AN FTI CONSULTING REPORT – SEPTEMBER 2024

Assessment of Likely Impacts of Proposed Reforms to the Balancing Mechanism Within a National-Price Regime

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1. Introduction

1.1 There is widespread agreement that the GB electricity market needs a fundamental redesign to enable it to achieve decarbonisation, energy security and price competitiveness. Indeed, eighty percent of respondents agreed with DESNZ's assessment in the first Review of Electricity Market Arrangements ("REMA") consultation that "current market arrangements are not fit for purpose".[1]

1.2 A key issue is the cost of transmission constraints, which has risen eight-fold since 2010, from under £170m to over £1.3bn in 2022,[2] and is recovered from consumers through an additional charge.

1.3 One solution to this is to introduce locational pricing in the wholesale market which would reflect losses and network congestion in wholesale prices, giving a price which more accurately reflects the value of electricity in a particular location.

1.4 Other commentators have instead proposed reforms either to the Balancing Mechanism ("BM") where transmission constraints are currently resolved, or to the system operator's ("SO's") role in balancing the market near real-time delivery.[3] They argue that such reforms would eliminate the need for fundamental change to the national wholesale market.

1.5 In this note we evaluate the merits of the alternatives that have been proposed. The note is structured as follows:

1. We provide a taxonomy of the current BM reform proposals.
2. We critically assess the three broad buckets of proposals.
3. We zoom out and consider the longer-term impacts of the financial transfers embedded in the current market design.

1.6 Overall, we find that none of the stakeholder proposals are likely to be effective in addressing the underlying problems of the current market design. They are likely to have only minimal impact and lead to unintended consequences – including introducing inefficiencies in market trading, gaming opportunities, the imposition of arbitrary costs, and discrimination between classes of market participants. Furthermore, some proposals might actually worsen, rather than alleviate, the constraint problem.

1.7 In short, the proposals for incremental reform suggested to date do not materially address the generally acknowledged failings of the current market design in a way that these would be addressed by locational pricing.

BM reform proposals can be categorised into three buckets

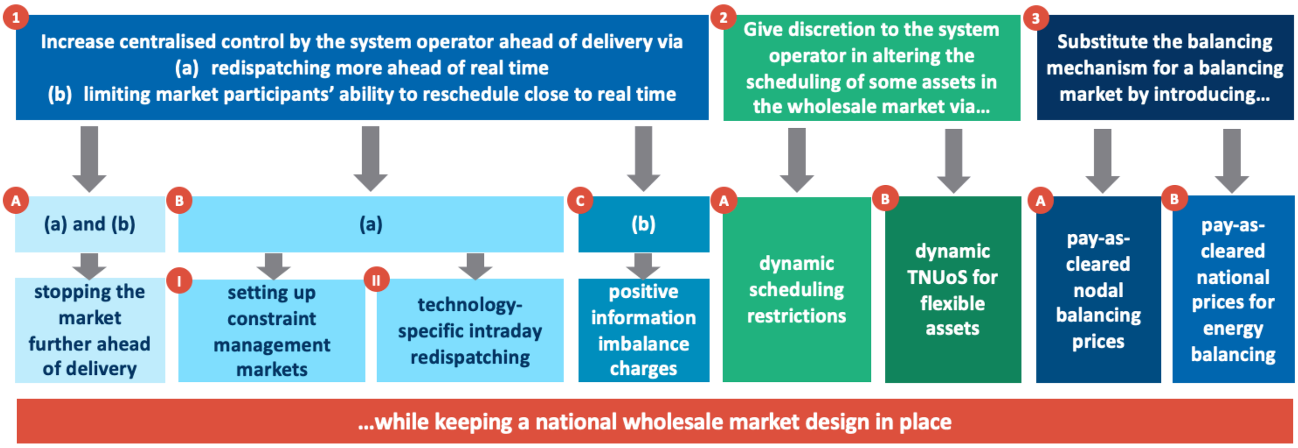
1.8 Based on our review of recent position papers by other consultancies and think tanks commissioned by market participants, we have created a taxonomy of BM reform proposals as shown in Figure 1.1. We group them into three broad buckets (which are not necessarily mutually exclusive).

