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Effective policy to achieve the Australian Government's commitment to 82% renewable energy by 2030

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Sydney, NSW, 2000
August 2023

Australian climate change policy has been fraught for at least two decades. Around a decade ago, Nelson et al (2010) estimated that carbon policy uncertainty would result in electricity prices being $8.60 per MWh higher than necessary. Sadly, the study significantly underestimated both the policy gyrations that would occur and the associated costs. The only effective and enduring national policy has been the 20% Renewable Energy Target (RET). Additional frameworks have been established at the state government level which incentivise further investment in renewable energy. However, there is still no overarching national framework. In this article, we model the National Electricity Market (NEM) to determine whether existing policies will achieve the Commonwealth Government's target of 82% renewable energy (RE) by 2030. We find that there is indeed a gap of ~10% and that extending the RET architecture is the obvious and most equitable solution for energy consumers.

Keywords: electricity market; production subsidy; variable renewable energy
JEL Codes: D04, D47, Q40, Q41, Q48

1. Introduction

Australia has committed to reducing greenhouse gas emissions to 43% below 2005 levels by 2030 and a multi-year emissions budget from 2021-2030. The Commonwealth Government projects that achieving this commitment will require a carbon budget of 4,381 million tonnes (Mt) of carbon dioxide equivalent (CO_2e). Even if all existing state and federal announced and implemented policy commitments are assumed to be achieved, emissions are projected to be only 40% below 2005 levels by 2030 and 1% above the carbon budget (DCCEEW, 2022). One of the key policy commitments assumed in this projection is the delivery of the policy objective of 82% of all electricity production coming from renewable energy (RE) by 2030.

There is currently no policy suite in place at the national level to deliver 82% renewable energy by 2030. The key existing policy mechanisms that contribute towards investment in renewable energy are: the now fulfilled mandatory large-scale Renewable Energy Target (LRET) which is a renewable obligation certificate (ROC) trading scheme; the Small Scale Renewable Energy Scheme (SRES) which acts as a subsidy for installation of rooftop solar PV; and various state government Contract-for-Difference (CfD) policies such as the 12 GW NSW Energy Roadmap.

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Without a national framework in place, it is unclear whether the Commonwealth's target of 82% renewable energy by 2030 will be met. If it is not met, additional emissions abatement will be required from other sectors to meet the 43% economy-wide emissions target, at potentially higher cost to consumers. The renewable investment megacycle identified by Simshauser and Gilmore (2020) between 2017 and 2020 was driven almost entirely by the LRET. This policy, which required an additional 33 TWh of variable renewable energy (VRE) by 2020, drove investment in ~12 GW of new renewable energy comprising more than $20 billion in capital expenditure spanning 105 projects. With the LRET now largely satisfied and no new further investment required (other than voluntary RE commitments by energy users), other state-based policies are now being relied upon for further renewable investment stimulus.

State based investment stimuli policies, however, are pivoting away from certificate-based market instruments such as the LRET and towards more interventionist policies such as government-issued CfDs. There is a lack of integration between policies that have previously been relied upon to underpin renewable investment such as the LRET and the new suite of government-issued CfDs. This has created confusion and wealth transfers between various market participants. The use of government-issued CfDs also creates significant issues for the efficient operation of the electricity market (see Simshauser, 2019).

The purpose of this article is to: model whether existing state-based renewable energy investment stimuli policies are sufficient to achieve the Commonwealth Government's 82% renewable energy commitment; and provide policy recommendations for better integration of state-based policies into a nationally consistent framework. We build on the work of Nelson et al (2022) in suggesting ways of utilising the LRET architecture to fulfil state-based CfD policies in a manner that overcomes many of the detrimental impacts identified by Simshauser (2019) and achieves the current 'ambition gap' between our modelling and the 82% renewables target. Our article is structured as follows. Section 2 provides an overview of Australia's emissions and decarbonisation policies in theory and practice in Australia. Our modelling methodology and data assumptions are provided in Section 3. The results of our modelling are presented in Section 4 with policy implications and discussion outlined in Section 5. Section 6 provides a brief conclusion.

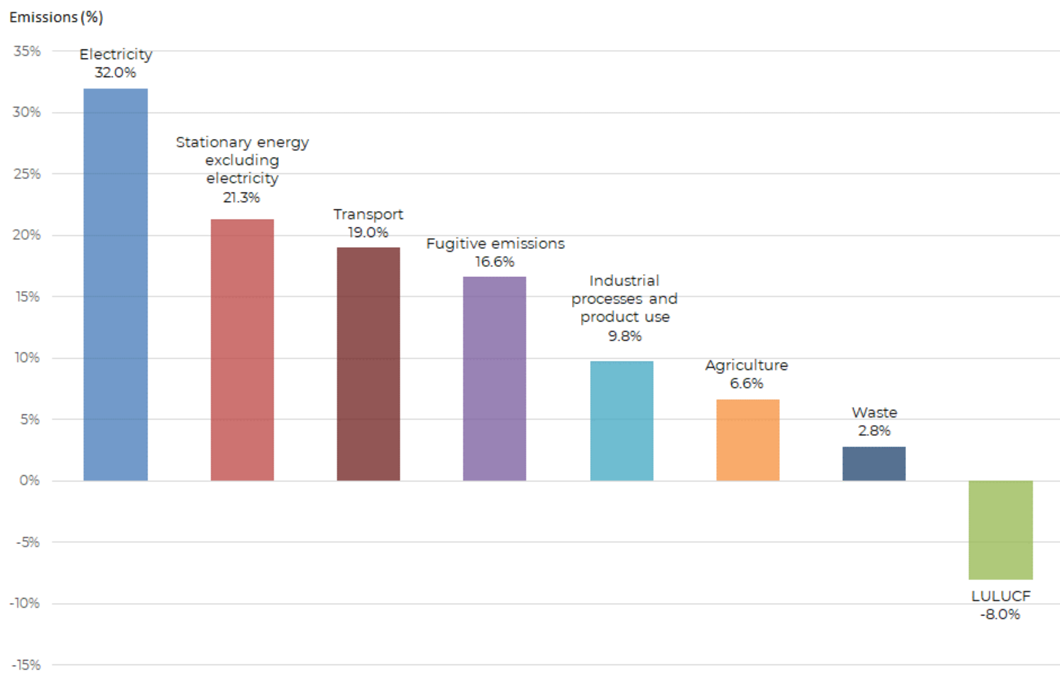
2. Australian emissions and decarbonisation policies in theory and practice

2.1 Australia's greenhouse gas emissions and carbon budget

Australia currently produces around 500 Mt of greenhouse gases annually. The sectoral distribution of this emissions footprint is shown in Figure 1. Emissions associated with electricity generation remain the single biggest contributor to Australia's greenhouse inventory at around 32% of total emissions. Electricity sectoral emissions increased materially from 1990 levels of 130 Mt to a peak of 212 Mt in 2009. However, since 2009 emissions have fallen by around 25% to 158 Mt in 2022. This is largely due to the introduction of the revised 20% Renewable Energy Target in 2009 (DCCEEW, 2022).

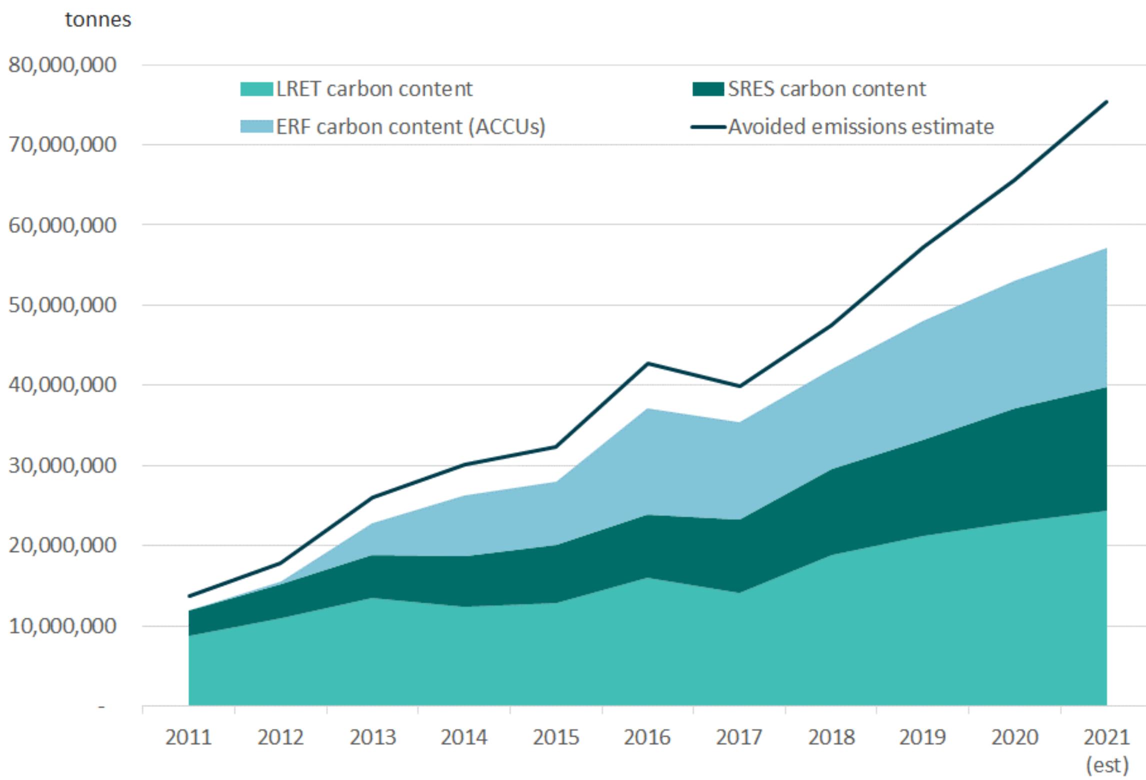
Figure 2 shows the source of abatement by policy type. The Renewable Energy Target (comprising the SRES and LRET) accounts for over half of Australia's greenhouse gas abatement, delivering 40 Mt out of a total ~75 Mt. The adoption of renewable energy has been heavily relied upon to achieve Australia's existing emission reduction commitments. However, while the current LRET target of 33 TWh has been met, it is set to expire in 2030. Furthermore, the level of susbidy under the SRES is winding down each year to 2030. As such, current abatement has been delivered by policies that are soon to be phased out and discontinued. This presents a dilemma for policy makers given the urgency of emission reductions required to achieve Australia's international commitments.

