Least cost 100% renewable electricity scenarios in the Australian National Electricity Market

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Abstract

Least cost options are presented for supplying the Australian National Electricity Market (NEM) with 100% renewable electricity using wind, photovoltaics, concentrating solar thermal (CST) with storage, hydroelectricity and biofuelled gas turbines. We use a genetic algorithm and an existing simulation tool to identify the lowest cost (investment and operating) scenarios of renewable technologies and locations for NEM regional hourly demand and observed weather in 2010 using projected technology costs for 2030. These scenarios maintain the NEM reliability standard, limit hydroelectricity generation to available rainfall, and limit bioenergy consumption. The lowest cost scenarios are dominated by wind power, with smaller contributions from photovoltaics and dispatchable generation: CST, hydro and gas turbines. The annual cost of a simplified transmission network to balance supply and demand across NEM regions is a small proportion of the annual cost of the generating system. Annual costs are compared with a scenario where fossil fuelled power stations in the NEM today are replaced with modern fossil substitutes at projected 2030 costs, and a carbon price is paid on all emissions. At moderate carbon prices, which appear required to address climate change, 100% renewable electricity would be cheaper on an annual basis than the replacement scenario.

Keywords: renewable electricity, least cost, genetic algorithm

1. Introduction

This paper presents the findings of a study seeking to investigate least cost options for supplying the Australian National Electricity Market (NEM) with 100% renewable electricity in 2030. Different scenarios of technology mix and

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locations were assessed through simulations of electricity industry operation. A genetic algorithm was used to identify the lowest investment and operating cost scenarios.

The electricity sector is a prime candidate for rapid decarbonisation due to its significant greenhouse gas emissions yet wide range of zero emission supply options. The NEM is highly emissions intensive by world standards (Garnaut, 2011a), producing in excess of 190 megatonnes (Mt) of greenhouse gas emissions per year. This is the single largest source of emissions in Australia (Ison et al., 2011) and represents around one third of Australia's greenhouse gas emissions. Over the past decade, however, and even with relatively modest renewable energy targets, there has been significant deployment of wind and solar generation.

Recently announced renewable electricity targets for 2050 by Germany (80%) and Denmark (100%) are a bottom-up approach to mitigating greenhouse gas emissions at the national level, simultaneously addressing other objectives such as energy independence (Lilliestam et al., 2012) and competitiveness in clean technology industries (Schreurs, 2012). Although there is a well established body of academic literature going back over a decade evaluating 100% renewable energy scenarios on various geographic scales, more detailed studies are now emerging from government and industry (German Advisory Council on the Environment, 2011; Hand et al., 2012). In Australia, the Federal Government Multi-Party Climate Change Committee (2011) has requested the Australian Energy Market Operator (AEMO) to expand its current planning scenarios to "include further consideration of energy market and transmission planning implications in moving towards 100% renewable energy".

Previous work by the authors has demonstrated the potential technical feasibility of using 100% renewable energy sources to supply current NEM demand while meeting the market's reliability standard in a given year[1] (Elliston et al., 2012b). We simulated a 100% renewable electricity system for one year, using actual hourly demand data and weather observations for 2010. In the simulations, demand is met by electricity generation mixes based on current commercially available renewable energy technologies: wind power, parabolic trough concentrating solar thermal (CST) with thermal storage, photovoltaics (PV), existing hydroelectric power stations, and gas turbines (GTs) fired with biofuels.

For the second phase of this study the simulation framework has been extended in three ways. First, the program now calculates the overall annual cost of meeting demand in the simulated year including annualised capital costs, fixed operating and maintenance (O&M) costs, variable O&M costs and, where relevant, fuel costs. Second, the simulation can now make high level estimates of transmission costs associated with different spatial deployments of renewable energy technologies. Third, the simulation framework can now be driven by a real-valued genetic algorithm[2] to search for the lowest cost configuration in

[1]The NEM reliability standard is currently set at 0.002% unserved energy per year.

[2]Real-valued genetic algorithms use real numbers for chromosome values in contrast to binary digits.

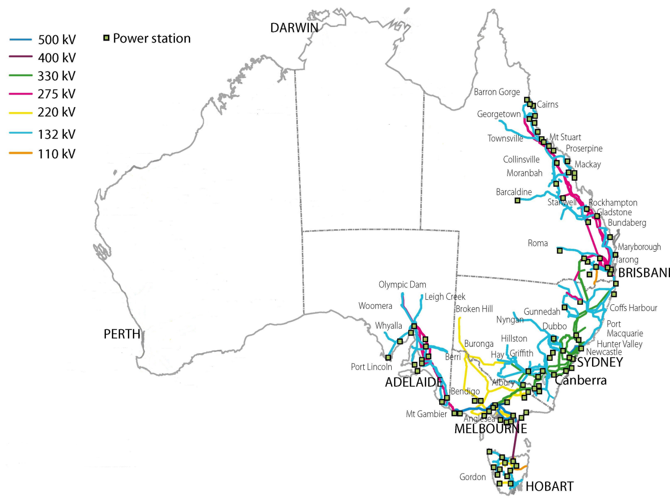

Figure 1: Existing power stations and transmission lines in the National Electricity Market. Locations are indicative only. Source: Geoscience Australia.

the simulated year that fulfills certain constraints such as meeting the NEM reliability standard.

The earlier research contained a simplifying assumption that treated the NEM area as a 'copper plate': that is, power could flow unconstrained across the NEM. Australia is an increasingly urbanised country with 64% of the population living in the eight capital cities, mostly on the coast (Australian State of the Environment Committee, 2011). The present transmission network is oriented towards fossil fuelled generators situated close to the points of fuel extraction (Figure 1). Some renewable energy sources are more abundant in rural and remote regions of Australia. For example, the Eyre Peninsula of South Australia has high average wind speeds, and the centre of the continent has very high direct normal insolation by world standards. Spatial mismatches between renewable electricity generation and demand may require an extensive reconfiguration of the transmission network. Transmission network refurbishment, expansion, and greater interconnection have been identified as urgent priorities for European countries to fulfil their renewable electricity objectives (Schellekens et al., 2011).

In the present paper, the 'copper plate' assumption is partially removed by separating the NEM into its five existing market regions and by introducing regional interconnections to the simulation framework. The regions are connected by a simplified transmission network with interconnectors between all adjacent regions. By accounting for regional energy exchanges, the balancing requirement between regions and the investment cost becomes evident. The ability to simulate the operation and overall costs of particular renewable technology portfolios, including transmission requirements, supports the use of evolutionary programming techniques to determine lower cost generation mixes through repeated simulations of a population of possible options.

The outline of this paper is as follows. Section 2 describes previous literature of these types of scenario studies. Section 3 presents some background to the NEM regional structure and the existing transmission network. In Section 4, an overview of the simulation program is given. Although there is a focus on the extensions made since earlier work was published, enough background information is provided to assist the reader. Section 5 describes the application of a genetic algorithm to explore the problem space of generation mixes – sites, technologies and capacities – that minimise annual cost within several constraints. Section 6 presents the results of the search. As a preliminary basis for comparing a 100% renewable system with alternative scenarios, Section 7 calculates the annualised cost of a replacement generation fleet for the NEM, where each present power station is replaced with the most suitable fossil-fuelled substitute. Section 8 provides an analysis and discussion of the results. Section 9 concludes the paper.

