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ScienceDirect
Energy Procedia 63 (2014) 6864 – 6870
Energy Procedia

GHGT-12

Pathways for deploying low-emission technologies in an integrated electricity market: an Australian case study

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Abstract

In this paper, Australia is used as a case study to evaluate potential pathways for staged deployment of low-emission technologies in an integrated, emission intensive electricity market. We assume that carbon capture and storage is implemented at existing and new power plants. To meet projected demand increase by 2050, the total generation capacity increases by 35 %. The cost of electricity in 2050 is more than double the current value, with a moderate annual increase between now and then. An 80 % emission reduction target can be achieved by 2050. The results are compared with the future generation scenarios previously analysed by CSIRO and AEMO.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: Renewable Energy; Carbon Capture and Storage; Power Generation; Economics

1. Introduction

The global electricity sector is a large CO_2 emitter that accounts for more than 40 % of global CO_2 emissions [1]. In response to climate change challenges, options need to be explored for the electricity sector to transition towards a low-carbon future whilst ensuring the security of energy supply. In this paper, Australia is used as a case study to evaluate the potential for reducing CO_2 emissions by deploying low-emission technologies while meeting projected electricity demand in an integrated electricity market.

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Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.720

The Australian National Electricity Market (NEM) is a wholesale market that supplies electricity to retailers and end-users in the eastern and southern states of Australia. It represents around 90 % of the total Australian electricity demand. Electricity is predominantly produced by fossil-fuel power plants – approximately 80 % from black and brown coal and 10 % from natural gas [2]. Australia has committed to reduce its CO_2 emissions by between 5 % and 25 % below 2000 levels by 2020, and by 80 % below 2000 levels by 2050 [3].

One option for decarbonising the NEM would involve the widespread deployment of carbon capture and storage (CCS). The recently published paper by Elliston et al. [4] conducted a comparison of the least cost scenario of 100 % renewable energy with a number of CCS scenarios. The study concluded that CCS scenarios can only compete with the renewable scenario under a few combinations of future carbon prices, gas prices and CO_2 storage costs. However, the study assumed that all power plants are new-build. It did not consider retrofitting CCS at existing power plants, for which costs would be much lower. By 2030, a large number of existing fossil-fuelled plants will still be operating. In addition, only one type of plant was considered in each CCS scenario. In practice, a combination of technologies is more likely in the NEM and might achieve a lower system cost.

In this paper, we examine a scenario that implements CCS at existing and new power plants. We analyse the potential impact on the cost of electricity and the emissions trajectory for the entire system. The results are then compared with the future generation scenarios previously published by CSIRO [5], Elliston et al. [4] and the Australian Energy Market Operator (AEMO) [6].

While the scenarios analysed and discussed in this paper might not represent the actual future generation mix in the NEM, they are snapshots of possibilities that provide a simple basis for comparing different options for decarbonising the NEM.

2. Setting up scenario

The total electricity generation in the NEM was around 200 TWh during 2010–2012 [7-9]. We use the actual demand data from AEMO from 2010 to 2012 and assume a growth rate of 1.15 % from 2013 to 2030 and 0.98 % from 2030 to 2050 based on projections by AEMO [10]. This results in a total estimated demand of 289 TWh in 2050.

The NEM has a total existing generation capacity of 50,300 MW [11]. This is comprised of around 28,100 MW from coal-fired plants, 10,100 MW from gas-fired plants, 7,800 MW from hydro plants and 4,300 MW from other renewable plants. We assume that all existing plants will operate until the end of their expected technical life based on the data provided by the AEMO for each individual plant [2].

We assume that CCS is retrofitted at existing black coal, brown coal and CCGT plants. To meet future growth in electricity demand new fossil-fuel plants with CCS are installed. Existing peaking plants, smaller plants and renewable based plants are assumed to operate at business-as-usual. Those new renewable plants (mainly wind) that are already committed or recently completed and expected to start operating in 2–3 years are also included in the generation mix [12].

