Zonal Pricing, Volume Risk and the 2030 Clean Power Target

UKERC Working Paper

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Preface to this Working Paper

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This has particular importance where policy relevant topics have become highly contested and commercial interests are substantial – as with the debate over zonal pricing. This Working Paper does not seek to provide a definitive view on all the dimensions of zonal pricing. Rather, it provides focused analysis on an issue that has had limited attention in the debate thus far, but is critical to the success of the Clean Power 2030 Mission.

Summary

Volume Risk and 2030

The UK Government is considering implementing zonal pricing in Great Britain's electricity market. Uncertainty regarding this policy shift could significantly impact upcoming Contract for Difference (CfD) auction rounds, critical to the Clean Power 2030 Mission. UKERC has undertaken independent analysis exploring how uncertainty over zonal pricing and transmission capacity expansion affect investor risk and consumer costs. Initial findings were published in a Discussion Paper in March 2025. This Working Paper provides additional methodological detail.

The Clean Power Mission requires at least 20 GW of new wind power to be delivered in forthcoming CfD Allocation Rounds, much of it in Scotland and Northern England. Connecting this generation to demand centres necessitates major transmission upgrades, which the Clean Power Mission is seeking to accelerate. The Government has promised to decide on zonal pricing before the next CfD auction in July 2025.

UKERC's modelling reveals three key findings:

1. Increased Strike Prices: Uncertainty relating to the future introduction of zonal pricing could increase strike prices in upcoming CfD auctions by up to £20/MWh, as investors factor in potential exposure to the additional future volume risk that stems from transmission capacity uncertainty.
2. Higher Consumer Costs: These elevated strike prices could increase the cost to consumers by up to £3 billion annually in the period to 2030. These increases will further persist for the duration of the CfD contract period, but could be reduced by any potential net financial benefits from zonal pricing.
3. Diminishing Future Risk: Zonal pricing risks should decrease over time as transmission infrastructure development unfolds, suggesting that zonal pricing would ideally be introduced after resolving key transmission uncertainties.

The analysis suggests that implementing zonal pricing before resolving transmission uncertainties risks "putting the cart before the horse”, exposing investors to unnecessary near-term risks that would raise the cost of meeting 2030 targets, and could negate zonal pricing's benefits. The only alternative to delaying zonal pricing would be fully compensating prospective bidders for volume risk, though it is currently unclear whether or how this could be done.

Moving South

Zonal pricing combined with transmission constraints could reduce generation investment in constrained regions. To illustrate the impact of this we also explore ‘Plan-B’ scenarios that try to meet the 2030 targets by replacing on/offshore wind in Northern Britain with onshore wind and solar located further south. Three experiments were conducted:

1. Maintaining total renewable generation with onshore wind-dominated southern additions: **This fails to meet CO_2/gas reduction targets.**

2. Meeting CO_2 targets with onshore wind-dominated southern additions: **<u>This significantly increases total new capacity needed, generation costs and GB-wide curtailment.</u>**

3. Meeting CO_2 targets with equal wind and solar southern additions: **<u>Curtailment increases less than Exp. 2, but costs still increase, and even more new capacity must be added.</u>**

More capacity is required because output is less correlated with demand and capacity factors are lower, which also drives increased GB-wide curtailment. Replacing 15 to 20 GW of on/offshore wind in Scotland/Northern England would need an extra 17-33GW of onshore wind and 5-25GW of solar in England and Wales. This would require around 400-800 additional wind farms and 100-500 solar farms – a five-to-nine-fold increase on current installed capacities.

Questions for policymakers

The debate over locational pricing is overshadowing forthcoming allocations of CfDs that will be essential if the CP30 goal is to be achieved. Policy choices around zonal pricing are now urgent, and our analysis suggests the following questions:

1. How acceptable is the risk of a material increase in AR7-9 CfD bids, with knock-on effect on bills, relative to an alternative where zonal pricing is not introduced?
2. Is a 'plan-B' feasible, such that the 2030 Target can still be met, should some investors decline to participate in AR7-9, or bid-prices are unacceptably high?
3. Is it possible to provide investors with enough information to allow them to develop an informed view of the impact of zonal pricing in time for AR7-9? This might include location and number of zones, rules for trading across zones, market clearing arrangements during periods of oversupply, and any arrangements in place to protect forthcoming and legacy investments.
4. Is it feasible to fully protect AR7-9 investors from the uncertainties created by moving to zonal pricing ahead of build-out of new transmission capacity, to avoid them pricing this risk into their bids, including any measures to protect them from the volume risk that this would entail?
5. How substantial and certain is the 'size of the prize' associated with moving to zonal pricing now (rather than some later date), such that the short-term costs associated with doing so are outweighed by the benefits that could accrue in the mid-2030s and beyond? And related to this, whether a package of incremental reforms could deliver many of the operational efficiencies that zonal pricing provides long-term with fewer negative effects on the CP2030 target.

The 2030 clean power mission is an exceptionally bold endeavour that requires coordinated action across government and industry to mobilise unprecedented investment in generation and transmission capacity. Our analysis focuses on the risks for market participants if Government tries to bring in zonal pricing at the same time. These are substantial and there is no straightforward plan B. The key question is not whether zonal pricing has benefits, but whether the time to introduce it is now.

Contents

1. Introduction

For some time, the UK Government has been undertaking a review of electricity markets, known as REMA.[1] This includes considering a move away from a single wholesale power price everywhere in Great Britain, breaking the country up into multiple zones each with its own electricity price. Zonal pricing has generated considerable debate among stakeholders, with strongly held views and contradictory evidence emerging on both sides.[2,3,4,5,6]

A UKERC Discussion Paper[7] published in March 2025 provided findings from analysis using electricity system and financial risk modelling to help inform this important policy decision[i]. This Working Paper restates these findings and describes the methodological approach adopted for the analysis. Our research seeks to understand how zonal pricing will impact investor risk in upcoming Contract for Difference (CfD) auction Allocation Rounds (AR7-9). [8] These auctions are critical to the success of the Clean Power Mission[9], a major plank of government policy. Government has yet to reach a decision about zonal pricing. It has promised to do so before the next Allocation Round (AR7) takes place in July 2025.

The Clean Power Action Plan[10] makes clear that large capacities of new wind and solar must be commissioned through AR7-9: at least 20 GW of additional wind power alone. Much of the new wind power is expected in Scotland and Northern England, where wind speeds are high, and sites have already been secured.[11] To connect this excellent wind resource to demand further south, major upgrades to transmission infrastructure are underway.[12]

This is where the debate over zonal pricing intersects with the Clean Power Plan. One of the most significant areas of consumer savings claimed for zonal pricing arises from reducing or removing payments to renewable generators when energy needs to be constrained due to network capacity.[13] The flipside of this is that reduced and/or more uncertain volumes of electricity sales in constrained zones would be expected to feed through into higher CfD bid prices. Since CfD strike prices are set GB-wide, CfD prices across the country could increase.

As a result, removing constraint payments is not costless. Even if future sales volumes in constrained zones were known with complete certainty, a lower volume of electricity sales would be expected to result in a higher CfD price, all other factors being equal. However, since the number and location of zones is currently unclear, and the timing of transmission upgrades remains somewhat uncertain, developers also face considerable uncertainty about future sales volumes. The uncertainty affects developers in all parts of the UK and gives rise to a phenomenon known as volume risk.

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[i] The analysis has been undertaken independently of government and any stakeholders, though we have consulted with industry experts in order to understand key issues such as price formation and routes to market during periods of zero or negative pricing. The research has been supported solely through core funds in the UKERC Phase 4 Technology and Policy Assessment theme, and UKERC 2024 – 2029 Responsive Research Theme.

The role of CfD prices in consumer bills is set to rise as the share of renewables increases. This can reduce exposure to volatile gas prices, and CfDs offer the potential to reduce household bills.[14] However, higher CfD prices would counteract, at least in part, savings associated with removing constraint payments. Indeed, exposing developers to the volume risks inherent in moving to zonal pricing ahead of transmission expansion could *increase* costs to consumers rather than reducing them. If the ability to sell electricity in constrained zones is reduced, generators may also decide not to proceed with a project at all. The scale of these impacts is the focus of this paper:

Section 2 provides an overview of findings of analysis of the impact of volume risk on forthcoming CfD bid prices, and hence consumers[ii].

Section 3 explores a 'plan B' scenario, where uncertainty over transmission upgrades and zonal pricing drives investment away from Scotland and Northern England. 'Moving South' assesses the extra onshore wind and solar needed in England and Wales to meet the 2030 target, and how this impacts total capacity, costs and curtailment.

Section 4 discusses the fundamental economics of high variable renewable systems.

Section 5 highlights the issues for policy that follow from the analysis.

Section 6 explains the methodological approach adopted for our analysis.

[ii] Our analysis proceeds on the assumption that zonal pricing is announced prior to AR7-9 and without explicit protections against volume risk, such as recommended by the Energy System Catapult. We return to this in our discussion of policy implications, below.

2. Zonal Pricing, Transmission Upgrades and Volume Risk

Under Clean Power 2030 targets, both renewable energy and the transmission capacity to connect it with demand are scheduled for significant expansion.[15] The geographical disconnect between good renewable resource locations and historical generation sites necessitates substantial new transmission infrastructure development.[16] Britain's electricity grid was planned and built in the mid-20th century, and reflected the resource base of the time – our one-time coal dominated system required transmission from good locations for coal-fired power to demand centres.

The need for new transmission capacity is established by policymakers based on system needs modelling. A planned approach is adopted in most countries because transmission development involves capital-intensive, long-term investments that require years to complete.[17,18] A substantial expansion of transmission capacity across the country is planned for the coming decade. Our last remaining coal-fired power station has closed, coal-by-wire of the 1960s is finally over, and we need to re-engineer our electricity system so that we can exploit the UK's excellent renewable energy resources.

Under a zonal pricing regime, price differentials between zones would directly correlate with capacities of generation/demand within zones and the available transmission capacity connecting them. With unconstrained electricity flows between zones, price variations would be minimal, limiting the impact of zonal pricing. However, transmission investment is being planned so we can access the best renewable energy resources, and it will not be directly driven by zonal price differentials. In a zonal market, transmission capacity is a price-maker rather than a price-taker. Consequently, uncertainty regarding future inter-zonal transmission capacity creates significant uncertainty over both prices and sales volumes within individual zones.

