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Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market

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ABSTRACT

Policy makers face difficult choices in planning to decarbonise their electricity industries in the face of significant technology and economic uncertainties. To this end we compare the projected costs in 2030 of one medium-carbon and two low-carbon fossil fuel scenarios for the Australian National Electricity Market (NEM) against the costs of a previously published scenario for 100% renewable electricity in 2030. The three new fossil fuel scenarios, based on the least cost mix of baseload and peak load power stations in 2010, are: (i) a medium-carbon scenario utilising only gas-fired combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs); (ii) coal with carbon capture and storage (CCS) plus peak load OCGT; and (iii) gas-fired CCGT with CCS plus peak load OCGT. We perform sensitivity analyses of the results to future carbon prices, gas prices, and CO_2 transportation and storage costs which appear likely to be high in most of Australia. We find that only under a few, and seemingly unlikely, combinations of costs can any of the fossil fuel scenarios compete economically with 100% renewable electricity in a carbon constrained world. Our findings suggest that policies pursuing very high penetrations of renewable electricity based on commercially available technology offer a cost effective and low risk way to dramatically cut emissions in the electricity sector.

1. Introduction

There is a growing recognition of the urgency for large, rapid and sustained emissions reductions to avoid dangerous global warming. Achieving deep cuts to greenhouse gas emissions in some sectors (e.g., transportation, agriculture) is likely to be more difficult than the electricity sector. The Australian Government has a policy to reduce greenhouse gas emissions to 80% below year 2000 levels by 2050. Electricity generation in the Australian National Electricity Market (NEM) is responsible for around one third of national emissions [1] and is therefore an obvious candidate for early efforts to reduce emissions. Given the availability of low carbon options for electricity generation, it could be argued that the electricity sector should be almost completely decarbonised to contribute towards the 2050 target. One approach to decarbonising the electricity sector being considered world-wide is a transition to 100% renewable energy sources.

In this paper, we compare the cost estimates of previously published scenarios for 100% renewable electricity ("RE100") hour-by-hour in the NEM against a number of alternative options available to policy makers: greater use of efficient gas-fired generation, and the use of carbon capture and storage (CCS). Nuclear power is not examined as it is prohibited in Australia under the Commonwealth Environment Protection and Biodiversity Conservation Act 1999. The key question being addressed is how these alternative scenarios compare with the RE100 scenario and whether they are likely to be significantly lower cost. Indeed, is it worth either deploying gas-fired generation with lower, but still substantial emissions, or waiting for immature CCS technologies to emerge at sufficient scale? The intent of this paper is to help inform policy as governments develop strategies in the face of significant uncertainty about technology development and costs.

The national circumstances of Australia are somewhat unique for a developed country. Australia is a wealthy nation with a well educated workforce and a technological services sector, but with a large share of commodity exports from primary industries. The electricity sector has an ageing fleet of fossil-fuelled thermal generators and is highly emissions intensive by world standards due to

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its dependence on domestic supplies of lignite and black coal [2,1]. Yet, Australia has manifold low carbon electricity options including wind, solar, biomass, marine and geothermal energy [3], and considerable aquifer storage for 70–450 years of emissions at an injection rate exceeding current NEM annual emissions [4]. If CCS cannot be developed rapidly to commercial scale, there will be no future for coal-fired electricity in a carbon constrained world. While some mature renewable energy technologies, namely wind power and photovoltaics (PV), have experienced rapid cost reductions in recent years, progress on scaling up and commercialising CCS has been poor [5].

The Australian Government presently has one main policy to promote utility-scale renewable electricity: a tradeable certificate scheme to reach 41 TWh per year of renewable generation by 2020, or 20% of generation forecast at the outset.[1] There is now an active discussion in Australia about long-term future energy scenarios and appropriate policies to enable the necessary electricity industry transition. The Australian Bureau of Resources and Energy Economics (BREE) published the Australian Energy Technology Assessment (AETA) in July 2012 [6]. The report extensively examines the current and projected costs of 40 electricity generation options in Australian conditions including renewable, fossil and nuclear technologies; not all are commercially available today. Where technologies are not yet commercially available, the report estimates when they will become so. Although some cost figures in the report are disputed, the AETA has found wide use as a consistent basis for modelling by universities, government and industry researchers.

A body of previous research has examined the technical and economic feasibility of operating the NEM completely from renewable energy sources, leading to zero operational emissions. Scenarios have been developed by the Australian Energy Market Operator (AEMO) [7], by the authors [8,9], and by environmental research organisation Beyond Zero Emissions [10]. In evaluating the cost of a 100% renewable electricity scenario, it is necessary to compare with other future scenarios produced by a consistent method. A criticism of the AEMO study [7] has been that no reference scenario is provided to put the costs into context with alternative scenarios that can equally fulfil climate protection objectives [11]. The authors have also previously compared the cost of a 100% renewables scenario against a replacement of the current fossil-fuelled NEM generation fleet with modern, thermally efficient plant [8]. This “efficient fossil” scenario cannot meet the 2050 target but provides a basis against which to compare the evaluation of the cost of 100% renewable electricity. Further research into long-term scenarios for the NEM requires considering other possibilities including gas-fired plant and CCS.

In this paper, we consider three lower carbon scenarios for the NEM based on the estimated least cost mix to meet actual demand in 2010 of:

(i) conventional combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs);
(ii) CCS-equipped coal plant and non-CCS OCGTs; and
(iii) CCS-equipped CCGTs and non-CCS OCGTs.

For these scenarios, a criterion used to select technologies for our previous RE100 scenarios is relaxed: that the technologies be currently commercially available, although we use 2030 cost estimates for them. Scenario (i) above employs commercially available technology, but scenarios (ii) and (iii) do not.

