



Transition Risk:

Investment signals in a decarbonising electricity system

Working paper

Authors:

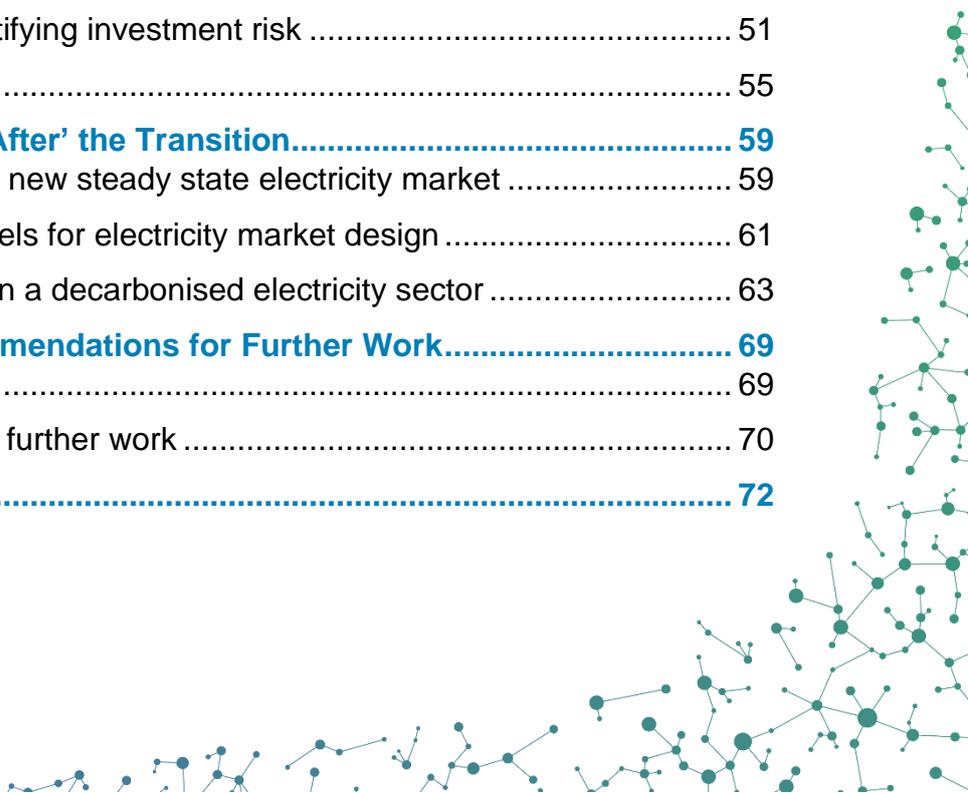
Will Blyth, UKERC, Oxford Energy Associates
Robert Gross, UKERC Director, Imperial College London
Malte Jansen, UKERC, Imperial College London
Stephen Nash, Kuungana Advisory
Jamie Rickman, UKERC, University College London
Callum MacIver, UKERC, University of Strathclyde
Keith Bell, UKERC Co-Director, University of Strathclyde

April 2023



Contents

Executive Summary	i
Key messages	i
Policy context.....	ii
Quantifying transition risk.....	ii
Lessons from international comparisons.....	iii
Need for de-risking investment during the ‘build phase’ of the transition	iv
Market reform options after the transition (‘re-optimisation’ phase)	v
1 Introduction.....	1
1.1 Context.....	1
1.2 Price formation in low carbon markets	2
1.3 A debate over market design	4
1.4 Risks and cost of capital	5
2 Country Comparisons	6
2.1 Introduction	6
2.2 Germany	9
2.3 South Africa.....	19
2.4 Australia	28
2.5 Texas, United States.....	36
3 Quantifying Transition Risk.....	44
3.1 Overview of approach	44
3.2 Electricity system model.....	45
3.3 Decarbonisation pathway scenarios.....	48
3.4 Methodology for quantifying investment risk	51
3.5 Results	55
4 Implications for Policy ‘After’ the Transition.....	59
4.1 Levers for designing a new steady state electricity market	59
4.2 Alternative target models for electricity market design	61
4.3 Market design needs in a decarbonised electricity sector	63
5 Conclusions and Recommendations for Further Work.....	69
5.1 Conclusions.....	69
5.2 Recommendations for further work	70
References.....	72



Executive Summary

Key messages

As electricity markets shift away from fossil fuels towards low carbon technologies with low marginal costs of production, the wholesale price of electricity will tend to drop (so-called 'price cannibalisation') which could adversely affect investment signals. The degree to which this occurs depends on the nature of the supply and demand technologies that come on to the system during the decarbonisation pathway, as well as the prevailing policy framework. We use the term 'transition risk' to describe risks that investors face relating to this pathway uncertainty.

At the same time, the energy price shocks of 2022 have shone a harsh spotlight on risks to consumers, emphasising the need for policy to take account of allocation of risk between generators and consumers both of higher- and lower-than-expected prices.

This report assesses the impact of these risks on the financial case for offshore wind, using a methodology that can be readily applied to other types of generation.

- We characterise the current stage of the low-carbon transition as a 'build phase', where large volumes of investment are needed to get on a path to a net-zero electricity system.
- International experience indicates that successful policies to achieve this investment have in common the ability to provide a steady, stable and predictable outcome for investors.
- During the build-phase, the final physical state of the decarbonised system is still uncertain, meaning there is significant price risk in future wholesale markets.
- Current 'contracts for difference' provide a fixed price for renewables, shielding investors from these risks, helping to minimise the cost of capital for these projects during this critical build-phase of the transition.
- Exposing projects fully to transition risk at this stage could increase the cost of transition by at least a third (from £15bn to around £18-£20bn per year for offshore wind alone).
- A number of market design options that provide an alternative to use of CfDs to address price cannibalisation may become feasible and attractive in the longer-term once the risk characteristics of the decarbonised system are better understood.

Policy context

Rapid deployment of renewable energy is at the forefront of the UK government's plans to decarbonise the power sector by 2035, as a precursor to meeting broader net zero aspirations by mid-century. The British Energy Security Strategy (April 2022) highlighted the importance of offshore wind in particular, and extended previous aspirations by setting an ambition to deliver up to 50 GW offshore wind by 2030, including up to 5 GW of floating wind. Installing 30-40 GW of new offshore wind in nine years is a significant challenge. It requires amongst other things the mobilisation of something of the order of £55-70 billion of investment.¹ However, this is just the beginning. Scenarios from National Grid ESO, the Great Britain² system operator, put the amount of wind needed for a fully decarbonised system at between 80-110 GW by 2040 (1) requiring investment of up to £160 billion.

The process has already started. In the last 20 years, Britain has installed around 10 GW of wind around our shores – a remarkable achievement that places the UK at the forefront of sea-based renewable energy and helped drive down costs globally.

'Contracts for Difference' (CfDs) are the centrepiece of UK policy support for renewable energy schemes that have underpinned these investments. With prices set through auctions, they provide government-backed 15-year contracts to deliver green electricity. This has made renewable energy projects attractive to low-risk investors such as pension funds who control large pools of low-cost capital. These arrangements have helped see the prices offered to new offshore wind farms in Great Britain plummet from well over £100/MWh to below £40/MWh (2012 prices) – making offshore wind cheap compared to almost all other forms of power generation. Onshore wind and solar prices have also dropped under CfD support to £42/MWh and £46/MWh respectively in the most recent auction round in December 2021 (2).

Now that renewables are so cheap, some commentators are questioning whether they need the continued government support, arguing that markets might be able deliver decarbonised power more efficiently without the provision of these long-term contracts. They argue instead for an alternative approach, such as a low carbon obligation on suppliers. The logic is that although CfDs make investment less risky, they also largely remove any incentive for renewable generators to respond to the short-term price signals that reflect the value of electricity at particular times of the day or year.

Quantifying transition risk

In this report, we aim to contribute to a particular strand of this debate, namely the dichotomy between the desire to minimise the cost of capital of new investments in

¹ This is based on the generation plant only, using BEIS estimates of £1800/kW in 2030 (2018 prices)

² Throughout the report we refer to UK climate targets and to Great Britain or GB electricity markets. This is because the electricity market arrangements under discussion apply in GB because separate arrangements apply in Northern Ireland under the integrated single electricity market for Ireland and Northern Ireland.

order to minimise the overall cost of the transition, and the desire to use market signals to optimise the efficiency of investment and operation of electricity system assets and promote innovation. We characterise this debate in terms of a simple equation:

Do the cost savings arising from low cost of capital achieved through de-risking policies outweigh the potential system cost benefits that might arise from exposing renewables projects to greater levels of market price risk?

We conclude that the answer depends on the stage of transition being considered. The 'build phase' of the transition to a future decarbonised electricity system will require massive investment in renewables, electrification of transport and heat, flexible demand, hydrogen infrastructure, interconnectors, carbon capture and storage and nuclear. The mix of these technologies is still highly uncertain and policy-dependent. For example, the focus on nuclear shifted again recently in the government's British Energy Security Strategy, and the degree of hydrogen demand in the economy remains highly uncertain.

Our analysis indicates that at least until there is greater clarity on the technology mix that will prevail in a zero-carbon electricity sector, significant changes to the current commercial framework for supporting investment in clean energy could result in a significant increase in the cost of capital, potentially increasing the cost of transition by a third. Given the huge amounts of capital required to deliver the transition, such an increase could put the transition itself at risk.

The balance of this equation is likely be different towards the end point of the decarbonisation process, when the technology mix is clearer and price formation and risk allocation can be better understood. Our qualitative assessment of different market design option shows some promising candidates, though not an obvious policy 'winner'. The analysis identifies challenges that would need to be addressed by any future market design options, but the choice is likely to be clearer once the future technology mix is more certain.

Lessons from international comparisons

A variety of renewable energy (RE) policies have been shown to be effective at incentivising investment. It must be noted that there is no silver bullet, no single policy that 'works best'. The policies and their results are highly context specific and must be treated in such way. Nonetheless, some countries have fared better than others, providing valuable lessons on the level of policy effort (and intervention) required to manage the energy transition and keep the lights on.

In some cases (e.g. Germany, CfD auctions), these act primarily as a revenue stabilisation mechanism, helping to offset price cannibalisation effects in the wholesale market. In other cases (e.g. US / Texas, Federal tax credits), the policies create an additional but variable income stream which supplements the underlying

strong economic case based on the favourable availability of good low-cost RE resources.

In all cases, the relationship between the renewable support mechanism and the wider system provides an essential investment context. This includes:

- The degree to which renewables are exposed to market price, and the different levels of risk this may impose depending on the level of wholesale market volatility / price risk in the country.
- Differences in the way grid connection issues are handled. E.g. in Germany, the CfD auctions are an important way of gaining access to the grid. In Texas & Australia, transmission constraints and congestion have an important effect on prices.
- The extent to which the market allows or facilitates projects to be able to strike long-term Power Purchase Agreement (PPA) arrangements outside of the formal RE support mechanism.

However, the policy solutions explored in this paper relate to investment under conditions where market risks are relatively well established through mature markets. The extent to which these market risk characteristics persist under conditions of deep decarbonisation have not been tested in the reviewed case studies.

Need for de-risking investment during the ‘build phase’ of the transition

There is an urgent policy imperative to ensure that low-carbon infrastructure is rolled out fast enough to meet decarbonisation goals. Although some features of this infrastructure can already be outlined, the details are still uncertain. Some of the risks are commercial in nature, but some relate to matters of public policy that lie outside the control of electricity sector players³. This distinction matters because imposing risks on investors which they are not in a good position to manage could simply increase the cost of capital needed to finance the transition without any commensurate benefits in terms of improving the design and quality of the projects.

We characterise these major decarbonisation pathway uncertainties as ‘transition risks’, and aim to quantify their impact on the cost of building out offshore wind.⁴ We use published scenarios from National Grid ESO to illustrate different pathways to a zero-carbon electricity system, all of which include very large increases in offshore wind capacity from 10 GW now to 100-120 GW in 2040. The cost of this amount of offshore wind would be around £15bn per year if financed at moderate cost of

³ As examples, we look at the risk of under-delivery of various types of flexibility (such as hydrogen and interconnectors), but we have not carried out an exhaustive analysis of different types of risk factor.

⁴ This is an illustration of the wider infrastructure financing challenge, and the methodology can be equally applied to other types of investment.

capital. Very roughly, for every 1%-point increase in the cost of capital, this figure increases by £1bn per year.

We then look at how exposure to decarbonisation pathway risks during this build phase varies depending on the policy / market design frameworks in place for remunerating wind power. Initial results indicate that the degree of exposure varies by around 1-5 percentage-points between the most risk-exposed framework and the least risk-exposed. This suggests that the choice of policy framework could impact the cost of delivering the offshore wind component of the low-carbon transition by between £1-5bn per year (up to a third of the overall annual cost).

We have not yet attempted to quantify the degree to which exposing wind projects to more market price risk would achieve cost savings in the wider electricity system (i.e. the grid & balancing costs) by encouraging more efficient choices in the location, type, design or operation of wind projects. However, to result in a net cost saving, reduction in grid and balancing costs that can be directly attributed to exposing renewables schemes to greater price risk would have to be at least as large as the cost of capital effects. The value of flexibility in a low carbon system is underscored in our analysis and already widely appreciated (3). However, there are many ways this could be delivered that are independent of CfD reforms, from changes to the Capacity, Balancing and Wholesale markets to new incentives for storage, interconnectors or demand response.

This is a relatively simple and stylised analysis designed to illustrate the key 'moving parts' and drivers of risk in the transition. Our intention is to help inform the current debate about what policy instruments are the most appropriate to ensure that this investment is delivered in a cost-effective way, culminating in the BEIS review of electricity market arrangements (4). Our contribution has been to provide a methodology based on open-source tools and publicly available data that helps to quantify financial exposure to different pathway risks which should help assess which risks should be managed by whom.

Market reform options after the transition ('re-optimisation' phase)

The case for substantial market design changes in a future decarbonised electricity sector is different from the case for market change at the earlier stages of transition. In a future decarbonised phase, the fundamental physical characteristics of the system and subsequent market behaviour will be more easily quantified, and depending on the characteristics of the steady-state, market solutions could help to re-optimize the deployment of capital within a sector that has already been largely decarbonised, and support continued growth to meet greater electrification of the economy.

A qualitative assessment of the pros and cons of different possible future market design options has been undertaken. The design options assessed include:

- **Merchant+:** the short-run energy price is the main price signal in the electricity market, but with modifications to achieve evolving system objectives, such as decarbonisation. This might, for example, simply rely on a very high carbon price.
- **CfD+:** build decisions continue to rely on Government-driven procurement decisions, which result in long-term contracts being awarded, with stable revenues on offer to successful bidders. This could include models that require relatively modest changes to the current approach to procuring renewables, such as a CfD floor price (5), or shifting from energy to capacity-based revenues for renewables (5,6).
- **2-market solutions:** some authors, such as Malcolm Keay (8), have suggested splitting the energy market into a market for firm, dispatchable energy (also referred to as 'on demand' energy), and a separate market for non-dispatchable ('as available' energy). Such a market would in theory allow consumers to determine the level of security of supply that they find acceptable.
- **Obligations:** this category would include models such as the Energy Systems Catapult's Supplier Obligation model (9), which would rely on a decarbonisation standard and a reliability standard, both of which suppliers would be required to meet. It could be argued that this overlaps with the Merchant+ category because these standards would supplement a short-run wholesale electricity price.

These options are then assessed in terms of the likely performance against five tests:

- Test 1: The market delivers the contractual commitments required to deliver low carbon generation capacity.
- Test 2: The market delivers the flexible capacity required to meet peak net demand.
- Test 3: The market is well equipped to determine the supply quantities needed to meet system energy and capacity requirements.
- Test 4: The market is well understood and can be modelled.
- Test 5: The market results in politically acceptable outcomes.

This analysis shows that there is no one market design currently identified that is clearly suitable for the re-optimisation phase of the transition. However, different technology pathways might point towards a different shortlist of market design options:

- If short-run wholesale market price signals remain robust, then a **Merchant+** route might be feasible. Short-run price signals might remain robust if gas CCS has a substantial role in the energy mix, if a mature market for flexible demand develops, or if a deep hydrogen market develops (and hydrogen is widely used in the electricity sector), with well understood pricing. This would likely need to be supplemented by a Capacity Market or equivalent.
- If short-run wholesale market prices tend towards zero during most hours, a **CfD+** route (or some other long-run pricing mechanism) might be required.

This could be required in high electrification pathways where electricity storage plays a major role, but without a deep hydrogen market.

- In theory, a **2-market** or **obligation-based** approach might offer a more sophisticated solution, but these market design options would need to first be shown to pass the five tests above.

1 Introduction

1.1 Context

At the end of 2020, the UK Prime Minister announced an aspiration to build 40 GW of offshore wind by 2030. With poetic references to the wind that puffed the sails of Drake, Boris Johnson placed offshore wind at the forefront of a ‘green industrial revolution’(10). In October 2021 the UK Net Zero Strategy doubled down on this, reiterating the importance of offshore wind and the key role of a decarbonised power sector in meeting net zero aspirations (11).

The British Energy Security Strategy (12) extends this further, setting an ambition to deliver up to 50 GW offshore wind by 2030, including up to 5 GW of floating wind, with the accelerated timetable to be largely facilitated by a streamlining of the planning process.

In the last 20 years, Britain has installed around 10 GW of wind around our shores – a remarkable achievement that places the UK at the forefront of sea-based renewable energy and helped drive down costs globally. However, to more than quadruple the amount of offshore wind in half that time will be no mean feat. To put it mildly, installing 30-40 GW of new offshore wind in nine years is a significant challenge. It requires amongst other things the mobilisation of something of the order of £55-70 billion of investment.⁵ However, this is just the beginning. Scenarios from National Grid ESO, the Great Britain⁶ system operator, put the amount of wind needed for a fully decarbonised system at between 80-110 GW by 2040 (1) requiring investment of up to £160 billion.

Renewables in general and offshore wind in particular play a substantial role in most recent UK/GB decarbonisation scenarios. The Net Zero Strategy reaffirms the central role of renewables in decarbonisation of power noting that in 2035 and 2050 power generation is likely to be ‘composed predominantly of’ wind and solar (11). This is because the costs of wind and solar have fallen substantially. There is also a very large potential resource in the UK, particularly offshore.

Policies put in place in 2013 under ‘Electricity Market Reform (EMR)’ have played a key role in driving cost reduction and deployment (13). Government backed contracts known as Contracts for Difference, or CfDs, have proved attractive to investors and developers (14) whilst prices set through auctions place downward pressure on prices. Renewable energy expansion has continued apace whilst other low carbon options have struggled to become established. Nuclear power and CCS

⁵ This is based on the generation plant only, using BEIS estimates of £1800/kW in 2030 (2018 prices)

⁶ Throughout the report we refer to UK climate targets and to Great Britain or GB electricity markets. This is because the electricity market arrangements under discussion apply in GB because separate arrangements apply in Northern Ireland under the integrated single electricity market for Ireland and Northern Ireland.

appear to need additional support, or more action by government to de-risk investment (15,16).

The scale of renewables expansion needed to meet Net Zero means the roll-out has scarcely started. Although existing policies appear to be successful in terms of deployment and cost reduction, the Net Zero Strategy also restates a question the government first posed in a Call for Evidence at the beginning of 2020 (17). It reiterates the value of the current policies but also asks if “*broader reforms to our market frameworks are needed to unlock the full potential of low carbon technologies to take us to net zero.*” Similar calls for review have been made by the Climate Change Committee (18). Since then, through the British Energy Security Strategy (12) the government has now committed to “*undertaking a comprehensive Review of Electricity Market Arrangements (REMA) in Great Britain, with high-level options for reform set out this [2022] summer.*”

One of the key drivers of this debate about the need for market design review is differing views about the extent to which government or industry is best placed to make strategic choices about volumes of investment in different generation technologies. On one side, the argument goes that centralising these decisions through government allows for larger-scale, longer-term and de-risked procurement processes that minimise the cost of renewable roll-out by giving companies sufficient certainty to allow them to build robust supply chains and reducing the cost of capital. The simplest way to do this is by fixing volumes and allowing companies to compete on price through auctions such as those used for the CfDs.

Others argue that this centralised approach to determining supply volumes reduces innovation and that de-risking investment to this extent may suppress some of the dynamic efficiencies that industry-led decision-making might bring to the choice of what, how much, and where to build new generation (9). Industry commentators have also raised concerns with the status quo regarding the economic viability of wind and solar farms when they reach the end of CfD or previous support schemes, cautioning that existing market structures could result in premature retirement of existing assets as they may be unable to recover their ongoing costs from the market (19).

In practice, much of the debate hinges on whether, to what extent, and how to increase exposure of low carbon generators to wholesale market price risks. In this paper we focus on a subset of these issues by looking at the potential impact of increased revenue risk on the cost of capital, a key component of the overall cost of the energy transition. We focus our attention on the case of offshore wind, but the methodology can be applied to any type of electricity generation. We leave the question of the degree to which exposure to market risks creates dynamic efficiencies for future work.

1.2 Price formation in low carbon markets

At the time of writing this paper, the pressing question of energy policy is how to deal with high wholesale electricity prices driven by high gas prices. Wholesale electricity

markets usually price electricity according to the cost of producing a marginal unit of power. Currently, and for some time to come assuming economic recovery continues to maintain higher levels of demand, this marginal price is mainly set by the cost of gas-fired power plant.

In the longer-term, once the system is dominated by renewables that are very low cost to run, this marginal pricing mechanism may begin to create problems, at least from the perspective of renewable generators. Increasing levels of renewables tend to depress prices through the so-called 'price cannibalisation' effect (20). This was observed during periods of low demand during the first Coronavirus lockdown in the UK at the start of 2020 (21,22). The effect is even more pronounced for wind plant, as their output tends to be correlated with periods when prices are low, meaning they receive a reduced so-called 'capture price'. The effect will tend to get stronger as more wind enters the system. To a large extent, this effect is structural, it reflects the changing physical nature of the system, and how it interacts with wholesale market price formation, rather than the policy framework in place.

The price capture effect can be partially offset by increasing system flexibility through making consumer demand more responsive as well as major infrastructure solutions such as long-term storage and long-distance interconnectors. For example, electrolysis for producing green hydrogen (23) could be a major source of demand to soak up large quantities of power when the wind is blowing, helping to prop-up prices during these periods. Delivery of this infrastructure is quite uncertain (24). Future demand for green hydrogen depends on decarbonisation pathways for industry, transport and heat. Total demand for power is also dependent on these pathways. This indicates the strong interrelationship between the investment case for renewables and other elements of the energy infrastructure needed for the energy transition. Crucially, many of these infrastructure pathway choices are also dependent on public policy, for example in the domestic heating sector (25), which is outside the control of power market participants.

There are also questions about the sequencing and coordination of the different components of the net zero transition. The availability of surplus electricity at certain points of the day or year ought to provide an incentive to invest in demand response or storage, but demand and supply *both* respond to low prices. Whilst low or negative power prices ought to stimulate demand, they might just choke off supply. Investment in low carbon generation could simply stall before the smart chargers, interconnectors or green hydrogen plants turn up. Indeed, a great many risks surround each of the various component parts of a net zero electricity system. In the long-run, a fundamental question facing policymakers is whether a different market structure will be needed that moves away from system marginal cost (which mainly focuses on running costs) to one that reliably remunerates capital costs, which is where the bulk of the cost of renewables and other low-carbon infrastructure lies.

1.3 A debate over market design

'Contracts for Difference' (CfDs) are the centrepiece of policy support for renewable energy schemes in the UK. With prices set through auctions, they provide government-backed 15-year contracts to deliver green electricity. They were created in the Energy Act of 2013 to help de-risk low carbon energy projects by insulating them from wholesale power price uncertainty for at least a part of their operational life, and providing a reliable counterparty (13). This has made renewable energy projects attractive to low-risk investors such as pension funds who control large pools of low-cost capital. These arrangements have helped see the prices offered to new offshore wind farms in Great Britain plummet from well over £100/MWh to below £40/MWh (2012 prices) – making offshore wind cheap compared to almost all other forms of power generation. Onshore wind and solar prices have also dropped under CfD support to £42/MWh and £46/MWh respectively in the most recent auction round in December 2021 (2).

Now that renewables are so cheap, some commentators are questioning whether they need the continued government support, arguing that markets might be able deliver decarbonised power more efficiently without the provision of these long-term contracts (9). They argue instead for an alternative approach, such as a low carbon obligation on suppliers (26). The logic is that although CfDs make investment less risky, they also largely remove any incentive for renewable generators to respond to the short-term price signals that reflect the value of electricity in particular locations or at particular times of the day or year. The central rationale behind this argument for reforming or removing CfDs is that if renewable projects were more exposed to wholesale price movements over time and in different locations, renewable generators could be incentivised to generate more when demand is high and not to generate when demand is low. This is also linked to a wider set of arguments associated with incentives for demand response and provision of flexibility.

Evidence in favour of this approach is that the market is now delivering wind projects outside of current policy support mechanisms. Currently, however, these remain a low proportion of the total market, below 1 GW out of a total of 48 GW (27). The extent to which these could be reliably scaled to cover the bulk of the wind power needed over the next 10-15 years remains untested.

Others argue that applying this approach to wind and solar generators would put the cart before the horse in terms of investment priorities. This line of argument is that we have only just started to deliver the massive shift in the country's power infrastructure needed for decarbonisation of the electricity system by 2035, and electrification of other sectors in order to meet net zero (28). Since renewable power generation will form the bulk of total electricity system costs in the future, the primary policy objective should be to maintain as low a cost of capital as possible during the build-out phase. Newbery (29) points out that at least some of the dynamic efficiencies of the market can be replicated through design changes to the CfD, and that this would be a more efficient approach to delivering investment than fully exposing plant to wholesale price risk.

1.4 Risks and cost of capital

Financial risk management is a complex topic, but a simple rule of thumb generally applies: higher-risk projects require a higher rate of return in order to attract investors which, all else equal, increases project costs. This is particularly significant when projects are dominated by upfront capital investments rather than ongoing running costs as is the case for renewables and other low-carbon infrastructure. Exposing project developers to risks they are well placed to manage can help to sharpen the design of projects, reducing the chance that consumers get saddled with the costs of poor project choices. However, exposing projects to risks they are not well placed to manage raises the cost of capital with no commensurate benefit in terms of project quality. It is therefore important to understand the nature of the risks facing renewable power projects as the electricity system transitions towards zero-carbon generation.

The importance of keeping capital costs and the costs of raising capital as low as possible are underlined in the Net Zero Strategy, which notes that the principal economic costs of net zero arise because of the capital intensity of low carbon. These are huge, equating to something like 1 – 2% of GDP (11). Similarly, the CCC assessments of net zero emphasise the importance of capital expenditure in the initial phases of decarbonisation, noting how this eventually provides a payoff in the form of huge reductions in gross expenditures on fuels.

At this stage in the energy transition, uncertainty over the size and fundamental characteristics of the electricity system could present risks which project developers and investors are not currently in a good position to manage. Arguably, these systemic risks are at their highest point in the near future given the policy dependent pathway choices that lie ahead. As the system progresses through the transition, some of these pathway uncertainties will be resolved. In the meantime, if the cost of capital dominates the overall cost of delivering the infrastructure investments that underpin the zero-carbon transition, this would suggest that now is not the time to change course on de-risking investment. This is not to argue for maintaining current CfDs in perpetuity. Indeed, a de-risking mechanism only partially covering the operational life, with only partial coverage of the market may lead to avoidable additional costs and a sub-optimal outcome.

However, in order to inform the debate about the impact of moving away from CfDs it is important to properly understand the scale of any impacts on investment risk. We need to quantify the impact of the risks imposed by marginal cost price formation on offshore wind and other renewables so that the costs and benefits of new market and incentive designs can be better understood.

2 Country Comparisons

2.1 Introduction

As noted above, adding renewables to the energy system depresses wholesale prices as conventional generation with higher marginal cost is displaced through the 'merit-order effect' (30), reducing the average price (capture value or market capture price) that VRE generators receive on the market (weighted by their own output), creating a 'price cannibalisation' (31). This effect can be observed empirically in virtually all wholesale markets in the world (see Figure 1), though the details depend on the specifics of each country's system (in particular the nature of the renewables, and the flexibility of the system into which they are being integrated). For each market, we indicate the capture ratio between the capture price of solar and wind, respectively, and the average market price

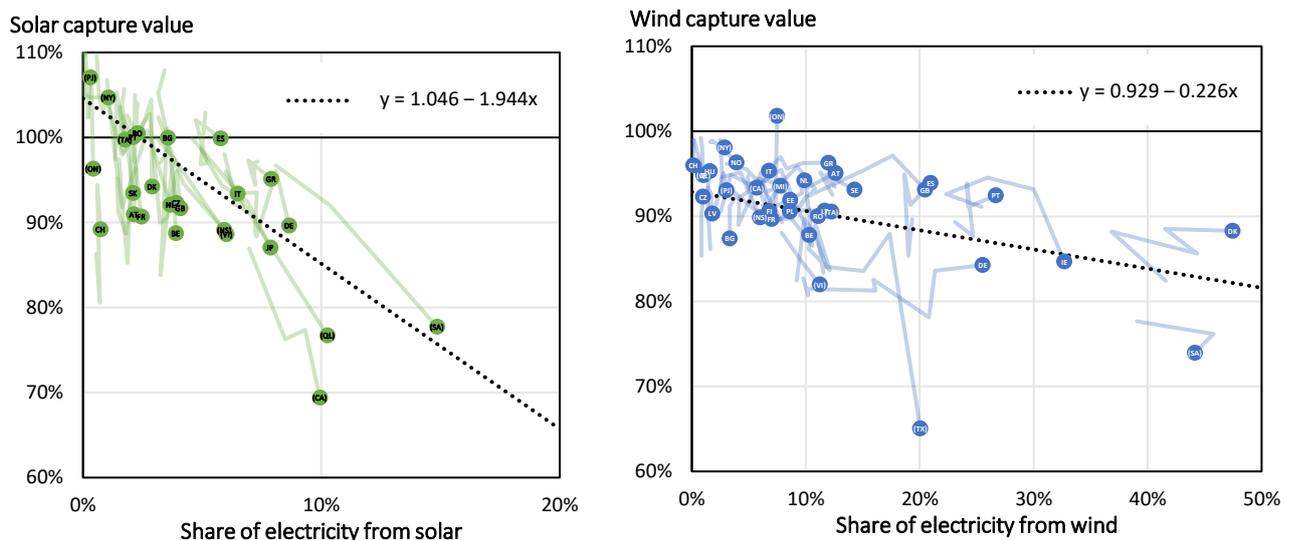


Figure 1. Capture values and price cannibalisation in 37 different electricity markets worldwide (32).