The Government has initiated measures to accelerate transmission development as part of the Clean Power 2030 Action Plan. However, potential investors cannot disregard uncertainties surrounding implementation timelines and the initial operational performance of new transmission capacity once built. This uncertainty presents significant risks to investors, as both zonal prices and renewable generation sales volumes are highly sensitive to transmission capacity development.

Price risk can be largely ameliorated through a local CfD reference price.[19] However, if transmission expansion is delayed or falls short of projections, there is increased volume risk: renewable investors face the risk of being unable to sell their electricity during constraint periods. Under the CfD scheme, payments are only made when plants are self-dispatched, requiring generators to secure a market route for their output. During oversupply periods, not all generators will be able to secure this market access, exposing them to non-dispatch risk and loss of CfD payments. This risk will be most acute in constrained zones under zonal pricing.

The risk inherent in moving to zonal pricing before transmission upgrades are in place is made worse by substantial uncertainty regarding the potential implementation, timing, and specifics of zonal pricing. At the time of writing the locations and number of zones are still to be determined and there is little clarity about protections for existing and forthcoming investments transitioning from the current market structure to this new environment.

Consumer Impacts of Zonal Pricing Uncertainty

Volume risk will increase somewhat regardless of zonal pricing. Our modelling shows that growth in GB-wide renewable generation will periodically create oversupply conditions, which is consistent with NESO analysis.[20] While generators face these risks under both national and zonal pricing models, zonal pricing significantly alters risk distribution between zones. Transmission uncertainty creates volume risks for generators on both sides of zonal boundaries, as delayed or underperforming transmission infrastructure will affect non-dispatch patterns. This specific transmission-related volume risk only exists under a zonal pricing regime.

Such externally imposed risks will inevitably be factored in when developers formulate their CfD auction bids. This has direct implications for consumers, as increased bid prices will raise the overall cost of renewable energy. Consumers ultimately bear these costs through the clearing price mechanism of renewable auctions, where the highest price bid that clears in the auction sets the price paid for each unit of renewable energy generated GB-wide from that auction.

Our analysis shows that the risk exposure is asymmetrical and a function of the scale and pace of transmission build. Only some bidders in regions most reliant on transmission scale up would see the full extent of negative volume risks, but if those units price that risk into their CfD bid and end up setting the auction clearing price, then the consumer cost impact would apply to all successful CfD participants, GB-wide. As we explain in more detail below, in the longer-term and once new transmission and generation capacities are more certain, market participants could respond to volume risk. At the current time, investors face combined uncertainty over policy changes, transmission build and renewable generation expansion.

The nature and scale of this interrelated uncertainty over zonal pricing and pace of transmission build has not been a significant feature in the discourse over zonal pricing. UKERC therefore undertook analysis of the impacts on CfD bid prices and consumers using energy system dispatch and financial modelling under different assumptions about transmission build out.

Our analysis focused on the Scotland-England border, modelling an 'expected' transmission capacity of 10.7GW consistent with the NESO CP30 scenario.[21] We examined multiple scenarios: a reduced transmission scenario assuming a permanent 30% capacity reduction, a delayed transmission scenario where this reduction lasts for five years, and a higher transmission scenario of 13.7GW aligned with the previous Ten Year Plan[22]. The transmission scenarios are explained further in the Methodological section.

Zonal Volume Risk Findings

Our analysis reveals several critical findings regarding the potential impact of zonal pricing on the GB electricity market:

Finding 1: Increased Strike Prices

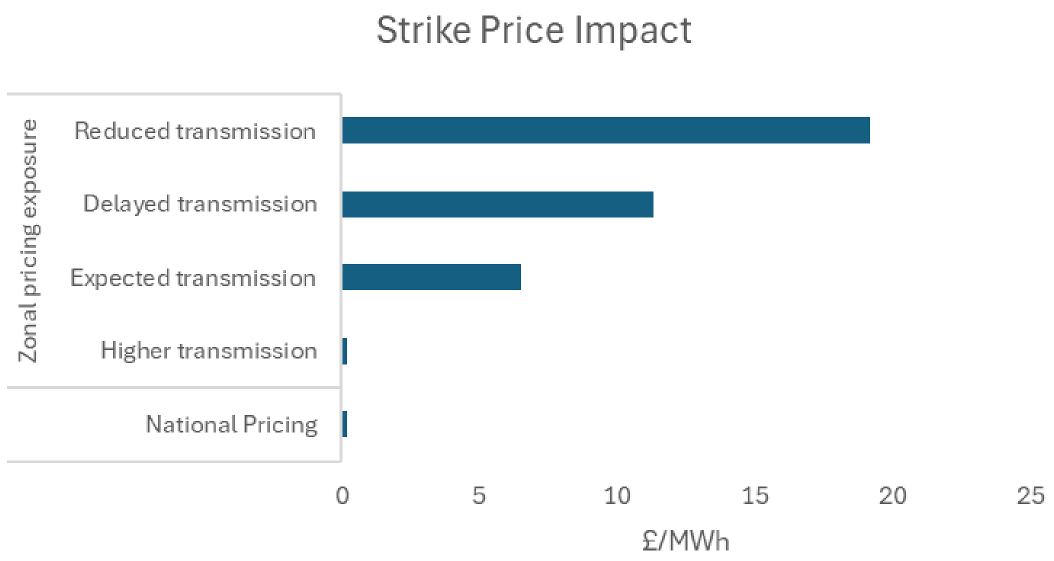

Figure 1. *Effect on strike prices*

Uncertainty surrounding zonal pricing implementation could increase GB-wide strike prices in upcoming renewable energy auction rounds by up to £20/MWh, with concomitant impacts on the costs of achieving renewable energy targets. This increase stems from investors' heightened exposure to transmission capacity uncertainty, prompting them to elevate auction bid prices to cover this risk. Our modelling indicates that strike prices could rise by up to £20/MWh depending on investors' risk perception, including uncertainty regarding protection levels for AR7-9 bidders.

In our analysis we have tried to represent the uncertainty that developers face over progress with transmission upgrades. By using different scenarios, we illustrate how different levels of success and performance with transmission upgrades impacts sales volume and hence CfD strike price. The range we have chosen represents a reasonable spread of possibilities, based upon discussions with stakeholders, but reflects a judgement on the part of the authors. If investors perceive transmission upgrade risks to be higher or lower than these illustrative scenarios, then the impact on strike prices will change commensurately. Should investors expect transmission upgrades be slower than our reduced transmission scenario, the impact on strike prices would be larger still. As the chart illustrates, if investors expect transmission build to go to plan the strike price impacts are much smaller, though not immaterial.[iii]

[iii] In future analysis we will explore the strike price impact in the 'expected transmission' scenario, and other sensitivities relative to increases in constraint payments to generators in the 2030s without zonal pricing.

The principal point of the analysis is that developers will seek to represent a spread of possible outcomes when faced with the unavoidable uncertainty associated with trying to judge the outcome of an ambitious programme of investment in transmission. The analysis is a simplification, that retains an expected level of return in the face of uncertainty, and shows how our chosen worse-case scenario impacts strike prices. However, we believe that it provides a clear and simple indication of the scale of volume risks faced by would-be developers as a result of moving to zonal pricing whilst the pace of transmission build-out remains uncertain.

Finding 2: Consumer Cost Implications

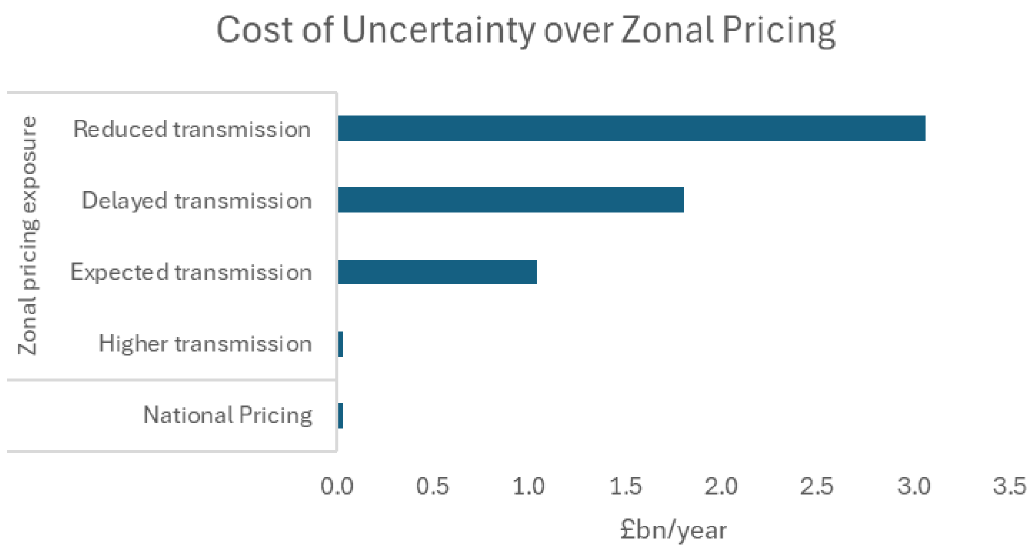

Figure 2. *Effect on total costs*

These elevated strike prices will directly affect consumers, potentially increasing costs by up to £3 billion annually. This substantial cost increase represents the total additional investment expense depending on investors' risk perception, which will ultimately be passed through to consumers. Some analyses[23,24] postulate that zonal pricing will allow producer surplus to be redistributed to consumers. Our analysis is unable to assess the potential for producer surplus, but we note that the increased risks in some zones described above are likely to increase CfD clearing prices across *all* zones. Unless CfD prices are set within zones rather than GB-wide (see below) zonal pricing creates a new source of potential producer surplus that impacts consumer bills.

Finding 3: Future Risk Reduction

Zonal pricing risks should diminish over time as transmission infrastructure development becomes more certain. If implemented at a later stage, investors could incorporate locational risks into their investment decisions with greater confidence once transmission uncertainty decreases. However, for the present, the variation between our modelled transmission scenarios represents a significant risk that investors would face under near-term zonal pricing implementation.

This suggests that since transmission functions as a price-maker rather than a price-taker in zonal markets, zonal pricing would ideally only be introduced after resolving key uncertainties regarding major infrastructure developments. Early implementation risks "putting the cart before the horse," exposing investors to unnecessary risks potentially reaching £3 billion annually, which could negate many of the financial benefits that zonal pricing might otherwise deliver.

