Network Infrastructure Projects Policy Paper: Consultation submission form

This form is to be used to provide feedback on a series of questions included in the Network Infrastructure Projects Policy Paper to help inform the development of the regulations. The Network Infrastructure Projects Policy Paper considers detailed policy options to support Part 5 of the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act).

Please see the Electricity Infrastructure Roadmap webpage for more information.

Consultation questions

You do not need to answer every question. Please answer the questions of interest to you.

Chapter numbers indicate the location of questions in the policy Paper.

Please make your submission by **5pm on Friday 12 November**.

Confidentiality and submissions

Providing submissions is entirely voluntary, is not assessable, and does not in any way include, exclude, advance or diminish any entity from any future procurement or competitive process regarding the Electricity Infrastructure Roadmap, or any other NSW programs.

All submissions will be made publicly available unless the stakeholder advises the Department not to publish all or part of its submission. Authors may elect for some or all of their submission to be kept confidential. If you wish for your submission to remain confidential please clearly state this in your submission.

Your details

Submission type	☐ Individual ☒ Organisation ☐ Other Click or tap here to enter text.
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	☐ Energy retailer ☐ Government or market institution ☐ Individual ☐ Other (please specify) Click or tap here to enter text.

Questions

Questions related to the guiding principles	
Question 1: Do you agree with the proposed guiding principles? Are there additional principles that should be considered?	Yes, we agree with the principles proposed and believe it would be beneficial to consider additional principles such as Enabling Decarbonisation towards achieving net zero, decoupling transmission investments from individual renewable projects to drive down network costs, and promoting a transparent competitive process on a level playing field for all participants to drive best value for customers. A holistic approach to network design where practical can ensure a higher penetration of renewables over a shorter timeframe and accommodate complimentary renewable resources across the sme assets, reduciung the MWh price for participants. These additions are directly linked and compatible, with timely implementation, and Consumer interests which are principles already included. However, 'enabling decarbonisation' could be considered as an overarching principle as this is driving the transformation requirement and should be aligned with ambitious policy decisions. The resulting interests/benefits accrued should take into account not onlty financial ones but also the social and environmental aspects that materialise from a coordinated approach. Regarding the financial aspect of NSW consumers interests, it's critical that the NSW Government embraces competition by opening up market opportunities for network infrastructure projects. Other jurisdictions, such as Great Britain, have progressed with the development of frameworks for competitive tendering of onshore transmission licences, with conservative estimations of the net benefits to consumers of between £300m to £500m, and savings of up to £1.2bn (see reference 1 in the supporting information space). Given the scale of the challenge for facilitating the roll-out of cost effective generation technologies in Australia such as solar and wind, we believe Network infrastructure development and deployment will need 'all hands on deck' to ensure a timely and efficient transition. No one entity is likely to

	have the balance sheet capability of delivering all timely infrastructure within the requisite timeframe. We had the pleasure of attending the webinar on this consultation on 4th November, and were surprised to see that none of the predetermined answers on the eligibility criteria for Networks Operators to carry out a REZ infrastructure project alluded to the intention of allowing new entrants with relevant international experience that could add value to the industry, promoting healthy competition among the already regulated TNSPs, or companies with local experience. We encourage NSW Government to look above and beyond existing available options that can provide benefits to NSW electricity consumers and other stakeholders.
Questions related to the classification of Renewable Energy Zone network infrastructure	
Question 2: What are your views on the proposed approach to defining classes of network infrastructure?	We agree that using already defined asset classes can make the process more familiar to market participants. We assume by including the four definitions that a REZ infrastructure for the purposes of tendering can include a single or combination of classifications as defined in the consultation, and will be deployed appropriately on a case by case basis. If this is the case, consideration should be given to understand the implications e.g. licencing, on successful tenderers, and what are the potential implications of having different categories may have on bidders. Any approach should not limit the interested parties in the process as this has a potential to reduce the competitive benefits. We would also ask that consideration should be given to DCAs as, under certain circumstances, it may be beneficial in delivering them as part of the main infrastructure and reduce interfaces and delays. We assume that system services, critical to the maintaining the overall system stability to which these infrastructures will be connecting, would be included in Class 4. However, this needs to be confirmed. We support that the framework is capable to deliver locational services needs in favour of ensuring a timely implementation of services, avoiding potential delays on fully using the Network Infrastructure, and therefore, access to clean and affordable energy for NSW electricity consumers.
Question 3: Are there any risks to the effective delivery of a REZ	Yes. As indicated in question 2, we believe that not including these necessary system strength or ancillary

if the necessary system strength services are not included as a class of network asset under the EII Act?	services as part of the classes may create miscoordinations in the delivery of the infrastructure and services. This could create potential delays on the connection of the new network infrastructure, and related generation/storage, along with suboptimal performance of the existing infrastructure in the case new projects are connected in advance of the system strength solutions. These assets, if attached to the main infrastructure, can also provide a more cost effective solution to a group of developers rather than relying on individual units across a number of sites and should have financial and performance benefits for all connecting parties. There is a question on how this can be done in coordination with the local TNSP while maintaining the right levels of transparency, confidentiality and level playing field across potential participants.
Question related to the funding and financing of preparatory activities and development works	
Question 4: Does the proposed method appropriately balance the transparency of costs recovered through the Scheme Financial Vehicle against the certainty needed to conduct preparatory activities and development works to deliver timely REZs?	We support the premis that the Infrastructure planner commences pre development works and subsequently recovers these costs from the successful network operator. The advancement of these works will support minimise delays to the ultimate connection of rhe REZ, should aim to minimise disruption to local communitities that might be adversely affected by multiple developers approaching the project with subtly different early concepts and the provision of the information to bidders will help ensure equal access to relevant information and detail to all participants. Other relevant information procered from the TNSP in the pre development phase should also form part of the data provided. In recovering these costs as part of the process, the Infrastructure Planner should be clear on what will be provided. and the stage of maturity of information at the tender stage as well as what the successful bidder would have to undertake and include in their bid submission. We believe it may not be efficient for these costs which transfer to be subject to any efficiency test or present an unknown risk to bidders in order to minimise any risk premiums included within the bid. It may even be prudent that the Infrastructure planner continues to finalise pre development activity even after award to get the project to an agreed stage, particularly with respect to land rights. We would also like to point out that the Infrastructure Planner should be rightly resourced to effectively

	undertake preparatory activities. As a new formed entity, EnergyCo should be facilitated with the right level of resources and expertise in order to avoid potential risks being carried out for the project at different stages that may need to be assumed/absorb by the Network Operators participating in a competitive contestable process.
Question related to the funding and financing of preparatory activities and development works	
Question 5: What information relating to network options do Long-Term Energy Service Agreement and access right tender participants require to provide sufficient certainty and confidence to participate in the bid processes?	The availability and timing of new network connections will be critical parameters for investors when evaluating potential development sites. Given typical development timeframes, certainty around planned network will be important for ensuring a pipeline of projects for each REZ. Participants in the bid process at a minimum would require: - Preferred network option and certainty of progression, and any parameters still subject to uncertainty - Target capacity to be connected in the REZ, and any access rights frameworks to apply (including whether rights are for a specific project, a MW access, etc.) - Total transfer capacity in MW - Defined Route and connection date - Potential range of connection charges, including system strength charging framework - Certainty on progression towards final authorisation (likelihood of proceeding). A critical parameter will be around the risk connection delays, and what exposure the project will take. Connection delays have been a significant source of uncertainty and additional costs to generation projects elsewhere in the network; reducing this risk (physically or financially) for projects will increase the attractiveness of the REZ.We encourage that considerations are given to find a balanced risk allocation approach across relevant stakeholders for delivering Network infrastructure projects. More generally, we strongly urge the NSW Government to not exclusively tie LTESAs with the new REZ development. Projects outside of a REZ may be valuable for NSW, and have been well served by the

	open access framework to date. That is, we should seek to increase the attractiveness of REZs rather than penalise those elsewhere on the network. Finally, we urge the NSW Government to write LTESAs on the environmental credit (i.e. LGC) rather than the electricity price. This will minimise the risk to consumers and force projects to participate in the electricity market and manage the spatial and temporal risks associated with electricity supply. Attached is a paper that was recently published in the Australian Journal of Agricultural and Resource Economics that provides a superior model for LTESA design.
Question 6: What eligibility criteria should apply for Network Operators that may be authorised to carry out a REZ network infrastructure project?	Having competent organisations delivering these large infrastructure projects is key to ensure a good experience for all stakeholders and therefore, having the right technical and financial capabilities are key in de-risking the delivery and operation of the asset throughout its lifetime. To this end, and to promote effective competition, it's important to allow for new market entrants with relevant international experience in delivering transmission infrastructure to be afforded the opportunity to compete in any future tenders. Financiability is also key criteria to consider when carrying out a project such as REZ network infrastructure project. Network Operators should be able to have a robust finance capability to commit with such profile of projects. Iberdrola Network Development business (part of Iberdrola Group) has relevant experience financing and operating a number of transmission concessions across Europe and the Americas, where the business is well used to developing, financing, constructing and owning projects in the multi-billion AUD range. It's critical for the interests of NSW consumers to allow for broader competition above and beyond local TNSPs and/or Network Infrastructure providers. Furthermore, ringfencing considerations could be considered in order to build investor's confidence in the framework, and potential contestability processes, which is necessary for attracting a degree of participation required for hosting healthy competitive tenders.