Figure 1: Australia's greenhouse emissions by sector



Source: DCCEEW (2022)

Figure 2: Source of abatement achieved by policy type in Australia



Source: DCCEEW (2022)

Through the UNFCCC process, Australia has committed to reducing its emissions to levels consistent with limiting anthropogenic climate change to no more than 2°Celsius(C) with an aspiration to achieve no more than a 1.5°C change. Meinhausen et al (2021) note that, from 2021 onwards, Australia's remaining carbon budget is 6,161 Mt CO2e for a 2° target and 3,521 Mt CO2e for a 1.5° target. Given this accounts for seven to twelve years of current annual emissions, it is critical that policies be enacted to deliver on both the overall emissions reduction objective and individual sectoral goals (such as the 82% renewables objective by 2030).

Unfortunately, Australia has been without an integrated energy and climate policy for at least two decades. Many studies have shown that there are significant costs associated with carbon policy discontinuity or uncertainty (see Nelson et al, 2010; Simshauser and Tiernan, 2019). National approaches to pricing carbon have been introduced only to be later abandoned. Almost all of the abatement achieved in the electricity sector has been driven by investments in renewables through the LRET and SRES (as noted in Figure 2). More recently, individual state governments have introduced their own policies but investment in new renewable energy has stalled with no new projects reaching financial close in Q1 2023 (CER, 2023). Given the urgency of reducing emissions to achieve a 1.5° or 2° carbon budget, it is critical that policy makers reconsider the optimal policy approach in a federal system of government and integrate approaches between the state and Commonwealth governments.

2.2 Decarbonisation policies in theory and practice

Governments have pursued various policy options in the electricity sector to fulfill international climate change commitments. These can be broadly categorised into a four stream taxonomy:

- Carbon pricing or emissions trading schemes (ETSs) imposed on electricity generators (Freebairn, 2014; Garnaut, 2014);
- Renewable energy targets (RETs) imposed on energy retailers or networks (MacGill, 2010; Onifade, 2016);
- Government-led contracts-for-difference (CfDs) funded by taxpayers or electricity consumers (Bunn & Yusupov, 2015; Kozlov, 2014; Wild, 2017);
- Policies promoting distributed energy resources (DER), such as solar feed-in tariffs (Nelson et al 2011; Pollitt & Anaya, 2016).

There is no consensus on the ideal mix of policy instruments as objectives can differ based on the stage of technology development. As noted by Pollitt and Anaya (2016) and Onifade (2016), most countries pursue different combinations. Over time, Australian governments have implemented all of these policy instruments, although few have been enduring (Daly & Edis, 2011; Garnaut, 2014; Jones, 2009; Nelson, 2015).

Freebairn (2020) notes that a well-designed carbon pricing mechanism like a cap-and-trade scheme is widely considered the most effective policy for reducing greenhouse gas emissions. The strength of emissions trading is that the externality of emitting greenhouse gas emissions is internalised through a transparent, economy wide pricing mechanism. All demand side and supply side abatement is eligible and mature technologies are deployed to reduce emissions in an orderly manner. Importantly, emissions trading is useful for deploying existing mature technologies. In the electricity market, wholesale electricity prices begin to reflect this externality cost. Nelson et al (2012) found that, due to emissions trading, electricity prices rise by the *average* emissions intensity of the generation stock.

However, Australian policymakers have struggled to establish a lasting and stable carbon pricing mechanism. Both the Clean Energy Future package of reforms and the New South Wales Greenhouse Abatement Scheme (GGAS) have been introduced and then repealed (Nelson et al., 2022). Instead, policymakers have predominantly relied on other mechanisms, including premium feed-in-tariffs (PFiTs) and derivatives of PFiTs (such as the SRES), renewable obligation certificate (ROC) trading schemes (such as the LRET), and more recently, reverse auctions for contracts-for-difference (CfDs) (Simshauser, 2019). A timeline of these developments is provided in Figure 3.

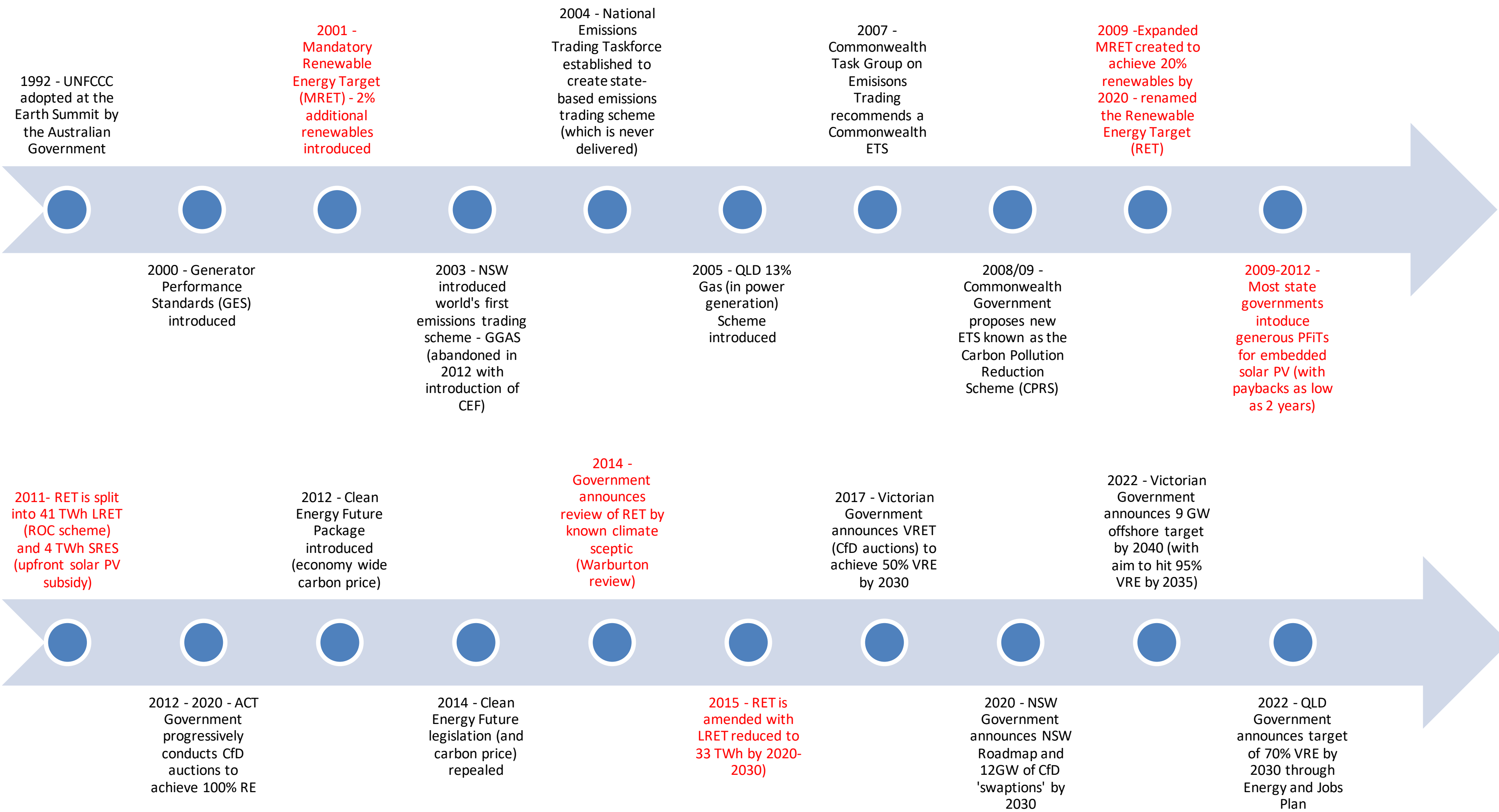
Due to the vexed political issues associated with emissions trading in Australia (see Simshauser and Tiernan, 2019), governments have pivoted away from market based mechanisms. Instead, they have focused on policies more suited to driving technology innovation, even though many technolgies targeted, like solar and onshore wind, are already mature. Setting aside climate change policy, Australia has established stable, long-lasting, and internationally renowned electricity-related policies at the wholesale level (MacGill, 2010; and Simshauser, 2014). However, policymakers face a significant challenge in achieving a stable and durable climate change policy architecture, given the strong political differences historically at the national level (Apergis and Lau, 2015; Byrne et al., 2013; Freebairn, 2014; Garnaut, 2014; Molyneaux et al., 2013; Nelson, 2015; Nelson et al, 2010; Simshauser, 2014; and Wagner et al., 2015).

The consequences of this policy discontinuity have been the absence of a single and enduring pricing signal for optimising abatement across both renewables, energy efficiency and improvements in thermal and firming technology efficiency. Figure 4 shows the various certificate prices across the multitude of energy policy incentives outlined in Figure 3. Trading across commodities has been impossible given the different units (i.e. MWh, tCO_2e, etc) and the lack of any formal fungibility. It is highly likely that this lack of policy integration has driven significantly higher costs than what would have been had a national carbon price been in place (see Freebairn, 2020).