In many countries, the effect has led policymakers to supplement conventional 'energy only' wholesale markets with additional supportive policies for wind and solar, not necessarily to contain the payment of subsidies, as happened in the past, but focusing on the reduction of investment risks for developers through some form of revenue stabilisation.

Beiter et al. (33) provide a typology and overview of different renewable energy support schemes which create different exposure to merchant risk.

At the low price-risk end, feed-in tariffs (FIT) pay the project owner a fixed price for each kilowatt-hour of electricity, with no market price risks for the generators. FiTs are usually set by a national agency (or similar), but can be determined competitively as well. Power Purchase Agreements (PPA) also effectively fix prices for generators.

These are typically set through competitive auctions with government counterparties, or directly through commercial business-to-business arrangements.

At the other end of the risk exposure scale, are policies where renewables receive the market price with an additional premium. These premia can be fixed, as in the case of feed-in-premium (FIP) schemes, and government tax credits. These are usually set administratively. Tax credits can be either based on the produced energy, or the installation costs. Alternatively, premia can be variable, as in the case of Renewable Energy Certificates (REC), Renewable Obligations and Portfolio Standards. These add a variable additional revenue to what can be obtained through the energy market, with the additional price premia determined in response to contracts to fulfil mandatory decarbonisation requirements imposed by the government. The price of certificates can be determined through trading and may be affected by price buy-out or penalty rates applying to the policy.

In between these two, contracts-for-Difference (CfD) come in multiple designs, spanning different levels of exposure to merchant risk. They can be categorised into symmetric (2-sided CfD) and asymmetric (1-sided CfD). The 2-sided CfD is similar to a PPA, in that any difference between its strike price and the reference price is compensated. However, this can be made conditional on market conditions, such as the CfD designs across Europe where price support excludes times when prices remain negative for longer than a specified number of hours (typically six hours or less).

1-sided CfDs serve as a floor price for the generators but allow advantage to be taken of the upside, when market prices exceed the strike price. The 1-sided CfD can have many design differences, which are often described as sliding premium or sliding FIT. They can also be combined with a price cap to provide a cap-and-floor structure. 1-sided CfD strike prices or price floors are (normally) determined in auctions.

The duration of support is also an important element to the degree of risk protection provided by a policy. Typically, revenues from a plant's output will be subject to full merchant risk once it goes beyond this duration.

Table 1 shows how different countries have applied these different schemes. It also includes reference to Ernst & Young's (EY) "Renewable Energy Country Attractiveness Index" (RECAI) which ranks the world's top 40 markets on the attractiveness of their renewable energy investment and deployment opportunities. This gives an indication of the wider enabling environment in each country.

Table 1: Key characteristics of RES support schemes in different parts of the world. (34–36)

Country	Technology Focus	Funding Scheme / Headline RES support schemes	Support Duration (years)	Likeness to UK/GB	Price risk exposure (33)	Renewable Energy Country Attractiveness ^a Index (37)
Germany	Offshore W Onshore W Solar PV	1-sided CfD (Sliding Premium)	20	High	Medium	6
Spain	Onshore W Solar PV	1-sided CfD	-	Medium	High	10
Netherlands	Offshore Wind	1-sided CfD	15	Medium	High	11
Denmark	Offshore Wind	2-sided CfD	20 (was ~12)	High	Medium	15
Australia	Onshore W Solar PV	PPA RO	Typically 15	Medium	High	7
France	Offshore W	2-sided CfD	20	Medium	Low	4
China	Offshore W Solar PV	Admin. & competitive feed-in-tariff (for OW)	20	Low	Low	2
Taiwan	Offshore W	Admin. & competitive feed-in-tariff	20	Low	Low	30
Belgium	Offshore W	Fixed OREC/RO	20	Medium	Low	26
South Africa	Solar PV	Feed-in-tariff/ PPA	20	Low	Low	34
Chile	Solar PV	PPA	20	Medium	High	12
UAE	Solar PV	PPA		Low	Low	-
Japan	Offshore W Solar PV	Feed-in-tariff	20-25	Medium	Medium	8
New York	Offshore W Solar PV	PPA/RO/REC Fed. Tax Credit	20 (REC) 10 (Tax)	Medium	Medium	1 ^b
Texas (US)	Offshore W Solar PV	RO/var. OREC Fed. Tax Credit	10 (Tax)	High	High	1 ^b

^a Lower number is more attractive.

^b Applies to the entire United States.

Some of these support schemes may have similar effects to the UK's contract-for-difference (CfD) implementation in terms of revenue stabilisation, but very different underlying market designs. This has implications on the overall investment landscape of an energy system, which is determined by more than just the headline policy scheme. In addition to specific revenue stabilisation policies, it is generally recognised that there is a need for a wider policy framework to support the entire energy system to create incentives for flexibility and deliver best value for money.

To put UK policy choices into a wider international context, we investigate four countries to understand this relationship between revenue stabilisation policies for renewables and the wider market design arrangements. In the following sections, we

review the policy environments and market settings for Germany, South Africa, Australia and Texas with the aim to learn from a diverse set of funding schemes. This includes the type of technology, price risk allocation through the headline renewable energy support scheme and the wider market, overall investment environment for renewables, price formation mechanism in wholesale markets, system operation and likeness to the UK/GB energy system.

2.2 Germany

2.2.1 Overall energy policy environment

Germany has a long history of supporting the development and roll-out of renewable energy. It has pioneered wind power technologies at a large scale, such as the GROWIAN, the world's first 3 MW wind turbine in 1983. On the policy side, it has trailblazed renewables support in 1990, with the Stromeinspeisegesetz (StromEinspG), the world's first feed-in-tariff law for green electricity and which is the predecessor of today's Renewable Energies Act (Erneuerbare-Energien-Gesetz (EEG)). The country's long-standing history demonstrates its commitment to the roll-out of renewables, despite major changes throughout the decades. For example, major cutbacks on funding and a "capacity corridor" were introduced to slow down the growth of solar in 2012 to address rising consumer costs. A couple of years later, further build-out of anaerobic digestion was stopped over environmental concerns of biomass farming and its competition with food production.

In recent years, onshore wind is experiencing 'strong headwinds' over state-level planning laws, slowing down the rollout. Part of the problem is the (arguably excessive) "distance to settlement" rules in Bavaria of 10H (i.e. distance to settlement ten times the blade tip height of the turbine), which in effect is a 2 km distance rule for new wind development. The rule is in contradiction with federal law that requires a minimum distance of 1 km, which is still essentially preventing construction in more populous parts of the country altogether or reduces the wind farm size to a handful of turbines.

In its current inception from January 1st, 2021, the renewable energy act supports a variety of technologies, such as onshore and offshore wind, solar photovoltaics (PV), hydropower, anaerobic digestion and other. The exact rules are technology-specific in terms of funding conditions, but have a common basis. All but the smallest installations are subject to competitive procurement tendering (i.e. auctions) in which they bid for a sliding feed-in-premium support, which is essentially a one-sided CfD, for 20 years. This premium is funded via the EEG levy/surcharge on all consumers' electricity bills, although generous exemptions apply for the "energy-intensive industry" (38,39).

Participation in the auction is contingent on prequalification, which includes obtaining environmental permits and providing bid bonds, which are €30 /kW for onshore wind, €5/kW + €40/kW (bid+completion) for solar PV and €100 /kW for offshore wind,

representing ~3% of the total capex for each technology. Not fulfilling awarded bids are punished with the gradual loss of bond, and ultimately the loss of award.

Awarded capacity is granted a grid connection, free of charge, at the point of production. For offshore wind this can be a considerable benefit, estimated (40) to be worth up to €35/MWh, and is thus a significant part of the overall project costs. Nonetheless, obtaining grid connection is far from trivial, as the country has almost 1000 distribution system operators (DSO), which poses a challenge for solar PV and onshore wind in particular. For offshore wind, bids are made for individual clusters, for which the grid connection is pre-developed by the TSO, with a known connection date before the auction. For onshore wind and solar, grid connection is pre-developed on a state level and realised for wind and solar priority areas through the responsible grid operator (i.e. one of the ~1000 DSOs up to 110 kV). In case of delays with the grid connection, mostly due to technical difficulties, the generators under the EEG get reimbursed for any damages. This is mainly the loss of income from electricity that would have been produced.

In addition, grid congestion inside Germany is a rising challenge, with frequently occurring 'redispatch' of power plant due to the lack of transmission lines. Redispatch is carried out by the TSOs when the optimal dispatch, as determined by the market, cannot be fulfilled physically, for example, due to grid constraints. The grid build-out is further hampered by local opposition to essential additional north-south power lines. This is despite a concerted and constantly revised effort since 2012 to develop the necessary grid infrastructure (German: Netzentwicklungsplan) for net zero. The opposition is directed to the proposed new HVDC corridors which in 2022 are only in the later planning and consenting stage. Whilst wind generators are financially compensated for their losses, the resulting redispatch costs are levied onto consumers' grid charges. Delays in offshore grid connections are also likely and frequent, exposing developers to energy price risks due to later start dates of project and increased maintenance costs, despite being able to claim for damages. Ultimately, all grid costs are levied onto final consumption, which involves a complicated charging structure by region, grid operator, consumer type and metering types(41). This is relevant for hybrid projects of renewables and storage, hydrogen production, demand-side response or self-consumption, impacting their business case significantly.

2.2.2 Specific renewables support schemes

2.2.2.1 Wind-auf-See-Gesetz (Offshore Wind Act)

Offshore wind auctions are governed by the Offshore Wind Energy Act (WindSeeG), not the EEG, and are held by the Federal Network Agency (BNetzA). Two initial auctions were held in 2017/2018 for a capacity of 3 GW. A total of 29 prequalified projects took part in the auctions, with aggregate capacity of 8.7 GW and commissioning dates between 2021-2025 (42). In total, 11 awarded bids using the 'pay-as-bid' mechanism were awarded. A third auction was held in 2021, with three additional successful bids, bringing the total auctioned capacity to 4.0 GW.

For this first round of auctions in 2017, the time span between bid award and final investment decision (FID) is extremely long compared to other auction schemes in Europe, with no FID expected before 2022. The press releases from the wind farms (43–47) confirm that FIDs for winning projects were planned for years 2020 – 2023, but the COVID-19 pandemic and the resulting uncertainty around power prices might have pushed these to the latest possible date. Future auction rounds will require this period to be no longer than 18-24 months after bid or grid connection. A revised version of the WindSeeG came into force by the end of 2020 governing the annual auction process from 2021 onwards for wind farms with a commissioning date after January 2026, with a capacity of 900-950 MW for the 2021-2023 auctions and 3 GW each in 2024 and 2025. This, however, is likely to be revised upwards in the light of more ambitious targets by the new ‘traffic light’ coalition government (i.e., social democrats (red), liberals (yellow) and the green party) that came into power in 2021.

Whilst offshore wind auctions in 2017 and 2018 have produced ‘zero-subsidy bids’, which essentially means that wind farms are entirely financed on wholesale market revenues, final investment decisions are still pending and expected for 2022. More recently in 2021, all the offshore wind farms have bid zero. With more zero bids than available capacity, the decision of successful bids was made by drawing lots. This has also led to increased confidence for the realisation of earlier bids.

More than half of the capacity awarded in 2017/2018 were zero bids, which means that projects rely entirely on electricity market revenues, indicating economic competitiveness of offshore wind with conventional power generation (34,48). The grid connection, which makes up 15-30% (34) of the overall project costs, is provided free of charge. This will most likely convince developers to participate in the WindSeeG auctions, rather than going ‘fully merchant’ with a power purchase agreement (PPA) only project. Higher bids can be observed for solar PV and onshore wind, with no ‘zero-subsidy’ to date (see further down).

The headline-grabbing low bids of German offshore wind auctions require contextualisation, however. The 2017/2018 auction was fiercely competitive, oversubscribed by a factor three and losing the auction would block the route to market for these projects, as the cluster connections are fully occupied, and only later connection dates would be available. At the same time, project developer’s penalty for non-delivery would only amount to 3% of the total investment costs, which in total may have triggered extremely low bids and potentially contributed to the ‘winners’ curse’ (49).

2.2.2.2 Erneuerbare-Energie-Gesetz (Renewable Energy Act)

There are several types of auction in which solar can compete: 1: utility scale solar up to 10 MW, 2: innovation tenders, potentially with storage and competing with onshore wind, and 3: rooftop solar. In total 35 auction rounds accessible for solar PV with a procured capacity of 8.3 GW have been held to date since the 2014 EEG revision (38,50) and 1576 project bids were awarded. From 2017 onwards, only solar PV projects between 750 kW and 10 MW were eligible (51) and smaller projects are able to access a traditional FiT. Auctions were held at least three times per year until

2018 (52), increasing to five in 2019 and to seven rounds thereafter, including pilot joint solar PV/onshore wind auctions (53), which are dominated by solar PV projects. Like for offshore wind, the Federal Network Agency (BNetzA) organises and regulates the auction process. Only prequalified projects can participate and must prove the development status of the project and provide the initial bid bond and must be commissioned within 18 months from the time of award.

Solar PV auctions in the beginning were heavily oversubscribed (38), which has led to quickly falling bid prices since the commencement of auctions in 2015. However, bids (and presumably costs) of solar PV installations with a commissioning date of 2019 and later have been on a flatline trajectory, having largely stagnated around the €50 /MWh mark. This is likely due to the availability of land, project backlog, high labour and land cost, which reduces the significance of overall technology cost reduction. In addition, the advent of fully-merchant PPAs means that the best sites will be realised outside the EEG. For selected sites solar PV is being realised outside the EEG, even forgoing some of the benefits, such as free grid connection. However, grid costs are an order of magnitude smaller than for offshore wind, so not very relevant in terms of overall project costs. At the same time, project size restrictions of 10 MW under the EEG are no longer valid and projects of 100 MW and more are possible (54).

Onshore wind has technology-specific auctions – alongside technology-neutral innovation tenders, where solar PV outcompetes onshore wind consistently – which supports deployment. In a total of 23 auctions (not counting innovation tenders), a capacity of 12.6 GW has been procured by the end of 2022 with 1836 awarded bids, and an average price of €58.3±6.3 /MWh. The low prices observed in the 2017 auctions – as low as €22.0 /MWh and on average €38.2 /MWh (capacity-weighted average for the whole auction) – have crept up again to over €60 /MWh (55) since the second half of 2018. Auctions are lacking competition and are undersubscribed in many cases (56).

For onshore wind, the EEG has an emphasis on regional equity for the distribution of assets, to allow wind turbines to be built economically at less favourable wind sites with higher hub heights. This enables a regional distribution across the entire republic. For onshore wind this means that the ‘reference yield model’ adjusts the bid price post-auction to account for site quality. This will see the bid adjusted with a correction factor for their bid prices between 1.35 and 0.79 for wind sites with 60% to 150% of energy yield (depending on the wind site conditions) in relation to a defined reference site.

In Germany, solar PV is affected by price cannibalisation more than wind (32), which means that developers will have to face market price risks and expect decreasing revenues over time, something that assets within the EEG have to face to a lesser extent.

2.2.3 Wholesale market price formation

Predating any price movements induced by events in 2021/2022, price developments in Germany's power market were typically more predictable than in other countries, partly linked to long-term gas contracting and the feed-through to these to electricity prices due to Germany's weighting towards the 'energy-only' market. In place of a capacity market, the regulator maintains consented disconnection allowance strategy for fossil generators before market exit to maintain capacity adequacy. This means that generators must ask the regulator for permission to disconnect and decommission a generator, which is only approved if sufficient capacity remains on the grid. Any extension of operation will be approved by the regulator on a cost basis and then levied onto consumer's grid fees.

This in turn generates investment signals in the wholesale spot market itself with price peaks and creates little interference in the price finding function of the spot market (32). In similar fashion, ancillary services markets are well aligned to the spot market and cause little price disruption as product lengths and gate closure times allow generators to provide ancillary services that are available for energy production anyway, reducing must-run capacity (57). About 38% (58) of all power consumed in Germany was traded on the largest exchange EPEX SPOT in 2019, the year before the pandemic. This provides important price signals to large parts of the market by proxy, incentivising optimal dispatch of plants. Germany is also heavily integrated into the European power grid with about 15 GW of interconnection capacity to neighbouring markets, which constitutes about one fifth of its total peak demand (59), creating further opportunities for capacity sharing, streamlining dispatch and providing reliable energy price signal for the largest power market in Europe.

Figure 2 shows Germany's day-ahead spot prices in €/MWh over the gross load minus solar and wind for the last decade. The shape of this curve, its scatter and reaction to extreme events (i.e. the ends of the curve) show the high predictability of prices in the power markets, when compared to other markets. (See Halttunen et al. (32)).



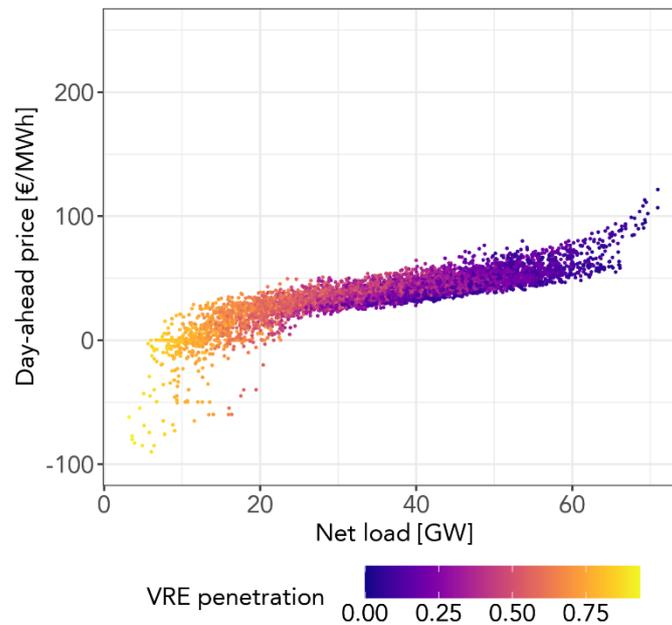


Figure 2: Germany’s day-ahead spot prices in €/MWh over the net-load (gross load minus solar and wind) for 2010-2019. The colour of the dots indicates the instantaneous penetration of wind and solar for each hour. For comparison with other countries see Halttunen et al. (32).

As a result, prices in the German electricity market correlate highly with renewables output and time-dependent variables, such as a time of day, weekdays and seasons. This holds true to some degree, even with the commodity price shocks observed in 2021/2022. Overall (short-term) prices are still somewhat stable and predictable, albeit at a different level due to the change in the fundamentals (i.e. higher gas prices). Future prices are therefore predictable enough for actors to make investment decisions based on wholesale market price expectations, especially when accounting for the government’s stated policies for reliable build-out of renewables and closure of fossil generation and taking into endogenous (long-term) price shock scenarios.

Government policies thus create an environment that not only fosters investments into renewables (i.e. through CfDs), but also changes the market setup and composition (e.g. coal phase out, hydrogen production, grid batteries). Whilst the coal phase-out will likely drive price levels and their volatility up, the introduction of hydrogen will reduce their volatility again. In terms of providing long-term outlook, out of 37 markets investigated worldwide, Germany has historically scored the highest in this category (32). This makes a good investment case outside the EEG using PPAs, despite inherent uncertainty of long-term price forecasts. Potentially strong policy measures on the demand-side (hydrogen, demand-side response, EU ETS carbon pricing) will further support developers as they tend to stabilise power prices in the long run.

2.2.4 Price risk allocation

Beiter et al. (33) categorise Germany's support scheme as medium price risk exposure, which is reflective of the overall situation. The exact exposure to prices, however, changes significantly on the relationship of bid price to the overall power price (expectations) for the project. The immediate counterparties for the arising long-term price risks of the subsidy component of payments lies with the German Transmission System Operators (TSOs), which shift the costs onto all consumers through the EEG levy onto their electricity bills. Not all price risks are covered through the RES support schemes, and increasingly low bids shift this risk towards the generators (see Figure 3 below). The sliding-premium setup of Germany's 1-sided CfD means that revenues bear significant short-term price risks, as the CfD strike price acts as a floor price. The policy mandate of "direct marketing", which requires trading of (almost) all renewable electricity through third-party aggregators, sees all renewable electricity sales facilitated through PPA-style arrangements or spot-market sales and thus requires appropriate risk hedging strategies (e.g. long-term PPAs).

The long-term market price risk allocation under the EEG's one-sided CfD is firmly allocated on the side of the households and smaller electricity consumers and some non-energy-intensive consumers (i.e. below 1 GWh/a and energy costs are below 15% of total costs) for CfD strike price (bid prices) significantly higher than market average prices. A high strike price means revenues for generators are (seemingly) safe. Large energy consumers are largely exempt from paying the EEG levy, thus do not assume the price risk of the national renewable energy portfolio.

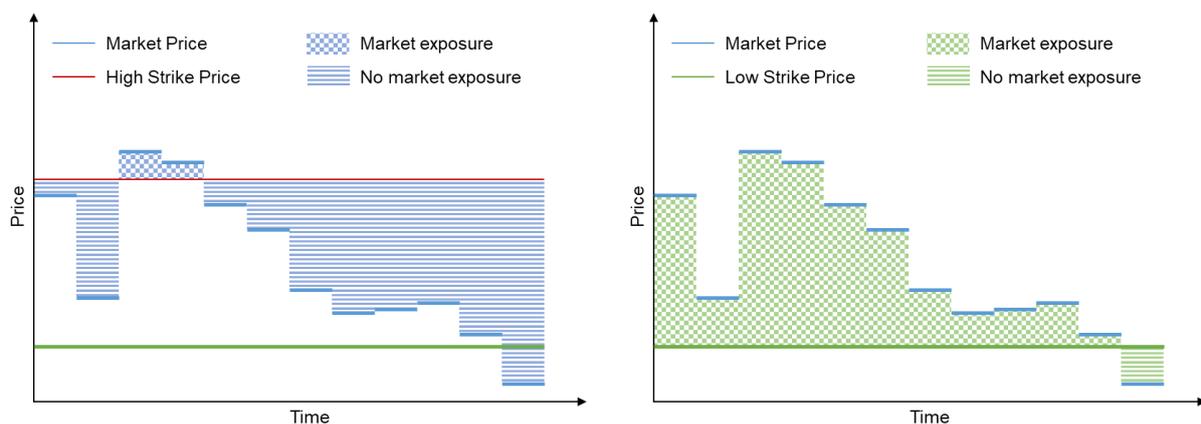


Figure 3: Market price exposure in relation to the strike price

For strike prices close to or below the market average, market price exposure of renewable investment is increasingly exposed to (and thus financed on) power market prices only, with some offshore wind farms being fully financed on market terms. Bids from the solar PV and onshore wind auctions indicate a certain 'sweet spot' around the average market price, where some risk hedging is still provided long term, whilst being able to monetise some of the market upside. This can be seen in

Figure 4 by the 'levelling off' of the strike prices in solar auctions around the (long-term) average wholesale electricity price.

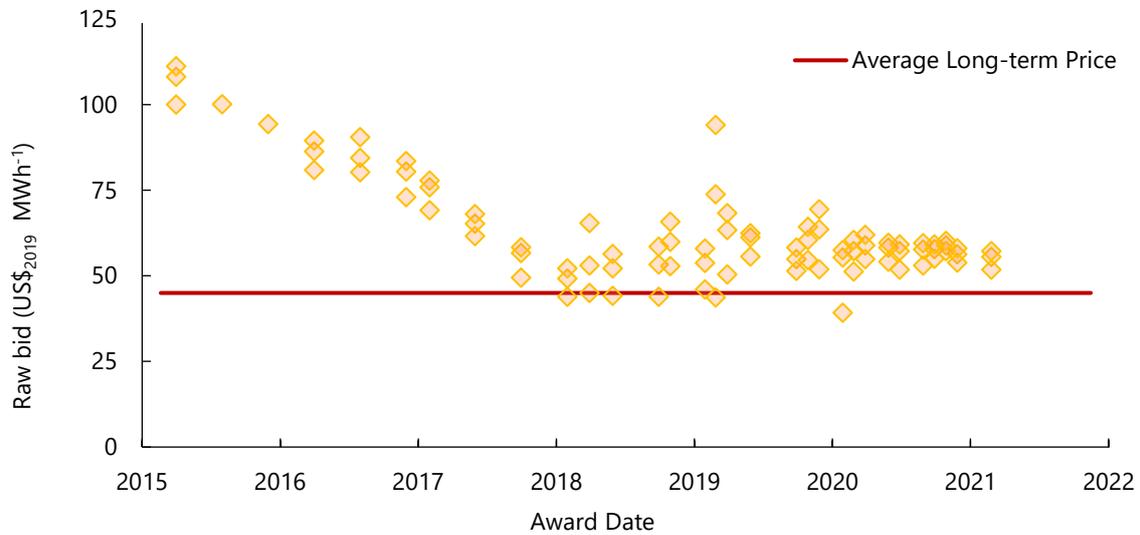


Figure 4: Raw bid prices from Germany's solar auctions and average long-term market price (2015-2019) (60)

The absence of bids between this sweet spot and zero bids shows that there is no competitive advantage for winning projects by going lower than this, whilst increasing market price exposure significantly, which is similarly high when bidding zero. The frequency of auctions for solar PV and onshore wind (i.e. on average every three months) and the currently low level of competition means that financial costs of not being awarded a CfD in a specific auction are low, as the company can bid in the next auction and tune its bidding behaviour based on past results.

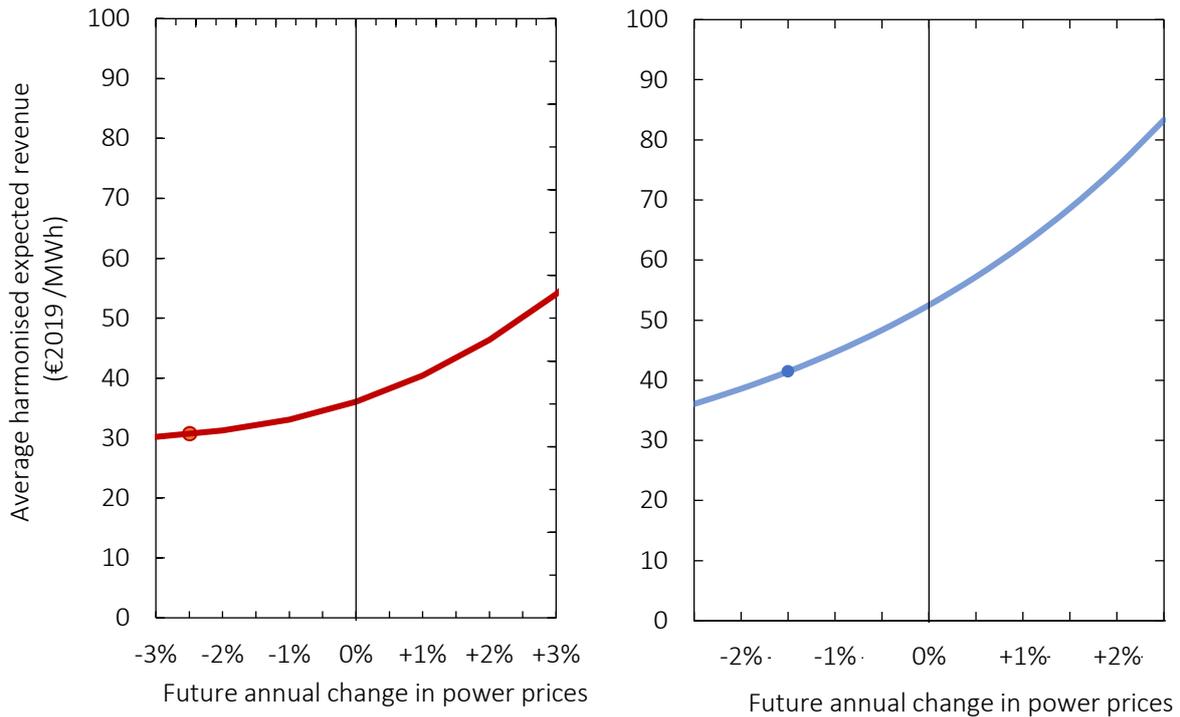


Figure 5: Harmonised expected revenues for the lowest bids in Germany for solar (left) and offshore wind (right) as a function of the future power price development. Changes indicated are in percent per annum based on 2015-2019 average wholesale electricity prices. Adapted from(34)

The use of PPAs is still in its infancy in Germany. They are mostly used to generate additional revenue for legacy onshore wind farms after the end of the legacy 20-year FiT funding period or to facilitate the sale of electricity under EEG's direct marketing scheme since 2012 (61). However, the PPA market for solar PV is generating new capacity outside the EEG (54,62), which means subsidy-free solar is actually being realised 'fully merchant', which further supports the logic of not bidding zero-subsidy bids in the EEG. In addition, solar PV assets from PPA deals are typically larger than the 10 MW plants possible under the EEG, leveraging economies of scale to make the project viable. Most analysts see the PPA market grow significantly over the next couple of years (63), despite PPA projects being more risky investment than EEG-based projects (64,65).