2. Previous literature

Numerous scenario studies have been published that model the potential for countries, regions, and the entire world, to meet 80–100% of end-use energy demand from renewable energy by some future date, typically mid-century. National scenarios exist for Australia (Wright and Hearps, 2010; Elliston et al., 2012b), Ireland (Connolly et al., 2011), New Zealand (Mason et al., 2010), Portugal (Krajačić et al., 2011), the Republic of Macedonia (Ćosić et al., 2012), Japan (Lehmann, 2003), the United Kingdom (Kemp and Wexler, 2010), the United States (Hand et al., 2012), Germany (German Advisory Council on the Environment, 2011) and Denmark (Lund and Mathiesen, 2009). More broadly, regional studies have been produced for Europe (European Climate Foundation, 2010; Rasmussen et al., 2012), northern Europe (Sørensen, 2008), and several studies of the global situation have been produced including by Sørensen and Meibom (2000), Jacobson and Delucchi (2011), Delucchi and Jacobson (2011), Teske et al. (2012) and WWF (2011).

Building on earlier work demonstrating, at a high level, the technical feasibility of high penetration renewable electricity, models are becoming more sophisticated. Hart et al. (2012) classifies existing analyses as zeroth order, first order or second order. Zeroth order analyses use annual or seasonal means of resource availability, first order analyses use deterministic time series data to characterise resource variability and second order analyses use stochastic techniques such as Monte Carlo simulation to characterise resource uncertainty.

Early work in this field typically involved zeroth order analyses. In contemporary efforts, a first order analysis is more common. Some simulations retain a small amount of energy supply from fossil or nuclear sources to evaluate the impact of a high penetration of renewable generation on existing generation technologies (Denholm and Hand, 2011). In the case of 100% renewable electricity in New Zealand, where existing supply is dominated by hydroelectricity, the system is simulated by eliminating the residual share of energy supplied by fossil fuels (Mason et al., 2010). Hart and Jacobson (2011) describes a second order analysis using a deterministic generator planning model coupled with a Monte Carlo dispatch simulation of the California Independent System Operator (CAISO) grid in 2005 and 2006. System balancing and spinning reserve is achieved by fossil fuelled flexible plant, so forecast errors contribute to overall power system carbon emissions. Hart and Jacobson (2012) extends this work to include an analytical approach to estimating carbon abatement potential from a portfolio of high penetration renewables.

Budischak et al. (2013) introduces a cost optimisation model using a first order analysis for the years 1999–2002 in a single region of the the United States (PJM Interconnection). An important finding is that at 99.9% load coverage, with unserved energy being met by existing fossil generation, renewables are predicted to be at "price parity" with the existing PJM generating system in 2030.

3. The NEM and its regions

The NEM is the longest interconnected power system in the world, spanning 5,000 km from Far North Queensland to South Australia (AEMO, 2012a). The network spans an area of almost four million square kilometres across diverse climate zones. Figure 2 illustrates the climate zones of Australia, contrasting the tropical climate of the far north with the cool temperate climate of Tasmania in the south. Climatic conditions in each zone can result in significant variation in weather systems, influencing the temporal and spatial patterns of electricity demand and renewable electricity supply on a range of time scales.

The NEM is the amalgamation of restructured electricity industries in the states of Queensland, Victoria, New South Wales (NSW), Tasmania, South Australia (SA) and the Australian Capital Territory (ACT). Today the NEM comprises five market regions, one region for each of the states listed. The ACT does not have its own market region and is subsumed into the NSW region. The NEM covers around 90% of the population and electricity demand of Australia.

Before restructuring of the electricity industry in Australia and the formation of the NEM, each state and territory government operated isolated, vertically integrated electricity industries. Since the 1950s, state electricity networks have been gradually interconnected to improve supply reliability and enable competition between generators, although these interconnections remain relatively weak (Diesendorf, 2010). Figure 1 shows the location of existing power stations and transmission lines.

4. Simulation overview

The simulations described in the present paper are carried out using a computer program developed by the lead author and previously described in detail (Elliston et al., 2012b). The program is written in the Python programming

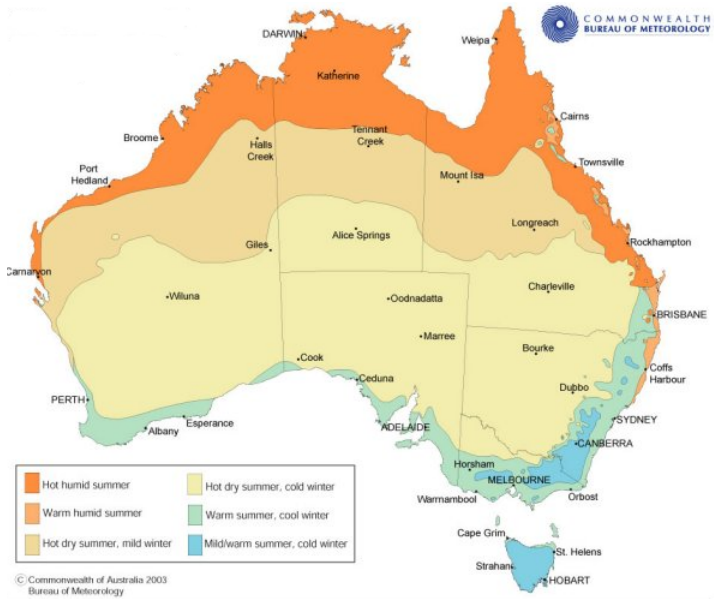

Figure 2: Australian climate zones based on temperature and humidity. Source: Bureau of Meteorology

language and has three components: a simulation framework that supervises the simulation and is independent of the energy system of interest, a large integrated database of historical meteorology and electricity industry data, and a library of simulated power generators. The simulations are deterministic and assume ideal generator availability, transmission network availability (hence, no reserve margin), and perfect meteorological forecasting skill.

We simulate and evaluate the cost of a generating system in the year 2030 in present day dollars to meet load given the 2010 demand profile for the NEM. Although it is optimistic to assume that electricity demand will not grow between now and 2030, long-term historical patterns of demand growth are unlikely to be representative of future demand. Demand in the NEM has declined by around 1.7% annually since 2008 (AEMO, 2012b; Pears, 2013), attributed to higher electricity prices, energy efficiency schemes, and the deployment of solar PV on residential rooftops. As with the model used by Budischak et al. (2013), there is no simulated plant or network failure, no spinning or non-spinning reserve capacity is maintained, and sub-hourly generation fluctuations are not modelled. At the end of a run, the simulation reports the percentage of unserved energy, the number of hours where supply does not meet demand and, for these hours, the minimum and maximum power shortfalls.

A key requirement for the program is short running time. When the computational cost of running a single simulation is sufficiently low, it becomes feasible to employ simulation-based optimisation techniques to explore the problem space. With the high performance computer[3] used for this work, eight parallel simulations can be completed every few seconds. This contrasts with other more detailed models such as the ReEDS/GridView combination employed by the National Renewable Energy Laboratory (NREL) in the Renewable Electricity Futures Study with a single run time of around 10 hours (Mai, 2012).

The simulation currently includes the following classes of simulated generators: wind, PV, CST, hydro with and without pumped storage, and gas turbines. While there is no electrochemical storage included for balancing, unlike similar simulations performed by Rasmussen et al. (2012), there is energy storage inherent in hydro generation, CST and gas turbines fuelled by bioenergy. The simulated generators use historical meteorological observations from the database to estimate electrical output at a given location. The program explicitly specifies the merit order with less controllable generation (wind power and PV) being dispatched before more controllable generation (CST, hydro and gas turbines). At the end of a run, the simulation produces a report and an hourly plot for the year showing the demand and the dispatched generation. The report includes the regional location of each simulated generator, annual energy from each generator, total energy surplus to demand (*spilled* energy), number of hours of unmet demand and total unserved energy for the year.

In the following sections, we describe extensions to the simulation framework: a cost model that calculates the annual cost of the simulated system, and a means of recording the hourly energy exchanges between regions.