Transitioning the energy sector requires policymakers to adopt long-term perspectives spanning decades and there is likely to be a role for more than one policy instrument. Emissions trading schemes and carbon taxes are effective in incentivising operational and investment decisions to achieve short-term carbon reduction targets. These mechanisms encourage the deployment of mature technologies and promote more efficient behavior (Freebairn, 2020). Technology-specific subsidies such as PFiTs and Contracts-for-Difference (CfDs) aim to drive investment in emerging and less mature technologies, facilitating learning and cost reductions (Jacobsson and Bergek, 2004). It can therefore be argued that PFiTs and CfDs are suitable for supporting investments in emerging technologies such as offshore wind in Australia. CfDs may create positive feedback mechanisms such as learning by doing, economies of scale in production and consumption, learning by using, incremental product development, decreased uncertainty, and economies of scope (Arrow, 1962; Katz and Shapiro, 1986; Rosenberg, 1982; Cowan, 1991; and Sandén and Azar, 2005).

A significant distinction between technology-specific policies lies in how risks and returns are allocated to market participants, particularly consumers and investors (generators). This is crucial when considering the substantial spatial and temporal price risks associated with electricity systems. Policies such as PFiTs and government-provided CfDs tend to remove risks from participants and shift potential losses onto consumers or taxpayers. This approach, mainly aimed at emerging technolgies like solar in the 2000s and offshore wind today, can effectively drive technology diffusion (Jacobsson and Bergek, 2004). However, it remains unclear why Australian policymakers are using CfDs to incentivise already mature technologies such as large-scale wind and solar. CfDs are primariliy tailored to reduce risks for project proponents, as highlighted by Woodman and Mitchell (2011).

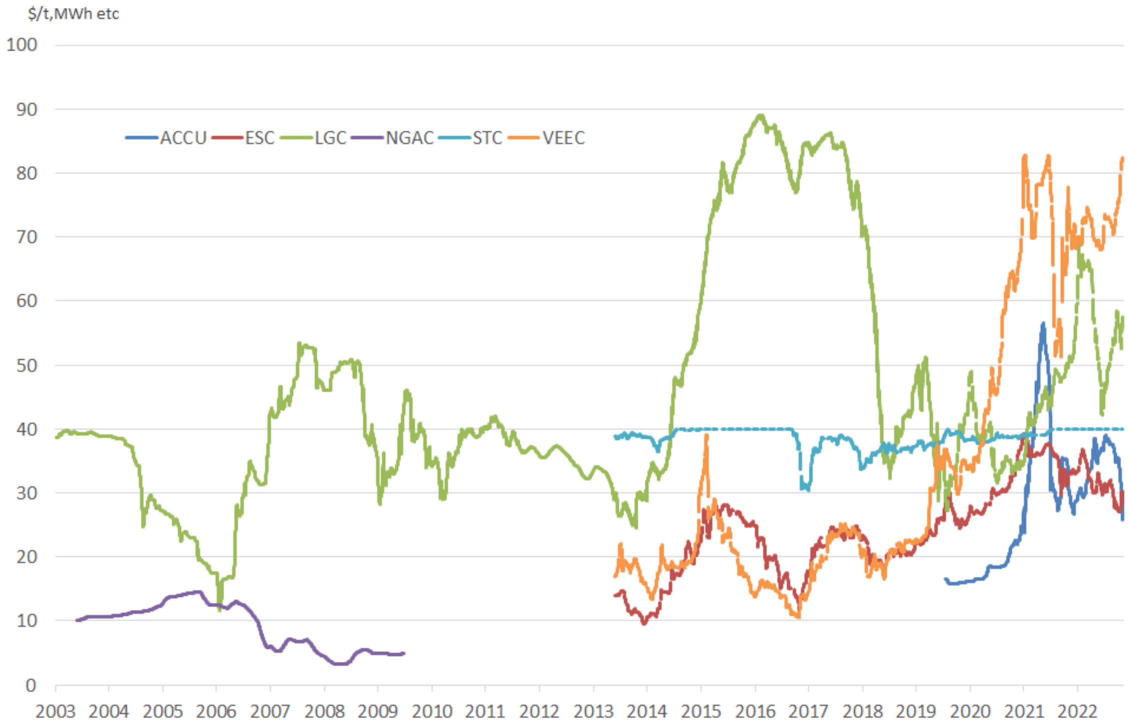
Figure 3: Timeline of Australian climate policy



Early 2010s – Commonwealth Government is driving energy and climate policy using market mechanisms

Mid to late 2010s – Commonwealth Government has no integrated energy and climate policy. State governments step in to drive VRE adoption post the RET being achieved in 2020 through CfDs

Figure 4: Various carbon, energy efficiency and renewable energy policy pricing since 2003



Source: Clean Energy Council and Clean Energy Regulator

In contrast, ROC trading schemes such as the LRET require market participants to bear the market risks associated with their investments. Bunn and Yusupov (2015) demonstrate that trading schemes and ROCs reduce risks for consumers/taxpayers compared to CfDs or PFiTs, particularly when there is a negative correlation between renewable output and wholesale electricity prices. ROC policies necessitate that market participants manage the risks associated with participating in the electricity market, which CfDs do not require. ROCs are generally more suitable for driving investment in relatively mature technologies, as demonstrated by Nelson et al. (2015), Foxon and Pearson (2007), Wood and Dow (2010, 2011), and Sioshansi (2021). In fact, Nelson et al. (2022) argue the ROC scheme, the LRET in Australia, has been the most successful climate policy in the country. It has driven substantial investment in mature renewable energy generation without imposing unnecessary risks on consumers or taxpayers.

Despite the success of certificate policies, Australian governments have increasingly turned to government-initiated CfDs to support commercially mature technologies. For example, the Victorian Government has utilised CfDs to underwrite new investments in VRE as part of its VRET policy, aiming for 50% renewable energy by 2030 as legislated in the *Renewable Energy (Jobs and Investment) Act 2017*. The Australian Capital Territory (ACT) has also set a goal of 100% renewable energy procurement through a series of CfD contracts, while the NSW Government has legislated a complex version of CfDs known as 'swaptions' or long-term energy service agreements (LTSEAs) to drive renewable generation and storage capacity.

Recently, researchers have proposed 'hybrid' ROC/CfD policies. Nelson et al. (2022) suggest that CfDs could be issued with reference to the 'green certificate', in particular the Large Scale Generation Certificate (LGC) under the RET, rather than bundled electricity and environmental credit revenues. This method addresses the limitations of CfDs that Simshauser (2019) identified, such as shielding market participants from electricity generation price risk and introducing "quasi-market" participants. Additonally, it increases hedge market participation with associated beneficial impacts on retail competition and encourages the use of nuanced metrics beyond just levelised cost of electricity (LCOE).

Given the lack of a nationally consistent and integrated energy and climate policy and the fulfillment of the policy that has delivered the most abatement (the LRET), it is appropriate to consider two important questions: whether existing policies are sufficient to achieve the national target of 82% renewables (given Australia relies upon this for its international emission reduction commitments); and could policy be integrated in a more efficient manner to facilitate any aspiration gap between existing policy and the 82% goal.[1]

3. Modelling approach and assumptions

To determine the answer to whether existing policies will be sufficient to achieve the national goal of 82% renewable energy by 2030, we have utilised the Linear Programming (LP) model PLEXOS. The model has an objective function of meeting projected electricity demand at least cost (eq. 1) with constraints imposed in relation to energy balances (see eq. 2), operational constraints (eq. 3), and meeting committed policy targets.

$$Minimise: \quad \sum_{y}\sum_{g} DF_{y} \times (C_{g} \cdot x_{g,y}) + \sum_{y} DF_{y} \times (FOM_{g} \times x_{g,y}) + \sum_{t} DF_{t\in y} \times L_{t} \times [VoLL \times USE_{t} + \sum_{g} (SRMC \times g_{g,t})] \qquad \textbf{eq. 1}$$

$$Subject\ to: \quad \sum_{g} g_{g,y} + USE_{t} = D_{t} \qquad \textbf{eq. 2}$$

$$g_{g,t} \leq \sum_{t} x_{g,t} \cdot r_{g,t} \qquad \textbf{eq. 3}$$

$Where:$ $DF\ is\ discount\ factor$
$C_g\ is\ overnight\ capital\ cost\ of\ generator$ g
$x_{g,y}\ is\ capacity\ built\ of\ generator\ g\ by\ year\ y$
$FOM\ is\ fixed\ operational\ and\ maintenance\ cost$

[1] The government has noted that the pace of change is unlikely to deliver 82% renewables without some other form of action. For example, the Commonwealth energy and climate change department Deputy Secretary has noted: "With solar, we've got the pace of investment we need. Where we don't have it, at the moment, is wind. We've had, broadly, on average, about one gigawatt of wind capacity added in the past five years. We need that to increase to about three gigawatts of wind capacity, per year." (West Australian, 2023).

L_t is duration of dispatch period t
$VoLL$ is value of lost load
USE_t is unserved energy in dispatch period t
$SRMC$ is short run marginal cost
$g_{g,y}$ is dispatch level of generating unit g in period t
$r_{g,t}$ is the rating of generator g in period t

Relevant outputs from the modelling are total system cost, capacity build, transmission build, wholesale prices, generation mix, and emissions. Core assumptions are presented in Table 1 and Table 2. For the purposes of our research question, we have assumed all announced and legislated state-based policies are fully implemented and achieved.