1.9 **Bucket 1: Increasing centralised control by the SO ahead of delivery** with the aim of reducing the costs of managing transmission constraints. For instance, the time window between the end of wholesale market trading and actual dispatch of electricity could be increased, for example, to six hours. More control by the SO could help reduce constraint costs, as the SO would have better information at an earlier stage about the likely constraints on the system and could take more proactive action to resolve constraints.

1.10 **Bucket 2: Giving the SO discretion in restricting or altering the scheduling of certain classes of assets in the wholesale market** with the aim of reducing the volume of transmission constraints. For instance, the SO could be given more powers to prevent interconnectors to other countries from operating when doing so would increase transmission constraints.

1.11 **Bucket 3: Changing the way constraint management is organised** with the aim of increasing competition between different types of assets and so reducing the cost of managing transmission constraints. For instance, if the SO decides to pay a wind farm not to generate, the price it receives could be based on the clearing price in a market for constraints (so-called "pay-as-cleared") rather than, as at present, what it bids ("pay-as-bid"). This could in principle make it easier for different types of assets to participate in the balancing market, thereby increasing competition and reducing constraint costs.

Figure 1.1: Taxonomy of BM Reform Proposals



Source: FTI Consulting analysis of selected commentators

1.12 A key problem with **Bucket 1** style approaches is that, by design, all participants retain the current rights of access to the network. This means that the volume of transmission constraints will not be reduced by any of the proposals. While the proposals may improve, probably only slightly, the price at which the ESO resolves the constraints, we find that they bring a very significant risk of unintended consequences. For example, depending on which option is considered, these might include:

- introducing greater inefficiency in market participant trading;
- increasing the likelihood of participant gaming; and
- in some cases, actually introducing the risk that distorting participant behaviour leads to increases in the volume of congestion to be resolved and therefore worsening, not alleviating, the constraint problem.

1.13 **Bucket 2** style approaches do have the advantage that they would potentially reduce the volume of transmission constraints. However, they do this by reducing rights of access to the network for some asset classes. These "second class assets" might be interconnectors, batteries or, conceivably, more recently connected assets (such as, say, newly connecting wind farms in some locations). The obvious problem with these proposed solutions is that the "two-tier market" is inevitably somewhat arbitrary and will introduce inefficiencies into the system. Furthermore, the proposals disadvantage some classes of users financially and, because of this discriminatory treatment, may lead to legal and political challenges.

1.14 **Bucket 3** style approaches propose significant changes to the operation of the BM. We find that all of these proposals introduce the risk of material unintended consequences by distorting participants' incentives in the preceding wholesale market. In particular, there is a risk of increasing the volume of congestion (by providing stronger incentives for some cohorts of participants to withdraw from the wholesale market and operate in the BM instead) or, in another option, by sending somewhat arbitrary price signals in the BM to some users – which will impact, probably unhelpfully, on the behaviours of wholesale market participants.

1.15 A final point to note is that, with the possible exception of some of the more extreme variants of the second genre of proposed reforms (i.e. those in Bucket 2), none of the proposals address materially the significant financial transfers from consumers to generators that occur under the current market design. Therefore, aside from being an ongoing (and substantial) burden on consumer bills, over the long run, this means that market participants are receiving inappropriate locational signals which impact adversely, from a system perspective, on siting decisions. This further increases costs to consumers – either through even higher constraint costs or a greater need for transmission assets. Suggestions that there are potential reforms possible to the current transmission network use of service ("TNUoS") transmission charging methodology to correct for this are, in our view, highly optimistic.

2. Each of the Reform Proposals Could Have Serious Unintended Consequences

2.1 In this section, we assess the expected impacts of the different types of reform proposal. We also cover likely negative unintended consequences which their proponents have thus far tended to ignore or downplay.