4.1. Cost model

The framework has been extended to perform cost accounting in the simulated year. Each generator type is assigned an annualised capital cost in \$/kW/yr, fixed O&M in \$/kW/yr, and variable O&M costs in \$/MWh. These costs need not be constants and may be computed by the simulated generators as the simulation advances. For example, a gas turbine may have stepwise maintenance costs based on the number of elapsed running hours. At the end of a simulation run, the framework calculates the total annual cost of each generator in the simulated year.

Table 1 lists the predicted costs of the chosen renewable energy technologies in the year 2030, taken from the Australian Energy Technology Assessment (AETA), a report by the Australian Bureau of Resources and Energy Economics (2012). The AETA, published in July 2012, extensively examines the current and projected costs of 40 electricity generation options in Australian conditions.

Australia has comparatively little experience with the construction of large-scale renewable electricity plant, in contrast to countries considered to be forerunners in the transition to renewable energy. As of mid-2012, Australia has operational wind farms with a rated capacity of around 2 GW, no operating

[3]National Computational Infrastructure (NCI) at the Australian National University provided access to a computer with eight CPU cores and 48 GB of memory running the Linux operating system.

CST plants of significant capacity, and the largest PV plant has a rated capacity of 10 MW. Consequently there is little empirical data available on the costs of deploying these technologies in Australia.

Typically, European data such as those published by the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA) have been the main sources of data for Australian research. Projects commencing in Australia are likely, at least initially, to have quite different costs to projects undertaken in more experienced countries. The timeliness of data is also increasingly important due to the rapidly falling costs of some renewable technologies. IRENA (2012c) notes that, "even data one or two years old can significantly overestimate the cost of electricity from renewable energy technologies".

For each technology, the AETA includes capital cost for 2012, a range of projected capital costs for 2030, fixed O&M, variable O&M and levelised cost of energy. These data offer the advantage of currency, transparency and consistency of assumptions, although some figures (eg, the projected capital cost of CST) are contested (Want, 2012; Beyond Zero Emissions, 2012). Despite these concerns[4], we use the AETA figures for consistency with broadly accepted government and industry expectations.

The AETA provides cost data for CST plants with six hours of thermal storage and a solar multiple of 2.0. As the simulations are based on CST plants with 15 hours of storage and a solar multiple of 2.5, the CST capital cost was adjusted. The AETA provides a breakdown of CST component costs: 33% for the solar field and 10% for storage. The capital cost of the simulated CST plant was derived by scaling the solar multiple by 1.25 and the storage by 2.5. Therefore, the range of CST costs listed in the table are derived from data sourced from the AETA.

Throughout this paper, the two ends of the AETA cost range, termed *low cost* and *high cost*, are used for sensitivity analysis[5]. In the low cost scenario, the lowest capital cost in the range is chosen for each technology. Similarly, the high cost scenario selects the highest estimated capital costs. These two scenarios provide a lower and upper bound for the projected capital costs of an entire generating fleet.[6]

As hydroelectric stations typically have a very long design life (150 years), we assume that existing hydroelectric stations in the NEM will remain under all future scenarios and they are therefore excluded from the investment costings. As the potential for significant further expansion of hydroelectric energy

[4] As just one example, AETA assesses the fixed O&M costs of on-shore wind at \$40/kW/yr and variable O&M costs at \$12/MWh. For a wind farm with a capacity factor of 0.3, this leads to average O&M costs of \$27/MWh. United States data suggest that total O&M costs of \$10/MWh were achieved in the 2000s, with wind farms as recently as 2008 achieving total O&M costs below \$10/MWh (IRENA, 2012c).

[5] We note that four digit precision in the projected 2030 capital costs is inappropriate, given the uncertainties involved.

[6] O&M costs in the AETA report are not given as ranges.

Technology	Efficiency (GJ/MWh)	Capital cost ($/kW)	Fixed O&M ($/kW/yr)	Var. O&M ($/MWh)
Supercritical black coal	8.57	2947–3128	59	8
Supercritical brown coal	10.59	3768	71	9
Combined cycle GT	6.92	1015–1221	12	5
Open cycle GT (gas)	11.61	694–809	5	12
Open cycle GT (biofuel)	11.61	694–809	5	92
On-shore wind		1701–1917	40	14
CST		5622–6973	65	23
PV		1482–1871	25	0

Table 1: Estimated costs in 2030 for selected generating technologies (2012 $). 2012 operating and maintenance costs are increased by 17.1%. Source: Bureau of Resources and Energy Economics (2012)

generation is limited by a lack of water and environmental concerns (Geoscience Australia and ABARE, 2010), the hydroelectric generating capacity is fixed in the simulations.

4.2. Discount rates

We also perform sensitivity analyses using two discount rates: 5% and 10%. This gives a total of four scenario combinations, with each scenario requiring one optimisation run. The 5% discount rate is chosen as a social discount rate and the 10% rate as a private discount rate. Although the evolving electricity supply system in Australia is likely to be built by the private sector, low emissions generation will confer significant benefits to future generations and so a social discount rate may be more appropriate.

The choice of discount rate is vigorously debated in the literature. Harrison (2010) describes two approaches to choosing a discount rate, the “descriptive approach” where the discount rate is influenced by the opportunity cost of capital in private markets and the “prescriptive approach” based on value judgements about the welfare of future generations. The main recommendation that Harrison (2010) makes, however, is to perform sensitivity analyses with a range of discount rates to assess the viability of a project. A discount rate of 5% is higher than the social discount rates advocated by others in avoiding damage from climate change (Stern, 2009; Garnaut, 2011b). Conversely, a discount rate of 10%, as used in the AETA is a private discount rate appropriate for a higher degree of investment risk and is higher than would be used for most commercial investments.

4.3. Regions

Each generator in the simulation is assigned to one of the five NEM regions, based on its geographic location (Table 2). Generators are selected to ensure a wide geographic dispersion over the NEM regions, limited to the commercially available technologies described in the introduction, and subject to data

Generator name	Region
VIC wind	VIC
SA wind	SA
NSW wind	NSW
TAS wind	TAS
Melbourne PV	VIC
Sydney PV	NSW
SE Qld PV	QLD
Canberra PV	NSW
Adelaide PV	SA
Woomera CST	SA
Nullarbor CST	SA
White Cliffs CST	NSW
Roma CST	QLD
Longreach CST	QLD
Tibooburra CST	NSW
QLD pumped hydro	QLD
NSW pumped-hydro	NSW
TAS hydro	TAS
NSW hydro	NSW
VIC hydro	VIC
NSW gas turbines	NSW
VIC gas turbines	VIC
QLD gas turbines	QLD
SA gas turbines	SA
TAS gas turbines	TAS

Table 2: Generators defined for the simulations

availability. Electricity demand is treated on a regional basis rather than an aggregate basis.

Table 2 lists multiple generators of the same type. For example, hydroelectric generation is represented by three simulated generators in each of Tasmania, NSW and Victoria. PV and CST generators are assigned to specific locations. CST generators are sited in locations with high annual solar insolation and complete weather observations for 2010. PV generation is distributed within the built environment of the major mainland cities of the NEM: Adelaide, the greater Brisbane region, Canberra, Melbourne and Sydney.

4.4. Regional interconnections

Today, most adjacent NEM regions have a direct transmission connection, although some have low power capacity (Figure 1). Figure 3 shows a simplified network with the same regional interconnections as the NEM. For energy exchanges to occur between two distant, non-adjacent regions (eg, Queensland and Tasmania), energy must be transferred through one or more intermediate

Figure 3: Nodes in a simplified transmission network. Dashed lines indicate two additional interconnections for South Australia that are not presently in the transmission network. Map courtesy of Geoscience Australia.

regions. Excluding the four cases in the opposite direction, the remaining six cases are: QLD/TAS, QLD/VIC, SA/TAS and TAS/NSW (Figure 3).