[1] The 41 TWh target now equates to approximately 25% of forecast generation in 2020.

The paper is organised as follows. In Section 2, we briefly review recent developments in 100% renewable electricity scenarios. The current status of CCS, particularly in Australia, is given in Section 3. Section 4 describes each of the scenarios. Section 5 provides an overview of the simulation tool developed to model 100% renewable electricity scenarios and describes how this tool is used to simulate the least cost mixes in the three fossil fuel scenarios. Section 6 outlines sources of data used in the simulations. Section 7 documents the results for each of the scenarios. Section 8 discusses the implications of our findings and concludes the paper.

2. Status of 100% renewable electricity scenarios

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 now exist for Australia [7–10], Ireland [12], New Zealand [13,14], Portugal [15], the Republic of Macedonia [16], Japan [17], the United Kingdom [18], the United States [19], Germany [20] and Denmark [21]. More broadly, regional studies have been produced for Europe [22,23], northern Europe [24], and several studies of the global situation have been produced [25–29].

Over time these scenarios are becoming more sophisticated in scope and detail, chiefly due to greater available computing power and, to a lesser extent, improved data. For example [13], have revised their scenario for New Zealand extending the analysis period from three to six years. Recent studies by AEMO and the U.S. National Renewable Energy Laboratory have been completed to a high level of detail and with participation from industry [7,19].

In July 2011, the Australian Government commissioned AEMO to undertake a detailed techno-economic feasibility study of 100% renewable electricity in the NEM. Acknowledging the many differences in assumptions such as what technologies are considered available (e.g., the inclusion of geothermal power), AEMO produced findings broadly consistent with our own previously reported findings. AEMO noted, “the operational issues appear manageable”, and that the costs of such a system might increase current retail electricity tariffs by less than nine cents per kilowatt hour or around 30% of current residential rates [7].

3. Status of carbon capture and storage

Like other emerging energy technologies, CCS faces challenges due to competition from other lower carbon sources (e.g., unconventional gas and wind power), a lack of ambition in climate policies, and a difficult policy environment. The International Energy Agency (IEA) reports that there are 13 large-scale CCS demonstration projects operating or under construction world-wide [5]. The majority of these projects are capturing, or will capture, emissions from gas processing facilities, not power stations. Several integrated CCS power generation projects are operational or under construction, capturing a small fraction of total plant emissions.

In its two degree scenario (2DS), the IEA projected that around 65% of all coal-fired generation world-wide in 2050 would be equipped with CCS. Some pilot projects have been cancelled in recent years, causing a large shortfall in the annual rate of CO_2 expected to be sequestered by 2012: 65 Mt CO_2 per year as against 260 Mt CO_2 per year in the 2DS. The IEA has expressed concern that, “To deploy CCS on the scale and timeline outlined in the 2DS, policy makers will need to take immediate actions to enable and, further, to actively encourage private investment in CCS” and that, “CCS must be developed and demonstrated rapidly if it is to be deployed after 2020 at a scale sufficient to achieve the 2DS”. Currently, there are no coal-fired power stations demonstrating CCS at commercial scale [5]. At current rates of progress, it appears difficult to achieve this level of deployment by 2050.

In Australia, there has been an expectation by government and industry that CCS will play an important role in decarbonising the emissions intensive electricity sector and, ultimately, securing the future of thermal coal exports by transferring CCS technology to trading partners [30,31]. The Australian Government has been a strong supporter of CCS through a number of research and development programs, demonstration programs, and a national CCS roadmap. Australia established the non-profit Global Carbon Capture and Storage Institute in 2009. Four coal-fired power stations in the NEM are trialling small pilot post-combustion capture units and one oxy-fuel combustion pilot is underway [32,33]. Australia does not have specific financial incentives for operating CCS-equipped power plants. The IEA lists the United Kingdom as the only country proposing incentives to promote CCS beyond demonstration phase through feed-in tariffs, a floor on carbon prices and a minimum standard on the emissions intensity of new power stations [5].

As a result of pressures in the 2013-14 Commonwealth Budget, the Australian Government reduced funding to the main Carbon Capture and Storage Flagships program by $500 million over the next three years [34]. While this may not indicate a crisis of confidence in the ability to commercialise CCS, this cut to research and development programs is problematic given the slow progress of CCS development and deployment.

4. Fossil fuel scenarios

This section describes each of our fossil fuel scenarios, plus the RE100 scenario from earlier work. Note that none of these “lower carbon” fossil fuel scenarios yields an electricity supply system with zero operational emissions. This can, notionally, only be achieved by the RE100 scenario. Four features are common to all scenarios:

1. capital costs projections for 2030 are taken at the low end of the range for each technology as reported in the AETA with a 5% discount rate;
2. transmission requirements are not modelled (further elaboration is given in Section 8.1);
3. OCGTs in our scenarios do not capture any CO_2 emissions because there has been no development of capture units for OCGTs. These generating units are typically operated at a low capacity factor that does not justify the capital expense of capture equipment [35]; and
4. to reduce the number of simulated generators and speed up the simulation runs, each fossil-fuelled plant technology is represented by one simulated generator with a large capacity. That is, we do not consider regional variations in fossil-fuelled plant efficiency or fuel costs.

Baseline parameter values for all scenarios are given in Table 1 and discussed in more detail in Section 6. If a parameter is not varied for sensitivity testing, its value is taken from Table 1.

4.1. CCGT scenario

In the CCGT scenario, the generation fleet consists of conventional CCGTs plant, the existing NEM hydroelectric power stations,[2] and OCGT plant fuelled by gas. Generation is dispatched in that order. A carbon price is paid on all emissions as none are captured.