2.2.5 Overall investment environment

Upcoming policy changes in the 2021 EEG revision will see an increase in auctioned capacity across different technologies, introduction of cost caps, the introduction of innovation tenders (i.e. technology-neutral next generation auction procedures), tight integration with the hydrogen strategy and incorporation of more ambitious climate targets. The entire process has been debated heavily, especially arguing over investment conditions for developers. In one example, policy makers wanted to introduce negative bids to the EEG auction system in a two-step auction process for

offshore wind, to further drive down costs and recover some of the grid connection costs. The state's role would have transitioned from a procurer to seller (of seabed rights). It was the desire to address high offshore grid connection costs by extracting rent from offshore wind projects and lower consumer's bills. This has found fierce opposition from the industry, which had advocated for a UK style CfD system (66). The debate concluded in a compromise, which in essence sees the continuation of the current system as is (67). This example is a showcase for German policy making, based on consensus and reason, which in part provides the highly reliable larger policy environment.

The recently elected parliament has led to change in government. This sees the social democrats leading a coalition government with the green party and the liberal democrats. Their coalition agreement envisages a step change by 2030 such that 80% of all electricity consumed would be from renewables, some 600 TWh. This means reaching 200 GW of solar PV, 30 GW of offshore wind and 10 GW of electrolysis by 2030. The coal exit will also be accelerated by up to eight years to 2030 as well, which at the time of writing in May 2022, is still the intended – and indeed legislated – pathway, despite the effort to reduce reliance on Russian gas imports (68). Reducing the reliance on Russian gas is intended to be achieved by building two LNG terminals in Germany, (69) with plans to phase out all gas-powered generation by 2040. 2% of Germany's area will be earmarked for onshore wind (70). The outgoing government itself had set things in motion for the world's first hydrogen offshore wind auction, "sometime" in 2022 (71).

The renewables support policy is embedded in a wider policy landscape of streamlined and high-efficiency power and ancillary services market designs. Add to that the rollout of heat pumps for heat decarbonisation has crossed the threshold of over 50% in new-build housing in 2020 (72) and will be providing flexibility to the electricity market in the medium term, a strong hydrogen strategy and a tight European integration on all levels. Said market integration of renewables is a long-standing policy goal in Germany, which has created markets 'fit for purpose', creating visibility for investors.

The German 'Energiewende' is of course not without its controversies, despite generally supportive policies on low carbon transition. So far, the policy programme was lacking decisive action in addressing CO₂ emissions from coal, especially lignite, and heavy industry. The coal exit compromise, which foresaw a phase out of all coal generation by 2038, is another example of consensus-based policy decision making, which often leads to policies unfit for reaching net-zero sufficiently. In the light of the war in Ukraine and a new government taking office, this has now been brought forward to 2030, setting aside the decision in the time-consuming and costly coal exit compromise. The decision of levying RES support costs mostly on household consumers to protect industrial consumers revenues or the construction of the (and now defunct) Nord Stream 2 gas pipeline are counterpoints to the otherwise supportive environment for investment in renewable energy.

Overall, Germany provides a well-developed market environment. The funding structure means that investment signals depend more on market prices than

elsewhere, but price developments follow fundamentals more than elsewhere as well, which creates good visibility for investment.

Access to capital and the resulting low rates of weighted average cost of capital (WACC) are encouraging signals to investors. A survey in 2019 has revealed that the WACC for onshore wind was 1.3-2.5%, the cost of debt 0.8-1.8%, the cost of equity 2.8-7.8% and gearing ratio of 77/23-100/0 was applied. The WACC for offshore Wind was found to be 3.5-9.0% (73).

When considering the long-standing commitment of Germany to the energy transition, with its (mostly) holistic approach to policy making, and despite major policy changes and challenges, the country provides a fundamentally reliable investment environment, due to its overall direction and clarity. This gains Germany the overall 6th position in Ernst&Young's Renewable Energy Country Attractiveness Index (RECAI) (37).

2.3 South Africa

2.3.1 Overall energy policy environment

As a signatory of the Paris Agreement, South Africa has committed to peaking its emissions by 2025 with subsequent plateauing and reduction thereafter (74). In the medium term until 2030, the country's policy is governed by the Integrated Resource Plan (IRP) 2019, which set the country on a path to reduce its emissions, 80% of which are originating in the energy sector (including oil and gas) and 50% in the electricity sector. By building 20.4 GW of renewable energy, 14.4 GW of wind and 6 GW of solar PV by 2030, alongside measures for energy efficiency and increases in public transport, the country seeks to decrease its use of coal for power generation. The net-zero trajectory has committed the wholly state-owned utility Eskom to net zero-emissions by 2050. For the long-run, the country relies on the Low Emission Development Strategy (LEDS) to move towards net-zero. However, legislative action is yet to enshrine these targets into law. (75)

South Africa's generation mix is heavily dependent on coal power plants (83% of demand) with an installed capacity of 38 GW (76), which makes it the country with the highest coal-reliance of all G20 countries (77). The country also operates one nuclear power plant and several diesel and gas power plants. Renewables have a combined installed capacity of 8.3 GW, covering hydropower, wind, solar and concentrated solar power (76,78). Eskom is South Africa's vertically-integrated national utility (79) and the country's largest GHG-emitter. It supplies 95% of the electricity demand (79,80) and manages all aspect of generation, transmission and distribution.

South Africa's power sector is failing to supply enough electricity to match the demand. Decades of low investment activity in new generation capacity has left the country with an ageing power plant fleet. In large part due to the supply gap derived from company mismanagement with severely lacking maintenance and virtually no investment in new generation capacity from the private sector, which further

entrenched Eskom's monopoly status in the electricity market (81–83). The lack of maintenance of its existing fleet, has left the country facing an existential economic and social crisis, which have led to a loss in GDP by up to 10% (R300bn, approximately \$20billion) by 2014 (84). The existing coal fleet has an average age of 39 years old and fleet-wide availability was down to 65% in 2020 (76,78,85). Since 2018, continuous scheduled load shedding across the country is part of daily operations (82,84), which has occurred for at least 43 days, or roughly 10% of operating hours (76) and between April 2020 and March 2021.

Eskom's central position has made it vulnerable to 'state capture', which has brought it to the brink of bankruptcy and cash flow issues prevented maintenance of existing assets or providing reliable services (79,86). In an attempt to remedy the situation by the government, the utility's operation will be unbundled by December 2022 into the three separate subsidiaries (83,87), which should improve Eskom's financial position significantly. However, the fact that Eskom can only service about R200bn of more than its R464bn in debt by itself and that only a government bailout of R128bn in 2019 prevented the total financial collapse shows the long road to recovery (86). This is exacerbated by outstanding payments of more than R35bn, owed by the municipalities for services already delivered.

The government's 'Integrated Resource Plan 2019' expects that the supply gap of 2-3 GW will persist for at least five years, mostly due to the decommissioning of 11 GW of coal power (88). In March 2021, Eskom announced that the situation will be even worse, indicating a generation shortage of 4 GW for another five years, due to planned and unplanned maintenance activities and delays in bringing additional capacity online (76,78,85). The government's emergency power procurement has taken measures to address these issues with a procurement plan of 28 GW in new capacity additions to narrow the gap by 2030 (87,88). Improving the supply situation comes at a considerable cost and the country requires reliable, secure, and affordable energy generation, for which onshore wind, solar PV, and concentrated solar power are being actively explored to reduce the reliance on fossil fuels.

2.3.2 Specific renewables support schemes

2.3.2.1 Risk Mitigation Independent Power Producer Procurement Programme

The South African government has implemented a Risk Mitigation Independent Power Producer Procurement Programme (RMIPPPP). This is an attempt at reducing the gap between demand and supply by procuring 2 GW of emergency supply capacity, which was estimated to be online by June 2022 (89). These auctions would lead to long-term PPAs between the awarded generators and Eskom, which function as FiTs due to the monopolistic structure. This capacity includes renewable generation, storage and gas-powered generation. Four out of eight winning bids receiving a PPA with Eskom are RES power plants, while the rest relies (at least partially) on liquified natural gas (90). The largest contracted capacity of 1,220 MW (out of 1,845 MW) will be fulfilled by so-called "power ships", which are

vessels outfitted with gas or heavy fuel oil generators to produce electricity (91). The overall costs for emergency power solutions could amount to R218bn, as the power average price is approximately R1,600 /MWh for a 20-year PPA (92). The decision to use the power ships has recently been rescinded by the energy ministry due to a negative environmental impact assessment (93), exemplifying investment risks in the current situation, but also the country's desperation for reliable, secure, and affordable energy.

2.3.2.2 Renewable Energy Independent Power Producer Procurement Programme

In 2011, the country's Department of Energy (DoE) (now Department of Mineral Resources and Energy (DMRE)) set out to strengthen the generation mix, allowing independent power producers to feed into the grid and add renewable capacity through the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP or REI4P) (81,94,95). The REIPPPP auction scheme follows a multiple-item format and the auctioned volume for each round is split into different technology bands. Renewable generators can bid for grid access and subsidies in an auction, which is then implemented as a 20-year power purchase agreement (PPA). The immediate counterparty is Eskom and financial payments are ultimately guaranteed by the government (96).

Four bidding rounds with a capacity of 6.3 GW have been held to date (96). Overall, the REIPPPP was successful in encouraging falling prices for renewables (see Figure 6), high project realisation rates of 95% for the first three rounds, and limiting market concentration (95,96). However, Eskom refused to sign awarded PPAs in the fourth bidding round over concerns that it would impact their balance sheet negatively in the future, despite government guarantees (97) jeopardising investments in clean generation in favour of new coal generation (97). This means that the unclear and/or unsatisfactory regulatory framework for cost recovery from the REIPPPP (and RMIPPPP) will pose a challenge for further renewables build-out (94,95). In addition, delays in announcing the fifth round led to the loss of some manufacturing capacity in the country (98), which exacerbates the fact that manufacturing and installation facilities for large renewable projects are often lacking in emerging economies, contributing to additional capex.

The fifth round was opened in April 2021 and closed in August 16, 2021 (99,100) and is set to procure 2.6 GW of renewables capacity, 1.6 GW onshore wind and 1 GW solar power (99). The auction scheme features a weighted point-based system, in which the bid price accounts for up to 90% of the total score, and 10% based on economic development scores, such as job creation and skill development, local content, ownership and management control as well as contributions to the local community, with distinct requirements for SA citizens, especially black people and a special emphasis on black women and black youth. This is a marked departure from the fourth round in which the price requirements were weighted with 70% and shows the stronger emphasis on economic performance in the auction, likely increasing the economic pressure (101). Local and international project developers are allowed to

bid, given that they comply with the auction criteria above and provide proof of financial standing, environmental consent and ten years' worth of energy sales forecasts (in the case of solar PV). The pay-as-bid principle in the bidding procedure is applied and payments are made in South African Rand (ZAR), adjusted for inflation in line with the South African Consumer Price Index.

The responsibilities of securing project sites and obtaining grid access from Eskom or relevant municipal distributors also fall on the project developers (102). The ministry has also stated that the qualification criteria require projects to be fully developed before bidding and operational in 12-24 months after taking FID (98).

Successful bids close a 20-year PPA with Eskom, regulated by the National Energy Regulator of South Africa (NERSA) and backed by "Implementation Agreements" with the government. Implementation agreements have their own conditions attached, but serve as a fallback option in the (not highly unlikely) case of default by Eskom (103).

Until FID has been reached, the awarded bids can be adjusted to reflect changes in projects' investment requirements (102). 24 to 30 months is the typical lead time (allowed) for projects to reach commercial operation from FID (104,105). Delays in operation are penalised by shortening the support length by one day for every day that operation is delayed, until potential contract termination after a delay of 18 months. In addition, fiscal penalties apply and can lead to termination, if economic development requirements are not adhered to (39,102).

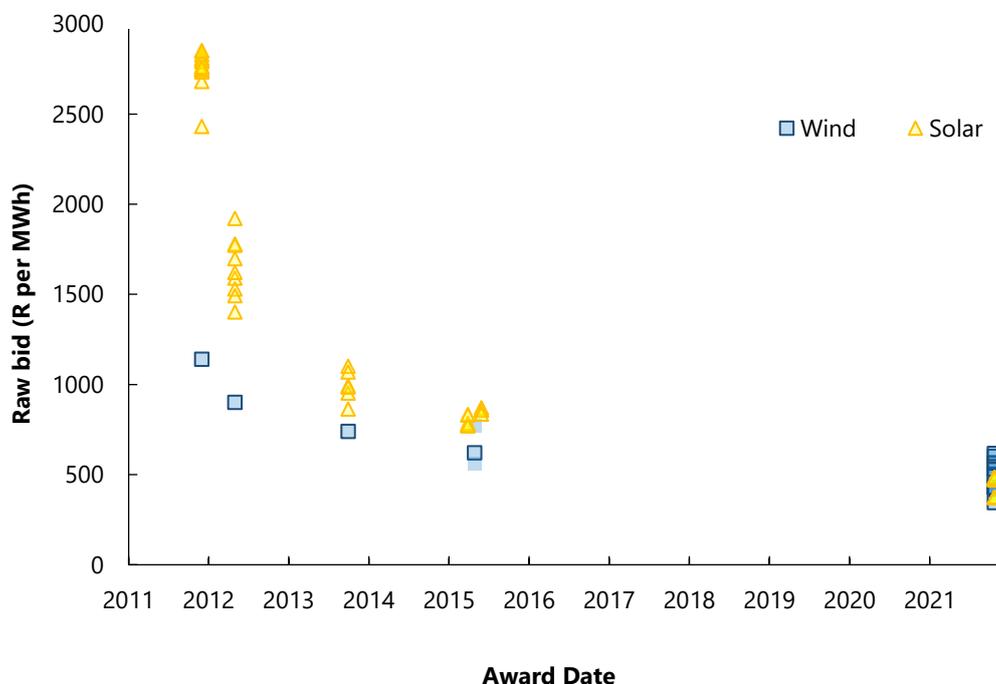


Figure 6: Awarded bids for solar PV and onshore wind in South Africa. Wind data from (106), solar data from Department of Mineral Resources and Energy Renewable Energy Independent Power Producer Programme.

By early 2021, 4.2 GW of solar capacity was installed in South Africa (107) and analysts forecast an annual growth of 10+% until 2026 (108). To date, 2.2 GW of solar have been procured through REIPPPP auctions, with an expected 1 GW to be added in 2021. Additional capacity has been awarded through the RMIPPPP programme, e.g. the 150 MW solar PV and storage project in the Northern Cape region which is part of a larger 540 MW solar farm and linked to a 225 MW/1.14 GWh of battery storage (109). However, we expect the REIPPPP programme to be the main driver for capacity additions in the future.

A total of 45 projects have been awarded under this programme, and the latest are expected to be online no later than October 2021. Solar PV projects are to be no smaller than 1 MW and no larger than 75 MW in order to participate. We can observe projects at both ends of the scale, but the average capacity of the projects is around 50 MW, which indicates that developers choose to build preferably larger projects as to leverage economies of scale. The capacity-weighted average of all four previous rounds is R1537 /MWh (approximately \$90/MWh). However, this includes bids dating back to 2011, when the overall cost of solar technology was considerably higher than it is today. Early projects that came online between 2014 and 2016 had significant cost reductions, some over 30% per year, whereas later projects have slowed down to single digits cost reductions (~5%). More indicative for the future is the lowest bid observed so far at R771 /MWh, which may come at lower-than-average system generation costs, making it virtually subsidy-free for the South African electricity consumers.

The bidders must provide a bid bond of R100,000 /MW. Successful projects pay an additional R200,000 per MW and also must pay a development fee of 1% of the total capex (105). Developers pay for the grid connection as well as transmission network charges (in R/kW) to Eskom, although projects in the Cape and Karoo zones are exempt from this (110).

The capacity cap of 75 MW for solar and 140 MW for wind still holds true for the fifth round of the REIPPPP programme. The bid window 5 was keenly awaited by many developers who had developed projects waiting for access to the market after delays in getting the round off the ground (111). In addition, projects must ensure that sufficient grid connection capacity is available to operate the project. For this purpose, Eskom publishes the available connection capacity for any potential projects. Eskom's grid constraints mean that projects will be slightly more dispersed across provinces (112), causing bidders to choose slightly worse meteorological conditions, as there was no available capacity in the Northern Cape region for bid window 5 (113).

In total, 63 bidders for 1 GW of solar capacity (112) have been registered. Assuming the average project size from the last four rounds of 50 MW, the round will be at least three times oversubscribed, although developers might have even larger projects on their books, considering the increased size cap of 75 MW. The results from the fifth round show that 13 solar projects have successfully bid, with prices of

R431±52 /MWh (min: R375 /MWh); max: 484.60 /MWh). All projects were awarded with the maximum possible capacity of 75 MW (101).

While solar has taken the centre stage in recent years in South Africa, onshore wind has been in operation for years. The accumulated capacity from the first four rounds of the REIPPPP tender is 3.4 GW, with 2 GW in operation and a further 1.4 GW under commissioning. Wind farms in operation are 92 MW on average and 126 MW for the newer ones under construction (114). Prices in the last four auctions rounds have been consistently lower than for solar PV and average bids for the fourth round were R620 /MWh, lower than the lowest bid observed so far. The lowest bid for onshore wind is at R560 /MWh (96), which firmly puts it into the zero-subsidy area, as for solar PV mentioned above.

For onshore wind 39 bidders are participating in the fifth auction round of 1.6 GW of capacity (112). Assuming future wind farms, which have a capacity cap under REIPPPP of 140 MW, are of similar size as the ones currently under construction, it is likely that about 5 GW of onshore wind are in the developers' pipeline. Thus, the 1.6 GW of capacity in the auction would be oversubscribed by factor three. This will lead to fierce competition, especially when considering the project backlog due to delays in the fifth round and ultimately very competitive pricing. The results from the fifth round show twelve successful onshore wind projects have won bids, at an average capacity of 134 MW – only two projects were below the 140 MW capacity cap – and an average price of R494±81 /MWh (min: R344 /MWh; max: R617.70 /MWh)(99).

The country also has recently lifted the capacity ceiling above which licensing is required for distributed generation (including solar). This will help to build capacity outside the REIPPPP, paving the way for potentially lower cost solar (115).

South Africa has large offshore wind resource potentials along its coastlines amounting to several hundred gigawatts (116) with significant technical potential in its EEZ (116–118). This is paired with a challenging bathymetry of a continental shelf falling off steeply close to the coast. This limits the potential for traditional bottom-fixed offshore wind turbines to a few locations to 45 TWh/a at depths of 50 metres and less. The wind potential of 2400 TWh/a at depths of up to 1 km (118) is firmly in the realm of floating offshore wind turbines, a technology still being refined in the most mature markets in Europe.

A recent study finds that 5-8 GW of potential is instantly economically exploitable with bottom-fixed offshore wind turbines at no extra cost to the system, assuming prevailing macro-economic conditions in the country. A much higher potential would be accessible if financing costs were reduced. A reduction in WACC would increase this multiple times (119). An international developer of floating wind farms partnered with a local enterprise in May 2020 to plan the first offshore wind farm (120). Given the state of the technology in Europe, actual construction will not happen instantly, but the Global Wind Energy Council ranks the country in the top three future wind markets in 2025 (121). Despite the available wind resource, plan for the exploitation of offshore wind have yet to be announced.

2.3.3 Wholesale market price formation

As a vertically-integrated utility, Eskom covers all aspect of generation, transmission and distribution for South Africa. Generally, households and businesses cannot choose a different supplier electricity. There is no wholesale market environment for generators and consumers to trade. Instead, all dispatch decisions are made within Eskom's structure, following regulations. Price formation is therefore implicitly given within the business model, but cannot be observed from the outside. Eskom's financial difficulties mean that pricing of services and generation costs was not aligned with the revenues realised and thus a mismatch is likely to have occurred.

2.3.4 Price risk allocation

According to Beiter et al. (33), South Africa's REIPPPP programme has a low market price exposure. In fact, the 20-year PPAs closed between the generator and Eskom are at the long end of typical support schemes lengths. In addition, the price inflation risk is mitigated by an adjustment to the consumer price index (CPI), which means that the support payments are constant, in real terms. ESKOM is the counterparty and thus accepts the (inherent) price risk.

In any case, market price exposure can only remotely be assumed through Eskom's activities, due to the absence of a wholesale market altogether. This will have challenging implications for the continued operation of the assets after the funding period to finance ongoing operation, assuming no wholesale market has emerged by then. Price risks for generators are mostly of an administrative nature, where the underperformance of the asset will be penalised. To summarise, Figure 7 shows the market price exposure for a solar PV plant, with an assumed lifetime of 25 years. Due to the contract structure, virtually all the price risk stems from the period after the end of Eskom's PPA.

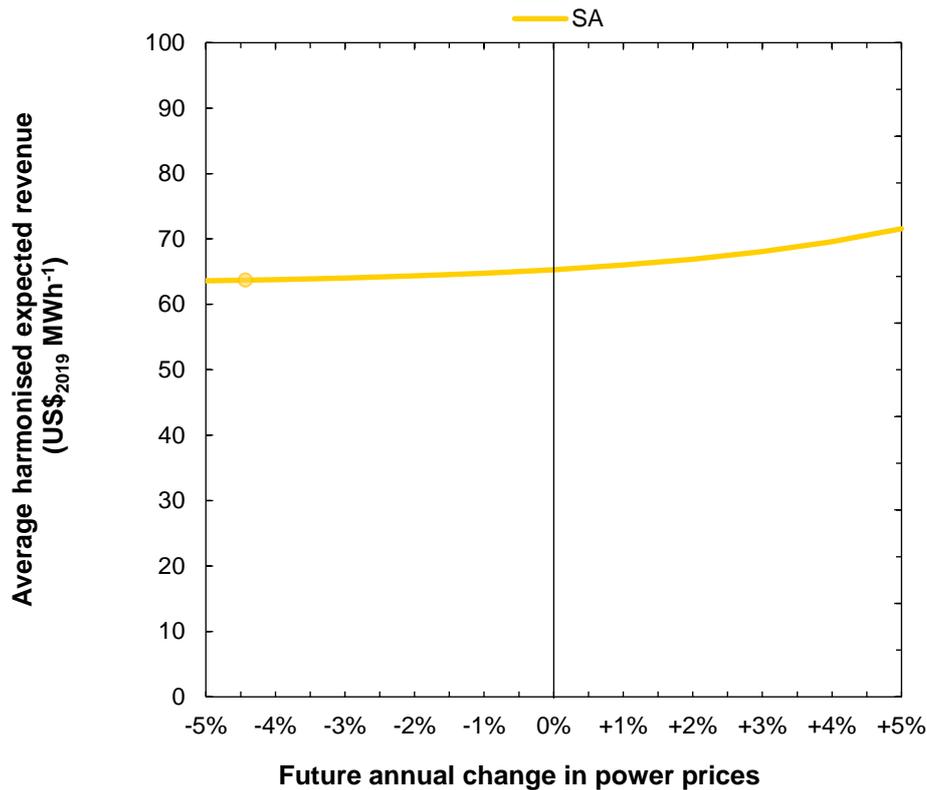


Figure 7: Harmonised expected revenues for the lowest bids in South Africa for solar as a function of a future power price development in a hypothetical market. Adapted from(34)

Without access to a wholesale market, the RMIPPPP or REIPPPP programmes are (almost) the only routes to market at the current stage. Very recently however, news has emerged on possibilities outside of auction, with individual companies tendering PPAs, to improve their carbon footprint and gain access to reliable electricity at lower prices (122). Whilst no contracts have been closed yet, and henceforth no capacity realised through these schemes, one could imagine a more dynamic world, with shorter PPA lengths, which then negotiated and traded on shorter timespans than 20 years, from which market price uncertainties could arise.

2.3.5 Overall investment environment

The larger policy environment has set the stage for reaching net-zero in 2050. South Africa has one of the best wind and solar potentials in the world and exploiting it for clean energy should be at virtually no extra cost to consumers. However, the net-zero target is yet to be implemented legislatively and necessary reforms and planning have yet to be carried out. For the medium-term, the country has set out a plan for changes up until 2030, but a comprehensive plan on how to reach net-zero beyond this is still pending. Necessary structural changes to facilitate the energy transition are in progress and the outcome of these may not come into full effect

before the mid-2020s. For example, the unbundling of Eskom, though repeatedly announced, will not happen before the end of 2022 at the earliest.

First, structural shortcomings in the electricity system, such as the absence of a wholesale market or a shortfall in transmission capacity, hinder the roll-out of renewables in several ways. The absence of a wholesale market means that investors have little visibility of the value of their renewables assets in the long-run and few routes to the market to realise projects. The main means to realising renewables projects is through the REIPPPP and RMIPPPP programmes, both contingent on government policy and interaction with Eskom. The delays in announcing the fifth REIPPPP round and subsequent decline in companies in the field is symptomatic for this. Although the government has repeatedly confirmed the roll-out of renewables, there is no reliable schedule on when auction round six and seven are taking place, making it difficult for investors to upscale their economic activities. Add to that the relative scarcity of renewables auctions, and it makes a difficult decision for the overall investment landscape in the field.

Second, Eskom's precarious financial situation, its pivotal role for the country's economy and contribution to the overall GHG emissions, emphasise how politicians are 'walking on hot coals' with this issue. It is imaginable that policy makers want to overexert political power over the utility, potentially scuppering the unbundling in all but name. Additionally, cost pressures on Eskom might tempt the utility to protect its profitable parts of the business and delay the rollout of renewables in an attempt to recover more cashflow from its existing coal fleet.

Despite being a relative stable and prosperous economy, when compared to its immediate neighbours, South Africa has major macro-economic issues. The country has an high average inflation rate of 6.67% (2000-2019)(123). The ongoing economic problems, partly due to its energy crisis, has put the country's currency under pressure for a long time, where the exchange rate in 2000 of 6.94 R/\$ has deteriorated to 16.49 R/\$, exposing investments in Dollars, Euros or Sterling to significant currency risks. This is somewhat offset by CPI adjustments in renewable energy projects, but causes problems attracting the necessary funding, nonetheless.

As a result, the weighted average cost of capital (WACC) is significantly higher when compared to mature western economies. The WACC for large renewable projects in South Africa is 11.24%, which can be approximated from several studies (124–140). This is especially relevant for the cost of debt, although first studies indicates that this disadvantage may vanish over time as markets mature (141) and the incumbent coal generation has a perceived increased in investment risk, which to date stands to have a WACC of 8.0% (142,143). The outlined investment environment in the South African markets gains it the 34th position in Ernst&Young's Renewable Energy Country Attractiveness Index (RECAI) (37).

2.4 Australia

2.4.1 Overall RES policy environment

Australia is rich in natural resources and mining contributes 10% to its GDP(144). With its abundance of open pit mineable coal deposits, it is the largest coal-exporting country in the world and third largest fossil fuel exporter (145), despite the ban of Australian coal imports by China in 2020 and the fact that coal mining adds little to the overall employment of Australians (146). The country is also the second largest producer of uranium (147), despite not having nuclear power plants itself. At the same time, the country is blessed with excellent solar and wind potentials across most of the continent.

Considering the favourable conditions for renewables, and despite the low costs of thermal coal, investments in renewable energy sources are outrunning those for fossil fuels at an astonishing pace. Renewables capacity is being added ten times faster on a per capita basis than the global average and still four times faster than in Europe, China, Japan or the US (148). However, Australia's generation mix is still dominated by fossil fuels, with 54% of the energy from coal (hard coal and lignite), 20% from fossil gas and 24% from renewables (149). The share of fossil fuels capacity is expected to drop to 28% by 2030 (150) with a half dozen coal plants exiting the system over the next 15 years (148). More recent news from December 2021 indicates that the energy transition is happening much quicker than previously anticipated and coal could retire at three times the expected pace, with all lignite power plants retired by 2032 (151).

As a federal nation, decisions are taken by the central federal government, six state and two territory governments. Nonetheless, Australia's previous Conservative government has committed the country to reducing its GHG emission by 26-28% below 2005 levels by 2030 and to reach net zero by 2050. This goal has not changed with the new government, but prospects of actually reaching the target have risen. The constitution allows for climate change action to be taken on state and federal levels, but in the absence of federal policies, states have a history of 'stepping up' in the face of inaction (152). Tension between federal and state governments was exacerbated by events in September 2016, where power lines were severed and customers in South Australia were left without power for more than 24 hours, after which the 'Finkel Review' identified an 'unclear allocation of regulatory and operational responsibilities'(152).

Given the political struggle and the emergence of 'competitive federalism' it seems unlikely that policies of the previous government were sufficient to reach the emissions reductions needed. In fact, GHG emissions reductions have stalled, despite an accelerating rollout of renewables. The federal energy strategy is embedded in wider foreign policy to build links within the region and to support Australia's mining industry, for example producing hydrogen from lignite for the Japanese market (153). The country's energy policy is characterised by two decades of back and forth and the absence of necessary policy measures on a federal level

and a cacophony of state-led policies as a result of that, are challenging the setup of federal energy and climate policy itself (152,154,155). In contrast to the federal government, which prefers a recovery built on natural gas for the domestic market, all state governments have adopted net-zero targets by 2050 (148,152). In 2022, Australia elected a new government which is more ambitious on climate than the previous one. The effects of the new federal government on specific policies are yet to be seen. So far, climate action falls behind the election promises, and is failing to address Australia's global role as a major coal exporter (156).

A wide range of targets were introduced by the states, to continue renewables rollout and target GHG emissions beyond 2020. Queensland (QLD) has set a target of 50% renewable electricity by 2030, the Australia Capital Territory (ACT) has legislated a 100% renewable energy target by 2020 and reached it some months before the deadline (157). Victoria (VIC) has set a target to use 25% of renewable energy sources by 2020, 40% by 2025 and 50% by 2030, with the 2020 hurdle successfully taken in time (158). South Australia is committed to cover 50% from renewables by 2025 (with the target reached in 2017 already), New South Wales had set a target of 20% by 2020 and the Northern Territory (NT) adopt a 50% renewable energy target by 2030. (152,159)

Earlier renewables investments were in wind power, currently standing at 7 GW (meeting 10% of total electricity consumption) with this expected to quadruple by 2030 (150). However, the main focus going forward is solar PV. The deployment of solar is second to none in the world, with the highest per capita capacity of rooftop solar, recent additions of utility-scale solar PV and a rapidly-evolving solar PPA market (148). With about 2.7 million PV installations (160) in total and as much as 40% of homes with solar PV in some states (i.e. Queensland (QLD) and South Australia (SA), ~25% for all of Australia)(161). Some analysts estimate that solar will grow from 22 GW in 2021 to 80 GW by 2030 (150), with an estimated peak production of 38 GW (162). Solar is already covering up to 66% of maximum capacity in individual states (New South Wales (NSW) and QLD) and 62% in SA, and up to 78% of instantaneous demand in SA, but 30-40% in the rest (163).