Question 7: What factors should be considered by the Consumer Trustee in recommending that the Minister direct, and by the Minister in directing, a Network Operator to carry out a REZ network infrastructure project under the EII Act?	Some of the main factors to be considered either are (particularly for contestable processes): - That the successful bidder is capable of satisfying the conditions necessary to be licenced as a TNSP. - Has the resources and approach necessary to deliver the project in line with the plans and key dates submitted within the bid documents. - Is capable of delivering the desired specification in a safe manner using certificated partners and constractors. - Is able to warranty the safe operation of the asset during its operational lifetime - Has well thoughtout and executable environmental and stakeholder engagement plans with a local presence to communicate and deal with issues in an effective manner. - The bid offers the best value to NSW customers
Questions related to the Transmission Efficiency Test and the Regulator's determination	
Question 8: How can consumer and stakeholder input be considered in the TET and revenue determination processes?	As a general point a TET is generally required when there is no real competitive comparison to provide against market test and to guage efficiency. With a properly thought out competitive process, there should be enough evidence available to assume efficiency of the winning bid ,and therefore, remove the need for a TET, or at least limit to only those elements that are not fixed at the award stage. It is important for investors' confidence that the process is transparent and accessible. Without compromising some of the commercially sensitive items in tender documents, it should be expected that the final annual allowace should be published including as much other information as possible on the differetials to unsuccessful bidders. This could also be covered by clear rules on the process for selection of the winner and any criteria for differentiating the same. In some countries, the system use is for operator data to set a maximum price for the infrastructure which can provide a benchmark aligned with the normal regulatory process. Whilst never completely accurate, it can provide a guage on the competitiveness of the bidding process. Consumer and stakeholder engagement may well be required via public consultation and other public events such as forums, roundtables, webinars, etc.

	With any commercially sensitive process, it may not always be possible to provide the level of detail necessary to satisfy all stakeholders, so consideration could be given to allowing officers of key stakeholder groups to witness certain parts of the final process, or be bold and make final determinations available on line.
Question 9: Is clarification required with regard to the principles to be taken into account by the Regulator and the Objects of the Act, and are there any additional principles that should be considered by the Regulator?	We believe there should be clear differentiation, and therefore, clarification regarding contestable vs non-contestable approaches to deliver Network Infrastructure, and how these would be considered by the Regulator and the Objects of the Act.
Question 10: What views do you have on these elements and is there any other guidance that should be included in the TET Guidelines to be developed by the Regulator?	In line with the initial answer to 8 above, we think any TET should be limited only to elements of the bid that are not fixed at time of award. We think its essential that tenders have detail on how's proposed elements for the Guidelines would apply on contestable processes and ay implications that may spill over from non-contestable elements.
Question 11: Should financeability concerns be addressed in the NSW framework?	Yes, financiability concerns should be addressed within the framework but without compromising the ability for NSW Government to increase competition, opening the market for designing, developing and building Network Infrastructure through contestable processes in benefit of NSW consumers. Its also worth considering the financing structure of bidders including fixing gearing, actual debt costs, amoritisation and asset depreciation principles as well as treatment of refinancing etc.
Question 12: What views do you have on these elements and is there any other guidance that should be included in the Guidelines regarding the revenue determination to be developed by the Regulator?	We would like detail on how's proposed elements for the Guidelines would apply on contestable processes and, how these compare with non-contestable ones.
Question 13: Are there any elements of the AER's approach to assessing and setting regulated revenue requirements which should be modified or added to when considering the	These contestable assets will be market tested as part of the process which is different from a regulated asset base of multiple network assets of varying ages and conditions. In running the competitive process, we expect the lowest lifetime costs to be achieved where more certainty is given and would advocate that the revenue determination is in place for a period of no less than 25 years, and not subject to 5 year reviews. This

framework that will be applied under the EII Act in NSW?	will remove uncertainty for both parties on outcomes every five years, allow finance to be secured for the duration of the project, and remove risk premiums in the bid. This works well in other countries and delivers value for customers, and it's also being proposed framework design in Great Britain by National Grid ESO, and Ofgem, were they are minded-to 45 years cap for the Tender Revenue Stream [See Reference 3 and 4] One other thing to consider under this model is what happens at the end of the revenue period, and how the asset will be considered: should it be considered like a normal regulated asset attracting investment to extend life, or will it be decommissioned or retrned to incumbent TNSP. Form our perspective, and to ensure optimal servce thoughout its life, we would favour the first approach with a mechanism to recognise refurbishment expenditure toward the end of its contracted life under normal AER approach. We would also like detail on how the AER propose to approach the assessing and setting of regulated revenues in the case of contestable processes.
Question 14: What do you think about an incentive scheme to ensure the availability of projects and the timely connection of generators to a REZ by Network Operators? How could that be designed?	We agree that incentives should be included in the framework as long as they drive the right outcomes for consumers and operators. We also believe that an innovation incentive could be considered to ensure the promotion and implementation of new innovative approaches that can be cost-effective and provide value to NSW customers. However, we believe these incentives, and potential penalisations, should be subject to a cap in order to provide limits to the risk applied by Network Operators at the time of the tendering (contestable process). The design process of these incentives could be inspired from relevant jurisdictions such as Great Britain, where Ofgem includes Timely connections incentives into the price control determination of incumbent Transmission Operators through Output Delivery Incentive Financial (ODI-F). See reference 5 for more info, We would welcome more information about how customers would apply for connections and how the connection process/framework would need to work within REZs, including responsibilities in coordination with incumbent Network Operator. Addressing customers connections within contestable processes should not be underestimated within the proposed

	framework, as coordination and interactions between relevant parties could add a significant level of complexity, specially if the number of customers connecting to the infrastructure is not clearly known at the time of the contestable procuring process.
Questions related to reviewing a revenue determination	
Question 15: Do you agree there should be limited circumstances in which the Consumer Trustee directs the Regulator to review and remake a revenue determination outside of the five-yearly cycle?	Any changes to revenue determinations on contestable processes provide for uncertainty and should be limited to extreme events that both parties consider worthy of review. Any additional risk to lifetime revenues positive or negative can either increase risk or provide opportunity for gaming of the process and distortion of the bids.
Question 16: Do you agree with the proposed circumstances that the Regulator may adjust a revenue determination during the five-yearly cycle?	We agree these are sensible events that can be catered for at the time, and should not affect the tendering process but these can occur whether in a 5 year cycle or in a 25 year agreement.
Question 17: Is there a need to clarify the process for transitioning of assets between the NSW and national frameworks?	We believe the NSW's framework should minimise unintended consequences such as the risk of being utilised as indirect funding to 'business-as-usual' Network Infrastructure which is funded via regulated arrangements, particularly in the case of potential contestable processes. This could create unintended disadvantages to new entrants that may not have a pre-established strategic interest, and synergies, on the proprosed projects within the EII Act framework.
Question 18: Is there a need to clarify the circumstances by which a transfer of network infrastructure from a Network Operator to another person may occur under the EII Act?	Yes, further clarity on when or how these cirmcumstances will be allowed would be welcomed. We believe the framework under EII Act should encourage for contestable tender participants to have a long-term role to play in the development of Transmission infrastructure in NSW. Reducing the possibility of having unintended consequences, such as players having speculative approaches while tendering for then looking for early transfer, should be a must for building investor's confidence.

Supporting information

If you have additional information you would like to provide to support your views, please provide it here.	Reference 1. BEIS Extending competitive tendering in the GB electricity network: Impact Assessment template (publishing.service.gov.uk)

If you have additional documents to provide to support your views, please email it with your submission.	Reference 2. Attached paper recently published in the Australian Journal of Agricultural and Resource Economics that provides a superior model for LTESA design: 'What's next for the Renewable Energy Target – resolving Australia's integration of energy and climate change policy?'. Reference 3. NGESO Early Competition Plan April 2021 download (nationalgrideso.com) Reference 4. Consultation on Ofgem's views on Early Competition in onshore electricity transmission networks Early_comp_August_2021_Final (1).pdf Reference 5. RIIO-2 Final Determinations Electricity Transmission System Annex RIIO-2 Final Determinations Electricity Transmission System Annex (REVISED) (ofgem.gov.uk)

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- the Clean Energy Finance Corporation or the Australian Renewable Energy Agency or distribution network service providers
- the entities appointed or to be appointed under the EII Act (Consumer Trustee, Financial Trustee, Scheme Financial Vehicle and Regulator).

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- the Australian Energy Market Operator, Energy Security Board, Australian Energy Market Commission, Australian Energy Regulator, Independent Pricing and Regulatory Tribunal or the Australian Competition and Consumer Commission
- the Clean Energy Finance Corporation or the Australian Renewable Energy Agency or distribution network service providers

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The Australian Journal of
Agricultural and Resource Economics

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AUSTRALASIAN AGRICULTURAL & RESOURCE ECONOMICS SOCIETY

Australian Journal of Agricultural and Resource Economics, 59, pp. 1–28

What's next for the Renewable Energy Target – resolving Australia's integration of energy and climate change policy?*

Tim Nelson, Tahlia Nolan and Joel Gilmore†

Australian climate change policy and its integration with Australia's electricity markets have been fraught for at least two decades. The only enduring policy has been the Commonwealth Renewable Energy Target (RET). Despite the relative success of the RET in driving investment and reducing emissions, state governments have now pivoted towards contracts-for-difference (Cfds). In this article, we outline the issues associated with policy discontinuity and the large-scale RET and review its effectiveness as an emissions reduction tool and driver of electricity sector abatement. We find that the RET has been relatively successful across the key criteria of cost and emissions reductions and is a better policy instrument than contracts-for-difference, which are increasingly being adopted by state governments. Building on the work of Nelson et al. (2020), we propose a new approach, which would allow for continued use of Cfds but utilising the RET's policy architecture.

Key words: electricity market, production subsidy, variable renewable energy.

