Economic curtailment: understanding its scale and impact

A working paper

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Content and introduction

Content

Introduction

As part of today's reformed national pricing process, there is an acute focus on reducing network curtailment volumes and costs. That is the renewable generation we have to switch off due to grid constraints, and the cost of doing so and of replacing it with non-renewable generation elsewhere.

In this working paper I look at curtailment caused by a different reason: oversupply of renewables. That is when the output of wind and solar exceeds what the GB electricity system can use, even after accounting for flexibility.

This is economic curtailment, curtailment driven by the national balance of supply and demand, not by network limits.

One of the key messages of the paper is that economic curtailment could be far larger than today's network curtailment, but its potential scale is still poorly understood. The paper explores what drives it, what it means for generators, market operation, and ultimately consumers.

The work includes illustrative analysis using a simple but credible model. It shows that for a net-zero compliant pathway, the FES 2025 *Holistic Transformation* scenario, economic curtailment could be well over 100 TWh a year in the mid-2030s. I don't claim this is the 'right' answer, rather the work highlights that the scale of curtailment could be significant and there is an urgent need to develop our understanding of the issue.

Another key message is that the impacts could be similarly significant. They include impacts on renewable investability, on the effective operation of the wholesale market, and ultimately on consumer bills.

This paper doesn't have all (or possibly any) of the answers. Instead, it highlights a major design challenge for a net-zero electricity system. We must understand it better, and design markets and systems that can manage it.

Simon Gill, November 2025

Foreword

Johnny Gowdy,
director Regen

REGEN

It was great to discuss and review this paper by my colleague, Dr Simon Gill.

Too much clean energy is rarely considered a problem; it is certainly preferable to too little, which perhaps explains why it has received less attention from policymakers. However, as periods of oversupply become more frequent, the question of what happens when the wind blows, the sun shines and nuclear energy is at full tilt is an important one that needs to be addressed.

It is part of a broader question of what happens in a market when the marginal commodity cost of energy deviates strongly from its long-run or levelised cost. In the case of economic curtailment, the focus of this paper, the marginal cost sinks to zero or even a negative value, leaving generators with a dilemma of whether to produce at a loss or curtail their output.

There has been an increase in negative prices in GB and Europe, and the consensus is that their occurrence will likely rise significantly over the next decade. The market functions to the extent that it clears, and the lights stay on; however, unexpected things can happen as generators scramble to find a customer and establish a position between day-ahead and intra-day markets. As the system operator has already found to its cost, unexpected behaviour can lead to unpredictable volume movements that can undermine its own balancing actions.

Simon's paper does not present all the answers, but it does begin to unpack some of the key questions. The market may work, albeit with distortions, but is the value of abundant low-cost energy passed to the consumer? Do revenue support measures continue to reduce investment risk? Is the cost merit order maintained? Will CfD holders become price setters, and if so, will we see a propensity towards zero-price day-ahead markets? If there is economic curtailment in one part of the market, will that result in liquidity shifts to others? Will we see increased bilateral trading to re-allocate volume between market participants? What other gaming strategies might traders adopt to capture value?

They may seem mundane and academic, but the answers to these questions will be key to understanding how markets will function during more frequent periods of oversupply and will help policymakers tasked with designing future market arrangements and revenue support schemes.

Summary: key points

1. **Economic curtailment** happens when electricity demand and system flexibility are insufficient to absorb available wind, solar and inflexible generation, forcing wind and solar to be curtailed. It is unrelated to network limits and would occur even with unlimited grid capacity.

Economic curtailment | Occurs when | Inflexible generation + Wind and solar availability | is greater than | Demand + Flexibility | Nationally, across the whole of GB

2. **Relatively rare today:** Although network constraints are common (in 2023 they led to around 4 TWh of *network* curtailment) economic curtailment is minimal in today's system because renewable capacity is still small relative to demand.
3. **More common in future, and potentially a major challenge:** NESO's *Holistic Transformation* pathway projects 41 TWh of *economic* curtailment in 2035. But modelling for this paper suggests that with different assumptions the real value could be even higher – by up to a further 100 TWh – for the same renewable capacity but under different assumptions.
4. ***Direct* costs fall on generators …** Unlike network curtailment (the costs of which are recovered from consumers via BSUoS), economic curtailment directly reduces generator revenues by removing revenue derived from the wholesale market and from support payments which are paid on output (e.g., ROC, CfD).
5. **… But costs will still be passed through to consumers:** economic curtailment will influence renewable investment decisions and the strike prices generators bid in CfD auctions, meaning that consumers may end up funding higher support payments to generators.
6. **Low strike price generators are curtailed first:** market operation means that merchant projects and those with very low support payments (i.e. low strike prices) will be curtailed first whilst generators with higher support costs will continue to run. This market behaviour would maximise the cost of support payments to billpayers.
7. **Economic curtailment magnifies the effect of CfD design on market distortions, ultimately undermining market functioning:** CfD payments which are linked to a generator's output, combined with negative pricing rules in the CfD contract, distort bidding in the day-ahead market. The CfD reference price definition also discourages forward trading. The result is an increasingly dysfunctional wholesale market.
8. **Economic curtailment is also an opportunity:** it represents near zero short-run marginal-cost wholesale energy that could serve new demand at low cost.
9. **Negative pricing is an additional risk for CfD generators, particularly from AR4 onwards: t**his is a further nuance of economic curtailment we need to better understand.
10. **We need to understand and design for economic curtailment …**
11. **… to make sure the electricity system and market works for consumers:** avoiding excess impacts on support payments, early closure of generation, and distorted dispatch. Market reform needs to directly engage with the challenge of economic curtailment to avoid higher bills.