Rooftop solar is king in Australia, with 50% of the installed capacity system coming from 10 kW systems or smaller (161). Since 2018, however, a continued trend towards larger systems has emerged. A marked uptick in the installation of systems larger than 30 MW since 2019 can be observed, driving most of the acceleration in capacity additions (164). By 2030, mostly driven by solar PV, the share of electricity from renewables is set to reach 70%, facilitated by frequent auctions and feed-in tariffs (150).

This goes in line with recent announcements of megaprojects within a league of their own. One example is the planned Australia-Asia Power Link scheme (a.k.a. Sun Cable), which is planned to link 17-20 GW of solar PV and 36-42 GWh of battery storage to Singapore, due to complete in 2027 (165). The solar array in the Northern Territories would supply 15% of Singapore's electricity demand using a 5,000 km high-voltage direct current cable (HVDC) cable. The federal government has announced that it will fast-track the ambitious A\$30bn scheme (166), which will

provide electricity on commercial terms without any subsidies. At the same time, studies are carried out in linking the Northern Territory to Alice Springs, potentially laying the groundwork for further interconnection with the more populated east of the country (167).

Grid connection issues are plaguing the Australian electricity system, which struggles to keep pace with the expansion of renewables capacity. The Australian Market Operator (AEMO), responsible for market and system operation, is addressing this by increased transmission infrastructure, for example the 'Energy Connect Project' between Wagga Wagga and Red Cliffs, reinforcing the transmission grid (168). The Snowy 2.0 hydro scheme, operational in 2025, will add 2 GW of pumped-hydro capacity to the energy system, with the stated goal of balancing renewables (169). Holding the title of the world's largest battery, the 150 MW Hornsdale Power Reserve is providing balancing and ancillary services (170). The scheme has kept the lights on during a 17 days system separation event in 2019 and has recovered its initial construction costs in just two and a half years (171). Even larger batteries are planned, like the 1.2 GW in NSW (172), foreshadowing massive investments in grid and balancing infrastructure whilst renewables developers move towards solar+wind+storage hybrid projects. Overall, this shows the irrelevance of the (previous) federal government's policy (inactions).

2.4.2 Specific renewables support schemes

2.4.2.1 Federal Renewable Energy Target Scheme (RET)

Funding and investment security for existing wind farms comes mostly from the federal Renewable Energy Target Scheme (RET), which is a tradeable certificate scheme. The scheme initially mandated 41 TWh of renewable generation by 2020, but was lowered 33 TWh (23.5% of demand) in 2015, which makes Australia's energy policy unique among any of the G20 states in that it has reduced renewables targets over time. The renewed 2020 target was reached one year early, but no target increases beyond the 33 TWh were announced by the end of 2022. In fact, the federal government refused to extend the scheme, leading to considerable uncertainty for investments, and ultimately rendering the federal policy irrelevant for incentivising new investment in renewable energies. Once again, the slack was picked up by the state governments, filling the political vacuum, to support their fledgling renewable energy industry and to address GHG emissions (152,159).

2.4.2.2 State-led Renewables Targets

In practice the state-wide renewables targets are realised mostly through RET-style arrangements (e.g. in Victoria) using tradeable certificates, mirroring the federal policy setup, and auction mechanisms for utility-scale generation (e.g. New South Wales). Renewables investments are now supported by (favourable) state policies, but depend on a patchwork of different policies without central coordination (152,159).

Victoria completed its 1st auction in 2017 and awarded 928 MW of renewables capacity, 673 MW of wind and 255 MW of solar. This will result in A\$1.1bn of investment. Although initially procuring for 650 MW only, the auction was heavily oversubscribed with over 3500 MW of capacity on offer. Winning bids received a CfD-type funding, with a minimum price of A\$56 /MWh for wind, A\$53 /MWh for solar PV and A\$56 / MWh for tracking solar PV (39,173). In 2021, the 2nd auction of 'at least' 600 MW was opened, due to complete in mid-2022, sporting stricter network requirements and a grid enforcement programme carried out alongside by the state (174). In both auctions, the government assumes counterparty risks for the duration of the CfD arrangement.

The Australian Capital Territory to date has procured 840 MW of large-scale renewable generation through auctions, including capacity installed throughout the entire NEM area. Projects must meet milestones, deliver specified energy amounts, engage with the community, and invest in the local renewables industry (175). Payments are guaranteed by the ACT government and facilitated by the state's nominated distributor, currently Evoenergy. Effective subsidy payments vary with wholesale power price forecast, and stood at A\$30 /MWh in Q2/2021 for all of the wind and solar farms funded by ACT, coming down from A\$60 /MWh in the four previous quarters (176). This strike price for solar in average was \$A183 /MWh and for wind A\$84 /MWh, with wind winning the joint auctions (177).

Queensland has held an auction to support up to 150 MW of solar projects with a CfD in 2015. In 2019 it announced its second auction, dubbed the 'Renewables 400' for up to 400 MW of renewable energy capacity and 100 MW of energy storage, with 10 projects shortlisted, three wind (+storage) and seven solar (+storage) (178,179).

South Australia held an auction for concentrated solar power (CSP) in 2017 in which 150 MW was awarded at a price of A\$78 /MWh and later in 2018 an auction for a 100 MW storage facility adjacent to a large wind farm, which resulted in the Hornsdale Power Reserves battery energy storage system.

The New South Wales government has announced an infrastructure roadmap to support 12 GW of wind and solar and 2 GW of storage, more than Victoria's and Queensland's plans combined. For New South Wales, this will be the first use of auctions and a departure from its coal-reliant infrastructure and will provide an A\$32bn boost to private investment in the sector. The project will be realised in two zones. For the first zone of 3 GW, expressions of interest with a capacity of 27 GW were received, making the auction nine times oversubscribed. For the second zone of 8 GW, more than 80 registrations of interest were made with a combined capacity of 34 GW. Auctions are expected to launch 2022 (180).

At the same time, and possibly due to the policy vacuum left by the federal government, Australia has developed a rapidly maturing PPA market, with corporate PPAs in the focus. In 2018, Sydney Metro closed a 15-year PPA deal with the 87 MW Beryl Solar Farm to offset all of its emissions (181). PPA sizes are decreasing over time, being 44 MW in 2019, down from 65 MW in 2018, with most PPAs realised for plants in New South Wales and Victoria (182). This trend extends to commercial rooftops as well, as they are now economically competitive. Thus

corporate PPAs are becoming the norm and are likely to become standardised in a similar fashion to state-led auctions, which will drive investment in renewables sustainably in the long-term (183).

Small-scale renewables are supported through state-led feed-in tariff (FiT) schemes, due to the lack of a nationally mandated FiT scheme. Thus, the FiTs are different by states, including capacity limits and eligibility criteria. Other aspects include time-dependent FiTs for solar energy customers (Queensland) and rates set annually by the retailers.

2.4.3 Wholesale market price formation

The Australian National Electricity Market (NEM) is operated by Australian Electricity Market Operator (AEMO). It covers New South Wales, the Australian Capital Territory, Queensland, South Australia, Victoria and Tasmania with over 40,000 km of interconnection lines. Western Australia and the Northern Territories are not interconnected with the rest of the system and are governed by different regulatory arrangements (184). Prices are determined by matching demand and supply in each region as well as on an aggregated basis across states, accounting for (limited) interconnection (152). The NEM features 5-minute settlement periods, the shortest one in the world (185) and has been in the news several times for price spikes of up to A\$14,000 /MWh (186). The market floor price is -A\$1,000 /MWh and since July 2020 the market price cap was set to A\$15,000 /MWh, which is adjusted annually for inflation (187).

AEMO forecasts renewables to provide up to 90% of instantaneous electricity production by 2035 (148). The market is currently set to be reformed to better integrate flexible demand and distributed energy resources, account for government schemes and provide price signals for investments in reliable, secure and affordable electricity for consumers (188). This also includes a new obligation for all retailers to enter contracts for dispatchable supply, replacing AEMO's reserve electricity measures. This is likely to support unprofitable coal generation for a little while also sending investment signal for clean dispatchable generation (189).

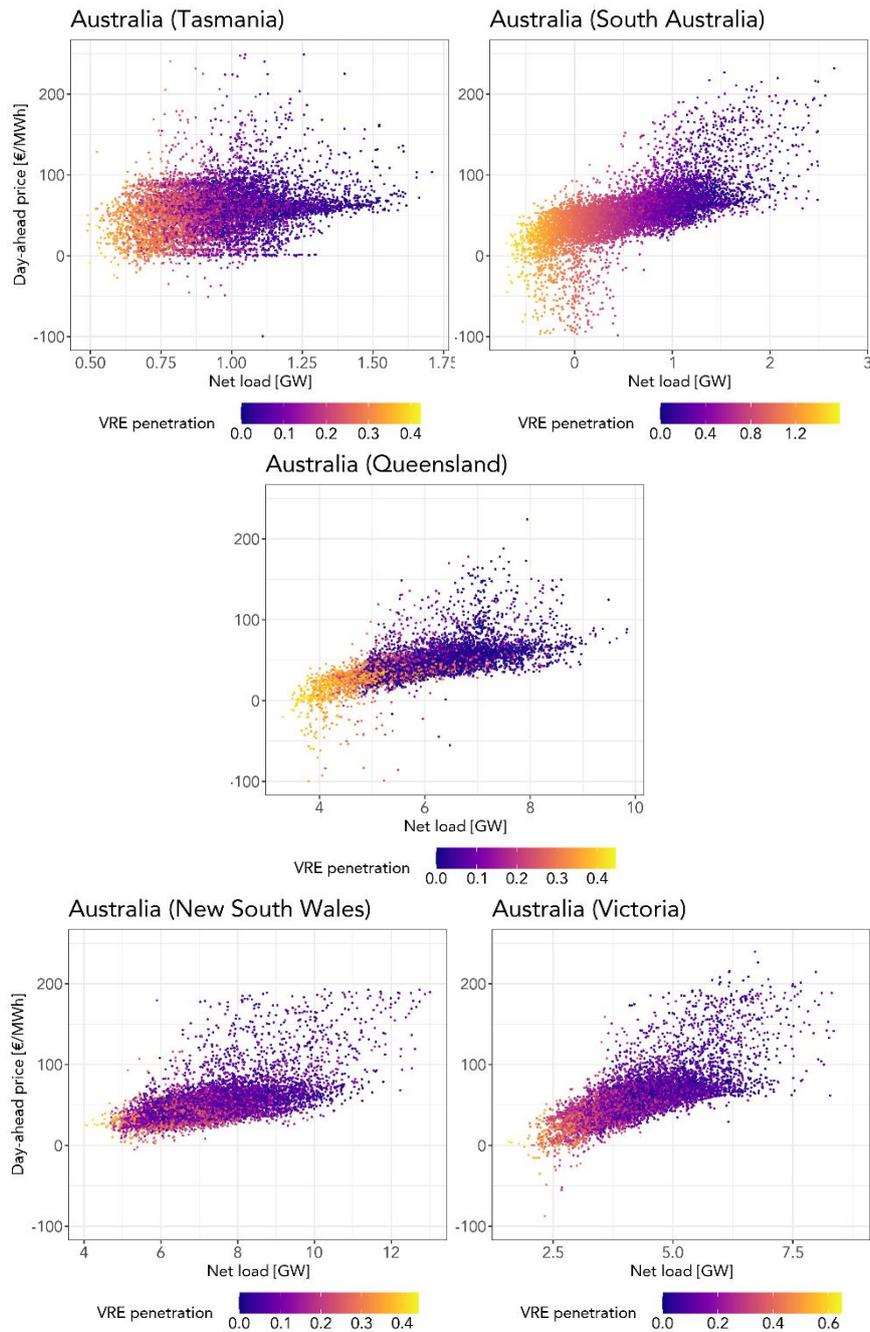


Figure 8: Australia's day-ahead spot prices in €/MWh over the net-load (gross load minus solar and wind) for 2010-2019. The colour of the dots indicates the instantaneous penetration of wind and solar for each hour. For comparison with other countries see Halttunen et al. (32).

When compared to other markets around the world, it is noteworthy that the prices in the NEM shown in Figure 8 are highly changeable over time. However, as each of the markets act as a price zone to a larger market, some of the variability will be smoothed, if enough transmission capacity is available. Directly compared to Germany, it is visible that prices do not correlate as highly with renewables feed-in as in Germany. According to Halttunen et al. (32), the Australian energy markets of Victoria, Tasmania, South Australia, Queensland, New South Wales and the

Australian Capital Territory are the least correlated out of a group of 37 markets. A high correlation between prices between renewables and prices would be indicated by bunching of dots with a similar colour, which is only the case for South Australia, but not elsewhere. This absence of correlation may be due to the 5-minute settlement interval of the power system (most international systems are settled on a 15, 30, or 60-minute basis), omitting some 'smoothing effects'. In conclusion, evidence on critical grid situation, indicative detachment of power prices and renewables feed-in, and the rapid renewables uptake, the need for further reforms is evident.

2.4.4 Price risk allocation

As Australia is using a number of different constructs to realise renewable energy projects, no single point of price risk allocation can be identified. Instead this will have to be dissected based on the scheme use, and categorised according to Beiter et al. 2020 (33).

First, the federal government's RET scheme involves tradeable certificates which can change in price at the time of issuance, but also change in value over time, as the energy system changes. In this quota system, suppliers are mandated to procure a certain number of certificates for the electricity supplied. The inherent value of the certificate is changing as energy demand of the system is expanding or contracting (190). This means that investment under federal RET scheme, have a high-risk exposure for the developers.

Second, the state-led auction schemes, offering typically 15-year CfDs, provide a low-price risk exposure for the developers. The contracts are (typically) structured as two-sided CfDs, which means that each generator receives a fixed amount of money per unit of energy produced. Although FiTs are targeting household consumers, they are very similar in risk exposure as the auction-based schemes.

Third, the risk exposure from the PPA contracts can vary significantly. This is due to differing PPA lengths and conditions that could be written into the contracts, where both counterparties are able to agree their preferred terms into the contract. Standardisation efforts of PPAs changes their nature more towards that of long-term futures. The profile and volume risks can be allocated on the long or short side, but will usually be shared in sensible ways.

The fact that storage solutions are targeted by every state and are also part of the domestic solar funding schemes, showcases the need for additional balancing capabilities. The (relatively) high price volatility in the NEM makes the overall price risk exposure higher in the NEM than in other countries in Europe or the US, all other things being equal.

2.4.5 Overall investment environment

Australia's renewables support and investment is characterised by policy uncertainty on the federal level and (relative) certainty on the state-level. The policy vacuum left

on the national level up to the 2022 federal election has mostly been filled by legislators on the state-level, which in some cases are even from the same political party. This dichotomy is a pattern observed in the United States during the Trump administration, with different levels of ambition on different levels of governance. In Australia it appears that policy makers only have an influence on the pace of change, but there is little to stop the development altogether, barring strong prohibitive legislation. Australian renewables have proven to be resilient towards changing political headwinds and the political situation has created pragmatic and innovative approaches for business to survive (and thrive). The reason for this can be found in the continent's outstanding meteorological wind and solar resources, making a compelling economic case already, which will only grow stronger as technology prices continue to plummet.

There are numerous examples of development outside of government funding schemes. A developer-led renewables revolution has started towards a low-carbon economy, creating opportunities for Australian companies. If Australia manages to continue along this path, the country may become a renewable energy exporter to replace its coal exports, being the green superpower of the region.

Favourable investment conditions, such as relative low WACC for wind and solar projects of around 5.0% (191) and a long-term inflation rate of 2.9% (192), has earned Australia the 7th position in Ernst&Young's Renewable Energy Country Attractiveness Index (RECAI) (37).

2.5 Texas, United States

2.5.1 Overall RES policy environment

Texas is the energy (super-)powerhouse of the United States, both in terms of access to fossil energy sources and outstanding solar and wind resources (193). In Texas, the energy crown is shared between “King Oil” and “King Wind”, with solar picking up pace in recent years. The Electric Reliability Council of Texas (ERCOT) is the power system and market operator, which makes Texas one of nine US states with a deregulated electricity market, both on the generation and supply side. ERCOT covers most, but not all of the state’s area. The ERCOT grid area is considered an electrical island, due to the lack of (significant) interconnection to the rest of the United States. In 2020, 28% of consumption was covered by wind (87.1 TWh), 3% by solar (8.8 TWh). The rest was served by gas (55% / 173.8 TWh), coal (22% / 68.5 TWh) and nuclear (13% / 41.5 TWh) (194). 54% of ERCOT’s capacity additions were wind power in the last decade (2011-2020)(195). However, solar PV is hot on wind’s heel, adding 4.6 GW in 2021 alone, doubling solar PV capacity additions. Another 5.4 GW are expected in 2021, bringing it to 14.9 GW by the end of 2022 (196).

As ERCOT is contained within Texas, it is not regulated on federal level through the Federal Energy Regulatory Commission (FERC), but governed by Texan authorities only, namely the Public Utility Commission. This makes Texas special in many regards, when compared to the rest of the United States, and has laid the groundwork for the creation of this one-of-a-kind electricity system, which is often regarded as the most competitive power market in the world with a ‘hands-off’ regulatory approach and strong market framework. This is supported by a generally business-friendly mindset and comparatively low labour costs.

Wind is clearly the dominant renewable generation technology in ERCOT. Texas has the lowest capex for onshore wind in the US at \$1280 /kW and average capacity factors for (newer) onshore wind turbines of 40-50%. That constitutes, essentially, offshore wind conditions at onshore prices, creating the lowest average levelised cost of electricity (LCOE) for new projects in the whole of the United States, standing at \$29 /MWh with some large variations across ERCOT (195). It is no surprise that Texas holds the largest fleet of wind capacity for any of the states in the country, totalling 32.7 GW at the end of 2020 (not all of them located in ERCOT) and has added 4.1 GW in 2020(195), which includes one of the largest onshore wind farms in the world at 735.5 MW. Texas also has the largest capacity of renewable hybrid projects with 0.86 GW of wind+storage capacity, mostly located in the grid-constrained western Texas area. About 85% of the Texan use of electricity is consumed in competitive markets, whereas the rest is served by publicly-owned utilities (i.e. municipality or co-operative owned) serving their costumers as a fully integrated utility.

Recent woes in February 2021 have led to blackouts following an ‘arctic outbreak’ from Canada, with temperatures as low as -22°C . Coincident with many gas power

stations and wind turbines being inoperable due to the lack of winterisation packages at the equipment, possibly driven by efficiency incentives in the market (197), the subsequent surge in electricity demand for heating could not be met by the grid. The cold temperatures had a cascading effect on the energy system, with power plants failing and the gas supply chain freezing up (198). The blackout affected 10 million Texans, some without electricity for 3 days, and has cost 210 lives (199). Power prices spiked to \$8,800 per MWh, which is almost 200 times their normal level (200). Some households on variable rate tariffs were hit with bills over ten thousand dollars (201), and three utility companies have already declared bankruptcy(202). Texas has a troubled history with blackouts, pointing to a system incident in 1989 when the grid almost went dark. In 2011 – commonly referred to as the Groundhog Day blizzard – large parts of the grid were subject to rolling blackouts. In both cases, recommendations for the weather-proofing of the energy system were not implemented (203), showing the limits of the ‘Texas only’ regulatory solution(197). ERCOT still identifies a risk up to 14 GW of generation shortage in extreme and unlikely weather scenarios – 2021 was one of those scenarios – this time for the summer peak load(194). In part this is addressed by demand-side programmes, expected to add 2.9-4.7 GW peak-shaving capacity over the next five years (194), which will add to the extensive demand side programmes that have been running for a long time (204).

The grid buildout to support renewable energy has been carried out pre-emptively in anticipation of new wind farms under the CREZ programme(205), which is regarded a large success (206). This foresight allowed wind curtailment to be reduced from 17% in 2009 to just 0.5% in 2014, though more recent trends show that additional grid capacity is required. Grid development is ultimately the responsibility of ERCOT and overseen by the Public Utility Commission (PUC) establishing a positive (long-term) business case for grid expansion. The lack of grid connection capacity means that nodal prices will change and make projects on the “right side” of the congestions of ERCOT more profitable today, without lengthy waits for the grid expansion in the future. In the long-run, these projects might end up at the “wrong” site, with lower nodal prices and poorer wind conditions, when the congestion is alleviated (207).

2.5.2 Specific renewables support schemes

Texas renewable energy producers are supported with a range of mechanisms on a state and federal level, which can stack in some case. Despite the various support schemes, a significant amount of more recent wind (and likely solar) capacity can be attributed to its economic competitiveness.

2.5.2.1 Texas Renewable Portfolio Standard

In Texas, renewables deployment is supported by the Renewable Portfolio Standard (RPS), which obliges suppliers to provide a certain quota in their retail portfolio. Alongside market liberalisation, the RPS was introduced in 1999. Obligated parties under the RPS are all electricity retailers in competitive markets (85% of

consumption), but publicly-owned utilities must only comply with the RPS if they choose to compete in the market (193). The state-wide target with the RPS for 2025 was set (implicitly by wind's capacity factors) to 10 GW, which has been exceeded substantially as wind alone is standing at 32.7 GW (208).

Renewable energy certificates (REC) are issued for electricity produced by eligible assets. RECs serve to track and verify compliance with the RPS and can be traded at ERCOT (193). They are traded on a market basis, thus being volatile in price and in location, due to locational marginal pricing applied. RECs' market value is somewhat low at around \$1.30 /MWh on average in 2019 and 2020, approaching the \$2 /MWh mark towards the end of 2020(195), but some peaks have traded as high as \$57 /MWh in 2021 during the energy crisis. Particularly due to the nodal pricing setup, price can vary significantly. Especially in areas with lots of solar, the market value of wind is high, and vice versa. Nonetheless, the low REC value is likely to have little impact on driving investment and is outshone by the Federal Tax Credit and wholesale market revenues.

2.5.2.2 Federal Tax Credits

On a federal level, several tax relief support schemes are available to support renewables generation. Taxation relief is a tool heavily relied on across the entire United States, not just Texas, but nonetheless is relevant to the rollout of renewables in Texas as well. Essentially, three different tax relief schemes are relevant:

- The investment tax credit (ITC) for solar PV and offshore wind power plants⁷, or
- The production tax credit (PTC) for onshore wind power plants, and
- The MACRS programme allowing for an accelerated depreciation of a large array of assets, including renewables.

From the above it is evident that renewable energy assets will either be eligible to receive ITC or PTC and can make use of accelerated depreciation tax credits in addition. In some cases, tax credits can be worth up to 40-50% of solar PV capex, assuming the highest tax brackets relief rate under the ITC (210).

The COVID-19 pandemic has resulted in a number of adjustments to the ITC and PTC schemes. For example, the timelines for eligibility have been adjusted and the tapering (i.e. the gradual reduction in tariffs down to zero) is stretched over several years. Tax reliefs are granted based on the "start of construction date". Start of construction is defined as the physical start of the construction, or having spent 5% of the project's cost, which now grants extended timelines under the "Continuity Safe Harbor" programme (211).

The Investment Tax Credit (212) is a federal tax relief option, which is available to any eligible generators in the United States. This extends to solar PV and offshore wind (amongst a long list of other technologies), typically assets with significant

⁷ Offshore wind is not a relevant energy source in Texas (yet), due to its access to large areas with very high average wind speeds.

capex expenditure upfront. Tax reliefs are granted based on the “start of construction date” with a tax reduction of up to 30% of their capex. Solar projects that have commenced construction up to 2019 are eligible for a 30% tax relief. As one of the last actions in office, President Trump signed the “Extenders Bill”, which aims at mitigation of the impact of the pandemic, granting projects a delayed tapering. Tax rates are now tapered to 26% for projects starting construction in 2020-2023, 22% for 2023 and 10% thereafter. All projects must be placed “into service” by 31st December 2025 to take advantage of the higher rates (213). The tapering of tax credits was adjusted in light of the COVID-19 pandemic to the now extended schedule above. The “Extenders Bill” also extended the possibility for onshore wind projects to receive ITCs in lieu of PTCs by one year to the end of 2021 at a rate of 18%. This mirrors the one-year extension applicable to PTCs. Onshore wind projects commencing construction in 2022 or later are not eligible for ITCs (214). Offshore wind is also granted ITCs in lieu of PTCs if construction has started by December 2025, with a ten-year window for completion of construction works (215).

The Production Tax Credit grants an inflation-adjusted tax credit based on each kilowatt hour produced from eligible generators. The baseline tax credit is \$2.5 /kWh (\$25 /MWh) on the sale of electricity produced from the qualified energy resources, mostly onshore wind, but also for biomass and geothermal energy. In similar fashion to the ITC, the PTC is time limited and designed to phase out (216). The PTC is paid for ten years after start of operation production. It is proportionally capped and bound to a reference wholesale market price, which would see the tax benefits gradually reduced when wholesale prices are \$50-80 /MWh and to reach zero, if the reference price exceeds \$80 /MWh (217). For onshore wind, the PTC rate tapers from 100% for any projects that started construction in 2016. Projects with construction start in 2017 received 80% of the PTC (\$19 /MWh). Subsequently, projects in 2018 received 60% (\$14 /MWh), 40% in 2019 (\$10 /MWh), 60% in 2020 and 2021 (\$15 /MWh) and are not eligible for any PTCs from 2022 onwards. Under the revised schedule of the “Extenders Bill”, project have six years to completion, if construction started before 2020, and five years thereafter. With long-term decarbonisation goals established by the Biden administration, several policies are in the legislative process, including a long-term extension of the PTC, with no concrete results at the time of writing (195).

Renewables can take advantage of the Modified Accelerated Cost Recovery Systems (MACRS) programme for an accelerated depreciation of assets for tax purposes (218). This will allow renewable energy projects to write down the entire value of the project within just five years for tax purposes (219). This can significantly enhance the projects’ cashflow situation, as they are allowed to lower the amount of taxable income, reducing the owed taxes. ITC and PTC do not reduce the taxable income for the MACRS programme (only the payable tax), and MACRS can be used in addition to either ITC or PTC.

2.5.2.3 Residential Solar PV programmes

Many local utilities and municipalities in Texas offer a net-metering programme including (e.g. El Paso Electric, the City of Brenham, CPS Energy, and Green

Mountain Energy), mostly for residential solar PV (220). These programmes allow owners of rooftop solar PV to offset their electricity bill with electricity produced on their roof. Depending on grid tariffs and the LCOE of the rooftop solar, this can amount to a significant reduction of the electricity bill, especially as net metering can be stacked with the ITC programme (and potentially other solar rebate programmes).

Similarly to the net-metering programmes, many utilities and local governments provide support to homeowners with rooftop solar. For example, Austin Energy has a rebate of \$2,500 on the installation costs, and has a feed-in tariff of \$97 /MWh. CPS Energy customers can receive a payment of up to \$1.20/W for their rooftop solar PV installation. The City of Sunset Valley solar PV Rebate Program offers up to \$3,000 for up to 3 kW systems (218). In many programmes, the incentive is gradually reduced with an increasing installed capacity on the grid. A comprehensive overview of funding and support by location is captured in the Database of State Incentives for Renewables & Efficiency (DSIRE), which lists 76 programmes in Texas overall (218). Texas also has a renewable energy systems property tax exemption scheme, which prevents house price increases from rooftop solar PV to cause a rise in locally determined property taxes (220).

2.5.3 Wholesale market price formation

ERCOT features a nodal pricing energy-only electricity market, which means wholesale prices are differing largely across ERCOT's grid area, accounting for infrastructure constraints and thus leading to locationally varying prices at different times. ERCOT does not operate a capacity market to provide the security of supply and solely relies on peak pricing to incentivise capacity adequacy, although marginal on-grid capacity is constantly monitored.

In a search for the most efficient market design, the ERCOT market has evolved from a zonal electricity market to a locational marginal price market in 2010. This means that physical grid constraints influence the price finding algorithm in the market, and price convergence between different busbars in the grid (a.k.a. nodes) in the absence of congestion. In the presence of congestion and wind curtailment in the West Texas, different prices will emerge for each node (221), potentially incentivising investments in high-value areas of the grid, despite poorer meteorological conditions. For many economists, this represents the purest form of an energy-only market design. Investment signals are assumed to be derived from scarcity pricing of up to \$9,000/MWh, which incidentally was reached in February 2021.

In addition to deregulation on the supply side, about 85% of Texans live in deregulated electricity consumer markets and thus have the opportunity to choose their electricity supplier. Retail prices in 2017 were about 20% below the US average (222), owing to the competitive market structure and access to cheap natural gas, although the February 2021 blackout has led to rising prices, especially for consumers on variable retail tariffs. Texas's electricity market ERCOT is regarded as the most competitive electricity market in the world.

