Seven solutions to the rising cost of transmission network constraint management

Regen insight paper

August 2022

Summary and introduction

The costs of managing network constraints are rising and are predicted to rise further.

Some have put the blame on renewables being in the wrong place, with complaints of "too much wind" where it is not needed.

The reality is that constraints are the result of a policy to delay the costs associated with infrastructure investment, and instead to manage constraints as they arise.

The problem with this "connect and manage" approach is that the delays in investment have now become acute. Meanwhile, reliance on large-scale and inflexible gas-fired generation to provide balancing services has, since the gas price surge, led to a ballooning constraint management bill for the ESO.

Waiting for market reform

The projected rise in constraint management costs has been a major driver of recent calls to radically redesign the GB energy market towards nodal or locational marginal pricing (LMP) and a return to centralised dispatch. LMP, it is hoped, would shift the risk of constraint onto generators and demand customers, encouraging them to relocate to nearby areas or those with grid capacity.

While this is an option being considered in the BEIS-led **Review of Energy Market Arrangements**, our view is that an LMP solution is very unlikely to be adopted and would be a retrograde step for the GB energy market. As Regen has **argued elsewhere**, we think that LMP would be detrimental to the delivery of the UK's Net Zero plan and Energy Security Strategy by choking off investment in low carbon generation. If LMP did reduce constraint costs, it would be for the wrong reason: that investment in low carbon technology stalls.

A more direct and targeted approach

Any radical market reform is likely to take years to implement. Meanwhile, constraint costs are rising - to the tune of £1.2 billion in the past 12 months. However, there is no reason to wait for a market reform which may ultimately prove ineffective; there are several actions that could be taken today to start reducing and managing constraint costs within existing market arrangements.

We have picked seven targeted solutions and initiatives that could be implemented to significantly reduce constraint management costs. No doubt there are other potential solutions which could also be considered. The solutions we put forward are not new and many are already in progress, or have been trialled or identified in recent reports and studies - they just need to be fully implemented and accelerated. Importantly, the solutions we highlight would support investment in low carbon technology and flexibility services for a smarter and more flexible net zero energy system.

Why do we have constraints and where are they?

It's normal, and expected, that an energy system would be managed with some degree of constraint, both for demand customers and generation.

Building a network with capacity to avoid all constraint would be very expensive and suboptimal. The challenge is to run a system with the right level of constraint that can be efficiently managed, by using flexibility or customer curtailment.

In recent years, however, the pace of infrastructure investment in the networks has fallen behind the rate of actual deployment and the pipeline of planned projects, including generation, storage and new demand sources.

In the past 12 months, 78% of constraint costs are related to Scottish boundary constraints.

But we are also seeing constraint hot-spots across the network, for example severe constraints in West London.

Investment in GB network capacity has fallen behind the rate of deployment needed to drive green growth and achieve net zero. This is especially true in the case of Scotland, where most generation constraints currently occur.

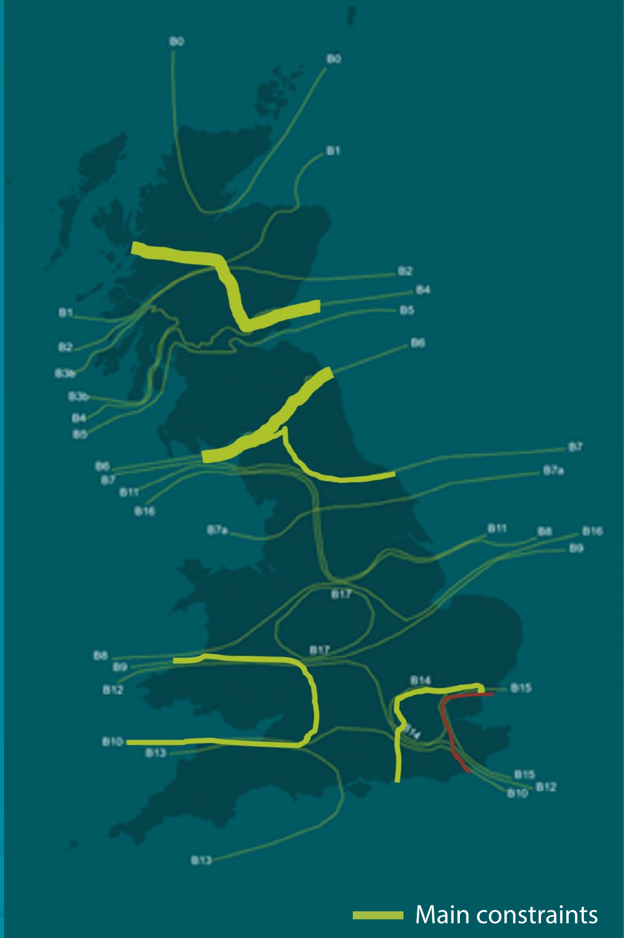
The main Scottish constraints relate to long-running delays in the approval and deployment of both west coast and east coast HVDC "bootstrap" links to England. These should now be deployed by 2028[1].

While Scotland is the dominant issue right now, there are constraints occurring – or predicted to occur – more generally across the network. The process of "connect and manage" is falling behind, in part due to the tardiness of Ofgem to approve new investment and the inherent challenge of building large-scale grid capacity.