Table 1 – Government policy assumptions for PLEXOS Modelling

Government Policy	Assumption
Emissions trajectory	Australian economy wide emissions reduction of 43% on 2005 levels by 2030, Net-zero by 2050.
Emissions Policy	Emissions constraint managed by iterative modelling adjusting coal closures and market driven renewable generation.
State Emissions policies	NSW Roadmap: 12GW VRE by 2030 and 2GW of long duration storage VRET: 50% by 2030 QRET: 50% by 2030 TRET partially implemented
NSW Roadmap trajectory	VRE: Linear targets from 2022 (zero) to 2030 (12 GW) Firming: Linear targets from 2025 to 2030
QLD Energy and Jobs Plan	70% VRE generation by 2032 (incl. rooftop PV) 80% VRE generation by 2035 (incl. rooftop PV) 7GW new 24hr pumped hydro (Borumba PHES 2GW 2030, Pioneer-Burdekin PHES 5GW 2035)
Vic Offshore Wind Policy	Victorian Offshore Wind 9GW target implemented with delays to the last 5GW (final delivery from 2040 back to 2045) Trajectory of 1GW by 2030, 2GW by 2032, 4GW by 2035, 9GW by 2045.
Vic Gov Energy Storage Initiative	2.6GW storage (large-scale BESS and Pumped Hydro) built by 2030 6.3GW storage (large-scale BESS and Pumped Hydro) built by 2035

Table 2 – Cost and technical characteristics assumptions

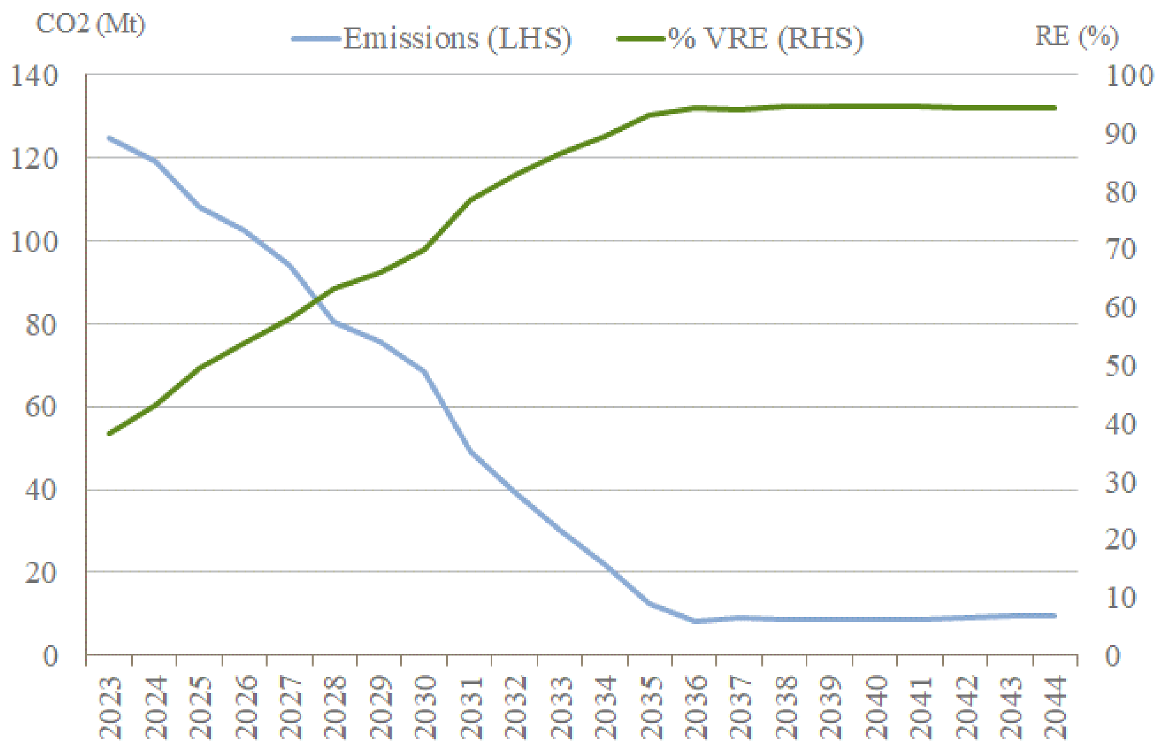
Costs and technical characteristics	Assumption
Coal closures	End of life, plus economic or consistent government policy where applicable
Demand	AEMO 2022 ISP Step Change
EVs	AEMO 2022 ISP Step Change
Fuel Prices	Gas and coal: Forwards to FY25, then commodity prices outlook long-term (~$7/GJ Wallumbilla) Coal: International commodity prices. Plant specific contracts from industry or AEMO otherwise
WACC	Post-2030, Merchant WACC: 6.5% (real, pre-tax)
Market efficiency	Perfect foresight; projects build according to system least-cost, subject to constraints of government policy targets implemented
Capital Costs in FY22	Starting point reflecting current industry costs, based on cost breakdown from CSIRO GenCost study. Wind CAPEX $2,450-2,700/kW. Solar CAPEX $1,850-2,150/kW.
Capital Costs Learning Rate	Learning rate adjusted from CSIRO GenCost to account for higher starting point, with costs converging with long-term prices as per 22-Q3 forecast by 2050
MLFs	Wind: 0.9120, Solar: 0.8778
Wind Resource	New build capacity factors: - QLD: 33% - NSW: 35% - SA: 38% - VIC: 36%

Costs and technical characteristics	Assumption
Solar Resource	New build capacity factors: - QLD: 28% - NSW: 28% - SA: 30% - VIC: 25%
Capacity Degradation	Wind: no degradation Solar: 0.5% p.a. Batteries: 2% p.a.
Fixed Operation and Maintenance	Innovation for wind & solar - declines over time AEMO ISP 2022 for other technologies, including existing coal
Variable Operation and Maintenance	Zero for existing wind & solar (assume all O&M in Innovation FOM, excluding market charges)

4. Modelling results – will the NEM reach 82% RE by 2030?

Our modelling results show that there will be significant transformation of the NEM within two decades. Policies such as the NSW Government 12 GW Energy Roadmap, Queensland Energy and Jobs Plan (70% VRE by 2032) and Victorian Government 50% VRET by 2030 drive significant investment in new solar, wind and energy storage. Total emissions between now and the middle of the century in the NEM are projected to be 1065 Mt CO2e. This is reasonably consistent with the NEM achieving its 'fair share'[2] of the 1.5° budget of 3,521 Mt CO2e (noted in Section 2). Total emissions are plotted in Figure 5.

Figure 5: Emissions and proportion of renewable energy in the NEM



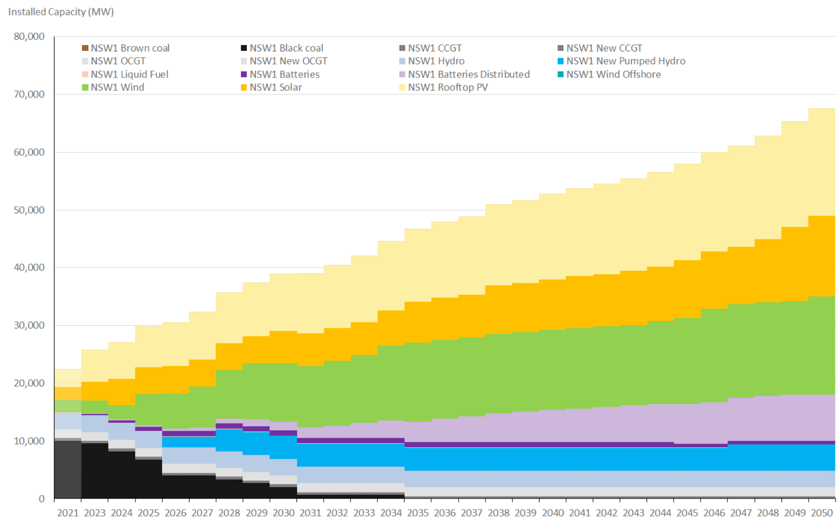
Source: PLEXOS modelling outputs

Figure 5 displays yearly emissions from 2023 and 2045 as well as the proportion of RE (including embedded PV) in the NEM. RE levels quickly rise to around 85% by the late 2030s, but in 2030 RE only accounts for ~70% of total energy. Both South Australia and NSW surpass the 82% target, while QLD and VIC fall short. The breakdown of output by energy source in each state of the NEM is shown in Figure 6.

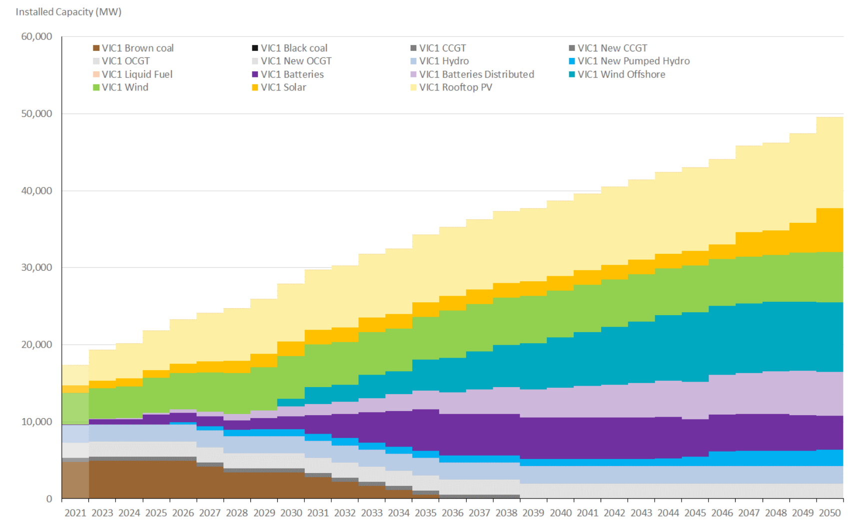
[2] As electricity sector emissions are approximately one-third of total greenhouse emissions, limiting NEM emissions to less than one-third of the total carbon budget allows us to make this conclusion.