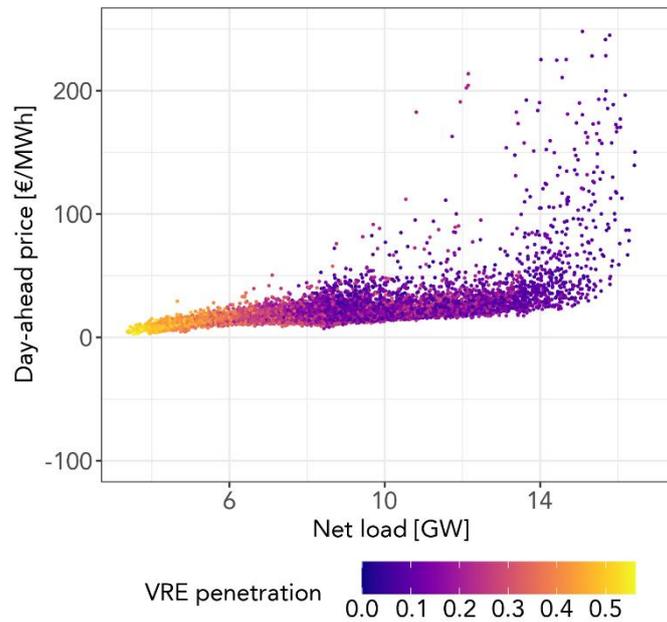


Figure 9: Texas’s day-ahead spot prices in €/MWh over the net-load (gross load minus solar and wind) for 2010-2019. The colour of the dots indicates the instantaneous penetration of wind and solar for each hour. Note that this is a single-node representation of a nodal pricing market setup. For comparison with other countries see Halttunen et al. (32).

2.5.4 Price risk allocation

ERCOT being (one of) the most competitive electricity markets worldwide, it comes as no surprise that renewables are in a competitive environment. The exposure to price risks according to Beiter et al. (33) is high to very high for renewable generators. Whilst tax credits do provide a reliable source of “income”, all other income streams in the ERCOT market are variable. Whilst tax benefits make up a substantial part of the income for wind farms and solar PV projects today (223), these benefits are gradually phased out by the federal government (i.e. tapered), leaving Texan renewable energy assets only market revenues to cover their capex and opex in the future.

On the first glance, income of generators will vary hugely, as market mechanisms dictate the value of wind and solar. Firstly, generators will receive variable payments from the spot market, which can differ significantly over time, but also depend on the location in the grid. The application of the nodal pricing makes ERCOT a highly dynamic market environment, where prices are highly volatile. Secondly, the Texan RPS allows trading of the RECs. This means that the implied subsidy through RECs is determined by market mechanics, not just in time, but also affected by the location

in the grid. This means that the price risk is almost exclusively with the renewable generators, with no counterparty assuming wholesale market price risk.

Naturally, renewable energy projects will try to hedge the volatility in the market to produce a stable income (outlook) to finance their project. On the demand side, suppliers will have a similar interest in closing long-term reliable supply contracts alike, which will lead to the closure of long-term PPAs. The presence of PPAs in the Texan market is a routine process to hedge price risks (195).

Derived from the wholesale prices alone, market values of wind are relatively low at \$10/MWh in 2020 down from \$19/MWh in 2019 (224), with some very large regional variations. One wind farm had a market value of \$53/MWh in 2020, whilst another had just a market value of \$0.5/MWh. On average, wind value factors – the share of the average wholesale market price that wind can capture – stands above 50% and is set to fall (32,195).

Grid constraints are the largest driver of these variations and keep affecting the overall profitability of wind farms and curtailment stands at 4.6% (in 2020). The value of wind is (somewhat) reflected in closed long-term PPA prices in ERCOT which were close to the \$20/MWh mark in 2020 (195) and prices have rebounded in 2021 to around \$30/MWh (225), which is a marked uptick from previously lower levels a year ago. Amongst low interest rates, declining costs, and higher capacity factors, the PTC is a major enabler to these low PPA prices. The revenues are in line with the costs for projects in ERCOT (225).

Despite the competitive (and at times challenging) market environment, Texas has been going strong on the deployment of onshore wind and (as of late) solar PV beyond political support schemes and tax reliefs. This is down to one simple reason: wind and solar are cheaper than any other generation technology in large parts of Texas, outcompeting unabated coal and natural gas generation (226,227) ⁸.

In future, wind and solar farms will have to be financed on wholesale terms only and thus paving the way for the last step of truly merchant renewables in the world's most competitive power market. Despite the competitive (and at times challenging) market environment, Texas has been going strong on the deployment of onshore wind and (as of late) solar PV beyond political support schemes and tax reliefs.

The Renewable Energy Country Attractiveness Index (RECAI) (37) places the United States at the top of the leader board, making it the most investable market in the world. Texas, despite its recent weather-related woes, is by far the largest wind market in the United States. If it was a country, it would be the fifth largest wind power country, by installed capacity. The ongoing growth in Texas is certainly supported by the ambitious measures of the Biden administration on a federal level and the excellent wind and solar conditions. The (debt) interest rates in 2021 of 3% and equity interest rates of 7% are up from 2020. This trend is expected to continue with increasing interest rates. However, access to finance is still relatively cheap, and the wind industry's risk margins have decreased significantly in the last decade, which will likely drive further development. This will make Texas the prime spot for

⁸ Uses economic cost data from Wiser et al. (195) for wind and retains default settings for the rest.

investments, and viable in the long-run, if ERCOT manages to address grid congestion issues.

Following the blackouts in early 2021, policy makers are targeting renewables in an attempt to find a scapegoat for the power crisis, attempting to put the burden of paying for ancillary services onto renewable generators (228). To date, no concrete bills have been passed into law (229). The discussion is (finally) focusing on improving reliability of ERCOT's power markets. This will create opportunities for dispatchable generation such as natural gas and/or renewables+storage. Texas is already the leading market in the U.S. for the latter. Last, but not least, Texas benefits from very business-friendly environment, allowing for the fast deployment of renewables and innovative business models.

3 Quantifying Transition Risk

The above analysis of current investment conditions in different countries shows that there are many ways to support renewables investment. It shows contrasting approaches to the exposure of renewable investors to wholesale market price risk, with low levels of exposure in Germany, for example, and high levels of market risk exposure in Texas. For individual projects, the ‘devil is in the detail’ and investment risk will be a complex function of the details of these specific support policies, the nature of the wider market design, the economic context in the country, as well as the nature of the underlying renewable energy resource.

However, looking ahead, investors also face risks associated with the nature of the overall energy transition itself. Whilst the goal of the transition is known (i.e. zero-carbon electricity), the details of this end-point in terms of technology mix, price formation and degree of price cannibalisation are still uncertain. The risk profile of future decarbonised electricity markets is likely to be quite different from current market conditions, and difficult to predict. The pros and cons of exposing renewable investors to these uncertain market risks can be boiled down to a relatively simple equation:

Do the cost savings arising from low cost of capital achieved through de-risking policies outweigh the potential system cost benefits that might arise from exposing renewables projects to greater levels of market price risk?

This section aims to provide quantitative evidence on the first part of this equation by estimating the order of magnitude of these macro-level energy transition risks. The analysis is not setting out to define the market design pathway with the overall lowest cost, but is assessing the impact on financing costs of different market design options from the perspective of new projects during the transition.

3.1 Overview of approach

We start with a simplified characterisation of the transition as comprising two phases. Firstly there is a ‘build phase’, during which fossil fuel generators (which are currently price-setters in the market) are replaced with low-carbon generators (many but not all of which are currently price-takers in the market). The investment decision is assumed to be taken part-way through this build phase during which time the final characteristics of the decarbonised electricity system are still uncertain.

Secondly the final decarbonised system is treated as a ‘steady-state’ phase during which the new low-carbon plant will operate and receive most of its revenues.⁹ The physical characteristics of this decarbonised system (i.e. generation mix, demand profile etc) are modelled to determine the system marginal cost of generation which

⁹ In reality this will not be ‘steady-state’ as the electricity system will likely need to grow substantially after it has decarbonised in order to allow for greater levels of electrification of the economy, and the nature of electricity demand will continue to change. We leave analysis of these dynamic effects for future work.

is assumed to be the basis for wholesale price formation. This provides a quantification of market price risk in the future decarbonised system, including the degree of price cannibalisation and curtailment of renewables in the future decarbonised system. The electricity system model is described in Section 3.2.

Different ways in which the effects of price cannibalisation and curtailment may be countered in this future steady-state phase are represented in the analysis as ‘policy options’. These include, for example, policies such as CfDs as well as renewable energy premiums that might be negotiated directly through the market. The characterisation of different policies is described in Section 3.5.

We assume that a hypothetical investor has some expectation about the final physical state of the system in the steady-state phase, that this determines their expectations about the financial performance of their investment, and that they use this to determine their response to the available policy options. For example, these expectations determine how the investor would bid into CfD auctions of various designs, or the kind of renewable premium they would need / expect to negotiate in the market in order to make a reasonable return on investment.

We then stress test these financial cases by introducing physical states of the system that differ from those assumed in the investors initial expectations. These scenarios are described in Section 3.3. These different physical states of the system create different outturns in the level of cannibalisation and curtailment and therefore different financial returns for the project. The analysis of financial returns is presented in Section 3.4.

This spread of financial outcomes is taken to represent the degree to which an investor would need to increase their overall returns on investment in order to cover the energy transition risk. This is used as the basis for assessing the implications of transition risk on the cost of capital. Results are presented in Section 3.6 showing the extent to which different policy options shield investments from these transition risks, and therefore the potential impact of these policy options on the cost of capital.

In this paper, we restrict our analysis to the case of investment in offshore wind, but the approach could be used to assess investment risk in all types of generation and storage.

3.2 Electricity system model

3.2.1 Overview of ANTARES model

In this study, we make the simplifying assumption that wholesale market prices will be primarily determined by the system marginal cost of generation. We model the system marginal cost using an optimal electricity system dispatch model, building on earlier work by Maclver et al. (230). In that previous study, a European scale transmission system model was developed to model the behaviour of a coupled European electricity market. The model uses ANTARES, an open source electricity market modelling tool developed by French system operator RTE (231). Each

European country is represented by a single node (with the exception of the UK and Denmark, each with two nodes denoting separate islanded regions) with modelling of an appropriate generation mix separated by type while constraints are imposed on the maximum net transfer capacity (NTC) of electricity trades that can take place between connected countries.

The implementation takes the form of a unit commitment (UC) model that determines a schedule of generation units that minimises “the overall system operation cost over a week, taking into account all proportional and non-proportional generation costs, as well as transmission charges and “external” costs such as that of the unsupplied energy (generation shortage) or, conversely, that of the spilled energy (generation excess) (232). It is constrained by the minimum and maximum production of each generation type, the maximum rate of change of production from each generator and the minimum amount of time for which it must be on if committed to run, or run if it is not needed. ANTARES is capable of running in different modes. For the current study, each run represents a single year, modelled as a sequence of 8760 hours, coupled by time-related constraints such as generation ramp rates. The model is solved in weekly blocks, which are coupled for the whole year with constraints respecting hydro-reservoir storage capacities. Transmission system flows are driven by price differences between the modelled nodes assuming a perfectly coupled market with within-week foresight. Renewable generation availability is modelled across Europe with reference to real historical outputs which respect temporal and spatial correlations.

The structure of the ANTARES model set-up and methodology used for the current study is largely the same as described in Maclver (230), and the reader is referred to that paper for a fuller description of the methodology.

3.2.2 Representation of system flexibility

It is important to capture the effects of additional system flexibility, given that this is a key feature of the way electricity markets and pricing will respond to increased levels of variable renewable generation. Some flexibility options were already included in the previous model. In particular, this included representation of pumped storage facilities modelled with 72% round trip efficiency and the ability to charge/discharge over a 24-hr cycle to minimise system costs. This effectively represents 10-hr storage capacity at maximum output, which approximately matches the combined storage capacity of GB pumped storage facilities.

Interconnection is also already inherently built into ANTARES, so the same methodology was used as for the previous study. Many of the scenarios show considerable scale-up in the degree of interconnection between GB and Europe. In this study we make the simplifying assumption that existing interconnector routes are simply scaled-up to accommodate the additional capacity.

For this study, additional flexibility options for GB were added to represent demand-side management (DSM), batteries and hydrogen electrolysis (to flexibly absorb cheap or surplus wind power). DSM and batteries are both represented in a similar

way, essentially as storage facilities with the ability to push or pull power from the GB node if that helps to minimise overall system operation cost.

Representation of hydrogen electrolysis is implemented in a simplified way by representing electrolysis as a negative source of generation (i.e. demand) within the GB node. The level of electrolysis demand in a given hour is pre-determined as a model input, and is calculated as a function of the residual load (i.e. total GB demand less the variable renewable supply in that hour).

3.2.3 Other input data sources and assumptions

The modelling framework described above has been populated with data available in the public domain. Table 2 sets out the key assumptions and sources of this input data.

Table 2. Input data sources and assumptions

Model input	Assumptions	Data source
Technology CAPEX, non-energy OPEX and performance	Based on BEIS 2040 figures. Hydrogen CAPEX and non-fuel OPEX assumed to be the same as CCGT	BEIS Electricity Generation Costs 2020 (237)
Fossil fuel prices	Future Energy Scenarios 2040 fuel prices	FES 2021 Data Workbook (238) (Sheet CP1)
Average GB solar capacity factor	Renewables.ninja calculation of GB average based on 1984 solar irradiation patterns	Renewables.ninja (239) European solar data set version 1.1
Average GB wind capacity factor	Recalibrated Renewables.ninja average GB capacity factors based on future fleet scenario ¹⁰	Renewables.ninja European wind data set version 1.1
Hourly demand profiles	Hourly demand profiles from ENTSO-E, with demand variability scaled to match the peak and average demand specified in each scenario	ENTSO-E 10 year network development plan (234)

¹⁰ The hourly GB wind generation profile in the model is based on a recalibration of hourly data from Renewables.ninja. The Renewables.ninja baseline uses historical wind data (we choose 1984), and then uses a future scenario of the distribution of GB wind power across the country to calculate average hourly wind capacity factors for the country as a whole based on the wind speeds in those locations. We then need to recalibrate these hourly capacity factors to get the correct future GB annual capacity factor specified in the generation scenario (described in the next section). In particular this average capacity factor is sensitive to the mix of onshore and offshore wind, because of the significantly higher capacity factor for offshore wind.

3.3 Decarbonisation pathway scenarios

3.3.1 How different are future scenarios of zero-carbon electricity?

We start by assessing the degree of uncertainty over which decarbonisation pathway we may be on. This uncertainty relates to physical characteristics of the system such as the type of generation on the system, the shape and scale of demand, and the availability of different types of flexibility options such as interconnectors, hydrogen etc.. We have based this analysis on the four National Grid ESO [Future Energy Scenarios](#) (FES) for 2040 (1).

Three of the FES scenarios published in 2021 meet net zero goals:

- **Consumer Transformation (CT-base).** Based on electrified heating, consumers willing to change behaviour, a high level of energy efficiency and a high degree of demand-side flexibility and interconnection to Europe. Wind power reaches 116 GW by 2040. We use CT-base as our reference scenario for assessing investment risk in Section 3.4.
- **System Transformation (ST-base).** Based on a greater role of hydrogen for heating, consumers being less inclined to change behaviour, lower energy efficiency and a greater reliance on supply-side flexibility, interconnectors and electrolysis. Wind capacity reaches 97 GW by 2040.
- **Leading the Way (LW-base).** Based on the fastest credible rate of decarbonisation across the economy as a whole, implies significant lifestyle changes, and includes a mix of hydrogen and electrification of heating. Wind capacity reaches 117 GW by 2040.

The final FES scenario fails to make enough progress to be compatible with net zero goals:

- **Steady Progression (SP-base).** Based on the slowest credible rate of decarbonisation, minimal behaviour change, slow decarbonisation rates in power and transport, and heat fails to decarbonise. Wind power reaches 77 GW, and there is more than 40 GW of unabated gas power remaining on the grid in 2040.

The role of the FES scenarios in our work is simply to illustrate some of the uncertainties that surround the composition and characteristics of a notional future power system. We use them to generate a set of hypothetical system prices so we can explore risks. Other scenarios are available, and the analysis does not seek to demonstrate which scenarios are better, more likely, or plausible.

In addition to these four main FES scenarios, we also introduce an additional three variants to explore different risk factors:

- **CT-HiPrices.** This scenario doubles the carbon price (to £116/tCO₂) and increases the long-term gas price by two-thirds (to £10/GJ) compared to the CT base.

- **CT-LowInterC.** This scenario reduces the amount of interconnection in the scenario by a third (from 27 GW to 19GW) compared to the CT base, replacing this two-way flexible capacity with an equivalent amount of generation capacity from 1-way flexible biomass generation.
- **ST-LowElectr.** This scenario halves the amount of electrolysis in the system, from 9.8 GW in the ST base case to 4.9 GW.

3.3.2 How do these physical differences translate into revenue risk?

The electricity system model described in Section 3.2 is used to assess how these different electricity system configurations would affect electricity revenue risk for different renewable generation sources. Revenue risk has two components: price risk (due to wholesale price cannibalisation), and volume risk (due to curtailment when the system is oversupplied). Figure 10 shows how price risk (positive y-axis) and volume risk (negative y-axis) vary for offshore wind under different electricity system scenarios.

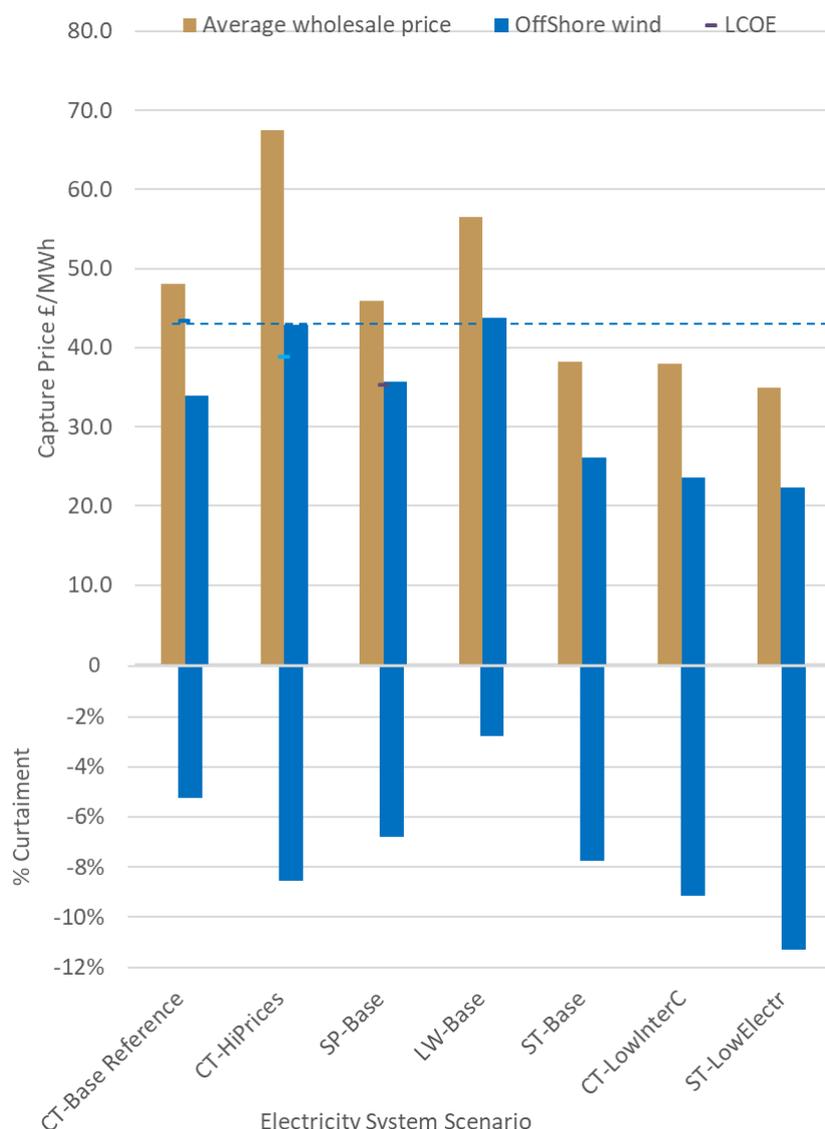


Figure 10. Price cannibalisation and curtailment rates in different decarbonisation pathways

From Figure 10 we draw the following conclusions taking each of the scenarios in turn:

- **CT-Base (reference case).** Capture price is below the LCOE and curtailment levels are around 5%.
- **CT-HiPrices.** The increase in gas and carbon prices drive up average capture prices relative to the reference. The benefits of these higher prices are somewhat offset by the increased levels of curtailment which arise because the higher cost of fossil fuels drives up prices in Europe making the interconnectors more constrained than in the reference scenario.
- **SP-Base,** the higher share of unabated gas remaining in the system (43GW compared to 13GW in the reference case) leads to slightly raised average capture prices. However, curtailment levels are also slightly increased relative to

the reference, due to lower levels of flexible plant (particularly flexible demand, electrolysis and interconnectors) compared to the reference case.

- **LW-Base.** Despite having less than 1GW of gas remaining in the system, this scenario sees higher average prices and reduced curtailment rates mainly due to greater levels of hydrogen generation (7.2GW vs. 4.7GW) and electrolysis (24GW vs. 13GW) compared to the reference case.
- **ST-Base.** This scenario has greater levels of nuclear (14GW vs. 10GW), gas + CCS (9GW vs. zero) and hydrogen (12GW vs. 5GW) compared to the reference case, but significantly reduced levels of two-way system flexibility, including flexible demand (9GW vs. 19GW), interconnectors (20GW vs. 27GW) and electrolysis (10GW vs. 13GW). Overall, this reduced level of system flexibility leads to lower average capture prices and increased levels of curtailment relative to the reference case.
- **CT-LowInterC** assumes a reduced level of interconnectors (19GW vs 27 GW), reducing system flexibility, leading to lower average capture prices and increased levels of curtailment.
- **ST-LowElectr** sees similar consequences of reduced system flexibility due to a further reduction in electrolysis capacity compared to the ST-Base scenario (10GW vs. 13GW).

3.4 Methodology for quantifying investment risk

3.4.1 Calculation of investment risk

The hourly plant-level dispatch and system marginal cost results from the ANTARES model presented in Section 3.3 are subsequently imported into a Microsoft Excel-based discounted cashflow model developed for this analysis. This aims to quantify investment risk by assessing how price formation affects cashflows differently under each of the scenarios. The range of cashflows is represented as a discount-rate impact relating to uncertainty over future price formation processes as represented by the different scenarios. The degree to which different policy options provide revenue stabilisation and a potential reduction in the cost of capital is then assessed.

To assess the risk posed by different decarbonisation pathway scenarios, we treat one of the scenarios (CT-Base) as a reference case. We take this reference case as the basis on which financial planning for an investment project in solar or wind is undertaken. We then treat the other decarbonisation pathway scenarios as 'risk' cases against this reference case.

The steps are as follows:

1. The reference scenario (CT-Base) is used to determine the expected financial performance of each type of generation, taking account of capture prices and curtailment levels.

2. This expected financial performance is then used to determine the average price premium that each generation type would need to recover over-and-above market prices¹¹ in order for the investment to break even (i.e. to have a positive NPV under a risk-neutral discount rate).
3. For CfD-style policies, this reference case expectation about the required breakeven premium is used to simulate the strike price that would be achieved in a CfD auction. The auction is assumed to take place before the investor knows which state of the electricity system they will be exposed to. The strike prices vary according to the design of the policy (e.g. 1-sided vs. 2-sided CfDs etc.) because the CfD design affects the expected revenue received, so investors are assumed to adjust their bids accordingly (see Table 3). Energy-only markets are modelled in a simple way by assuming that these price premia would be recovered directly in the market through privately-developed trading arrangements. We use two simple assumptions about the riskiness of these market premia, described in the next section.
4. The cashflow that would be realised in the risk cases are then calculated, keeping the CfD strike prices unchanged from Step 3. This takes account of the phasing of construction costs, the cost of debt and equity during this period, the timescale of any CfD or other policy support, and the annual market revenue each decarbonisation pathway scenario.
5. The model then converts the differences in cashflow between the decarbonisation scenarios into a 'risk adjusted hurdle rate'. This is the change in project discount rate required to equalise the NPV in the base case scenario with the NPV for the 'risk' decarbonisation scenarios under any given policy option. This change in the discount rate is the basis of the results presented in the next section.

3.4.2 Policy Options

As noted above, zero-carbon wholesale electricity markets based on system marginal cost are structurally prone to price cannibalisation, and can lead to varying amounts of curtailment depending on the level of flexibility in the system. In this analysis, we focus attention on various CfD designs as described in Table 3. Section 2.1 provides a general description of how CfDs operate.

We also investigate a simplified representation of how the market might try to 'solve' the price cannibalisation problem without direct policy intervention by offering a low-carbon premium above system marginal cost levels. We do not attempt to define how such premium mechanisms could emerge and/or whether they would be delivered through market participants or policies. They are broadly consistent with what would be needed under a 'low carbon obligation' approach to policy (9) but such a premium could also in principle arise directly through market contracts between generators and suppliers. Whether or how such premium payments could or would occur is not the purpose of this analysis; they exist merely so we can

¹¹ Using system marginal cost as a proxy for market prices

represent the risk implications of exposing investors to a price environment based on system marginal price.

In all cases the policies we present are simplified and illustrative. A range of variants can be envisaged, and alternative policies could deliver a similar outcome. For example a 1-sided CfD might be expected to have similar characteristics to a market-wide floor price, the fixed premium might or might not be a feed in tariff, the negative price rule could be applied selectively and the analysis does not take account of opportunities to value stack, for example in providing ancillary services.

Table 3 – Market and policy design options tested

Policy option	Characteristics assumed in cashflow model	Comments	CfD Strike Price¹²
2-sided CfD	15-year contract pays the difference between an agreed strike price (set at auction) and the wholesale market price.	By fixing prices for multiple years, it reduces exposure more than the other policy options considered. This is based on the original form of the CfD which led to reductions in auction prices.	52.4
2-sided CfD (extended)	As above, but with 25 year contract.	Longer contracts extend the period over which projects recover their investment, lowering strike prices, and reducing tail risks of plant being unable to recover costs in the later part of their technical lifetime. However, they lock-in consumers for a longer duration.	43.3
2-sided CfD with negative price rule	As above, but does not pay out if prices go negative (as per current design of the CfD).	This exposes projects to uncertainty over the degree of negative pricing events under different risk scenarios. All else being equal, projects would be expected to bid higher in auctions compared to Option 1 to compensate for reduced revenues.	58.5
1-sided CfD (price floor)	If wholesale power prices fall below the floor, payments are made to the recipient up to the floor. Generators receive all upside payments.	This reduces exposure to downside risk, but projects can benefit from any upside so would be expected to bid lower in the auctions compared to Option 1. Exposure to upside might attract a different type of investor, but it transfers significant risk from investor to consumers.	45.5

¹² This is the modelled price required for the investment to breakeven over the contract period under the reference scenario. Where the CfD policy is a floor or cap&floor, the price here indicates the floor price.

1-sided CfD with clawback	As above, but where wholesale power prices rise above the floor, generators do not receive the positive difference until the gross value of payments received under the CfD have been reimbursed.	This reduces exposure to downside risk to the same extent as standard price floor, but gives a more even distribution of upside risk between investors and consumers.	52.4
Cap and floor	This sets a minimum and maximum, with prices determined by the market when they are within this range.	We assume that the price cap is determined by the regulator (we set it at £70/MWh). We then assume that the floor price would be bid at auction at a level that would be expected to recover costs over the duration of the contract under the reference scenario.	47.8
Wholesale price + fixed premium	Wholesale price plus fixed price top-up	This scenario aims to represent a market-based solution, where electricity users would pay a premium on top of the short-run system marginal cost to procure electricity from renewables, enabling them to recover capital costs. In this case, we assume that there is no volatility in the price of this additional market revenue source, so that it acts like a fixed premium negotiated under expected (reference scenario) conditions to recover investment costs.	N/A
Wholesale price + floating premium	Wholesale price with multiplier	As above, but here we assume that rather than being fixed, the additional market revenue acts as a multiplier to the electricity revenue, and so is subject to the same degree of risk. The multiplier is set at a level that recovers investment under the reference scenario.	N/A

The CfD strike prices shown in Table 3 reflect the different expected revenues under each policy design under the reference decarbonisation scenario.¹³ Although the bid prices are different for each CfD design, they all result in the same expected average revenue under the reference scenario.¹⁴ This revenue is exactly sufficient to recoup

¹³ At this point in the analysis, by assuming that investors base their decisions on expected annual revenue, we assume bidders are risk-neutral i.e. they value expected upside as much as downside. This allows us to later to value the potential risk premium associated with down-side risk relative to this expectation.

¹⁴ However, revenues differ in the 'stress test' scenarios.

all project costs within the contract period covered by the CfD. Strike prices are therefore not a guide to overall system cost-effectiveness or cost to consumers.

These strike prices can be compared to an LCOE under our model assumptions of £43.3 / MWh. We make the following observations on these strike prices:

- **2-sided CfD.** The strike price is substantially above the LCOE reflecting the 15 year contract period over which investment is assumed to be recouped.
- **2-sided CfD (extended).** The longer duration of the CfD to match the technical lifetime of the project brings the strike price to the same level as the LCOE.
- **2-way CfD with negative price rule.** The strike price is higher than the standard 2-way CfD option due to the expected reduction in payments under this option.
- **1-sided CfD** is substantially **lower** than the strike price under the 2-sided CfD, because investors will expect to capture the upside when prices are above this floor.
- **1-sided CfD with clawback** has the same strike price as the simple 2-sided CfD option because the expected revenues are the same in the reference scenario. This reflects the fact that the clawback mechanism effectively prevents investors from benefiting from upside revenues given the capture prices remain below market prices on average in the reference scenario due to price cannibalisation under the conditions assumed in this study.
- **Cap and floor.** The floor price lies between the 1-way CfD floor price and the 2-way CfD strike price. This is because investors will see some upside when prices are above the floor, but this upside is constrained by the price cap.

These CfD auctions determine the revenues that generators realise in the high- and low-price decarbonisation scenarios. The differences in revenue represent generators' exposure to price formation risk, and are expressed as a change in project discount rate and compared across CfD design options,¹⁵ as presented in the next section.