As well as leading directly to constraint costs it is also, ironically, leading to delays and queues for the connection of solutions, like battery storage, that could ultimately help to alleviate constraints.

1 Ofgem approval of Eastern HVDC link

Transmission boundaries



Constraint costs are rising – why is that?

The volume of constraints in the year 2021/22 is lower than in the previous year 2020/21, but the costs of constraint management have risen significantly.

This is in part due to the rise in gas prices and the cost of replacing relatively low-cost renewable energy with very expensive, and relatively inflexible, gas-fired generation.

National Grid ESO has reported that in the past 12 months[1] total balancing costs have reached £2.4 billion, of which constraint management costs totalled £1.2 billion[2].

On a single day – 20 July 2022 – the ESO spent £55m importing energy from Belgium to manage a system constraint in the south-east of England.

Generation constraint management normally involves two actions within the Balancing Mechanism (BM) 1): **a turn down** of a generation asset e.g. an onshore wind farm, and 2) **the turn up** of a generation asset, which is currently almost always a gas CCGT plant, to meet the demand on the other side of the constraint boundary.

The turn-up action is significantly more expensive to invoke than the turn-down of a generator. Why is that? The average cost to turn down a wind farm generator is circa £50 per MWh[3], while the average cost to turn up a CCGT plant is circa £200 per MWh, plus a CCGT plant typically needs to run for longer at a minimum power output.

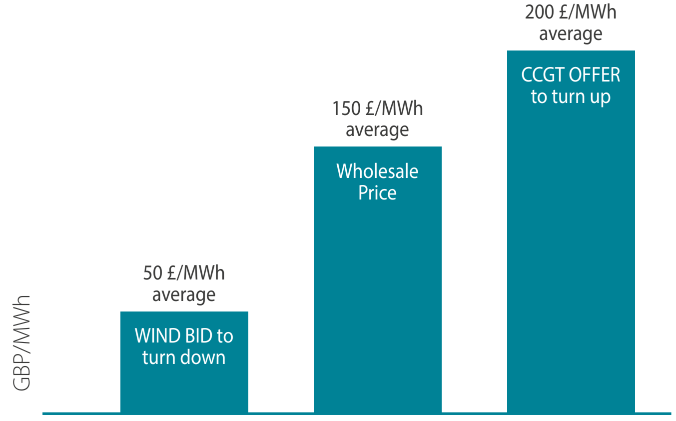
Analysis published by LCP showed that wind farm constraint cost £507m in 2021/22

- 85% of constraint costs related to generation turn up actions
- 82% of constraint costs related to Scottish boundary issues
- 94% of turn-up payments where made to large CCGT plants

Source: **LCP Curtailment cost report for Drax 2022**

Average accepted price per MWh to turn down a wind generator and turn up a CCGT gas plant

March 2021-April 2022



Source: ESO BM Dispatch Data & APX Day Ahead Wholesale price data

1 National Grid ESO BM data July 21-June 22
2 Plus, the economic value of the energy that is constrained

3 **Wind farms are not allowed to make "Excessive benefit" from being turned down (Ofgem letter)**. Hence average wind bids are circa £50 per MWh – approx. the lost ROC value plus a bit for lost REGO and operational cost.

If CCGT plants are so expensive, why are we using them?

It's a good question and it should be noted that the market is changing, albeit slowly.

CCGT plants have been the mainstay of the GB energy system since the "dash for gas" in the 1990's.

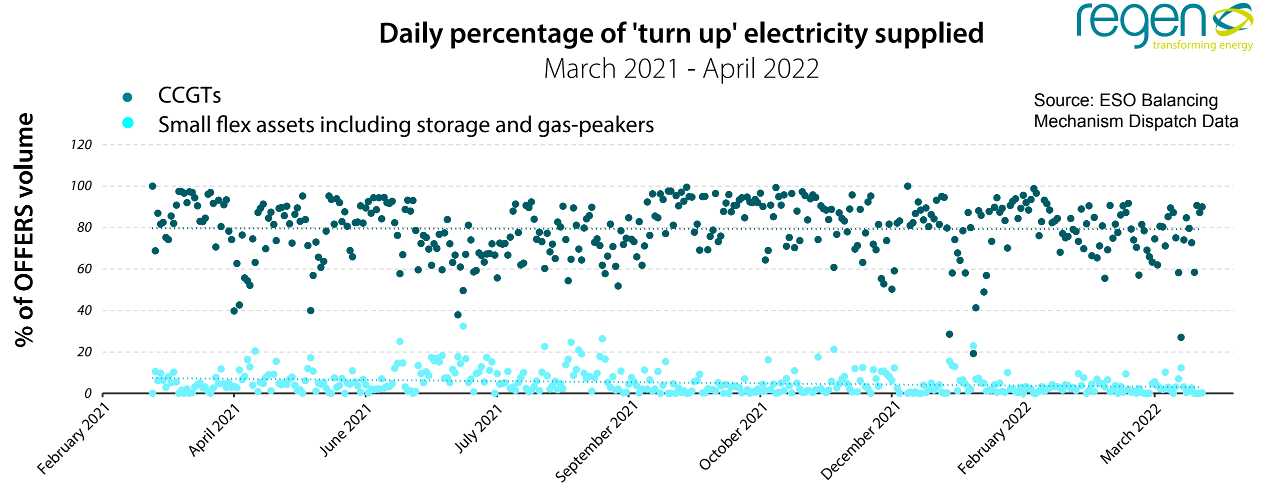
They are dispatchable and, at a price, can be reliably called upon to respond to system balancing requirements.