[2] 7.1 GW total capacity including 2.2 GW of pumped storage hydro stations. Long-term average generation is 12 TWh per year.

Table 1
Baseline parameter values chosen for scenarios. Costs shown are projections for 2030 in current dollars.

Black coal price	$1.86	/GJ
Gas price	$11	/GJ
Carbon price	$56	/t CO_2
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	%

The CCGT scenario has some appealing characteristics: it relies on proven and commercially available technology, it could be constructed quickly, it has lower capital costs than coal-fired plant, and it has the lowest emissions of all commercially available fossil-fuelled technologies (approximately 400 g CO_2 per kWh). It has been noted by Viebahn et al. [36] that a CCGT plant produces “only 45% more emissions (400 g CO_2 per kWh) than the worst [performing] power plant with CCS (pulverised hard coal with 274 g CO_2 per kWh)” when the additional emissions associated with capture (88% capture rate), compression, transportation and storage are included. If the emissions reductions associated with heat recovered from a combined heat and power CCGT are included, CCGT has a similar emissions intensity to black coal with CCS.

The CCGT scenario is consistent with some of the approaches of the IEA four degree scenario [37]. That is, switching from coal to lower carbon fuels and dramatically improving the conversion efficiency of thermal plant. The main disadvantages of this scenario are that it does not achieve the emissions reduction required to meet the 2050 target and it produces a generation fleet almost completely dependent on a single fuel that has considerable future price risk.

4.2. Coal CCS scenario

In the coal CCS scenario, the generation fleet consists of supercritical pulverised black coal plant fitted with post-combustion capture and storage, existing hydro, and OCGT plant fuelled by gas. Generators are dispatched in that order. CO_2 transportation and storage costs, hereinafter abbreviated to CO_2 storage costs, are applied to each tonne of captured emissions and a carbon price is paid on emissions not captured by the coal plant and OCGTs.

Although other CCS technologies are under development, namely pre-combustion capture through integrated gasification combined cycle (IGCC) plants, and oxy-fuel combustion, we have limited our analysis to post-combustion capture. This choice reflects the fact that coal-fired plant with post-combustion capture has the lowest projected capital cost in 2030 of the three CCS technologies surveyed in the AETA report.

Table 2
CO_2 storage costs by region. Costs in 2009 dollars using a 12% discount rate (d.r.) are shown alongside adjusted costs using a 5% discount rate. Third column shows 2013 dollars using a 2.5% per year inflation rate. Data derived from Allinson et al. [43].

Region	2009 $ (12% d.r.)	2009 $ (5% d.r.)	2013 $ (5% d.r.)
North Queensland	41	25	28
South Queensland	23	14	15
New South Wales	72	44	48
Victoria	22	15	17
Mean	40	24	27

4.3. CCGT-CCS scenario

The CCGT-CCS scenario is identical to the CCGT scenario, except that post-combustion CCS is fitted to the CCGT plant. A carbon price is paid on non-captured emissions from the CCGT plant and all emissions from the OCGT plant. CO_2 storage costs are applied to captured emissions.

4.4. 100% Renewable electricity scenario

In the RE100 scenario the generation fleet consists of commercially available renewable energy technologies [8]. The mix includes wind power in existing wind farm locations and scaled to the desired capacity, PV distributed across rooftops in the capital cities of the NEM area, concentrating solar thermal (CST) with a solar multiple of 2.5 and 15 h of thermal storage in six high insolation inland regions, existing hydro, and OCGTs fuelled with gasified bioenergy, typically from crop residues. Generation is dispatched in that order. This scenario has zero operational CO_2 emissions.

5. Simulation overview

The scenarios described in this paper are simulated using NEMO, a software package developed by the lead author and previously described in detail [9]. NEMO is written in the Python programming language and has three components: a 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 and perfect meteorological forecasting skill. No spinning or non-spinning reserve capacity is maintained, and sub-hourly generation fluctuations are not modelled. A review of 37 energy modelling software tools available in 2009 classified the tools by their capabilities, geographical scope, energy sectors included, timeframe and time step [38]. Using the terminology of the review, NEMO can be approximately described as a simulation tool, a bottom-up tool, an operational optimisation and an investment optimisation. It is similar to tools such as SimREN and EnergyPLAN that have been used to model national energy systems based on 100% renewable electricity.

We simulate and evaluate the cost of a generating system in the year 2030 in current dollars to meet load given the 2010 hourly 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. In 2010, total electricity demand in the NEM was 204.4 TWh. Annual demand has declined in recent years and, as of July 2013, has returned to 2005 levels [39]. This decline can be attributed to higher electricity prices, energy efficiency schemes, and the deployment of solar PV on residential rooftops [40].

The simulation tool currently includes the following classes of simulated generators: wind, PV, CST, hydro with and without pumped storage, and a range of thermal plant: coal with CCS, CCGT, CCGT with CCS, and OCGT. For the weather-driven technologies, the simulated generators use meteorological observations from 2010 to estimate electrical output at a given location for each hour over the year. Each scenario specifies a generator list that determines the type and location of generators and the order in which they are dispatched. 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. For each generator, the report includes the annual generation, CO_2 captured where applicable, and CO_2 emissions where applicable. The report also summarises total energy surplus to demand, the number of hours of unmet demand and the total unserved energy for the year as a percentage of demand.