A 5 × 5 matrix **C** represents the regional connectivity between the regions. Currently, the framework only permits a single path between any two regions. There are three possible cases for each element $c_{i,j}$:

- an empty list in the diagonal entries, $c_{i,i} = \epsilon$;
- for regions that are directly connected, $c_{i,j} = (i, j)$; and
- for regions that are not directly connected, $c_{i,j}$ is a list of directly connected region pairs forming a path from region i to region j.

The distance between each region is coarsely approximated using the geodetic centre of each state and territory (Geoscience Australia, 2010) and is given in Table 3. This choice provides a reasonable compromise between the location of the major demand centres, typically near to the coastline, and the most promising locations for renewable generation, sometimes far inland. Although additional transmission infrastructure will be required to completely connect generators to demand centres, this simplified network assists in approximating the transmission requirements of different geographical and capacity configurations.

4.5. Regional dispatch algorithm

In the earlier simulations, generators were dispatched in a pre-determined merit order using the following simple algorithm:

	QLD	SA	TAS	VIC
NSW	1,100	1,100	1,100	600
QLD		1,200	2,200	1,600
SA			1,600	1,100
TAS				600

Table 3: Direct distance between NEM region centres (km)

for each hour of the year
    for each generator in merit order
        dispatch power to meet residual aggregate demand

Any energy surplus to demand is either stored by storage-equipped generators (eg, pumped storage hydro), or spilled. The dispatch algorithm has been modified to dispatch power from each generator in merit order to regional loads around the NEM:

for each hour of the year
    for each generator in merit order
        dispatch power to meet residual regional demand
        (in proximity order)

Proximity order is defined as:

(i) the region where the generation being dispatched is sited;
(ii) a directly connected neighbouring region; and
(iii) a non-neighbouring region, with closer regions preferred over farther regions so as to minimise transmission losses.

Dispatching power in proximity order is not strictly necessary, as the optimisation is likely to arrive the same result through minimisation of transmission costs. The dispatch algorithm was implemented in this way to assist the genetic algorithm with faster convergence. Using a simpler dispatch model and allowing the genetic algorithm to completely optimise for transmission costs without this guidance would be a useful future exercise. As before, surplus energy is either stored by storage-equipped generators or spilled. Storage sites are selected in order of proximity to the generating region.

It must be emphasised that the dispatch algorithm continues to meet demand in the fixed merit order, corresponding to increasing marginal cost. Within an individual simulation run, the simulation framework dispatches available plant in merit order, while the genetic algorithm operates in a supervisory role, changing the system configuration between individual runs. Electricity demand and supply are not balanced on a region-by-region basis before energy may be exchanged between regions. For example, a biofuelled gas turbine located in Tasmania is not necessarily used to serve residual Tasmanian demand if wind power, higher in the merit order, is available from nearby Victoria. We assume that it is preferable to meet demand using lower marginal cost, less controllable generation such as wind and solar PV from distant regions, even if this leads to larger energy exchanges between regions.

4.6. Energy exchanges

The simulation framework records energy exchanges each hour between every pair of regions. Capacity constraints are not imposed on the interconnections, so we do not model the transmission network as would be traditionally done in a power flow analysis. Instead, we use the simplified transmission network to gain a high level appreciation of the transmission network cost implications of different generation mixes and siting. This enables the cost of different system configurations to be better compared.

5. Genetic algorithm

In previous simulations (Elliston et al., 2012b), the generating capacities of the various renewable plant were chosen by 'guided exploration' to ensure that low marginal cost generation such as wind and CST contributed a large share of generation, that bioenergy consumption was kept to low levels, and that the NEM reliability standard was met. In the present paper, a genetic algorithm (GA) is used to vary the generating capacity of each generator in the system and ensure that various constraints are met.

Briefly, a GA is a search technique that emulates the evolutionary process of breeding and mutation over a number of generations to find the fittest individuals according to objective criteria. Genetic algorithms are a powerful way of searching very large problem spaces by evaluating only a small number of the total possibilities. Goldberg (1989) is a useful resource for readers unfamiliar with genetic algorithms.

For this work, we use a Python toolkit called Pyevolve (Perone, 2009). Pyevolve requires a programmer to supply only a suitable genetic representation for each individual and an evaluation function to score the fitness of each individual. The representation and evaluation function are described in the following sections.

A large number of simulations are run as the parameter space is explored. After some experimentation to ensure that the parameter space was being adequately explored, the GA parameters in Table 4 were chosen. Individuals are propagated to the next generation by the rank selection algorithm with elitism, which ensures that the fittest individual in each generation is always propagated.

A similar cost minimisation model presented by Budischak et al. (2013) is based on five parameters: generating capacity of on-shore wind power, generating capacity of off-shore wind power, generating capacity of PV, power capacity of one of three storage technologies, and the energy capacity of the storage. Each parameter has 70 possible values, based on a linear spacing from zero to the maximum feasible value, giving 70^5 (1.6 billion) possible points in the parameter space. The parameter space is exhaustively evaluated using a 3,000

Population size	100
Generations	100
Mutation rate	0.2
Cross-over rate	0.9
Selection algorithm	Rank selection

Table 4: Genetic algorithm parameters

node computer cluster with a runtime of 15.5 hours (Budischak et al., 2013). Instead, using a genetic algorithm to reduce search time, our model is able to employ a much greater degree of parameterisation. For example, additional parameters can be introduced to represent the generating capacity of new wind farms located around the NEM.

5.1. *Genetic representation*

There are 25 generators listed in Table 2. The existing NEM hydroelectric stations, represented by five generators, have fixed generating capacities and are excluded from the representation. Each individual is therefore encoded with 20 real values, each value representing the capacity of a generator. It is possible for the GA to exclude a generator by setting its capacity to zero.

5.2. *Evaluation function*

The evaluation function calculates a projected annualised cost of meeting 2010 demand in the NEM in 2030 in billions of dollars (2012 \$). Hence, the GA searches for the individual with the *lowest* fitness score. The evaluation function is defined as the sum of:

- total annualised capital cost of generating capacity (excluding hydro);
- total fixed O&M costs for the year;
- total variable O&M costs for the year;
- penalty functions to enforce three constraints:
  - unserved energy shall not exceed 0.002% of annual demand D:

$$f(x) = \max(0, x - \frac{D}{50000})^3$$

  - generation from bioenergy shall not exceed 20×10^6 MWh (20 TWh):

$$g(x) = \max(0, x - 20 \times 10^6)^3$$

  - hydroelectric generation shall not exceed 12×10^6 MWh (12 TWh):

$$h(x) = \max(0, x - 12 \times 10^6)^3$$

- and, optionally, the estimated cost of transmission.

Note that each penalty function is raised to its cube to guide the GA strongly towards each target value. The drawback of other approaches such as a step function with a single large value denoting a constraint violation is that it provides the GA with no indication about the degree to which an individual violates the constraint (Zalzala and Fleming, 1997). In our experience, an appropriate power function is effective in leading the GA to converge on the target value.

The evaluation function may optionally include an estimate of the transmission network costs between the various NEM regions. As described earlier, the framework records the energy exchanges between regions as dispatching occurs each hour. The transmission cost t is calculated as the sum of transmission costs between every pair of regions:

$$t = \sum_{i=1}^{5} \sum_{j=1}^{5} e_{i,j} \cdot d_{i,j} \cdot c$$

where $e_{i,j}$ is the peak energy exchange encountered during the year, $d_{i,j}$ is the distance between region i and region j (Table 3), and c is the annualised unit cost of transmission in \$/MW-km/yr. The capital cost of transmission has been conservatively estimated at \$800/MW-km (Bahrman and Johnson, 2007). The annualised cost of transmission was calculated using a lifetime of 50 years.

