficient inertia, frequency control and handling of fault conditions becomes more difficult. The rate of change of frequency during a transient condition may be unacceptably fast. The frequency nadir may trigger load shedding before primary response can inject energy into the system to stabilise the frequency.

The choice of non-synchronous penetration (NSP) limit is very system specific, depending on the generator portfolio, power quality requirements, the choice of AC versus DC interconnection, and synchronous interconnection with other networks. In Ref. [2]; the operational model limited NSP to 85%. In Ireland today, Eirgrid maintains a 50% NSP limit due to its reasonably isolated grid, but believes that a 75% NSP limit is achievable in the future [8]. In the present study, a limit of 85% is applied as used by Ref. [2]. The simulation models this limit by dispatching generators out of merit order once the total non-synchronous generation reaches 85% of instantaneous demand.

3. Methods

To examine the impact on system costs of approaching 100% renewable electricity in the NEM, a least cost optimisation was carried out using load data and simulated renewable generation for the year 2010 under an 'RE plus CCS' scenario. The average cost of electricity is calculated by adding the amortised capital cost (based on 2030 projections) of all simulated generators (except existing hydro), the fixed and variable O&M for the simulated year and other costs such as fuel and greenhouse gas liabilities, and then dividing by the number of megawatt hours of demand in 2010. The 'RE plus CCS' scenario includes all of the commercially available RE technologies and fossil fuel technologies including post-combustion CCS which is only at limited demonstration phase (see Table 4). Nuclear power is not included as it is not currently used, legal or foreseen in Australia. Other parameters used in every optimisation run are documented in Table 5.

Table 4
Technologies included in the 'RE plus CCS' scenario.

Technology	Polygons
Black coal (supercritical)	
Black coal with CCS	
CCGT	
CCGTs with CCS	
PV (single-axis tracking)	13, 14, 21, 37
Wind	1, 20, 24, 38b, 42
Central receiver CST	14, 20, 21
Hydro (existing)	
Pumped storage hydro (existing)	
Biofuelled gas turbines (GTs)	
Natural gas fuelled GTs	

In every optimisation, three constraints are enforced:

- unserved energy is not to exceed 0.002% of annual demand as specified by the NEM reliability standard;
- generation from bioenergy is not to exceed 20 TWh, conservatively chosen based on a previous bioenergy resource assessment [13]; and
- hydroelectric generation is not to exceed the long-term average of 12 TWh per year.

The change in average cost of generation when approaching a fully decarbonised NEM is examined using three policy approaches:

- by increasing the minimum share of generation that must come from renewable sources;
- by placing an increasingly stringent upper limit on allowable CO_2 emissions; and
- by placing an increasing price on CO_2 emissions.

In the scenarios presented below, each approach imposes additional constraints or costs. The transition to a system with very low (or zero) operational emissions is examined through two main viewpoints: carbon pricing versus regulatory measures such as emissions caps or mandated minimum shares of RE.

3.1. Mandating the minimum share of renewable generation

In the first series of scenarios, electricity generation from RE sources is guaranteed a minimum share. Eleven optimisation runs are performed, from zero demand being met by RE up to 100% in 10% increments. Coal prices are projected to be relatively stable over the long-term [1], however a sensitivity analysis is performed on the much less certain natural gas price. Three price points are used: low ($3 per GJ[3]), moderate ($6 per GJ) and high ($9 per GJ). Gas prices in Australia have historically been low by world standards, but have now reached $9 per GJ. The long-term outlook for these higher prices is unclear. The carbon price is set to zero for all cases.

[3] All prices are quoted in Australian dollars.

Table 5
Baseline parameter values chosen for scenarios.

Coal price	$1.86	/GJ
Gas price (varied)	$3–9	/GJ
Carbon price (except Series 3)	$0	/t CO_2
Average CO_2 storage cost	$27	/t CO_2
Emissions rate of coal plant	0.8	t/MWh
Emissions rate of OCGT plant	0.7	t/MWh
Emissions rate of CCGT plant	0.4	t/MWh
CCS post-combustion capture rate	85	%
Discount rate	5	%

3.2. Caps on CO_2 emissions

In the second series of scenarios, annual CO_2 emissions from electricity generation are constrained at a maximum level in megatonnes (Mt). There are 16 optimisation runs performed: 150 Mt per year stepping down to zero in 10 Mt steps. As in the previous series, a sensitivity analysis is performed with low, moderate and high natural gas prices. The carbon price is set to zero in all cases.

3.3. Increasing the carbon price

In the third and final series of scenarios, no constraints on renewable generation or CO_2 emissions are imposed, but a carbon price is steadily increased from zero to $200 per tonne CO_2 in $20 increments. A sensitivity analysis is performed with low, moderate and high natural gas prices.

4. Results and discussion

Figs. 2–4 illustrate the least cost generation mix for each step of each series with low, medium and high gas prices. The inverted triangles in each column of the plots show the CO_2 emissions produced in the simulated year. The heavy points illustrate the average system cost ($ per MWh) in the simulated year.

For all three series, it was found that with a low gas price ($3 per GJ), the fossil fuel generation in the least cost mix is dominated by CCGTs. With high gas prices ($9 per GJ), black coal takes the place of CCGTs. The threshold price appears to be close to the medium gas price ($6 per GJ). This indicates that the degree of uncertainty over future gas prices is sufficiently broad to encompass a wide range of potential least cost generation portfolios. The design of any policy mechanism to promote investment in gas-fired generation as a greenhouse mitigation measure should bear this in mind, and seek to be robust to this substantial degree of gas price uncertainty.

It is important to note that this modelling does not account for the sunk capital costs of the existing generation portfolio of the NEM. The model finds a new least cost generation fleet, with the exception of the long-life hydroelectric stations which are retained. This means that the results presented here should be interpreted with caution; they do not represent transition pathways from the present NEM to various future states, but rather provide insight into the cost trade-offs between various possible futures, under possible policy settings. This limitation of the modelling is particularly apparent in the $3 per GJ gas scenarios, which favour high proportions of CCGTs, even in the absence of external policies to reduce greenhouse gas emissions. The resulting least cost systems are not reflective of the present NEM, which is dominated by coal-fired generation. However, the $9 per GJ gas price scenarios for series 1 and 2 could represent a realistic transition from the present NEM, especially given the smooth trend in the series results.