Bucket 1: more centralised SO control to manage constraints further ahead of delivery is likely to come at the expense of less efficient wholesale markets

2.2 The first bucket of proposals includes three ways to grant more control to the SO further ahead of delivery.

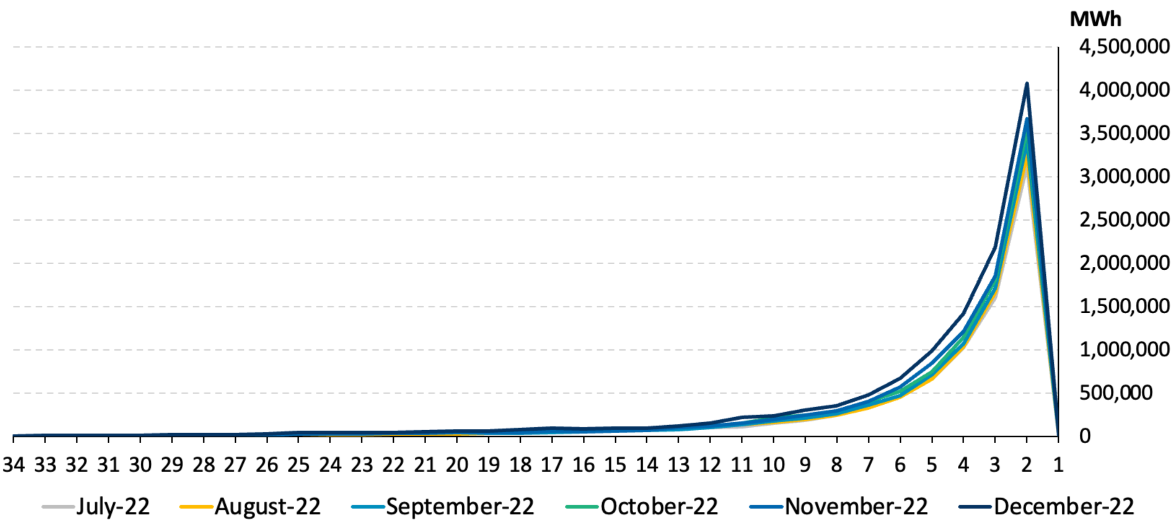
Proposal 1.A: Stop the wholesale market further ahead of delivery

2.3 Moving gate closure from its current one hour ahead of real time to earlier (say six, eight or even 24 hours ahead) could in principle enable the SO to improve the efficiency of final dispatch by having a longer optimisation horizon (e.g., batteries) and by having access to resources that otherwise would not be available (e.g., thermal generators that require a longer start-up time). Moreover, since market participants would not be able to reschedule their assets, the SO could have greater visibility of the status of participants' intended generation and consumption, potentially enabling it to select more efficient balancing actions.

2.4 However, these potential benefits come with an important trade-off. Market participants would no longer be able to reschedule their assets close to real time in the intraday market as more accurate information becomes available. This is especially important for intermittent renewable generators, for whom production forecasts improve significantly in the hours before delivery. Figure 2.1 shows the volume of matched intraday trade in the EU within the hours before delivery. It shows that most trade happens within three hours of delivery, suggesting a strong preference among market participants to trade close to real time.

- introducing greater inefficiency in market participant trading;
- increasing the likelihood of participant gaming; and
- in some cases, actually introducing the risk that distorting participant behaviour leads to increases in the volume of congestion to be resolved and therefore worsening, not alleviating, the constraint problem.

Figure 2.1: Total Volume Matched in the EU Single Intra-Day Coupling (SIDC) Within Hours Before Delivery



Source: Market Coupling Steering Committee, 2023

2.5 One of the key ideas of liberalised electricity markets is to make market participants responsible for accurate forecasting of their own production volumes and consumption - on the grounds that they are better placed to know their own portfolios and have better incentives to reduce forecast errors. This should lead to lower overall system imbalances and improved system security. In the short run, this means that the SO needs to intervene less to resolve imbalances. In the longer run, it means that lower volumes of reserves are required. This results in consumer savings as most of the costs of reserve procurement are typically socialised across consumers. Conversely, moving gate closure earlier in GB could be expected to have the opposite effect – increasing reserve procurement due to greater system imbalances.[4]

2.6 In short, **when trying to address one problem (high transmission constraint costs) by moving gate closure further ahead of real time, another problem is created – increased expense and difficulty of managing energy imbalances.**

2.7 The trade-off in increasing energy imbalance volumes versus more cost-efficient management of transmission constraints only surfaces under the existing national wholesale market design. Locational pricing would significantly reduce the volume of balancing actions to resolve constraints. As a result, there would be little need to move gate closure forward. Transitioning to a locational market design is likely to reduce further the costs of resources to manage energy imbalances, through better system visibility and reduced risk that procured reserves are not deliverable.[5]

Proposal 1.B: Organise constraint markets running in parallel with the wholesale market

2.8 A related proposal is to reserve units for redispatching and/or start redispatching actions earlier than the current gate closure time, i.e. in parallel with intraday wholesale markets. This can be done via technology-agnostic constraint management markets (“CMMs”) (Proposal 1.B.I) or technology-specific redispatching ahead of gate closure (Proposal 1.B.II).