5.1. Cost model

A cost model calculates the annual cost of the system by summing the annual cost of each generator in the simulated year. Each generator type is assigned an annualised capital cost in \$/kW/yr, fixed operating and maintenance (O&M) in \$/kW/yr, and variable costs in \$/MWh. The projected technology costs for 2030 are taken from the AETA [6] and appear in Table 3. Note that CCS plant have lower thermal efficiency and higher variable costs than their non-CCS counterparts due to the auxiliary load of CO_2 capture and compression.

5.2. Least cost search

The simulation framework is driven by a genetic algorithm (GA) to search for the lowest cost generating system. By keeping the computational cost of a single simulation sufficiently low, it becomes feasible to employ simulation-based optimisation techniques to explore the problem space. With the high performance computer used for this work, eight parallel simulations can be completed every few seconds.

The objective function for the GA is the minimum cost generating system that fulfils three constraints: meeting the NEM reliability standard by limiting unserved energy to 0.002% of annual demand, limiting hydroelectric generation to the long-term average of 12 TWh per year, and, for the RE100 scenario, limiting electricity from bioenergy sources to 20 TWh-e per year. The use of the GA to search for the lowest cost configuration of a generating system composed of a variety of technologies, locations and capacities is described in detail in earlier published work [8]. The generating capacity of each simulated generator is typically represented by one parameter in the GA. Using a GA has the advantage of permitting a large number of simulation parameters, which precludes exhaustive search approaches [41].

5.3. Comparison with optimal mix

The traditional method of finding the economically optimal mix for conventional generation uses a characteristic load duration curve. Equations (1) and (2) calculate the number of load hours met by intermediate plant with greater operational flexibility and higher running costs than "baseload" plant, and by peak load plant with the highest flexibility and running costs [42]. Fig. 1 shows the

Table 3
Projected costs (low end of range) in 2030 for selected generating technologies (2012 dollars). Consistent with AETA methodology, operating and maintenance costs are inflated by 17.1% over the period.

Technology	Heat rate (GJ/MWh)	Capital cost (\$/kW)	Fixed O&M (\$/kW/yr)	Variable O&M (\$/MWh)
CCGT	6.92	1015	12	5
CCGT w/CCS	8.35	2095	20	11
CST		5622	65	23
OCGT	11.61	694	5	12
OCGT (bioenergy)	11.61	694	5	92
On-shore wind		1701	40	14
PV		1482	25	0
Supercritical black coal	8. 57	2947	59	8
Supercritical black coal w/CCS	11.46	4453	107	18

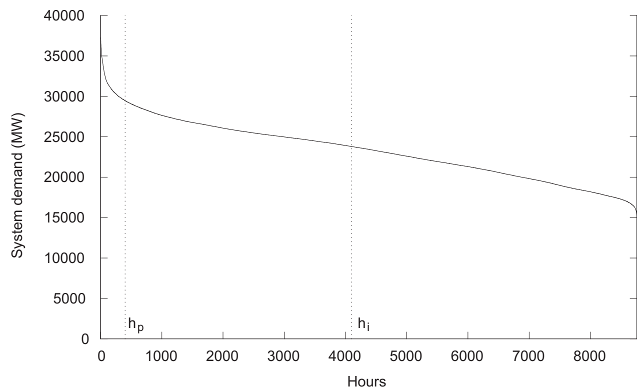

Fig. 1. System-wide load duration curve for the NEM in 2010 with h_p and h_i chosen arbitrarily for illustration. h_p and h_i are the number of hours of peaking and intermediate plant operation, respectively. Data source: AEMO.

2010 system-wide load duration curve with arbitrary set points h_i and h_p for illustration. The plant serving baseload notionally operates every hour of the year, subject to availability. In these equations, c is the plant capital cost and r is the running cost. Subscripts b, i and p represent baseload, intermediate load and peak load, respectively.

$$c_i + h_p r_i = c_p + h_p r_p \tag{1}$$

$$c_b + h_i r_b = c_i + h_i r_i \tag{2}$$

For consistency, the same simulation tool was used to determine the least cost plant mix for the fossil fuel scenarios. The advantage of this approach is that it is easy to develop new scenarios with different generation mixes and, through multiple runs, test the sensitivity of some parameters. The GA can be expected to find the same mix as the analytic technique and we verified this using a simple scenario of one coal-fired plant, one CCGT for intermediate load, and one OCGT for peak load.

6. Cost and performance data

In addition to the technology cost projections listed in Table 3, this section explains the other data used in the scenarios.

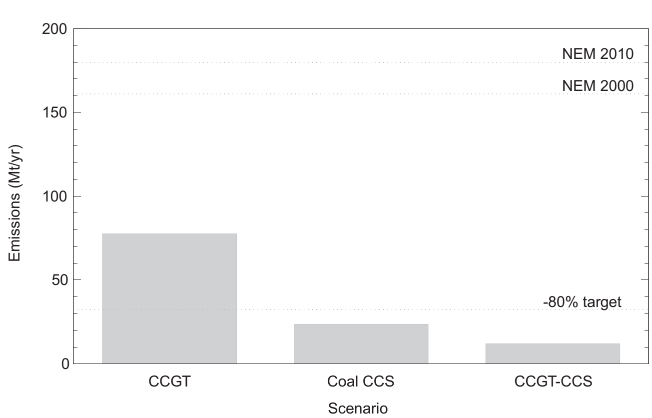

Fig. 2. Annual emissions from different fossil fuel scenarios for electricity generation. Horizontal lines show emissions produced from NEM operations in the year 2000 and 2010. The level required to reduce emissions by 80% is also shown.

6.1. CO_2 transportation and storage costs

As well as the capital cost of carbon capture equipment at the power station, CCS involves the transportation of compressed CO_2 via pipelines to suitable storage sites. Allinson et al. conducted a first-pass scoping study for CO_2 transportation and storage potential in Australia based on industry-supplied costs and resource data [43]. To date, it remains the only comprehensive analysis of the costs of CO_2 transportation and storage in Australia.