Some minor variability is observable as each series progresses towards higher renewable shares, particularly in the amount of open cycle gas turbine (OCGT) generation included in each portfolio. The average costs of these portfolios maintain a smooth trend, demonstrating how several different mixes may have very similar costs and be selected by the evolutionary algorithm. In all scenarios modelled, existing hydro generation is fully exploited (12 TWh per year). The model does not assign any capital cost or operating cost to existing hydroelectric stations in the NEM, so hydro is essentially "free" generation.

The features of the results for each series are described in the sections below.

4.1. Series 1: mandating a minimum level of RE generation

Fig. 2a–c illustrate the least cost generation mix for each step in the series where an increasing proportion of renewable generation is mandated over time, at the three specified gas prices. Capacity and generation data for each series at each of the three gas prices are tabulated in A and B, respectively.

As the minimum share of renewable generation is increased, wind and PV begin to enter the mix in increasing proportions (Fig. 2a). The least cost generation mix favours wind generation, with over 65% of the renewable generation in each portfolio coming from wind power. The contribution of PV is much lower, providing only 7.3%–8.8% of the renewable generation in each portfolio. As observed in other studies, PV tends to saturate at quite low levels, since it is highly self-correlated, being only available during daylight hours [14]. Even in the portfolio with 100% RE, the least cost mix only includes 8–10% from PV. In contrast, wind generation installed across the very large physical area of the NEM exhibits a significantly lesser degree of correlation, and therefore is subject to more geographical smoothing. This allows higher proportions of wind power to feature in the least cost generation portfolios. It is likely that this modelling underestimates the degree of smoothing available, since a relatively small number of generation traces have been used to represent wind variability.

Wind and PV suffice to meet the entire RE proportion required in each least cost portfolio up to and including 70% RE. It is only when an RE share of 80% is mandated that CST technology enters the mix (in all gas price cases). This indicates that the more predictable dispatch capability of CST is important for achieving least cost RE shares of 80% and higher, but that it is not important for achieving least cost RE systems of lower proportions. This suggests that policy mechanisms to encourage investment in RE technologies with inherent storage and more predictable dispatch capability (eg, geothermal and CST) could be limited to technology demonstration and commercialisation, rather than immediate major deployment of these technologies. In the near term, policy mechanisms that promote major early investment, rapid deployment and streamlined integration of wind and PV into grids are likely to be more effective for achieving significant emissions reductions, and may be sufficient to reduce greenhouse gas emissions to as low as 30% of present NEM emissions. This is a reassuring result as wind and PV are well proven technologies with existing generation of around 4% and 2.4% of annual NEM demand, respectively.

Portfolio costs are found to escalate approximately linearly as the RE share is increased from zero to 80%, at a rate of around 5% for each additional 10% of RE share (in the $3 per GJ gas price case). There is some evidence of escalating incremental costs from investment in RE shares exceeding 80%; the cost of moving from 80% to 90% RE is an additional 9%, and the cost of moving from 90% to 100% RE is an additional 10.8%. However, clearly this effect is minimal. The escalation in cost at very high RE shares is related to the inclusion of CST in the portfolios, taking advantage of the increased dispatch capabilities of this technology.

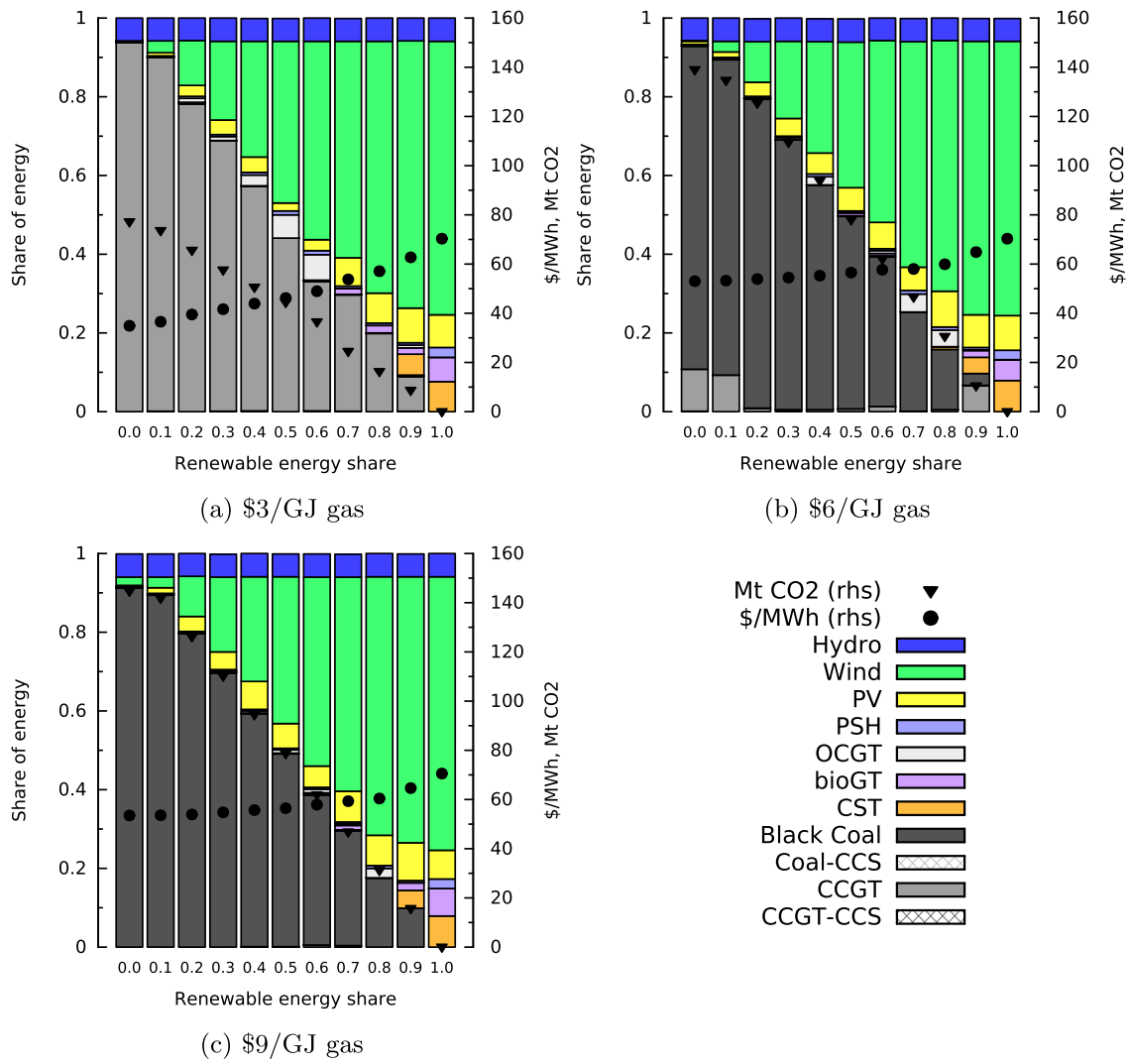


Fig. 2. Series 1 with varied gas prices.