3. Migrating Generation South – What Would 'Plan B' Entail?

Moving South – analytical basis

The analysis above concentrates on the risks associated with moving to zonal pricing whilst simultaneously trying to build out around 11GW of new transmission capacity and around 20 GW of new on/offshore wind in Scotland/Northern England by 2030. This raises the question of whether it might be possible to put at least some of that generation somewhere else entirely. Indeed, relocating generation to less constrained locations is identified as a benefit in some zonal pricing analyses.[25]

This section explores the proposition that locational pricing and/or delayed transmission investment would deter investment in constrained regions, so if the 2030 target is to be met more renewable generation capacity would be needed closer to the main demand centres in southern GB.

To investigate the potential changes in renewable generation capacity location and mix, we employed an energy balance model of the GB electricity system (see methodology section). We conducted three experiments, each reducing new off/onshore wind capacity in northern GB while increasing new onshore wind and solar capacity in southern GB calibrated to meet the targets for renewable generation and reduction in gas burn/CO_2 emissions defined in the NESO 2030 Further Flex and Renewables scenario (NESO 2030).[26] Onshore technologies were selected because they could, in principle, be deployed at the scale and speed necessary to continue to meet the 2030 Clean Power Target. We assume that the timeline for identifying and developing new offshore sites would likely be longer, and in any case could give rise to further transmission constraints. The overall effect rebalances some of the CP30 capacity additions from northern to southern GB.

Experiment 1: Adds sufficient new southern renewable capacity to match total renewable generation output calibrated to match NESO 2030.
Experiment 2: Adds sufficient new southern renewable capacity to meet the CP30 emissions target, with onshore wind capacity additions predominating.
Experiment 3: Follows Experiment 2 but maintains equal additions of onshore wind and solar capacity, and adds sufficient additional battery storage to allow solar to make the same contribution to energy balance as in NESO 2030.

In each experiment, reductions in new northern wind capacity increase step-wise up to 15GW in our main case. We also examine the impact of reducing new northern wind capacity by up to 20GW to explore more pronounced responses to locational pricing and/or lack of new transmission capacity.

Moving South Main Findings

In this section, we report outcomes relative to UKERC analysis calibrated to match NESO's FFR 2030 scenario, showing the implications of progressively reducing wind capacity additions in Scotland and Northern England.

Experiment 1: Keeping annual VRE generation constant, with wind-dominated southern capacity additions

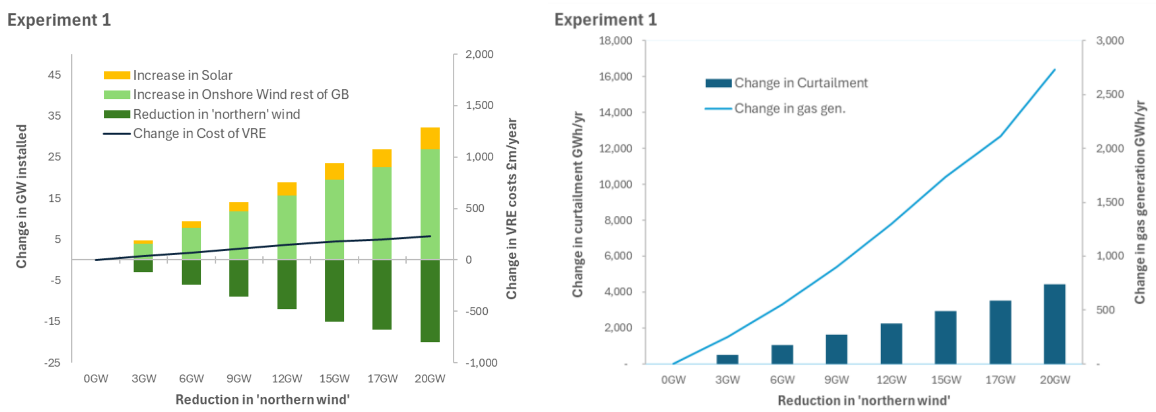

Figure 3. *Experiment 1 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- Total renewable energy capacity increases. The impacts on annualised costs of variable renewables and imported electricity volumes are minimal.
- The higher installed capacity operating at lower load factor and poorer correlation with demand means that curtailed variable renewable output increases[iv] while exported electricity volumes decrease.
- **The CP30 CO_2 target is not achieved** because unabated gas-fired generation must increase to maintain system reliability. This is driven by the poorer correlation of southern renewables with the GB demand profile.

[iv] While higher installed capacity at lower load factors can result in the same annual TWh of renewables availability, curtailment increases because peak generation is higher. This increases the scale of mismatch between supply and demand in hours when the renewable output is in surplus.

Experiment 2: Keeping unabated gas-fired generation constant, with wind-dominated capacity additions

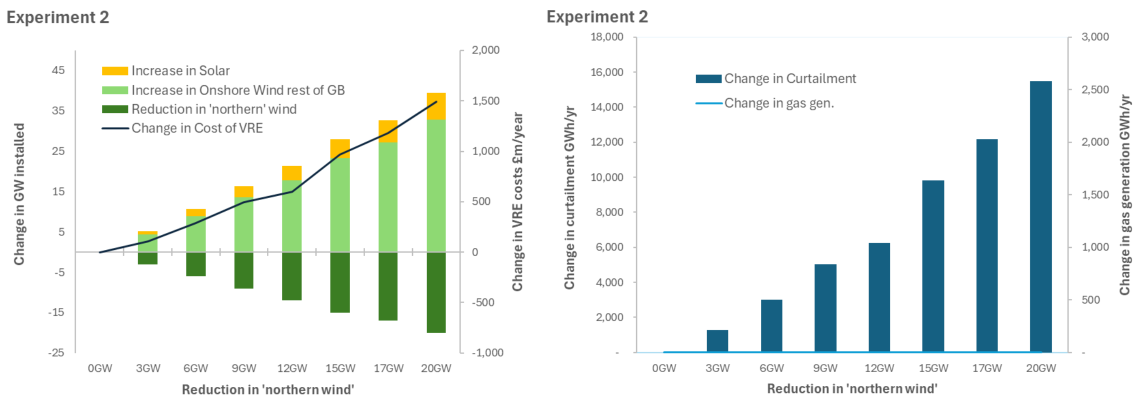

Figure 4. *Experiment 2 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- The CP30 CO_2 target is met because unabated gas-fired generation is kept below the 5% of total generation aspiration. This requires considerably more variable renewable capacity compared to Experiment 1.
- Imported electricity volumes remain largely unchanged, while exported volumes increase.
- As with experiment 1, a higher capacity operating at lower load factor mean that **annualised generation costs and curtailed variable renewable output increase** significantly – by up to £2.5bn per year.

Experiment 3: Keeping unabated gas-fired generation constant, with equal wind and solar capacity additions

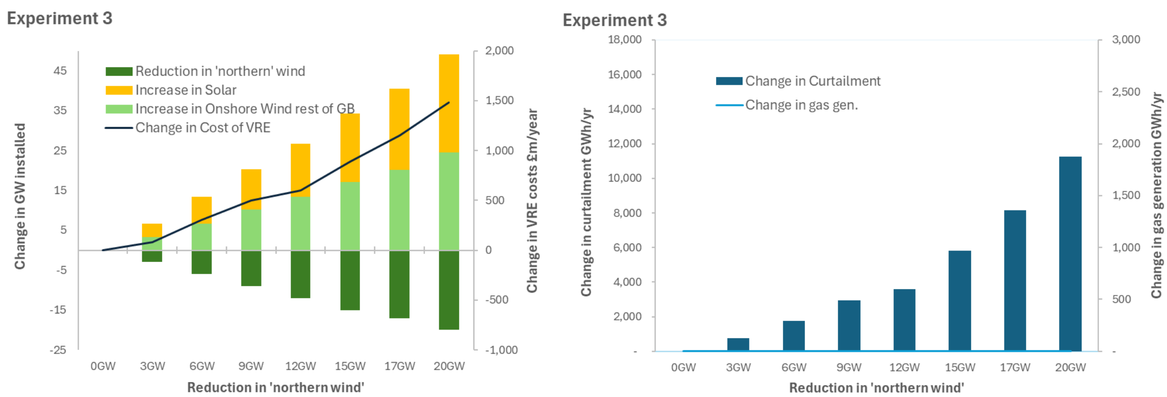

Figure 5. *Experiment 3 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- As with Experiment 2, the CP30 CO_2 target is met.

- Imported electricity volumes remain largely unchanged. Exported volumes increase, relative to the starting conditions, and are higher than in Experiment 2.
- Annualised costs increases are similar to Experiment 2. Curtailed variable renewable output increases significantly relative to NESO FFR, but by less than in Experiment 2.

Moving South Increases Renewable Capacity Needs, Costs, and Curtailment

The analysis reveals that substantial additional onshore wind and solar power capacity would be required if more variable renewable capacity is located in southern GB. Simply replacing the "lost" output from the new northern variable renewable capacity with an equivalent amount of southern variable renewable output is insufficient to meet CP30 clean power system objectives. This stems from several factors: i) the weaker correlation of southern renewables with the GB demand profile, ii) the generally higher load factors of offshore wind compared to onshore wind, and iii) the superior load factors of northern offshore and onshore wind compared to the rest of GB.[v] This means that the total level of generation that cannot be absorbed GB-wide goes up, even though transmission constraints may be reduced: curtailed energy volumes *increase* by 5.8 – 15.5 TWh/year.

A summary is provided in Figure 6 below.

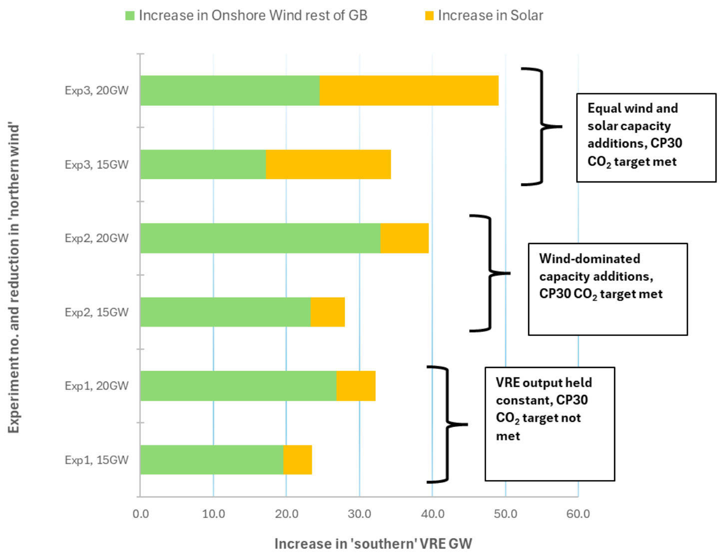

Figure 6. *Summary of effect on capacity requirements across the three experiments*

[v] Our analysis aggregates wind speed data from sites across England and Wales. This may even overstate generation output in England, noting the higher wind resource but more limited site availability in Wales, and potential for much lower load factors in locations in Southern England where wind farms are currently largely absent. Further analysis could test sensitivity to load factor data.