In a control room, under time and resource pressure and without much automation, they are easier to dispatch than trying to corral lots of smaller assets.

They are not significantly more expensive than a gas-peaker plant to run per MWh, and have a lower carbon intensity, but they do have longer lead times and longer minimum run times compared to other flexibility solutions.

National Grid ESO has recognised the need to open up the BM market to other participants, including energy storage plants, demand-side response providers and assets that may be connected to the distribution networks.

However, it remains the case that almost all (80-90%) turn-up actions and most turn-down balancing actions still involve a CCGT plant. This is partly operational – CCGT plants are relatively easy to dispatch within a limited time window to achieve a given outcome – but it also reflects current processes and technology within the control room. In fairness, the use of other flexibility assets is still relatively new and may be seen as higher risk for controllers whose priority is to keep the lights on.



In the past year typically 80-90% of "turn-up" actions involved the use of a CCGT plant. Storage and gas-peakers have begun to play a minor role (data for these technologies is not split out) as well as interconnectors.

Are CCGT operators taking advantage of the situation?

Almost certainly yes, judging by anecdotal evidence and the price spikes in the BM; but it difficult to pinpoint specific instances were CCGT operators have broken regulatory rules.

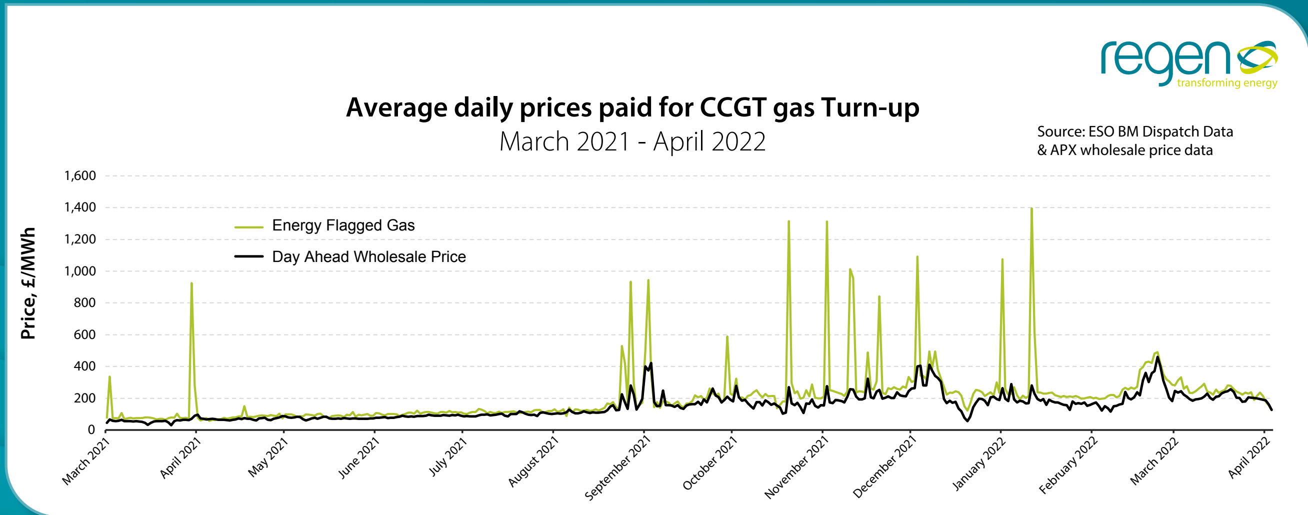
In November 2021, the ESO launched an investigation to look at irregularities in the behaviour of BM participants. That study, which led to a report in July 2022, identified a long list of recommendations, but concluded there was "no clear evidence" of definite rule-breaking.

Perhaps unconvinced, Ofgem has responded by announcing its intention to undertake "a range of near-term interventions to improve existing market arrangements".

Price volatility is not necessarily a bad thing; strong price signals are needed to affect market behaviour and to encourage investment - for example, in flexibility services. There is also a "missing revenue" argument that, faced with lower utilisation rates in the main energy markets, fossil generators will naturally seek to maximise profits when providing balancing services.

It is problematic, however, if participants can manipulate the market to force the ESO into a position where it must award very high "scarcity rents". Such tactics can include making late changes to Physical Notifications, bid gaming and setting unreasonable technical parameters for minimum run times (MNZT) and minimum downtime (MZT).

The ESO BM study identified several other cost driver factors including biased forecasting, plant inflexibility, lack of forward reserve buying and the skipping of lower cost plant which may have contributed to higher balancing costs. It is also very likely that the behaviour of market participants and the mechanism of the balancing market may be contributing to "bullwhip" effects.



What are "bullwhip" effects and why do they matter?

A "bullwhip" is created when a market event, imbalance or error causes market actors to overreact in the first instance and then to overcompensate. The amplified wave resembles a bullwhip.