Implementation of CCS in Australia is not yet a commercial reality although options are under consideration. Current reports suggest that around 10 years of exploration and appraisal are required for potential storage sites to be ready for large scale CO_2 injection [13]. For simplicity, we assume that CCS is implemented at successive 20 % increments on the existing fleet from 2025 at 5-year intervals, until 2045 when the entire fleet is assumed to be operating with CCS [14]. For this paper, 5 year time intervals are used but other time intervals could be used if desired.

Given the age of existing coal and CCGT plants, the remaining life for some plants is shorter than the operating life of CCS facilities. There are also some plants that are expected to retire before CCS is ready. While the current coal prices are still low in Australia, there are a couple of coal plants being upgraded to extend life and improve efficiency [12]. Therefore, as an extreme case, we assume that all coal and CCGT plants will be refurbished, with the coal plants being upgraded to ultra-supercritical at the time of their original expected retirement. After upgrading, the thermal efficiency (higher heating value) of coal and CCGT plants are increased to 45 % and 46.1 % respectively [15]. Plant life is assumed to be extended for 30 years after upgrading. We assume that these plants are able to vary their annual capacity factors up to 85 % to meet electricity demand while still allowing for scheduled maintenance and forced outages.

As the energy required for capture is parasitically extracted from existing plants, electricity sent out from plants with CCS retrofitted will decrease. From 2030, existing capacity is not able to meet the projected demand and new capacity is needed. We assume that new coal and CCGT plants with CCS are installed together with new OCGT plants to meet peak demand. For simplicity, the share of generation from these plants is assumed to remain the same as at present. The required future capacity for each technology is estimated based on their average capacity factors. Further, we do not consider the siting of the plants and assume that electricity can be transmitted within the NEM without constraint.

Figure 1 shows the estimated electricity generation and generation capacity in the NEM. Coal remains the major source of electricity generation from 2010 to 2050. Total generation capacity in the NEM increases to 66 GW in 2050.

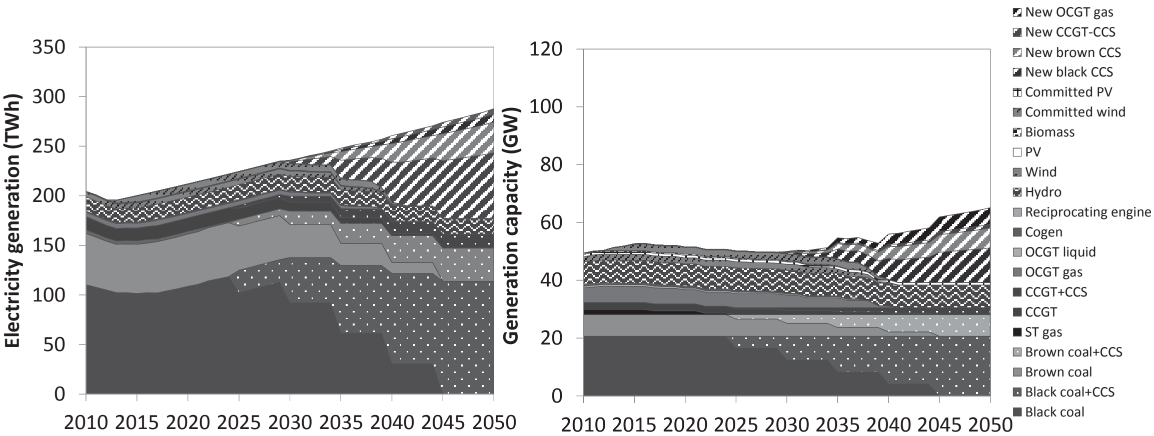

Fig. 1. . Estimated electricity generation and required capacity by technology for the CCS scenario from 2010 to 2050

3. Economic assumptions

For capturing CO_2, we assume post-combustion capture using MEA solvent absorption with a capture rate of 90 %. After CCS is implemented, the emission intensity of black coal, brown coal and CCGT plants are 0.11 tCO_2/MWh, 0.18 tCO_2/MWh and 0.05 tCO_2/MWh respectively. The capture costs are calculated using a techno-economic model developed by UNSW Australia for the CO2CRC [16]. The model enables calculation of the total energy consumption and equipment dimensions for CO_2 pre-treatment, separation and compression. More details are available elsewhere [17].