Allinson et al. produced central estimates of the costs for CO_2 transportation and storage, excluding the cost of capture, compression of the pure CO_2 stream to 8 MPa, and transportation to the nearest node in the pipeline network [43]. The transportation network assumes that emissions from an individual power station or industrial process are carried by pipeline to a regional hub, where they are further compressed for long-distance transportation to a reservoir. There is significant variation in the costs for different source and sink site combinations around Australia. The costs are still highly uncertain, but are dependent on the CO_2 injection rate, the storage reservoir characteristics and geographic location. The most sensitive factor in the cost of CO_2 transportation and storage is the reservoir characteristics. Some aspects of the costings are more certain, as CO_2 transportation and storage utilises relatively mature gas handling technologies.

CO_2 transportation and storage is capital intensive, requiring pipelines, compressors and reservoir preparation. A cost per tonne of CO_2 avoided was calculated by Allinson et al. using the present value of project expenditure over 25 years (using a 12% discount rate) divided by the present value of emissions that could be sequestered over the 25 years [43]. For each region of the NEM, we have taken the lowest cost combination of source and sink sites (Table 2). To place these costs on equivalent terms to other costs in the scenarios, we recalculated the costs using a 5% discount rate (central column, Table 2) and adjusted them to current dollars for regions of interest (rightmost column, Table 2). Costs were escalated at an inflation rate of 2.5% per year.

6.2. Other data

In this section, each of the other values in Table 1 are explained.

- The black coal price is assigned a single value of $1.86 per GJ. This represents an average projected 2030 price for black coal across the NEM regions [6]. Some coal mines supply fuel to nearby power stations as they have no economic means to move coal to export facilities. Presently, NEM coal-fired power stations are somewhat insulated from international coal prices.
- Gas prices in the Australian domestic gas market have traditionally been low by world standards. The present development of export terminals along the east coast of Australia will give domestic gas producers access to international markets and this is increasing gas prices in the domestic market from around $3 per GJ to as high as $9 per GJ [44]. BREE highlights the wide variation in long-term gas price projections between market analysts and even the same analysts over time [45]. From 2010 to 2012, one analyst repeatedly increased its projection of eastern state gas prices in 2030 from $7.50 (2010 dollars) per GJ to $11–12 per GJ depending on the region (2013 dollars). We have assumed a baseline projected 2030 gas price of $11 per GJ with a number of different prices tested from $3 to $15 per GJ.
- The baseline carbon price of $56 per tonne CO_2 is the projected price by the Treasury in the Australian emissions trading scheme in 2030 [46], adjusted to current dollars. This estimate is based on a conservative core policy scenario which assumes a 550 parts per million (ppm) stabilisation target. The projected

price of carbon for the high price scenario, based on a 450 ppm stabilisation target, is $120 per tonne CO_2, adjusted to current dollars. The IEA estimates similar carbon prices for an appropriate response to a 450 ppm target (e.g., US$120 in 2035). A wide range of carbon prices for 2030 are therefore analysed in the simulations from $20 to $140 per tonne CO_2.

- We use a single average cost of CO_2 storage from regions around the NEM (Table 2). Due to the wide range of values and uncertainty discussed in Section 6.1, this parameter is varied in the simulations from $20 to $100 per tonne CO_2. The NEM-wide average of $27 is situated in the lower end of the range as the lowest cost source and sink site combinations were chosen in each region.
- The gross emission rates of the simulated coal, OCGT and CCGT plant is 0.8, 0.7 and 0.4 tonnes CO_2 per MWh (sent out), respectively. For CCS variants, a fraction of this CO_2 is captured and the net emissions are released.
- The post-combustion capture rate is estimated at 85%. This is a slightly conservative figure, as capture rates as high as 90% have been reported for small-scale pilot projects [33].
- Choosing a discount rate is contentious and only one discount rate (5%) has been used in this work to keep the scope manageable given all of the other uncertainties being considered. When modelling a single year, as we have done, the discount rate has only the effect of altering the magnitude of annualised capital repayments. The fact that fuel and operating costs in subsequent years will be discounted at different rates is of no consequence when modelling one year.

7. Results and analyses

7.1. 100% Renewable electricity scenario

We have previously examined mixes of commercially available renewable energy technologies that maintain the NEM reliability standard, limit hydroelectric generation to available rainfall, and limit bioenergy use to ecologically sustainable levels. The generation mix is summarised in Table 4. The least cost estimate of this scenario is $19.6 billion per year [8].

7.2. Coal CCS scenario

Fig. 3 shows 30 annualised least cost solutions for the coal CCS scenario under a range of different CCS plant capital costs and CO_2 storage costs.

It is not readily apparent from the near-linear increase in annual costs seen in Fig. 3, but changing variables in the simulations such as coal CCS capital cost, CO_2 storage cost and carbon price changes the lowest cost generation mix. When CO_2 storage costs are higher and/or carbon prices are lower, it becomes economic to move a greater share of generation to the OCGT plant without emissions capture and to incur the cost of emissions.

Table 4
Generation mix for the least cost 100% renewable electricity scenario to meet hourly demand in 2010 [8].