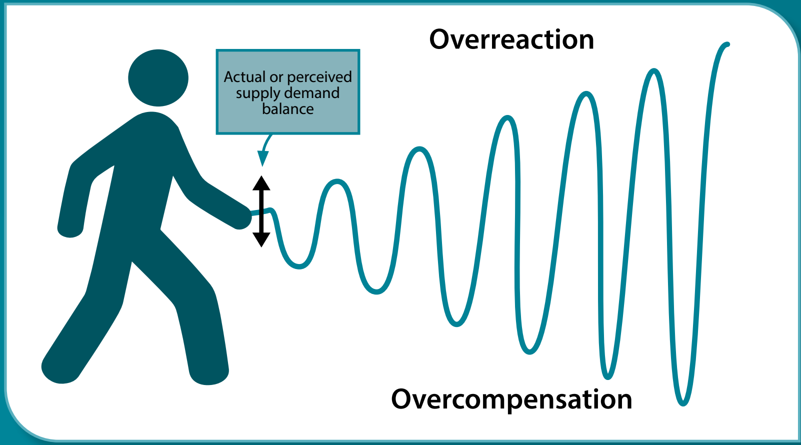
High volatility can sometimes be considered a good thing, if it is an appropriate response to a "real" market condition. A "bullwhip" however represents an exaggeration or overreaction with an economic and system cost that could be avoided.

Bullwhips are usually propagated by a combination of poor information and market sentiment: risk, fear or greed.

Bullwhips are then amplified by other market factors including inflexibility, long lead times, wrong incentives and in some cases deliberate gaming or speculation.

There are lots of examples of potential bullwhips in the electricity markets.

One current example is the **"fear of being short in a short market"** bullwhip, which is the result of a fear of extreme balancing costs causing market participants to put themselves into a long position, with the result that the market itself ends up being long (with over supply).



This leads to a paradox: during **low wind** periods with **high wholesale** prices there is **over supply** and a need to **turn down** generation in the BM.

In the case of constraint management, bullwhips can be caused by forecast errors, overcaution towards supply risk, plus the inherent inflexibility of CCGT plants, compounded by very short response windows. This causes control room functions to overreact to an expected constraint and overshoot the turn-up of gas generation.

Ultimately this results in a longer, deeper and more costly constraint management intervention than would otherwise be necessary.

Bullwhip = **Forecast error or event** + **Sentiment** (e.g. risk, fear, greed, incentive) X **Market factors** (e.g. inflexibility, lead times, gaming)

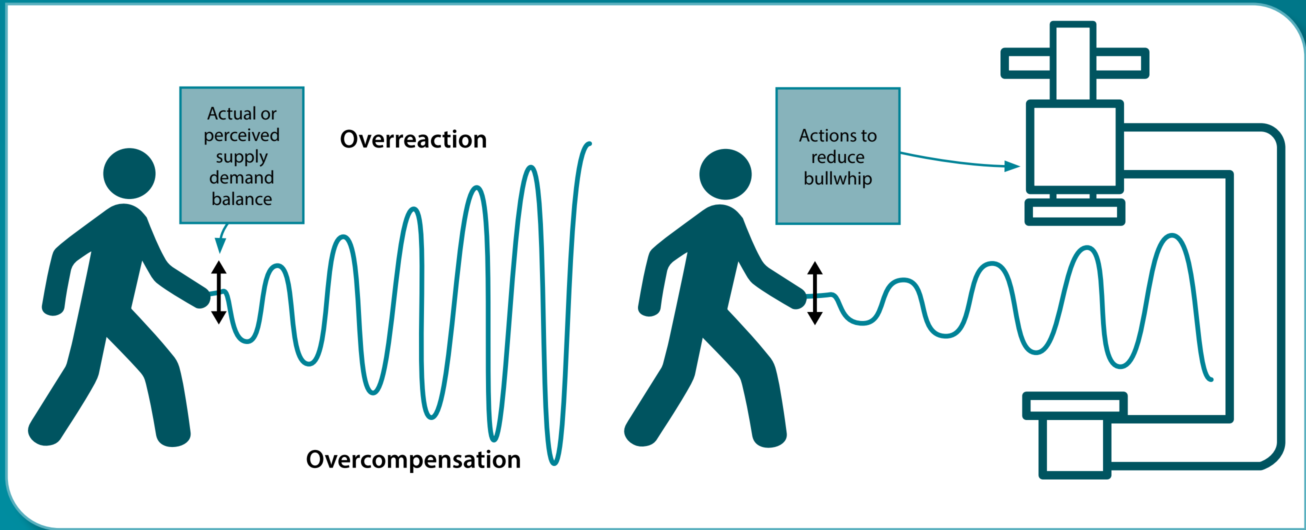
Propagation **Amplification**

Clamping down on "bullwhip" effects

The obvious solution to a bullwhip is to remove the trigger that causes the market imbalance – in other words, the constraint.

But, given that market events like constraints are inevitable, and that price volatility is not in itself a bad thing if it represents an appropriate market response, the best approach is to limit the bullwhip impact through:

- Better forecasting and planning
- Increased market transparency and openness, with clearer messaging
- Better risk management/allocation
- Reducing lead times, faster response and increasing levels of flexibility
- Preparedness – e.g. having response solutions and options in place
- Competition and reduction in gaming
- Analysis, learning and adoption of a continuous improvement ethos



Reduction of bullwhips effect caused by network constraints

Improvements to forecasting and modelling can help the market and ESO prepare for potential network constraint actions and make more accurate interventions.