The analysis indicates that replacing 15 to 20 GW of northern GB wind creates a need for 17 - 33GW of additional onshore wind and 5 - 25GW of additional solar capacity. This translates to approximately 400-800 additional wind farms and 100-500 additional solar farms, based on current typical sizes for new large-scale farms.[27,28] This would be in addition to the 4GW of new onshore wind and 32GW of new solar in the rest of GB already envisaged in the CP30 FFR scenario. In total, including the CP30 FFR scenario, our experiments demonstrate that meeting CP2030 goals with less new Scottish/Northern England wind energy would require a combination of **five to nine times more onshore wind and large-scale solar generation** in England and Wales compared to current installed capacity.

We do not take a view on whether this scale of expansion is plausible in terms of available sites, planning, or distribution network capacity. However, it illustrates the challenge entailed in a 'plan-B' scenario where generation moves away from Scotland and Northern England in response to zonal pricing and transmission constraints.

4. Economic Curtailment – a Fundamental Feature of High Renewables Systems

Wind and solar generation inherently lack flexibility, producing power only when weather conditions permit. Nevertheless, it is possible to create reliable electricity systems primarily powered by renewables by complementing them with various flexibility mechanisms. These include investments in electricity storage technologies (such as batteries and hydrogen storage), demand flexibility enhancements, and improved import-export capabilities with neighbouring countries.

However, economic constraints limit the extent to which such flexibility investments are cost-effective. Consequently, in an economically optimised electricity system using current technologies, some variability from wind and solar generation will likely remain unbalanced, and surplus electricity will be ‘spilled’, meaning renewable generators curtail. Spillage typically occurs when electricity's marginal value is low, during prolonged high variable renewable generation periods, low demand periods, or when existing storage capacity is fully utilised. In line with other analyses[29], our research shows this is true GB-wide as well as within constrained zones. Indeed, we find that moving wind and solar out of constrained zones, expanding onshore wind and solar such that CP2030 targets are met, would *increase* GB-wide curtailment.

Energy spillage does not necessarily constitute an economic or technical problem. Some degree of spillage may be economically optimal when the cost of additional equipment needed to capture excess energy exceeds the value of the energy itself. Generally, optimal spillage levels increase when generation costs are low (due to abundant renewable resources) and/or flexibility mechanisms are expensive.

The current arrangements combine CfDs where renewable generators receive fixed payments for their output, with firm access rights, meaning that generators are compensated if energy is curtailed. This arrangement means consumers pay above wholesale market value during periods of low electricity prices but pay less during high-price periods. Overall, CfDs are designed to reduce consumer costs by lowering investment risks and capital costs for developers.

The interaction between zonal pricing and CfDs in the presence of uncertain and/or limited transmission upgrades would change the terms of the arrangements. The strike price in CfD auctions is determined by developers spreading total project lifetime costs across anticipated sales hours. If policy changes reduce sellable hours, developers will proportionally increase auction bids to maintain commercial viability. Moving to zonal pricing could reduce constraint payments to renewable generators, but if it also results in higher GB-wide CfD prices this will not reduce overall consumer costs.

Our findings diverge from some other analyses in the field. Other studies acknowledge that transmission capacity uncertainty significantly impacts renewable generators' sales volumes during constrained periods, but they draw different conclusions about the economic consequences. Rather than factoring this risk into renewable energy delivery costs as we have done, alternative analyses suggest that under zonal pricing sales volume reductions from transmission constraints would translate to consumer savings. We consider this assumption flawed, as it presumes investors would maintain their original investment plans despite these risks.

This is why we have explored both the impact on prospective CfD prices and the scale of expansion needed in less constrained locations to hit the 2030 clean power goal. It is beyond the scope of this paper to examine whether 'plan-B' – a five to ninefold increase in onshore wind and solar in England and Wales – is feasible. Some of it might be, but if we retain the assumption that expanding on/offshore wind in Northern England and Scotland is the most plausible route to 2030 goals then zonal pricing induced volume risk in forthcoming CfD auctions remains a key policy challenge.

Our analysis has deliberately limited scope to the potential impact of zonal pricing on forthcoming CfD auctions, and hence costs of meeting the government's 2030 target. A wider set of options is still under review as part of REMA, including changes to the fundamentals of CfD arrangements. One option is to make CfDs 'deemed' or 'capacity-based'. Doing so would disconnect CfD revenues from electricity output (in full or in part) and could alleviate volume risk. An alternative (or additional action) is to move CfD prices to regional rather than a GB-wide basis, which could reduce the likelihood of volume risk in constrained zones driving up CfD prices across Great Britain.

Substantial CfD reform is not possible in time for AR7 and possibly all CP2030 relevant CfD auctions. This demonstrates how different dimensions of REMA interact, and how the fundamental issues that REMA is rightly grappling with need to be tackled together.

5. Policy Implications

Surprisingly, the impact of volume risk on CfD prices does not appear to be given much attention in most analyses of the benefits of zonal pricing, at least until very recently.[30] Instead, it appears that some analyses simply count the reduction in constraint payments that stem from prices clearing within local zones rather than national markets as a saving that can be passed through to consumers. Under zonal pricing, there arguably could/should be some reduction in constraints over time in response to the new price signals (e.g. new demand, new sources of flex etc.) and we note the possibility that developers may be able to mitigate some of the risks directly. Our concern is that this effect is too uncertain for investors to rely on in advance of AR7-9, and they will simply factor the full amount of volume risk into their prices. Since CfD locks in prices at the beginning of the contract, these premiums get baked-in for the duration of the CfD term, and there's no room for learning.

Zonal markets offer efficiency gains relative to the current status quo, for example in reducing payments to gas generators required to 'turn up' by the System Operator to replace constrained generation under national pricing. They would also be likely to dispatch interconnectors more efficiently. Options to enhance locational signals under national pricing also exist[31]. However, the fundamental dynamic where reduced/more uncertain sales volumes in constrained zones feed through into increased CfD prices appears to us to be an inevitable consequence of moving to zonal prices. This is particularly problematic now, when uncertainties are highest. The proposition is to introduce zonal pricing whilst trying to simultaneously deliver unprecedented expansion in capacity of renewable generation in parallel with build out of new transmission lines, the timelines for all of which are inevitably uncertain.

Assuming no substantial changes to CfD designs, if Government wishes to avoid the risk of negative impacts on forthcoming Allocation Rounds, the only feasible alternative to ruling out zonal pricing until conditions change would be to undertake to fully recompense prospective bidders for volume risk. This approach was advocated by the Energy Systems Catapult in a report published in October 2024.[32] However, there are no clear plans to mitigate volume risk in the most recent report on REMA.[33] Whether measures to protect against volume risk would be practical, and adequate to reassure prospective investors given the short time between any decision on zonal pricing and AR7 remains to be seen. There has to be a risk that investors would price risks into CfD bids regardless, and yet still be eligible for volume risk compensation – the worst of all worlds.

Concluding Questions

Despite extensive consultations and analysis REMA has yet to conclude. As a result, we now find ourselves in a situation where uncertainty over REMA risks failure of the CP30 mission, because the debate over locational pricing is overshadowing forthcoming allocations of CfDs that will be essential if the CP30 goal is to be achieved.

Since policy choices around zonal pricing are now extremely urgent, we propose the following questions for policymakers:

1. Is there appetite for the risk of a material increase in CfD prices for AR7-9 relative to a counterfactual where zonal pricing is not introduced?
2. Is a 'plan-B' feasible, such that the 2030 Clean Power Target can still be met, should some investors either decline to participate in AR7-9, or if bid-prices turn out to be unacceptably high as zonal volume risks feed through into CfD prices?
3. Is it possible to provide investors with enough information to allow them to develop an informed view of the impact of zonal pricing in time for AR7-9? This might include location and number of zones, rules for trading across zones, market clearing arrangements during periods of oversupply, and any arrangements in place to protect forthcoming and legacy investments.
4. Is it feasible to fully protect AR7-9 investors from the uncertainties created by moving to zonal pricing ahead of build-out of new transmission capacity, to avoid them pricing this risk into their bids, including any measures to protect them from the volume risk that this would entail?
5. How substantial and certain is the 'size of the prize' associated with moving to zonal pricing now (rather than some later date), such that the short-term costs associated with doing so are outweighed by the benefits that could accrue in the mid-2030s and beyond? And related to this, whether a package of incremental reforms could deliver the operational efficiencies that zonal pricing provides long-term with fewer negative effects on the CP2030 target.

Our analysis is deliberately focused on the risks that stem from introducing zonal pricing ahead of major transmission and generation capacity build-out needed for the 2030 target, with all the risk and uncertainty concomitant with such a bold endeavour. We do not dispute the potential for zonal pricing to yield operational efficiencies in theory, or in the longer-term. We also do not consider wider factors, including Parliamentary time for new legislation, distributional impacts on households, or implications for industrial competitiveness around the UK. In many cases trade-offs must be deliberated, which is why the decision over zonal pricing is difficult. However, unlike the interactions with forthcoming CfD auctions, few of these are time critical. The most immediate question for policymakers is not whether zonal pricing is a good idea in principle but whether now is the right time to implement it.