At 100% renewable generation, the optimisation finds a generation mix with an average cost of approximately $70 per MWh, consistent with previous modelling studies, although somewhat lower due to revised technology cost projections [10,11,25]. Although this cost is approximately double the wholesale cost of electricity in the NEM at present, it does not appear that this should be an insurmountable barrier to a transition to 100% RE. It must be noted that current retail tariffs for residential and small business in Australia are approximately five times the wholesale price, suggesting that even a doubling of the wholesale price might mean a far more modest price increase for most customers.

The modelling indicates that an appropriate RE share target could be around 80% RE, if the aim is to avoid escalating incremental costs, but that a target of 100% RE may also be reasonable, and only moderately escalates the costs.

4.2. Series 2: limiting CO_2 emissions

Series 2 explores an alternative policy approach of progressively limiting total greenhouse gas emissions from the NEM. The least cost portfolios in this series are illustrated in Fig. 3a–c.

In the low gas price scenario (Fig. 3a), where CCGT dominates and there are no tight emissions caps, annual emissions total 77.1 Mt per year. This means that reducing the annual CO_2 emissions cap does not have any effect on the least cost system until a limit of 70 Mt is reached. Once the emissions cap is reduced to 70 Mt or below, renewable technologies (wind and PV) that have zero operational CO_2 emissions enter the generation mix to progressively reduce total greenhouse gas emissions to the required level.

With a high gas price (Fig. 3c), coal-fired generation is chosen over pCCGT, and is immediately and progressively displaced by wind and PV as the emissions limit becomes more stringent. Coal-fired generation is replaced by wind and PV without an initial switch to gas-fired generation. This is an important finding: unless gas has a sufficiently low cost, the transition from coal-fired generation to renewables in these scenarios occurs without gas-fired generation as an intermediate step. This is subject to the stated assumptions of technology availability, cost estimates (without subsidy), and without a carbon price.

At a moderate gas price ($6 per GJ), coal-fired technology is initially favoured (Fig. 3b), but a rapid transition to gas-fired generation occurs as the carbon limit is reduced. A second transition to renewable generation then occurs, reducing greenhouse gas

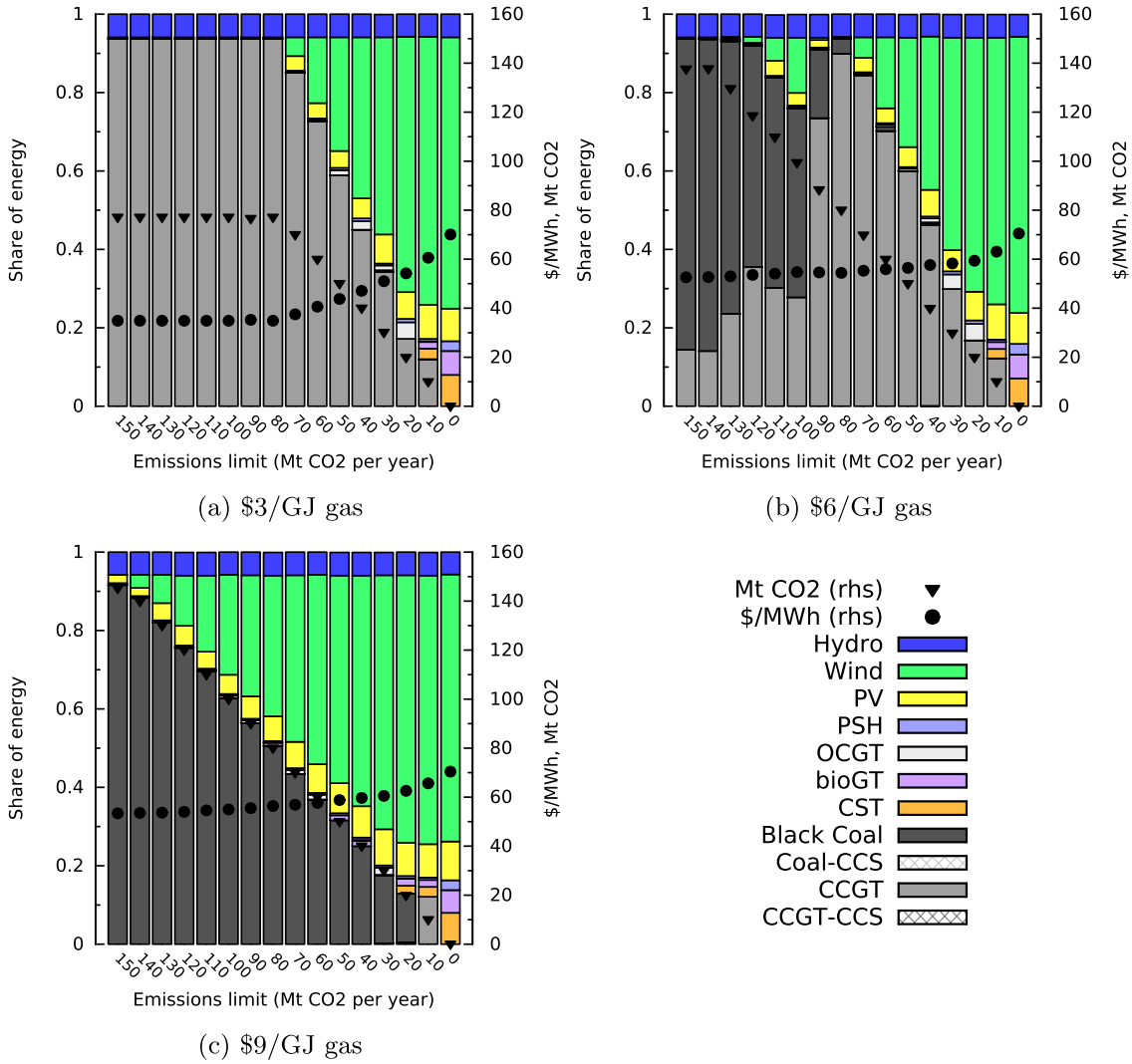


Fig. 3. Series 2 with varied gas prices.