Technology	Capacity (GW)	Energy (%)
Wind	34.1	46.4
CST	13.3	21.5
PV	29.6	20.1
Gas turbines (biofuelled)	22.7	6.2
Conventional hydro	4.9	5.6
Pumped hydro	2.2	0.2

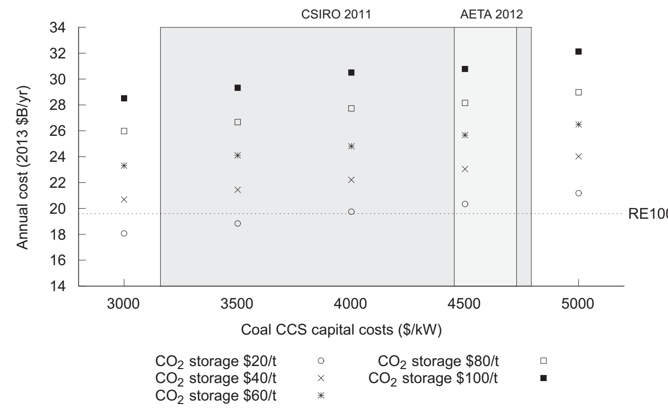

Fig. 3. Sensitivity of annual costs to coal CCS capital costs ($/kW) and CO_2 storage costs ($ per tonne CO_2) in coal CCS scenario. Shaded regions show range of estimates from CSIRO [47] and the AETA [6].

The shaded regions of the plot show the range of plant capital cost estimates from CSIRO [47] and the AETA [6]. Carbon and coal prices are held constant. Of the combinations tested, the only cases that produce a lower annual cost than the RE100 scenario are those with a CO_2 storage cost of $20 per tonne CO_2 *and* plant capital cost below $4000 per kW. Every case where the cost of CO_2 storage is $40 per tonne or more is uneconomic compared to the RE100 scenario.

The sensitivity of the coal CCS scenario to CO_2 storage costs and the carbon price is shown in Fig. 4. The plant capital cost and coal price are held constant. A range of carbon prices ($20 to $140 per tonne CO_2) and a range of CO_2 storage costs ($20 to $100 per tonne CO_2) were tested. The principal finding is that the RE100 scenario is lower cost than the coal CCS scenario in all of the cases tested. Within the range of CO_2 storage costs tested, there is not much sensitivity to the carbon price, as most of the emissions in the coal CCS scenario are sequestered. Some emissions from the coal-fired plant are not captured, in addition to emissions from the OCGT peak load plant.

Fig. 2 shows that the coal CCS scenario would reduce NEM emissions to below the level required to meet the 2050 target. If demand in 2030 is significantly greater than in 2010, emissions will be higher and could exceed the 2050 target. As noted earlier, cuts greater than 80% may be required in the electricity sector if other sectors are more difficult to decarbonise.

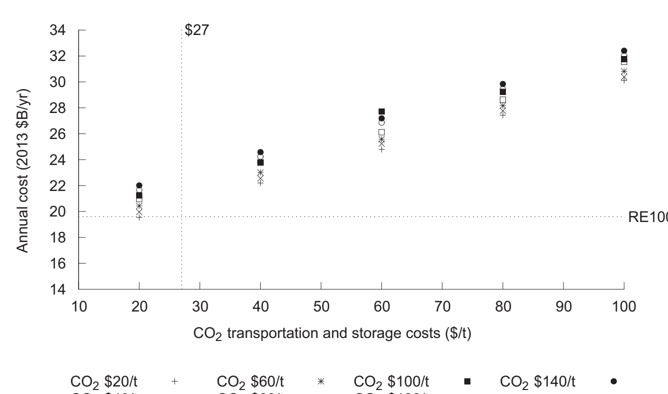

Fig. 4. Sensitivity of annual costs to carbon price and CO_2 storage costs ($ per tonne CO_2) in coal CCS scenario. Vertical line is the baseline CO_2 storage cost from Table 1.

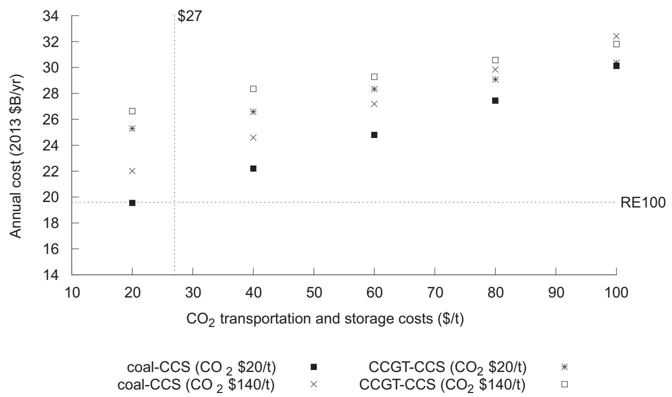

Fig. 5. Sensitivity of annual costs to CO_2 storage costs ($ per tonne CO_2) for different scenario and carbon price combinations. Vertical line is the baseline CO_2 storage cost from Table 1. Plant capital costs, coal price and gas price are held at baseline values in Table 1.

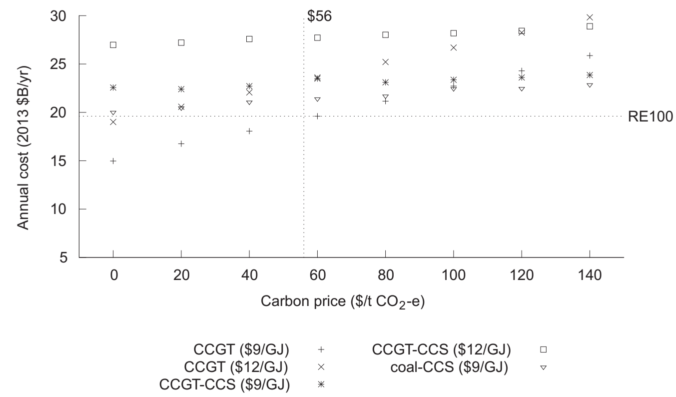

Fig. 6. Sensitivity of annual cost to carbon price ($ per tonne CO_2) and gas prices ($ per GJ). Vertical line is the baseline carbon price from Table 1.

