2015 ASIA-PACIFIC SOLAR RESEARCH CONFERENCE

Peer Reviewed
2015 Solar Research Conference

Generator investment transition in the Australian National Electricity Market with increasing penetrations of renewable energy

Stephanie Easton[1], Anna Bruce[1] and Iain MacGill[2]

[1]*School of Photovoltaic and Renewable Energy Engineering, UNSW, Sydney, Australia*

[2]*Centre for Energy and Environmental Markets and School of Electrical Engineering and Telecommunications, UNSW, Sydney, Australia*

E-mail: s.easton@student.unsw.edu.au

Abstract

The use of policy to mitigate the externality cost of greenhouse emissions from electricity generation has a strong theoretical basis, yet has produced unexpected, often adverse, market outcomes to date when implemented internationally. Other approaches including regulated emissions limits and renewable energy targets have, in some jurisdictions, seemed to have driven greater impacts. Australia's electricity industry has one of the world's highest greenhouse intensities and it is important to understand how policy may impact the long-term trajectory of Australia's restructured National Electricity Market (NEM), where wholesale spot prices provide a market clearing function that sends both short-term operational and long-term (via derivatives) investment 'signals' to market participants. The study presented in this paper aims to assess the potential effectiveness of different emissions policies when applied over the medium to long-term in the Australian NEM.

This research uses the PLEXOS market modelling software, with the National Transmission Network Development Plan (NTNDP) model created by the Australian Energy Market Operator (AEMO) to simulate long-term market operation and investment for transmission planning purposes. Different policy scenarios – a renewable energy target (RET), carbon price, and emissions intensity limit – are applied over a 25 year horizon within PLEXOS. For each scenario, the resultant energy generation mix, average wholesale spot price, generator profits, and industry emissions intensities are evaluated for different levels of policy ambition. It is found that the RET and carbon price policies may be ineffective at achieving emissions reduction if they are not aggressive enough to encourage the retirement of incumbent generators, which is critical for achieving major emissions reductions. The use of an expanded RET over the long-term will likely devalue the information contained within spot market prices and suppress their increase as the dependency on revenue from the external renewable energy certificates (REC) market grows for renewable generators.

1. Introduction

A transition from emissions-intensive to low-emissions electricity generation is required to ensure that Australia can appropriately contribute to global greenhouse gas emission reductions. Recent years have seen significant deployment of renewable energy technologies in Australia, including a significant number of wind farms and an extraordinary uptake of distributed household photovoltaic systems. Thus far, however, excess generation capacity due to a combination of new renewables capacity and declining electricity demand has not resulted in an orderly exit of high-emissions generators from Australia's National Electricity Market (NEM) (Clean Energy Council, 2014). Indeed, if anything, rising gas prices and the removal of a carbon price on generator emissions have seen coal generation rise (pitt&sherry, 2015). These developments threaten both emission reductions, and the operational viability of technologies such as gas peaking plant that appear better suited to facilitating highly variable renewable generation than existing coal-fired plant. There has been considerable work exploring generation investment challenges and options in the NEM over recent years. However, there has been less attention to date on this critical question of exit. The two issues, are of course, inherently linked as new investment requires some 'room' into which to enter and this can only arise from demand growth or existing plant departure.

The growing impact of low short-run marginal cost renewable generators on spot market prices in the NEM and elsewhere raises questions about the adequacy of the revenue produced from the current market arrangements to encourage new investment in capital intensive generation. While incumbents also suffer from these low prices, they represent effectively sunk investments and have considerable incentive to continue to operate. The future of both new generation entry and incumbent generator exit will therefore, critically, be influenced by future policy efforts to rectify existing market failures such as environmental externalities. This paper presents the findings of a study investigating the potential impact of different policy mechanisms on generator exit and new generation investment over the coming decades. The context and aim of the research is described in Section 2. A model to simulate this electricity market transition is then outlined in Section 3, and the policy mechanisms tested are described. The results of simulations are presented in Section 4 and the implications for emissions reduction effectiveness and policy efficiency are discussed. Concerns for policymakers raised by the research are then highlighted in Section 5.

