Public

Constraints Collaboration Project phase two update on 31 March 2025 – Webinar Q&A

Questions	Answers
Will the recording be shared afterwards?	Yes, slides and webinar recordings are available on our website : https://www.neso.energy/industry-information/balancing-services/constraints-collaboration-project
I understood that LCM is scheduled to end this December - has this changed?	LCM is currently contracted to end in Dec 2025, but part of the original tender always included the potential for two 1+ extensions (out to 2027). There is no decision on this yet as it is aligned to the broader strategic discussions about CCP/ DFS but we are conscious we need to provide clarity on its future as soon as possible. It is important that LCM is delivering MWs of actions ahead of real time, which can show a consumer cost saving as this will help inform the decision. We have made a number of changes to the format to improve access. (such as Asset metering only, ABSVD Opt Out, Sub 1MW etc) and so please do review and let us know if you want to participate.
Who is reforming the BM and how? This seems to be a very secret project, and we need more transparency.	There was a number of incremental reforms to the BM identified as part of our REMA case for change work, which reviewed the current dispatch arrangements. It's not a secret project at all, just more incremental, BAU type changes that we will make in advance of any bigger market reforms, which should help create a more level playing field and a better system in conjunction with the OBP work.
Will the constraint management work feed into learnings for the transmission acceleration project?	We will make sure that we share any relevant findings with this project. We cannot answer the specific question about TO visibility of forecasts constraints planning but we will pass it on to the team.

I. E. Will TOs have visibility of forecast constraints in planning timescales so an effective cost comparison decision can be made	
What is your team's view on the 2030+ wholesale market reform solution(s) and how does this strategy change based on the REMA final decision due in the summer?	Our NESO position has been communicated through our REMA team and our findings in CCP support a recommendation for more fundamental market reform. We have worked to ensure that value will be delivered in advance of these potential market reforms but will ensure that CCP projects can transition into any long-term market reforms.
Could you please provide the contact details for project leads who are needing input, including for example Frazer Nash	Frazer Nash Consultancy (FNC) will be looking to engage technology stakeholders that may be able to provide this type of service. If you are interested and would like to connect with FNC, please contact us directly so we can liase with FNC accordingly Contact us at box.market.dev@uk.nationalenergyso.com
Boundary Flow Smoothing project - Really good to see this is being explored. Will NESO consider whether the Transmission Constraint Licence Condition may	If the concept is proven feasible, in future stages these kinds of factors will be taken into consideration.

impact an asset's ability to participate?	
Could you please provide the list of information you need from industry? (WRT to the boundary smoothing project)	This has not been determined as yet - but may include parameters such as tech type, location, power, duration, response time, ramp-rate. Once the work on this has started, we will write down a list of questions and share them.
Do we have such market for the FSP to provide this service after the project completed? If it is how can we track such market mechanism? Since it will be good market for the technology such as BESS to participate such market. (WRT to the boundary smoothing project)	We need to assess first if there are savings to be made through this approach, before we can consider how we'd implement it. We obviously would like this to be a cost-effective solution and a competitive approach would be the best way to do that. However, we will have to think carefully about how we can best do that with such a locational need.
Boundary Flow Smoothing project - How will the Market Facilitator engage in this?	For now, they don't' need to be involved in the innovation project, If there is some value, then we will assess if/how Market Facilitator involvement is needed.
Will the boundary flow smoothing project consider wider benefits of making more granular boundary level	This is not in the scope of this innovation project at this stage. We currently publish 3 constraints forecasts. The longest term is the Electricity Ten Year Statement (ETYS), which

constraint data available to the market?	forecasts the constraints at various boundaries within the GB grid for 10 years with a one-year granularity. In the medium term we publish the constraint limits for the main boundaries on the transmission system on weekly bases for 24 months ahead. The shortest-term forecast is the Day Ahead Constraint Flows and Limits, which has a granularity of 30 minutes. The Centralised Strategic Network Plan (CSNP) will also improve long term forecasting by publishing thermal requirements by region.
DfC and Arup - Is it worthwhile having a separate session on this? As Alifa said there is a lot of information to digest; would be good to give industry opportunity to review and reflect.	We have published the full Cost Benefit Analysis (CBA) so please have a read of the report and then revert back with questions. In the meantime, we have a lot of work to do with addressing some of the risks, so we will look into hosting another update webinar soon, once we've had the chance to work through our next steps. In the meantime, we would be happy to address any questions you might have through box.market.dev@uk.nationalenergyso.com
Question for modelling : did the CBA also consider impact of seasonal boundary capabilities and whether it is more cost effective to deploy dynamic line ratings (DLR) or a combination of demand reduction with DLRs?	Arup assumed a flat boundary capability across each year and therefore this was not explored as part of the study.
Do you have the breakdown for the	The Arup CBA report includes the assumptions per case on which technologies are likely to be able to connect onto the