7.3. CCGT and CCGT-CCS scenarios

Fig. 5 shows the CCGT-CCS scenarios for the carbon prices at each end of the range: $20 and $140 per tonne CO_2, alongside the equivalent coal CCS cases for comparison. The coal CCS scenario is more sensitive to increased CO_2 storage costs due to the volume of emissions produced. The much higher cost of gas ($11 per GJ) over coal ($1.86 per GJ) means that the coal CCS scenario has a lower annual cost, despite the higher volume of emissions, until the CO_2 storage cost exceeds $100 per tonne. The cost advantage of coal CCS diminishes and the four scenarios approximately converge at a CO_2 storage cost of around $110 per tonne. At this point, the CCGT-CCS scenario starts to become lower cost than coal CCS as the higher thermal efficiency of the combined cycle plant reduces the volume of captured emissions. At realistic costs for gas, carbon, and CO_2 storage, CCGT-CCS is uneconomic compared with the RE100 scenario.

Fig. 6 shows the effect of gas and carbon prices on the annual cost of the CCGT and CCGT-CCS scenarios. CO_2 storage costs are held constant. The CCGT scenarios perform well due to their high thermal efficiency and comparatively lower emissions. The annual cost of the CCGT scenario (without CCS) with a $9 per GJ gas price exceeds the RE100 scenario at a carbon price of $60 per tonne CO_2. Provided that the gas price and/or the carbon price is low, the CCGT scenario is a lower cost option than the RE100 scenario. Note, however, that these scenarios still produce over 77 Mt of CO_2 per year (Fig. 2), far higher than the level required for Australia to meet its 2050 target. The CCGT scenario is more accurately described as "medium carbon".

Even if there is no carbon price, a gas price of $12 per GJ would enable the RE100 scenario to compete economically with the CCGT scenario. With no emissions being captured, the cost of the CCGT scenario rises sharply with an escalating carbon price. The CCGT-CCS scenarios are much more costly than the RE100 scenario unless the gas price is lower than $9 per GJ. At a carbon price of $60 per tonne[3] none of the fossil fuel scenarios has a lower annual cost than the RE100 scenario.

Fig. 7 shows the effect of carbon price and gas price on annual cost in the CCGT and CCGT-CCS scenarios, holding CO_2 storage cost constant. The CCGT scenario with a nil carbon price is included as a limiting case. At a gas price of $3 per GJ, all the fossil fuel scenarios are lower cost than the RE100 scenario. At $6 per GJ, all cases except CCGT with a carbon price of $140 per tonne CO_2 are lower cost than the RE100 scenario. At $9 per GJ, the CCGT scenarios are lower cost than the RE100 scenario provided that the carbon price is low. The CCGT-CCS scenarios are higher cost due to the higher capital cost of CCS-equipped plant. At $12 per GJ, the only scenario that is lower cost than the RE100 scenario is CCGT with no carbon price. At $15 per GJ, the CCGT and CCGT-CCS scenarios have a higher annual cost than the RE100 scenario in all cases.

In summary, the three fossil fuel scenarios have different sensitivity to coal price, gas price, carbon price and CO_2 storage costs. Just as the annual cost of operating a fossil-fuelled power station is influenced by the cost of fuel, the economics of a CCS-equipped power station are influenced by plant thermal efficiency, fuel cost, the price of emissions permits, and the cost of transporting and storing compressed CO_2. A less thermally efficient power station produces more emissions and is more sensitive to CO_2 storage costs. In a complete generating system, the carbon price and CO_2 storage cost variables induce opposing effects in the least cost generating system. If one variable increases relative the other, then the least cost mix changes. For example, in the coal CCS scenario with coal CCS plant, existing hydro and OCGTs, a prohibitively high CO_2 storage cost produces the effect of the genetic algorithm shifting *all* generation to OCGTs such that the lowest cost solution becomes independent of the CO_2 storage cost.

8. Discussion and conclusion

Testing the three fossil fuel scenarios (coal CCS, CCGT and CCGT-CCS) under a range of plausible parameter values, we find that the

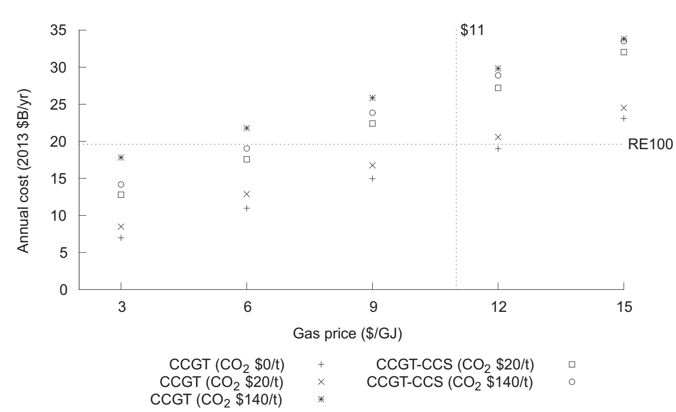

Fig. 7. Sensitivity of annual cost to gas price ($ per GJ) in various scenarios. Vertical line is the baseline gas price from Table 1.

[3] Refer to all points at 60 on the *x* axis in Fig. 6.

majority of cases do not compete economically with the RE100 scenario. We believe that the baseline values in Table 1 are reasonable estimates for the year 2030 given the inherent uncertainty and underlying drivers of carbon prices, gas prices, technology capital costs, and CO_2 storage costs. In some limited circumstances, the fossil fuel scenarios can be lower cost than the RE100 scenario, but this requires multiple conditions (e.g., a low gas price and low CO_2 storage costs).