3.5 Results

3.5.1 How do different policies affect exposure to price risks for offshore wind?

In this step, we look at how the variations in capture prices and curtailment rates presented in Section 3.3 translate into investment risk, taking account of different

¹⁵ The discount rate impact is calculated as the change in the discount rate required to get back to the same net present value expected in the base case. Fully methodology can be found in: Transition risk: Uncertain investment signals in a decarbonising electricity system, UKERC working paper, 2022.

policy options described in Section 3.5. Here we present results for offshore wind as a particular case study, although the approach is applicable to any power generation asset.

We assess how each electricity system scenario would affect an offshore wind projects' returns compared to the Consumer Transformation (CT-Base) reference scenario, expressing this difference as a discount rate impact.¹⁶

Figure 11 shows for offshore wind projects how the different policy regimes (listed down the vertical axis) result in different levels of exposure to the risks of different decarbonisation pathways (indicated by the different coloured bars).

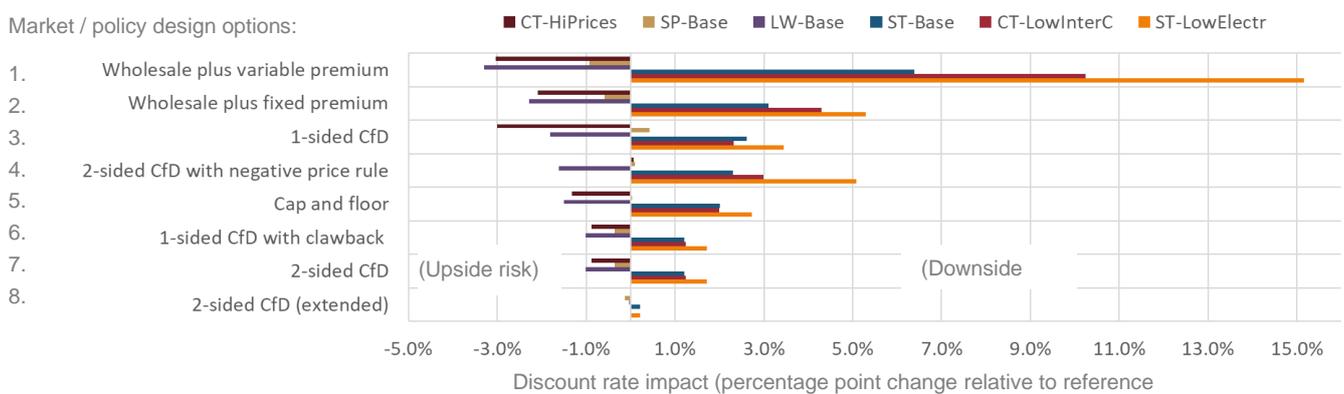


Figure 11. Exposure of offshore wind projects to uncertainty in decarbonisation pathway under different policy and market regimes.

The righthand side of Figure 11 indicates how **downside risks** vary relative to the CT reference scenario depending on the policy option. These downside risks are the key driver for assessing cost of capital. During the 'build phase', during which the long-term technology mix remains uncertain, the cost of capital is likely to account for the impact that this uncertainty (represented by the coloured bars) will have on the financial performance of a project.

Taking the policy design options in the order shown in Figure 11, the key messages are:

- Both **wholesale market design options** show the greatest level of exposure to downside risk which can considerably exceed 5 % points, extending as high as 10-15 % points under some cases. This financial exposure particularly reflects the risk of lack of investment in major flexibility infrastructure (such as flexible electrolysis demand and/or interconnectors) in the different decarbonisation scenarios.

¹⁶ The discount rate impact is calculated as the change in the discount rate required to get back to the same net present value expected in the base case. The downside risks help give an indication of the extent to which investors will need to be compensated for this risk in their returns. However, the cost of capital impact will be lower than the discount rate impact because different types of investor will value risk differently and some will also take into account the upside risk.

- **1-sided CfD** substantially reduces downside risk compared to the market options, although upside risk is still high. This asymmetrical allocation of risk between investors and consumers (i.e. allowing upside risk to accrue to investors whilst protecting them from downside risk) may be considered a disadvantage in the light of recent market price trends.
- **CfD with negative price rule** exposes projects to higher levels of downside risk (up to 3-5%) driven by uncertainty over the degree of curtailment and the impact of this on revenues.
- **2-sided CfD and 1-sided CfD with clawback** cases provide identical and relatively high degree of de-risking of the options assessed, with downside risks limited to around a 1% impact on the hurdle rate. The clawback option effectively means investors never receive any upside in revenues due to price cannibalisation, making this option identical in terms of revenues to the standard 2-sided CfD.
- **2-sided CfD (extended)**. This option almost entirely eliminates revenue risk because the 25 year contract period matches the assumed technical lifetime of the project.

Although the focus of this analysis is mainly on downside risk, upside risks also have important policy implications. The Steady Progression pathway, which fails to decarbonise, presents an upside risk to wind investors (i.e. delivers higher capture prices than in the reference scenario), particularly for policy cases 1-3 shown in the chart where projects are more exposed to market price risk¹⁷. The effect is more pronounced with the higher carbon and gas price variant of the CT scenario, which also has residual gas generation. This is a concern as it could lead to a disincentive to fully decarbonise unless strong additional policy measures are in place.

Interestingly, the Leading the Way (LT-Base) scenario also shows considerable upside risk, even though this is a fully decarbonised scenario for the GB system. This reflects the considerably greater degree of interconnection under this scenario compared to the other decarbonisation scenarios. In the assumptions used for this work, the European system still has considerable degree of fossil fuel use, which tends to keep capture prices elevated for interconnected wind plant in the GB system. This is an assumption that needs to be tested through more analysis of different European-level decarbonisation scenarios.

3.5.2 Implications for the cost of delivering offshore wind?

The final step is to illustrate the impact of these risk premiums on the implied cost of delivering the total stock of offshore wind expected in our base case scenario. The risk premium for a project is just one of many factors that will impact cost of capital. In practice financing costs will be affected by a range of project specific factors,

¹⁷ A related issue affects price setting by interconnectors with Europe. Under the assumptions modelled here, Europe has still not fully decarbonised, so prices received through interconnection are elevated by the presence of a carbon price. This is why the 'Lead the Way' scenario, which is highly interconnected to Europe, also looks attractive in these results. Different assumptions about decarbonisation rates in Europe would change this result.

including the debt leverage that can be achieved by different investors, and financial markets' risk appetite. In this analysis, we have not attempted to address these more complex aspects of project financing, but make the observation that although cost of capital will vary for different investor types, the calculated discount rate impacts are illustrative of the scale of impact of different policy options on cost of capital across the market.

From Figure 11, we observe that the (downside) risk premiums of the first two options (wholesale plus premium) are mostly between 2 and 5 percentage points above the standard 2-sided CfD (Option 7), with some cases showing considerably greater increase in risk premium of over 10 percentage points. In Table 4, we use a conservative estimate of this range of up to 5 percentage points to illustrate the potential impact on cost of delivering the offshore wind envisaged in the Consumer Transformation scenario, which amounts to 80 GW installed capacity, generating 350 TWh of electricity by 2040. This calculation indicates that every percentage point increase in the cost of capital implies an additional £1 bn to the cost of delivering the full fleet of offshore wind expected to be needed. A 5 %-point increase in the discount rate represents a third extra in capital costs.

Table 4. Illustration of the impact of cost of capital on the costs of delivering 80 GW offshore wind by 2040

<i>Discount rate increment</i>		<i>Base</i>	<i>+1%</i>	<i>+2%</i>	<i>+3%</i>	<i>+4%</i>	<i>+5%</i>
<i>Levelised cost</i>	£/MWh	43.9	46.4	49.0	51.7	54.6	57.6
<i>Annual generation</i>	TWh	350	350	350	350	350	350
<i>Total annual cost</i>	£bn/yr	15	16	17	18	19	20
<i>Increment rel. to Base</i>	£bn/yr	-	1	2	3	4	5

4 Implications for Policy ‘After’ the Transition

The analysis presented in Section 3 focused on investment risk during the ‘build phase’ of the transition. It shows that at least until there is greater clarity on the technology mix that will prevail in a zero-carbon electricity sector, significant changes to the commercial framework for investments in clean energy could result in increased cost of capital. Given the huge amounts of capital required to deliver the transition, such a chance could put the transition itself at risk.

This does not mean that market design changes will not be necessary or desirable in a future decarbonised electricity sector. In a future ‘steady-state’ phase, although considerable investment will be needed to meet growing demands from electrification of the economy, the fundamental physical characteristics of the system and subsequent market behaviour will be more easily quantified, and well-designed market mechanisms could help to re-optimize the deployment of capital within a sector that has already been decarbonised.

This section asks in a qualitative way what types of market design might be appropriate for this ‘re-optimisation’ phase. Over the past ~15 years, government intervention in the GB electricity market has gradually increased, primarily with the introduction of policy instruments aimed at delivering large volumes of renewable energy. As a result, government actors are the main players in determining the mix of new energy sector investors. While the policy mechanisms may be necessary, it seems almost certain that this will result in substantial inefficiencies in the allocation of capital. Unintended consequences are also likely; for example, with generators potentially closing early as their initial support arrangements (e.g. a CfD) expire. The analysis presented below considers which market design options might be most appropriate beyond the rapid change and uncertainty of the ‘build’ phase of the transition. Are there credible market design options that, even if they cannot deliver the energy transition itself, might help to sustain and optimise the end-state?

4.1 Levers for designing a new steady state electricity market

When considering the options for future changes to market design, there are many characteristics to explore. It is important to consider how the market is created, what it is that drives demand, what obligations result from engaging in the market, and how these obligations are traded between different market participants. Table presents a summary of some of the key design levers to be thought about. While this is not an exhaustive list, trying to answer the questions in this table can be useful in testing the completeness of a market design proposal.

Table 5. Market design levers

Demand	
What is the product?	<i>Energy or capacity? What rights are transferred to the buyer?</i>
How is demand created?	<i>Operational necessity? Regulatory obligation?</i>
Who sets the level of demand?	<i>Government or regulator? Market participants?</i>
Product characteristics	
Physical or financial?	<i>Linked to physical energy, or a financial instrument?</i>
Cashflow at settlement	<i>How are payment flows defined at settlement?</i>
Delivery obligation	<i>Is there a requirement to deliver physical energy at certain times? How is this defined?</i>
Penalties for non-delivery	<i>If the delivery obligation is not met, what penalties apply?</i>
Nominations and dispatch	<i>Do buyers nominate how much product they need? How do nominations work and to what extent is this linked to dispatch in practice?</i>
Markets and trading	
Centralised or decentralised?	<i>Is there a single centralised platform where all trading takes place? Is participation in the market for the product mandatory?</i>
Price setting	<i>How are prices defined and set?</i>
Secondary trading and optimisation	<i>Can market participants optimise the position that they have? What are the mechanisms by which they can do this?</i>
Net zero	<i>How is the market designed to ensure alignment with net zero targets?</i>

Alternative market design options can be described by deploying these design levers in different combinations. For some market designs, there can be more than one product; for example, GB’s current market design involves wholesale energy, CfDs, and the Capacity Market (CM). The relevant questions in Table should be addressed for each of the key products in a market design proposal.

Test cases can also be used when evaluating a market design proposal. A range of technologies or project types can be analysed, to assess how that project would engage and participate in the market.

Table lists some of the resource types that might be needed in a zero-emissions electricity sector. While this is again not an exhaustive list, testing the viability of these projects under a given market design can be helpful in evaluating the proposal. It might also be the case that not all the asset classes listed in Table are required.

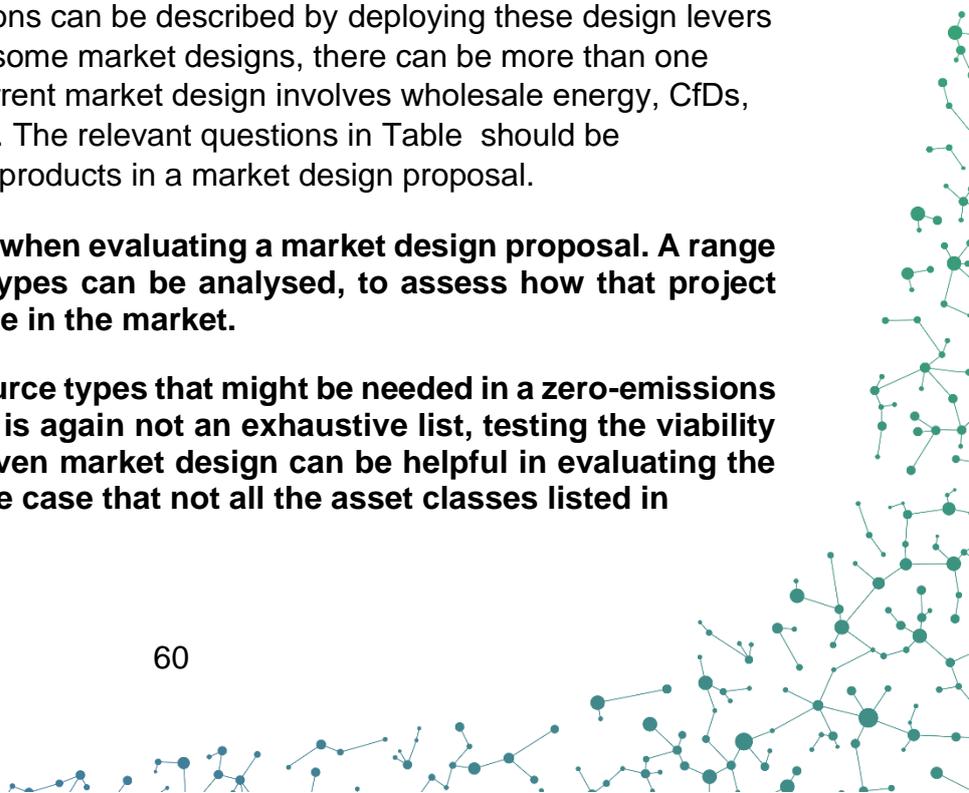


Table 6. Test cases

	Example asset classes
Non-dispatchable renewable energy	Wind, solar PV
1-way flexibility (upward)	Gas engine, DSM
1-way flexibility (downward)	Demand increase, e.g., electrolysis for H ₂
2-way flexibility	Batteries and other storage technologies
Inflexible baseload	Nuclear
Renewable energy with some dispatchability	Solar PV with co-located battery storage

4.2 Alternative target models for electricity market design

A range of market designs can be considered when assessing possible options for optimising the electricity system, after the ‘build’ phase of the transition. A wide range of ideas have been published in the literature, and these options can be grouped into four broad categories. These categories overlap and are imperfect, as any similar categorisation would be, but they provide a useful basis for the discussion that follows:

- **Merchant+:** the short-run energy price is the main price signal in the electricity market, but with modifications to achieve evolving system objectives, such as decarbonisation. This might for example rely on a high carbon price, or as in the US, the use of tax credits to incentivise investment in low-carbon generation.
- **CfD+:** build decisions continue to rely on government-driven procurement decisions, which result in long-term contracts being awarded, with stable revenues on offer to those successful bidders. This could include models that require relatively modest changes to the current approach to procuring renewables, such as a CfD floor price (5), or shifting from energy to capacity-based revenues for renewables (6,7).
- **2-market solutions:** some authors, such as Malcolm Keay (8), have suggested splitting the energy market into a market for firm, dispatchable energy (also referred to as ‘on demand’ energy), and a separate market for non-dispatchable (‘as available’ energy). Such a market would in theory allow consumers to determine the level of security of supply that they find acceptable.
- **Obligations:** this category would include models such as the Energy Systems Catapult’s Supplier Obligation model (9), which would rely on a decarbonisation standard and a reliability standard, both of which suppliers

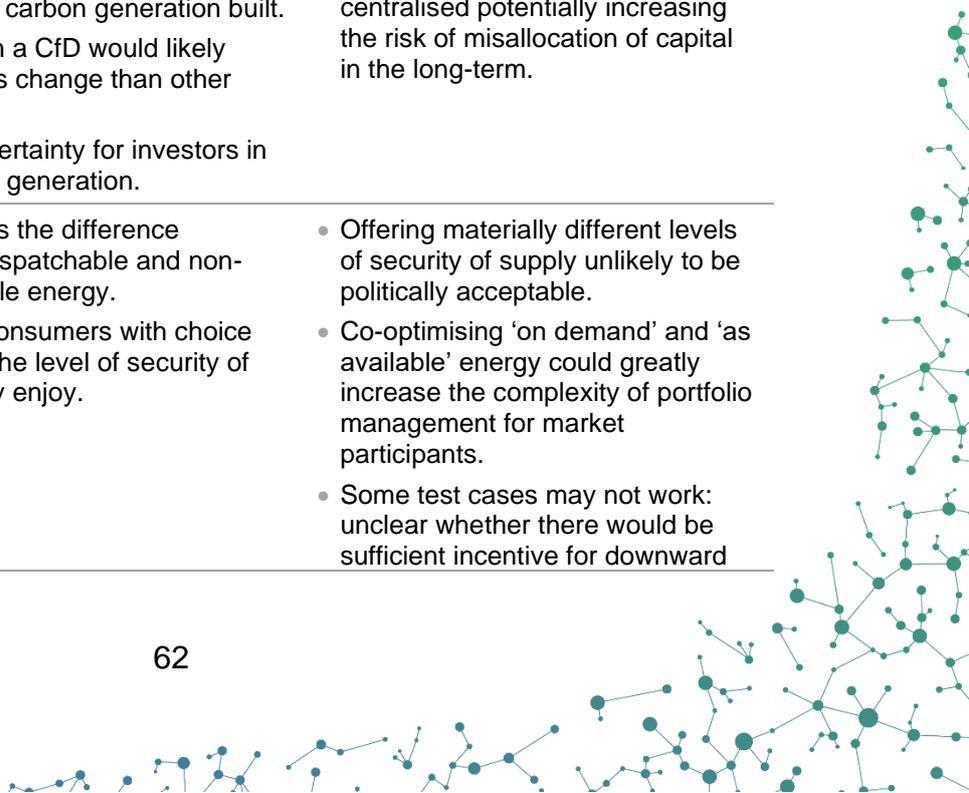
would be required to meet. It could be argued that this overlaps with the Merchant+ category because these standards would supplement a short-run wholesale electricity price.

The categorisation above consciously does not include market design options that would require substantially greater regulatory involvement (such as a Regulated Asset Base model), because this chapter is focused on assessing whether it might be possible to reduce the level of intervention after the initial ‘build’ phase of the energy transition.

There are different pros and cons for each of these types of market design. By considering the market design levers and the test cases presented in Table and Table respectively, any gaps in the designs can be identified. Table presents some of the pros and cons identified for each category or type of market design. This does not amount to a systematic or exhaustive evaluation of market design options; deliberately so, because the table focuses on broad categories of market design, rather than specific, tightly defined options.

Table 7. Pros and cons of market design categories

Market design type	Pros	Cons
Merchant+	<ul style="list-style-type: none"> • Build decisions returned to the private sector. • Minimises distortion of short-run energy price signals. • If dependent on a high carbon price, highly focused on the primary objective of the transition (i.e., emissions reductions). 	<ul style="list-style-type: none"> • Lack of revenue certainty, at least during transition while the generation mix is changing rapidly. • If the generation mix is dominated by near-zero marginal cost plants, even a high carbon price is of limited use to intermittent renewables, and flexibility providers are dependent on scarcity pricing during a decreasing number of hours.
CfD+	<ul style="list-style-type: none"> • CfD provides a proven model for getting low carbon generation built. • Variants on a CfD would likely require less change than other options. • Revenue certainty for investors in low carbon generation. 	<ul style="list-style-type: none"> • Procurement decisions remain centralised potentially increasing the risk of misallocation of capital in the long-term.
2-market solutions	<ul style="list-style-type: none"> • Recognises the difference between dispatchable and non-dispatchable energy. • Provides consumers with choice regarding the level of security of supply they enjoy. 	<ul style="list-style-type: none"> • Offering materially different levels of security of supply unlikely to be politically acceptable. • Co-optimising ‘on demand’ and ‘as available’ energy could greatly increase the complexity of portfolio management for market participants. • Some test cases may not work: unclear whether there would be sufficient incentive for downward



		flexibility (i.e., demand increase) or nuclear, which is unlikely to build a robust investment case in either market.
Obligations	<ul style="list-style-type: none"> • Seeks to preserve short-run energy price signals, similar to the Merchant+ category. • Shift burden of procurement planning back to the private sector. • Focused on desired policy outcomes, rather than means. 	<ul style="list-style-type: none"> • Unclear how a reliability obligation is in practice different to Merchant+, where suppliers would still likely aim to meet demand. • Without additional instruments to provide revenue certainty, unclear how flexibility providers would engage with the market.

4.3 Market design needs in a decarbonised electricity sector

None of the market design types are consistently strong across all the test cases listed in

Table , some provide useful mechanisms for investing in certain asset classes but leave others unaddressed. Because of the uncertainty over which technologies will be used in a decarbonised electricity system, it is unclear how important (or not) these gaps might be. This provides further support for the conclusion from the analysis presented in Section 3: that any radical change in market design during the ‘build’ phase of the transition could be detrimental, pushing up the cost of capital and potentially eliminating technology options that might be needed in reaching net zero targets.

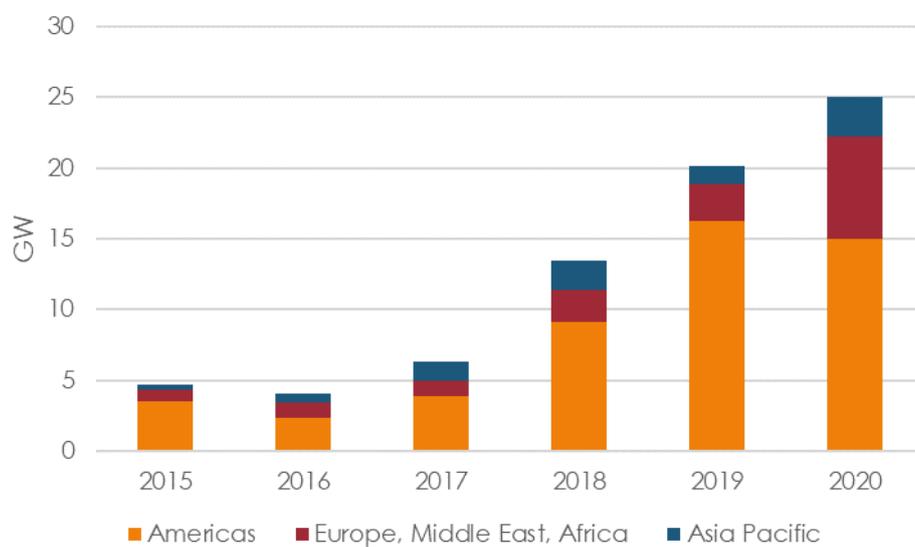
In the longer-term, we have identified a set of tests that need to be met for a proposed market design option to be credible. These five tests are again not intended to be exhaustive, but they do provide a useful framework for suggesting which types of market design might be appropriate for re-optimising the electricity system after the intense ‘build’ phase of the next few years.

Test 1: The market delivers the contractual commitments required to deliver low carbon generation. Of the tests presented here, this is the easiest to address. Indeed, some low carbon generation is already being delivered outside of support mechanisms such as the CfD. An increasing number of corporate energy consumers are decarbonising their supply chains, including their energy supply. Many are achieving this through procuring energy directly from renewable generators. However, while the corporate PPA market has grown rapidly in recent years (this is a global trend – see Figure), there could be limits to this expansion:

- Many of the procurements currently taking place are being driven by large corporate energy consumers. While there is a certain amount of standardisation in the market now, it is unclear to what extent similar models can be deployed to ever smaller customers, or perhaps even beyond corporate energy consumers.

- In many cases, renewable energy procurement offers savings to corporate energy consumers on the wholesale energy component of their energy bills. This is especially the case under current natural gas prices. It is unclear whether the current business case is sustainable under scenarios with very high price cannibalisation.
- While corporate procurement of renewable energy has grown rapidly, it remains a small portion of the total market. It is unclear whether the market would deliver the marginal unit of required renewable generation.

Nonetheless, while these limits are yet to be fully tested, it is possible to imagine continued commercial innovation addressing the challenges noted above.



Source: IEA Renewable Energy Market Update (240)

Figure 12. Corporate PPA volumes by region and year of procurement

Test 2: The market delivers the flexible capacity required to meet peak net demand. In the past, before the large-scale introduction of intermittent renewables, this was relatively straight-forward. During the late 1990s and the 2000s, investment decisions for dispatchable gas-fired power plants were made based on wholesale power price expectations. Market participants (often a large trader or supplier offtaker) were willing to become counterparties to CfD contracts, making use of their natural hedge with the correlation between gas and electricity prices. Dispatch risk was relatively low because these assets would typically operate at high load factors for many years before being displaced by newer, more efficient plants. By the time the generator was operating at the margin, and exposed to more volatility in its financial performance, the plant would often be fully depreciated. In a world with high renewables penetration, the capacity factor for flexibility providers will often be low, volatile, and uncertain from day one. In theory, scarcity value in the energy price should mean that no further intervention is necessary. But, in reality, outturn peak prices in a small number of hours are very difficult to forecast or to use for a

bankable investment case (241). The Capacity Market was introduced as part of EMR with the aim to address some of these issues.

Test 3: The market is well equipped to determine the supply quantities needed to meet system energy and capacity requirements. This is another test that has become more difficult to meet because of changes in the electricity generation mix. The generation mix of the 2000s was dominated by dispatchable thermal generators. Price formation was relatively straight-forward: if the system started to get tight, wholesale electricity prices would rise, and new capacity would be brought forward by investors. As noted above, investors could perform market analysis that would give them sufficient confidence over the capacity factor that a plant would achieve, and indeed the impact that the new project might have on a utility's portfolio.

In a decarbonised sector, the relationship between capacity and energy becomes more nuanced. There are trade-offs between over-building non-dispatchable capacity (and accepting more curtailment) and increasing the amount of dispatchable capacity. Dispatchable flexibility providers cover a range of requirements: some will operate at low capacity factors for short durations, others will operate at higher capacity factors (although lower than new build CCGTs of 20 years ago), for longer durations; still others will operate rarely but, when they do, will need to produce for some days during wind drought conditions. There are complex whole system considerations: large-scale hydrogen deployment might result in greater dispatchability in the electricity system, potentially reducing the demand for some other flexibility providers.

In theory, the optimal generation mix can still be modelled, but the outcome will largely depend on technology cost curve assumptions, which themselves are highly uncertain. Different investors will likely make different assumptions, and the overall uncertainty may mean that most investors are unwilling to deploy capital at scale without some form of government-backed risk mitigation.

Test 4: The market is well understood and can be modelled. For investors to deploy capital into a market it is important that risks are well understood and that they can be quantified. Where this is not possible, then intervention may be required to mitigate those risks. In the absence of such risk mitigation the required electricity generation capacity may not be built, or it might be built at very high cost, because of a high cost of capital. A good first test as to whether a market design proposal is sufficiently well defined is to ask whether the commercial arrangements that will be used to implement the design (i.e. the heads of terms) have been written down. As far as we are aware, this has not been done for the 2-market or Obligation-based market design proposals cited earlier. This in turn suggests that further detailed design work would be required before the market design could be modelled, and thus understood by potential investors.

Test 5: The market results in politically acceptable outcomes. Some market design options may be elegant in theory but could result in outcomes that are unacceptable to society, elements of the media, and/or politicians. For example, a merchant market might in theory result in sufficiently high prices in a small number of hours to support investment in a low capacity factor flexibility provider, but the very

high prices required might not be politically acceptable (notwithstanding the bankability concerns raise above). Similarly, 2-market solutions might allow energy consumers to select a service level that suits their requirements. But if a consumer has selected a low cost ‘as available’ product, it seems unlikely that it would be politically acceptable for their supply to be cut off during a cold, windless January.

The previously identified market design types can be assessed against these tests. Table presents a high-level assessment, showing how each of the market design categories performs against each of the tests. It is recognised that the assessment is highly subjective. Green indicates that our judgement that a requirement is ‘met’, amber that it is ‘partially met’, and red that the requirement is ‘not met’. The relative number of green or red indicators does not necessarily mean that a particular market design options is better or worse, but it does indicate where a given option’s strengths and weaknesses lie. Ultimately, these tests are hygiene factors, and ideally any new market design would need a green indicator against each test. The fact that no option achieves this suggests that market intervention or a suitable combination of interventions remain a requirement for now.

Table 8. Assessment of market design types against tests

	Merchant+	CfD+	2-market solutions	Obligations
Test 1: The market delivers the contractual commitments required to deliver low carbon generation	 Corporate PPA market is demonstrating some appetite for renewables to be contracted directly but unclear what the limits of this trend might be.	 Market designs with CfDs or an equivalent provide a separate de-risked framework for renewables procurement, and can be tailored to deliver required volumes.	 Energy consumers have already demonstrated an appetite for green power, but here they are also expected to directly face the security of supply consequences of intermittency.	 As with Merchant+, there is uncertainty over how much of the requirement could be met by the market – who takes the volume risk if suppliers over-procure?
Test 2: The market delivers the flexible capacity required to meet peak net demand	 In theory a merchant market might result in a price signal that would pay for this capacity, but this is unlikely to be bankable, calling for further intervention, such as a Capacity Market.	 Additional measures, such as a Capacity Market, would be required to also deliver the system flexibility required to absorb renewables capacity.	 Without the introduction of additional instruments to provide revenue stability, it likely suffers the same shortcomings as Merchant+.	 A penalty regime could create a price signal but it is not clear how this would be set. Possible need for an associated market to avoid collective over-procurement.