For CO_2 transport and storage costs, a study by Neal et al. [18] is used as the basis for estimating the costs. They conducted a scoping study for CO_2 transport and storage in Australia for different combinations of source-sink matches. In this scenario, we use a volume weighted average cost for the entire NEM based on the lowest cost combinations for each NEM region. The cost is escalated to 2011 Australian dollars using the Upstream Capital Cost Index.

It should be noted that all capital costs are estimated on the basis of an Nth-of-a-kind plant in Australia and hence do not include cost premiums for the delivery of a first-of-a-kind plant. Costs are for current technologies and do not include any effect of learning. All costs are presented in real 2011 Australian dollars. In 2011, an exchange rate of 1 US dollar to 1 Australian dollar was applicable. Fuel costs are based on average projected fuel prices in 2011 [10] with A$1.5/GJ for black coal, A$0.7/GJ for brown coal and A$6/GJ for natural gas. Construction times are 3 years for power plants and 2 years for CCS facilities.

We use a real discount rate (i.e. excluding inflation) of 7 % for all technologies. To calculate annualised capital cost, an amortisation period of 25 years is used for all technologies. The carbon price used is based on the core projected carbon price trajectory by the Australian Treasury [19] increasing from A$23/t in 2012 to A$150/t in 2050.

Australia has a Mandatory Renewable Energy Target (RET) of 20 % by 2020. Each megawatt-hour (MWh) of electricity generated from accredited renewable based power stations is equivalent to a Renewable Energy Certificate (REC). REC prices since 2009 have varied between approximately A$30 and A$50 and the volume weighted average market price for 2013 was A$39 [20]. We therefore use a constant REC price of A$40 until 2020 with no extension beyond 2020. We treat the RECs as revenue for renewable plants.

We calculate the yearly NEM-wide cost of electricity (COE) from 2010 to 2050 as opposed to the levelised cost of electricity (LCOE) reported in many published studies, as it is more suited to the purposes of this paper. The equations used for calculating the yearly COE are given below.

$$Annualised\_Capex = \frac{Capex}{Annuity\_factor} \tag{1}$$

$$Annuity\_factor = \frac{1}{discount\_rate} - \frac{1}{discount\_rate \times (1 + discount\_rate)^{25}} \tag{2}$$

$$Yearly\_System\_COE = \frac{(Annualised\_Capex + annual\_opex + fuel\_\cos t + carbon\_tax - REC)}{Annual\_electricity\_sent\_to\_grid} \tag{3}$$

4. Results and comparison

4.1. CO_2 emissions

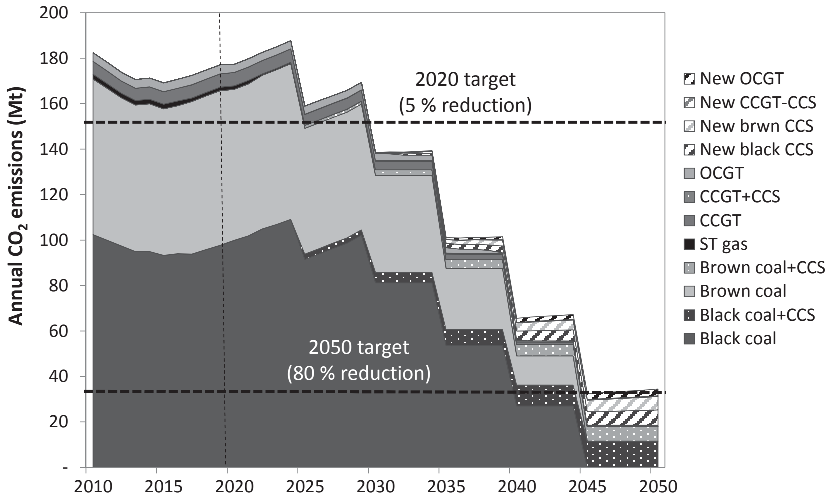

Fig. 2. Estimated annual CO_2 emissions and emission intensity from 2010 to 2050.