2.9 There are two overarching concerns with these proposals:

- First, there is a significant risk that market participants might adjust their positions in intraday markets in a way that is unhelpful for the system (e.g., recreating the constraints that were intended to be resolved by earlier redispatched units). To avoid this, the possibility of deviation from day-ahead positions needs to be limited, reducing intraday market activity.
- Second, the activation costs of “regular” BM actions are not yet known when the SO would need to make decisions in the intraday timeframe about which units to redispatch. Incomplete information would often lead to sub-optimal final dispatch, raising consumer costs.

2.10 In addition, with regard to CMMs, there are likely to be significant gaming risks. The same market participants that are awarded availability contracts in the CMM are those that can create the need for a CMM in the first place. Ehrhart et al. study the incentives of market participants in reservation markets for constraint management purposes.[6] They find that the availability payment incentivises participants to change their energy consumption or generation behaviour in unhelpful ways, which eventually increases the volume of constraints. [7] They conclude that such mechanisms “[do] not resolve network constraints, while causing costs for the compensation payments”. We share this concern – that with easier access to constraints markets, some participants may now face a stronger incentive to divert transactions from the wholesale market to the constraints market and, in so doing, actually increasing the volume of constraints.

2.11 Alternatively, the SO could be granted the power to redispatch assets from specified technology classes (e.g. interconnectors) ahead of gate closure, as suggested by Frontier Economics. This is likely to lead to inefficiencies as the costs of alternative BM actions are not known when these redispatch actions would take place. It is also discriminatory, creating a risk of a patchwork of gate closure times running in parallel for different technologies.

2.12 As with the proposals for earlier gate closure, there are limited benefits of distortionary CMMs or discriminatory, technology-specific early redispatching actions with locational pricing. There would be much less need for such interventions since improved scheduling in the wholesale market would dramatically reduce overall constraint volumes that need to be resolved.

Proposal 1.C: Improve the ESO's visibility of market conditions by incentivising market participants to provide better asset-specific dispatch information

2.13 In this proposal, market participants provide asset-specific dispatch information through initial physical notifications ("IPNs"), and final physical notifications ("FPNs") at the day-ahead stage and at the time of gate closure, respectively. These should match the expected physical output of the asset, and the Grid Code mandates that generators follow the Good Industry Practice. However, there is no obligation to ensure that FPNs match day-ahead IPNs, or that deviations are limited, and this limits the ESO's visibility of expected generator positions at the day-ahead stage.

2.14 Frontier Economics and AFRY propose introducing formal procedures that market participants must follow to justify deviations between IPNs and FPNs. Unlike the other proposals we consider in Bucket 1, this proposal is likely to have only relatively small benefits or costs. The benefits include potential incremental improvements in the SO's ability to identify constraint problems, and thus to tackle them at an earlier stage. The costs include additional administrative burdens and potential reductions in market participants' willingness to trade close to real time.

2.15 Frontier Economics and AFRY additionally propose introducing positive information imbalance charges whenever there is a difference between expected and metered asset-specific volume in the BM. This proposal could help produce higher quality FPNs but would come with a potential cost resulting from double penalisation of imbalances for market participants.[8] This would particularly affect harder-to-forecast intermittent renewables and demand. Under locational pricing, the SO would have greater direct visibility as market participants would only be able to benefit from portfolio balancing across assets located in the same zone or node. As such, positions at portfolio-level and unit-level should be more aligned. Also, contracts between market players would be settled at a specific zone or node, improving the information available to the SO. Locational pricing would therefore be expected to reduce the potential benefits of information imbalance charges.