Figure 6: Capacity growth in each mainland NEM state

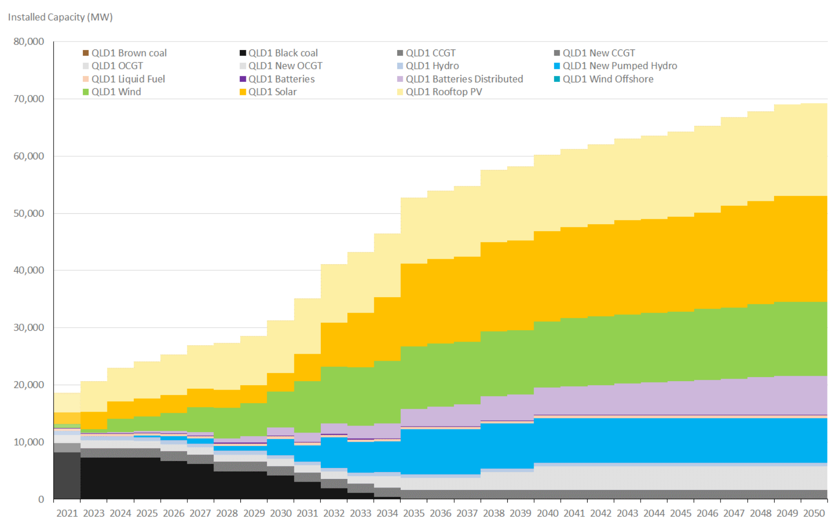
New South Wales



Victoria



Queensland



South Australia

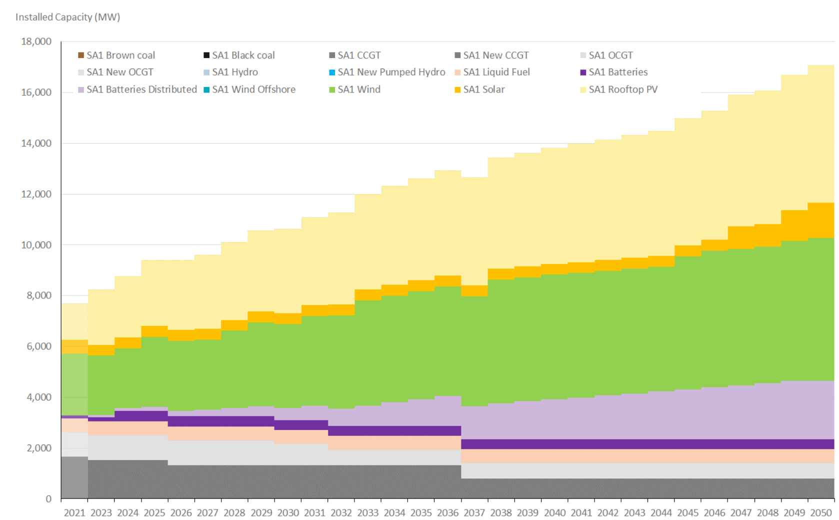
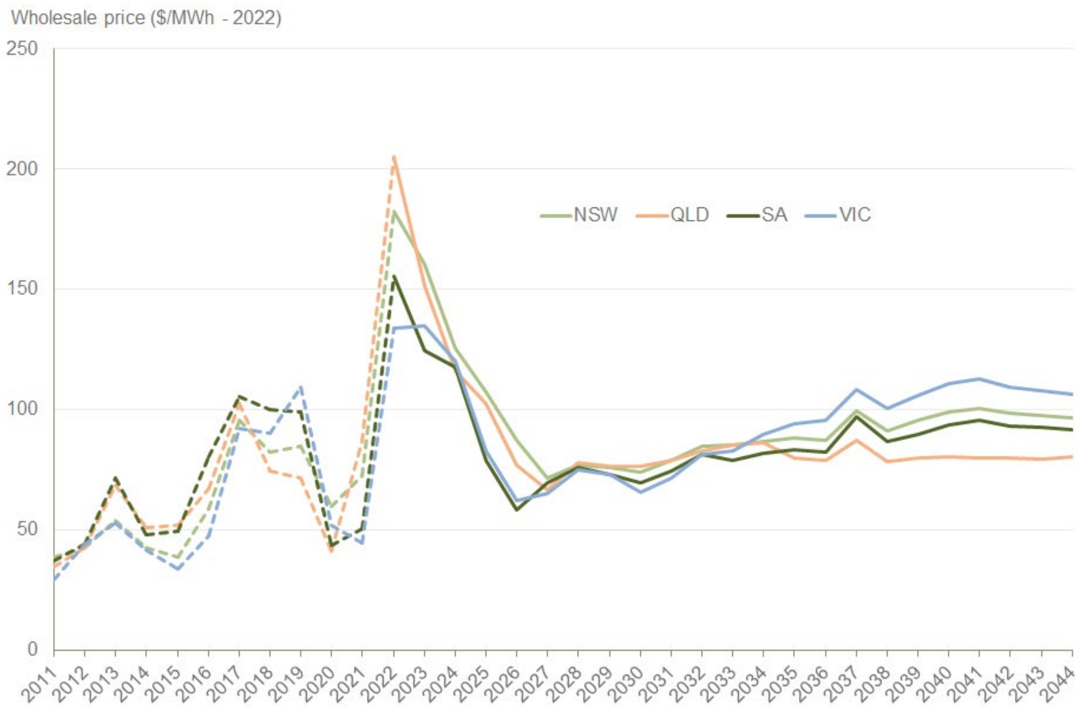


Figure 6 shows the capacity growth in each NEM mainland jurisdiction from 2023 through 2050. It is clear that state-based policies (particularly in New South Wales) drive significant uptake of new wind and solar. However, the uptake is insufficient to meet the Commonwealth Government's 82% RE target. The Victorian and Queensland Government's commitments drive a step change in investment in the post 2030 period as offshore wind and coal closure commitments result in a significant uptake in new wind, solar and energy storage.

Figure 7 shows the wholesale price projections by mainland NEM jurisdiction between 2011 and 2022 (observed) and 2023 and 2045 (projected). There are three key observations. Firstly, LP models such as PLEXOS tend to 'smooth' prices relative to observed prices in the past. Secondly, the period between 2023 and the early 2030s is projected to result in lower prices as policies drive investment using out of market payments that are specific to the individual project (i.e. government-issued CfDs and swaptions for CfDs). This has material implications which we will address in the subsequent policy implications section of this article. Finally, the period beyond the mid-2030s is characterised by rising prices as investment is driven by market requirements and not government policy.

Figure 7: Wholesale prices between 2011 and 2022 (observed) and 2023 and 2045 (projected)



Source: PLEXOS modelling

5. Policy Implications

Our results show that there is a policy aspiration gap between the projected levels of RE achieved by existing state-based policies and commitments and the Commonwealth Government's target of 82% RE. Given this, policy makers have a chance to bridge this gap using national (or nationally consistent state-based) policies.

i. Implications for carbon budgets and sectoral abatement

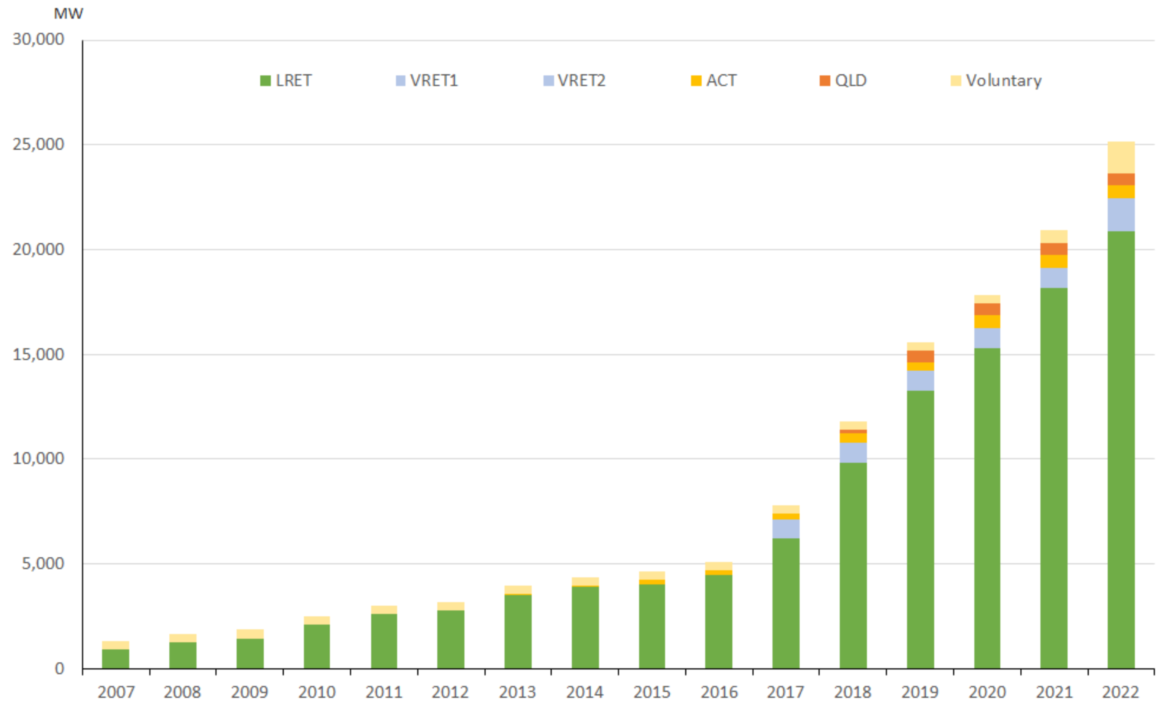
While there is an aspiration gap between the projected levels of RE achieved by existing state-based policies and the 82% RE objective, the existing policy frameworks are largely consistent with the electricity sector staying within a 1.5° carbon budget. This perspective overlooks the important role that the electricity sector is likely to play in decarbonising transport and some industrial processes (through electrification). As such, it is important for policy makers to consider how electricity sector abatement can be exported to other sectors that may require more time to develop new decarbonised products and production processes.[3]

ii. The practical and theoretical importance of having a sector-wide price on emissions

As noted in Section 2, there has been a pivot away from market-based mechanisms such as carbon pricing and renewable energy trading schemes like the LRET towards state-initiated project specific subsidies via CfDs. This presents a risk for an efficient, least cost transition to a decarbonised electricity system. Notably, as Figure 8 shows, the vast majority of the $40billion+ in investment in renewable energy has been driven by the LRET.