6. Search results

A series of GA runs showed that the aggregate capacity and energy generated by each technology remained similar from run to run. Some variation in the aggregate energy generated by each technology can be attributed to differences in capacity factors achieved by identical generators sited in different locations. The allocation of generators to regions can vary significantly when there is no cost associated with transmission. Figure 4 shows the performance of the GA on a single run, converging on a solution within 70 generations. Each plotted point represents the minimum value of the evaluation function at the end of each generation. Average and maximum fitness values are not shown as the penalty functions can produce excessively large values.

Table 6 provides annualised costs for 100% renewable electricity fleets for three variables: discount rate, low/high cost for renewable technologies, and whether transmission costs are included. Table 5 lists the aggregate capacity and energy served by each renewable technology in the fittest – that is, the least cost – plant configuration. The reliability of the fittest configurations is shown in Table 7. The supply shortfalls are not significant and could be addressed by briefly shedding large industrial loads (Elliston et al., 2012b).

A number of observations can be made about the generation mixes found by the GA. On-shore wind is the largest contributor to annual energy supply. In the low cost scenario, wind represents around 46% of total energy supply and around 58% in the high cost scenario. Wind is deployed to such a great extent due to its relatively high capacity factor and because it is one of the lower capital cost technologies available. Reliability is achieved by the whole generating system, even with a high fraction of downward dispatchable generation. The generation mix in Table 6 is in agreement with the technology mix found for world-wide renewable energy supply in Jacobson and Delucchi (2011): 50% wind, 20% PV, 20% CST, 4% hydroelectricity and 6% from other sources. In that study, the need to balance demand using a diversity of more costly energy sources was recognised.

In the high cost scenarios, significantly more energy is spilled as a result of the large contribution from relatively low cost, downward dispatchable generation. This occurs despite the availability of higher cost, dispatchable generation, demonstrating that in some cases, the spilling of renewable energy can be economically optimal. This agrees with a conclusion of Budischak et al. (2013), that least-cost generation mixes may involve significant over-generation because storage to reduce the incidence of spilling may not be cost effective. Budischak et al. (2013) also suggests that some value of this spilled electricity can be recovered by diverted spilled electricity to thermal loads, thereby potentially displacing fossil fuel use in other sectors.

In the high cost, 5% discount rate scenario, 9.4 GW of CST plant generates 13.8% of total energy, illustrating that, despite the high capital costs in this study, CST power plays a valuable role in providing low marginal cost, flexible and dispatchable generation (Denholm et al., 2012), and in limiting the use of gas turbines fuelled with a constrained bioenergy resource. In all scenarios, the gas turbines produce 6.2–7.1% (12.6–14.5 TWh) of annual energy from bioenergy sources such as crop residues. Geoscience Australia and ABARE (2010) have estimated the potential for electricity generation from bioenergy in 2050 at 47 TWh.

The capacity of the gas turbines ranges from 22.3–23 GW, or around 63% of the highest peak demand (35 GW). (Hart and Jacobson, 2011) has previously identified the potential new role for dispatchable plants in a high penetration renewable system, whereby "reliable capacity is valued over energy generation". In discussing the potential for large-scale electrical storage to replace fossil-fuelled peaking plant in the CAISO simulations, Hart and Jacobson (2012) find that the capacity of this storage would need to be around 65% of the peak demand. Although taken from a different locality, these results are broadly consistent.

The ability to supply 50% of electricity in 2030 (with 2010 weather data) from wind power is dependent on wind conditions for that year. It is likely that this high reliance on wind power could produce more supply shortfalls in other years, although there is more research to be done to produce a high resolution wind climatology for the Australian continent over a longer period. No wind farms are simulated in the Queensland region because the only significant wind farm in Queensland (12 MW) is not required to make generation data publicly available. The integration of wind power from a wider geographic area, particularly from Queensland, is worthy of closer examination. Using wind power time series derived from synoptic data for 2010, however, we have shown that relocat-

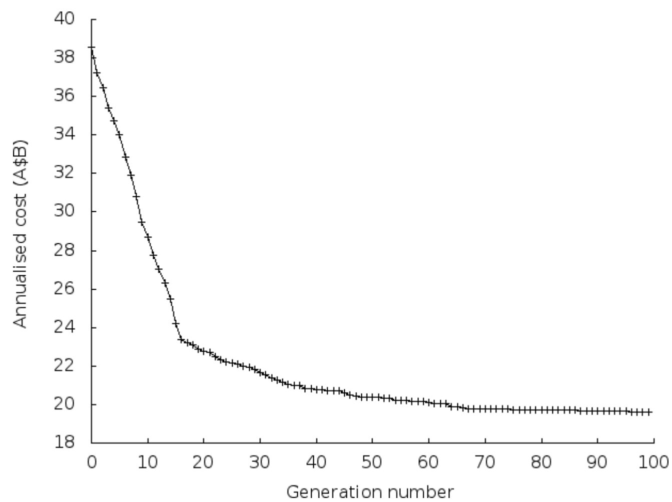

Figure 4: Annualised cost of the best population member in each generation of a single run of the genetic algorithm

ing some amount of wind capacity into northern Queensland can significantly reduce cross-correlation with existing wind farms in South Australia, reducing periods of both low and high wind output (Elliston et al., 2012a). High penetrations of wind power in the NEM should be possible given appropriate market rules and policies policies that facilitate integration (MacGill, 2010). However, a 50% wind contribution would be challenging for power system operation.

6.1. Energy exchanges

When including the cost of transmission in the optimisation, the peak energy exchanges in Table 9 are observed. A more interconnected transmission network significantly reduces the peak energy exchanges between certain regions, particularly between SA and Victoria. Victoria is a region with high annual electricity demand, second only to NSW. South Australia is a region that can host a high level of the relatively low cost wind power, which features high in the merit order. By introducing two new interconnections from South Australia (the dashed lines in Figure 3), a lower overall cost of transmission is achieved because this energy can be delivered via a shorter path. This eliminates the very high peak energy exchanges that are otherwise seen between South Australia and Victoria.

We found that very large energy exchanges can occur between different regions to balance the availability of renewable generation with demand around the NEM. The idea of operating the grid in this way is already being explored in the European context (Schleicher-Tappeser, 2012; Rodriguez et al., 2012). Referring to Table 9, some of the largest peak energy exchanges occur between the most populous states of New South Wales and Victoria.

The cost of a transmission network to facilitate this is not particularly onerous when considered in the context of the total cost of either the 100% renewable

Technology	Low cost scenario Cap. (GW)	Share (%)	Energy (TWh)	Share (%)	High cost scenario Cap. (GW)	Share (%)	Energy (TWh)	Share (%)
5% discount rate								
Wind	34.1	31.9	94.8	46.4	47.1	41.4	119.7	58.6
PV	29.6	27.7	41.0	20.1	27.6	24.2	31.3	15.3
CST	13.3	12.5	43.9	21.5	9.4	8.3	28.2	13.8
Pumped hydro	2.2	2.1	0.5	0.2	2.2	1.9	0.8	0.4
Hydro	4.9	4.6	11.5	5.6	4.9	4.3	11.1	5.4
GTs	22.7	21.3	12.7	6.2	22.7	19.9	13.3	6.5
Spilled			8.8				24.9	
10% discount rate								
Wind	35.1	33.9	97.4	47.7	46.0	39.4	117.9	57.7
PV	24.3	23.5	34.3	16.8	32.6	27.9	35.7	17.5
CST	13.9	13.4	46.2	22.6	8.8	7.5	26.1	12.8
Pumped hydro	2.2	2.1	0.4	0.2	2.2	1.9	1.1	0.5
Hydro	4.9	4.7	11.5	5.6	4.9	4.2	11.0	5.4
GTs	23.0	22.2	14.5	7.1	22.3	19.1	12.6	6.2
Spilled			6.8				27.1	

Table 5: Capacity and energy mix for the fittest individual generating system (four scenarios). Transmission costs excluded.