<p>Test 3: The market is well equipped to determine the supply quantities needed to meet system energy and capacity requirements</p>	<p style="text-align: center;">●</p> <p>It seems unlikely that the market could address the trade-offs between procuring energy in the absence of a bankable cashflow for flexibility providers.</p>	<p style="text-align: center;">●</p> <p>It seems unlikely that the market could address the trade-offs between procuring energy in the absence of a bankable cashflow for flexibility providers.</p>	<p style="text-align: center;">●</p> <p>Consumers explicitly define how much 'dispatchable' they want the market to provide, although it would still be non-trivial to translate this into capacity and energy demand numbers, and to frame reliability products in a way that users can make informed choices</p>	<p style="text-align: center;">●</p> <p>It seems unlikely that the market could address the trade-offs between procuring energy in the absence of a bankable cashflow for flexibility providers.</p>
<p>Test 4: The market is well understood and can be modelled</p>	<p style="text-align: center;">●</p> <p>Wholesale energy prices can be modelled where price formation is well understood. However, peak prices for plants operating at low capacity factors are difficult to forecast.</p>	<p style="text-align: center;">●</p> <p>CfD price expectations can be modelled and understood by market participants, and this would likely be the case for similar variants.</p>	<p style="text-align: center;">●</p> <p>Not currently defined at a level of detail that allows for the development of heads of terms and/or a representative model.</p>	<p style="text-align: center;">●</p> <p>Not currently well-defined, although it seems likely this would be quite similar to Merchant+ in many respects.</p>
<p>Test 5: The market results in politically acceptable outcomes</p>	<p style="text-align: center;">●</p> <p>Very high peak prices required to attract flexibility providers might not be politically acceptable, especially if they still failed to bring forward new investment.</p>	<p style="text-align: center;">●</p> <p>Continued centralised procurement is likely to be politically acceptable, although this partly depends on how flexibility provision and capacity/energy trade-offs are addressed.</p>	<p style="text-align: center;">●</p> <p>Unlikely to be acceptable to cut off households who select a cheaper, 'as available' product, however conscious and informed that decision was.</p>	<p style="text-align: center;">●</p> <p>As with Merchant+, likely to depend on very high peak prices to attract flexible capacity, which may not be acceptable.</p>

While this analysis shows that there is no one market design that is clearly suitable for the 're-optimisation' phase of the transition, different technology pathways might point towards a different shortlist of market design options:

- If short-run wholesale market price signals remain robust, then a Merchant+ route might be feasible. Short-run price signals might remain robust if gas CCS has a substantial role in the energy mix, if a mature DSM market

develops, or if a deep hydrogen market develops (and hydrogen is widely used in the electricity sector), with well understood pricing. As shown in Table , this would likely need to be supplemented by a Capacity Market or equivalent.

- If short-run wholesale market prices tend towards zero during most hours, a CfD+ route (or some other long-run pricing mechanism) might be required. This could be required in high electrification pathways where electricity storage plays a major role, but without a deep hydrogen market.
- In theory, a 2-market or obligation-based approach might offer a more sophisticated solution, but not until the shortcomings and the gaps in design detail highlighted in Table are addressed.

The future evolution of technology cost curves will also be an important consideration in market design choices. As shown by the analysis in Section 3, uncertainty over technology pathways is a major driver of the investment risk that would arise if material market design changes were to be made during the 'build' phase of the transition. Uncertainty over which technology pathway will prevail is itself largely a result of uncertainty over the evolution of technology costs. The removal of the risk mitigation tools (CfDs, Capacity Market) and centralised procurement are likely to be difficult and maybe impossible steps to take until this uncertainty has been greatly reduced.

5 Conclusions and Recommendations for Further Work

5.1 Conclusions

Investment is key to achieving the transition to a zero-carbon electricity system. Scenarios from the Climate Change Committee imply this transition needs to be made by the mid-2030s to put the UK on track to meet 2050 net-zero targets, and the UK Government has set a target of zero carbon electricity by 2035, subject to security of supply (242). A primary function of energy policy is therefore to attract the necessary investment at sufficient speed and scale. The degree of risk that investors face will be key to the feasibility and cost of achieving this. Our work suggests that the cost of capital can vary by about a third depending on the extent to which policies expose investors to transition pathway risk. In general, the greater the exposure to wholesale market prices, the greater the risk and cost of capital will be. The primary policy mechanism investigated here for managing this risk is the Contracts for Difference (CfD). These substantially reduce investment risk, albeit with considerable variation in risk exposure between different CfD designs.

At the same time, the energy price shocks of 2022 have shone a harsh spotlight on costs and risks to consumers. This contrasts with the low-demand, low-price conditions in 2020 during Covid lockdowns where a primary policy concern was investor risk and price cannibalisation. This emphasises the need for policy to consider the allocation of both upside and downside risks between generators and consumers. Work by Gross et. al. (243) shows that 2-sided CfDs can also help reduce the extent to which upside price risk is passed through from investors to consumers.

Experience from international case studies suggest that policy design is highly context-specific, depending on the evolution of regulatory frameworks, market structures and behavioural norms. No examples exist of fully decarbonised systems at national level, although useful lessons can be drawn from the behaviour and performance of different market designs and policy regimes during the current phase of the transition.

General principles dictate that risks should be allocated to those best able to manage them. This work has concentrated on risks associated with uncertainty over the future pathway of decarbonisation. In particular, the work shows that there are fundamental risks associated with the degree of flexibility in the electricity system, which in turn is influenced by wider macro-trends such as the degree of hydrogen consumption and electrification of different parts of the economy, and the degree of system flexibility that these might bring. Future whole-system pathways are not within the power of individual power generation investors to manage, and are highly policy- and path-dependent, making associated price behaviour difficult to predict and hedge.

Many of these transition risks and uncertainties will tend to reduce over time as the pathway is revealed, and there is greater clarity over the physical and operating characteristics of the system. We have referred to the current stage of the transition as the 'build-phase' where speed of response is paramount, risks are high, and there is a strong case for socialising these risks with an equitable allocation between investors and consumers. Once we are closer to a decarbonised system, investment rates will still need to be high, due to growing demand from increased electrification. However, we see here a more 'steady-state' phase in terms of the structure of the electricity system, with greater understanding of system operation, price formation and associated risk characteristics. At this point, market hedging structures will become more feasible, making allocation of risk to market participants more efficient than it is now.

5.2 Recommendations for further work

The analysis presented here can be expanded in a number of ways:

- More UK decarbonisation pathway scenarios could be modelled to broaden the analysis of different risk factors, and investigate in more detail the implications of fully decarbonised systems (noting that a number of the scenarios investigated here still maintain some degree of unabated fossil-fuel use). This would be relatively easy to implement by increasing the number of scenarios run through the Antares model.
- More Europe-wide decarbonisation pathways could be modelled. In this work, we use only a single scenario, which does not assume full decarbonisation. This has important impacts on the economics, operation and effectiveness of interconnectors which needs to be further investigated. Again, this is relatively easy in principle to implement in Antares, though requires considerable preparatory effort to design suitable internally consistent decarbonisation pathways at a European level.
- Other low-carbon generation technologies (beyond offshore wind) could be analysed, helping to inform the degree to which risk exposures vary across different generation types. These could be relatively easily included by increasing the number of technologies run through the discounted cashflow model.
- Investment risk for plant contributing to system flexibility (e.g. electrolysis, interconnectors and flexible demand) could be included in the analysis. This would help inform policy design for incentivising investment in these types of technology. This would require some additional work to adequately represent cashflows for these technologies within the model.
- Weather risk could be investigated in more detail by running additional weather years, beyond the single weather year assessed in this work. This would be relatively easy to implement by increasing the number of scenarios run through the Antares model.

- There could be further investigation of the potential trade-offs between static and dynamic risks and efficiencies and their allocation between generators and consumers associated with CfDs. This would require more significant changes to the approach to move beyond the current static model structure which focuses on a single snap-shot year, to look at how risks evolve throughout the transition pathway.



References

1. Future Energy Scenarios [Internet]. 2021. Available from: <https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021>
2. BEIS. CfD Allocation Round 4 Results [Internet]. Available from: <https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-4-results>
3. Heptonstall, Phil, Gross R. A systematic review of the costs and impacts of integrating variable renewables into power grids. Nat Energy. 2021;
4. BEIS. Review of Electricity Market Arrangements. Available from: <https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements>
5. Miller G. Letter to BEIS advocating a CfD floor price [Internet]. 2019. Available from: <http://www.newpower.info/wp-content/uploads/2019/01/CfD-floor-price-letter-to-BEIS.pdf>
6. Newbery D, Pollitt MG, Ritz RA, Strielkowski W. Market design for a high-renewables European electricity system. Renew Sustain Energy Rev. 2018;91(April):695–707.
7. Hu J, Harmsen R, Crijns-Graus W, Worrell E, van den Broek M. Identifying barriers to large-scale integration of variable renewable electricity into the electricity market: A literature review of market design. Renew Sustain Energy Rev. 2018;81(September 2016):2181–95.
8. Keay M, Robinson D. The decarbonised electricity system of the future: the ‘two market’ approach. 2017.
9. Keay-Bright S, Day G, Newey G, Alikhanzadeh A, Lawton P, Mee D, et al. Rethinking Electricity Markets: EMR2.0: a new phase of innovation–friendly and consumer–focused electricity market design reform. 2021.
10. HM Government. The Ten Point Plan for a Green Industrial Revolution. 2020;(November):14–6.
11. HM Government. The Net Zero Strategy: Build Back Greener [Internet]. 2021. Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1026655/net-zero-strategy.pdf
12. HM Government. The British Energy Security Strategy [Internet]. 2022. Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067835/british-energy-security-strategy-web.pdf
13. HM Government. Energy Act Electricity Market Reform provisions [Internet]. 2013. Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

14. Energy Futures Lab. Electricity Markets, Incentives and Zero Subsidy Renewables [Internet]. 2019. Available from: <https://www.imperial.ac.uk/energy-futures-lab/research/policy-innovation/briefing-papers/paper-4/>
15. HM Government. RAB Model for Nuclear [Internet]. 2019. Available from: s://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943762/Nuclear_RAB_Consultation_Government_Response.pdf
16. HM Government. The Carbon Capture and Storage Infrastructure Fund. 2021; Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984001/ccs-infrastructure-fund-cif-design.pdf
17. HM Government. Energy White Paper: Powering our net zero future [Internet]. 2020. Available from: <https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future>
18. UK Committee on Climate Change. Independent Assessment of the UK Net Zero Strategy [Internet]. 2021. Available from: <https://www.theccc.org.uk/wp-content/uploads/2021/10/Independent-Assessment-of-the-UK-Net-Zero-Strategy-CCC.pdf>
19. LCP. Net zero power without breaking the bank [Internet]. 2021. Available from: [https://insight.lcp.uk.com/acton/attachment/20628/f-d32a3b26-13a3-4334-9d7f-0cb5634e5b9d/1/-/-/-/Net zero without breaking the bank - LCP SSE report 2021 .pdf](https://insight.lcp.uk.com/acton/attachment/20628/f-d32a3b26-13a3-4334-9d7f-0cb5634e5b9d/1/-/-/-/Net%20zero%20without%20breaking%20the%20bank%20-%20LCP%20SSE%20report%202021.pdf)
20. Miller G. Wholesale Power Price Cannibalisation [Internet]. 2018. Available from: <https://www.cornwall-insight.com/our-thinking/insight-papers/wholesale-power-price-cannibalisation/>
21. Bell KRW, Hawker G. Electricity demand during week one of COVID-19 lockdown [Internet]. 2020. Available from: <https://ukerc.ac.uk/news/electricity-covid-lockdown/>
22. UK's power system emissions hit all-time low and wholesale power prices go negative. 2020; Available from: <https://www.energylivenews.com/2020/05/26/uks-power-system-emissions-hit-all-time-low-and-wholesale-power-prices-go-negative/>
23. Climate Change Committee. Hydrogen in a low carbon economy [Internet]. 2018. Available from: <https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf>
24. Froggatt A, Kuzemko C. Brexit Implications for UK Decarbonisation Objectives Policy brief Key findings and policy recommendations. 2021; Available from: <https://ukerc.ac.uk/publications/brexit-uk-decarbonisation/>
25. Rosenow AJ, Lowes R, Hawker G, Wu J, Gross R. The pathway to net zero heating in the UK A UKERC policy brief Key findings.
26. Day G. Can we make electricity markets work better – or is ambitious reform all just too risky to contemplate? [Internet]. 2021. Available from:

- <https://es.catapult.org.uk/insight/can-we-make-electricity-markets-work-better-or-is-ambitious-reform-all-just-too-risky-to-contemplate/>
27. Dixon T. Energy Spectrum. 2021;(763):4.
 28. Bell K, Maclver C, Blyth W, Gross R. BEIS call for evidence: Enabling a high renewable, net zero electricity system [Internet]. Available from: <https://ukerc.ac.uk/publications/beis-call-for-evidence-enabling-a-high-renewable-net-zero-electricity-system/>
 29. Newbery D. Designing an incentive-compatible efficient Renewable Electricity Support Scheme. Cambridge Work Pap Econ [Internet]. 2021;(July 2021). Available from: <https://ideas.repec.org/p/cam/camdae/2128.html>
 30. Sensfuß F, Ragwitz M, Genoese M. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. Energy Policy. 2008 Aug;36(8):3086–94.
 31. López Prol J, Steininger KW, Zilberman D. The cannibalization effect of wind and solar in the California wholesale electricity market. Energy Econ. 2020 Jan;85:104552.
 32. Halttunen K, Staffell I, Slade R, Green R, Saint-Drenan Y-M, Jansen M. Global Assessment of the Merit-Order Effect and Revenue Cannibalisation for Variable Renewable Energy. SSRN Electron J. 2020;
 33. Beiter P, Heeter J, Spitsen P, Riley D. Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States. Golden, CO; 2020.
 34. Jansen M, Staffell I, Kitzing L, Quoilin S, Wiggelinkhuizen E, Bulder B, et al. Offshore wind competitiveness in mature markets without subsidy. Nat Energy. 2020 Aug;5(8):614–22.
 35. Szabó L, Bartek-Lesi M, Diallo A, Dézsi B, Vasilios A, del Rio P. Design and results of recent renewable energy auctions in Europe. Papeles Energ. 2021;41–67.
 36. Jansen M, Beiter P, Riepin I, Müsgens F, Guajardo-Fajardo VJ, Bulder B, et al. Policy choices and outcomes for offshore wind auctions globally. Energy Policy. 2022;167:113000.
 37. Ernst & Young. October 2021 Renewable Energy Country Attractiveness Index (RECAI). 2021.
 38. Sach T, Lotz B, von Blücher F. Auctions for the support of renewable energy in Germany. AURES II: D2.1-DE. Karlsruhe, Germany; 2019.
 39. IRENA. Renewable Energy Auctions: Status and Trends Beyond Price. Abu Dhabi: International Renewable Energy Agency (IRENA); 2019.
 40. Girard Y, Kemfert C, Stoll J. Comparing regulatory designs for the transmission of offshore wind energy. Econ Energy Environ Policy. 2020;10(1).
 41. Federal Network Agency. Monitoring Report 2021 in accordance with section 63(3) in conjunction with section 35 of the Energy Industry Act (EnWG) and

- section 48(3) in conjunction with section 53(3) of the Competition Act (GWB) [Internet]. 2022. Available from: https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2021.pdf?__blob=publicationFile&v=2
42. BSH. Bundesamt für Seeschifffahrt und Hydrographie (BSH), Liste über Offshore-Windparkvorhaben im Sinne des § 26 WindSeeG, 19.12.2016. Available at: https://www.bsh.de/EN/TOPICS/Offshore/Public_notifications/public_notifications_node.html. 2016.
 43. Ørsted. DONG Energy awarded three German offshore wind projects. Press release [Internet]. 2017; Available from: <https://orsted.com/en/company-announcement-list/2017/04/1557851>
 44. Ørsted. Ørsted wins 551.75MW in German offshore wind auction. Press release [Internet]. 2018; Available from: <https://orsted.com/en/company-announcement-list/2018/04/1731313>
 45. Innogy. Innogy successful in German offshore auction. Press release [Internet]. 2018; Available from: <https://w3.windfair.net/wind-energy/pr/28154-innogy-offshore-tender-kaskasi-auction-wind-farm>
 46. Reuters. Iberdrola Plans One Billion Euro Investment in Baltic Sea Wind Farms. 2018 Apr; Available from: <https://www.reuters.com/article/uk-iberdrola-offshore-wind-investment/iberdrola-plans-one-billion-euro-investment-in-baltic-sea-wind-farms-idUKKBN1HY2DY>
 47. Güsewell D, Kancy S, M., Münch (EnBW). EnBW press conference. 2018.
 48. Hübler D, Radov D, Lorenz W. Method or Madness: Insights from Germany's Record-Breaking Offshore Wind Auction and Its Implications for Future Auctions. NERA Econ Consult. 2017;
 49. Müsgens F, Riepin I. Is offshore already competitive? Analyzing German offshore wind auctions. In: International Conference on the European Energy Market, EEM [Internet]. 2018. Available from: <https://ieeexplore.ieee.org/document/8469851/>
 50. BnetzA. Beendete Ausschreibungen / Statistiken (Solar-Anlagen) [Internet]. 2020. Available from: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Solaranlagen1/BeendeteAusschreibungen/BeendeteAusschreibungen_node.html
 51. Deutscher Bundestag. Renewable Energy Sources Act (EEG 2017) [Internet]. Bundesgesetzblatt Berlin, Germany, Germany: Deutscher Bundestag; 2017 p. 2532ff. Available from: https://www.bmwi.de/Redaktion/EN/Downloads/renewable-energy-sources-act-2017.pdf?__blob=publicationFile&v=3
 52. Kruger W, Eberhard A, Swartz K. Renewable Energy Auctions: A Global Overview [Internet]. Management Programme in Infrastructure Reform and Regulation (MIR): Report 1: Energy and Economic Growth Research

- Programme (W01 and W05) PO Number: PO00022908. Cape Town, South Africa: University of Cape Town; 2018. Available from: http://www.gsb.uct.ac.za/files/EEG_GlobalAuctionsReport.pdf
53. BMWi. Result of the joint auctions of onshore wind and solar PV. National tenders and results [Internet]. 2020. Available from: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Gemeinsame_Wind_Solar/BeendeteAusschreibungen/start.html
 54. Solarserver. Photovoltaik: PPA für 100 MW in Deutschland. Solarserver. 2020 Aug;
 55. Bundesnetzagentur. Beendete Ausschreibungen / Statistiken - Windenergie an Land [Internet]. 2021. Available from: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Wind_Onshore/BeendeteAusschreibungen/BeendeteAusschreibungen_node.html
 56. Bundesnetzagentur. Beendete Ausschreibungen / Statistiken [Internet]. 2021. Available from: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Wind_Onshore/BeendeteAusschreibungen/BeendeteAusschreibungen_node.html
 57. Jansen M. Economics of control reserve provision by fluctuating renewable energy sources [Internet]. 2017. Available from: <https://www.zhb-flensburg.de/dissert/jansen-malte/>
 58. EPEX SPOT. New trading record on EPEX SPOT in 2019 [Internet]. 2020. Available from: <https://www.epexspot.com/en/news/new-trading-record-epex-spot-2019>
 59. Fraunhofer ISE. Energy-Charts.info - Cross-border physical flows of Germany in December 2022 [Internet]. 2023. Available from: https://www.energy-charts.info/charts/power/chart.htm?l=en&c=DE&source=cbpf_saldo&stacking=stacked_absolute&year=2022&interval=month&month=12
 60. Federal Network Agency. Results of the bidding rounds for solar systems 2022: Completed tenders [Internet]. 2023. Available from: <https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Solaranlagen1/BeendeteAusschreibungen/start.html>
 61. Statkraft. Statkraft enables first wind PPA in Germany [Internet]. 2018. Available from: <https://www.statkraft.com/newsroom/news-and-stories/archive/2018/statkraft-enables-first-wind-ppa-in-germany/>
 62. RenewablesNow. Germany's Enovos, Solar-Konzept agree PPA for 100 GWh of solar. RenewablesNow [Internet]. 2021 Jul; Available from: <https://renewablesnow.com/news/germanys-enovos-solar-konzept-agree-ppa-for-100-gwh-of-solar-707477/>
 63. PV Magazine. German solar PPA market to reach 300 MW in 2020. 2020; Available from: <https://www.pv-magazine.com/2020/10/14/german-solar-ppa-market-to-reach-300-mw-in-2020/>

64. PV Europe. Tenders less risky than PPAs in Germany - pv Europe. PV Europe [Internet]. 2019 Sep; Available from: <https://www.pveurope.eu/markets-money/tenders-less-risky-ppas-germany>
65. S&P Global Platts. European PPA offers “relatively stable” despite rising power prices: Zeigo | S&P Global Platts [Internet]. 2021. Available from: <https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/042821-european-ppa-offers-relatively-stable-despite-rising-power-prices-zeigo>
66. Deutscher Bundestag. Verfahren zum Bau von Windkraft-anlagen auf See kritisch bewertet [Internet]. 2020. Available from: <https://www.bundestag.de/dokumente/textarchiv/2020/kw37-pa-wirtschaft-windenergie-706318>
67. ErneuerbareEnergien. Offshore-Wind: Zweite Gebotskomponente ist vom Tisch - ERNEUERBARE ENERGIEN. ErneuerbareEnergien [Internet]. Nov; Available from: <https://www.erneuerbareenergien.de/markt/windmarkt/wind-auf-see-gesetz-offshore-wind-zweite-gebotskomponente-ist-vom-tisch>
68. Deutsche Bundestag. Federal government on the future of coal [Internet]. 2022. Available from: <https://www.bundestag.de/presse/hib/kurzmeldungen-895770>
69. Wire CE. Does LNG have a place in Germany’s energy future? [Internet]. Available from: <https://www.cleanenergywire.org/factsheets/liquefied-gas-does-lng-have-place-germanys-energy-future>
70. SPD, BÜNDNIS 90/DIE GRÜNEN, FDP. Mehr fortschritt wagen - Mehr Fortschritt wagen – Bündnis für Freiheit, Gerechtigkeit und Nachhaltigkeit. Koalitionsvertrag 2021–2025 zwischen SPD, BÜNDNIS 90/DIE GRÜNEN und FDP [Internet]. Berlin, Germany; 2021. Available from: https://www.spd.de/fileadmin/Dokumente/Koalitionsvertrag/Koalitionsvertrag_2021-2025.pdf
71. Bundesministerium für Wirtschaft und Energie (BMWi). Bundeswirtschaftsministerium treibt Wasserstoff auf See voran: Verordnung zur Vergabe von Flächen für die Wasserstoffherzeugung auf See veröffentlicht [Internet]. 2021. Available from: <https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2021/09/20210924-bundeswirtschaftsministerium-treibt-wasserstoff-auf-see-voran-verordnung-zur-vergabe-von-flachen-fur-die-wasserstoffherzeugung-auf-see-veroeffentlicht.html>
72. Solarserver. Wärmepumpe knackt 50-Prozent-Marke im Neubau | Solarserver. Solarserver [Internet]. 2021 Jun; Available from: <https://www.solarserver.de/2021/06/07/waermepumpe-knackt-50-prozent-marke-im-neubau/>
73. Roth A, Brückmann R, Jimeno M, Đukan M, Kitzing L, Breitschopf B, et al. Renewable energy financing conditions in Europe : survey and impact analysis. 2021;(817619). Available from: <http://aures2project.eu/2021/06/29/renewable-energy-financing-conditions-in-europe-survey-and-impact-analysis/>

74. McSweeney R, Timperley J. The Carbon Brief Profile: South Africa [Internet]. 2018. Available from: <https://www.carbonbrief.org/the-carbon-brief-profile-south-africa/>
75. Lee J, Zhao F. Gobar Wind Report 2021 [Internet]. Global Wind Energy Council. 2021. Available from: <https://gwec.net/global-wind-report-2021/Wind-Report-2021.pdf>
76. Calitz JR, Wright JG. Statistics of utility-scale power generation in South Africa in 2020. 2021;2(March):1–211. Available from: https://www.researchgate.net/publication/349980017_Statistics_of_utility-scale_power_generation_in_South_Africa_in_2020
77. Graham E, Burton J. Global Electricity Review 2021: South Africa tops the G20 for reliance on coal power [Internet]. 2021. Available from: <https://ember-climate.org/app/uploads/2021/03/Global-Electricity-Review-2021.pdf>
78. Oberholzer J, Dukashe P, Scheppers S. System Status and Outlook Briefing (March 2021) [Internet]. Johannesburg; 2020. Available from: <https://grocotts.ru.ac.za/wp-content/uploads/2021/03/System-Status-Briefing-15-March-2021Final.pdf>
79. Sylvy Jaglin, Alain Dubresson. Eskom: Electricity and technopolitics in South Africa [Internet]. Cape Town: Juta and Company (Pty) Ltd; 2016. 1–178 p. Available from: <http://www.ifas.org.za/research/2018/eskom-2/>
80. Ndlovu V, Inglesi-Lotz R. Positioning South Africa's energy supply mix internationally: Comparative and policy review analysis. *J Energy South Africa* [Internet]. 2019;30(2):14–27. Available from: <http://link.springer.com/10.1007/978-3-319-25510-1>
81. Pollet BG, Staffell I, Adamson K-A. The Energy Landscape in the Republic of South Africa. Cham: Springer International Publishing; 2016. 60 p. (SpringerBriefs in Energy).
82. Lawrence A. South Africa's Energy Transition. 1st ed. South Africa's Energy Transition. Palgrave Pivot, Cham; 2020. 1–177 p.
83. Department of Public Enterprises (Republic of South Africa). Roadmap for Eskom in a Reformed Electricity Supply Industry [Internet]. Government of South Africa; 2019. Available from: <https://dpe.gov.za/roadmap-for-eskom-in-a-reformed-electricity-supply-industry/>
84. Lawrence A. Eskom and the Dual Character of the South African State. In: South Africa's Energy Transition. Palgrave Pivot, Cham; 2020. p. 59–83.
85. de Ruyter A. Address for Status of the System Briefing by Eskom Group Chief Executive André de Ruyter. South Africa: Eskom; 2021. p. 6.
86. Sguazzin A, Naidoo P, Pronina L. Eskom Bailout Emerging as Equity Swap by Biggest Bondholder. Bloomberg. 2020.
87. de Ruyter A, Eberhard A, Altman M, Singh A. An Independent Transmission System and Market Operator (ITSMO) in SA: A dialogue hosted by Nedbank, EE Business Intelligence and JCSE at Wits University. Johannesburg; 2020.