Overall conclusions on first bucket of proposed reforms

2.16 The proposed reforms discussed above have a common feature of not seeking to change the access rights of market participants to the grid. Rather, all participants would continue the practice of trading in the GB wholesale market as if there are no transmission bottlenecks and they would continue to receive compensation payments to the extent that system constraints cause participants' intended production volumes to be curtailed by the SO. Hence, the proposed reforms cited above can, in no way, address the volume of constraints that occur because they do not address the underlying incentives that the current structure of the wholesale market provides (and would continue to provide if any of the above proposals were implemented).

2.17 The reforms might, at the margin, allow the SO to trade out the (same volume of) constraints in a slightly more cost-effective manner in the BM than now. However, even this would come at a very significant cost surfacing elsewhere. As we have explained above, these costs would include either much reduced trading opportunities for market participants near real time; the introduction of new risks of inefficient actions by the SO; very significant risks of gaming (that would be costly to consumers); and the risk of arbitrary charges being levied upon market participants.

Bucket 2: giving discretion to the SO to alter or restrict wholesale market scheduling for certain classes of asset would bring significant risks

2.18 Proposals in the second bucket are very different to the first buckets in that they envisage the ending of the practice of firm access rights for some subsets of market participants. Firm access rights for certain assets could be altered by giving discretion to the SO to alter or restrict the scheduling of these assets in the wholesale market without providing financial compensation. This type of proposal can be implemented either through:

- dynamic scheduling restrictions; or
- dynamic TNUoS charges.

2.19 Unlike the first set of proposals described above, these offer the potential opportunity to address the volume of constraints on the system and so reduce costs.

2.20 With dynamic scheduling restrictions, the SO would set limits to how certain assets can be scheduled in the wholesale market based on system conditions. These limits can change from one hour to another. The aim of scheduling restrictions is to reduce constraint volumes, most probably for two-way assets such as interconnectors. Under the current national market design, interconnectors are often scheduled "in the wrong way". For example, interconnectors between southern England and the EU are frequently scheduled to export from GB even though system conditions in southern England suggest they should be importing.[9] Under dynamic scheduling restrictions, the SO would prevent the interconnector from exporting or importing if doing so would exacerbate GB system congestion. The same logic can potentially hold for restricting the scheduling of wind generators, batteries, or electrolysers, if policymakers so chose.

2.21 Alternatively, assets that are currently "wrongly scheduled" in the wholesale market could be made subject to dynamic TNUoS charges. Frontier Economics proposes ex-post TNUoS charges for interconnectors based on the difference between the national price and an ex-post estimate of a zonal price. Knowing that the charge would be applied ex-post would lead market participants to take account of the expected value of the charge when purchasing capacity and nominating flows.[10]

2.22 There is no a priori reason why dynamic TNUoS charges could not also be applied to other asset classes such as batteries and electrolysers. Such charges can be more nuanced than scheduling restrictions (which tend to be binary, with plant either allowed to operate or not), and thus could result in scheduling of generation and demand that is close to what would be expected under locational pricing. In theory, optimally-determined dynamic TNUoS charges could replicate the incentives of locational pricing by encouraging market participants to take likely network constraints into account when bidding in wholesale markets.

2.23 The costs and benefits of ending firm access therefore look similar to those of locational pricing – at least for the participants impacted. However, introducing non-firm access to only a subset of market participants is obviously discriminatory. There seem to be significant additional risks of this approach, of which we highlight four:

- **Legal concerns.** Proponents of dynamic scheduling restrictions or dynamic TNUoS charges argue that such changes may be simpler to implement than locational pricing. However, it is far from obvious that this is the case. Removing firm access rights would have significant negative impacts on the revenues of the relevant assets and seems likely to result in protracted legal challenges.[11] In the specific case of interconnectors, decisions by the SO would also affect wholesale prices in interconnected countries and thus consumer costs and producer income in those countries. It is also unclear how dynamic restrictions or dynamic TNUoS charges on interconnectors would affect current agreements on cross-border trade.
- **Transparency of price formation.** Because dynamic scheduling restrictions or TNUoS charges would imply much more SO discretion than locational pricing, they are unlikely to have the benefits of transparency or bankability that market pricing can achieve.
- **Risk management.** Market participants may find it hard to forecast their net revenues over time as scheduling restrictions or dynamic TNUoS charges evolve. Market parties would be unable to hedge these risks in forward markets, unlike in locational wholesale markets.
- **Inefficiencies in dispatch**. Depending on their implementation, dynamic scheduling restrictions or TNUoS charges create high risks of inefficiencies in scheduling, including:
- If only one asset-class is affected, assets from that class might be constrained-off where it would be more efficient to constrain off another class of asset that is not subject to such restrictions or charges.
- If all asset classes are affected (so that any asset can be curtailed without compensation), inefficiencies could occur because market participants may be tempted to distort their wholesale market bidding to ensure that they are scheduled (so-called "disorderly bidding").[12]
- Dynamic TNUoS charges would inevitably result in inefficiencies due to forecast errors. If they are set ex-ante, errors by the SO in setting optimal charges would lead to inefficient scheduling. If they are set ex-post, errors by market participants in anticipating likely charges would lead to inefficient scheduling.