Figure 2 shows the annual CO_2 emissions trajectories in the CCS scenario over the 40 year period. In 2010, the total CO_2 emissions are 182 Mt, the majority of which (94 %) is generated from coal-fired power plants. Emissions drop significantly every 5 years from 2025 as more power plants are retrofitted with CCS. From 2030, emissions also decrease because new low-emission power plants are added to the generation mix. By 2050, the emissions are 34 Mt since there are still some emissions that cannot be captured and stored. There is also a small amount of CO_2 emitted from the new peaking OCGT plants. Nevertheless, a reduction of 80 % can be achieved by 2050 compared to the 2000 emissions. However, without other carbon abatement measures, such as already planned energy efficiency measures and demand side management, or more aggressive CCS or renewable energy deployment, the 2020 emission reduction target cannot be achieved with the assumed scenario.

4.2. Yearly system COE

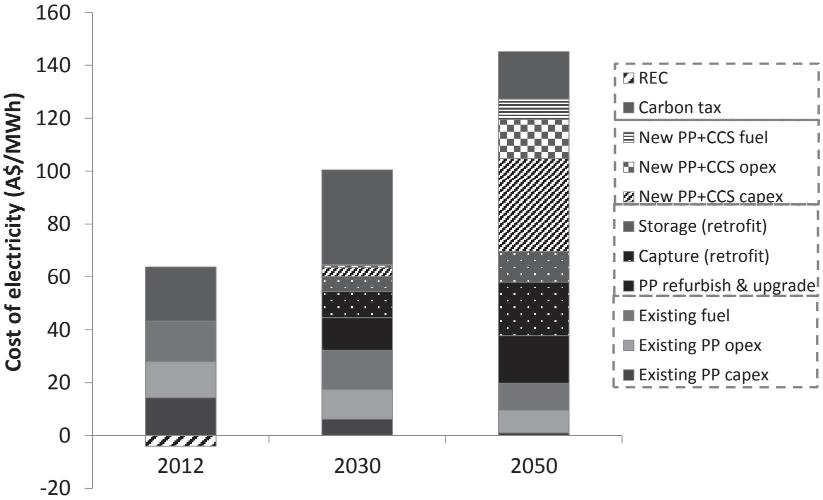

Fig. 3. System COE in 2012, 2030 and 2050 (capture and storage costs shown in the figure include both capital and operating costs.)

Figure 3 shows the estimated breakdown of system COE for 2012, 2030 and 2050. These years are chosen because they are representative of the transition pathway for these scenarios. The system COE increases significantly over the 40 year period and is more than doubled by 2050 despite the fact that the generation capacity only increases by 35 %. In 2012, the system COE is approximately A$60/MWh. It then increases to A$100/MWh in 2030 and further increases to A$145/MWh in 2050. Despite this high total increase, our estimates show that the average annual increase is moderate at 2.36 %. The figure shows the estimated COE based on the current cost of these technologies. If the ranges of learning rates projected by CSIRO [13] and AEMO [2] are used, the system COEs are estimated to reduce to A$97–98/MWh and A$134–139/MWh in 2030 and 2050 respectively.

The breakdown of the cost indicates that the increase is driven by the cost of upgrading and capturing CO_2 from the existing plants, as well as the cost of constructing new power plants with CCS. The carbon tax also accounts for a large proportion of the COE. The annual operating costs and fuel costs are relatively lower.

4.3. Comparing with other scenarios

While implementing CCS is one option for decarbonising the NEM, other options are available. These include significant deployment of renewable energy, natural gas fired power plants or even nuclear. CSIRO [5] has modeled a number of future generation scenarios in the Australian NEM assuming different demand forecast, technology costs, fuel costs and backup options. Its baseline scenario represents current market structure and policy settings in Australia. In the first 20 years the projected generation mix is mainly dominated by existing coal plants with increasing generation from wind power. After 2030, with the impact of carbon price, there is a steady decline in coal fired generation with an increase in gas fired generation, wind and solar power. By 2050, gas fired plants contribute to half of the total generation with wind, solar and a small amount of coal plants contribute to the rest.