1. Introduction

Australia has had a haphazard approach to integration of climate change and energy policy for decades. This is despite Australia having committed to reducing greenhouse gas emissions in a manner consistent with a carbon budget that would limit anthropogenic climate change to no more than two degree Celsius. The implied carbon budget for Australia to meet this commitment is a 50% reduction on 2005 emission levels by 2030 (Meinshausen et al., 2021) and achieving a 1.5 degrees outcome (which is an aspirational goal of all governments through the United Nations Convention on Climate Change: UNFCCC) would require a 75% reduction. It is worth noting that this is significantly greater than the current Commonwealth Government target of 26–28% by 2030. It can therefore be inferred that greater emission reduction targets in the future are likely, with international

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doi: 10.1111/1467-8489.12457

pressure likely to 'ratchet up' commitments by the Australian Government, for the emissions reduction target through to 2030 and/or for emissions reduction targets for the post-2030 period.

At the national level, only two policies have materially reduced emissions within the electricity sector: the Clean Energy Future (carbon pricing) package, which was introduced on 1 July 2012 but then repealed on 1 July 2014; and the Renewable Energy Target. At the state level, several policies were utilised prior to the Clean Energy Future package superseding them. These included the NSW Greenhouse Gas Abatement Scheme (GGAS) and the Queensland 13% (and subsequently 18%) Gas Scheme. Importantly, governments have tried and failed to agree on a national approach to an emissions intensity scheme through the National Energy Guarantee (Simshauser & Tiernan, 2019).

The Renewable Energy Target is a renewable certificate obligation (ROC) or renewable portfolio standard (RPS) style policy. Energy retailers must buy a set percentage (currently 20%) of their energy from renewable generators.[1] This is achieved by new renewable projects selling certificates (called large-scale generation certificates, or LGCs) for each unit of production to retailers. This results in new investment in wind, solar and other green technologies. Policies utilising a ROC-style framework have been well studied in markets in Europe and Australia (see Foxson & Pearson, 2007; Nelson, 2015; Wood & Dow, 2010, 2011; Woodman & Mitchell, 2011). Sioshansi (2021, p.3) notes that, 'renewable portfolio standards have long been favoured in the United States – as opposed to Feed-in-tariffs or other instruments popular in Europe'.

Despite the enduring success of the RET as Australia's only long-term emissions reduction policy for the electricity sector, the lack of a comprehensive national policy approach to reducing emissions has seen state governments continue to implement suboptimal contract-for-difference (Cfd) style policies (Nelson & Gilmore, 2021). A Cfd is effectively an agreement for the government to make up the difference between the market price for electricity and the price agreed to between the renewable generator and the government. The Victorian Government has utilised Cfd structures to support new VRE investment through its VRET policy which is aimed at achieving 50% renewable energy by 2030. This has been legislated in the *Renewable Energy (Jobs and Investment) Act 2017* (Vic). The ACT has similarly utilised Cfd structures to achieve its goal of 100% of the territory's energy being sourced from renewables. Table 1 provides a breakdown of investment in renewables by scheme driver.

As shown in Table 1, Cfds have comparatively driven only a small percentage of renewable energy investment with the vast majority of

[1] While the RET includes both the Small-Scale Renewable Energy Scheme (SRES) and the Large-Scale Renewable Energy Target (LRET), this article utilises the RET acronym to refer to only the LRET component of the policy.

Table 1 VRE investment by policy driver

Policy	Total MW underwritten by policy as at June 2021
RET – LRET	16,007 MW
RET – SRES	14,133 MW
VRET	950 MW†
ACT Auction	Up to 650 MW
QLD 50%	933 MW

†669MW was contracted under VRET auction. An additional 259MW of capacity was added by generators because of government underwriting. ~255MW of solar (3 projects), and ~675MW of wind (3 projects).Source: Compiled from Clean Energy Regulator data.

Australian renewable energy projects banked under the RET (Simshauser & Gilmore, 2020). However, the NSW Government has now legislated one of the world's most ambitious policies through the NSW Energy Roadmap. Under the *Electricity Infrastructure Investment Act 2020*, the NSW Government has committed to using 'swaptions' or long-term energy service agreements (LTSEAs) to underpin 12 GW of new renewable generation across three new Renewable Energy Zones (REZs).[2] 'Swaptions' are contracts where the seller has an option to take up a Cfd at some point in the future. The plan also involves the use of an underwriting mechanism to deliver ~2 GW of new firming capacity such as battery storage or pumped hydro. It is therefore a critical policy juncture point to assess whether the RET in a moderated form or Cfds are a superior policy choice to drive renewable investment and reduce greenhouse gas emissions.

The NSW Government is responding to market forecasts that over the next 20 years Australia's ageing baseload coal fleet will be progressively replaced by 30–45 GW of additional utility scale renewable energy capacity (AEMO ISP, 2020, p. 12). It is anticipated that this renewable growth will be facilitated by the parallel development of 15–20 GW of flexible, dispatchable, fast-start firming capacity. Given the high expected levels of variable renewable energy (VRE) penetration, around half of this firming capacity is likely to be 'medium' and 'deep' energy storage (+4hrs). Technologies likely to be deployed include pumped storage hydro, long-duration battery storage and potentially hydrogen fuel cells or turbines.

Given the shortcomings of Cfd style policies being adopted by state governments are well known (see Simshauser, 2019), it is unclear why policymakers have pivoted away from ROC/RPS policies towards Cfds.[3] The purpose of this paper is to evaluate the effectiveness of the RET in this context and consider how it could be utilised in the future as part of Australia's policy architecture to reduce emissions cost effectively within the

[2] For contrast, peak demand in the entire NSW region is only ~14 GW.
[3] The existing RET legislation may in fact override the ability of states to create their own certificated schemes, although this has never been tested by Australian courts.

electricity sector. Section 2 provides a brief literature review of analysis of Australian and international renewable energy stimulus and greenhouse abatement policies. Section 3 presents simple quantitative analysis of the RET across the twin objectives of efficient design and emissions reduction. RET policy design adjustments, based upon quantitative analysis of marginal and average abatement, are presented in Section 4 with concluding remarks following in Section 5.

2. Literature review

The existing literature is heavily skewed towards analysing the use of a broad-based carbon price to reflect the externality cost of producing greenhouse gas emissions. It is almost universally agreed that a well-designed carbon pricing mechanism would be a superior policy choice for reducing emissions (Freebairn, 2020). Studies examining national and international greenhouse gas emissions pricing include the following: Freebairn (2012, 2014a, 2014b, 2018); Garnaut (2011, 2014, 2015); Holden and Dixon (2018); Quiggin et al. (2014); Wood and Blowers (2016); Naughten (2013); The Climate Institute (2013); Kember et al. (2013); and Clarke (2011). Many of these studies are quantitative in nature and conclusions have been built upon through the use of Computable General Equilibrium (CGE) modelling. These include Adams (2007), Adams and Parmenter (2013), Adams et al. (2014) and Meng et al. (2013). In particular, McKibbin, Wilcoxen and their colleagues have published multiple studies since the 1990s (see, e.g., McKibbin et al., 2009, 2012, 2014; McKibbin & Wilcoxen, 2002a, 2002b; Pearce & McKibbin, 2007).[4]

However, although the theoretical and applied literature demonstrating a well-designed emissions trading scheme should be adopted, most of the political debate is fixed on the future of coal and gas within the real economy in Australia. Sadly, this completely misrepresents the real risks to the Australian economy (Nelson, 2015). Australia is one of the world's largest energy exporters. Coal (14.8%) and gas (10.6%) comprise around one-quarter of Australian exports. Australia is the largest exporter of coal with around 30% of all total coal exports and has recently overtaken Qatar as the world's largest exporter of LNG. In this context, it matters little what Australian politicians think the future of gas and coal looks like. What matters are the views of Australia's largest energy trading importers such as Japan, Taiwan, China and Korea. All of these countries have committed to net zero and are shifting consumption away from Australia's fossil fuel exports. The sad outworking of this situation is that, 'According to the 2020

[4] Both McKibbin (in general) and Nelson (2015) make the point that mitigation impacts on Australia are likely to be mostly incurred through other countries shifting their energy mix away from coal and gas, two large sources of export revenue.

Climate Change Performance Index, Australia was ranked as the worst-performing country on climate change policy (Ali et al., 2020)'.

2.1 The cost of uncertainty and the 'merit-order effect'

Given the fraught political debate about the future of coal and gas in the Australian economy, there has been ongoing policy discontinuity in relation to energy and climate change (see Simshauser & Tiernan, 2019). The costs of this ongoing policy uncertainty have been well documented in the Australian literature (see Byrnes et al., 2013; Jones, 2010, 2014; Nelson, 2015; Nelson et al., 2010, 2012). Many of these studies note that in a capital-intensive industry such as electricity, a lack of certainty in relation to public policy results in suboptimal capital investment (including the potential for stranded asset risk in higher capacity factor gas plant). Over time, this manifests in higher than necessary electricity costs driven by a higher weighted average cost of capital (WACC) and an industry preference to minimise capital at risk by deploying higher operating cost technologies (see Nelson et al, 2010; Nelson et al, 2013).

Simshauser and Gilmore (2020) provide a very useful overview of the 'rate of change' problem whereby significant additional costs have been imposed on the Australian economy due to Australia's policy incoherence. Ongoing policy changes resulted in an 'investment megacycle' whereby ~12,000MW of plant commitments comprising $20+ billion across 105 projects was squeezed into just three years (2017–2020).[5] Unsurprisingly, there were significant connection delays and major issues with system frequency operating outside normal bands, critical reductions in system strength and increasing interventions by the market operator to keep the system secure. Instead of focusing on these important engineering issues, the policy debate shifted towards market redesign proposals with a focus on future reliability and resource adequacy. Sadly, very little of the debate was grounded in an understanding of the problem (see Nelson et al., 2018).