6. Methodology

This section describes the approach and assumptions used in our analysis. It sets out four key elements:

1. Our methodology for quantifying zonal price risks
2. The electricity system model (SEEMM) used to quantify the volume of non-dispatch in different zones as a function of different transmission constraint assumptions
3. The cash-flow model used to convert these volume risks into financial risk and consequent cost increases as presented in Section 2
4. The energy balance model used to explore alternative ‘Plan B’ renewable generation pathways for meeting 2030 targets as described in Section 3

Methodology for assessing zonal pricing risk

This section sets out a detailed description of our methodology for quantifying the potential system cost impacts posed by uncertainty about the introduction of zonal pricing. This is a simplified analysis focusing on a single so-called “B6” transmission boundary between Scotland and the rest of GB (i.e. England and Wales). This two-zone approach is intended to be illustrative of the issues that may arise in a more complex multi-zonal framework that would be implemented under zonal pricing.

Assumptions about price-setting in the CfD auctions

The first key assumption is that CfD auctions result in a single pay-as-clear strike price. This means that plant at the margin of the auction stack set the price for all other successful bidders in the auction. In our analysis we focus on the B6 boundary, which roughly aligns with the administrative border between Scotland and England. Hereafter we refer to projects north of the boundary as ‘Scottish’ and south as ‘England and Wales’. The focus on the B6 boundary is a simplification. Other boundaries will also experience constraints and full zonal would involve multiple zonal prices, including the potential for other low wholesale/higher CfD price zones in southern GB (for example in Eastern England). We assume that base costs for wind plant in Scotland and England and Wales are roughly at parity, given that higher wind speeds in Scotland may be approximately offset by higher transmission costs. However, once transmission risk premia are added in, this will tend to make Scottish plant the marginal price setting plant. In other words, any risk premia faced by these marginal plants will also be fed through to the rest of the market. The mechanism is described schematically in Figure 7.

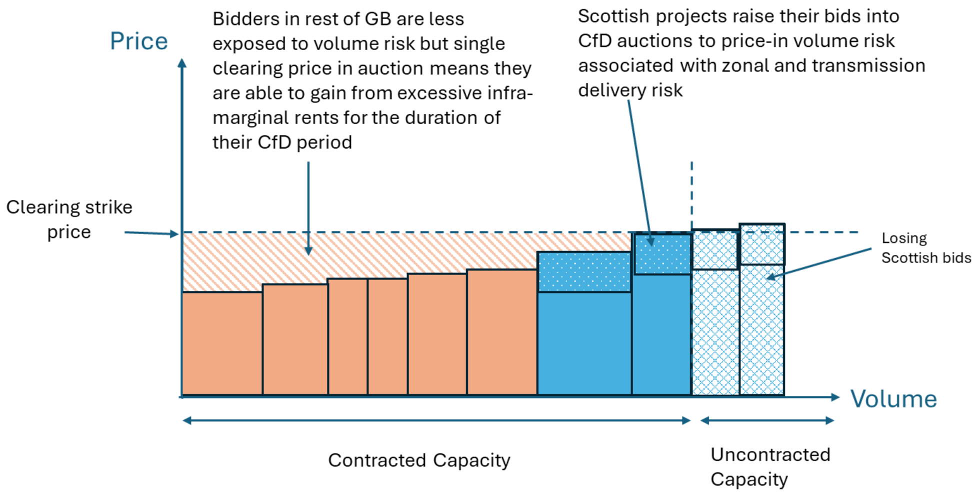

Figure 7. *Schematic showing pass-through of risk premia from Scotland to the whole GB under current CfD auction design*

National Pricing with no transmission constraint

The strike price (SP_0) set by the CfD auctions, as described above sets the price received for each unit of generation in GB. The cost of delivering renewables in GB under National Pricing if there are no transmission (Tx) constraint risks in the system NP_0 is the sum of the volume of generation in each zone, multiplied by the price. In the figure below, we use X to label the total payments to wind plant in England and Wales, and Y to label the payments to wind plant in Scotland.

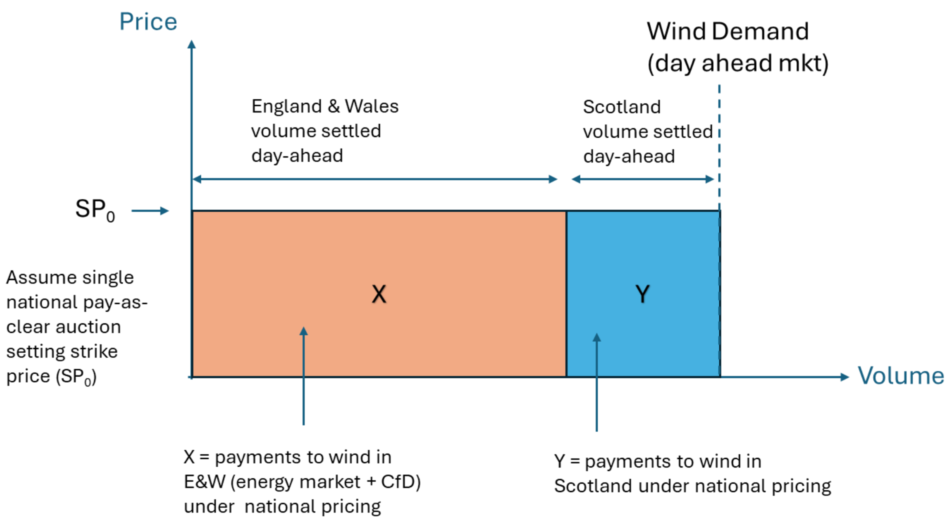

Figure 8. *Cost of energy under National Pricing with no transmission constraint*

National Pricing with no risk adjustment

If transmission constraints are introduced (ΔTx), then not all of the energy purchased in day ahead markets in Scotland can be delivered, so additional energy from flexible generators (E_{flx}) needs to be purchased, and this incurs a cost penalty (B_{flx}) because under national pricing this additional energy needs to be purchased in the balancing market (BM) which is less efficient than the energy market. B_{flx} also includes the cost of unwinding sub-optimal day-ahead dispatch positions of interconnectors and storage plant that occur when there are transmission constraints under national pricing.

Payments to generators in Scotland (Y) are assumed to remain unchanged by the constraint as although they would lose the CfD payment, we assume that they would be made whole through equivalent payments under the BM.

Total costs of renewable energy under national pricing with no risk pass-through (NP_0) would therefore be:

$$NP_0 = X + Y + E_{flx} + B_{flx} \qquad \text{(Eq1)}$$

This is the base case scenario against which other transmission constraint risks are assessed in the results presented in Section 2.

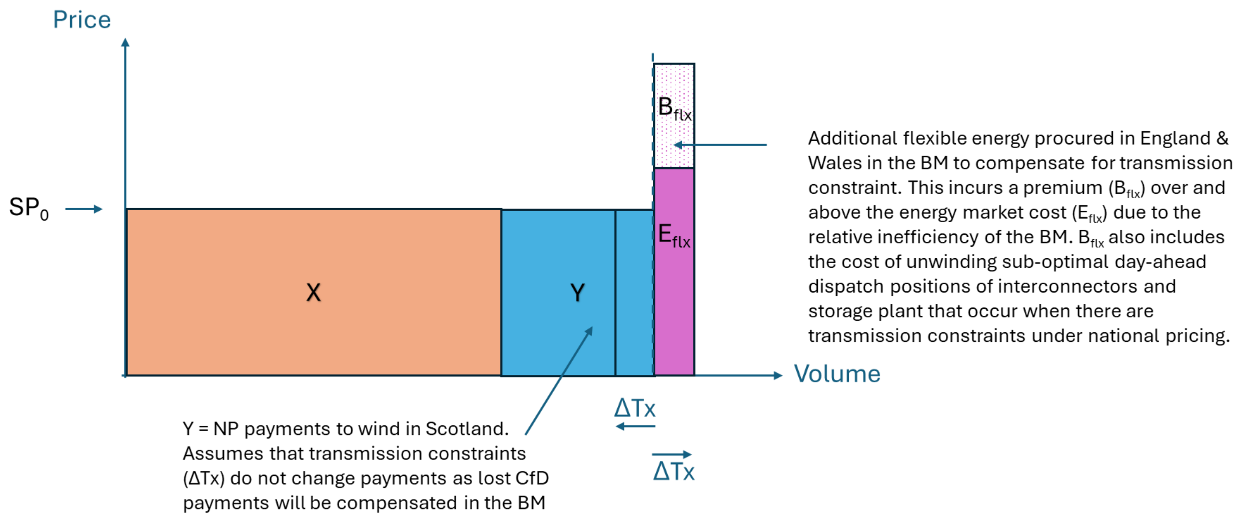

Figure 9. *Cost of renewable energy under National Pricing with no Tx risk pass-through*

Zonal Pricing with no risk adjustment

Under zonal pricing, the volume in Scotland that is not able to dispatch into England due to transmission constraints (Y_v) is not paid to producers. If it is assumed that this lost revenue is not recovered in any way by producers, then in principle this saving could be passed through to consumers.

Additional savings accrue under zonal pricing because the additional energy purchased in England and Wales to cover the transmission constraint would be made in the energy market, and would not incur the balancing market premium (B_{flx}). In the longer-term, there could also be dynamic efficiencies from zonal pricing as supply and demand rebalance in different zones, but these are assumed to play out over a longer period of time than is covered by this analysis which focuses on impacts on delivery of the 2030 target. The total cost of renewables for zonal pricing with no risk adjustment (ZP_0) is therefore lower than national pricing:

$$ZP_0 = NP_0 - Y_v - B_{flx} \qquad \text{(Eq2)}$$

More detailed variants of this result are reported and evaluated in various studies.[34]

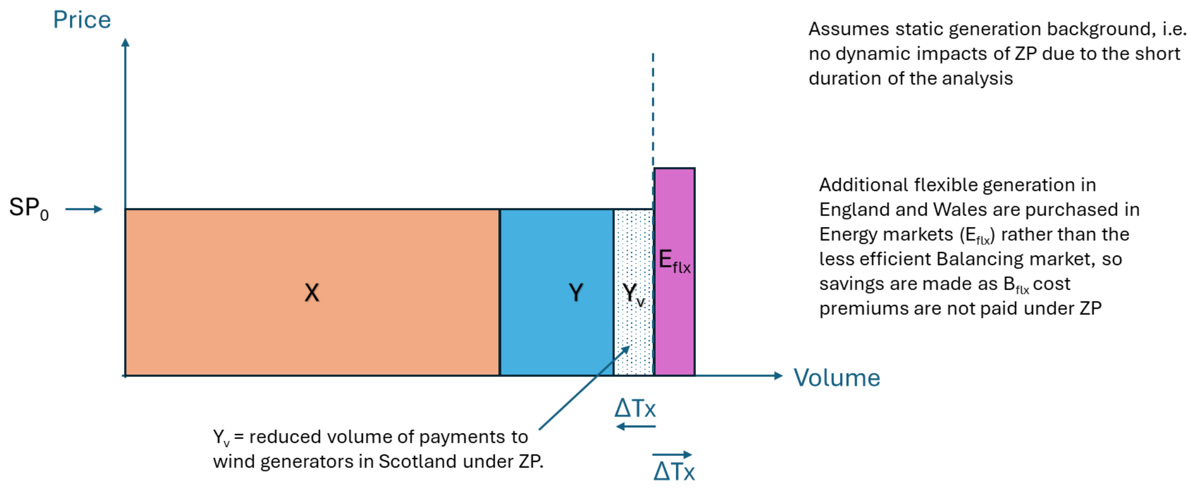

Figure 10. *Cost of renewable energy under Zonal Pricing with no Tx risk pass-through*

Risk-adjusted Zonal Pricing

We now introduce the assumption that investors in Scotland will not simply absorb a loss in revenue from reduced volumes of sales during periods of transmission constraint, but rather would look to recoup those lost revenues by increasing auction bids so that the risk-adjusted Strike Price (SP_r) is such that the increased revenue Y_r matches the potential lost revenue Y_v (Figure 11). This risk premium Y_r therefore exactly negates the portion of consumer benefit Y_v assumed in the previous section to arise from avoiding payments to producers for constrained energy generation.