Summary: potential scale of economic curtailment

		2023: Historical	2035: FES Holistic Transformation assumptions	2035: Alternative load factor and interconnector assumptions
		Economic curtailment ~0% (Network curtailment 4 TWh; 5%)	Economic curtailment 8%	Economic curtailment 24%

		2023: Historical	2035: FES Holistic Transformation assumptions	2035: Alternative load factor and interconnector assumptions
Renewables	Onshore wind	15 GW Load factor - 26%	38 GW of which 15 GW existing and 24 GW new Load factor - existing 26%, new 30%	38 GW of which 15 GW existing and 24 GW new Load factor - existing 26%, new 40%
Renewables	Offshore wind	16 GW 44% load factor	86 GW of which 16 GW existing and 70 GW new Load factor – existing 44%, new 44%	86 GW of which 16 GW existing and 70 GW new Load factor: existing 44%, new 55%
Renewables	Solar	16 GW 12% load factor	62 GW All capacity has 12% load factor	62 GW All capacity has 12% load factor
Flex	Interconnector:	8.3 GW, 14.5 TWh	19 GW, 109 TWh export	19 GW, 84 TWh export
Flex	Electrolysis:	-	2.1 GW, 7.8 TWh demand which reduces curtailment	2.1 GW, 11.3 TWh demand which reduces curtailment
Flex	Storage:	7.4 GW / 33.8 GWh	39 GW / 156 GWh (4-hour discharge duration)	39 GW / 156 GWh (4-hour discharge duration)

Network curtailment is widely seen as a key challenge for the reformed national pricing (RNP) process. In 2023 it amounted to around 4 TWh, or 5% of total GB wind and solar availability.

Looking ahead, NESO's *Holistic Transformation* pathway includes 41 TWh of economic curtailment in 2035.

Some of the assumptions used in NESO's modelling could underestimate the level of economic curtailment seen if the level of renewable capacity in that pathway is delivered. Under alternative assumptions, it could be as high as 141 TWh in 2035.

However, some of the mid-2030s capacity assumptions in the FES pathways look highly optimistic.

This analysis highlights that economic curtailment is a critical issue to understand and engage with. That engagement should start with a review of these assumptions and inputs.

Summary: recommendations for government and the sector

We need a clearer understanding of the drivers and potential scale of economic curtailment to inform the RNP process and future renewable support mechanisms. Economic curtailment, when combined with current market arrangements, creates significant risk for both new and existing CfD holders. Improved understanding will allow us to design markets that meet tomorrow's needs, not just today's, and will help unlock flexibility across storage, interconnectors, hydrogen electrolysers, electrified heat, and demand response. The four categories below list a series of actions that government and industry should develop together to ensure we understand the challenge and response appropriately.

1. Understand the scale of economic curtailment

- Commission analysis to assess curtailment levels across a range of scenarios and assumptions.
- Quantify the financial impact on generators and the implications for investability and CfD strike price bids.
- Quantify the risk that uncertainty about the level and distribution of economic curtailment creates for market participants, including CfD holders.
- Conduct technology-specific analysis on both wind and solar.

2. Design markets and systems to manage it

- Ensure the RNP process addresses the question of market allocation of economic curtailment.
- Review tie-breaker rules in power exchange auctions.
- Assess the likely impact on merchant generators and prevent curtailment from driving unduly early closures.
- Explore economic curtailment through a locational lens considering its interaction with network curtailment.
- Integrate a growing understanding of economic curtailment into strategic spatial energy and network planning.

3. Review the implications for CfD design

- Assess how current CfD rules distort market behaviour during periods of economic curtailment and quantify the detriment created.
- Quantify the likely level of negative pricing in the market under a range of assumptions about trading behaviour.
- Consider CfD reforms that reduce or remove market distortions. This should include options that move away from 'pay on output' support such as deemed or capacity-based CfDs.

4. Treat economic curtailment as an opportunity

- Use evidence on the scale of curtailment to identify opportunities for flexibility and accelerated electrification of heat, transport, industry and green hydrogen.
- Embed these opportunities in policy and regulatory frameworks – for example, the Hydrogen Production Business Model.
- As understanding of economic curtailment grows, ensure markets and support mechanisms enable long-term investment in demand and flexibility as well as short-term dispatch.

What is economic curtailment?

Economic curtailment happens when electricity demand and system flexibility are insufficient to absorb available wind, solar and inflexible generation, forcing wind and solar to be curtailed. It is unrelated to network limits and would occur even with unlimited grid capacity.

Economic curtailment | Occurs when | Inflexible generation + Wind and solar availability | is greater than | Demand + Flexibility | Nationally, across the whole of GB

A comparison of economic and network curtailment

Network

- Occurs when the wholesale energy market schedules renewable generation even if it sits behind a network constraint.
- The transmission system cannot always carry that power within safe operational limits.
- NESO steps in, mainly via the Balancing Mechanism (BM), to redispatch the system: reducing output behind the constraint and increasing it elsewhere.
- Renewables are compensated for lost support payments through the BM.
- Costs fall on consumers through Balancing System Use of System (BSUoS) charges.

Economic

- Occurs when the wholesale market is oversupplied with inflexible, wind and solar generation.
- Some renewables cannot sell their power because there are no buyers.
- These generators should "self-curtail"
- Economic curtailment therefore arises naturally from how the wholesale market clears supply and demand; it is not directed by NESO.
- Renewables are not compensated; lost revenue falls directly on generators.
- This will impact on investability and CfD strike price bids.

The electricity system must always stay in balance. At every moment, total generation must equal total demand. After accounting for generation that cannot easily be adjusted (such as nuclear) the market then turns to flexibility. This can include charging energy storage, exporting via interconnectors, or increasing flexible demand. If there is still more wind and solar available than can be used, some of it must be curtailed to balance the system.

It is important not to confuse economic curtailment with network curtailment (sometimes called constraint curtailment). Network curtailment is about physical limits on the transmission system: whether power can flow from where it is generated to where it is needed. Economic curtailment, by contrast, is about the GB-wide balance of supply and demand.

There is another key distinction: economic curtailment is allocated by the wholesale energy market, not by NESO. Economically speaking, it isn't "curtailment" at all – it is simply an oversupply of low short-run marginal-cost generation. The result is that some generators can't sell their power in the market, despite their very low marginal costs. In respect of other goods an oversupply is normal: we aren't concerned with less than 100% occupancy of hotel rooms, or trains that aren't full every time they run.