The key step, however, is to provide the ESO control room with more competitive and responsive options that give controllers the capability and confidence to take more targeted actions, that avoid the overshooting associated with the use of an inflexible CCGT plant. Having flexibility contract options in place in advance, with very short response times, would allow controllers to delay and optimise the scale of constraint actions.

Instigating a process of learning from experience, backed by historical performance analysis, will optimise future constraint management interventions.

Reducing constraint management costs:
Seven potential near-term solutions

1 **Improve and accelerate the planning, decision making, timing and delivery of network investment**

2 **Send a stronger market signal - identify when and where constraints are likely to occur, their value and duration**

3 **Expand the use of forward contracts for flexibility services**

4 **Accelerate deployment of short and long duration storage – including addressing connection issues**

5 **Open the BM to many more participants, offering flexibility services and improve dispatch processes to ensure that they are used effectively**

6 **Continue to improve control room functions through better forecasting, digitalisation, automation and continuous improvement**

7 **Accelerate policies and regulatory reforms that are already in progress**

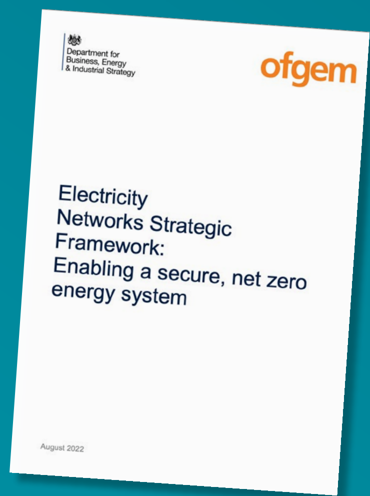
We have picked seven potential solutions or initiatives that could significantly reduce the cost of balancing and constraint management in the near term. There are others, no doubt.

The solutions we have chosen are not new, they have all been identified and many have work in progress.

Our main point is that they could be accelerated and extended to really get to grips with constraint costs.

It is very positive that several of these have been highlighted in the recent **Electricity Networks Strategic Framework**:

- Better network planning and investment
- Digitalisation and automation
- Smart and flexible solutions
- Procuring flexible solutions
- Improving forecasting and monitoring capabilities
- Enable competition
- Agile regulation



1 Improve and accelerate the planning, decision making, timing and delivery of network investment

What could be done…

Lots can be done with flexibility and smarter solutions to maximise network utilisation but, fundamentally, the availability of network capacity at both the transmission and distribution network level is now a critical enabler of both the net zero transition and the green growth agenda.

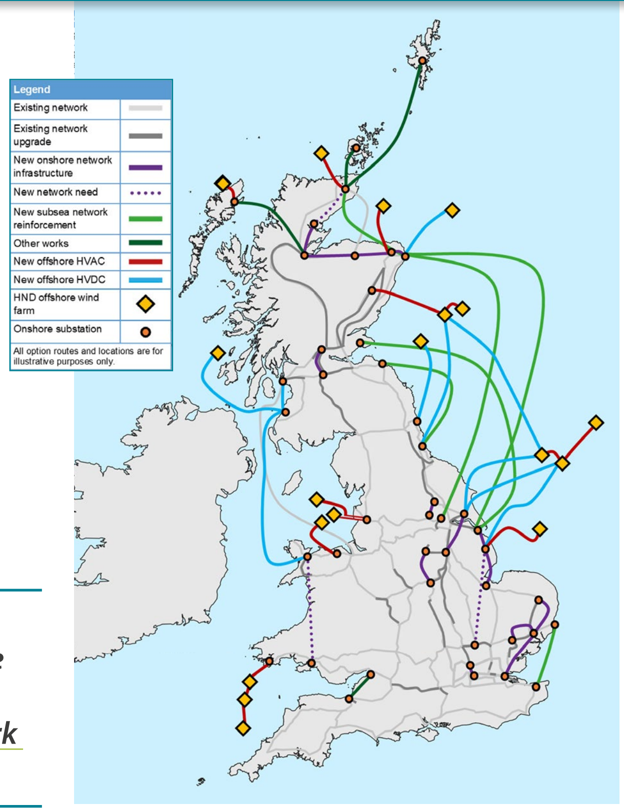
The delays to network investment, especially on the transmission network, are a key cause of current constraint levels and the very large queue of projects that are waiting to connect.

Potential improvements:

- Better and more holistic planning of network investments
- Updating the Network Options Assessment process to reflect net zero targets and the recent Holistic Network Design
- Speeding up the process for network investment approval, planning and delivery
- Reform of regulatory budget approval process to accelerate strategic and anticipatory investment
- Introducing more rigour and competition to ensure network investment is delivered on time and budget
- Better integrate onshore, offshore and interconnector investment

The **Pathway to 2030 Holistic Network Design** report has identified 94 onshore network reinforcements totaling £21.7 billion, to complement the £32 billion required to build offshore transmission networks in order to deliver 50 GW of offshore wind.

"Over the next two years network planning will evolve iteratively into a single Centralised Strategic Network Plan (CSNP)"



Work in progress…

The recent Holistic Network Design Pathway to 2030 is a good example of a more holistic, strategic approach to onshore and offshore network investment planning. It is important however that this type of strategic thinking is now integrated into business planning.

Ofgem has launch a consultation on the acceleration of **network investment** and to reform **network planning**.