We further assume that this increased strike price flows through to the rest of GB. This raises the costs of generation in England and Wales by X_r. Because the generation volume in England and Wales in coming auction rounds is expected to be significantly higher than for Scotland (by about a factor of 3), the value of X_r is significantly greater than the value of Y_v.

Under this scenario, zonal pricing would however still save the BM cost premium. Because Y_r and Y_v cancel each other out, the cost of renewables under a risk-adjusted zonal pricing scenario (ZP_r) is therefore:

$$ZP_r = NP_0 + X_r - B_{flx} \qquad \text{(Eq3)}$$

From Eq3, zonal pricing will only lead to a reduction in short- to medium-term costs if the savings from inefficiencies of national pricing (B_{flx}) are greater than the additional risk premium (X_r). We have not evaluated B_{flx} in our work, but estimates have been made by others.[35]

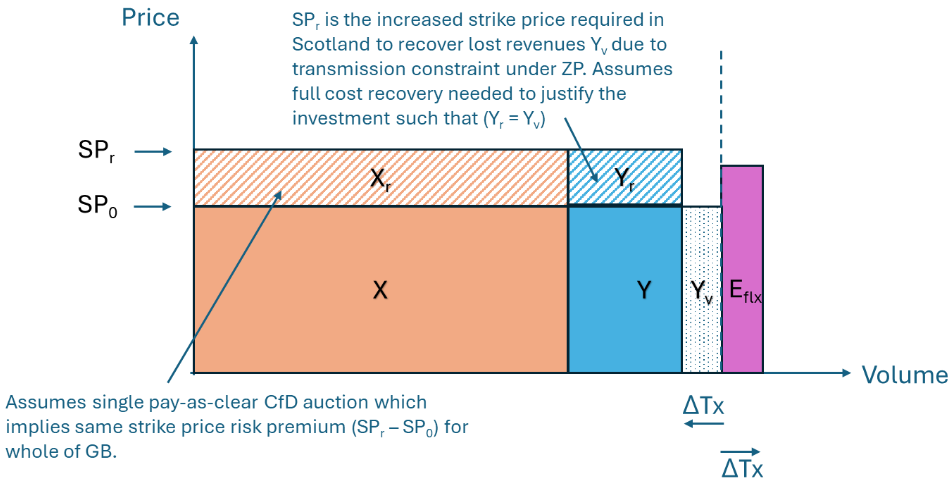

Figure 11. *Risk-adjusted cost of renewables under Zonal Pricing*

Risk-adjusted National Pricing

Finally we look at a worst case scenario, Figure 12, where exposure to the additional volume risks associated of zonal pricing are priced into investors bids in upcoming auction rounds, but then zonal pricing is not in the end enacted and payment volumes revert to a national pricing format. Nomenclature in the figure is the same as the previous figures. A small additional payment Y_{r+} in this scenario represents the additional risk premium charged on BM constraint payments to wind to reflect the higher strike price. In this scenario, we are back to having to purchase flexible energy from the balancing mechanism incurring the financial penalty B_{flx}.

Compared to the case where volume risks associated with zonal pricing are not considered (NP_0), under a risk-adjusted national pricing scenario (NP_r) the risk premium is applied across the entire GB fleet such that total costs become:

$$NP_r = NP_0 + X_r + Y_r + Y_{r+} \qquad \text{(Eq4)}$$

This is the scenario used for the results presented in Section 2. It is consistent with an assumption that the current uncertainty regarding introduction of zonal pricing could feed through to pricing behaviour and consumer costs irrespective of the actual outcome of the zonal pricing policy itself.

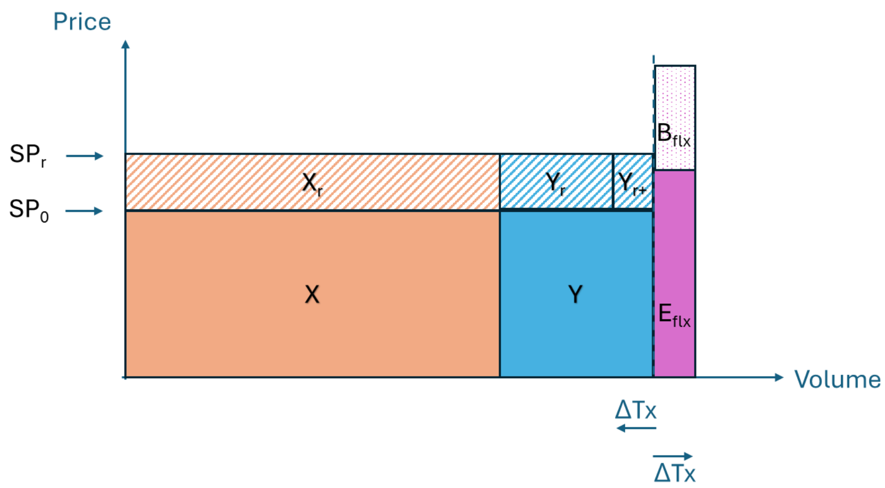

Figure 12. *Risk-adjusted cost of renewables under National Pricing*

The Strathclyde European Electricity Market Model (SEEMM)

This study uses and expands upon a previously developed European scale transmission system model of a coupled European electricity market. The Strathclyde European Electricity Market Model (SEEMM), previously described in work by report authors[36,37], uses ANTARES, an open-source electricity market modelling tool developed by the French system operator, RTE[38]. Each European country is generally represented by a single node, designated with an appropriate generation mix separated by generation type while constraints are imposed on the maximum net transfer capacity (NTC) of electricity trades that can take place between connected countries. Some countries like Denmark and the UK are split into two constituent island parts (i.e. GB and N. Ireland).

This iteration of SEEMM extends the basic capabilities set out in previous work by disaggregating the GB node into 14 internal zones, each with distinct generation capacity, demand and weather profiles. The zones largely follow the main constraint boundaries of the GB system as identified by the Electricity Ten Year Statement[39] allowing for representation of the main GB transmission system constraints. A visual representation of the model is given in Figure 13. This allows for an assessment of transmission related constraint volumes and comparisons between zonal and national[vi] day ahead market outcomes. Full details of recent model developments will be described in a forthcoming publication[40] while the key aspects of the model set-up are described further below.

[vi] The national market outcome is represented by running the model with no internal GB-transmission constraints

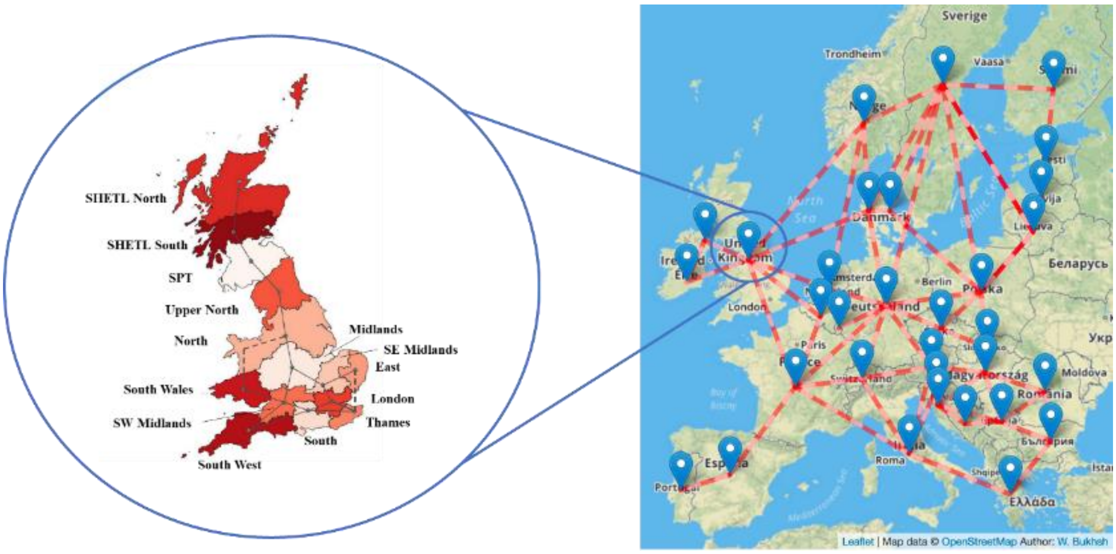

Figure 13. *Strathclyde European Electricity Market Model with 14-zone disaggregated representation of the GB system*

SEEMM solves a classic unit commitment problem and so determines a schedule of generation units and storage assets that minimises overall system operational costs taking into account various system constraints such as the minimum and maximum production of each generation type, start-up costs and minimum on and off times for generating units. 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.

The following sections breakdown the key inputs and modelling assumptions:

Generation

The generation background in GB is aligned as far as possible with the Clean Power 2030 Further Flex and Renewables Scenario as published by NESO. Generation was split into the 14 modelled zones using regional data as far as it is published with reference to CP30 documentation, FES 24 Holistic Transition scenario for 2030 (from which the CP30 scenario was partially derived) and mapping and analysis of proposed projects in the TEC Register.