Figure 8: Cumulative new renewable capacity commitments by government investment driver

[3] This is also important for addressing the opaque and somewhat confusing practice some electricity companies currently use to claim 'carbon neutral' electricity supply. For example, Energy Australia's 'Go Neutral' carbon neutral electricity supply plan is marketed as 'no cost to you' and utilises cheap international carbon credits from projects in Brazil and India. It is highly likely consumers are unaware that such a practice reduces domestic abatement and the chances of Australia staying within a carbon budget.

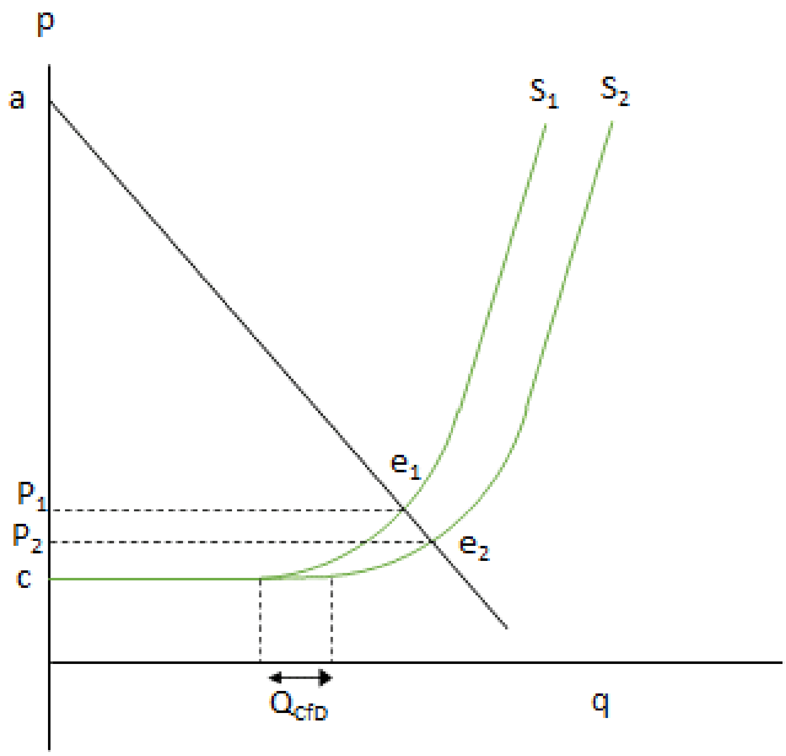


Source: Compiled from industry data

Figure 8 presents the cumulative new renewable capacity by government investment driver. Over 80% of new investment has been driven by the LRET. All of these projects require revenue from electricity markets and LGCs to be economic. The use of CfDs effectively strands these investments by reducing revenues through the transfer of renewable energy project producer surplus to consumers. This is likely to have a chilling effect on investments and raise the cost of capital as existing investors become wary of supporting new projects in a market that has used government policy to strand existing investments.

To demonstrate this, we present simple partial equilibrium analysis. Figure 9 illustrates the existing energy industry aggregate supply function, represented by the curve (S_1). Renewables built to date receive two types of revenue streams: electricity market revenue at the equilibrium price P_1 and revenues from LGCs (acting as a proxy for the carbon emissions). The total electricity market consumer surplus is marked by the triangle area a, e_1, P_1. Producer surplus is shown in the area c, e_1, P_1.

Figure 9: Partial equilibrium analysis in a market with new CfD induced supply



We can then extend our analysis in Figure 9 by demonstrating what occurs if governments use CfDs to stimulate further investment in renewable energy. In this scenario, the supply curve shifts from S_1 to S_2 due to the increased RE capacity shown by Q_{CfD}. The increase in supply creates a new point of equilibrium e_2 and a lower price P_2. The 'merit-order effect' has driven down wholesale price outcomes by introducing more supply. Consumer surplus increases from a, e_1, P_1 to a, e_2, P_2. Producer surplus falls from c, e_1, P_1 to c, e_2, P_2. There has been an effective transfer of producer surplus to consumer surplus represented by the area P_1, e_1, P_2. The economics of *incumbent* renewable generation have been altered by lower wholesale prices.[4] In contrast, the economics of *new* renewable generators are subsidised through out-of-market CfD payments. It is worth noting these costs are ultimately recovered from energy consumers through higher network charges.

This outcome of lower wholesale prices would not necessarily be a bad outcome if policy frameworks continued to price the externality of carbon emissions for all generators. However, the pivot to CfDs subsidises new generators but in a manner that results in a cessation of externality revenue streams post 2030 (when the LRET architecture expires) for all other renewable generators. Considering that both equity and debt investors in incumbent projects will be asked to provide funding for new projects, this inconsistency in policy may increase the risks attributed to new projects and raise overall project costs.

Our partial equilibrium analysis highlights that pivoting towards government-issued CfDs, instead of a consistent and enduring market-based approach such as the RET, leads to

[4] The NSW Energy Roadmap specifically notes that a key feature of the policy's design is to reduce wholesale electricity prices (see NSW Government, 2020).

sub-optimal results. This builds on the case against the use of CfDs best summarised by Simshauser (2019): the shielding of market participants from electricity generation price risk and the introduction of 'quasi-market' participants; the reduction in hedge market participation with associated impacts on retail competition; and the use of simplified metrics such as LCOE. In contrast, schemes better targeted to the carbon externality (including carbon pricing and the LRET) preserve the underlying energy market signals, and reward either low cost or high value projects (or both).

It is also possible to contrast the economics of RE in an environment with an emissions trading scheme compared with the RET. Figure 10 offers a simplified view of electricity pricing in the NEM under an emissions trading scheme and contrasts this with that of a renewable certificate scheme.

Figure 10: Stylised representation of electricity pricing with an emissions trading scheme contrasted with a renewable certificate scheme

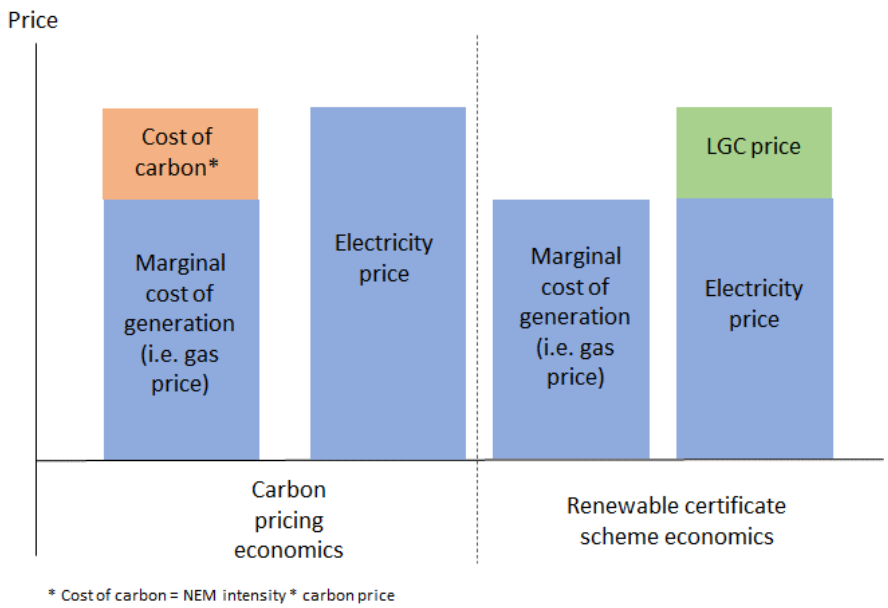
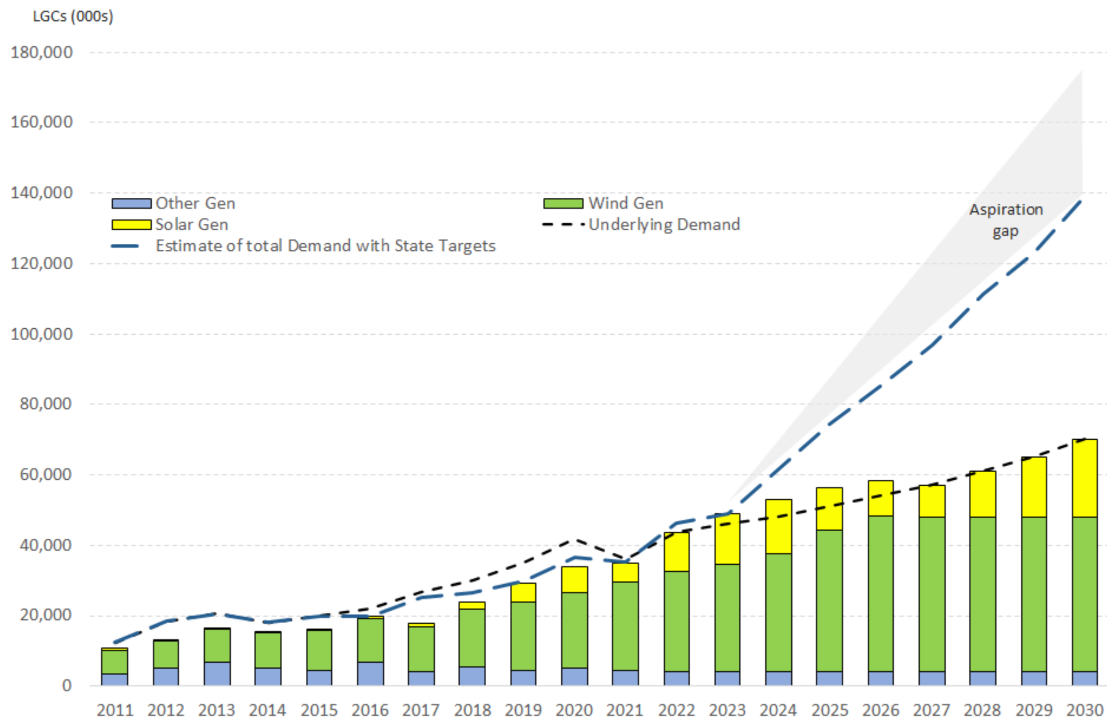