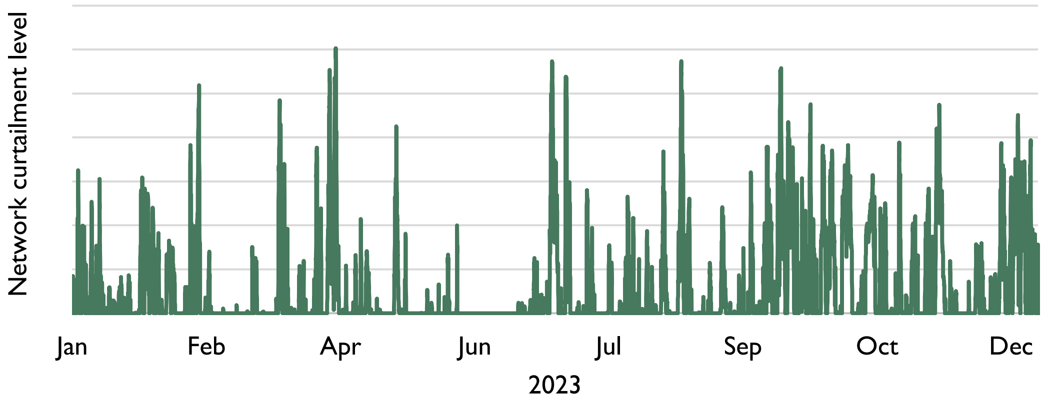
How common is curtailment today?

Economic curtailment is relatively rare today: although network constraints are common (in 2023 they led to around 4 TWh of network curtailment) economic curtailment is minimal in today's system because renewable capacity is still small relative to demand.

Network curtailment is already common, and how to manage it is one of the big questions in the RNP process. It drives much of today's debate on network planning and strategic spatial energy planning.

Because it is visible and directly affects consumer bills through BSUoS charges, network curtailment also plays a prominent role in the wider public debate.

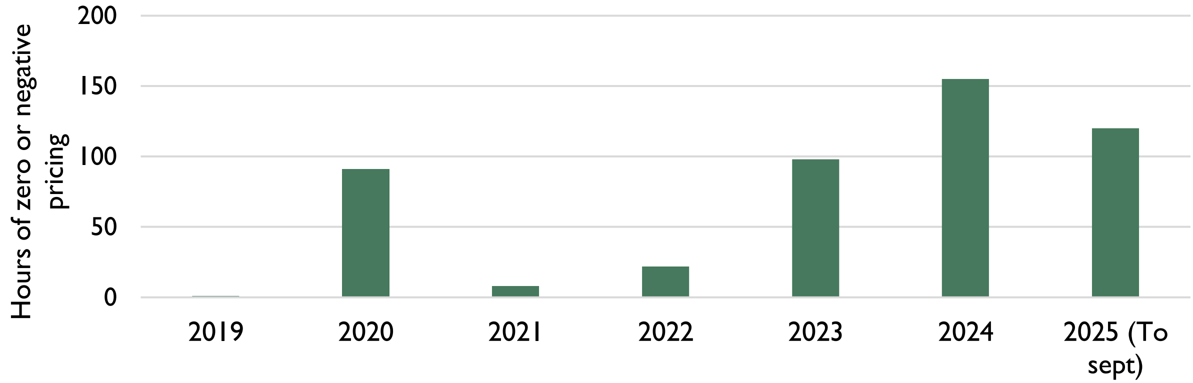
In 2023, Elexon data shows that around 4.3 TWh of wind was curtailed through the Balancing Mechanism. Curtailment happened in around 3,400 hours of the year, that is 41% of the time, and almost all of it was due to network constraints.



Economic curtailment is harder to track than network curtailment because there isn't a direct source of data. One useful indicator of oversupply is when day-ahead power exchange prices fall to zero or below. The chart below shows how often that happened in recent years.

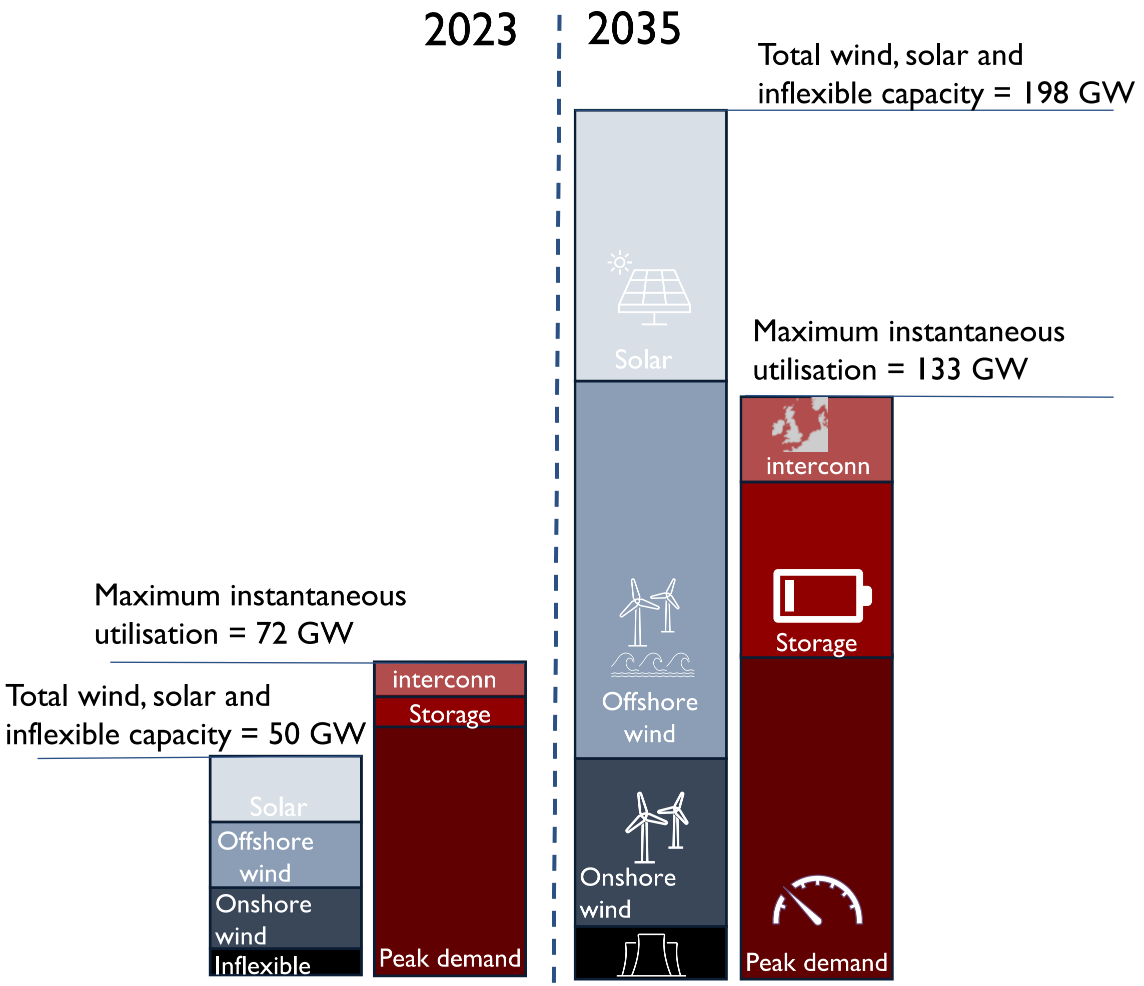
Negative prices have become more common recently, rising from a very low base in 2019 (the spike in 2020 reflects exceptionally low demand during Covid). By 2024, there were 155 hours of negative prices, just under 2% of the year.