2.24 Locational wholesale pricing has significant advantages relative to this 'back door' route of introducing dynamic scheduling restrictions or TNUoS charges. This is because better scheduling of all assets would result directly from the reflection of transmission constraints in the wholesale market clearing algorithm. Moreover, locational wholesale prices would be determined by transparent delineations of bidding zones, not by potentially untransparent and unpredictable choices of the SO.

Bucket 3: changing how prices are determined in the BM would often lead to higher consumer costs

2.25 The third bucket of proposals contains ideas for redesigning the balancing mechanism, with the aim of reducing the costs of constraints for a given volume. These would not aim to reduce levels of constraints, but look to improve the efficiency of the BM.

Proposal 3.A: Bolting a pay-as-cleared nodal market in the BM onto a national wholesale market exacerbates gaming opportunities

2.26 The current pay-as-bid and proposed pay-as-cleared market structures represent two fundamentally different approaches to the BM. Introducing a market-based approach through a nodal pay-as-cleared arrangement in the BM (as suggested by Frontier Economics) implies that the BM evolves from a correction mechanism after the wholesale market to a real-time, more locationally granular extension of the current wholesale market.

2.27 While such an approach might be superficially appealing, it would introduce distortions that would amplify current gaming opportunities. Concretely, demand in export-constrained areas and generation in import-constrained areas would often have a greater incentive to transact in the BM rather than the national wholesale market. This would exacerbate constraint volumes and increase costs.

Proposal 3.B: introducing pay-as-cleared pricing for balancing actions to resolve energy imbalances will likely lead to higher BM costs

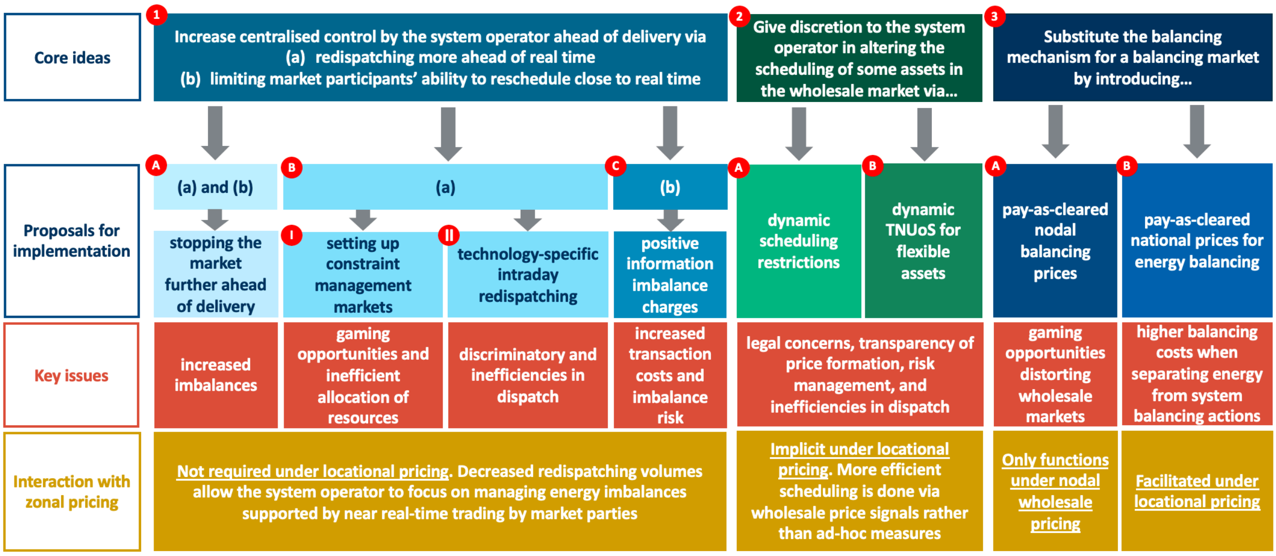
2.28 Currently, all assets activated in the BM are paid their bid price. Under this proposal, balancing actions to resolve energy imbalances would be pay-as-cleared while balancing actions to resolve other constraints would remain pay-as-bid. As such, prices for balancing actions to resolve energy imbalances would align with how imbalance prices are computed. This could create a ‘real-time price’ for balancing actions resolving energy imbalances, potentially increasing competition and providing a basis to settle forward contracts.