Discount rate	Low cost ($B/yr)	($/MWh)	High cost ($B/yr)	($/MWh)
5%	19.6	96	22.1	108
10%	27.5	135	31.5	154

Table 6: Least cost 100% renewable generating systems in 2030 (2012 $) excluding long-distance transmission

Scenario	Hours unserved	Min. shortfall (MW)	Max. shortfall (MW)
5% discount rate			
Low cost	8	136	920
High cost	7	47	891
10% discount rate			
Low cost	5	473	1294
High cost	8	104	1032

Table 7: Reliability statistics for the fittest generating systems

Discount rate	Low cost		High cost	
	($B/yr)	($/MWh)	($B/yr)	($/MWh)
5%	21.2	104	24.4	119
10%	31.2	153	35.4	173

Table 8: Least cost 100% renewable generating systems in 2030 (2012 $) including long-distance transmission

	NSW	QLD	SA	TAS	VIC
NSW		8.4	4.5		9.6
QLD	8.5		3.1		
SA	7.8	8.6			4.7
TAS					2.0
VIC	10.7		6.6	1.5	

Table 9: Peak energy exchanges (GWh) in 2010 between regions

electricity system or the replacement fossil-fuelled fleet (Section 7). The annualised cost of including the simplified transmission network is $1.6B to $3.9B per year depending on the discount rate, or 8% to 11% of the total cost of the 100% renewable system (Table 6). When renewable energy costs are taken to be at the lower end of the range of uncertainty, the transmission network represents a greater share of the total cost.

Delucchi and Jacobson (2011) performed a sensitivity analysis on transmission costs for a range of price estimates and transmission distances, finding that the cost of transmission would add between $3 and $30 per MWh to the delivered cost of electricity, with the best estimate being about $10 per MWh. Despite using a different methodology for estimating transmission costs, we arrive at similar results: $8 to $19 per MWh (see Table 8).

7. Costing a replacement fleet scenario for the NEM

In considering the cost of a 100% renewable system for the NEM, it is necessary to compare this with alternative future scenarios. Much of the existing plant in the NEM will reach the end of its economic life in the next two decades. In this section, we calculate and compare the cost of a new fossil-fuelled generation fleet for the NEM where every existing power station is replaced with current thermal plant technology at projected 2030 costs. A price is paid on all greenhouse gas emissions and it is assumed there is no capturing of emissions.

In this scenario, fuel costs are assumed to remain the same for the location of each plant and projected fuel prices out to 2030 are taken from data produced by ACIL Tasman (2009). The minimum, average and maximum projected fuel prices for each fuel type are listed in Table 10. These projections predict stable or slightly declining prices for brown and black coal in Australia to 2030, reflecting the poor economics of exporting coal from many of the current mining locations. Brown coal in the southern state of Victoria is not exported

Fuel type	Min.	Avg.	Max.
Black coal	0.76	1.29	2.13
Brown coal	0.08	0.70	2.00
Natural gas	0.95	7.61	12.25

Table 10: Projected 2030 location-specific fuel prices for all NEM power stations ($/GJ)

and is unlikely to be in the future. Black coal, found more widely across the country, is exported from some regions, but in others, prices are set based on the cost of local production (International Energy Agency, 2012). These prices are well below the market prices faced by fossil fuel importing regions today. The OECD average price for black coal is US $5.60/GJ (International Energy Agency, 2012).

Similarly, natural gas exports are presently constrained by the availability of export infrastructure and therefore some gas is sold domestically below international prices. However, the average price of natural gas available to power stations is expected to rise from around $3/GJ today to over $7/GJ in 2030. This is still below the price paid for natural gas imports in Europe ($9/GJ) and Japan ($14/GJ) today (International Energy Agency, 2012). Fossil fuels in Australia are cheap and abundant by world standards.

By using annualised capital costs, we avoid treating the current generation fleet as a sunk cost and can gain a full appreciation of the costs of constructing, maintaining and retiring plant in the current generation fleet. Existing hydroelectric stations are excluded from the costings for the reasons outlined in Section 4.1. The present NEM wholesale market currently trades around $10 billion of electricity each year excluding the cost of emissions. Assuming that generators are pricing electricity to recover all costs and make a profit, $10 billion should be indicative of the long-run annual cost of operating the generating fleet[7].

The annualised cost of the existing generation fleet was estimated using data from ACIL Tasman (2009) and costs from the AETA. For each registered generator in the NEM, the ACIL Tasman (2009) data set provides values for technical lifetime, thermal efficiency, location specific fuel cost and emission factors. The AETA data is used for costs of new entrant plant including annualised capital cost (2012 $/kW/yr), fixed O&M and variable O&M. These new entrants represent modern thermal plant technology with higher thermal efficiency, lower fuel consumption, and lower emissions per megawatt-hour of electricity generated than currently operating plant. In general, fuel costs out to 2030 were largely unchanged. Relevant costs are given in Table 1. Fuel costs are not included in the table for fossil fuel plants, as these are sensitive to the power plant location. Biofuel costs for the gas turbines are included in the variable operating and maintenance (VO&M) costs.

[7]This cost does not include most transmission and distribution network expenditure, which is recovered from end users in the NEM retail market.

For each fossil-fuelled plant in the NEM, the closest suitable replacement was chosen from the available new entrants. In some cases, a straightforward replacement was possible (eg, a supercritical thermal plant fuelled with black coal). In many cases, a direct replacement was not possible and the closest suitable replacement was chosen instead (eg, a supercritical brown coal plant to replace a 1970s era subcritical brown coal plant). In each case, the fuel type remains unchanged to reflect the availability and economics of the local fuel supply. In a limited number of cases, the choice of replacement is less straightforward. The following three assumptions were made:

- steam turbines fuelled by natural gas are replaced with combined cycle gas turbines (CCGTs);
- smaller plant such as reciprocating engines running on landfill gas or liquid fuels are replaced with open cycle gas turbines (OCGTs); and
- the two co-generation facilities in the NEM are replaced with CCGT technology.

The short run marginal cost (in \$/MWh) for each plant in the replacement fleet was calculated using the following equation, adapted from ACIL Tasman (2009):

$$\mathrm{SRMC_{SO}} = \mathrm{TE_{SO}} \cdot \mathrm{FC} + \mathrm{V} + \mathrm{TE_{SO}} \left(\frac{\mathrm{EF_c} + \mathrm{EF_f}}{1000} \right) \mathrm{CP}$$

where $\mathrm{TE_{so}}$ is the thermal efficiency (sent out) in GJ/ MWh, FC is the fuel cost in \$/GJ, V is variable operating and maintenance costs in \$/MWh, $\mathrm{EF_c}$ and $\mathrm{EF_f}$ are the combustion and fugitive emission factors in kg CO_2-e/GJ respectively, and CP is the carbon price in \$/t CO_2-e.

Electricity generated in 2010 by each existing power station in the NEM is determined by summing historical five minute dispatch data obtained from AEMO. To avoid penalising the existing fossil fuel system by including the cost of plant to maintain mandated reserve margins, any power station that generated zero energy in 2010 is excluded. The cost of replacement and operation for three selected power stations in the NEM is given in Table 11.