emissions further. The variability in portfolios on this series for emissions limits between 120 Mt and 80 Mt indicates that there are a range of portfolios with very similar costs, including varying amounts of renewable and gas-fired generation. This suggests that transition pathways via a gas transition, or shifting directly to renewables may be similar in cost under the chosen assumptions. The timeframe over which this transition is likely to occur will then become of critical significance in determining whether an initial gas transition is likely to be lower cost. If gas-fired plant are likely to have reduced operational lifetimes due to the eventual need to shift to lower greenhouse gas emissions, an initial gas transition is unlikely to be least cost.

This modelling suggests that policies to promote investment in gas-fired technology as an emissions reduction measure need to be considered in light of the significant uncertainty around future gas prices and the urgency of emissions reduction, and should be designed to be robust to this uncertainty. Policies directly promoting major early renewable investment may be lower risk and have lower cost in the longer term.

In the high gas price case, which most closely matches any transition from the present coal-dominated NEM, portfolio costs are found to escalate approximately linearly as the greenhouse gas emissions limit is reduced from 150 Mt to 30 Mt per year, at a rate of around $1.35/MWh for each reduction of 10 Mt. There is some evidence of escalating incremental costs from emissions limits that are more stringent than 20 Mt; the cost of moving from 20 Mt to 10 Mt is $6.36/MWh, and the cost of moving from 10 Mt to 0 Mt is an additional $9.52/MWh. The escalation in cost at very low emissions levels is related to the inclusion of CST in the portfolios, taking advantage of the increased dispatch and synchronous capabilities of this technology.

The modelling indicates that an appropriate long-term emissions limit target could be around 30 Mt, if the aim is to avoid escalating incremental costs, but that a target of zero emissions may also be reasonable, and probably only moderately escalates the incremental costs (assuming dispatchable technologies such as CST are available in the required timeframe, at the costs assumed in this analysis).

4.3. Series 3: carbon price

In the third series, a progressively increasing carbon price is applied, as illustrated in Fig. 4a–c. Unlike the previous two series, coal CCS and CCGT-CCS technologies both appear in the least cost

scenarios modelled with a carbon price. Neither technology is featured in Series 1 or 2 due to their capital costs, their operating costs and their carbon liability with the inability to fully capture emissions (an 85% capture rate was assumed). However, when a carbon price is applied these technologies are found to be a cost competitive way to reduce greenhouse gas emissions to sufficiently low levels to minimise carbon costs, such that the total scenario cost is fractionally below the 100% RE scenario cost. Even at a carbon price of $200 per tonne CO_2, residual greenhouse gas emissions in the range 2.1–2.2 Mt per year come from coal-CCS generation and CCGT-CCS (around 9% and 17% of generation, respectively), representing the flue gases that are not able to be captured. Notably, CCS technologies are not commercially available at present, and their inclusion in these scenarios significantly increases the uncertainty on costs and commercial availability. This should be considered if policy mechanisms are designed to promote inclusion of CCS technologies.

Unlike series 1 and 2 the carbon pricing series exhibits a number of "threshold" carbon prices, where investment in a new technology suddenly becomes cost effective. In the low gas price scenario, renewables do not start to enter the mix until the carbon price exceeds $60 per tonne CO_2. Emissions remain at 77.1 Mt per year but the average cost of generation rises as the carbon price adds to gas-fired generation costs. At a threshold carbon price between $60 and $80 per tonne CO_2, wind power is aggressively introduced into the mix, reducing emissions to around 20 Mt per year. At $100 per tonne CO_2, the CCGTs are replaced with CCGT-CCS. At $160 per tonne CO_2, emissions from the OCGTs fired with natural gas are eliminated by replacing them with biofuelled OCGTs.

Importantly, this trajectory does not represent a realistic transition pathway if carbon prices were increased linearly over time, for instance. It is more likely that there will be very little investment of any kind until the "threshold" carbon price of $60 to $80 per tonne is reached, at which point the majority of new investment will be in wind and PV generation (and similarly for the other price thresholds observed). There will necessarily be a time delay in the transition to high levels of wind generation, recognising the sunk costs in the existing power system. This modelling serves to identify and highlight the important "threshold" carbon prices at which certain technologies begin to become economically competitive. This work also suggests that if the goal is to achieve a high share of RE, carbon pricing may not achieve the desired outcome, and policies that directly target renewable generation may be more suitable.