Modelling carried out to support this paper agrees with historical outturn: given current levels of renewables, inflexible generation, flexibility, and demand, oversupply events remain relatively rare, but its prevalence is increasing.



How important could *economic* curtailment be in future?

More common in future, and potentially a major challenge: NESO's *Holistic Transformation* pathway projects 41 TWh of economic curtailment in 2035, around ten times today's network curtailment. This reflects very ambitious assumptions on renewable growth, while other factors such as low assumed load factors and optimistic expectations for system flexibility reduce projected curtailment. Modelling for this paper suggests that under alternative assumptions, with the same renewable capacity, curtailment could be up to a further 100 TWh.



Economic curtailment is set to become a much bigger feature of the electricity system in the 2030s.

This is obvious from the chart on the left which shows the *capacity* of wind, solar and inflexible generation against the maximum ability to use its output – peak demand and the capacity of flexibility. If GB succeeds in delivering CP2030, renewable capacity will far exceed the maximum level of electricity that can be used at a particular point in time.

That is to be expected in a well-designed, renewably-powered electricity system: GB will rarely see conditions where all wind and solar output is near 100%. Therefore, *capacity* in excess of peak demand will be a normal feature of a high renewable system.

But utilisation also varies. Away from peak periods, demand drops sharply. For example, NESO's demand in the *Holistic Transformation* pathway shows that minimum demand is 17 GW, compared with a peak of 76 GW.

The important question is how often and to what extent *availability* exceeds the ability to use generation at a particular point in time. To estimate the scale of economic curtailment, we need to run time-series analysis using realistic renewable and demand profiles, along with credible assumptions about flexibility.

NESO's data, published alongside its scenarios, suggest that in 2035, under their assumptions this would mean around 41 TWh of economic curtailment. However, there is a risk that these assumptions are not realistic, and economic curtailment could be significantly higher.

The following three pages present a simple hour-by-hour energy balance calculation to explore this further.

Modelling economic curtailment in 2035 (without flexibility)

The first stage of the modelling process is straightforward. An hour-by-hour time-series for inflexible demand (top graph) and renewable availability (middle graph) are created for the year. Then, for each hour, renewable availability and inflexible generation is subtracted from the demand profile to give a *net demand* time series.

The time-series have been created using the following inputs:

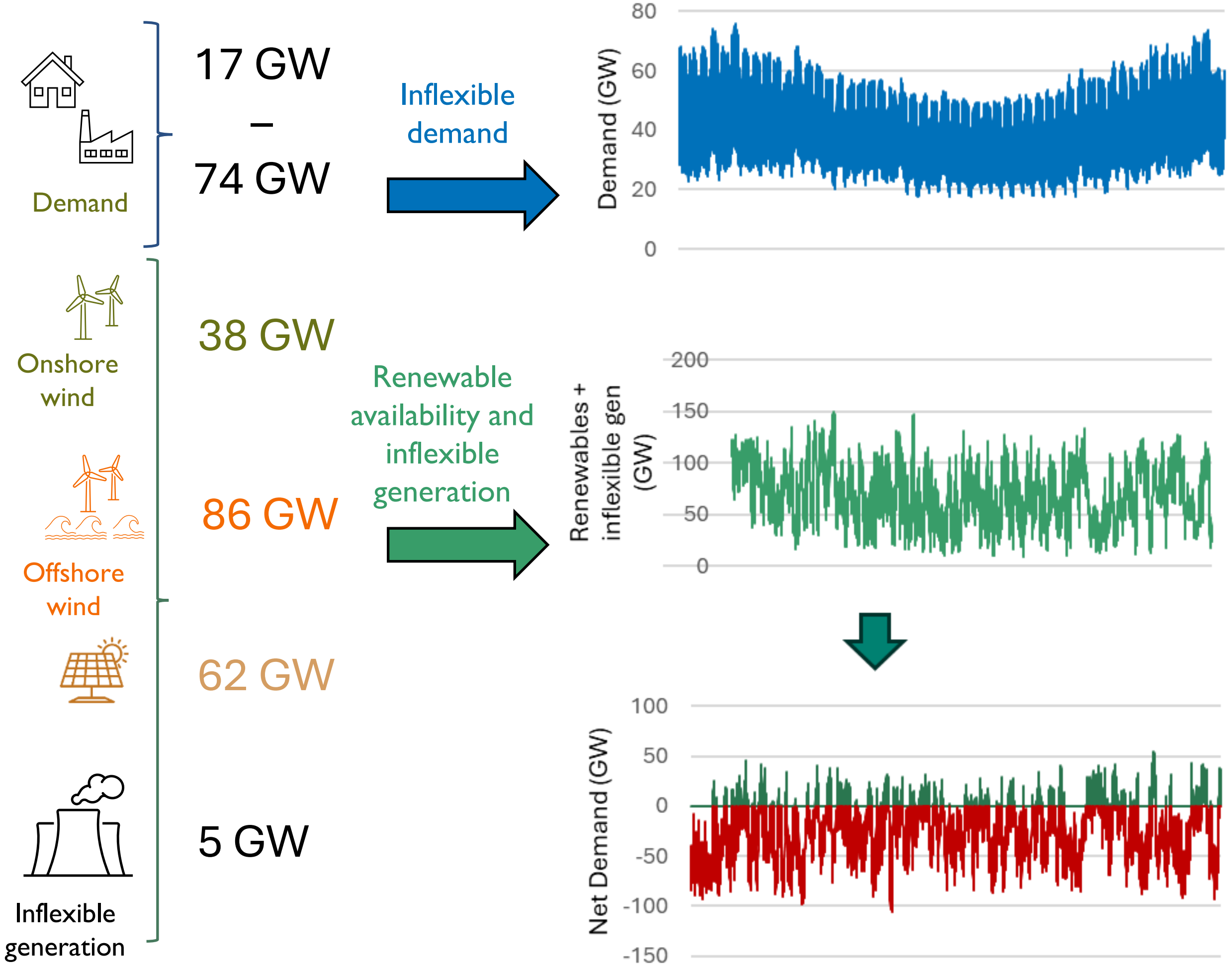
- **Demand:** peak, minimum, and total annual consumption for each demand type, taken from data workbooks.
- **Hourly demand profiles:** constructed from historic demand time-series plus modelled assumptions on electrified heat and transport.
- **Renewable availability:** based on historical meteorological reanalysis data, with capacity distributed geographically using existing and pipeline projects.
- **Correlations:** wind and solar availability correlations are captured.
- **Inflexible generation:** assumed baseload operation at 75% of installed capacity, to reflect downtime.