2.2 Renewable energy certificate schemes

The main limitation of mechanisms such as the RET is that they are not technology neutral. While they are a better policy design than general subsidies, they overlook opportunities for abatement (e.g. energy efficiency) because of their focus on new investment in production capacity (Freebairn, 2018). While mechanisms that subsidise new investment can lower wholesale electricity prices in the short run (assuming the absence of existing generator retirements) (Bell et al., 2017), the policy can have the perverse effect of stimulating electricity consumption beyond efficient levels (Freebairn, 2018). Critically, the 'merit-order effect' of lower prices is temporary. Wholesale

[5] For contrast, the NEM's entire capacity is ~50 GW.

prices will rise to the long-run average cost (LRAC) of the efficient new generation mix (see Nelson et al., 2018)[6]. Importantly, quantitative modelling has demonstrated that LRET style mechanisms have higher abatement costs than well-designed emissions tax and trading mechanisms (Buckman & Diesendorf, 2010). In short, most of the literature around LRET style policies finds that they are inferior to a well-designed emissions trading scheme (see Nelson et al., 2019).

There are also significant benefits associated with ROC-style policies such as the LRET. In the Australian context, the LRET has resulted in significant additional investment, particularly in new wind generation (Cludius et al., 2014). Bell et al. (2017) found that the LRET has lowered wholesale spot prices through reductions in technology costs. Rather than the overarching policy mechanism, design flaws of LRET in its implementation in a market with significant retail and generator concentration may have contributed to suboptimal outcomes (see, e.g., Buckman & Diesendorf, 2010; Simshauser & Tiernan, 2019). Furthermore, the ongoing review and amendment of the LRET and continuing disagreement between the Commonwealth and state governments is likely to have had a detrimental impact on its cost-effectiveness (see Jones, 2010, 2014).

2.3 Contracts-for-difference schemes

Government-initiated Cfds are relatively simple in structure.[7] Governments hold reverse auctions for capacity and award Cfds to the winning proponents of new generation. The Cfd structure generally involves a 'strike price', which is compared to the wholesale spot price in each settlement period. Where the wholesale price is lower than the strike price, the government pays the proponent the difference. If the wholesale price is higher than the strike price, the generator pays the government the difference.

While it is true that CfDs may reduce risks to individual project proponents from a LRET floating LGC price (Woodman & Mitchell, 2011), Bunn and Yusupov (2015) demonstrate that with negative correlation between renewable output and wholesale electricity prices, LGCs reduce counterparty investment risk when compared to Cfds or feed-in tariffs (FiTs).

There are obvious problems with utilising Cfds. Governments effectively 'become the market' and determine which generator investments proceed. While governments have learned important lessons from previous failures to deal with marginal loss factor (MLF) risk and prolonged oversupply and negative pricing, their continued use will effectively result in governments (rather than markets) absorbing all of the risk of poor investment decisions.

[6] A reviewer of this manuscript helpfully noted that this LRAC may in fact be lower than that of the previous efficient mix due to the introduction of new lower cost of technologies.
[7] A reviewer of an early draft of this manuscript helpfully noted that the discussion around Cfds in this Section is specific to government-initiated Cfds, not Cfds in general.

Electricity markets are incredibly dynamic and investments need to consider not just the Levelised Cost of Electricity (LCOE) but the spatial and temporal dynamics of market pricing. Building very low-cost generators with very high renewable resources in congested and weak parts of the grid has resulted in very poor outcomes in Victoria's north-west (see Simshauser & Gilmore, 2020). Furthermore, it is naïve to assume governments are well placed to decide which investments are likely to be economic due to the need to assess a project's production against a dynamic market with significant changes in demand across the day and season. In fact, one of the strengths of utilising a market approach rather than a Cfd is that poor investments result in the project proponent (rather than the government) writing down their investment with consumers benefiting.

Simshauser (2019) notes that there are three inherent limitations associated with Cfds:

- Government-initiated CfDs are usually awarded on simplified metrics such as minimising the LCOE. As noted above, ignoring temporal and spatial dynamics is likely to introduce inefficient plant entry. In contrast, well-designed renewable portfolio standards such as the LRET require investors in generation to determine not just costs but the spatial and temporal dynamics of the project relative to the market.
- Importantly, Cfds introduce a new category of 'quasi-market' participant that is completely removed from the market's locational, spot and forward pricing signals. Over time, this results in suboptimal decision making within the dispatch of energy and increases the risks to secure and reliable system operation.
- The use of Cfds results in these new 'quasi-market' participants withdrawing from primary issuance forward derivative hedge markets. Given the certainty of revenue due to the Cfd, there is little incentive for these new generators to manage price risk using financial derivative contracts. Over time, the government effectively becomes the market. Efficient pricing, retail competition and innovation are likely to be stifled as new participants are unable to compete.

One of the overlooked aspects of Cfds in the Australian context is the impact of shifting policy support to an alternative mechanism despite the significant investment made to date under a long-term enduring policy. The RET has delivered over 16 GW of new investment, which is underpinned by the market value of wholesale electricity prices and LGCs. By shifting towards Cfds, governments are effectively stranding investments and effectively transferring existing renewable proponent producer surplus to consumer surplus and new entrants with the potential for issues related to refinancing and 'toxic debt' (see Nelson et al., 2013; Simshauser & Nelson, 2012). Our analysis and policy recommendations in subsequent sections consider ways in which Cfds could be modified to minimise these impacts.

Advocates of Cfds generally use two arguments that are flawed in our opinion: reductions in the weighted average cost of capital; and the 'merit-order effect'. Given the significant exposure of existing debt and equity participants to the 16 GW of projects already built under the RET (with much of it being refinanced in 2022 and 2023), project proponents will likely face higher WACCs as a result of the erosion in value of their projects due to the switch from one form of policy support (RET) to another (Cfds) – see Simshauser and Gilmore (2020) for further analysis on this topic.

The 'merit-order effect' has been promoted as a reason for introducing both ROC and Cfd style policies. The phenomenon is well documented in the academic literature, with studies originating from around 2008. The earliest studies focused on economic impacts of introducing very low short-run marginal cost technologies such as variable renewables (Gelabert et al., 2011; Pirnia et al., 2011; Pöyry for the European Wind Energy Association, 2009; Sensfuss et al., 2008). Australian studies have also examined the phenomenon. Many studies have considered the impacts on the NEM price duration curve (see Bell et al., 2017; Cludius et al., 2014; Forrest & MacGill, 2013; MacGill, 2010) and the impact of coincident production on specific price bands.

However, as Nelson et al. (2012) and Simshauser (2019) note, the merit-order effect is a transitory phenomenon. Prices must return to levels that allow for fixed and operating costs to be recovered or plant is permanently withdrawn, resulting in significant intra- and interperiod pricing volatility (see Nelson et al., 2018). This is an important observation given one of the purported benefits of the NSW Energy Roadmap is permanently lower wholesale electricity prices.[8]

2.4 Emerging literature on policy evolution

A defining feature of good public policy is the creation of a uniform value of abatement. This allows for the lowest cost abatement to be pursued first (Freebairn, 2020). It is therefore worth considering whether the RET can be 'evolved' to better align with this principle by creating fungibility with other forms of abatement in Australia such as Australian Carbon Credit Units (ACCUs). This is something that was explored by Nelson et al. (2021) who proposed tying economic value from ROC, Cfd or PFiT policies to either emissions intensity or wholesale electricity prices.

Our analysis in the proceeding sections considers this issue. In particular, we find that the worst impacts of Cfd can be overcome if they are written against the LGC (rather than the wholesale price). This ensures that market

[8] It is important to note the two distinct pricing outcomes. One is the result of shifting to a lower cost mix of new technologies. The other is driven by government-induced oversupply with a transfer of existing producer surplus (including existing clean energy generation) to consumer surplus.

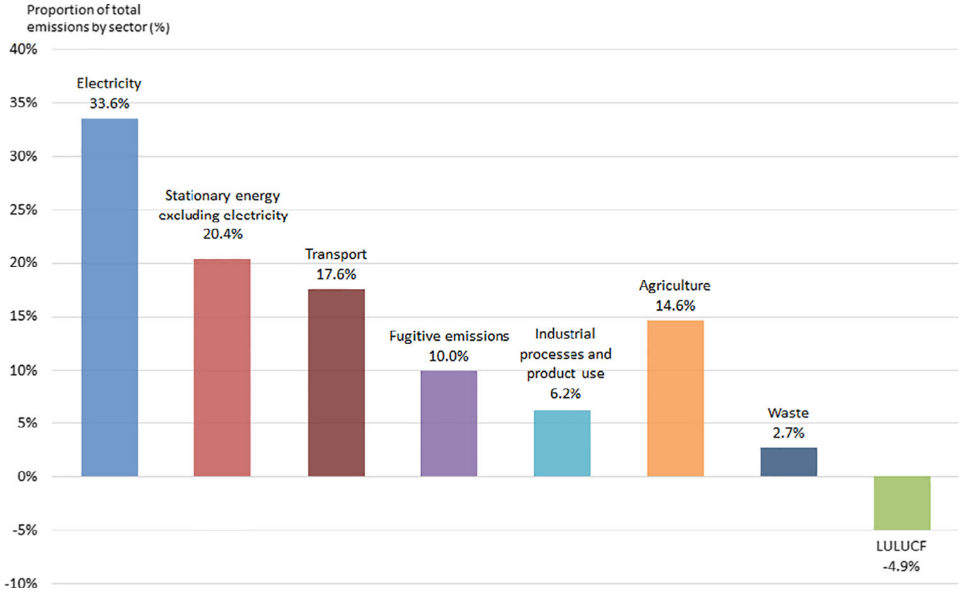

Figure 1 Australian greenhouse gas emissions by sector. Source: Australian Greenhouse Accounts.

participants continue to face the spatial and temporal dynamics associated with locating and operating in the NEM. This can also allow for integration of Cfd policies within a broader carbon framework due to the assignment of carbon abatement to LGCs through an emissions 'exchange rate'.

3. Assessment of the RET against multifaceted criteria

In this section, we evaluate the RET against qualitative and quantitative criteria: emissions abatement; and price and cost-effectiveness. The purpose of our analysis is to determine whether the RET has been successful as a means of providing a sustainable framework for cost-effective emissions reductions within the electricity sector.