2. Context

Australia has proposed a pledge of a 26% reduction on 2005 greenhouse gas (GHG) emissions levels by 2030 for the 2015 United Nations Climate Change Conference in Paris (Australian Government, 2015). Electricity generation accounts for 34% of annual Australian GHG emissions (Department for the Environment, 2015), and is widely agreed to to have a key role in contributing to this goal, and any strengthened goals for later years. The promising trajectory of commercialisation of renewable energy technologies and concerns over the carbon emissions, energy security and local air pollution impacts associated with a reliance on fossil fuels has seen over 144 countries, including Australia, prioritise the deployment of renewable energy into their energy mix (REN21, 2014). However, it has been suggested that policies that encourage the deployment of renewable energy alone may not be sufficient to effect an orderly transition to a low emissions electricity system - incumbent coal, and eventually even gas generation, must exit the market to both facilitate lower emissions intensity and to allow for an increase in the deployment of renewable energy technologies (Nelson, Reid, & Judith, 2014).

Around 86% of the NEM's electricity is sourced from fossil fuelled generation with 74% from coal fired generators, 12% from gas and a further 9% from large scale hydroelectric generation (Australian Energy Regulator, 2014). Since the transition to a restructured spot market in the 1990's, base load coal generators have typically been the market price setters for most operational periods in the three largest States, with higher priced gas and hydro generators typically covering periods of higher and more variable demand, including contingencies and short-term supply shortfalls.

The incumbent coal generation in the NEM has unique characteristics arising from historical circumstances. In 2014 the average age of brown coal plants was 34.2 years and black coal plants 27.4 years (Nelson, Reid, & Judith, 2014). Almost all of the coal fired generation fleet was built and paid for by State Government electricity commissions under the direction of State governments. While many of these plants have been sold to private market participants, they represent sunk investments and often have highly cost-effective, vertically integrated, fuel supply arrangements. As such, many of the plants have marginal operating costs well below the operating costs that a new fossil-fuel plant would face today (ACIL Tasman, 2009). For example the planning assumptions for the 2014 NTNDP state the fuel cost of Hazelwood and Loy Yang brown coal plants in Victoria as $0.092/GJ or $1.31/MWh electricity sent out (AEMO, 2013). This can be compared to Acil Allen's estimate for new black coal plants in their 2014 'Fuel and technology cost review' of $0.40 - $2.83/GJ (Acil Allen Consulting, 2014). Hazelwood, with eight brown coal units in Victoria built over a period of years starting in 1968, produced 9% of national emissions from electricity generators in the 2013-14 year, but only 5% of net energy production. The competitive advantages of these emissions intensive generators pose a significant barrier to the retirements that are required to achieve Australia's emissions reduction targets.

Theoretically, generator exit from a fully competitive electricity market should occur when operation and maintenance costs outweigh revenue for a sustained period of time. However external economic, social and political influences may delay official plant retirement. These factors may include: avoidance of high site remediation costs, first-mover disadvantage where the first plant's departure then sees increasing prices increase profits for those that remain, uncertainty resulting from fast rates of innovation or mixed policy signals, and the ability to 'sweat' plants that don't hold financial obligations and have little salvage value, until such time as they suffer mechanical failure (Frontier Economics, 2015). Estimates from annual reports indicate that site remediation costs for coal generators could be $100-300 million, typically ten times greater than the remediation bonds held by State governments towards this end (Environment Victoria, 2015; Nelson, Reid, & Judith, 2014). These remediation costs can be avoided when generators mothball as opposed to retire. Mothballing, unfortunately, represents a greater risk for new generation investment than retirement, as the mothballed plants may return if market conditions improve sufficiently. If such factors act to delay generator retirement from the NEM in the medium term, 'oversupply' may arise and suppress market prices, discouraging new investment until emission reduction targets force rapid, and potentially to disorderly, lumpy exit. This could threaten both reliability and security of supply.