2 Send a stronger market signal – identify when and where constraints are likely to occur, their value and duration

What could be done…

The market is beginning to work out the pattern of constraints and constraint actions but there is a lack of a clear signal regarding the location, duration and value of future constraints.

Distribution networks have greatly improved future constraint visibility by regularly upgrading system "heat maps" and publicising future flexibility requirements.

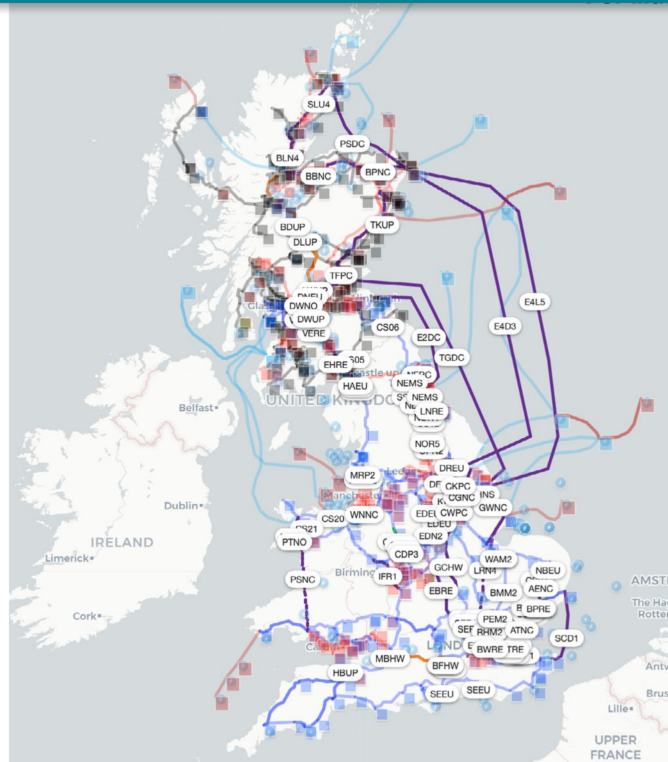
Rather than wait for a price signal to indicate that a constraint has already occurred, the ESO could begin to forecast and communicate when and where future flexibility services will be required.

This would enable storage and other flexibility providers to begin to plan and invest in assets that would alleviate constraints.

Although it is clear that many actions with the BM are already taken on a zonal basis, it could be that a more explicitly zonal BM market would send an even clearer price signal.

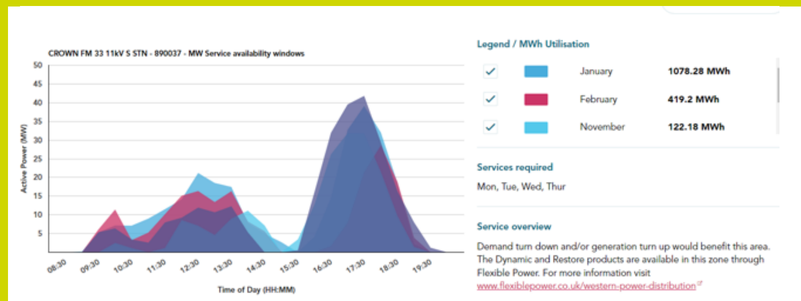
National Grid ESO is already publishing a map of planned transmission network reinforcement and current constraints.

This could be enhanced to include future constraints and to define future flexibility service requirements.



Work in progress…

Distribution networks are already publishing forward projections of flexibility requirements with details of when flexibility services are required – see for example **WPD Flexibility Map**



Expand the use of forward contracts for flexibility services

What could be done…

The use of forward contracts for flexibility services is already well established to manage distribution network constraints. The ESO has also begin to trial forward contracts for transmission network constraints and is expected to increase their use.

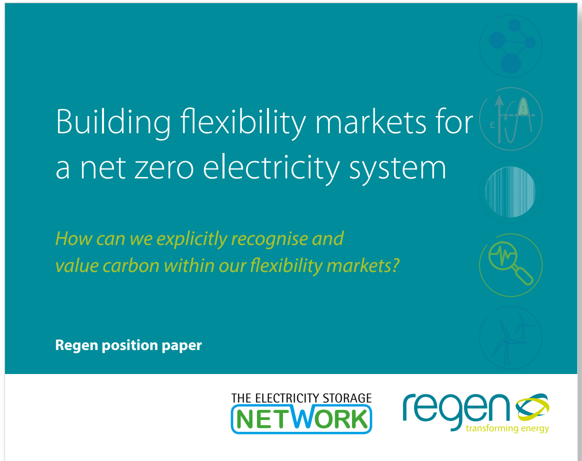
Forward contracts – usually based on an availability and utilisation service – can be for terms of months up to years, or for as long as a given constraint is expected to exist. These could take the form of flexibility tenders (as distribution networks are doing) or local constraint markets. Pre-gate closure contracting of flexibility assets could complement this.

The advantage of forward contracts, as a complementary approach to the BM includes:

- Potentially negotiating a lower constraint management price, especially in relation to power turn-up services
- Creating a competitive alternative to the use of gas fired generation in the BM
- Providing SO controllers with greater options and confidence, reducing the need to pre-emptively take constraint management actions that risk creating "bullwhip" effects
- Providing a price signal, revenue stream and business model that will enable investment in storage and other flexibility services

The use of forward contracts flexibility for transmission constraints is at **a pathfinder** stage but could be rapidly adopted.