3.1 Emissions abatement

Australia currently produces around 500 million tonnes (mt) of greenhouse emissions (carbon dioxide equivalent: CO_2e) each year. The sectoral breakdown of emissions is shown in Figure 1 below.

Figure 1 shows that the stationary energy sector (including electricity) produces around half of all greenhouse emissions. Electricity is the largest single point source of emissions with around one-third of total Australian emissions. However, it is also a relatively low-cost source of abatement with the potential for further technology evolution and deployment into other sectors through electrification (e.g. transport and stationary energy

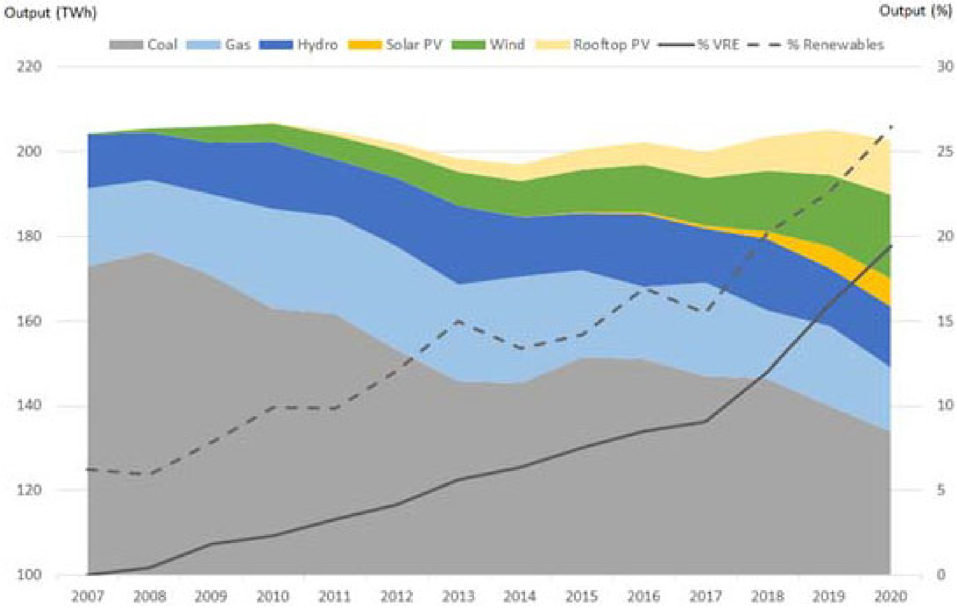

Figure 2 NEM output by technology. Source: opennem.org

processes). Given these dynamics, it is not surprising that the electricity sector has been the focus of policy makers through the RET and now emerging Cfd policies in the ACT, Victoria and NSW.

Figure 2 shows the impact of electricity sector policies on generation output in the NEM over the past decade. As uncertainty around the investment trajectory required by the RET was removed following the Warburton Review in 2014 (see Nelson, 2015), an investment megacycle occurred between 2017 and 2020 (recall Table 1). The share of variable renewables (VRE) climbed rapidly to around 20% in 2020. Almost all this investment utilised LGCs as part of project economics and financing.

Figure 3 shows the strong correlation between the penetration of VRE and electricity sector emissions in recent years. As new renewables have entered the system, existing and ageing coal assets have been retired. In fact, around one-third of Australia's coal-fired power stations closed in the 2010s as a consequence of renewables entering the system (Burke et al., 2018). The substitution of these relatively high emitting assets with renewables has reduced NEM emissions by around 15%. Importantly, the contribution of electricity sectoral emission reductions to the overall Australian inventory has been significant. This is shown in Figure 4.

Figure 4 demonstrates that the RET is likely to have done much of the heavy lifting in relation to Australian emissions reductions. Quarterly total emissions have decreased from ~145mt in 2010 to around ~125mt in 2020. Of this ~20mt reduction in quarterly emissions, the electricity sector has

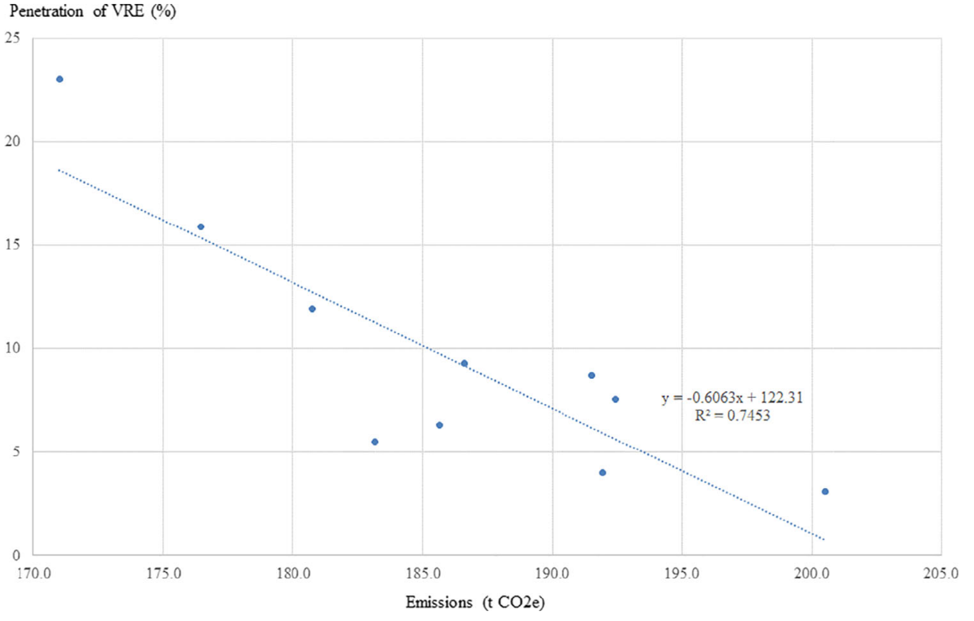

Figure 3 Correlation between penetration of VRE and electricity emissions. Source: Produced using data from opennem.org and Australian Greenhouse Accounts.

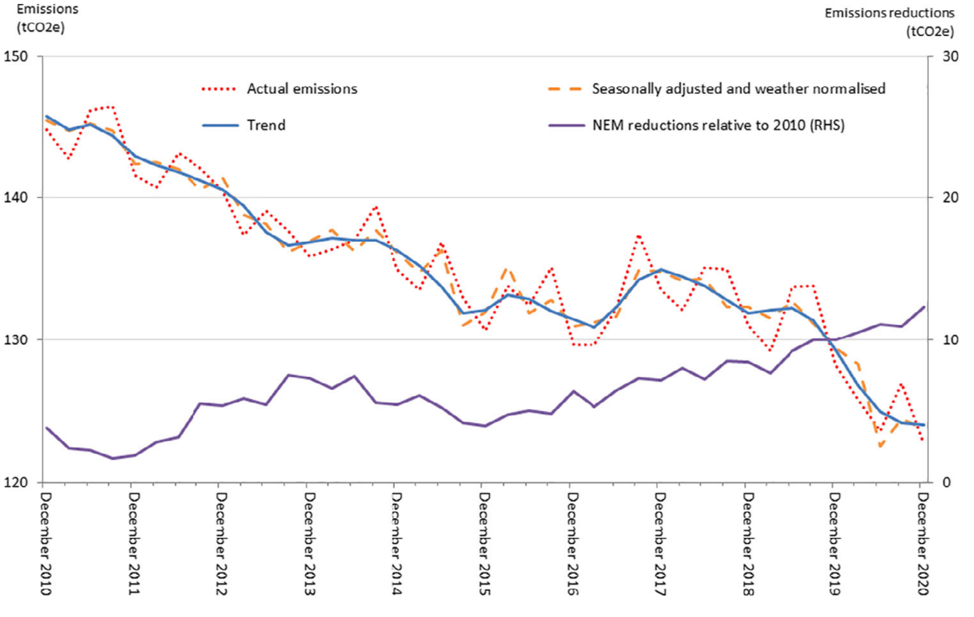

Figure 4 Quarterly Australia-wide emissions trends and NEM emission reductions. Source: Produced using data from Australian Greenhouse Accounts.

delivered around 60% or ~12mt per quarter. This is a nontrivial finding. Of all the policies introduced to reduce emissions (QLD 18% Gas Scheme, NSW GGAS, Clean Energy Future, Emission Reduction Fund and Safeguard Mechanism), a single policy is arguably delivering the majority of the emissions reductions that are being sustainably achieved (as noted in Figure 3 and supported by Nelson et al., 2018 and Simshauser, 2019).[9] As a policy instrument, the RET has been very successful in reducing emissions. It is continuing to provide the underlying policy architecture for additional reductions through voluntary purchases by corporate customers and households (via GreenPower).[10]

3.2 Pricing and economic effectiveness

Electricity pricing has been a politically charged topic in Australia following the closure of the Hazelwood power station and a rapid run up in wholesale electricity prices in 2017 and 2018. Since 2011, the general Consumer Price Index (CPI) rose by around 2% pa, while the electricity component of the CPI rose by around 3.5% pa. Much of this is explained by inefficient increases in network spending and a rise in new entrant costs for wholesale markets. Simshauser and Gilmore (2020) note that the NEM's history of new entrant cost is comprised of three separate and distinct time periods. Up until 2011, the NEM was characterised by new entrant costs of between $40/MWh and $60/MWh with the dominant technology shifting from coal to gas in the mid-2000s. Between 2011and 2015, the NEM new entrant cost increased further to between $60-80/MWh for a combined cycle gas turbine (CCGT) as higher gas prices manifested because of east-coast gas demand tripling due to the emergence of LNG exports. Since 2015, the new entrant cost has approximated $70–80/MWh as firmed wind has emerged as the technology of choice.[11,12]

It should be noted that the upward trend in new entrant cost is not simply a function of the RET. Input fuel costs for thermal plant have increased significantly over the past decade as both coal and gas markets became increasingly export exposed. In the case of coal, $AUD pricing increased

[9] While the RET has significantly reduced emissions, it is unclear how much higher emissions would have been without energy efficiency measures that have reduced energy consumption.