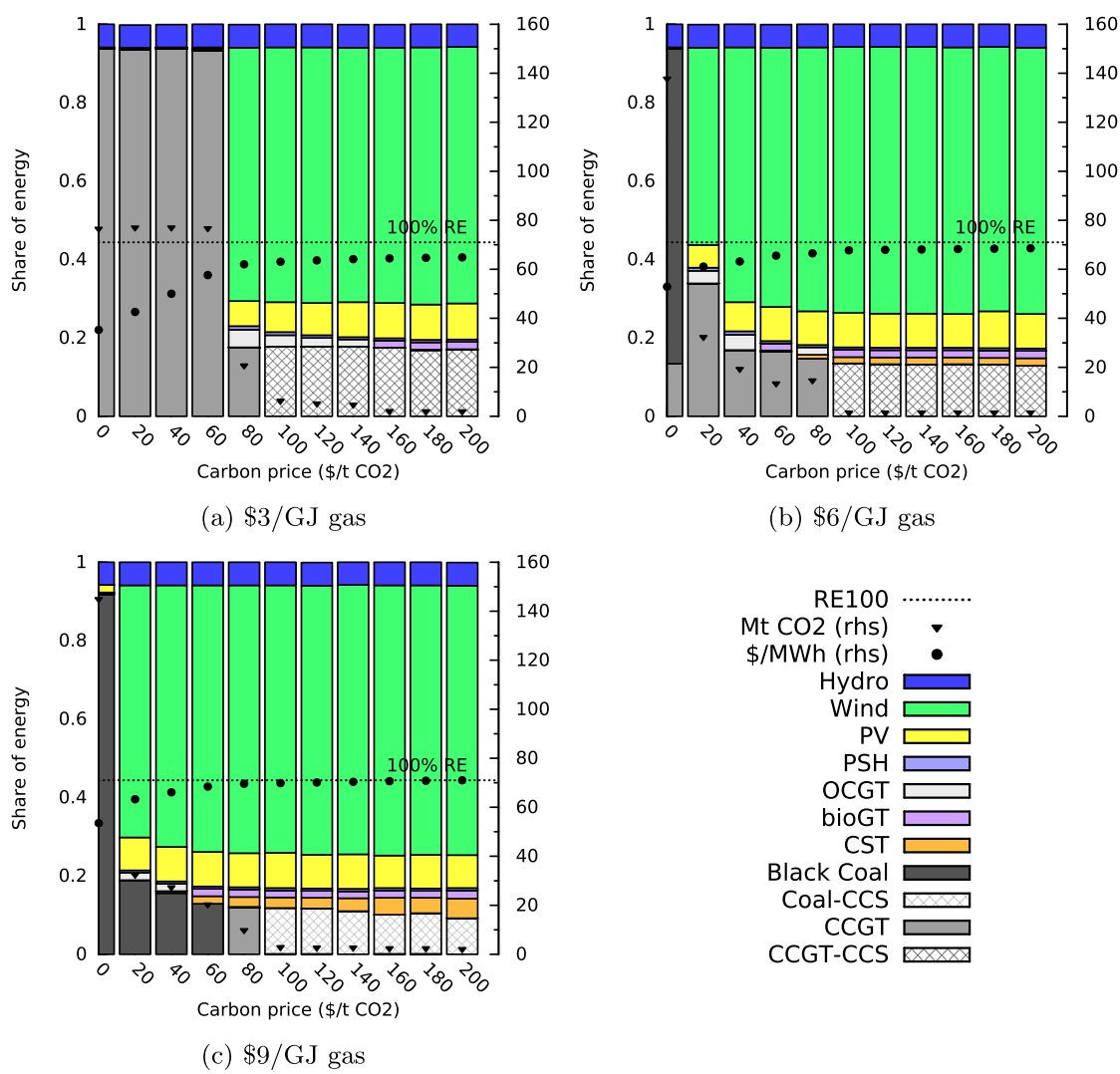


Fig. 4. Series 3 with varied gas prices.

With a moderate gas price, coal-fired generation is displaced by wind power and CCGTs when the carbon price reaches $20 per tonne CO_2. As the carbon price rises, wind and PV generation increases. At $100 per tonne CO_2, the average cost reaches a plateau. A small amount of residual emissions is produced from CCGT-CCS generation. The level of emissions is so low in this scenario that a doubling of the carbon price from $100 to $200 per tonne CO_2 does not have a material impact on the average cost of electricity. This average cost is slightly lower than the cost of 100% renewables (Fig. 4b).

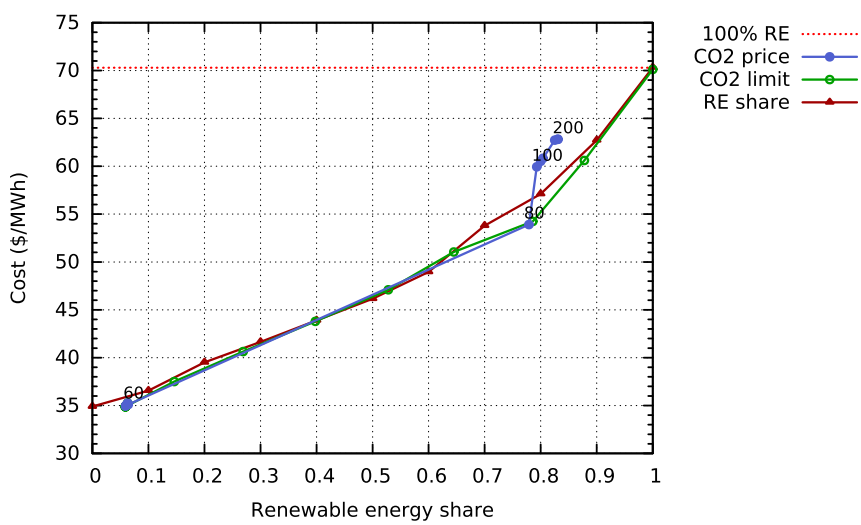
With a high gas price, a similar trend to the medium gas price scenario is observed, but coal-fired generation is favoured instead of gas-fired generation, except at $80 per tonne CO_2 where CCGT is used. At higher carbon prices, CCGT generation is replaced by coal-CCS and a small but growing share of CST.

4.4. Comparing the three series

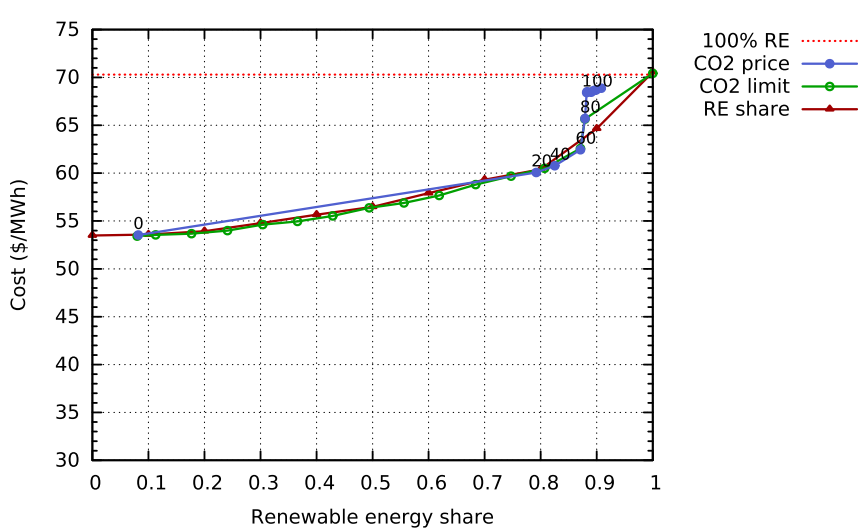
The plots in Figs. 5 and 6 compare the three different series that were modelled, showing the escalation in average cost as a function of the renewable energy share, greenhouse gas emissions, and carbon price. In each plot, the cost of the 100% RE scenario is shown as a horizontal dashed line.