The modelling shows that **before flexibility is used**, there is an oversupply of renewables during 80% of the year, with a total excess volume of 246 TWh.

These results highlight a central challenge: **flexibility is essential to minimise economic curtailment in a clean power system**.

Three key technologies likely to play an important role in addressing economic curtailment (the effect of their operation is shown on the next page):

- **Energy storage**, especially long-duration.
- **Interconnectors**, combined with dispatch mechanisms that actively reduce curtailment.
- **Flexible demand**, including new and dispatchable loads such as electrolysers.



" Without flexibility, net demand is negative 7034 hours a year, that 80% of the year, and would lead to 246 TWh of economic curtailment. "

Modelling economic curtailment in 2035 (with flexibility)

The impact of flexibility on economic curtailment depends on the modelling assumptions used. The assumptions used here are optimistic in the sense that they will tend to maximise the impact that flexibility has on reducing economic curtailment. **Therefore, the results are likely to place an upper bound on the effectiveness of a given capacity of flexibility.** In reality, for the same capacity of flexibility, the impact could be less, and economic curtailment could be higher.

Energy Storage

- **Capacity:** 40 GW of power capacity, 177 GWh of energy storage capacity (average discharge duration of 4.4 hours).
- **Technology mix:** represents batteries, pumped storage, and some compressed/liquid air.
- **Efficiency:** 70% round-trip (split evenly between charge and discharge).
- **Availability:** 100% dedicated to reducing curtailment (assumes no diversion to other services such as frequency response).
- **Dispatch:** Assumes perfect dispatch mechanism.

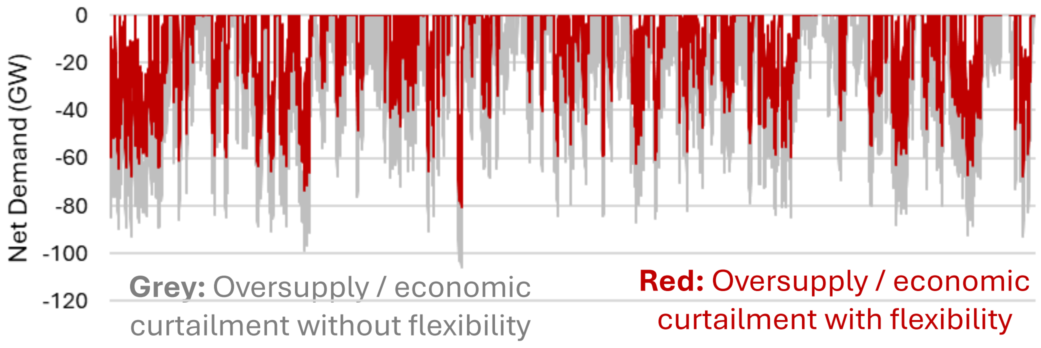
Interconnectors

- **Capacity:** 19 GW, linking GB to 7 countries.
- **Maximum coincident export:** capped at 70% of capacity, recognising that not all markets can absorb full GB exports simultaneously and other countries may also face oversupply.
- **Operation:** always assumed to export during oversupply until the surplus is cleared or interconnector export cap is reached.

The analysis for this paper does not include a detailed European-wide dispatch model. The maximum coincident export constraint is used as an appropriate proxy for inter-market impacts and friction.

H_2 Electrolyser

- **Capacity:** FES 2025 includes 2.1 GW of electrolyser capacity in 2035. Note this is a significant reduction from 7.4 GW in 2035 which was the equivalent value in the 2024 FES.
- **Role:** Electrolysers convert electricity into hydrogen. They are not an end use of energy. They only run if there is hydrogen demand, and that demand must be flexible - either to use hydrogen when it's produced or to store it for later.
- **Assumptions:** The model assumes full availability during oversupply, giving an upper-limit estimate of electrolysers' impact on curtailment.



> "With flexibility included, curtailment falls to 141 TWh and the share of the year affected by curtailment drops from 80% to 44%. In total, flexibility enables an additional 105 TWh of renewable electricity to be used."