[10] As at June 2021, there are around 3 GW of new large-scale renewable projects at various stages of commissioning and construction.

[11] Firmed wind is effectively the cost of a MWh of wind added to the cost of a $300 cap contract (which reflects the fixed cost of a gas-turbine). In this way, the MWh of wind becomes 'firmed' by the gas turbine and is equivalent to an MWh from a high-capacity factor thermal plant.

[12] Some market participants have announced Power Purchase Agreements (PPAs) well below these new entrant costs. This is due to the emergence of 'two-step pricing' whereby participants allocate low returns to equity in the short to medium term with a view that significant returns will emerge in the future due to higher pricing. This business model is unlikely to be sustainable.

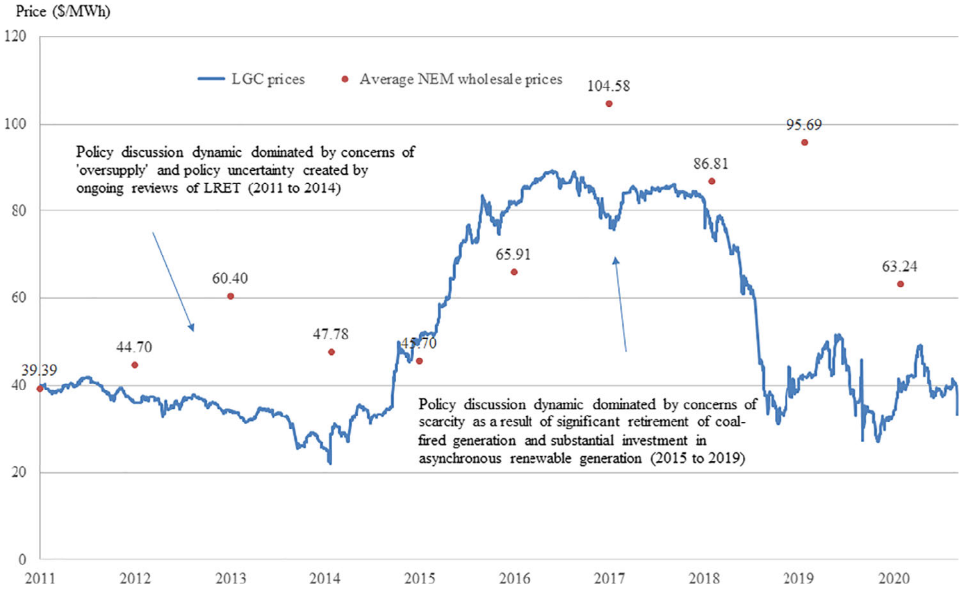

Figure 5 LGC and average NEM wholesale prices. Source: Compiled from industry data.

from ~$50/tonne in 2005 to ~$100–150/tonne over the past decade. Assuming a heat rate of 9 to 10GJ/MWh, the implied short-run marginal fuel cost has increased from $25/MWh up to as high as $65/MWh. Similarly, gas prices increased materially from a historical cost-plus model of around $3–4/GJ to LNG export netback prices of up to $15/GJ. Given this significant variability in fuel cost, it is unsurprising that the benchmark new entrant cost has become firmed renewables.

Figure 5 shows that the Australian NEM and RET are classic commodity markets. There is both intra- and interperiod volatility within the NEM, representing lumpy capital investment and withdrawal and short-term spatial and temporal constraints (see Nelson et al., 2018). When annual averages are considered, prices reflect market imbalances and are generally mean reverting (like any commodity market).

However, policy discontinuity also played a significant role in the market dynamics observed in Figure 5. Between 2013 and 2015, the Commonwealth Government repealed Australia's national carbon pricing framework and commissioned a debilitating review of the RET. During this period, renewable investment stalled as market participants faced lower prices due to oversupply, lower LGC prices due to concerns the Government was predisposed to repealing the RET legislation and waited for the outcomes of the Government's deliberations. With a revised trajectory settled in 2014/15, LGC prices rapidly recovered and existing coal-fired power stations continued to withdraw from the market driving wholesale electricity prices higher.

To assess the RET's effectiveness in sustainably driving new investment (despite the uncertainty discussed above), we have reconstructed the economics of a 'typical' wind project in South Australia developed in each year between 2011 and 2020. South Australia has been selected given the significant deployment of renewables over the past decade (largely due to the region's superior wind speeds). Capital costs, fixed and operating costs, and financing costs have been sourced from Simshauser and Gilmore (2020). The levelised cost of energy (LCOE) in each year is determined using the following formula.

$$LCOE = \frac{Capex \times CRF + FOM}{(8760 * CF)} + VOM \tag{1}$$

Where capex = overnight capital cost ($/kW). FOM = fixed operating and maintenance costs ($/kW), CF = capacity factor (%),VOM = variable operating and maintenance costs ($/KWh), CRF = capital recovery factor (the earning back of initial investment in capex plus a return represented by WACC).

The capital recovery factor is determined using the following formula:

$$CRF = \frac{\{WACC(1 + WACC)^t\}}{\{[(1 + WACC)^t] - 1\}} \tag{2}$$

where t is the number of time periods
WACC is the weighted average cost of capital, which is determined using the following formula:

$$WACC = r_d * Debt\, share + (r_e * (1 - debt\, share)) \tag{3}$$

where r_d and r_e represent the returns to debt and equity respectively and the debt share is the proportion of total funding that is debt (as opposed to equity).
Key input assumptions for deriving the LCOE in each year between 2011 and 2020 are presented in Table 2. The proportion of funding from debt and equity has been set at 50% in each year.

Having derived an LCOE for each year from 2011 and 2012 for a 'typical' wind project in the Australian market, we are then able to determine whether the LCOE is recovered from electricity and LGC revenue. The total revenue in each year is the aggregate wind profile dispatch weighted average (DWA) price for the year added to the average annual LGC price per MWh generated. The net revenue in each year is therefore:

Table 2 Key input assumptions for LCOE calculations

Year	Capex ($/kW)	O&M ($m//KW/a)	VOM ($/MWh)	Equity (%)	Debt (%)
2011	2343	39	2.61	12	8
2012	2711	40	2.66	12	7
2013	2088	41	2.72	12	7
2014	2325	42	2.77	12	6
2015	2325	43	2.83	12	5
2016	2485	43	2.88	12	5
2017	2114	44	2.94	10	4
2018	1930	45	3.0	10	4
2019	1855	46	3.06	10	4
2020	2049	47	3.12	10	4

Source: Adapted from Simshauser and Gilmore (2020).

$$Net\,\mathrm{Re}venue_t = DWA_t + LGC_t - LCOE_{construction\ year} \tag{4}$$

Two sets of results are presented in Tables 3 and 4 respectively. Table 3 shows the net annual revenue for 1 MWh of 'typical' South Australian wind farms built in each year from 2011 to 2020. Table 4 provides the same analysis but with only the electricity revenue (and not the LGC revenue) included in the calculations.

Our results demonstrate the variability in cash flows and profitability for merchant assets in an energy-only gross pool market. Wind farms built between 2011 and 2015 experienced losses during these years but significant profitability because of the tight supply/demand balance that prevailed between 2016 and 2018. As the market cycle swung back into oversupply in 2019 and 2020, all the projects built across all years (including 2020) once again experienced negative profitability. In total, 21 of the 55 annual profitability results provided in Table 3 are negative. This is an important feature of the RET's policy design. Consumers benefit from market participants overbuilding (and facilitating oversupply) through lower prices.[13]

However, if the LGC revenue is removed (as shown in Table 4), then the total number of years in which a negative economic outcome is recorded increases to 46 (out of the total 55 years). This has nontrivial implications for policy design which we will explore in further detail in the subsequent section. Put simply, utilisation of policy frameworks that only utilise the wholesale electricity price are likely to create a significant exposure for governments (and taxpayers) or energy consumers due to prolonged policy-induced periods of oversupply driving the out-of-market subsidy higher. If this is not

[13] It is important to note that LGC's may have been under long-term contract, and therefore, market prices may not be as relevant. However, it is important to note that consumers continued to pay LGC 'market prices' as these are referenced in customer contracts. As such, a key consideration for policy makers in the design of ROC style policies is whether market power could be used by a small number of liable entities to extract rents from consumers.

Table 3 Net Revenue by year for 'typical' South Australian wind farms built in each year from 2011 to 2020 (including LGC revenue)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
LCOE	101.76	111.74	87.14	92.41	89.76	92.32	73.74	69.24	67.61	73.13
Elec	29.12	39.95	65.80	39.94	38.22	60.13	97.59	78.89	70.41	29.39
LGC	39.17	35.66	34.07	30.46	55.39	82.3	83.24	74.33	42.53	35.43
Revenue by Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
2011	−33.47	−26.15	−1.89	−31.36	−8.15	40.67	79.07	51.46	11.18	−36.94
2012	NA	−36.13	−11.87	−41.34	−18.13	30.69	69.09	41.48	1.20	−46.92
2013	NA	NA	12.73	−16.74	6.47	55.29	93.69	66.08	25.80	−22.32
2014	NA	NA	NA	−22.01	1.20	50.02	88.42	60.81	20.53	−27.59
2015	NA	NA	NA	NA	3.85	52.67	91.07	63.46	23.18	−24.94
2016	NA	NA	NA	NA	NA	50.11	88.51	60.90	20.62	−27.50
2017	NA	NA	NA	NA	NA	NA	107.09	79.48	39.20	−8.92
2018	NA	NA	NA	NA	NA	NA	NA	83.98	43.70	−4.42
2019	NA	NA	NA	NA	NA	NA	NA	NA	45.33	−2.79
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	−8.31

Our analysis has been engineered to be deliberately conservative by using real LCOEs ($2020) but unadjusted revenues.