Policies that aim to reduce emissions from electricity act to disadvantage high emissions generation, including the incumbent generation fleet, in different ways. The introduction of a carbon price or an emissions trading scheme will directly increase the operational costs of high emissions generators, while an emissions intensity standard could force the exit of some generators, or require them to undertake retrofits that reduce their emissions to below the standard, while potentially marginally benefitting those that meet the standard. Organised exit has been trialed by the Federal government in 2011 with their Payments for Closure scheme. This was a voluntary scheme whereby payouts would compensate plants electing to close. The proposal was withdrawn as negotiations failed (GDF Suez, 2012). Renewable portfolio standards do not have a direct effect on incumbent generators, but the low short-run marginal costs of renewable generators tends to result in a 'merit order effect', which reduces spot market revenue for incumbents.

Since these policies interact in complex ways with a range of technical, market and external factors to determine generator entry and exit, their impact should be carefully considered to ensure that spot market prices are a cost reflective market clearing function, reliability is maintained, deployment of low or zero emission (notably renewable) technologies occurs, and increased production from existing high emission generators is avoided. In particular, the long-term implications of legislated policy are a critical determinant of market risk and the cost of project financing (Pricewaterhouse Coopers, 2014). This research uses modelling of key policy options and resultant transition paths for reducing emissions in the NEM, to gain an understanding of their effectiveness and possible implications.

3. Method

Planning decisions in the NEM were simulated under different policy arrangements over 24 years using a widely used industry market model. AEMO's 2014 NTNDP model (AEMO, 2015) was used with the PLEXOS energy market modelling software's long-term (LT) planning function. The NTNDP model uses hourly resolution load data, and technology and 'input' price projections for the coming decades commissioned by AEMO (Acil Allen Consulting, 2014). The policy options modelled are listed in Table 1. Each of these were assessed independently, and in combination.

Table 1. Policy options modelled

	Policy mechanism	**Description**
	Base	No policy mechanism is enabled including the current RET target.
Carbon price	20-50 CO2	A price of \$20/t$CO_{2\text{-}e}$ is enforced in 2014-15 and exponentially increased to \$50/t$CO_{2\text{-}e}$ in 2039-2040
	20-100 CO2	A price of \$20/t$CO_{2\text{-}e}$ is enforced in 2014-15 and exponentially increased to \$100/t$CO_{2\text{-}e}$ in 2039-2040
Renewable energy target	33,000 by 2030 RET	33,000 GWh of 2030 electricity production in 2030 will come from renewable sources with target growth stagnating in 2020. A replica of the currently legislated LRET targeting ~20% by 2020
	50% by 2030 RET	50% of projected 2014 NTNDP load in 2030 sourced from renewable sources. Linearly projected from the current generation mix. A potential interpretation of the federal oppositions energy policy
	40% by 2030 RET	40% of projected 2014 NTNDP load in 2040 sourced from renewable sources. Linearly projected from the current generation mix
Emissions intensity limit	1700-910 limit	Generators are not permitted to participate in the market if their emissions intensity is above a ruled rate. The rate decreases from 1700-910 kg $CO_{2\text{-}e}$/MWh at a decreasing rate over time

The 24 year investment trajectory under all policies was modelled using AEMO's 'Medium' growth scenario, with an average annual growth rate of 0.3%. Projections for annual generation growth for renewable energy targets and REC price reductions used the modelling framework of the 2014 NTNDP.

The impact of the policy tools on generation investment, average price, generator profitability, and emissions intensities was assessed. The policies are then evaluated in terms of efficiency and effectiveness through time.

4. Results

4.1. Capacity expansion and retirement

A noticeable difference in installed generation capacity, and projected new energy mix in 2038-39 was observed between the different policy mechanisms in Figure 1.