A major difference between Australia and other regions in the world is the prohibition of nuclear power. In many countries in the world, nuclear is one of the major sources of future electricity generation [1]. A sensitivity analysis was also carried out by CSIRO to illustrate a scenario with nuclear power permitted while other assumptions remain unchanged. The generation mix in this scenario shares similar features to the baseline scenario before 2025. After 2025, nuclear generation increases rapidly and overtakes coal to become the major source of generation by 2035. By 2050, nuclear energy supplies approximately 60 % of the total electricity, while solar, wind and natural gas power contribute to the rest.

AEMO [6] and Elliston et al. [21] have evaluated the potential for the NEM to meet 100 % of its electricity demand from renewable energy by a specified target year. The resulting generation mixes in these studies vary greatly given different assumptions on technology costs. Geothermal/wind, solar photovoltaic and solar thermal technologies are the major contributors. Biogas fired open cycle gas turbines (OCGT) are used as peaking plants.

4.3.1. Comparing emissions and COE

For CSIRO's baseline scenario, the system COE is projected to increase to \$107/MWh by 2030 and \$132/MWh by 2050 including the effect of learning. Comparing this scenario with the CCS scenario analysed in this paper, the cost of the CCS scenario is lower in 2030 but higher in 2050. This is because, before 2030, refurbishing and upgrading existing plants with CCS requires less capital than building new plants. However, after 2030, the construction of new fossil fuel plants with CCS results in a higher cost. In CSIRO's baseline scenario, given that generation from fossil fuels (without CCS) still has a large share over the 40 year period, the CO_2 emissions are much higher than our CCS scenario. By 2050, their projected emissions are 63 % below the 2000 levels.

For the CSIRO scenario involving large deployment of nuclear power, the system COE increases to A\$90/MWh in 2030 and A\$102/MWh in 2050, which are much lower than the costs for our CCS scenario. The emission reduction targets of 5 % by 2020 and 80 % by 2050 can both be achieved in the nuclear scenario. The low system COE is largely due to the low cost assumed for nuclear power. CSIRO adopted the cost of nuclear power estimated in the Australian Energy Technology Assessment (AETA 2012) by the Australian Bureau of Resources and Energy Economics (BREE) [13]. The estimated cost in that study is very competitive with other alternative low-emission technologies. Despite some criticisms on whether such low cost is achievable in Australia, nuclear power does appear to offer an additional option for cutting emissions with relatively lower cost, especially for those counties that permit nuclear power and already have the infrastructure in place.

For the 100 % renewable scenarios analysed by AEMO and Elliston et al., estimated COEs range from A\$96/MWh to A\$154/MWh assuming different future technology costs and discount rates. The higher cost is mainly because of the large capital investments required for constructing large and expensive new renewable based plants. The required large backup capacity for supporting intermittent power sources also affects the COE. Our estimated cost for the CCS scenario falls within this range. In terms of emissions, our CCS scenario achieves an 80 % reduction in emissions by 2050, while the 100 % renewable scenarios achieve zero emissions.

5. Conclusion

This paper evaluates the potential pathway for deploying CCS in the Australian NEM to reduce CO_2 emissions while meeting projected electricity demand. We assume that CCS is implemented at both existing and new fossil-fuelled power plants. While direct comparison with other markets in the world is difficult, the results presented in this paper are generally applicable to countries with a large fossil-fuel fleet.

With CCS implemented at all coal-fired and CCGT plants, the emissions reduction target of 80 % below 2000 levels could be achieved by 2050. However, to achieve the 5 % reduction target by 2020, other carbon abatement measures are necessary. Without taking into the effect of learning, the system COE increases from A\$60/MWh to A\$100/MWh in 2030 and A\$145/MWh in 2050. With potential cost reductions through learning, costs are estimated to be A\$97–98/MWh in 2030 and A\$134–139/MWh in 2050. This system COE lies within the range of the COE for other reported renewable scenarios. A reported nuclear scenario has a much lower system COE. However, the costs of renewable energy are subject to large uncertainties and implementation of nuclear energy in Australia is still fraught. In addition, these the literature studies are based on different assumptions to those used in this paper. Further work based on the same methodology and assumptions would give a more consistent comparison.

Acknowledgements

The authors would like to acknowledge the funding provided by the Australian Government through its CRC Program to support this CO2CRC research project.

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