Table 4 Net Revenue by year for 'typical' South Australian wind farms built in each year from 2011 to 2020 (excluding LGC revenue)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
LCOE	101.76	111.74	87.14	92.41	89.76	92.32	73.74	69.24	67.61	73.13
Elec	29.12	39.95	65.80	39.94	38.22	60.13	97.59	78.89	70.41	29.39
LGC	39.17	35.66	34.07	30.46	55.39	82.3	83.24	74.33	42.53	35.43
Revenue by Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011	−72.64	−61.81	−35.96	−61.82	−63.54	−41.63	−4.17	−22.87	−31.35	−72.37
2012	NA	−71.79	−45.94	−71.80	−73.52	−51.61	−14.15	−32.85	−41.33	−82.35
2013	NA	NA	−21.34	−47.20	−48.92	−27.01	10.45	−8.25	−16.73	−57.75
2014	NA	NA	NA	−52.47	−54.19	−32.28	5.18	−13.52	−22.00	−63.02
2015	NA	NA	NA	NA	−51.54	−29.63	7.83	−10.87	−19.35	−60.37
2016	NA	NA	NA	NA	NA	−32.19	5.27	−13.43	−21.91	−62.93
2017	NA	NA	NA	NA	NA	NA	23.85	5.15	−3.33	−44.35
2018	NA	NA	NA	NA	NA	NA	NA	9.65	1.17	−39.85
2019	NA	NA	NA	NA	NA	NA	NA	NA	2.80	−38.22
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	−43.74

Our analysis has been engineered to be deliberately conservative by using real LCOEs ($2020) but unadjusted revenues.

the case, then Cfd style frameworks are likely to accentuate the boom/bust nature of wholesale electricity prices resulting in poorer outcomes for consumers.[14] At the very least, the RET has not removed the incentive for participants to manage the temporal and spatial risks associated with operating in the wholesale electricity market. A renewable resource with a poor correlation to demand and price is penalised relative to a project that optimises location and resource to deliver energy where and when customers require it.

4. Policy recommendations: integrating Cfd frameworks using the RET

The RET required investment in renewable energy generation equivalent to the annual production of 33 TWh by 2020. At the time of writing, this objective has been achieved. Discussion about the future of the RET has largely been muted given the focus by state governments on developing Cfd policies to deliver climate change objectives. There are two observations from our analysis of the RET in the preceding Section which are worth noting in this context:

- Finding 1: the RET facilitated *both* positive and negative years of cashflow (relative to underlying LCOE). In other words, consumers benefited from overinvestment through lower prices (relative to LCOE) and *all* project proponents were required to address the risks associated with the NEM's spatial and temporal dynamics.
- Finding 2: Without LGC revenue, all projects would have experienced negative income (relative to LCOE) almost all of the time. This has nontrivial implications for policy design. Governments could have been exposed to significant 'out-of-the-money' Cfd liabilities of ~$0.25 billion in South Australia alone.[15] In other words, all producers would have been guaranteed to make a return on their investment: privatising profits and socialising losses.

The policy propositions that follow assume that the quantities of renewables being added to the NEM through to 2030 are fixed and that renewables continue to be the cheapest form of zero-emissions electricity (see Rai and Nelson, 2021). For completeness, we have provided quantitative modelling of Optimal Plant Mixes in 2030 for the NSW system[16] in two

[14] This is particularly relevant for large energy-intensive trade exposed industry which cannot be shielded from higher energy costs in the same way that they are under the RET (through an LGC surrender exemption).

[15] This approximate calculation is based upon total MWh produced by wind in South Australia in 2020 being exposed to the negative economic outcomes in Table 4.

[16] Our modelling is based upon the work of Berrie (1967). This model is outlined in detail in Nelson et al. (2013) so we do not replicate it here. Importantly, the 12 GW scenario utilises a residual demand curve based upon assumptions from AEMO's Integrated System Plan. All costs utilised are consistent with those in Table 2.

scenarios: build out of the 12 GW of VRE; and no build out of VRE. Our results (presented in Appendices S1 and S2) show that the price of electricity is substantially lower in the 12 GW built out case. The focus of our policy propositions are therefore not related to whether it is appropriate to drive abatement through VRE adoption, but consideration of superior policy design to limit unintended consequences associated with Cfds identified in Section 2.

4.1 Policy proposition 1 – utilising the RET architecture to implement Cfd polices

State governments are adopting ambitious policies to decarbonise electricity grids between 2020 and 2030. This article provides insights into how these governments could modify their policy frameworks to achieve these goals while limiting the most negative impacts of Cfds. Section 2 demonstrated that two limitations in particular require particular attention by policy makers: by underwriting projects through the wholesale price, governments effectively remove the need for market participants to efficiently locate and operate their projects to maximise value given spatial and temporal dynamics; and governments effectively underwrite all the new projects in the market.

Both limitations could be overcome by writing the Cfd or swaption on LGCs created through the RET policy architecture. By entering into a Cfd (or swaption) for the government to acquire and voluntarily surrender the LGCs, market participants would still be required to locate and operate their project efficiently within the wholesale electricity market to maximise value.[17] Market participants would be required to carefully consider location (to avoid issues related to reductions in dynamic marginal loss factors: MLFs) and forward hedging of output to minimise exposure to volatile spot pricing. Consumers would benefit from increased liquidity and transparency in the short-term and lower sustainable prices in the long-term as more efficient projects are built and market participants (rather than governments and/or consumers) face the risk of lower returns due to poor project performance.

The 'spread' of potential price outcomes for LGCs is likely to be lower than wholesale electricity prices. Assuming current forward market pricing (see Appendix S3), governments could sell put rights to LGCs for a strike of ~$20/LGC. As such, the maximum exposure in any year for each MWh would be $20, although it is unlikely that LGCs would be worth nothing (particularly given the proceeding discussion in this Article about carbon fungibility). This

[17] This could include trading off total volume (and potentially a higher LCOE) for additional value, allowing developers to value projects that better match load, are uncorrelated with other renewable projects, or includes storage that shifts production to higher value periods.

is a significantly better outcome than the average out of the market payment ($56/MWh) that would have been made in 2020 if projects built under the RET were receiving Cfds.

'Swaptions' rather than generic Cfds should be pursued by governments as a means of incentivising the engagement of voluntary buyers of LGCs. This would minimise the exposure of governments (and consumers if out-of-market payments are to be recovered through distribution charges) to growing financial liabilities. Demand for LGCs by businesses within Australia continues to grow with many companies committing to 'science-based targets' and aligning their operations and strategy to meet emission reduction targets implied by the Paris agreement. Companies are increasingly aware of the need to address climate risk within their operations and the implications for company directors to discharge their duties under corporate law.[18]

The Commonwealth Government is reforming reporting under the *National Greenhouse and Energy Reporting Act* to create greater transparency around how companies in Australia are claiming to be 'renewable' or 'carbon neutral'.[19] It is very likely that governments and investors will require companies to voluntarily surrender LGCs equal to their electricity use to be able to claim that they are using 100% renewable energy. The Government is instituting these reforms given the significant voluntary action already being undertaken by corporates in Australia. For example, 22 of the largest companies in Australia have formed a 'Climate Leaders Coalition' and many of Australia's largest emitters and electricity users are part of the Climate Active programme established by the Commonwealth Government.[20]

By utilising swaptions for LGCs, governments can effectively underwrite new investment while minimising their own financial exposure and maximising incentives for market participants to locate and operate their projects efficiently and find customers for the imbued greenhouse emissions abatement in their operation. No reforms of the existing RET policy architecture would be required. The Commonwealth and states could continue to have differing views on the pace of decarbonisation, but the framework underpinning new investment in the electricity sector would be nationally consistent.

[18] See https://www.governanceinstitute.com.au/resources/governance-directions/volume-73-number-5/risk-management-and-climate-change/, Accessed online on 24 June 2021.

[19] See http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/Corporate-Emissions-Reduction-Transparency-Report-consultation-paper.aspx?utm_source = Clean + Energy + Regulator + - + Update&utm_campaign = aafe9cea8e-PJ554_CERT_Consultation&utm_medium = email&utm_term = 0_56e080d9b7-aafe9cea8e-53060509, Accessed online on 24 June 2021.

[20] See https://www.afr.com/policy/energy-and-climate/top-ceos-form-exclusive-climate-change-club-20201125-p56hvo and https://www.climateactive.org.au/buy-climate-active/certified-brands#7, Accessed online on 20 June 2021.

4.2 Policy proposition 2 – Carbon fungibility and development of 'green hydrogen'

Another key consideration of policymakers in relation to the future of the RET is its alignment or 'fungibility' with other carbon reduction instruments in Australia. While LGCs surrendered for compliance purposes under the RET are obviously not 'additional', all other LGCs are reducing emissions beyond legislated targets. Substitution of existing emissions intensive generation with new renewables will only occur if: voluntary action is taken to purchase renewable energy beyond what it is required by the market; governments mandate new additional VRE investment through Cfds or 'swaptions'; and/or existing thermal generation is retired at its end-of-life and new renewables investment occurs to fill the gap created by generator exit.

The first two scenarios described above are clearly *additional*. Additional abatement is occurring because of voluntary market activity over and above what would occur through business-as-usual. It is therefore worth considering how governments create 'fungibility' between the greenhouse abatement facilitated as a result of LGC creation and other sectors where the Australian Carbon Credit Unit (ACCU) represents one tonne of abatement.[21]

To create 'fungibility', it is first necessary to define an exchange rate between LGCs (which represent 1 MWh of renewable energy production) and an ACCU (which represent 1 tonne of greenhouse abatement). This is achieved through converting LGCs into ACCUs through measuring the tonnes of abatement per MWh of renewable electricity generated and consumed. Nelson et al (2021) proposed that exchange rates could be based upon the *average emissions intensity (EI)* or the *marginal emissions intensity* at a point in time (such as each half hour of settlement within the NEM) or over a year.