2.29 In theory, there are benefits of creating a real-time price for balancing actions resolving energy imbalances. However, separating the pricing of BM actions for system constraints and energy imbalances while keeping the current national wholesale market in place would create significant problems. Notably, experience from Germany, where a similar proposal is already in place, reveals that the energy imbalance price to be only very loosely correlated with the day-ahead price - suggesting that the practicalities of the methodology would need to be considered carefully.[13] Further, accurate flagging of BM actions resolving system constraints is nearly impossible. In practice, BM actions are taken with both purposes in mind; balancing actions to resolve energy imbalances can affect required constraint management actions, and vice versa. In other words, there is no separable merit order for the different types of BM actions.

Summary

2.30 Overall, it is highly doubtful that the proposals we have considered would be effective in addressing the current recognised problems with the GB electricity market. Moreover, many of the proposals have the potential to create significant unintended consequences. Figure 2.2 summarises our assessment of different reform proposals.

Figure 2.2: Our Assessment of Different Reform Proposals



Source: FTI Consulting

3. Advocates of Reforms to the BM Within a National-Price Regime Fail To Consider Their Longer-Term Impacts

3.1 Many of the proponents of reforms to the status quo are, under the current market design, the beneficiaries of significant transfers – notably (but not only) generators that benefit from constrained-off payments. This is acknowledged in Frontier's report, which states that "…there are complex transfers between generators and customers which may mean, in some specific cases, minimising dispatch costs does not minimise customer costs. We do not consider these specific cases as part of this report."[14]

3.2 This is a very material oversight. As well as having distributional consequences that are often undesirable, large payments from consumers to generators for not generating significantly reduce the efficiency of the electricity system and the GB economy as a whole. This is for three main reasons:

- First, **generators and large sources of demand have little incentive to site in areas which would benefit GB as a whole** by reducing rather than increasing constraint costs, since they know they will pay or receive the same wholesale price in any case (experience suggests that TNUoS charges are unlikely to be strong or granular enough to provide good signals).[15]
- Second, **national wholesale pricing distorts decision-making about transmission build** – with the result that, under the current approach to assessing network investments, delivering these network plans are unprecedentedly costly and likely to be politically infeasible.[16]
- Third, following on from the previous two, **the current national pricing regime significantly reduces GB's competitiveness relative to the rest of the world,** as electricity-intensive demand is unable to access low electricity prices in renewable-rich regions. This reduces the attractiveness of GB as a producer of, say, green steel or green hydrogen relative to locations such as the north of Norway or Sweden (both which have zonal pricing). Attracting incremental demand in the right places would lead to a substantial reduction in the current waste of zero carbon electricity via curtailments.

3.3 As a result, reforms to the BM alone are unlikely to allow GB to achieve net zero in line with current targets, as the cost of doing so (both financial and in terms of, for instance, disruption resulting from network build) is likely to be increasingly challenged politically.