Modelling results and comparison with FES

This indicative modelling suggests, under the *Holistic Transformation* pathway, curtailment could be as high as 141 TWh. That is 24% of the maximum total available renewable generation. However, NESO's FES modelling for the same scenario only has 41 TWh of economic curtailment. The key factors driving the modelling differences appear to be assumed load factors for renewables and interconnector exports.

Interconnectors have the biggest impact in reducing economic curtailment. In this modelling they reduce it by 84 TWh.

Storage and electrolysers also help, but on a smaller scale - cutting curtailment by 10 TWh and 11 TWh respectively. The impact of storage is smaller than may be expected because, in a system with significant oversupply, there are long periods where storage can't discharge without increasing economic curtailment.

Even after flexibility, 141 TWh of renewable generation is still curtailed, around 24% of total available output. The graph below shows how renewable energy is generated and curtailed across the year after flexibility is applied.

TWh	**Generated**	**Curtailed**	**Curtailment *reduction of each technology***
No Flex	331	246	-
+ interconnectors	415	162	84
+ storage	427	152	10
+ electrolyser	437	141	11

For comparison, NESO's FES analysis projects 41 TWh of economic curtailment. The differences appear to be driven by two key assumptions:

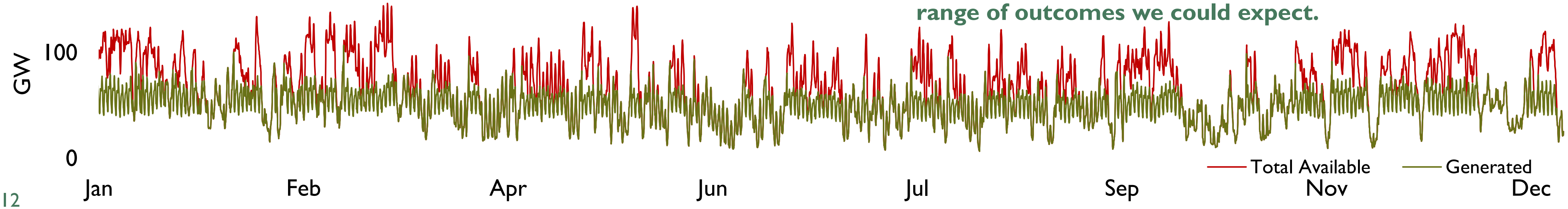
- **Load factor:** FES assumes lower load factors for both onshore and offshore wind. This means less generation per MW of installed capacity.
- **Interconnector exports:** FES includes much higher levels of export: 109 TWh compared with 84 TWh modelled here. Overall interconnector utilisation in FES is high. When imports and exports are combined, it equates to 80%.

Is 141 TWh realistic?

If a quarter of renewable output were lost, investment in renewables would be more challenging and, unless greater support was available, less wind and solar capacity would get built. This would reduce the level of economic curtailment, but at the expense of missing our climate change targets.

However, the *Holistic Transformation* pathway, with 86 GW of offshore wind in 2035, is ambitious not just in terms of delivering CP2030, but throughout the 2030s decade. It may be time to review the expected trajectory during the next decade.

The key conclusion from this analysis is not that 141 TWh is the right number, but that we need to better understand what drives it and the range of outcomes we could expect.



Allocation of economic curtailment across the fleet

Low strike price generators are curtailed first: market operation means that merchant projects and those with very low support payments (i.e. low strike prices) will be curtailed first whilst generators with higher support costs will continue to run. This would maximise the impact of support payments on bills.

The distribution of economic curtailment will depend heavily on market trading strategies and incentives. These include the value of support payments and the detailed rules of support mechanisms - such as how the CfD reference price is defined and how negative pricing rules are applied.

Generators will pay to avoid curtailment if it means losing support payments. In practice, they (or their offtakers) may be willing to bid down to the full value of their support payment - unless other rules, like the CfD negative pricing rule, limit that behaviour.

For CfD-backed generators, there is a strong incentive to sell power day-ahead rather than forward. This is because the CfD uplift is calculated against the day-ahead auction price. By selling day-ahead, a generator can hedge; it receives the auction price as market revenue, this becomes the CfD reference price, and the uplift payment perfectly bridges the gap to the strike price.

Negative pricing rules significantly change bidding incentives. AR4+ CfD contracts strongly disincentivise generators from bidding below zero. If the auction clears negative, they lose their uplift payment altogether even if they generate. This could result in many generators bidding exactly the same price: zero.

Tie-breaker rules are needed to allocate capacity between equal bids. By definition, these rules are arbitrary, yet they can have major implications for how curtailment is distributed across projects.

Intraday trading will reallocate any dispatch from the day-ahead stage. Unlike day-ahead, intraday trading is not constrained by negative pricing rules because the CfD reference price is now fixed. Intraday trading allows *all* generators to apply the "pay to generate" principle and those with the highest support payments should offer the most negative, win dispatch and avoid curtailment.

Final curtailment will fall on the least-supported generators because those with **higher support payments** can afford to bid most negatively.

Summary of theoretically correct market trading strategies

Merchant	Trades in forward, day-ahead, and intraday markets are based on the physical marginal price. Generators are likely to bid close to zero, with adjustments only for genuine physical considerations.
ROC	Trades in forward, day-ahead, and intraday markets are based on the physical marginal price minus the expected support payment. Generators are therefore likely to offer at negative prices.
CFD, Pre AR4	Avoids forward markets; trades in day-ahead power exchanges at the physical marginal cost minus expected support payments. Likely to offer at negative prices. May re-trade day-ahead volumes in intraday markets if others will pay above its support level.
CFD, AR4+	Avoids forward markets; trades in the day-ahead power exchanges at zero (not negative). In intraday markets, trades at the physical marginal cost minus expected support payments - likely offering negative if day-ahead cleared at zero.

The next page provides an illustrative example of the process …

Economic curtailment dispatch and revenue A simple example

The following simplified example shows how economic curtailment and the associated revenue impact is allocated: (1) physically the generators with the highest support payments, e.g. those with the highest strike prices, will be dispatched to generate, whilst those with the lowest level of support will be allocated curtailment; (2) The distribution of revenue depends on the arbitrary tie-breaker rules in the day-ahead auction; and (3) the final dispatch will tend to maximises support payments, which are recovered from customer bills.