88. Department of Energy (Republic of South Africa). Integrated Resource Plan (IRP2019). Johannesburg: Department of Energy (Republic of South Africa); Oct, 2019 p. 1–98.
89. Department of Mineral Resources and Energy of South Africa, Development Bank of South Africa, National Treasury of South Africa. IPP Risk Mitigation. 2020.
90. Smith T. Hang in there South Africa, emergency power on the way. ESI-Africa.com. 2021.
91. Carnie T. Despite Eskom approvals, Turkish powerships still need Transnet buy-in for 20-year harbour moorings. Daily Maverick. 2021.
92. Burkhardt P. Deal to supply SA power from ships estimated at R218bn. Bloomberg News. 2021.
93. Joseph Cotterill. South Africa rejects power ships on environmental grounds | Financial Times. Financial Times. 2021 Jun;
94. Ting MB, Byrne R. Eskom and the rise of renewables: Regime-resistance, crisis and the strategy of incumbency in South Africa's electricity system. Energy Res Soc Sci. 2020 Feb;60:101333.
95. Kruger W, Nygaard I, Kitzing L. Counteracting market concentration in renewable energy auctions: Lessons learned from South Africa. Energy Policy. 2021 Jan;148:111995.
96. Eberhard A, Naude R. The South African renewable energy independent power producer Procurement programme: A review and lessons learned. J Energy South Africa. 2016;27(4):1–14.
97. News24. No end in sight as Eskom stand-off on renewables continues. Available from: <https://www.news24.com/Fin24/no-end-in-sight-as-eskom-stand-off-on-renewables-continues-20170811>
98. SAWEA. A Closer Look at Reipppp Bid Window 5. South African Wind Energy Association. 2021.
99. Department of Mineral Resources and Energy of South Africa, Development Bank of South Africa, National Treasury of South Africa. IPP Renewables. 2021.
100. Reed E. South Africa opens window for renewable boom once more. Energy Voice [Internet]. 2021 Jun; Available from: <https://www.energyvoice.com/renewables-energy-transition/328048/south-africa-window-renewable/>
101. Department of Mineral Resources and Energy of South Africa. Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) - Overview 2021 [Internet]. Pretoria, South Africa; 2021. Available from: <https://www.ipp-renewables.co.za/PressCentre/GetPressRelease?fileid=3bef308e-2bba-eb11-9543-2c59e59ac9cd&fileName=REIPPPP BW5 Summary Final.pdf>
102. IRENA. Renewable energy auctions: Cases from sub-Saharan Africa

- [Internet]. Abu Dhabi: International Renewable Energy Agency; 2018. Available from: <https://irena.org/publications/2018/Apr/Renewable-energy-auctions-Cases-from-sub-Saharan-Africa>
103. Kruger W, Eberhard A. Renewable energy auctions in sub-Saharan Africa: Comparing the South African, Ugandan, and Zambian Programs. Wiley Interdiscip Rev Energy Environ [Internet]. 2018 Jul;7(4):e295. Available from: <http://doi.wiley.com/10.1002/wene.295>
 104. Eberhard A, Kolker J, Leigland J. Republic of South Africa: Review of the South Africa Renewable Energy IPP Process. eport No: ACS8826). Washington, DC: World Bank Group; 2014.
 105. Eberhard A, Naude R. The South African Renewable Energy IPP Procurement Programme [Internet]. Cape Town, South Africa; 2017. Available from: <https://openknowledge.worldbank.org/bitstream/handle/10986/20039/ACS88260WP0P1482120Box385262B00PUBLIC0.pdf?sequence=1&>
 106. Eberhard A, Kåberger T. Renewable energy auctions in South Africa outshine feed-in tariffs. Energy Sci Eng. 2016 May;4(3):190–3.
 107. South Africa installed 1.3 GW of PV last year – pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2021/07/21/south-africa-installed-1-3-gw-of-pv-last-year/>
 108. South Africa Solar Photovoltaic (PV) Market | Growth, Trends, COVID-19 Impact, and Forecasts (2021 - 2026) [Internet]. Available from: <https://www.mordorintelligence.com/industry-reports/south-africa-solar-power-market-industry>
 109. Scatec secures 150 MW of South African tender as part of solar-plus-storage project – pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2021/06/02/scatec-secures-150-mw-of-south-african-tender-as-part-of-solar-plus-storage-project/>
 110. Eskom. Tariffs & Charges Booklet 2020/2021 [Internet]. Johannesburg, South Africa: Eskom; 2020. Available from: https://www.eskom.co.za/CustomerCare/TariffsAndCharges/Documents/2020_21_Tariff_Book_final.pdf
 111. Legal dispute over South African content rules in 2 GW tech-neutral tender – pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2021/09/15/legal-dispute-over-south-african-content-rules-in-2-gw-tech-neutral-tender/>
 112. Sixty-three PV projects to compete in South Africa’s 2.6 GW renewables tender – pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2021/08/23/sixty-three-pv-projects-to-compete-in-south-africas-2-6-gw-renewables-tender/>
 113. White & Case. REIPPPP Bid Window 6: Grid Connection Capacity Constraints in the Northern Cape. Available from: <https://www.whitecase.com/publications/alert/reipppp-bid-window-6-grid-connection-capacity-constraints-northern-cape>

114. South African Wind Farms | South African Wind Energy Association [Internet]. Available from: <https://sawea.org.za/wind-map/wind-ipp-table/>
115. South Africa raises threshold for distributed generation to 100 MW – pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2021/08/16/south-africa-raises-threshold-for-distributed-generation-to-100-mw/>
116. The World Bank, International Finance Corporation. Going Global: Expanding Offshore Wind to Emerging Markets [Internet]. Washington, DC; 2019. Available from: <https://documents.worldbank.org/en/publication/documents-reports/documentdetail/716891572457609829/going-global-expanding-offshore-wind-to-emerging-markets>
117. Merle F Le. Go Where the Wind Blows: An Assessment of Offshore Wind Potential in South Africa. University of Oxford; 2019.
118. Rae G, Erfort G. Offshore wind energy - South Africa's untapped resource. J Energy South Africa [Internet]. 2020;31(4):26–42. Available from: <https://journals.assaf.org.za/index.php/jesa/article/view/7940>
119. Kern S. Evaluating Economic Potential of Offshore Wind in South Africa. Imperial College London; 2021.
120. Richard C. New offshore wind partnership targets South Africa [Internet]. Windpower Monthly. 2020. Available from: <https://www.windpowermonthly.com/article/1683040/new-offshore-wind-partnership-targets-south-africa>
121. GWEC. Global Wind Report 2021 [Internet]. Global Wind Energy Council. Brussels; 2021. Available from: <https://gwec.net/global-wind-report-2021/>
122. RFP For 900 MW Renewable Energy In South Africa | TaiyangNews [Internet]. Available from: <http://taiyangnews.info/business/rfp-for-900-mw-renewable-energy-in-south-africa/>
123. World Bank. Inflation, GDP deflator (annual %) [Internet]. World Bank Database. 2021. Available from: https://data.worldbank.org/indicator/NY.GDP.DEFL.KD.ZG?end=2019&locations=US-DE-ZA-CL-AE-JP&name_desc=false&page=2&start=2000&view=chart
124. Fernandez P, Bañuls S, Fernandez Acin P. Survey: Market Risk Premium and Risk-Free Rate used for 88 countries in 2021. SSRN Electron J. 2021 Jun;
125. Fernandez P. Market Risk Premium Used in 2008 by Professors: A Survey with 1,400 Answers. SSRN Electron J [Internet]. 2009 Apr; Available from: <https://papers.ssrn.com/abstract=1344209>
126. Fernandez P, Pershin V, Fernández Acín I. Market Risk Premium and Risk-Free Rate used for 59 Countries in 2018: A Survey. SSRN Electron J [Internet]. 2018 Apr; Available from: <https://papers.ssrn.com/abstract=3155709>
127. Fernandez P, Martinez M, Fernández Acín I. Market Risk Premium and Risk-Free Rate Used for 69 Countries in 2019: A Survey. SSRN Electron J [Internet]. 2019 Mar; Available from: <https://papers.ssrn.com/abstract=3358901>

128. Fernandez P, de Apellániz E, F. Acín J. Survey: Market Risk Premium and Risk-Free Rate used for 81 countries in 2020. SSRN Electron J. 2020 Mar;
129. Steffen B. Estimating the cost of capital for renewable energy projects. Energy Econ [Internet]. 2020;88:104783. Available from: <https://doi.org/10.1016/j.eneco.2020.104783>
130. Ondraczek J, Komendantova N, Patt A. WACC the dog: The effect of financing costs on the levelized cost of solar PV power. Renew Energy. 2015 Mar;75:888–98.
131. Mercer. Investment in African Infrastructure: Challenges and Opportunities [Internet]. St. Louis; 2018 Sep. Available from: <https://www.mercer.com/our-thinking/wealth/investment-in-african-infrastructure-challenges-and-opportunities.html>
132. Ameli N, Dessens O, Winning M, Cronin J, Chenet H, Drummond P, et al. Higher cost of finance exacerbates a climate investment trap in developing economies. Nat Commun 2021 121. 2021 Jun;12(1):1–12.
133. Fernandez P, del Campo Baonza J. Market Risk Premium Used in 2010 by Professors: A Survey with 1,500 Answers. SSRN Electron J [Internet]. 2010 May; Available from: <https://papers.ssrn.com/abstract=1606563>
134. Fernandez P, Aguirreamalloa J, Avendaño LC. Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers. SSRN Electron J [Internet]. 2011 Apr; Available from: <https://papers.ssrn.com/abstract=1822182>
135. Fernandez P, Aguirreamalloa J, Avendaño LC. Market Risk Premium Used in 82 Countries in 2012: A Survey with 7,192 Answers. SSRN Electron J [Internet]. 2017 Oct; Available from: <https://papers.ssrn.com/abstract=2084213>
136. Fernandez P, Aguirreamalloa J, Linares P. Market Risk Premium and Risk Free Rate Used for 51 Countries in 2013: A Survey with 6,237 Answers. SSRN Electron J [Internet]. 2013 Jun; Available from: <https://papers.ssrn.com/abstract=914160>
137. Fernandez P, Linares P, Fernández Acín I. Market Risk Premium Used in 88 Countries in 2014: A Survey with 8,228 Answers. SSRN Electron J [Internet]. 2014 Jun; Available from: <https://papers.ssrn.com/abstract=2450452>
138. Fernandez P, Ortiz Pizarro A, Fernández Acín I. Discount Rate (Risk-Free Rate and Market Risk Premium) Used for 41 Countries in 2015: A Survey. SSRN Electron J. 2017 Oct;
139. Fernandez P, Ortiz Pizarro A, Fernández Acín I. Market Risk Premium Used in 71 Countries in 2016: A Survey with 6,932 Answers. SSRN Electron J [Internet]. 2016 May; Available from: <https://papers.ssrn.com/abstract=2776636>
140. Fernandez P, Pershin V, Fernández Acín I. Discount Rate (Risk-Free Rate and Market Risk Premium) Used for 41 Countries in 2017: A Survey. SSRN Electron J [Internet]. 2017 Apr; Available from: <https://papers.ssrn.com/abstract=2954142>
141. Kempa K, Moslener U, Schenker O. The cost of debt of renewable and non-

- renewable energy firms. *Nat Energy* 2021 6(2):135–42.
142. Yelland C. Understanding the cost of electricity from Medupi, Kusile and IPPs. *ee.co.za*. 2016.
 143. Department of Energy (Republic of South Africa). Integrated Resource Plan (IRP2013). Johannesburg: Department of Energy (Republic of South Africa); 2013.
 144. In numbers: how mining came to be Australia's most profitable sector [Internet]. Available from: <https://www.mining-technology.com/features/in-numbers-how-mining-came-to-be-australias-most-profitable-sector/>
 145. What are the five biggest coal mines in fossil fuel-reliant Australia? [Internet]. Available from: <https://www.nsenenergybusiness.com/features/australia-coal-mines/#>
 146. The coal war: why has China turned its back on Australian coal? [Internet]. Available from: <https://www.mining-technology.com/features/the-coal-war-why-has-china-turned-its-back-on-australian-coal/>
 147. Uranium Production | Uranium Output - World Nuclear Association [Internet]. Available from: <https://world-nuclear.org/information-library/facts-and-figures/uranium-production-figures.aspx>
 148. How Australia's vast resources could make it a green energy superpower | EY Malaysia [Internet]. Available from: https://www.ey.com/en_my/power-utilities/how-australia-s-vast-resources-could-make-it-a-green-energy-superpower
 149. Australian electricity generation - fuel mix | energy.gov.au [Internet]. Available from: <https://www.energy.gov.au/data/australian-electricity-generation-fuel-mix>
 150. Solar PV to dominate renewable power growth in Australia in next decade [Internet]. Available from: <https://www.power-technology.com/comment/solar-pv-growth-australia/>
 151. Parkinson G. Brown coal likely to close by 2032, AEMO says, but all coal may be gone by then. *RenewEconomy* [Internet]. 2021 Dec; Available from: <https://reneweconomy.com.au/brown-coal-likely-to-close-by-2032-aemo-says-but-all-coal-could-be-gone-by-then/>
 152. Kallies A. The Australian Energy Transition as a Federalism Challenge: (Un)cooperative Energy Federalism? *Transnatl Environ Law* [Internet]. 2021 Jul;10(2):211–35. Available from: <https://www.cambridge.org/core/journals/transnational-environmental-law/article/australian-energy-transition-as-a-federalism-challenge-uncooperative-energy-federalism/FBB1D83EA9A4B3730607CFCF6555652C>
 153. In Australia, Japanese start producing hydrogen from brown coal | Reuters [Internet]. [cited 2021 Sep 27]. Available from: <https://www.reuters.com/article/australia-hydrogen-kawasaki-heavy-idUSL4N2L81IF>
 154. Renewable energy policy: retreat, renewal and revitalisation? – Parliament of Australia [Internet]. [cited 2021 Sep 27]. Available from:

- https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook45p/RenewableEnergy
155. Australia's states have been forced to go it alone on renewable energy, but it's a risky strategy [Internet]. Available from: <https://theconversation.com/australias-states-have-been-forced-to-go-it-alone-on-renewable-energy-but-its-a-risky-strategy-151086>
 156. Guardian. As long as Australia fails to transition away from fossil fuels its climate policy is meaningless. 2023; Available from: <https://www.theguardian.com/commentisfree/2023/jan/11/as-long-as-australia-fails-to-transition-away-from-fossil-fuels-its-climate-policy-is-meaningless>
 157. PV Magazine. Australian Capital Territory completes shift to 100% renewable electricity. 2019; Available from: <https://www.pv-magazine-australia.com/2019/10/01/australian-capital-territory-completes-shift-to-100-renewable-electricity/>
 158. Renew Economy. Victoria passes half way mark. Available from: <https://reneweconomy.com.au/victoria-passes-half-way-mark-on-road-to-50-renewables-by-2030/>
 159. International Energy Agency. Energy Policies of IEA Countries - Australia 2018. 2018;244. Available from: <https://webstore.iea.org/download/direct/139>
 160. • Australia: solar photovoltaic installations by state 2020 | Statista [Internet]. [cited 2021 Sep 27]. Available from: <https://www.statista.com/statistics/958498/australia-solar-photovoltaic-installations-by-state/>
 161. Australian Photovoltaic Institute • Mapping Australian Photovoltaic installations [Internet]. [cited 2021 Sep 27]. Available from: <https://pv-map.apvi.org.au/historical>
 162. AEMO | Maximum and minimum demand [Internet]. [cited 2021 Sep 27]. Available from: <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/nem-electricity-demand-forecasts/2017-electricity-forecasting-insights/summary-forecasts/maximum-and-minimum-demand>
 163. Australian Photovoltaic Institute • Live Solar Map [Internet]. [cited 2021 Sep 27]. Available from: <https://pv-map.apvi.org.au/live#2021-09-19>
 164. Australian Photovoltaic Institute • PV Postcode Data [Internet]. [cited 2021 Sep 27]. Available from: <https://pv-map.apvi.org.au/postcode>
 165. Sun Cable's huge solar project in Northern Territory a step closer after support from Indonesia | Solar power | The Guardian [Internet]. [cited 2021 Sep 27]. Available from: <https://www.theguardian.com/environment/2021/sep/24/sun-cables-huge-solar-project-in-northern-territory-a-step-closer-after-support-from-indonesia>
 166. Australia to fast-track world's largest solar-battery project with grid link to Singapore | Recharge [Internet]. [cited 2021 Sep 27]. Available from: <https://www.rechargenews.com/transition/australia-to-fast-track-worlds-largest->

- solar-battery-project-with-grid-link-to-singapore/2-1-849688
167. Australia's Northern Territory eyes 'electricity superhighway' to enable renewables integration - PV Tech [Internet]. [cited 2021 Sep 27]. Available from: <https://www.pv-tech.org/australias-northern-territory-eyes-new-transmission-links-to-enable-renewables-integration/>
 168. Project EnergyConnect [Internet]. [cited 2021 Sep 27]. Available from: <https://www.projectenergyconnect.com.au/>
 169. Snowy Hydro Limited. Snowy 2.0 [Internet]. Website. 2017. Available from: <http://www.snowyhydro.com.au/our-scheme/snowy20/>
 170. Adding 50MW/64.5 MWh to Tesla's big battery in Australia – pv magazine International [Internet]. [cited 2021 Sep 27]. Available from: <https://www.pv-magazine.com/2020/06/23/adding-50mw-64-5-mwh-to-teslas-big-battery-in-australia/>
 171. Tesla big battery in South Australia delivers stunning windfall profits | RenewEconomy [Internet]. [cited 2021 Sep 27]. Available from: <https://reneweconomy.com.au/tesla-big-battery-in-south-australia-delivers-stunning-windfall-profits-77644/>
 172. World's biggest battery with 1,200MW capacity set to be built in NSW Hunter Valley | Energy | The Guardian [Internet]. [cited 2021 Sep 27]. Available from: <https://www.theguardian.com/australia-news/2021/feb/05/worlds-biggest-battery-with-1200mw-capacity-set-to-be-built-in-nsw-hunter-valley-australia>
 173. Victoria Awards 928 MW New RE Capacity | TaiyangNews [Internet]. [cited 2021 Sep 28]. Available from: <http://taiyangnews.info/markets/victoria-awards-928-mw-new-re-capacity/>
 174. Victoria launches second renewables auction of 600MW, with stronger network requirements - PV Tech [Internet]. [cited 2021 Sep 28]. Available from: <https://www.pv-tech.org/victoria-launches-second-renewables-auction-of-600mw-with-stronger-network-requirements/>
 175. How do the ACT's renewable energy reverse auctions work? - Environment, Planning and Sustainable Development Directorate - Environment [Internet]. [cited 2021 Sep 28]. Available from: <https://www.environment.act.gov.au/energy/cleaner-energy/how-do-the-acts-renewable-energy-reverse-auctions-work>
 176. Renewable electricity costs and reviews - Environment, Planning and Sustainable Development Directorate - Environment [Internet]. [cited 2021 Sep 28]. Available from: <https://www.environment.act.gov.au/energy/cleaner-energy/renewable-electricity-costs-and-reviews>
 177. Jacobs. Review of Next Generation Renewables Auction and the Electricity Feed-in (Large-scale Renewable Energy Generation) Act 2011. Final summary report - NGR and large FiT Act Review. 2017;(May). Available from: https://www.environment.act.gov.au/__data/assets/pdf_file/0011/1096571/Review-Summary-report.pdf
 178. interest-grows-in-queensland-auction. reNews [Internet]. Available from:

- <https://www.renews.biz/35750/interest-grows-in-queensland-auction/>
179. Renewables 400 | Business Queensland [Internet]. [cited 2021 Sep 28]. Available from: <https://www.business.qld.gov.au/industries/mining-energy-water/energy/renewable/projects-queensland/renewables-400>
 180. NSW targets 12GW of renewables and storage under roadmap that includes auctions. RenewEconomy [Internet]. Available from: <https://reneweconomy.com.au/nsw-targets-12gw-of-renewables-and-storage-under-roadmap-that-includes-auctions-27022/>
 181. Sydney Metro announces PPA with NSW solar farm [Internet]. Energetics. [cited 2021 Sep 28]. Available from: <https://www.energetics.com.au/insights/thought-leadership/sydney-metro-announces-ppa-with-nsw-solar-farm>
 182. NUS Consulting. Australia Energy Market Power Purchase Agreements (PPA) Options [Internet]. [cited 2021 Sep 28]. Available from: <https://www.nusconsulting.com/energy-blog/australia-energy-market-power-purchase-agreements-ppa-options>
 183. Solar auctions to spread PV over the commercial landscape –. pv magazine International [Internet]. Available from: <https://www.pv-magazine.com/2020/09/28/solar-auctions-to-spread-pv-over-the-commercial-landscape/>
 184. National Electricity Market | energy.gov.au [Internet]. [cited 2021 Sep 27]. Available from: <https://www.energy.gov.au/government-priorities/energy-markets/national-electricity-market-nem>
 185. AEMO | Five Minute Settlement and Global Settlement [Internet]. [cited 2021 Sep 27]. Available from: <https://aemo.com.au/en/initiatives/major-programs/nem-five-minute-settlement-program-and-global-settlement>
 186. Saddler H. High price events in the NEM. 2017;(January):1–8.
 187. AEMO. AEMO | About the National Electricity Market (NEM) [Internet]. [cited 2021 Sep 28]. Available from: <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/about-the-national-electricity-market-nem>
 188. Energy Security Board | Post 2025 electricity market design project [Internet]. [cited 2021 Sep 27]. Available from: <https://esb-post2025-market-design.aemc.gov.au/>
 189. Paying Australia’s coal-fired power stations to stay open longer is bad for consumers and the planet [Internet]. [cited 2021 Sep 27]. Available from: <https://theconversation.com/paying-australias-coal-fired-power-stations-to-stay-open-longer-is-bad-for-consumers-and-the-planet-160083>
 190. Clean Energy Regulator Australia. How the scheme works [Internet]. [cited 2021 Sep 28]. Available from: <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works>
 191. Cost WA, Report C. NSW ELECTRICITY INFRASTRUCTURE ROADMAP

- Weighted Average Cost of Capital Report. 2020.
192. World Bank. Inflation, GDP deflator (annual %) - Australia | Data [Internet]. 2021. Available from:
https://data.worldbank.org/indicator/NY.GDP.DEFL.KD.ZG?end=2020&locations=AU&name_desc=false&page=2&start=1961&view=chart
 193. Langniss O, Wiser R. The renewables portfolio standard in Texas: an early assessment. *Energy Policy*. 2003 May;31(6):527–35.
 194. Federal Reserve Bank of Dallas. Surging Renewable Energy in Texas Prompts Electricity Generation Adequacy Questions - [Dallasfed.org](https://www.dallasfed.org/research/economics/2021/0817.aspx) [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.dallasfed.org/research/economics/2021/0817.aspx>
 195. Wiser R, Bolinger M, Hoen B, Millstein D, Rand J, Barbose G, et al. Land-Based Wind Market Report: 2021 Edition. 2021; Available from:
<http://www.osti.gov>
 196. U.S. Energy Information Administration (EIA). Texas likely to add record utility-scale solar capacity in the next two years - *Today in Energy*. 2021.
 197. Texas Power Grid Run by ERCOT Set Up the State for Disaster - *The New York Times* [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.nytimes.com/2021/02/21/us/texas-electricity-ercot-blackouts.html>
 198. Busby JW, Baker K, Bazilian MD, Gilbert AQ, Grubert E, Rai V, et al. Cascading risks: Understanding the 2021 winter blackout in Texas. *Energy Res Soc Sci*. 2021 Jul;77:102106.
 199. Death Toll From Texas Winter Storm Continues to Rise - *The New York Times* [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.nytimes.com/2021/07/14/us/texas-winter-storm-deaths.html>
 200. Texas power prices spike as deadly cold wave overwhelms grid | *Reuters* [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.reuters.com/article/us-usa-texas-power-prices-idUSKBN2AH0U0>
 201. Texas freeze raises concerns about ‘ridiculous’ variable rate bills | *Reuters* [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.reuters.com/business/energy/texas-freeze-raises-concerns-about-ridiculous-variable-rate-bills-2021-02-23/>
 202. Texas electricity company Griddy declares bankruptcy as winter storm fallout continues - *CBS News* [Internet]. [cited 2021 Dec 3]. Available from:
<https://www.cbsnews.com/news/griddy-energy-texas-files-bankruptcy/>
 203. Federal Energy Regulatory Commission, North American Electric Reliability Corporation. Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011 [Internet]. 2011. Available from:
<https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf>
 204. Chase A, Gross R, Heptonstall P, Jansen M, Kenefick M, Parrish B, et al. Realising the Potential of Demand-Side Response to 2025: A focus on Small Energy Users [Internet]. 2017. Available from:
<https://www.gov.uk/guidance/funding-for-innovative-smart-energy-systems>

205. Cohn J, Ph D. TEXAS CREZ LINES : HOW STAKEHOLDERS SHAPE MAJOR ENERGY INFRASTRUCTURE PROJECTS. 2020;(November).
206. Powering Texas. Transmission & CREZ Fact Sheet. 2018;1–3. Available from: <https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf>
207. Pontecorvo E. A backlog of projects is holding up a greener grid. Grist [Internet]. 2022; Available from: <https://grist.org/energy/renewables-are-growing-but-a-backlog-of-projects-is-holding-up-a-greener-grid/>
208. Is Your Renewable Energy Electricity Plan Really Supporting Texas Wind And Solar? – Houston Public Media [Internet]. Available from: <https://www.houstonpublicmedia.org/articles/news/in-depth/2021/08/12/405660/is-your-renewable-energy-electricity-plan-really-supporting-texas-wind-and-solar/>
209. Luhavalja A. Texas renewable energy credit markets advance; Green-e prices back off | S&P Global Market Intelligence. S&P Global [Internet]. 2020 Aug; Available from: <https://www.spglobal.com/marketintelligence/en/news-insights/blog/insight-weekly-us-stock-performance-banks-ma-risk-covid-19-vaccine-makers-earnings>
210. Schwabe P. Tax Incentive Based Financing Options for Renewable Energy. 2016; Available from: <https://www.energy.gov/sites/default/files/2016/09/f33/Schwabe.pdf>
211. U.S. Internal Revenue Service. Treasury, IRS extend safe harbor for renewable energy projects | Internal Revenue Service [Internet]. [cited 2021 Dec 5]. Available from: <https://www.irs.gov/newsroom/treasury-irs-extend-safe-harbor-for-renewable-energy-projects>
212. Thomson Reuters Practical Law. Investment Tax Credit (ITC) [Internet]. [cited 2021 Dec 3]. Available from: [https://uk.practicallaw.thomsonreuters.com/1-517-6442?transitionType=Default&contextData=\(sc.Default\)&firstPage=true](https://uk.practicallaw.thomsonreuters.com/1-517-6442?transitionType=Default&contextData=(sc.Default)&firstPage=true)
213. U.S Department of Energy. Guide to the Federal Investment Tax Credit for Commercial Solar Photovoltaics [Internet]. Energy Efficiency and Renewable Energy. 2020. Available from: <http://www.irs.gov/pub/irs-pdf/i5695.pdf>
214. Rodgers M, Dubov B. Stimulus Bill Brings Welcomed Changes to the Renewable Energy Industry [Internet]. White & Case LLP. 2021 [cited 2021 Dec 5]. Available from: <https://www.whitecase.com/publications/alert/stimulus-bill-brings-welcomed-changes-renewable-energy-industry>
215. WINDEXchange: Production Tax Credit and Investment Tax Credit for Wind [Internet]. [cited 2023 Dec 5]. Available from: <https://windexchange.energy.gov/projects/tax-credits>
216. Thomson Reuters Practical Law. Production Tax Credit (PTC) [Internet]. [cited 2021 Dec 3]. Available from: [https://uk.practicallaw.thomsonreuters.com/0-517-5382?originationContext=document&transitionType=DocumentItem&contextData=\(sc.Default\)&ppcid=5cf84d9c820b4d2aa5d487cbe5eb0029&comp=pluk](https://uk.practicallaw.thomsonreuters.com/0-517-5382?originationContext=document&transitionType=DocumentItem&contextData=(sc.Default)&ppcid=5cf84d9c820b4d2aa5d487cbe5eb0029&comp=pluk)

217. U.S. Internal Revenue Service. Renewable Electricity, Refined Coal, and Indian Coal Production Credit [Internet]. United States; 2021. Available from: <https://www.irs.gov/pub/irs-pdf/i8835.pdf>
218. DSIRE [Internet]. [cited 2021 Dec 5]. Available from: <https://programs.dsireusa.org/system/program/tx/solar>
219. U.S. Internal Revenue Service. How To Depreciate Property [Internet]. Available from: <http://www.irs.gov/pub/irs-pdf/p946.pdf>
220. 2021 Texas Solar Incentives, Tax Credits & Rebates | EnergySage [Internet]. [cited 2021 Dec 5]. Available from: <https://www.energysage.com/local-data/solar-rebates-incentives/tx/>
221. Triolo RC, Wolak FA. Quantifying the Benefits of Nodal Market Design in the Texas Electricity Market. 2021;(January):1–23.
222. Texas Renewable Energy Policy Sets an Example for the World - IEEE Spectrum [Internet]. [cited 2021 Dec 2]. Available from: <https://spectrum.ieee.org/texas-renewable-energy-policy-sets-an-example-for-the-world#toggle-gdpr>
223. Beiter P, Kitzing L, Spitsen P, Noonan M, Berkhout V, Kikuchi Y. Toward global comparability in renewable energy procurement. Joule [Internet]. 2021 May; Available from: <https://linkinghub.elsevier.com/retrieve/pii/S2542435121002038>
224. Wind energy market value | Electricity Markets and Policy Group [Internet]. [cited 2021 Dec 3]. Available from: <https://emp.lbl.gov/wind-energy-market-value>
225. US Department of Energy. Land-Based Wind Market Report: 2022 Edition [Internet]. 2022. Available from: https://www.energy.gov/sites/default/files/2022-08/land_based_wind_market_report_2202.pdf
226. Rhodes JD, King C, Gulen G, Olmstead SM, Dyer JS, Hebner RE, et al. A geographically resolved method to estimate leveled power plant costs with environmental externalities. Energy Policy. 2017 Mar;102:491–9.
227. Rhodes JD, King C, Gulen G, Olmstead SM, Dyer JS, Hebner RE, et al. LCOE Map [Internet]. [cited 2021 Dec 5]. Available from: https://calculators.energy.utexas.edu/lcoe_map/#/county/tech
228. Ferman M. Texas lawmakers target renewable energy while trying to fix the power grid. The Texas Tribune [Internet]. 2021; Available from: <https://www.texastribune.org/2021/04/19/texas-renewable-energy-oil-gas/>
229. Klump E. Renewables may be a victim in Texas grid revamp -. E&E News [Internet]. 2021; Available from: <https://www.eenews.net/articles/renewables-may-be-a-victim-in-texas-grid-revamp/>
230. Maciver C, Bukhsh W, Bell KRW. The impact of interconnectors on the GB electricity sector and European carbon emissions. Energy Policy [Internet]. 2021;151(June 2020):112170. Available from: <https://doi.org/10.1016/j.enpol.2021.112170>

231. Doquet M, Fourment C, Roudergues JM. Generation & transmission adequacy of large interconnected power systems: a contribution to the renewal of monte-carlo approaches. In: IEEE Powertech 2011. Trondheim; 2011.
232. RTE. Antares Simulator 7.1.0: Optimisation Problems Formulation [Internet]. 2019. Available from: <https://antares-simulator.org/media/files/page/4NOGQ-optimization-problems-formulation.pdf>
233. ENTSO-E. Ten Year Network Development Plan 2018 Scenario Report [Internet]. 2018. Available from: https://docstore.entsoe.eu/Documents/TYNDP_documents/TYNDP2018/Scenario_Report_2018_Final.pdf
234. ENTSO-E. Ten Year Network Development Plan 2020 [Internet]. 2021. Available from: <https://tyndp.entsoe.eu/scenarios/>
235. Staffell I, Pfenninger S. Using bias-corrected reanalysis to simulate current and future wind power output. *Energy*. 2016;114:1224–39.
236. ENTSO-E. TYNDP scenario building process Q&A [Internet]. Available from: https://2022.entsoe-tyndp-scenarios.eu/wp-content/uploads/2021/09/TYNDP-2022_Webinar_3_July_QAs.pdf
237. UK Department for Business Energy and Industrial Strategy. Electricity Generation Cost Report 2020. BEIS Electr Gener Cost Rep. 2020;(August):69.
238. National Grid ESO. Future Energy Scenarios 2021 Data Workbook [Internet]. 2021. Available from: <https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021/documents>
239. Pfenninger S, Staffell I. Renewables Ninja [Internet]. 2021. Available from: <https://www.renewables.ninja/downloads>
240. IEA. Renewable Energy Market Update, Outlook for 2021 and 2022 [Internet]. 2021. Available from: <https://iea.blob.core.windows.net/assets/18a6041d-bf13-4667-a4c2-8fc008974008/RenewableEnergyMarketUpdate-Outlookfor2021and2022.pdf>
241. Newbery D. Missing money and missing markets: Reliability, capacity auctions and interconnectors. *Energy Policy*. 2016;94(February 2015):401–10.
242. BEIS. Plans unveiled to decarbonise UK power system by 2035 [Internet]. 2021. Available from: <https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035>
243. Gross R, Maclver C, Blyth W. Can renewables and nuclear help keep bills down this winter? The case for a ‘pot zero’ CfD auction. [Internet]. 2022. Available from: <https://ukerc.ac.uk/publications/can-renewables-help-keep-bills-down/>