technologies in CBA such as percentage of BESS, pumped hydro been considered in the study?	system in each of those boundaries taking into account the assumptions already within FES. These vary per case.
Could you share a bit more about the avoidance of RO and other levies	In terms of avoidance of renewable support, when subsidy supported renewables are turned down during constrained periods, they do not receive subsidy-support payments. For further details, Arup has established the proportion of renewable assets currently supported by a CfD and assumed that 100% of future wind assets, and 50% of solar assets are CfD backed. The consumer costs associated with renewable support schemes is calculated as CfD supported RES generation multiplied by the delta between annual wholesale price and LCOE (as proxy for CfD strike price) based on DESNZ renewable electricity generation costs
Chat function not working for Mark Williams (EDF): Has identified candidate electric arc furnaces in Scotland/East Anglia given early investments look to be in South Wales/Teesside	Arup reviewed planned projects in each location and reflected these in the development of demand assumptions, these are detailed within the report.
What about the UK subsidy control regime? I think the issue may be not all customers can apply	Thanks for the information here, we will consider this carefully as we review our contract structure and eligibility requirements.

for this scheme/market. So it could be viewed as unduly discriminatory or a hidden subsidy.	
Industrial demand (depending on scope) is also classed as Energy Intensive Industries (EIIs)	Yes, that is correct but we've heard from our stakeholders that some industrial demand such as malting is not classed as EIIs.
On demand for constraints - the modelled savings you present are based on average contracted demand being in the range of TWh - what underpins this assumption given that current CMM addressing B4/B6 (LCM) has contracted <1GWh in the last year?	The limitation on LCMs contracted volumes has been due to limited volumes offered in the service at a competitive price to the BM counterfactual. Due to the contract term, the majority of the in merit volume has been from existing assets providing aggregated flexibility. We are continuing to explore how this can be scaled as a cost-effective option for both NESO and the service providers. Demand for constraints would provide a different opportunity, with longer-term contracts providing the certainty required for the deployment of new and larger scale asset types. For further info, please see section 2 of the report – it outlines in detail the assumptions behind the contracted volumes assumed.
Is it still the case that you are modelling additional demand - not shifted demand? Otherwise why is shifting demand north increasing wholesale power prices?	We have modelled additional demand over and above the demand in the Holistic Transition pathway. In the cases where wholesale prices increase, this is due to the additional baseload demand that is added behind the boundary

Can you explain how data centres and electric arc furnaces can deliver flexible demand rather than require baseload power? Is the assumption you are making that there will be gas fired on-site generation for the balance of supply?	For data centres, they can provide flexibility (for example through the use of back-up generators, cryptocurrency mining, mainframe batch processing) and can operate at off-peak times to support grid operation. Electric arc furnaces (EAF) can potentially offer some flexible demand due to cyclical nature of steel production (high demand during melting and refining, lower during tapping stage).
The conclusions around the small savings seem very counter intuitive - and if it were the case, would seem to be hard to justify any physical infrastructure investments such as HVDC links and their high costs. Is it the case that the modelling assumes all these expensive grid build outs happen, and the benefits accrued to this are on what is left?	Additional network investment is assumed to happen over the timeframe which we modelled out to 2035 – whilst there could be avoided network investment through flexibility, we believe that in the short term the need is so great, that we will need all of the network investment required out to 2035. However, in the longer term there could be a benefit in terms of avoided network investment.

What is your view of the expected lifetime of the LCM, given that the settlement fix was only established in October? We are being asked for assurance from customers who are considering joining the LCM but can't do so on the basis of the short time that is left.	Contract end date is Dec 2025 and we are currently reviewing the case for its extension. To make this decision, we'd like to see more volume in it to show value against alternative actions (or at least share with us your interest in participation, if the scheme continues).
Re DfC, could you explain your 50-50 flex and baseload demand assumption please? Does it mean that 50% of contracted demand is baseload (and has no flex) and 50% flex, or does it mean that providers would need to be able to flex at least 50% of their demand to be eligible?	Arup has then modelled four cases including demand contracted through the Demand for Constraints service. The four cases provide possible scenarios for whether the demand is included as flexible or whether some is included as baseload demand (100% flexible vs 50% baseload: 50% flexible). For example in Case 1 our assumptions are: - 3.5 TWh of average annual demand contracted across all boundaries. - 50% flexible and 50% baseload This means we assumed 1.75 TWh of demand contracted would be flexible, and the remaining 1.75 TWh would not be able to flex (or baseload).