Figure 10 shows that the electricity price increases by a function of the NEM intensity multiplied by the cost of carbon permits. This reflects the additional marginal running costs of the NEM generation fleet. *All* renewable and low-emission generators gain from increased electricity prices, capturing the true costs of emissions and aligning societal benefits with costs. Figure 10 also contrasts this with the economics of a renewable certificate scheme. In this scenario, wholesale electricity prices continue to reflect the marginal running costs of NEM plant (i.e. gas or coal) but renewable generation economics are supported by the LGC price. Nelson et al (2022) note that the RET has been very effective at delivering levelised revenues that recover levelised costs but with significant volatility from year to year.

iii. Role of voluntary renewable energy purchases by consumers

This article has so far established: that an aspiration gap exists between the national commitment of 82% RE by 2030 and the policy frameworks in place to deliver investment in renewables; and that the pivot away from national market based instruments such as the RET to state-based CfDs and swaptions creates risks of stranded RE assets, higher costs and a lack of fungibility between electricity sector abatement and other sectors of the economy. This aspiration gap is stylistically presented in Figure 11.

Figure 11: LGC market with committed generation and stylised 'aspiration gap'



Source: Compiled from CER and market data

Australia's Clean Energy Regulator has suggested that voluntary action by consumers to purchase renewable energy (in addition to state renewable energy targets) may be sufficient to deliver the 82% target. However, it is important to note that voluntary surrender of LGCs currently accounts for ~2% of NEM load (above RET obligations)[5]. While voluntary renewable purchase is expected to grow, driven by Environment, Social, Governance (ESG) metrics requiring companies to eliminate Scope 2 emissions or face barriers to efficiently raising capital, much of this voluntary action will be complementary to existing state targets rather than additional.[6]

Figure 12 presents partial equilibrium analysis of the supply (blue) and demand (black) for certificates as a function of price. Point A is the mandatory RET obligation, requiring a fixed percentage subject to a legislated penalty price (P_A). Demand is perfectly

[5] Certificates equivalent to a further 2% of NEM load also voluntarily surrendered to meet various compliance obligations, such as zero emissions from desalination plants.

[6] For more information on the perspectives presented by the CER, see https://www.cleanenergyregulator.gov.au/DocumentAssets/Documents/RET%20Administration%20Report%202022.pdf, Accessed online on 16 September 2023.

inelastic below price P_A and perfectly elastic beyond this price point. Beyond the demand indicated by the RET obligation, voluntary demand is assumed to increase with price declining at some rate (curve D_1). Point B represents the total quantity achieved by the RET and from legislated state schemes delivered via CfD. It is worth noting that there is no mandate that consumers utilise this supply for their own 'voluntary' VRE purchases. Beyond this point, the supply rises to the supply curve (blue) which is assumed to follow a standard monotonically non-decreasing curve[7]. Point C is the targeted volume (i.e., equivalent to reach 82%). The supply and demand curves do not intersect because the state schemes are the binding constraint. If the voluntary demand is increased (dotted black line D_2), it does not shift the equilibrium build until the new demand curve is high enough to intersect the market supply curve (voluntary demand curve D_3, leading to equilibrium build at point E). This minimal model shows that voluntary demand must exceed legislated schemes before the overall percentage of renewable energy increases.

Figure 12: Partial equilibrium diagram of interaction between mandatory and voluntary action

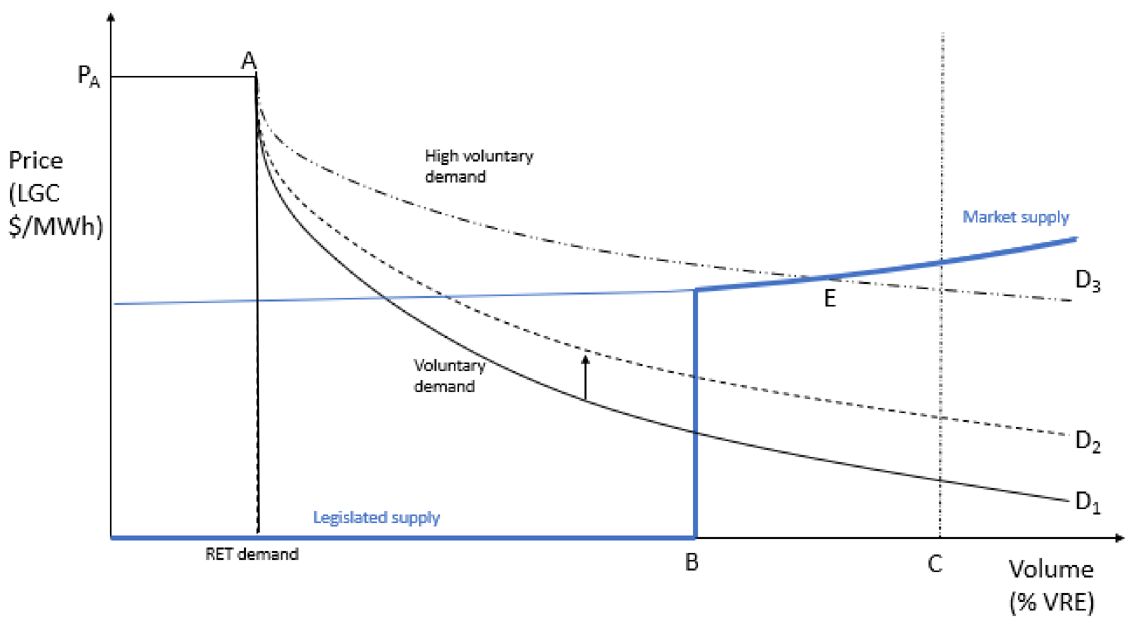


Figure 13 quantifies this analysis for the NEM, showing the percentage of renewable generation achieved in the NEM in 2030. It compares varying levels of achieved voluntary demand (vertical axis) with different mandatory surrender obligations[8] or Renewable Power Percentage (RPP) on the horizontal axis. Each scenario assumes the currently modelled state policies described in Section 3 allow for the creation of LGCs which are then available for purchase by consumers seeking 'voluntary' green energy. Any excess LGCs produced by state schemes but above voluntary demand are assumed to be banked for future years but do not otherwise change physical outcomes.

[7] We have used the LGC price as a proxy price axis in this diagram; in practice, exit of coal closures may see the price signal moved to the wholesale electricity price rather than as a pure certificate subsidy.

[8] Currently, ~17% of NEM load is exempt from some or all of the RET obligations, primarily large emissions intensive trade exposed loads that are both price and politically sensitive. For simplicity, this modelling assumes all loads are liable for the RET, potentially supported by border adjustment mechanisms.

Behind the meter rooftop PV production is assumed to deliver 40 TWh of energy which is added to the achieved percentage.

Utilising this simple model, we can confirm that current state-based policies would deliver approximately 68% renewable energy in 2030, up from ~34% in 2023. Under the current LRET RPP of 20% and currently legislated state policies, voluntary action up to ~ 55% of total electricity consumption would not change the physical build required in the NEM. Approximately 70% of load (up from ~2% today not including the 20% RET) would need to voluntarily purchase 100% green energy to achieve the 82% target. The only way of preventing this outcome is to explicitly prevent state-based schemes from creating LGCs.