In 2010, the NEM produced approximately 193 Mt CO_2-e due to combustion and fugitive emissions. The current fleet of thermal plant are generally well into their economic life, most being commissioned over 20 years ago. In one instance, the Energy Brix power station in Victoria was commissioned over 50 years ago and has one of the lowest thermal efficiencies in the fleet. By replacing the current thermal plant with modern equivalents, we found that NEM emissions for 2010 would be reduced to 156 Mt CO_2-e, a 19% reduction. This is broadly consistent with figures produced by the IEA Clean Coal Centre (2012).

7.1. Externalities and subsidies

The only negative externality that is incorporated into the cost of the replacement fleet is greenhouse gas emissions. There are other negative externalities

	Bayswater	Hazelwood	Newport
Fuel type	Black coal	Brown coal	Gas
Capacity (MW)	2720	1640	500
Capital cost ($M/yr)	1010.9	771.5	59.7
Fuel cost ($/GJ)	1.31	0.08	4.08
SRMC ($/MWh)	39.11	32.97	42.00
Energy (TWh)	14.46	11.48	0.25
Operating cost ($M/yr)	565.7	378.7	10.6
Emissions (Mt)	12.2	11.3	0.1

Table 11: Costs for three replacement power stations in 2030 (2012 $, $23/t CO_2-e carbon price, 10% discount rate). Data source: ACIL Tasman (2009)

whose costs are already being paid indirectly by society including air pollution, water pollution and land degradation. Another major public concern is the effect of fossil fuel combustion on mortality and morbidity (Kjellstrom et al., 2002; Muller et al., 2011). The total health burden of electricity generation in Australia has been estimated at $2.6 billion per year (Australian Academy of Technological Sciences and Engineering, 2009).

Subsidies in the Australian fossil fuel industry are also ignored in the costings, however these are believed to be of the order of $10 billion per year across the entire industry, principally the liquid fuel sector (Riedy and Diesendorf, 2003; Riedy, 2007). Specific subsidies to the electricity sector include low cost electricity to aluminium smelters creating 13% of electricity demand (Turton, 2002) and access to cooling water at very low cost (Foster and Hetherington, 2010). There are current plans for a state-owned coal mine in NSW to supply coal to generators at the cost of production (Tamberlin, 2011). These subsidies are provided to a mature and profitable industry with few, if any, conditions that would lead to their phase out.

Renewable energy in Australia presently receives subsidies in the form of feed-in tariffs and tradeable renewable energy certificates. These instruments are intended to transition the technologies from early stages of the product life cycle to maturity. These and other subsidies take one of two forms: research and development funding for technologies in early stages of development, and deployment subsidies to accelerate cost reductions through learning. Deployment subsidies are usually provided on the basis that they are progressively reduced. Recent experience world-wide, including in Australia, is that subsidies have been reduced rapidly or phased out in response to the falling cost of some technologies, particularly PV.

8. Discussion

8.1. Sensitivities

The sensitivity analyses presented in the Section 6 highlight a number of key issues for 100% renewable electricity. Using the cost data from the AETA, we find that wind contribution is increased in the high cost scenarios because of the narrower range of costs for wind power, making it relatively cheaper to the other options. Wind power is one of the most mature renewable energy technologies. While there are still future cost reductions predicted, these are not as significant as for other technologies. This serves to narrow the range of uncertainty about future costs. In high cost scenarios, we find that the share of PV and CST declines.

Due to the generation profile of rooftop PV, we find that without electrical storage, the penetration of PV is limited to about 20%, regardless of its cost. Hence, without storage, incentives to further reduce the cost of PV may not enable 100% renewables. It is important to reduce the cost of other commercially available technologies, too (eg, CST).

The generation mix is not particularly sensitive to the discount rate. When simulating a single year, O&M costs of generation are not discounted as would be the case in a multi-decade analysis. Furthermore, in each sensitivity analysis, the discount rate is used to calculate annualised capital costs for each renewable technology. Dividing the capital cost of each technology by a constant annuity factor does not change the relative costs of the different technologies in each analysis. The main effect of a varied discount rate is to change the relationship between annualised capital costs and O&M costs for each technology.

8.2. Implications for Australia

Assuming that the application of a higher carbon price ($50 per tonne CO_2-e) would not have altered plant dispatch in 2010, emissions from the existing NEM generating fleet of 190 Mt would have produced a carbon liability of $9.5B in 2010, bringing the cost of the current system ($19.5B) in line with the lowest cost scenario for a 100% renewable system. At carbon prices above $50 per tonne CO_2-e, rebuilding the NEM generating fleet with renewable energy becomes the lower cost option.

Figures 5 and 6 show the cross-over points for the annualised cost of the replacement fleet and the optimised 100% renewable system at discount rates of 5% and 10%, respectively. The figures show a range of uncertainty in the required carbon price to reach the cross-over point, principally due to uncertainty in the future cost of renewable energy technologies (low and high cost scenarios). In the 5% discount rate case, the fossil fuel system is more costly on an annualised basis when the carbon price exceeds the range $50–$65. With a 10% discount rate, the fossil fuel system is more costly when the carbon price exceeds the range $70–$100. When comparing the projected 2030 capital costs of wind, solar PV and CST in the AETA with other international sources (eg, IRENA, 2012a; IRENA, 2012b; IRENA, 2012c), the annualised costs of the 100% renewable scenarios in the Australian context are likely to be pessimistic.

The range of uncertainty in the cost of the fossil fuel system is much narrower than in the renewable energy systems (Figures 5 and 6). This is because the replacement fossil system remains dominated by coal and forecasts by ACIL Tasman (2009) project stable coal prices around the NEM over the next two decades.

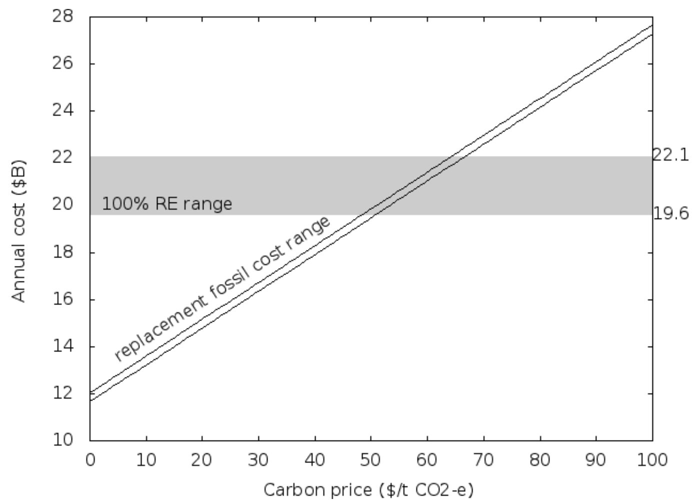

Figure 5: Annual costs for replacement fossil and least-cost renewable generating systems in 2030 as a function of carbon price (5% discount rate). Transmission costs excluded.

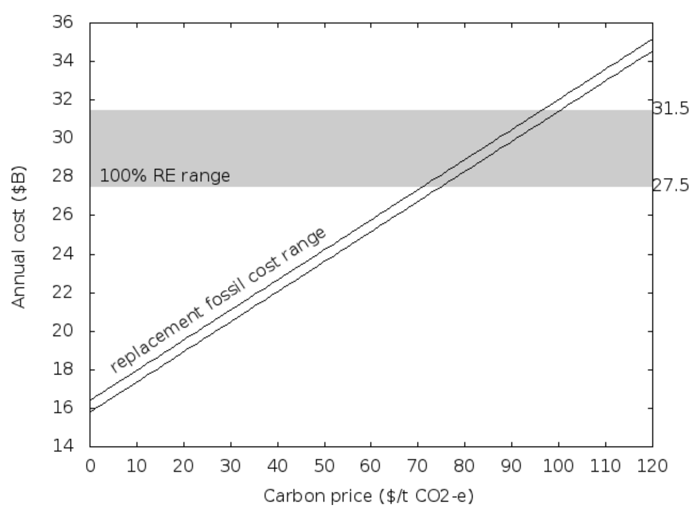

Figure 6: Annual costs for replacement fossil and renewable generating systems in 2030 as a function of carbon price (10% discount rate). Transmission costs excluded.