Demand to be met = 20 MWh	DA* bid/offer price	DA dispatch	DA revenue	ID* bid/offer price	ID dispatch (Adjusts DH)	ID revenue	Final dispatch	CfD payments	Net Revenue
AR3 (SP* = £80 / MWh) 10MWh available	£-80/MWh	Gen=10 MWh Curt=0MWh	£0	£-80/MWh	0	0	Gen=10 MWh Curt=0MWh	£800	£800
AR4 (SP = £70 / MWh) 10 MWh available	£0/MWh	Gen=5 MWh Curt=5MWh	£0	£-70/MWh	Gen = +5 MWh	£-350	Gen=10 MWh Curt=0 MWh	£700	£350
AR5 (SP = £60 / MWh) 10 MWh available	£0/MWh	Gen=5 MWh Curt=5MWh	£0	£-60/MWh	Gen = -5 MWh (i.e. Sells back)	£+350	Gen=0 MWh Curt=10 MWh	£0	£350
Note strike prices are illustrative only and do not represent actual auction outcomes	Clearing price = £0/MWh			Clearing Price = £-70/MWh			Effective price to consumer = £75 / MWh		

Simplifying assumptions (for sake of illustration)

- Perfect foresight
- Perfect market conditions
- Fully rational behaviour
- No market power
- Supply-side pricing convention
- Physical short-run marginal costs are exactly zero

Day-ahead

- AR3 offers at a negative price (set by its support payment), assuming the 6-hour negative pricing rule is unlikely to apply.
- AR4 and AR5 bid at zero to avoid dispatch if the CfD reference price is negative.
- With demand of 10–20 MWh, the market clears at zero.
- A tie-breaker: assumed to be pro-rata, splitting 10 MWh between AR4 and AR5.

Intraday

- CfD reference price now fixed at zero, so all generators guaranteed full uplift on any volume generated.
- AR4 willing to trade at £-70/MWh (paying up to £70 / MWh to generate or selling back at £70 /MWh to reduce).
- AR5 willing to trade at £-60/MWh.
- Market clears at £-70/MWh (under supply-side clearing convention).

Result

- Final dispatch: AR3 and AR4 fully generate; all curtailment allocated to AR5 (lowest support payments).
- Through intraday trading and CfD uplifts, AR4 and AR5 each receive £350 net revenue - even though AR5 generates nothing.
- Support payments from consumer bills is maximised.

The illustration highlights several ways in which the current CfD model distorts market operation: generators bidding based on support mechanisms rather than short-run costs, the impact of negative pricing rules, and the linkage between day-ahead power exchanges and the CfD reference price. These distortions appear during periods of economic curtailment and will therefore become more significant as curtailment increases. This points to the potential value of mechanisms that decouple support payments from market outcomes, reducing reliance on wholesale trading distorted by support structures or by administrative rules.

** DA = Day Ahead; ID = Intraday; SP = Strike Price*

What is the impact of economic curtailment?

Direct costs fall on generators … Unlike network curtailment (the costs of which are recovered from consumers via BSUoS), economic curtailment directly reduces generator revenues by removing revenue derived from the wholesale market and from support payments which are paid on output (e.g., ROC, CfD).

… But costs will still be passed through to consumers: economic curtailment will influence renewable investment decisions and the strike prices generators bid in CfD auctions, meaning that consumers may end up funding higher support payments to generators.

Economic curtailment magnifies the effect of CfD on market distortions, ultimately undermining market functioning: CfD payments which are linked to a generator's output, combined with negative pricing rules in the CfD contract, distort bidding in the day-ahead market. The CfD reference price definition also discourages forward trading. The result is an increasingly dysfunctional wholesale market.

Economic curtailment is also an opportunity: it represents near zero short-run marginal-cost wholesale energy that could serve new demand at low cost.

Economic curtailment is a wholesale market phenomenon. Its direct impact falls on generators who invest on the assumption that they can sell their output whenever the wind blows or the sun shines. The effect on any one generator depends both on the overall national scale of curtailment and on how it is distributed across the fleet.

Unlike network curtailment, consumers do not face the direct costs. When generators fail to get dispatched in the market there is no compensation. No replacement of market or CfD revenues which are 'paid on output'.

But those costs can still be passed onto consumers indirectly. Because most renewable costs are fixed, in order to get a positive investment decision, generators need the ability to recover the same fixed revenue across fewer units. To remain investable, they will need to find other ways to recoup revenue.

These effects will be exacerbated because of the way that economic curtailment magnifies the distortions created by the current CfD design. CfDs incentivise generators to bid at zero in the day-ahead market regardless of their real short-run marginal cost. Negative pricing rules create a cliff-edge in the market at zero, making it difficult to predict outcomes. The result is a dysfunctional market that does not deliver useful signals.

An opportunity

Economic curtailment should be seen not just as a problem but as a resource. It creates a major opportunity to grow new sources of demand and flexibility. Markets, regulation and policy must evolve to facilitate that growth and to treat curtailment as something to be used productively.

Electrifying energy demand is critical to delivering an efficient transition across the whole energy system. As CP2030 accelerates investment in renewable generation, we must also accelerate the *use* of those renewables.

Economic curtailment can also be paired with very long-duration flexibility, particularly **hydrogen** production, storage, and hydrogen-to-power. This has the potential to store large quantities of energy – tens of terawatt hours – over months and seasons – and supply clean electricity when the wind isn't blowing and the sun isn't shining. The *Holistic Transformation* pathway used here assumes very limited electrolyser capacity. There is the potential for more.

As shown in the modelling above, **interconnectors** will also be critical in balancing the electricity system. It is important they are developed and that markets help them operate effectively.

Economic curtailment and negative pricing

Negative pricing is an additional risk for CfD generators, particularly from AR4 onwards: it happens when there is an oversupply of generators willing to pay to generate, not just generate for a very low price, and when it happens it affects revenue for all AR4+ generators regardless of whether they are able to generate or not. This is a further nuance of economic curtailment we need to better understand.