The option to curtail or turn-up contracted assets within milliseconds reduces the need to pre-emptively constrain customers and the occurrence of overreaction bullwhip effects.


Building flexibility markets for a net zero electricity system

How can we explicitly recognise and value carbon within our flexibility markets?

Regen position paper

Regen: Building flexibility markets for a net zero system

Work in progress…

National Grid ESO is currently exploring a **winter demand flexibility service** for 2022/23 in response to the energy price crisis.

Incentivised by Totex incentive mechanisms, distribution networks are already holding regular auctions for flexibility services. Over the last 5 years these have become standardised and widespread with over **4 GW auctions in the past 12 months**.

In April 2020 National Grid ESO created a temporary "Optional downward Flexibility Management" trial which allowed the ESO to procure services. from assets that were not already active in the BM.

See also the ENA **Six steps for delivering flexibility services**.

4 Accelerate deployment of short and long duration storage – including addressing the connection issues

What could be done…

Deployment of storage has increased in GB over the last five years from 2.7 GW to over 4 GW. Much of this increase has been in short duration battery storage encouraged by the development of ancillary service markets like frequency response. By 2035 the electricity system will require at least 20 GW of electricity storage.

Despite this growth, and the clear need for more storage, deployment has been stalled. There is a huge pipeline of storage projects on both the transmission and distribution networks that could be contributing to GB's balancing and constraint management requirements.

Developers have cited costs and delays to obtain a network connection, and increasingly a problem with transmission-level constraints under the "statement of works" process. In part this stems from how storage is modelled to increase, and not alleviate, network congestion.

There is something wrong if assets that could reduce constraint costs are being prevented from connecting because of constraints.

- **New alternative connections and ANM style schemes**
- **Improve queue management and implement ENA guidance**
- **Review and reform "statement of works" process to accelerate storage projects in constraint areas**
- **Bring forward revenue support for long-duration storage**

One approach would be to change the way that storage is modelled in the connection process - recognising that it is far more likely to provide system benefits than constraints.

A further step would be to create new types of time-limited flexible connection agreements to allow storage projects to connect earlier, but ensure they contribute to reduced network costs, and potentially linking this to flexibility market participation to manage constraints.

Steps could also be taken to improve and rationalise the "statement of works" and "queue" management process, especially in those areas that are designated as constrained.

Work in progress…

Distribution networks are now looking at alternative network agreements, and ANM style schemes that will be offered to storage projects.

There is currently one storage project included in the ESO Constraint Management Pathfinder with a bespoke connection arrangement to provide flexibility services.

Queue management is subject to a delayed **Code modification** (CMP376) that could be brought forward.

BEIS has **agreed in principle** that long-duration storage will need a form of revenue support – this should be introduced quickly.

5 Open the Balancing Mechanism to many more participants offering flexibility services and improve the dispatch processes

regen transforming energy

What could be done…

More flexible and responsive assets could lead to greater competition in the BM and offer a more cost-effective constraint management response to reduce bullwhip effects.

Since 2020, National Grid ESO has widened access to the BM for smaller assets including battery storage. But, very few are actually being used, and so the BM is still dominated by CCGT plants for 80-90% of actions.

From the perspective of electricity storage providers, the BM market seems stacked against them. Part of the problem relates to dispatch processes which tend to favour easily dispatchable assets meaning that storage assets are "skipped" for operational reasons.

It has also been difficult to combine BM revenues ("revenue stacking") with other more attractive revenue sources such as Dynamic Containment.

This area is ripe for a task force to look at the reasons why flexibility assets are underutilised and to change the way the BM system is operated.

The ESO has successfully **trialled new processes** within the existing BM structure that would allow batteries to better compete with thermal plant. This could be extended.

Work in progress…

ESO is working to improve the utilisation of the least-cost solution through better forecasting, automation, and improvements in dispatch processes. Part of that work includes engaging with the storage sector through bodies like the **Electricity Storage Network**.

The ESO has published a **Roadmap for wider access to the BM** which sets out a series of initiatives and innovations that should increase BM competition.

See also solution 6) Improving control room functions.

6 Continue to improve control room functions through better forecasting, digitalisation, automation and continuous improvement

What could be done…

National Grid ESO is already embarking on several initiatives to improve the processes and performance of its control centre and dispatch functions.

Digitalisation and automation are key areas of investment in a control room which, until quite recently, was still reliant of telephone calls and faxes to communicate with generators and industrial customers.

The review of balancing costs identified short term forecasting as a key area for further improvement, as well as better BM performance monitoring. We would also add further data transparency including better, clearer system balance position forecast data which will help to reduce bullwhip effects.

The ESO has begun to publish detailed BM datasets and is committed to operational transparency. These datasets are extremely useful for the market to understand the actions that the ESO has taken and why.

Adoption of a culture of continuous improvement through analysis and performance review will help the ESO to better target cost reduction and innovation.

The **National Control Centre of the of the Future** will be far smarter, more digitalised and automated. This will better enable controllers to optimise the use of all balancing assets and target actions using the least cost solution. This is going in the right direction but needs to be accelerated.

Work in progress…

The publication of **BM data** including action codes has greatly helped the industry to understand how the control room functions.