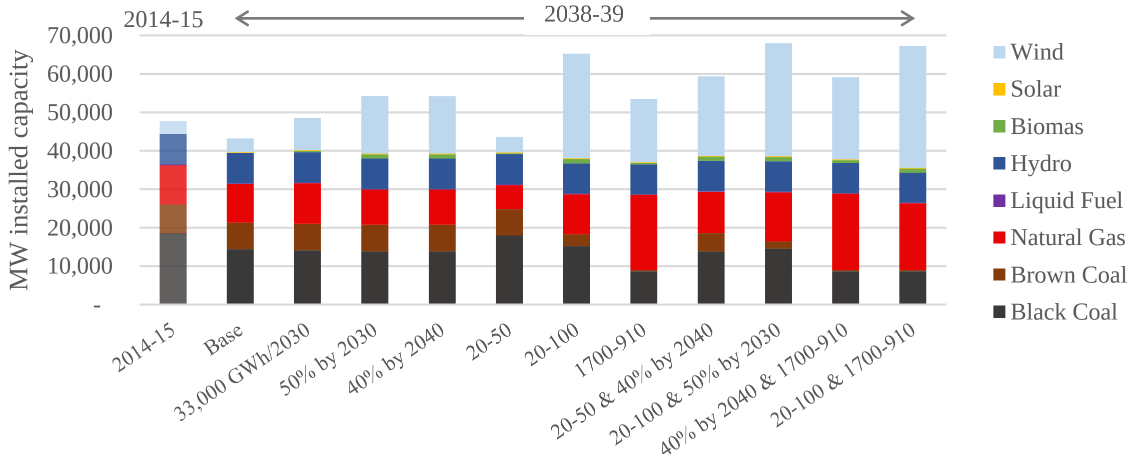

Figure 1. Installed capacity transition from 2014-15 to 2039-39

The Base model, with no policy implemented, and the weakest (20-50) carbon price show a net decline in installed capacity over the next 24 years, almost entirely due to some modest, and currently proposed, black coal retirements. This suggests a potential lag or inadequacy of policy to encourage incumbent generators to retire, and therefore a lack of opportunity for new investment. Interestingly more black coal remains under the 20-50 carbon price than the base case. This can be attributed to the ability of coal generators to pass on the carbon price to the retail market and remain profitable. Only when the carbon price is high enough and there are alternative generators available will the merit order vary and exclude them from the market. A relatively low carbon price shouldn't be used as it will likely have insignificant impact on transitioning the energy mix.

Coal retirements under all three RETs are approximately equal, with the uptake of wind generation being the main difference between scenarios. Capacity increases that deviate from load growth, especially low short-run marginal cost (SRMC) capacity, will likely lower average spot prices. This will signal against future investment.

As, expected the largest coal retirement is seen with an emissions intensity limit, which excludes high emissions plant from the market, regardless of its profitability. This policy mechanism also shows the largest uptake of natural gas generation installation. Due to the variable nature of current commercially available renewable technologies, there is a potential role for coal or gas to participate in a peaking capacity in years to come. Strict emissions intensity limits forces this role onto the more expensive gas generators. It has recently been suggested that such a gas transition step could be more expensive in the long-run given falling costs for renewables, and highly uncertain future gas prices (Riesz, Vithayasrichareon, & MacGill, 2015).

The combined policy options predict far less brown coal remaining in the market. The largest installed capacity was found by enforcing the high 20-100 carbon price with the aggressive 50% by 2030 RET, largely because of the low capacity factor of the significant amount of wind in the market.

4.2. Spot Market prices and generator profitability

Spot market prices are the only source of revenue for generators in the model. Penalty charges were not modelled, with no re-distributional effects, and there was no external market mechanism simulating the revenue for RECs to renewable generators. Figure 2 displays the weighted average of each State's spot market under different policy arrangements.