These figures illustrate that all three series have very similar outcomes in terms of incremental costs for given assumptions around future technology availability and costs. Incremental costs increase approximately linearly until very high RE shares (80%) or very low emissions limits (30 Mt) are achieved. The escalation in incremental costs are listed in Table 6 (as a function of RE share) and Table 7 (as a function of greenhouse gas emissions caps). The size of the increment is found to depend upon the gas price. Higher gas prices tend to increase the cost of portfolios with a lower RE share, or higher emissions. This means that the incremental cost increase is smaller as higher renewable proportions (or lower emissions) are achieved.

Some non-linear escalation in incremental costs is observed at very high renewable shares (or every low emissions levels), as listed in Tables 6 and 7. Lifting the renewable energy share increases

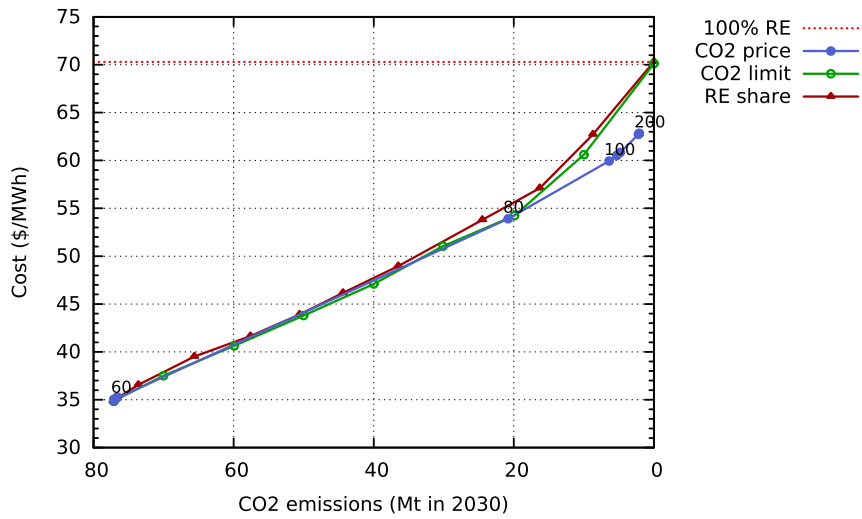


(a) $3 per GJ gas price

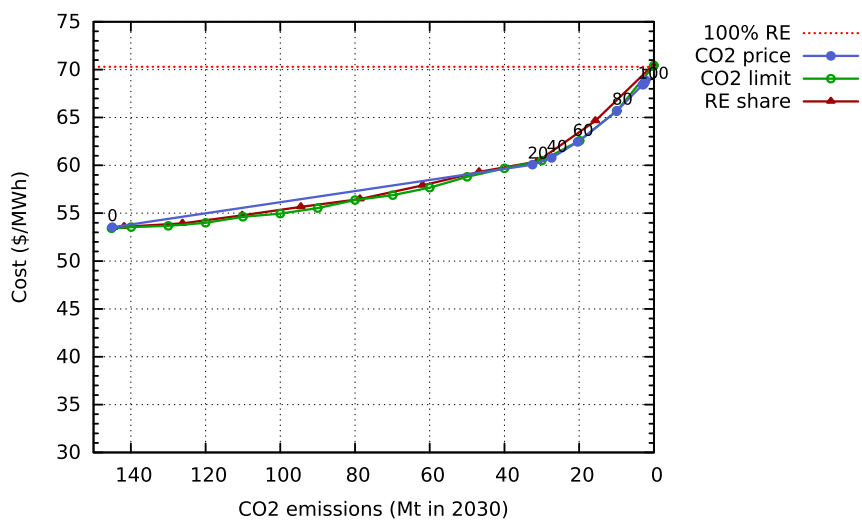


(b) $9 per GJ gas price

Fig. 5. Comparison of the average cost as a function of renewables share for the least cost portfolio for different series, with various gas prices. Note that the CO_2 price series involves different carbon prices (shown as data point labels), but the carbon liability has been removed to make them directly comparable to the other costs which do not include any carbon price.



(a) $3 per GJ gas price



(b) $9 per GJ gas price

Fig. 6. Comparison of the average cost as a function of carbon emissions for the least cost portfolio for different series with various gas prices. Note that the CO_2 price series involves different carbon prices (shown as data point labels), but the carbon liability has been removed to make them directly comparable to the other costs which do not include any carbon price.

the average cost of energy by 1.3–6.3% per 10% RE increase up to 80% renewables. Moving from 80% to 90% RE increases the average cost of energy by 7–9.8%. The final 10% step to 100% RE increases the average cost by 8.4–12.1%. Although some escalation in incremental costs is observed, it could be argued that these incremental cost increases remain moderate, especially for achieving a fully renewable electricity system.

Table 6
Incremental cost increases as a function of the RE share (calculated from Series 1).

	Incremental increase (average $/MWh) per 10% RE share increase		
RE share between	$3/GJ gas	$6/GJ gas	$9/GJ gas
0 and 80%	2.78	0.81	0.86
80 and 90%	5.62	5.37	4.24
90 and 100%	7.60	5.43	5.91

Series 3 exhibits some slightly different properties to Series 1 and 2. The carbon pricing approach applied in Series 3 produces a very low emissions scenario (2.2 Mt per year) at similar cost to the scenarios produced by constraining CO_2 emissions to zero, or mandating a 100% RE share. The carbon pricing approach appears to favour investment in CCS technologies. This leads to a small level of residual emissions that are difficult to eliminate even with a very

Table 7
Incremental cost increases as a function of emissions reduction (calculated from Series 2).