Q: Are you aware that the BM at present does not reward negative energy fairly if aggregators or customers themselves participate? The problem is analogous to the issue that was fixed recently in the LCM. The solution may emerge through P444 (tomorrow?) or IG114 (unknown timescale)	We acknowledge there are working groups in play to support industry in making improvements, for example the Elexon Issue group (IG) 114 which is looking at seven issues, all of which are related to the settlement of ABSVD for ancillary services delivered through independent aggregators. It is currently in the assessment phase. Issue 1 (Supplier Compensation for ABSVD) and Issue 5 (Imbalance adjustments for flexibility provided to Distribution System Operators) have been prioritised by IG members. These will be discussed in the main group whilst operational issues will be discussed separately in SME sub-groups. Issue 6 (Imbalance adjustments for sites with multiple Import and/or Export MSIDs) and 7 (Increased number of MSIDs wanting to use P354 ABSVD route due to data availability issue.) were raised by NESO. We presented at the IG on what we believe our role within the group is and have provided sight of aims, barriers and reiterated our support of the IG's work and Ofgem's calls for a holistic, enduring solution to be agreed by Suppliers and Aggregators, for enduring use across market.
How are you driving ENCC/NESO to utilise the LCM vs BM?	It is a live business as usual (BAU) service and dispatches are done on merit. All recent bids that have shown value vs the BM at Day Ahead have been dispatched. We would be happy to talk this through in more detail if needed, please email us at box.market.dev@uk.nationalenergyso.com
Can you remind us of the likely contractual arrangements for DfC, ie length of contract, would NESO be booking certain	Demand for Constraints is a long-term contract whereby NESO can ask a demand source to increase its consumption at times of constrained network. The intention of Demand for Constraints is to provide the price and locational signals currently lacking for investment and dispatch. To guarantee revenue certainty for service

number of hours over given time period at outset of contract or is contract essentially akin to framework contract where demand is called on month/day/hour ahead with no commitment to set or minimum number of hours utilisation?	providers, we would specify and get an agreed amount of annual half hour periods (e.g. 3000 hours in 2030) they will be called on in any one year. On that basis, we would need to assess how much notice would flex demand providers require. If you have any insights, we would love to hear from you.
Q: Boundary smoothing - one aspect of this might be buying a cap from wind farms. For example, a 100MW wind farm currently generating 80MW could agree not to go above 80MW. They would be agreeing to forego potential generation (if the wind comes) instead of actual (the wind is already here). This would surely be cheaper per MWh.	Thanks for your suggestion. Wind is one of the potential technologies that could contribute to volatility reduction as part of Boundary Flow Smoothing concept. However, setting a cap on wind farms is outside the scope of this innovation project.
Q: Boundary smoothing - how dynamic do you envisage this purchase being? The	Delivery of service - At the moment we think that the response will need to be very fast, in the order to prevent boundary limits being breached.

more dynamic it is, the more can be provided from a wide range of resources. I'm thinking of within-gate or immediate pre-gate timescales.	Procurement – Should the innovation project demonstrate the concept has operational potential and consumer value, this would be assessed in a future stage.
Can you explain why you would contract with baseload demand rather than restrict DfC to flexible demand turn up?	When designing the CBA, we listened to industry suggestions and included both baseload and flexible demand as part of the CBA to see how it would affect constraints. We found that inclusion of baseload demand drives wholesale electricity prices higher whilst also helping with constraints volumes. Additionally, as the demand is likely to come forward anyway, it was determined that we did not need to provide an additional incentive for baseload via DFC. Ultimately, our main objective from Demand for Constraints is to incentivise flexible demand to locate in areas that reduce constraint costs and volumes.
Thanks Gus. Have you considered an alternative pathway in REMA aside from NESO's position? The CCP work will play a key role in a Reformed National Market therefore it currently feels restrictive to only look short/medium-term.	This project has been providing insight into the REMA programme on how constraint volumes and costs can be reduced through different market-based options and other actions. Whilst this project has been focussed on the short term, the REMA team will consider these outputs and how they could apply to the different market designs they are considering.
On DfC - when are you going to be at the point of sharing some numbers around the	Our work to-date, including the CBA, has been highly informed by industry feedback, which has given us insights into their challenges, business models and needs. We will continue to use industry as a sounding board for the

proposed models? Industry can quickly feedback whether they will provide any stimulus for project investment or not. It feels like there are so many moving parts that the process would benefit from some real world projects sense checking and also highlighting any gaming risks.	market design as it develops. If anyone would like to provide more detailed feedback on the proposal and insight into more real-world projects, please do get in touch.