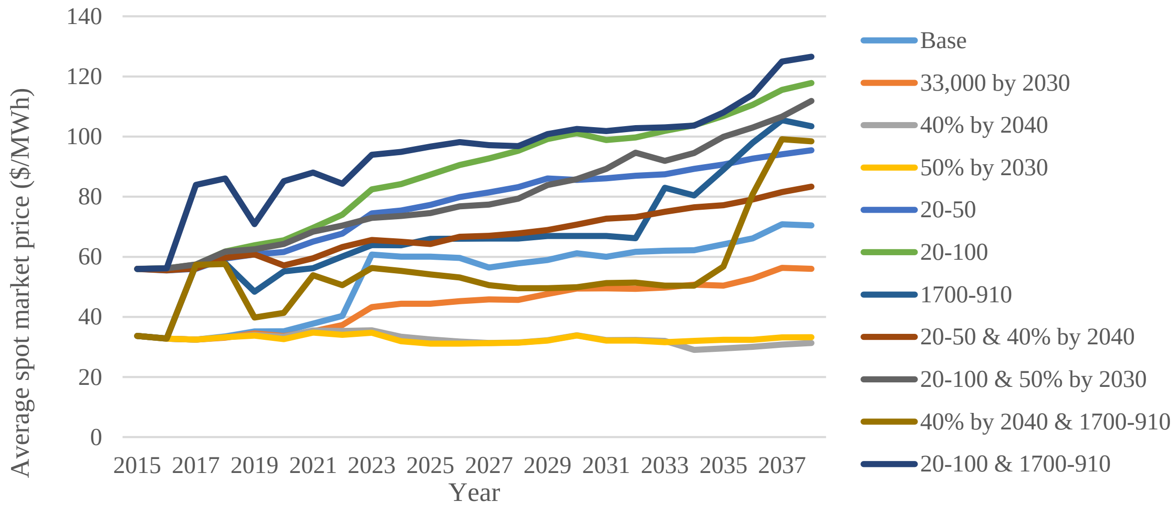

Figure 2. Weighted average spot price

The highest average prices are all linked with the 20-100 carbon price. This mechanism adds around $20/MWh to the spot price when first implemented, yet spot prices do not increase as quickly as the carbon price, reflecting the retirement of coal generation and increased wind generation in the market. Note that the carbon price will, of course, raise considerable revenue which can be used to reduce other taxes or appropriately compensate energy users.

The lowest prices are associated with renewable energy targets. The merit order effect is likely keeping prices low as 40-50% of loads are met by renewable generation with very low SRMCs. The spot market alone does not provide large opportunity for new investment, a problem that has been called 'the missing money problem'. At high RET levels it is likely that only renewable generators that could access RECs would be incentivised to build. Low prices would be problematic for generators already in the market with debt servicing obligations, as well as for reliability due to lack of dispatchable capacity to deal with load variability.

The moderate 20-50 carbon price and 40% by 2040 RET produced steady spot market price growth when combined, only sitting $10-15/MWh above the base scenario without policy.

While Figure 2 displays a weighted average of prices, these prices are individually determined by the model for each State. Under an emissions intensity limit, large price increases occurred in Victoria during the first decade of modelling, as brown coal plants were forced out of the market, with consequent equity implications for Victorian consumers. The overall lumpy growth in the spot market price could be managed more precisely with appropriate ramping of the standard policy design, with inter-region variability reduced through financial hedging tools external to the market. Revenue from carbon pricing can potentially be redistributed to consumers, where these potential equity implications are well understood in advance.

In order to understand the drivers for generation investment transitions, revenue from the market must be put into the context of generator operating costs and debt structure. The difference between long-term profitability for wind generation and incumbent coal generators can be seen in Figure 3 and Figure 4. Profit estimates for wind do not include any income from the sale of RECs or other possible support mechanisms. Profits for the existing wind plant do not include any repayment of capital costs.