To consider the most appropriate exchange rate, we have calculated the average emissions intensity by half hour period, the average marginal intensity of emissions by half hour period, the average and marginal intensities across the entire year, and the wholesale electricity price by half hour. We utilised 2019 data and calculated these metrics for New South Wales, Queensland, Victoria and South Australia. We have not considered transmission flows. For example, NSW does not 'import' brown coal emissions from Victoria. Our calculations for marginal emissions are based on the emissions intensity of the marginal price setter(s) from AEMO's NEMDE dispatch engine. In other words, the emissions intensity of the unit

[21] An ACCU is a unit issued to a person by the Clean Energy Regulator (Regulator) by making an entry for the unit in an account kept by the person in the electronic Australian National Registry of Emissions Units (Registry). One ACCU represents one tonne of abatement. The predominant buyer of ACCUs is currently the Commonwealth Government through the Emissions Reduction Fund, although voluntary demand for ACCUs to offset emissions is growing.

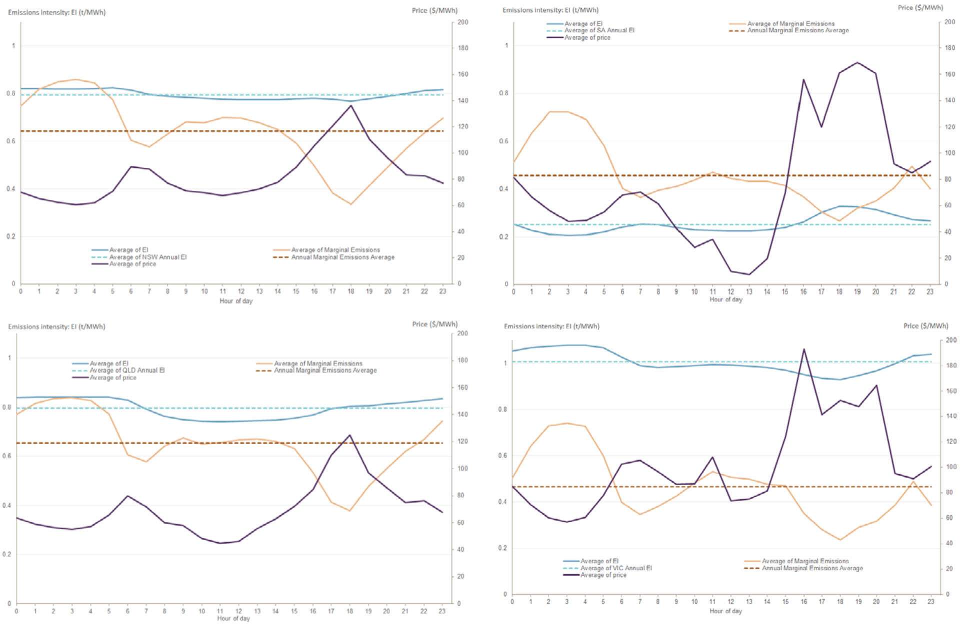

Figure 6 Average and marginal emissions intensity and correlation with wholesale electricity price (2019 data).

(s) that would have supplied additional MW in that region but could be located anywhere in the NEM.

The results of our emissions intensity analysis are presented in Figure 6. The first clear trend is that emissions intensity (particularly marginal emissions intensity) and price are anticorrelated. During periods of low prices, coal units are typically setting the price. If renewable generators produce at times of higher market prices, they are offsetting a generator that, on average, is almost half as emissions intensive (i.e. a blend of gas and hydro). Given the diurnal nature of electricity markets, marginal emissions are low during the evening peak and higher overnight.

Another key observation is that marginal emissions are similar in all regions (as the NEM is often unconstrained, with similar price setters across all regions), but average emissions vary significantly by state (due to the different composition of generation). In particular, the average is lower in South Australia, which has the highest penetration of large- and small-scale variable renewable generation. Importantly, average emissions do not change significantly throughout the day[22], but follow similar trends.

We recommend that policy makers set LGC/ACCU exchange rate fundamentals using the *average annual emissions intensity* of the entire

[22] The relatively constant temporal average emissions are due to the dominance of coal and renewable generation for *energy* with gas being relied upon for *capacity* (and a correspondingly low capacity factor).

NEM. The only way marginal emissions intensities could be used in a meaningful way would be through dynamic marginal emissions pricing (i.e. LGC conversion rates that vary every half hour). In practice, this would be incredibly difficult and administratively burdensome. Alternatively, average emission intensity provides an accurate outcome when considered across the entire market (recall Figure 3). As the NEM will increasingly be interconnected through transmission built out under the Integrated System Plan (ISP), it is increasingly certain that generation in any state will reduce emissions across the NEM.

By utilising LGCs when issuing Cfds or 'swaptions', creating fungibility between LGCs and ACCUs and utilising LGCs as a means of guaranteeing the origin of 'green hydrogen' (see Appendix S4), Australian policymakers would have effectively facilitated a nationally consistent and integrated energy and climate policy (without purposely seeking to do so). Market participants would continue to be able to invest with confidence in new supply and governments would be less exposed to growing out-of-market obligations to finance poor projects. International investors would be able to purchase quality Australian carbon units with significant stimulus to the Australian economy.

5. Concluding remarks

Freebairn (2020) provides a useful overview of how to consider a package of greenhouse abatement policies. While he argues a national emissions price is the most efficient policy tool, it is unlikely to be the only policy required. Two constraints exist to force this outcome. Firstly, institutional barriers, transaction costs and other nonprice barriers will exist that mute pricing signals. Energy efficiency standards for new appliances are a good example of this first barrier. The second constraint relates to the real political economy and public resistance to emissions trading and 'carbon taxes'. In the Australian context, the second constraint is likely to be more pervasive, although this may change due to the emergence of border adjustment taxes that are being developed by major trading partners such as the European Union.

Climate policy will therefore need to evolve in a way that maximises economic efficiency but is able to be enduring given political realities. In the Australian context, it is worth considering recent community polling, which indicates that 55 per cent of all voters agree with reducing emissions to 'net zero' by 2050 with 33 per cent undecided. At the same time, the proportion of voters that believe the target should be met through increased deployment of renewable energy is 61 per cent.[23] As such, there is considerable merit in

[23] Polling available at: https://www.smh.com.au/politics/federal/voters-want-australia-to-set-a-net-zero-2050-emissions-target-but-no-carbon-tax-20210615-p5813w.html, Accessed online on 19 June 2021.

exploring how the RET architecture could be utilised to support growth in investment in renewables beyond the mandated 33 TWh by 2030.[24]

This article has reviewed the effectiveness of the RET as a policy tool for driving investment in renewable energy and reducing emissions and contrasted it with emerging state-based Cfd style policies. The RET has been the primary policy tool for reducing emissions within Australia. In relation to its impact on electricity markets and consumers, we make two key findings:

- Finding 1: The RET facilitated both positive and negative years of cashflow (relative to underlying LCOE). In other words, consumers benefited from overinvestment through lower prices (relative to LCOE) and all project proponents were required to address the risks associated with the NEM's spatial and temporal dynamics.
- Finding 2: Without LGC revenue, all renewable projects would have experienced negative income (relative to LCOE) almost all the time. This has nontrivial implications for policy design. Governments or consumers could have been exposed to significant 'out of the money' Cfd liabilities. In other words, all producers would have been guaranteed to make a return on their investment: privatising profits and socialising losses.

Given state governments are pivoting towards Cfd auctions to facilitate new renewable investment, our policy recommendations relate to integrating the benefits of the RET and LGC framework within these auction processes. By writing the Cfd or swaption on the LGC, rather than the wholesale electricity price, policy makers could overcome the worst aspects of Cfds. Most importantly, new projects would continue to be exposed to dynamic spatial and temporal pricing signals and project proponents (rather than governments or consumers) would wear the risk of underperformance of their investment.

A further benefit of utilising the existing LGC framework is the integration of electricity sector abatement within a broader trend of corporates voluntarily reducing emissions.[25] This article has analysed half hourly marginal, average and annualised marginal and average emissions intensities

[24] While economists would contend that a technologically neutral policy would be more efficient, almost all energy economists, market participants and the peak body in Australia have publicly stated that renewables are now the cheapest form of energy. See https://thehub.agl.com.au/-/media/thehub/legacyimported/2018/05/presentation-for-grattan-2018.pdf?la=en&hash=773503322C309EBA6E8722F4734EA8CE as a good example. Accessed online on 20 June 2021. Even though renewables are lowest cost, additional policies (such as Cfds using the RET policy architecture) and voluntary purchases of abatement are required to hasten the substitution of existing coal plants with firmed renewables in a manner consistent with meeting Australia's carbon budget implicitly committed to as part of the Paris agreement.

[25] LGC prices have continued to be non-negative despite the RET being fully subscribed from a compliance perspective. This is due to continued growth in demand from electricity customers for LGCs to 'offset' their electricity consumption. Appendix S3 shows how forward LGC prices continue to trend above the fundamentals implied through a pure compliance lens.

and concluded that LGCs should be 'fungible' with ACCUs using the NEM annual emission intensity as an 'exchange rate'.

Data availability statement

All data used in this manuscript is publicly available and easily reproducible.

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Supporting Information

Additional Supporting Information may be found in the online version of this article:

Appendix S1 Optimal Plant Mix in 2030 (no 12 GW policy).
Appendix S2 Optimal Plant Mix in 2030 (12 GW policy in place).
Appendix S3 LGC price curves.
Appendix S4 'Green hydrogen'.