	Incremental increase (average $/MWh) per 10 Mt emissions decrease		
Emissions between	$3/GJ gas	$6/GJ gas	$9/GJ gas
150 and 30 Mt	1.35	0.47	0.59
30 and 20 Mt	3.20	1.11	2.08
20 and 10 Mt	6.36	3.73	3.07
10 and 0 Mt	9.52	7.42	4.77

high carbon price. The use of CCS technologies elevates the costs of Series 3 as a function of the share of RE, compared with the other two series. However, for low gas prices, Series 3 exhibits slightly lower costs than Series 1 and 2 at the lowest emissions levels. In this scenario, investment in the more costly CST technology is avoided, because CCGT-CCS technology is less costly with the low gas price.

Importantly, the present work suggests that the incremental costs do not depend significantly upon the nature of the approach used to achieve a certain RE share level, or emissions level. RE targets, emissions limits, and carbon prices all appear capable of producing similar cost outcomes at each RE share or emissions level, and a similar development of incremental cost.

4.5. Modelling limitations

This modelling effort has a number of important limitations. Many of the input assumptions including future technology availability (particularly CCS), technology costs, and fuel costs remain highly uncertain and can significantly affect the results. In light of this uncertainty, this paper has attempted to explore the impacts of a wide range of possible natural gas prices and carbon prices.

The modelling utilises three possible policy approaches for decarbonising the NEM. However the model did not calculate a sequential trajectory of investment as in a capacity expansion model, but instead provides a series of isolated optimisations to determine the least cost portfolio under different sets of constraints and input assumptions. The actual least cost trajectory will be somewhat different, especially in cases where a sudden transition was observed (such as in the series with an increasing carbon price). Furthermore, no timeframes are assumed for the transition; instead, cost assumptions are based upon the single year of 2030. In reality, costs will change over time as the transition occurs, and this is not captured in the model. These series still provide a great deal of value and insight, but must be carefully interpreted with these limitations in mind.

Network costs, including the additional expenditure in transmission networks that might be required has not been explicitly calculated for this modelling. Previous studies have suggested that the additional transmission expenditure required for a 100% RE system in the NEM are less than 10% of the capital costs of the generation infrastructure required [2].

5. Conclusions

This work indicates that the incremental costs of electricity systems are likely to increase approximately linearly as the RE share grows from zero to 80%, or as emissions are progressively capped from 150 Mt to 30 Mt, and are achievable based solely upon the least expensive and already commercially available wind and PV technologies. Renewable technologies that can be predictably dispatched are not required until very high RE shares (or very low emissions limits) are reached. Even in this case, incremental costs are observed to escalate only moderately. This suggests that severe escalation in costs is not a reasonable argument for policies that target RE shares lower than 100%, or electricity sector emissions limits higher than zero.

Wind energy is found to dominate the RE share of the portfolio, with PV providing typically only 20% of the RE in any portfolio. CST technologies are found to enter the least cost portfolios only when the required RE share is 80% or higher, indicating that policies to promote rapid deployment and improved integration of wind and PV may be effective for achieving very significant emissions reductions. These policies should potentially be prioritised in the near term over policies that progress pre-commercial technologies.

Gas prices are found to be a critical input assumption, with the range of uncertainty in future gas prices encompassing a wide range of possible least cost portfolios. This suggests caution is required if considering policy mechanisms that would support investment in gas-fired generation as a climate change mitigation measure.

Acknowledgements

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BREE, now the Office of the Chief Economist within the Australian Government Department of Industry, is to be commended for its efforts in continuing to revise the AETA data set. It is a valuable source of publicly available cost data for Australia and the authors recommend that the data continue to be maintained as more experience with the installation and operation of different RE technologies is gained in Australia.

Appendix. Capacity data for mandated minimum RE share scenarios

Table A.8
Generating capacity (GW) by technology for scenarios with a mandated minimum share of renewable energy ($3 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	0.0	23.3	4.7	0.0	0.0	0.0	0.0	0.0	4.9	2.1	0.0	34.90
10	0.0	21.7	1.1	0.0	0.0	2.6	0.6	0.0	4.7	2.2	3.3	36.56
20	0.0	18.3	7.0	0.0	0.0	8.3	1.9	0.0	3.7	2.1	0.0	39.51
30	0.0	16.0	7.8	0.0	0.0	13.2	2.6	0.0	4.1	1.9	0.0	41.64
40	0.0	13.3	10.3	0.0	0.0	17.8	2.7	0.0	3.0	1.9	0.0	43.90
50	0.0	10.3	13.2	0.0	0.0	24.0	1.4	0.0	2.6	2.2	0.0	46.16
60	0.0	7.7	14.5	0.0	0.1	29.5	2.0	0.1	2.6	2.0	0.0	48.96
70	0.0	6.9	3.2	0.0	0.0	35.3	4.9	0.0	4.8	2.2	8.2	53.79
80	0.0	4.6	1.2	0.0	0.0	41.0	5.2	0.1	4.8	2.0	11.5	57.10
90	0.1	2.1	10.2	0.0	0.0	43.4	6.1	3.0	4.2	2.1	4.1	62.72
100	0.0	0.0	0.0	0.0	0.0	46.2	5.7	3.7	1.8	2.1	17.7	70.32

Table A.9
Generating capacity (GW) by technology for scenarios with a mandated minimum share of renewable energy ($6 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	19.3	3.5	4.8	0.0	0.0	0.2	0.8	0.0	4.8	2.2	0.1	53.06
10	18.8	2.8	4.4	0.0	0.0	2.4	1.2	0.0	4.8	2.2	0.0	53.25
20	18.4	0.2	5.2	0.0	0.0	7.9	2.5	0.0	4.7	2.2	0.1	53.90
30	16.0	0.1	6.5	0.0	0.0	13.3	3.2	0.0	4.7	2.0	0.0	54.50
40	13.3	0.1	10.1	0.0	0.0	17.4	3.6	0.0	3.2	2.1	0.0	55.27
50	11.4	0.2	4.7	0.0	0.0	23.6	4.1	0.1	4.8	2.2	4.1	56.56
60	8.9	0.3	8.5	0.0	0.0	29.3	4.7	0.2	4.7	2.1	1.8	57.70
70	5.9	0.0	14.4	0.0	0.0	34.3	4.1	0.0	3.0	2.1	0.0	57.98
80	3.6	0.1	16.1	0.0	0.0	38.8	6.3	0.5	3.3	2.0	0.0	59.91
90	0.7	1.6	6.8	0.0	0.0	46.0	5.7	2.3	4.5	2.1	7.2	64.88
100	0.0	0.0	0.0	0.0	0.0	47.0	5.9	3.8	1.9	2.2	17.9	70.31