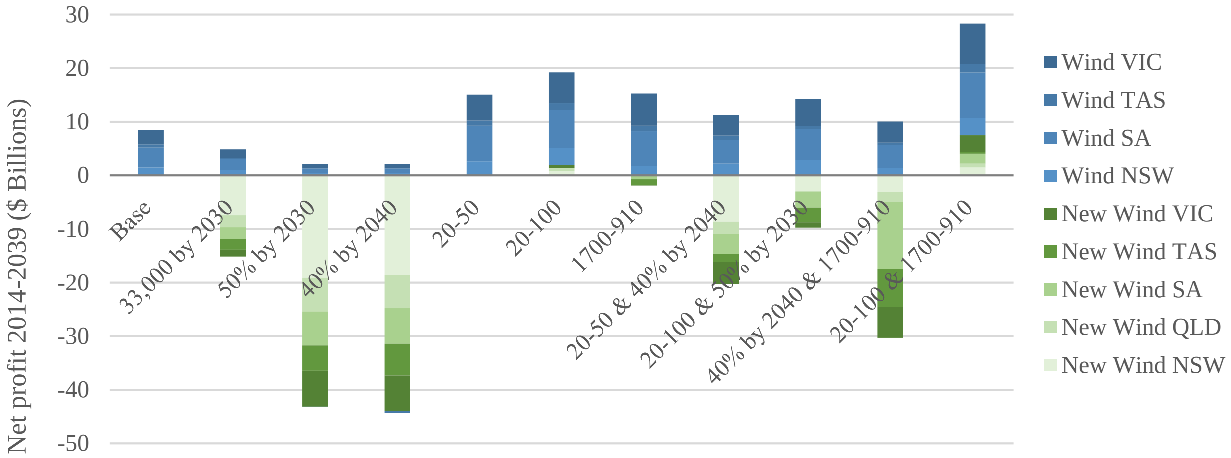

Figure 3. Net profit of all wind generators from 2014-2039 from spot market revenue

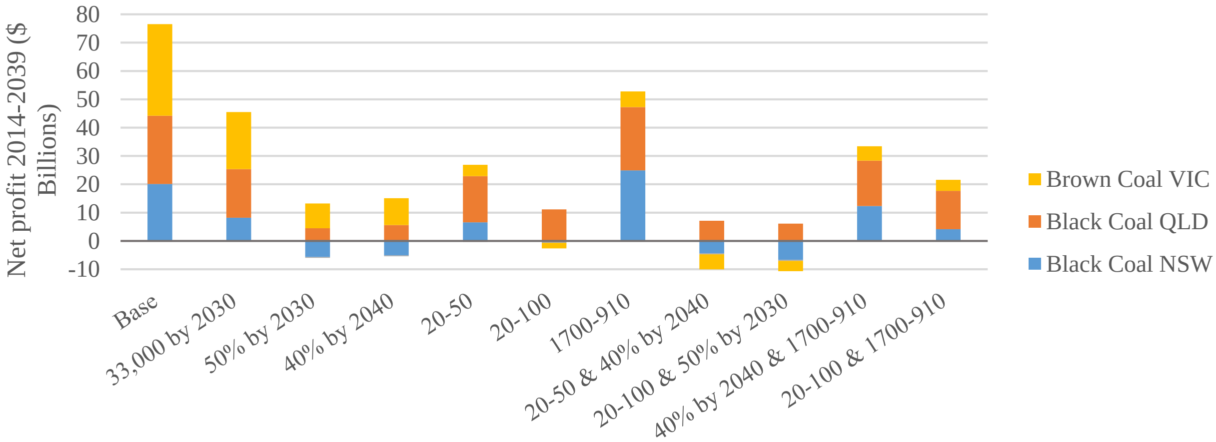

Figure 4. Net profit of all coal generators from 2014-2039 from spot market revenue

These results illustrate very clearly the advantage coal fired generation has over new build capacity. There is a two-fold effect in play: first, existing coal generators are sunk investments and it is assumed that they are not servicing capital costs so a large amount of their revenue can be realised in profits. In practice of course, these plants are occasionally bought and sold, notably with recent privatisation of generation in NSW. Additionally if renewable generators enter the market without some reduction in incumbent capacity, they are likely to supress market prices and reduce their own income.

All of the RET policy options had renewable generators making negative net profits, with some coal generators also seeing negative profits due to the supressed prices. The large losses taken in spot markets by new build wind generation under modelling of RET schemes implies that significant amounts of revenue need to pass through the REC market or another mechanism which also directly supports additional renewable generation, which raises concerns about the potential impacts of policy uncertainty, as seen in relation to the RET in recent years.

The most profitable policy for wind generation was the aggressive 50% by 2030 RET and 20-100 carbon price. The carbon pricing mechanism and emissions limit were generally profitable for wind generators. The base case was the most profitable for incumbent coal, however significant profits were also predicted under an emissions intensity limit due to higher spot prices.

4.3. Emissions reduction

This section compares the reduction in emissions intensity and the aggregate NEM emissions achieved under the modelled policies. Figure 5 displays the decline in weighted average emissions intensities. It should be noted that Tasmania has been excluded from the graph due to inconsistent variations in modelled outcomes due to the large amounts of hydroelectric generation.