Figure 13: Impact of voluntary and mandatory targets on NEM renewable percentage

	RET (RPP% of operational demand)																	
% load voluntarily going green	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%	80%	85%
2%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	72%	76%	80%	84%	88%
5%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	69%	73%	77%	81%	84%	88%
10%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	71%	74%	78%	82%	85%	89%
15%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	69%	72%	76%	79%	83%	86%	90%
20%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	71%	74%	77%	80%	84%	87%	90%
25%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	69%	72%	76%	79%	82%	85%	88%	91%
30%	68%	68%	68%	68%	68%	68%	68%	68%	68%	69%	71%	74%	77%	80%	83%	86%	89%	91%
35%	68%	68%	68%	68%	68%	68%	68%	68%	68%	71%	73%	76%	79%	81%	84%	87%	89%	92%
40%	68%	68%	68%	68%	68%	68%	68%	68%	71%	73%	76%	78%	80%	83%	85%	88%	90%	93%
45%	68%	68%	68%	68%	68%	68%	69%	71%	73%	75%	78%	80%	82%	84%	87%	89%	91%	93%
50%	68%	68%	68%	68%	68%	69%	71%	73%	76%	78%	80%	82%	84%	86%	88%	90%	92%	94%
55%	68%	68%	68%	69%	71%	72%	74%	76%	78%	80%	82%	83%	85%	87%	89%	91%	93%	94%
60%	68%	69%	71%	72%	74%	76%	77%	79%	80%	82%	84%	85%	87%	89%	90%	92%	93%	95%
65%	71%	73%	74%	76%	77%	79%	80%	81%	83%	84%	86%	87%	89%	90%	91%	93%	94%	96%
70%	76%	77%	78%	79%	80%	82%	83%	84%	85%	87%	88%	89%	90%	91%	93%	94%	95%	96%
75%	80%	81%	82%	83%	84%	85%	86%	87%	88%	89%	90%	91%	92%	93%	94%	95%	96%	97%
80%	84%	84%	85%	86%	87%	88%	89%	89%	90%	91%	92%	93%	93%	94%	95%	96%	97%	98%

Figure 13 implies that relying on solely on voluntary action to close the aspiration gap to 2030 will be challenging. To be clear, voluntary action will provide an important signal to government around willingness to pay and will facilitate investment, but the interaction with state targets will create significant impediments to efficient investment signals and open up serious questions of additionality and greenwashing (for customers making voluntary purchases from projects that are awarded pure CfDs by state governments).

iv. A potential policy solution – utisiling the LRET architecture

The aspiration gap identified by our modelling and shown in Figure 11 could be overcome using the RET policy architecture by simply increasing the mandatory target in each year to achieve a linear growth from current RE levels to 82% in 2030. This would be the simplest and easiest policy solution and would result in a pivot back towards using market-based frameworks (rather than CfDs). Such a policy solution has precedent given that Victoria had developed, and NSW was developing, their own renewables policies in the mid-2000s that were abandoned when the Commonwealth lifted the RET to its current 20% target.

The current RET is based on an absolute GWh target. Given the potential for significant electrification growth, an updated target might need to be flexibly expressed in percentage terms to deliver the 82% target. The Clean Energy Regulator (CER) would be tasked with setting specific GWh targets in each year to provide for the linear delivery of increased VRE between now and 2030 so that 82% VRE by 2030 is achieved. To maintain the integrity of the scheme and keep costs manageable, the CER could allow voluntary action to count towards the 82% target.[9] If optimistic forecasts regarding voluntary demand uptake are correct, the mandatory component's increase may end up being less than anticipated. Given the ESG benefits of '100% green energy', or of offsetting emissions in other sectors, it is credible that there is a tipping point where the incremental cost of closing the gap to 100% renewable energy would be a net financially positive for the economy. Based on Figure 13, an RPP of 65-70% would seem reasonable, particularly if governments were confident that at least 25-30% of voluntary demand would be delivered.

A major advantage of this approach is that it would utilise the existing policy architecture but create a uniform price for abatement delivered through renewable energy production. A higher RPP would also provide confidence that additionality of voluntary action would directly decrease NEM emissions. Other difficult to abate sectors could voluntarily purchase and surrender LGCs to offset emissions. Nelson et al (2022) suggest various options for determining an 'exchange rate' between LGCs and emissions abatement. They argue that, to strike a balance between accuracy with simplicity, using the state or NEM average annual emissions intensity is the most appropriate formula.[10] This uniform price for abatement then allows abatement from the electricity sector to be 'exported' to other sectors for use against other Scope 1 and Scope 3 sectoral emissions.

An extension of the LRET would bring the market closer to the fundamentals of carbon pricing outlined in Section 2. Unlike current state CFD policies, which create separate economic revenue streams for new projects relative to those that already exist, the extended LRET would ensure that all projects benefit from addressing carbon externalities. Considering the legislated 43% emissions reduction target by 2030, any excess electricity emissions will require additional abatement in other sectors at the marginal cost of carbon abatement which must ultimately be paid for by consumers. Based on a price of abatement of $50/tCO2-e and average grid emissions intensities of 0.2 to 0.7, the cost of not extending the RET would be equivalent to $10-$35/MWh on consumer bills. Governments could consider how this avoided cost should be recognised. By establishing an exchange rate between LGCs and carbon emissions as proposed by Nelson et al (2022), a lower overall decarbonisation pathway could be found.

This scheme could also be used to level the playing field for zero emissions generators by including the ~15 TWh of pre-1997 hydro. As noted earlier in this article, these generators would benefit under an emissions trading scheme via an uplift in electricity prices so it may now be appropriate to recognise the value of their zero negative externality production output. This would also allow high renewable energy regions such as Tasmania (which is supplied almost entirely by legacy hydro generators) to certify local load as 100% renewable.

If widespread voluntary action is considered sufficient to deliver 82%, the incremental cost of expanding the mandatory target is likely to be low or zero. Importantly,

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[9] A key advantage of this approach is that government would effectively allow customers with a higher 'willingness to pay' to do more of the abatement task, shielding low-income and hardship customers from some of the costs associated with reducing emissions.

[10] Carbon value = NEM intensity * LGC price.

governments should also consider the impacts of any decarbonisation policies on low-income and vulnerable consumers. Dodd and Nelson (2022) highlight that low-income households may face significant cost impacts because of their above-average consumption and limited access to energy transition technologies due to the split incentive problem (i.e. solar PV, energy efficiency capital upgrades to housing etc). As such, specific energy efficiency and embedded generation and storage policies targeted towards vulnerable consumers should be prioritised.

v. Leveraging state schemes

State schemes could continue to deliver jurisdictional targets, with a focus on technology and location. The RET would close the revenue gap for new renewable energy when compared to depreciated emissions producing existing assets[11]. Simultaneously, state schemes could be utilised to promote specific technology or locational signals. For example, locating in pre-determined Renewable Energy Zones, or driving investment in emerging technologies such as offshore wind.

Nelson et al (2022) note that the simplest and most effective method of overcoming the limitations of government-issued CfDs is for government to write CfD or swaption contracts on the LGC or abatement value rather than the bundled electricity price. With the expansion of a national target, state governments would enter into CfD or swaption contracts, using the LGC as the strike price, effectively becoming the ‘buyer of last resort’ for LGCs.

A key advantage of using this approach is the facilitation of voluntary abatement through the continued use of the LGC framework for state and national RE commitments. Renewable energy projects would be incentivised to find buyers of their abatement (measured through LGC creation) who are willing to pay more than the revenues achievable through government CfDs and swaptions. Utilities would be incentivised to lock in LGC supply rather than risk a shortfall that would need to be covered on a spot market. Any LGCs delivered to state governments could then be made available on the spot market, where they would be purchased to meet the expanded RET obligations.

If amalgamating state-based approaches into a single framework using the RET is politically unachievable, two other options could be considered by governments. Firstly, governments could pivot to voluntarily surrendering all LGCs procured through CfDs or option frameworks. This would reduce the emissions intensity of all consumers. This could reduce the surplus of certificates in the market, and support direct contracting between customers and generators, but would not necessarily drive additional demand beyond the targets.

To increase demand sufficient to meet the 82% target, the Clean Energy Regulator (CER) could be tasked with annually identifying the gap between expected supply of LGCs and the linear trajectory between that year and 2030 (net of the 33 TWh mandatory retailer liability, expected state-based scheme and voluntary surrender)[12].

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[11] This is a very important point that is often misunderstood in the public debate about renewable energy. Solar and wind technologies are the most economic of all new technologies for producing electricity. However, they compete with existing capital and emission intensive assets that are fully depreciated (e.g. coal stations). As such, the RET acts as a means to ensure that the energy transition is achieved at a faster rate than would be achieved via the status quo.

[12] As an equation this would be expressed as: Aspiration gap = Annual target consistent with RE 82% trajectory - Mandatory 33 TWh liability - Expected voluntary surrender (e.g. Green Power) - Expected state-based scheme surrender – Expected supply of LGCs

This gap would then be added to the mandatory surrender obligations of retailers. Careful consideration would be required to assess the additionality of voluntary action under such an approach. Alternatively, the CER could be tasked with conducting a reverse auction for LGCs for the quantity of the projected aspiration gap[13,14]. All certificates produced from these auctions would then be voluntarily surrendered and would be spread pro-rata over energy consumers or allocated to specific sectors (e.g., household consumers) to reduce their emissions without recovering costs through electricity bills.

The proposed policy solutions in this paper to overcoming the aspiration gap would also address the shortcomings of CfDs identified by Simshauser (2019). Projects would not be shielded from electricity market risk and would be incentivised to find customers for their energy. Governments would not be required to assess the long-term viability of different projects across different timeframes, locations and technologies. It would be far simpler to compare projects and minimise the exposure of consumers to ongoing costs.

6. Concluding remarks

This article has demonstrated that there is indeed an aspiration gap between state-based policies in place to achieve the Commonwealth Governments 82% RE commitment. This commitment is necessary for Australia to achieve its international emission reduction obligations. To overcome this aspiration gap, the simplest and most cost effective policy solution is to amalgamate state-based policy approaches into an expanded 82% RET by 2030. This would result in a pivot back towards market-based mechanisms and provide for fungibility with carbon accounting.

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[13] A reverse auction would be consistent with the approach being taken by the Commonwealth Government to incentivse firm capacity through its Capacity Investment Scheme (CIS) – see https://www.energy.gov.au/government-priorities/energy-supply/capacity-investment-scheme for further information. Accessed online on 1 August 2023.

[14] The Commonwealth Government may also wish to level the playing field between all generators and increase the mandatory target by the ~15 TWh of pre-1997 hydro and allow these generators to be eligible. As noted earlier in this article, these generators would benefit under an emissions trading scheme via an uplift in electricity prices so it would be appropriate to recognise the value of their zero negative externality production output.

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