Generation backgrounds in European countries to which GB is expected to be interconnected were also aligned with values given in the CP30 documentation but due to the short time available in the project other countries in Europe retained 2030 generation projections from previous iterations of the SEEMM model based on ENTSO-E TYNDP 2022 data. Generation availability is sampled based on assumed outage rates and repair times as given in TYNDP 2022. Fuel Costs and carbon prices are aligned with CP30 assumptions where possible and TYNDP data otherwise.

Renewable capacity factors in SEEMM are derived from Bloomfield et al[41]. However, adjustments were made to align the average GB capacity factor for the base 2013 modelling year with the input (pre-curtailment) capacity factors used by NESO for onshore wind, offshore wind and solar respectively in the CP30 modelling (as far as could be surmised from the available data for dispatch and curtailment) while retaining the regional and temporal variations of the base data. This allowed for a strong match with CP30 modelled outcomes and a good basis for analysing regional and national levels of renewable oversupply to inform on potential volume risk associated with zonal pricing.

Demand

Demand profiles in each country of the model with the exception of GB are taken from ENTSO TYNDP 2022 National Trends scenario projections. A separate approach is taken for GB demand which is derived as the combination of four constituent layers which are then disaggregated across the 14-zone model in line with available data from FES 24 on the regional breakdown of demand.

Total GB annual demand is aligned with quoted values in the CP30 work and derived as the sum of hourly profiles for underlying demand, EV demand, Electrified heating demand and Electrolysis demand. The underlying hourly demand profile is taken from Bloomfield et al and scaled to align with the total quoted demand in CP30 less the three elements of new demand - EV, electrified heat and electrolysis – that are treated separately and layered on top of the underlying demand.

Annual EV demand is matched to the CP30 quoted value with the hourly profile determined by assumptions on the seasonal and daily distribution of EV demand in line with ENTSO-E TYNDP approaches. A relatively high degree of time-shifted overnight charging is assumed in the baseline profile.

Similarly, electrified heating demand is aligned with annual totals expected in CP30 with the daily distribution of demand based on underlying temperature data from Bloomfield et al and the hourly distribution within day derived from literature on aggregated heat pump demand[42].

Electrolyser capacity is distributed regionally in alignment with the FES 24 Holistic Transition scenario. An off-model approach is used to dispatch electrolysis based on the status of residual demand (demand less available renewables) both regionally and nationally, such that it is switched on primarily in times of local or national surplus of renewable energy and switched off in periods in which it would exacerbate a national or regional peak in residual demand.

Storage

Battery and pumped hydro storage are modelled in SEEMM in line with the capacities outlined in CP30 and TYNDP background scenarios for each country. GB storage capacity is disaggregated zonally within GB via mapping from the regional data given in CP30. Battery storage is assumed to have 2 hour duration with 80% round trip efficiency while pumped storage is assumed to have 10 hour duration and 72% round trip efficiency. Storage within SEEMM is optimised on a weekly cycle with constraints ensuring that efficiency adjusted energy flows to and from these storage facilities are balanced across the optimisation cycle and that the maximum storage level is never exceeded.

Transmission

SEEMM is an energy balance model that does not model the full GB network but rather represents transmission constraints via net transfer capacities (NTCs) between the modelled nodes. Most model boundaries align with a real GB system boundary and so can be aligned with NTCs as stated by NESO in works such as the Electricity Ten Year Statement[43] or Beyond 2030 publications[44]. Some boundaries require assumptions to be made on net transfer capacity as a proportional aggregation of two or more real system boundaries. While NESO seemingly no longer directly publish a detailed breakdown of the assumed boundary capacity, NTCs in the SEEMM model were initially aligned with published data from ETYS 23 (the latest available at the onset of the modelling). However key boundaries were adjusted to align with latest Beyond 2030 and CP30 assumptions which represented a downgrade on assumed NTCs from ETYS 23 in many cases as identified in other similar modelling efforts, such as that by LCP Delta[45].

Interconnectors with European neighbours were aligned to the CP30 assumed total of 12.5GW with new additions to 2030 assumed to be to Ireland x2 and Germany, based on the real project pipeline and alignment with the GB total.

Transmission outages are not inherently sampled in SEEMM but can be added via off-model adjustments to the NTC capacities. Given time restrictions an idealised approach was taken in this work with a baseline assumption of full availability on NTCs across the year. A more detailed analysis would sample realistic outage patterns making assumptions on seasonal outage rates and down time. This means central assumptions on zonal volume risk in the modelled 2030 scenario are potentially an underestimate. Historic and future data provided by NESO[46] show that in recent history a main driver of high constraint costs has been low availability of transmission assets on key system boundaries vs their purported transfer capability.

To represent the impact of transmission related volume risk, as outlined in Section 2, sensitivity studies were performed on the boundary capacity on the main B6, Scotland – England, transmission constraint in the model. These can be interpreted as follows:

<u>Expected Transmission:</u> B6 NTC = 10.7GW – aligned with Beyond 2030 and CP30 assumptions on transmission buildout.

<u>High Transmission:</u> B6 NTC = 13.7GW – aligned with ETYS 23 B6 boundary capacity. While not an expected outcome, illustrative of the impact of a faster than timetabled rollout of transmission infrastructure and a scenario where transmission capacity across the B6 boundary does not so obviously lag assumed generation buildout.

<u>Low Transmission:</u> B6 NTC = 7.49GW – assumes a reduction to 70% of the expected transmission NTC. This is a simplified representation signifying a blend of delayed network delivery (for example of one of the major Eastern Green Link HVDC projects that is due to upgrade the route NTC), with a level of reduced operational capacity on the transmission route, as per recent precedent.

While the modelling of constraint volumes is restricted to a spot year analysis for 2030, the financial modelling projects the level of congestion for 2030 forward across the period of the CfD contracts. While a simplifying assumption this is not deemed to be an unreasonable assumption on how investors might view the future system unfolding in a world where generation buildout is expected to need to continue at pace with transmission developments continuing to play catch-up.

Delayed Transmission: This scenario is representative of a case where investors perceive that their volume risk would be associated with constraint levels that are aligned with the Low Transmission scenario for the first five years of project life before reverting to constraint levels associated with the Expected Transmission scenario.

The financial risk model

Overall Approach

In this part of the work, we aim to assess the impact of policy risks on the cost of delivering wind via the next few CfD auction rounds that are needed to meet 2030 targets.

In this analysis, policy risks relate specifically to uncertainties associated with the introduction of zonal pricing. These uncertainties include the timing, market conditions, infrastructure conditions (including transmission), as well as uncertainty over how projects bidding into coming CfD auction rounds would be exposed to such risks if and when ZP gets introduced in the future.

In order to do this, we take the following approach:

1. Use the different SEEMM scenarios to assess the range of potential volume risks that investors may be exposed to under ZP. These risks relate only to economic curtailment as discussed in Section 4. Other volume risks such as potential impacts on negative pricing[47] are have not been included.
2. Use a discounted cash-flow model to assess the impact of these volume risks on the risk premium added to exposed investors' bids into CfD auction
3. Assume that these risk premia will be added to the auction outturn strike price that applies to all generation from that auction cohort
4. Calculate the effect of raised strike prices on GB-wide system costs to consumers

The following sections set out these steps in more detail.

Interpretation of the SEEMM scenarios

The SEEMM scenarios allow us to calculate snapshots of possible project revenue outcomes in a ZP world based on the assumptions set out in the previous section. They are not weighted, and do not inherently provide a probability distribution of possible revenues. We therefore have to take a more stylistic approach to using these scenarios to represent investor risk.

A traditional risk analysis framework would be based on a probability distribution of revenues. An investor who is indifferent to risk would base decisions on the expected value of revenues, equal to the median or 50th percentile of the distribution. In most analyses, investors are assumed to be risk averse, meaning they would base decisions on a higher percentile, typically the 90th percentile – i.e. revenues would only be lower than the value used for the decision 10% of the time. The difference between the 50th and 90th percentile then gives an indication of the risk that the investor would be exposed to, and which they might try to recoup by adding a risk premium to their prices.

In our analysis, since we don't have a direct measure of these percentiles, we instead take a simplified approach of assigning one of the scenarios to be a central case representing the expected value (50th percentile), and then use the other scenarios to be illustrative of investors possible perceptions of 90th percentile outcomes. These in effect then become scenarios for perceptions of risk for an investor. The degree of non-dispatch due to system oversupply is taken to be the driver of revenue risk.

We therefore take the perspective of an investor in a wind project north of a potential B6 boundary transmission constraint. Our starting point assumption for the central case is that this investor goes into a CfD allocation round (such as AR7) with the expectation (50th percentile) that the national pricing regime will determine the degree of non-dispatch. As noted in Section 4 a certain degree of non-dispatch is expected even under a national pricing model where transmission constraints do not affect volume risk. Our modelling suggests this level of non-dispatch equates to around 11% of generation. The constrained transmission scenarios presented in Section 2 above are then interpreted as representing a range of perceived 90th percentile outcomes given the potential that zonal pricing may (or may not) be introduced in future, exposing them to these greater levels of non-dispatch. It is the difference in the level of non-dispatch between these constrained transmission scenarios and the central national pricing scenario that is used as an input to the calculation of strike price impacts in the cash flow model.

Volume risk / degree of non-dispatch

Volume risks are derived from outputs of the SEEMM model which calculates energy spilled, a measure of oversupply, usually occurring when there is more wind and solar generated than can be absorbed by sources of demand, exports, storage or other types of flexibility. We assume that periods of non-dispatch due to energy spillage only applies to wind and solar generation. The total volume of non-dispatch is then calculated as the annual volume of spillage divided by the total annual generation from wind and solar in the relevant zone. For the National Pricing scenario, the relevant zone is the whole of GB, which assumes no transmission constraints. For the zonal pricing constrained transmission scenarios, we take Scotland as the relevant zone of interest. For this analysis, we only include economic curtailment (Section 4), and do not include potential impacts on negative pricing.

This degree of non-dispatch is assumed to apply to equally to all wind plant in that zone. In reality, the risks to individual plants may be higher or lower than this average due to uncertainties over how periods of non-dispatch will be allocated between plant. For this paper, we have not included these additional plant-level risks

The values for each scenario are shown in Table 1.