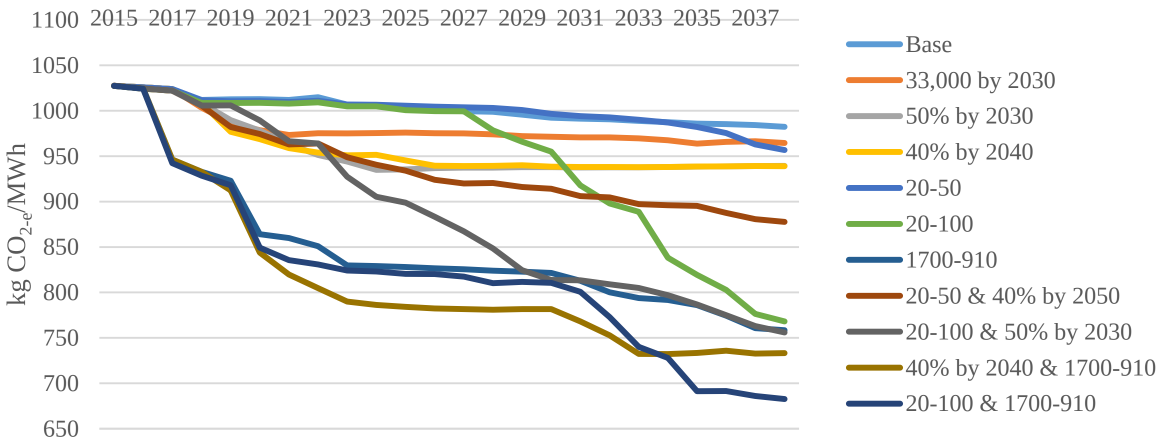

Figure 5. Weighted average emissions intensity of NSW, Qld, SA & Vic

Every scenario, including the Base case show a decline in emissions intensity over the next 24 years. The minimal difference between the Base case, 33,000 by 2030 RET, and the 20-50 carbon price is an indication that these policies are not successful. The cost of abatement achieved under these policy options seems likely to exceed the price of an alternative abatement method. One reason for this occurring under a more moderate carbon price could be the lack of noticeable change in the merit-order of generators and hence little change to the output of each generator, even as spot prices increase.

Policies, both individual and combined, which included an emissions limit were the most successful at reducing the emission intensity of the NEM. After around 10-15 years of increase to around \$45/tonne CO_{2-e} the 20-100 carbon price was able to achieve sharp reductions in emissions intensity. The renewable energy targets in general did not achieve significant reductions unless paired with another policy.

5. Discussion

Modelling of long-term planning decisions in the NEM under the influence of a range of emissions reduction policy options has highlighted some potential outcomes that may occur as the market transitions towards a lower carbon future. In some cases a trade-off was seen between effective and financially equitable policy outcomes, which would need to be addressed in policy design. Theoretical concerns over low revenues resulting from large amounts of low SRMC generation in the NEM were realised in this modeling, with average spot market revenues lower under RET schemes. In practice such low prices could encourage increased speculative activity, significant gains from obtaining and exercising market power, and a higher dependence on profits made during high price market events. These potential outcomes will be of concern to policy makers if renewable energy deployment is to be encouraged without plans to retire incumbent high emissions generators. Renewable energy generators are likely to financially suffer before the older incumbent fleet as their debt obligations mean short-term profitability is critical. Further, investment in future renewable energy generation is likely to not occur, or become more expensive if profitability is derived from policy dependent revenue achieved external to spot markets.

From the perspective of policy makers a ‘command and control’ policy like the emissions intensity limit was the most effective at translating policy intent into realised emissions reductions. However, this type of policy seems likely to be politically difficult to implement in the Australian market whereby a market based solution is often deemed preferable. The Federal government’s previous experience with organized exit with Contracts for Closure was an example of these potential difficulties. As seen in Figure 4 the financial opportunity cost to generators of staying in the market is significant, and generators would likely seek compensation for these losses.