8.1. Limitations

We have identified three principal limitations to the simulations described in this paper. First, the fossil fuel scenarios deliver a higher share of fossil-fuelled generation than is likely in practice. Existing hydro is included in our scenarios, but present wind power and wind power anticipated by 2020 is not. By 2020, Australia is expected to source around 25% of its electricity from renewable energy under the Renewable Energy Target, predominantly from wind power and hydroelectricity. Lund and Mathiesen have modelled the integration of CCS into high penetration renewable systems by introducing a single CCS-equipped combined heat and power plant into the Climate Plan 2050 scenario for Denmark devised by the Danish Society of Engineers [48]. They observed that unless the CCS plant is dispatched out of order (ie, ahead of lower marginal cost generation), the capacity factor of the CCS plant is too low to be economic. We have assumed that including wind power would increase the cost of the three fossil fuel scenarios when the carbon price and CO_2 storage costs are low. The cost of these fossil fuel scenarios therefore represents a lower bound.

Second, the transmission network is not modelled. In earlier work [8], we examined the transmission requirements to achieve hour-by-hour balancing between the five regions of the NEM and estimated the annual cost at $1.6 billion per year (5% discount rate over a 50 year economic lifetime). This cost is not particularly onerous when considered in the context of the total cost of the RE100 scenario ($19.6 billion per year). The transmission requirements for the fossil fuel scenarios are not significantly different to the present transmission network, but the requirements for the RE100 scenario will increase the costs as indicated. For simplicity, the simulations are of generation only.

Finally, detailed operational modelling of generation is not included. For example, ramp up rates, ramp down rates and minimum operating levels. Simulating these aspects can be expected to slightly increase costs in all of the scenarios.

8.2. Implications

The CCGT scenario provides useful insight into what is possible using lower carbon, commercially available fossil-fuelled plant. The CCGT scenario is sensitive to gas prices and, to a lesser degree, carbon prices. With emissions over 77 Mt per year, and well in excess of the 2050 target, it would have to be ruled out on environmental grounds. Generation portfolios based on large quantities of gas-firing require lower gas prices than are being faced in some gas markets today to compete economically with the RE100 scenario.

The transition from mostly coal-fired to mostly gas-fired generation has been presented as an assured opportunity for reducing electricity emissions by industry and some sections of government [49]. Gas is promoted as a transition fuel on the path to a completely decarbonised energy system – the so-called "bridge to the future" [50,51]. For Australia, gas offers the advantages of being an abundant, domestically available fuel with lower carbon content than coal. There are concerns that fugitive methane emissions from unconventional gas extraction may negate any savings from using gas instead of coal, and this is an active area of research in Australia [52,53].

Should CCS be developed at scale and in time to contribute to the decarbonisation of the electricity sector, on current projected costs for 2030, the scenarios based on CCS or gas-fired plant do not produce a result that is robustly cheaper than commercially available renewable energy technologies. The CCS scenarios demonstrate policy risks, utilising technology that has not been proven at commercial scale and with uncertain costs. Simulations show that these fossil fuel scenarios are not low cost and have the disadvantage of being reliant on non-renewable fuels. The CCGT-CCS scenario produces the lowest emissions of all three fossil-fuel scenarios, but with the highest cost on current projections. Coal CCS requires that CO_2 storage costs be minimised, particularly for power stations in New South Wales, which would require piping over long distance to the Cooper Basin in South Australia.

CSIRO quantifies the impact of CCS on generation costs for new black coal-fired plant, increasing costs from $55 per MWh to around $110 per MWh without considering carbon pricing [33]. The eFuture scenario tool[4] from CSIRO produces similar results. AEMO examined the impact on wholesale prices in its 100% renewables study and found that the two 2030 scenarios for 100% renewable electricity produce an average wholesale cost of $111 per MWh and $128 per MWh, depending on the input assumptions [7]. While these figures cannot be compared directly, it suggests that the dominant alternatives to renewable electricity are not substantially lower cost.

We have assumed that gas prices in Australia will rise in the medium-term to approach prices in international markets. The results presented in this paper are likely to be similar in countries where gas prices are already higher than faced in Australian domestic markets. Moreover, in countries with little domestic supply of coal and gas, these scenarios would lead to high dependence on imported fuel. It is possible that these scenarios would be ruled out in such countries on energy security grounds.

8.3. Conclusion

None of the fossil fuel scenarios in this work achieves zero operational emissions as the RE100 scenario can. As decarbonisation takes place across the economy, it may become evident that very deep cuts in emissions are required in the electricity sector to compensate for lesser cuts in more challenging sectors.

It is possible to argue that publicly funded CCS research and development should continue. If CCS technology can be delivered in a timely and cost effective manner, it offers significant abatement potential and increases the set of available options. The IEA states, "Delaying or abandoning CCS as a mitigation option in electricity generation will increase the investment required in electricity generation by 40% or more in the Energy Technology Perspectives 2012 2DS and may place untenable demands on other emissions reduction options" [5]. Our results suggest that without CCS, other low carbon electricity generation can be pursued at similar cost in the Australian context, at least.

Furthermore, the results suggest that it is not necessary to wait for CCS technologies to emerge. Policies pursuing very high penetrations of renewable electricity based on commercially available technology appear a reasonable option given the lower technology risks, lower investment risks, and the ability to reach zero operational emissions in the electricity sector.

[4] http://efuture.csiro.au.

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