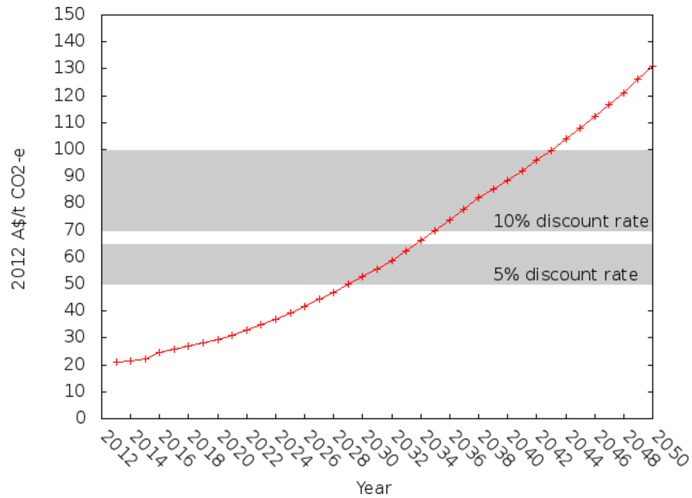

Figure 7: Trend in modelled Australian carbon price (in 2012 A$) with bands showing the expected range of years when the carbon price is high enough to equate the cost of the 100% renewable electricity system with the replacement fleet. Data: Australian Treasury (2011)

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We feel that future fuel costs could be more uncertain than the ACIL Tasman (2009) data suggests. Ball et al. (2011) reports that the fuel cost for NEM generators would be "considerably more" if generators faced international prices for black coal and natural gas. Liquefied natural gas terminals will soon be opening on the eastern coast of Australia, giving domestic natural gas producers access to potentially higher prices on the international market. The implication of higher fuel prices for the fossil fuelled generation fleet is that operating costs will be higher and a lower carbon price will be required to make the renewable electricity system more attractive.

Figure 7 shows the expected Australian carbon price to 2050 as modelled by the Australian Treasury (2011) in its 550 parts per million scenario. The lateral bands in the figure indicate the range of carbon price thresholds above which the 100% renewable electricity system is lower cost than the replacement fleet. The range of threshold values is due to uncertainty in the projected technology costs in 2030. These carbon prices are expected to prevail in the years 2029–2034 (5% discount rate) and 2035–2043 (10% discount rate). It was decided in 2012 to link the Australian emissions trading system (ETS) with the European Union (EU) ETS. Due to depressed carbon permit prices in the EU, the future trajectory of carbon prices is now less certain. The IEA 450 parts per million scenario, by contrast, estimates much higher carbon prices to achieve effective action on climate change: \$120 in 2035 compared with \$74 (2012 \$) in the Australian Treasury (2011) modelling.

8.3. International implications

In an international context, other regions of the world such as the Middle East and Africa have some similar characteristics to Australia: low price fossil fuels and an abundance of certain renewable energy sources (eg, solar radiation). Despite the abundance of renewable energy resources in Australia, the low price of fossil fuels makes the economic case for the 100% renewable system more challenging.

Some countries around the world, particularly in the EU, are well advanced on the path to renewable electricity supply. There are a number of aspects to the European situation which make it difficult to draw direct comparisons with this study: some that improve the economic case for 100% renewable electricity, and some that make it more difficult.

The more advanced deployment of renewable energy in other countries would likely permit new generation to be built and operated at significantly lower cost than in Australia, at least initially. Countries with high dependence on imported fossil fuels pay a much higher price for power station fuel. This also improves the economic case for 100% renewable electricity.

There are two aspects which may make the economic case more difficult in regions outside Australia. Australia has a highly emissions intensive generating fleet that is heavily penalised by a rising carbon price. Few other electricity industries in the world are so carbon intensive and may therefore require higher carbon prices to reach the same cross-over point where a 100% renewable energy system is the lower cost option. Furthermore, some renewable energy sources (eg, solar radiation) are abundant in Australia and not matched in many other populated parts of the world. This difference in resource availability leads to higher generating costs in countries with poorer resource availability and a more difficult economic case for 100% renewable electricity.

Finally, the requirement for extensive transmission lines is unlikely to cause as much community opposition in Australia as it does in Europe and the United States due to the low population density.

8.4. Further work

The simplified transmission network used in this work underestimates the full length of transmission lines required and therefore the cost of transmission. A more detailed network model based on more numerous and smaller regions is one area for further work. Another area of worthwhile exploration is alternative network configurations, which will influence the generation mix in order to maintain reliability. These configurations could be explored in more detail by removing the heuristic strategy in the dispatch algorithm and allowing the GA to completely co-optimise the cost of transmission.

There is further work to extend the model to incorporate stochastic failure of plant and network, hence necessitating system reserves. In the NEM, the Minimum Reserve Level (MRL) for each region is set based on available generation and interconnection in that region such that there is a high probability that the reliability standard will be met over a year (Tamblyn et al., 2009).

The reference scenario provided in this paper permits detailed costings to be made and compared with the 100% renewable electricity scenarios. However, the reference scenario does not deliver the emission reductions necessary to effectively address climate change. It can not be considered a realistic response to the need for low emissions electricity industries in Australia and elsewhere in the world. Alternative low emissions scenarios will be considered in future research, such as a carbon capture and storage (CCS) scenario, an all-gas scenario and a nuclear-gas scenario.

Possible future reductions in the cost of energy storage raises interesting questions about the impact of storage on the mix of technologies in 100% renewable systems. With cost-effective energy storage, we can speculate that the lower cost technologies, wind power and PV, will claim even larger shares of energy generation, displacing more expensive CST and bioenergy. Furthermore, energy storage would enable PV to further increase its penetration, presently limited by its generation profile and the coincidence of generation with demand.

9. Conclusion

By developing and using a computationally efficient technique, we have cost optimised a 100% renewable electricity generating system over a wide geographic area, a range of generating technologies, capacities and locations that meet reliability and sustainability criteria. Simulating with weather and demand data for the year 2010, a generating mix that is dominated by wind power, with smaller contributions from PV and CST, can meet 2010 electricity demand while maintaining the NEM reliability standard, limiting hydroelectricity generation subject to rainfall, and limiting the consumption of bioenergy.

Depending on the choice of discount rate, the 100% renewable system is cheaper on an annualised basis than a replacement fleet with a carbon price in the range of \$50–65 (5% discount rate) and \$70–100 (10% discount rate). Despite these conservative discount rates, the range of carbon prices that raise the cost of the replacement fossil-fuelled fleet above that of the 100% renewable energy system appear modest, and below those carbon prices that appear to be required in order to effectively address climate change out to 2050. This range of carbon prices has been projected to prevail between 2029 and 2043, with the uncertainty predominately due to uncertainty in long-term carbon prices and the future cost of renewable energy technologies.

Although it is clear that the conventional system cannot meet future emissions reduction targets, the annualised cost of a replacement fleet provides a useful reference. The carbon price at the point where the annualised cost of the replacement fleet equals the annualised cost of the 100% renewable system indicates the required cost of abatement from CCS if it is to be competitive. The prospect that a 100% renewable electricity system will be less costly than a renewed fossil-fuelled replacement fleet in the medium term poses some interesting policy questions about planning the construction of long-lived energy generation and infrastructure assets. These will be explored in future work.

10. Acknowledgements

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