Table A.10
Generating capacity (GW) by technology for scenarios with a mandated minimum share of renewable energy ($9 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	22.2	0.0	4.3	0.0	0.0	1.9	0.2	0.0	4.9	2.2	0.0	53.49
10	21.6	0.0	4.2	0.0	0.0	2.4	1.1	0.0	4.9	2.2	0.1	53.59
20	18.7	0.0	4.9	0.0	0.0	7.8	2.7	0.0	4.7	2.2	0.2	53.93
30	16.3	0.0	2.6	0.0	0.0	12.8	3.1	0.0	4.8	2.1	4.2	54.77
40	13.8	0.0	7.7	0.0	0.0	17.2	4.9	0.0	4.7	2.0	0.6	55.66
50	11.4	0.0	8.5	0.0	0.0	23.8	4.3	0.0	4.8	1.9	0.3	56.47
60	8.9	0.1	9.1	0.0	0.0	30.6	3.7	0.2	4.8	2.1	0.9	57.91
70	6.8	0.1	7.6	0.0	0.0	34.6	5.3	0.2	4.8	2.1	3.7	59.32
80	4.1	0.0	13.4	0.0	0.0	41.7	5.3	0.1	4.5	2.1	0.0	60.40
90	2.3	0.0	3.9	0.0	0.0	43.7	6.7	2.6	4.5	2.0	9.8	64.64
100	0.0	0.0	0.0	0.0	0.0	44.8	5.1	3.9	1.9	2.2	18.2	70.55

Appendix B. Generation data for mandated minimum RE share scenarios

Table B.11
Generation (GWh) by technology for scenarios with a mandated minimum share of renewable energy ($3 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	0.0	191.7	0.8	0.0	0.0	0.0	0.0	0.0	11.9	0.0	0.0	34.90
10	0.0	183.7	0.0	0.0	0.1	6.1	1.6	0.1	11.9	0.2	0.7	36.56
20	0.4	159.9	2.0	0.1	0.0	23.3	5.6	0.1	12.0	1.0	0.0	39.51
30	0.1	140.4	2.0	0.0	0.3	40.9	7.6	0.1	12.0	1.0	0.0	41.64
40	0.0	116.7	5.6	0.0	0.4	60.1	7.9	0.3	11.9	1.5	0.0	43.90
50	0.0	90.0	12.0	0.0	0.0	84.1	4.1	0.1	11.9	2.0	0.0	46.16
60	0.4	67.2	13.3	0.0	0.5	103.0	5.7	0.2	12.0	2.0	0.0	48.96
70	0.2	60.6	0.1	0.0	0.2	112.5	14.7	0.0	11.8	1.2	3.1	53.79
80	0.0	40.7	0.0	0.1	0.0	130.8	15.5	0.3	12.0	1.1	3.9	57.10
90	0.7	18.1	1.4	0.1	0.1	138.8	17.9	10.8	11.9	1.2	3.4	62.72
100	0.0	0.0	0.0	0.0	0.0	142.1	16.9	15.5	12.0	5.2	12.7	70.32

Table B.12
Generation (GWh) by technology for scenarios with a mandated minimum share of renewable energy ($6 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	167.8	21.9	0.7	0.0	0.1	0.4	1.6	0.0	11.7	0.0	0.1	53.06
10	163.7	19.1	0.8	0.0	0.0	5.5	2.9	0.3	12.0	0.1	0.0	53.25
20	160.7	1.9	0.6	0.0	0.0	21.1	7.4	0.0	11.9	0.6	0.0	53.90
30	140.2	0.9	1.0	0.1	0.0	40.0	9.2	0.1	12.0	0.7	0.0	54.50
40	116.8	1.1	4.4	0.0	0.0	57.8	10.8	0.1	11.9	1.5	0.0	55.27
50	99.8	1.5	0.3	0.1	0.0	75.7	12.1	0.4	12.0	0.9	1.5	56.56
60	77.6	2.7	1.3	0.0	0.0	94.4	13.6	0.6	11.9	1.0	1.2	57.70
70	51.6	0.0	9.5	0.1	0.1	117.1	12.2	0.1	12.0	1.8	0.0	57.98
80	31.3	1.0	8.5	0.0	0.0	130.2	18.5	1.4	11.8	1.6	0.0	59.91
90	6.1	13.8	0.4	0.0	0.1	142.1	17.0	8.4	11.9	1.2	3.5	64.88
100	0.0	0.0	0.0	0.0	0.0	142.5	17.9	16.2	11.9	4.9	10.9	70.31

Table B.13
Generation (GWh) by technology for scenarios with a mandated minimum share of renewable energy ($9 per GJ gas price).

%RE	Coal	CCGT	OCGT	Coal CCS	CCGT CCS	Wind	PV	CST	Hydro	PSH	GT (bio)	Cost ($/MWh)
0	186.5	0.0	0.7	0.0	0.0	4.4	0.6	0.0	12.0	0.2	0.0	53.49
10	182.8	0.1	0.7	0.0	0.0	5.6	2.8	0.1	12.0	0.2	0.1	53.59
20	162.7	0.0	0.6	0.0	0.0	20.8	7.7	0.0	11.9	0.6	0.1	53.93
30	142.5	0.0	0.1	0.0	0.0	38.9	9.2	0.1	11.9	0.7	0.8	54.77
40	121.1	0.1	1.1	0.0	0.0	54.5	14.5	0.1	12.0	0.8	0.3	55.66
50	100.2	0.1	1.7	0.0	0.0	76.3	12.9	0.2	11.9	0.8	0.2	56.47
60	77.8	1.1	1.9	0.1	0.0	98.1	10.9	0.6	12.0	1.0	0.7	57.91
70	59.5	0.5	0.8	0.1	0.3	111.3	16.0	0.6	11.9	1.1	2.2	59.32
80	35.8	0.0	5.0	0.0	0.0	134.3	15.7	0.2	12.0	1.4	0.0	60.40
90	20.2	0.0	0.1	0.0	0.1	138.1	19.7	9.2	11.9	1.1	3.9	64.64
100	0.0	0.0	0.0	0.0	0.0	142.0	14.9	16.2	12.0	5.0	14.2	70.55

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