Scenario	Volume reduction due to non-dispatch
National Pricing	10.7%
Higher transmission	10.7%
Expected transmission	16.5%
Reduced transmission	26.3%

Table 1. *Non-dispatch Summary*

Cash Flow Model

We implement a standard annual discounted cash flow model to assess what prices are needed to recover the expected project costs. Table 2 identifies some of the key features and assumptions used in the model.

Parameter	Assumption / comment
Technology costs and performance data	Based on DESNZ 2023 Cost of Generation 2023 report.[vii] We use the 'Medium' scenario for 2030. Costs are escalated by 20% to 2024 prices (based on Bank of England inflation calculator).[viii] This includes the phasing of capital construction costs, as well as fixed and operating costs. These costs remain the same for each of the scenarios.
Currency year	£2024
Discount rate	5%. This is taken as the risk-neutral discount rate reflecting our approach of taking the central scenario as being the risk neutral outcome, and then explicitly modelling separate scenarios to represent the risk-averse outcomes.
CfD contract duration	15 years
Revenues	Revenues are sales volume multiplied by price. The price is the CfD strike price for the first 15 years, and the merchant price thereafter.
Sales volumes	The volume of generation is based on the average annual GB capacity factors used in the SEEMM model scaled down to account for the degree of non-dispatch for the relevant scenario being considered (as discussed above). These volumes are assumed to persist for the project lifetime, except in the case of the 'delayed transmission' scenario, where the volume is equal to the reduced scenario for the first 5 years, and then reverts to the central scenario for the remainder of the project lifetime.
Strike prices	Strike prices are calculated as the price required for the discounted revenues during the CfD contract duration to match discounted costs. Costs are assumed to be covered

[vii] https://www.gov.uk/government/publications/electricity-generation-costs-2023
[viii] https://www.bankofengland.co.uk/monetary-policy/inflation/inflation-calculator

	within the CfD contract period (i.e. completely discounting merchant prices in the tail). Strike prices are assumed to increase to compensate for reduced volumes due to periods of non-dispatch shown in the previous section.

Table 2. *Key model assumptions*

Calculation of total system costs

The next stage is to look at the impact of these potential increases in strike prices on the cost of reaching the 2030 decarbonisation target. This total system cost is calculated as the increase in strike price multiplied by the volume of generation affected by that strike price increase. The cost increases only apply to onshore and offshore wind, we do not consider impacts on solar plant as the location of most solar farms means they are not behind the constraint that we have focused on.

The increase in strike price is the difference between the risk scenario and the base case expected National Pricing scenario.

The volume of generation affected by the strike price increase is assumed to include that all new wind power procured through auctions held in time to meet the 2030 target. We therefore assume that all wind power contracted during CfD auction rounds held prior to 2030 will be impacted by this risk premium, and that this includes generation procured prior to 2030 but which continues to be built out to 2032.

Since the strike price is only paid on dispatched energy, we then subtract the expected degree of non-dispatch for the relevant plant under National Pricing. These volumes are taken from the SEEMM model, which is calibrated to the NESO Further Flex and Renewables scenario for 2030.[48] Details are shown in Table 3.

		Offshore	Onshore	Units	Source
1	Amount added 2023-2030	35.9	13.6	GW	NESO CP30 TAB ES.1
2	Amount from earlier AR3-6	15.3	1.0	GW	NESO CP30 TAB CP.07
3	Capacity added 2030-2032	15.2	1.6	GW	NESO CP30 TAB ES.1
4	Total capacity affected by ZP risk	35.8	14.2	GW	(1)-(2)+(3)
5	Average capacity factor	47.5%	32.1%	%	SEEMM
6	Generation affected by ZP risk	148,752	39,895	GWh	(4)*(6)*8760
7	**Dispatched generation affected by ZP risk**	**132,263**	**28,299**	**GWh**	Net of economic curtailment (SEEMM)

Table 3. *Assumptions on the volume of generation affected by the strike price increase*

The energy balance model

For the analysis undertaken in the ‘Migrating Generation South’ part of the project the team used an Excel-based energy balance model of the GB electricity system. This model balances electricity generation with demand for every hour of a representative year. The model despatches generation for each hour in a fixed merit order, starting with variable renewables (offshore and onshore wind and solar), followed by nuclear, hydro, CHP, seasonal storage, interconnectors, short-duration storage (batteries), low-carbon dispatchable generation, and finally gas-fired generation (assumed to be CCGT). Capacity factors for wind are derived from the

SEEMM model inputs, with values for the 14 zones in SEEMM aggregated using a weighted average to give four separate capacity factors for Scottish offshore wind, Scottish onshore wind, the rest of GB offshore wind, and the rest of GB onshore wind respectively.

Technology cost assumptions are based on the UK Government's 2023[49] analysis for wind, solar, hydrogen-fired CCGT, and natural gas CCGT, and from the 2016 analysis[50] for nuclear. Battery cost assumptions are from NREL's 2023 analysis[51]. All costs are normalised to 2024 values using the UK GDP deflator[52].

For the model starting conditions, installed capacities for all generation types and total system demand are calibrated to the 'Further Flex and Renewables' (FFR) scenario for 2030 from the NESO CP30 report.[53] This calibration is applied to both capacities and outputs, meaning that utilisation rates for the different generation sources in the energy balance model are adjusted to achieve the same output as the FFR scenario.

The energy balance model is configured so that it allows generation capacities to be easily changed relative to the starting conditions. This facilitates the examination of the effects of, for example, having less Scottish offshore wind capacity relative to the NESO 2030 values and replacing that capacity with sufficient onshore wind in the rest of GB to ensure that total system demand is still met across all hours of the representative year. The model outputs of interest to our analysis include:

- Volume of gas-fired generation (in hours run, GWh, and % of total demand met)
- Curtailment (in GWh and the implied annual system cost)
- Annualised variable renewable costs
- Interconnector flows (in GWh)

All models involve trade-offs between complexity and computational expediency. The energy balance model we use for this work strikes a balance that tends towards the latter. On one hand the model has sufficient technological, temporal, spatial and cost granularity so that the results can provide useful insights. At the same time the speed of operation allows a range of exploratory scenarios (which we have termed experiments in the findings section above, and in the descriptions below) to be examined in a relatively short period of time.

Bearing this in mind, and the experiments that we use the energy balance model to explore, the key areas to caveat relate to the degree of spatial disaggregation and energy curtailment and constraint. The model uses weighted average capacity factors for Scottish offshore wind, Scottish onshore wind, the rest of GB offshore wind, and the rest of GB onshore wind respectively. Clearly, there is scope for much real-world variation within these areas that the model can only take into account at an aggregated level. In respect of energy curtailment, this happens in the model when the output from wind, solar and other non-flexible sources of generation[ix] in any given hour of the year exceed the combined maximum load from demand, storage and interconnector exports in that hour. The model does not have

[ix] Non-flexible sources of generation are assumed to include nuclear, hydro and CHP plant

constraints due to transmission system limits (so the model is effectively ‘copper plate’).

We have run three sets of exploratory scenarios, which we call Experiments 1, 2 and 3 respectively. All the experiments share some common characteristics. They all have the same starting conditions which are that the installed capacities for Scottish offshore and onshore wind, and offshore and onshore wind for the rest of the GB electricity system and solar match the values from ‘Further flex and renewables’ scenario for 2030 from NESO CP30.

This starting condition is labelled ‘0 GW’ in the model results charts. From this starting position, each experiment follows a multi-step process where installed capacities for Scottish offshore and onshore wind, and offshore wind for the rest of the GB are progressively reduced. At the same time, the installed capacities of onshore wind and solar power for the rest of GB are progressively increased at each step, by the minimum that is required to ensure that demand is still met for each hour of the year. Each experiment has seven steps, with the final step having a total of 20 GW less installed capacities across Scottish offshore and onshore wind, and offshore wind for the rest of the GB system. Each step therefore has 1 GW less of each of these capacities than the previous step. The exception to this is that there is no reduction on Scottish onshore wind capacity after step 5 (labelled ’15 GW’) and the reductions in Scottish and rest of GB offshore wind are 1.5 GW each for step 7 (labelled ’20 GW’). Note that in all cases the installed capacities for Scottish offshore and onshore wind, and offshore wind for the rest of the GB system are never less than the current (as of 2024) installed capacities.

There have been a number of studies in recent years that have explored the implications of moving to location pricing in the GB electricity system (see above, and reference list). Such studies tend to be focussed on the changes to overall system cost, regional pricing impacts, and the distribution of benefits and disbenefits between consumers and market participants. However, many of them do model how the geographical distribution of generation capacities may change under a range of location pricing scenarios. Some of these studies find that the volume of renewable generation capacity that may be relocated further south may be up to 10-15GW, a range which is represented by steps 3-5 in our experiments. Steps 6 and 7 of each experiment explore the impact of a more pronounced response to locational pricing – a reduction in Scottish/Northern England capacity of up to 20 GW.

There are two keys areas in which the experiments differ from each other. The first point of differentiation is whether it is total annual variable renewable generation or the share of unabated gas-fired generation that is kept constant through each step. The second point of differentiation is the relative mix of the additional onshore wind in the rest of GB and solar power capacity that is required to make up for the reductions in Scottish offshore and onshore wind and rest of GB offshore wind.

In Experiment 1 we add sufficient ‘southern’ onshore wind and solar power capacities to keep total annual variable renewable generation constant. These capacity additions are dominated by onshore wind with solar capacity additions kept to 20% of the corresponding onshore capacity additions.

In Experiment 2, we add sufficient ‘southern’ onshore wind and solar power capacities to keep the annual share of unabated gas-fired generation constant. These capacity additions are dominated by onshore wind with solar capacity additions kept to 20% of the corresponding onshore capacity additions.

Experiment 3 follows Experiment 2 in that we add sufficient ‘southern’ onshore wind and solar power capacities to keep the annual share of unabated gas-fired generation constant. However, in this experiment the capacity additions for onshore wind and solar are kept equal. Because of the relatively higher share of solar vs. wind in Experiment 3 compared to Experiment 2, we also add sufficient additional battery storage allow solar power to make the same contribution to energy balance as wind in displacing gas-fired plant. The scale-up of additional batteries required to achieve this energy balance function is calibrated against the capacity of battery storage included per unit of solar generation capacity on the system in the CP30 FFR scenario.

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