Economic curtailment and negative pricing are distinct but closely related effects

Negative pricing will happen whenever there is more generation capacity *willing to pay to generate* than there is demand and flexibility to use it. The box opposite explains when this will happen.

It is particularly important in the day-ahead auctions because of the wider importance of this part of the market, including its role in setting the CfD reference price and therefore interacting with negative pricing rules, and its use as an index for other trades.

It will be less common than economic curtailment, which occurs whenever *any* wind and solar generators are unable to sell their power even if their price to do so is zero or slightly positive.

But whilst economic curtailment only affects those generators who fail to sell in the market, negative pricing in the day-ahead market triggers negative pricing rules and means **all** generators with a CfD from AR4 onwards miss out on CfD uplift payments.

Economic curtailment	▪ A direct impact on generators that fail to sell in the market ▪ Occurs whenever there is an oversupply of renewables / inflexible generation
Negative pricing	▪ Direct impact on **any** generators with an AR4+ CfD ▪ Happens whenever there is an oversupply of renewables / inflexible generation *bidding negative and not just at zero*

What causes negative pricing in the day-ahead market?

Whether a period of oversupply also becomes a period of negative pricing depends on which type of generator clears the day-ahead auction:

- **Wind and solar with renewable obligations** will be willing to offer at a negative price because they receive a ROC for every MWh generated.
- **Pre AR4 CfD generators** will be willing to offer at a negative price most of the time because they will still receive a CfD uplift payment for every MWh generated.
- **Merchant renewables trading REGOs** which, even with a small value, could drive generators to offer at a slightly negative price.
- **Inflexible generation** which would otherwise be forced into a shut down / start up cycle, incurring significant costs and losing potential revenue for the duration of the cycle.
- **Interconnector traders** trading from countries with a negative price.

Further uncertainty is introduced by the potential for market power and gaming. For example, whilst traditional economic theory suggests that AR4+ CfD generators should not bid negative (see example, page 16), there may be benefit in one generator doing so where it believes it is unlikely that the auction will clear negative.

Previous work carried out with Regen shows that the sector still lacks a clear view of the expected scale of negative pricing. We need to explore the incentives acting on portfolio operators – those with a mix of generation types such as ROC, merchant, and pre- and post-AR4 CfD projects – as well as on operators with sufficient capacity to exert potential market power.

Impacts on generators, market and systems

We need to understand and design for economic curtailment … understanding its potential scale, the effect of different assumptions, and how it will be distributed across the fleet is critical. These insights must guide CfD, regulatory and market reform so they are effective at supporting the future electricity system.

So far, this paper has shown that the scale of economic curtailment could be large and the mechanism by which it and the associated revenue impacts are distributed across the renewable fleet are poorly understood. The corollary is that there could be an impact on consumers' bills, but the scale of the impact and the factors that affect it are unknown. We need to unpack each of the potential impacts. This page and the next highlights some of the most important impacts for further exploration.

Markets and system

Impact	Description
Amplifies market distortions associated with CfD design	CfD design already distorts market operation by potentially reducing liquidity in forward periods. Regular periods of economic curtailment will increase the number of hours that CfD rules distort market clearing. It also increases the need to use arbitrary tie-breaker rules and provides opportunities for portfolios to use market power to set prices.
Economic and network curtailment interact	Understanding economic curtailment and its likely geographic distribution is important in estimating network curtailment levels and constraint costs.

Generators

Impact	Description
Reduced volumes expected	If, at the point of CfD bidding, investors expect a reduction in the volume of energy they can sell, they are likely to increase their strike price bids. With a largely fixed cost base, both cost recovery and return on investment must come from fewer megawatt hours than if economic curtailment were not a factor.
Uncertainty over total expected volume	If, alongside an expectation of reduced volumes, there is significant uncertainty about the overall scale of curtailment, investors should add a risk premium to their bids, placing further upward pressure on strike prices.
Uncertainty over how revenue impact is allocated	The same effect arises if there is uncertainty over how the revenue impact of economic curtailment will be distributed across the renewable fleet. Such uncertainty could stem from reliance on tie-breaker rules in power exchanges, which make market dispatch hard to predict and which could also change in the future.
Expectation that impact could be greatest on merchant generators	If merchant generators bear the greatest impact of economic curtailment, this could create significant risk of earlier-than-expected decommissioning. If the volume of economic curtailment is high, these projects may struggle to cover ongoing running costs and gain the investment necessary for mid-life refurbishments.

TEL

Impacts on consumers

… to make sure the electricity system and market works for consumers: avoiding excess impacts on support payments, early closure of generation, and distorted dispatch. Market reform needs to directly engage with the challenge of economic curtailment to avoid higher bills.

Higher strike prices	The first three generator-side effects above are likely to drive higher strike prices, with the additional costs ultimately recovered through consumer bills.
Early closure	If wind and solar farms close earlier than expected, consumers lose out on low-cost renewables beyond the support period - and the transition to a fully clean power system could be delayed.
Lowest support generator curtailed first	As the lowest-supported generators are curtailed first, consumers pay the maximum possible level of constraint payments. This maximises short-run costs to consumers.

Consumers

Next steps and recommendations

We do not fully understand the potential scale of economic curtailment, how the market will allocate and respond to it, or what it could mean for generators, the wider system, and ultimately consumers. We need to engage with this challenge. This paper therefore concludes with a call to action, setting out key priorities for analysis, policy, and market design.

1. Understand the scale of economic curtailment
Commission analysis to test different assumptions and better understand the range of possible curtailment volumes the system may need to manage.

2. Design markets and systems to manage it
Make sure the RNP and strategic spatial planning processes address economic curtailment, so they not only solve today's challenges but remain robust for the future.

3. Review the implications for CfD design
Economic curtailment throws several of the downsides of the current CfD arrangements into sharp relief and magnifies their effect. It highlights the need to revisit CfD reform as part of the reformed national pricing process.

4. Treat economic curtailment as an opportunity
The most obvious way to reduce economic curtailment is to accelerate the electrification of the wider energy system, keeping pace with the acceleration in renewables generation being brought forward by CP2030.

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