A lot of work is now underway to improve control room processes, including the development of better forecasting tools and the creation of a **"digital twin"** environment enabling the ESO to model and review different system and balancing scenarios and analyse its historic performance. This could be developed into a continuous improvement tool with a range of key performance indicators.

7 Accelerate policies and regulatory reforms that are already in progress

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What could be done…

The ESO-commissioned study of BM costs[1] concluded that there was "no clear evidence" of regulatory rule breaking by BM participants during peak price periods last year.

However, Ofgem has issued a fairly clear open letter stating that it expects BM asset managers to adhere to the BM guidelines, especially around the setting of "technical parameters" such as minimum run times which should not be used to game the system. The letter also lists numerous potential regulatory interventions. BEIS has also signalled its interest in this area.

This follows previous letters reminding asset owners of their Transmission Constraint Licence Condition (TCLC) not to use curtailment to secure additional revenue benefits.

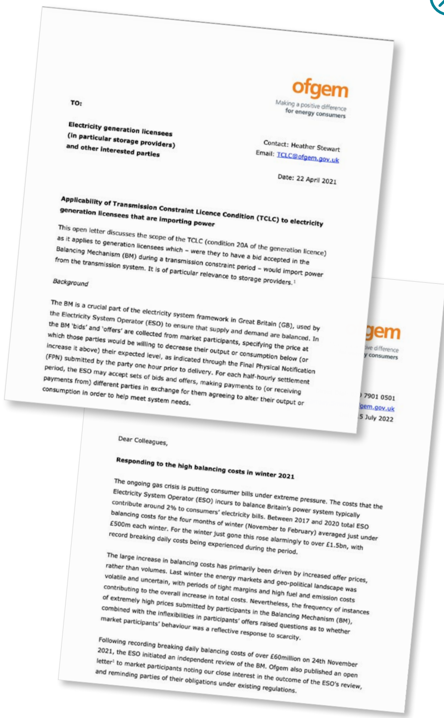
Tightening adherence to the guidelines will require closer monitoring of BM market behaviour, but could be an obvious and easy short-term measure. Changing BM market rules around bidding and price setting could also be effective.

In the medium term introducing more BM market competition would be a more impactful solution – which is why Regen believes that accelerating the deployment of energy storage is critical.

1 The study was completed by Cornwall Insight, LCP and Frontier Economics

Ofgem's letter to the industry identified possible interventions:

- Direct measures to restrict BM offer prices
- Limiting generators' ability to amend their schedules with little notice
- Restricting BM access or BM bidding flexibilities for generation capacity that is withdrawn with little notice
- Changing the rules for how parties structure their BM bids
- Introducing new license obligations that require generators to operate and behave in a manner that delivers in consumers' interests


ofgem
Making a positive difference for energy consumers

TO:

Electricity generation licensees (in particular storage providers) and other interested parties

Contact: Heather Stewart
Email: TCLC@ofgem.gov.uk

Date: 22 April 2021

Applicability of Transmission Constraint Licence Condition (TCLC) to electricity generation licensees that are importing power

This open letter discusses the scope of the TCLC (condition 20A of the generation licence) as it applies to generation licensees which – were they to have a bid accepted in the Balancing Mechanism (BM) during a transmission constraint period – would import power from the transmission system. It is of particular relevance to storage providers.[1]

Background

The BM is a crucial part of the electricity system framework in Great Britain (GB), used by the Electricity System Operator (ESO) to ensure that supply and demand are balanced. In the BM 'bids' and 'offers' are collected from market participants, specifying the price at which those parties would be willing to decrease their output or consumption below (or increase it above) their expected level, as indicated through the Final Physical Notification (FPN) submitted by the party one hour prior to delivery. For each half-hourly settlement period, the ESO may accept sets of bids and offers, making payments to (or receiving payments from) different parties in exchange for them agreeing to alter their output or consumption in order to help meet system needs.

Dear Colleagues,

Responding to the high balancing costs in winter 2021

The ongoing gas crisis is putting consumer bills under extreme pressure. The costs that the Electricity System Operator (ESO) incurs to balance Britain's power system typically contribute around 2% to consumers' electricity bills. Between 2017 and 2020 total ESO balancing costs for the four months of winter (November to February) averaged just under £500m each winter. For the winter just gone this rose alarmingly to over £1.5bn, with record breaking daily costs being experienced during the period.

The large increase in balancing costs has primarily been driven by increased offer prices, rather than volumes. Last winter the energy markets and geo-political landscape was volatile and uncertain, with periods of tight margins and high fuel and emission costs contributing to the overall increase in total costs. Nevertheless, the frequency of instances of extremely high prices submitted by participants in the Balancing Mechanism (BM), combined with the inflexibilities in participants' offers raised questions as to whether market participants' behaviour was a reflective response to scarcity.

Following recording breaking daily balancing costs of over £60million on 24th November 2021, the ESO initiated an independent review of the BM. Ofgem also published an open letter[1] to market participants noting our close interest in the outcome of the ESO's review, and reminding parties of their obligations under existing regulations.

Work in progress…

The ESO has also identified a **number of potential interventions**:

- A bidding code or license obligation determining how participants can bid into the market
- The implementation of price caps
- Further improvements in demand and/or wind forecasting
- Greater transparency of operational decision making and management of STOR

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