The high variation in success of policies involving selection of a carbon price or renewable energy quantity in order to achieve emissions reductions implies significant uncertainty in relation to emissions reduction outcomes, and justifies consideration of more alternative policy options. The fixed carbon price modelled here acts like a carbon tax. Alternatively, an emissions trading scheme might ensure the policy target is met, with a market mechanism determining price.

The motivation for incumbent high emission generators to exit the market looks to vary depending on the aggressiveness of the policy mechanism, with a combination of policies far more effective at achieving generator exits. As the conditions for exits take time to develop, policy design should take a long-term view. In addition, external barriers to exit for incumbents should be addressed, as they will likely exacerbate the difficulty of incentivising incumbent generator exit through reduced spot market profitability.

This modelling is limited by the inevitable resolution and prediction uncertainties required for such long-term modelling, in particular potential variations to load and cost reduction projections such as the ones unpredictably experienced in recent years. This modelling procedure also excluded the role external market and non-market factors may play. These findings, therefore, would be made more robust by expanding the modelled policy designs and testing the sensitivity of results to a range of assumptions including future fossil fuel prices, capital costs for new generation and other related market interventions such as demand-side response mechanisms.

6. Conclusion

This research used a market simulation model to gain insights into the generation investment transition path of the NEM, under different possible emissions reduction policy tools. A renewable energy target, carbon price and emissions intensity limit over a 24 year period were modelled, and the outcomes in terms of the energy mix, spot market prices, generator profits and emissions reductions were evaluated. RET and carbon price policies were found to be ineffective as a mechanism of emissions reduction if not designed aggressive enough. Long-term use of a RET was found to devalue the information contained within spot prices, increasing the dependency of renewable generators on RECs.

References

Acil Allen Consulting. (2014). *Fuel and technology cost review.* Australian Energy Market Operator.

ACIL Tasman. (2009). *Fuel resource, new entry and generation costs in the NEM.* ACIL Tasman Pty Ltd.

AEMO. (2013). *Planning Assumptions.* Retrieved from Australian Energy Market Operator: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions

AEMO. (2015, January 14). *Planning Assumptions.* Retrieved from Australian Energy Market Operator: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions

Australian Energy Regulator. (2014). *State of the energy market 2014.* Melbourne: Australian Competition and Consumer Commission .

Australian Government. (2015). *Australia's 2030 Emission Reduction Target.* Department of the Prime Minister and Cabinet.

Clean Energy Council. (2014). *Australia's Power generation Sector at the Crossroads.* Clean Energy Council.

Department for the Environment. (2015). *Quarterly Update of Australia's National Greenhouse Gas Inventory: March 2015.* Commonwealth of Australia.

Frontier Economics. (2015). *Barriers to exit for electricity generators in the NEM.* Australian Energy Market Commission.

GDF Suez. (2012, September 5). *IPR-GDF SUEZ Australia response to Contract for Closure decision.* Retrieved from International power - GDF SUEZ: http://www.gdfsuezau.com/media/UploadedDocuments/News/Contract-for-Closure-decision-final1.pdf

Nelson, T., Reid, C., & Judith, M. (2014). *Energy-only markets and renewable energy targets: complementary policy or policy collision?* Sydney: AGL Applied Economic and Policy Research.

pitt&sherry. (2015). *CEDEX® Electricity Update October 2015.* pitt&sherry, the Australia Institute.

Pricewaterhouse Coopers. (2014). *State of the Debt Markets for the Energy Supply Industry.* The Energy Supply Association of Australia.

REN21. (2014). *Renewables 2014 Global Status Report.* Paris: REN21 Secretariat.

Riesz, J., Vithayasrichareon, P., & MacGill, I. (2015). Assessing "gas transition" pathways to low carbon electricity – An Australian case study. *Applied Energy*.

Acknowledgements

Preparation and presentation of this paper was made possible with the UNSW School of Photovoltaic and Renewable Energy Engineering.

The authors acknowledge Energy Exemplar and FICO for providing academic licenses of PLEXOS and Xpress MP solver used in the modelling presented in this paper.