Endnotes

[1] DESNZ, 2023. Review of Electricity Market Arrangements: summary of responses, p. 17 https://assets.publishing.service.gov.uk/media/640226048fa8f527fe30dbba/review_of_electricity_market_arrangements_summary_of_responses.pdf

[2] ESO, 2022. Net Zero Market Reform: Phase 3 Assessment and Conclusions, p.13 https://www.nationalgrideso.com/document/258871/download

[3] For example, this includes (1) Frontier Economics, 2024. Analysis of reform options for status quo electricity balancing arrangements https://www.frontier-economics.com/media/leuh5cod/balancing-reforms-final-summary.pdf. (2) Regen, 2023. Improving locational signals in the GB electricity markets https://www.regen.co.uk/wp-content/uploads/Locational-Signals-Insight-Paper-Final-July.pdf. (3) AFRY, 2024. National and Zonal electricity market designs for Great Britain https://afry.com/en/national-and-zonal-electricity-market-designs-great-britain. (4) Cornwall Insight, 2023. Reform options for TNUoS and constraint management https://www.cornwall-insight.com/wp-content/uploads/2023/10/Reform-options-for-TNUoS-and-constraint-management.pdf?utm_source=website&utm_medium=website. (5) The Energy Landscape, 2024. Exploring options for constraint management in the GB electricity system: the potential for constraint management markets https://www.scottishrenewables.com/assets/000/003/640/Constraint_Management_Report_-_Exec_Summary_original.pdf?1705488005. An overview is provided in the "Thermal Constraints Collaboration Project" set up by the ESO https://www.nationalgrideso.com/industry-information/balancing-services/thermal-constraints-collaboration-project.

[4] It is unclear in the proposals to whom the responsibility to forecast production and demand accurately would be allocated when gate closure would be moved ahead: market participants or the SO. In the former case, this would lead to a significant increase in the imbalance cost risk, especially for intermittent renewables. In the latter case, it would be hard to incentivise the SO to minimise forecast errors in the same way as market participants are.

[5] When ERCOT transitioned from a zonal to a nodal market design in 2010, the volumes of Regulation Up and Down procured fell by nearly 50%, see Andrade, J., Dong, Y., and Baldick, R. 2018. "Effect of market changes on the required amounts of frequency regulation ancillary services in ERCOT" https://ceid.utsa.edu/ataha/wp-content/uploads/sites/38/2018/10/Ross.pdf.

[6] Ehrhart, K.-M., Eicke, A., Hirth, L., Ocker, F., Ott, M., Schlecht, I., and Wan, R., 2024. "Analysis of a Capacity-Based Redispatch Mechanism" https://www.zew.de/en/publications/analysis-of-a-capacity-based-redispatch-mechanism-1.

[7] For example, a battery located behind an import constraint can decide to charge up in the day-ahead wholesale market knowing that it would be eligible to receive an availability payment for being ready to discharge in a subsequent CMM. If the battery had not charged in the day-ahead wholesale market, it would not have been eligible to receive the availability payment. By choosing to charge in the day ahead wholesale market, the battery aggravates congestion.

[8] For example, if a market participant is imbalanced at portfolio-level, at least one asset of that market participant is also imbalanced at unit-level. As such, that market participant would be penalised twice for the same imbalance.

[9] This can lead to very high BM costs to unwind such trades – see Current-news, 2022. "UK buys power from Belgium at record prices of nearly £10,000/MWh" https://www.current-news.co.uk/current-price-watch-balancing-mechanism-hits-nearly-10-000-mwh/.

[10] A variant of this approach would be to have ex-ante dynamic TNUoS that are determined by the SO a little ahead of real time. The SO would use its forecasts of local demand and supply conditions to set the charges.

[11] This has been the case with Ofgem's recent more limited reforms to network charging methodologies (see e.g., https://www.bailii.org/ew/cases/EWHC/Admin/2022/865 html).

[12] For example, if a generator is expected not to be scheduled due to local constraints, the generator could be incentivised to bid as low as possible to ensure it is not constrained-off. This is a well-known feature (and weakness) of the current Australian electricity market design (see FTI Consulting, 2021. Forecast of congestion in NEM. Presentation for ESB) https://esb-post2025-market-design.aemc.gov.au/32572/1629773972-fti-esb-forecast-congestion-in-the-nem-final-5-august-2021.pdf.

[13] The correlation between the German day-ahead price and imbalance price was 0.21 for the first half year of 2024.

[14] Frontier Economics, 2024. "Analysis of reform options for status quo electricity balancing arrangements" https://www.frontier-economics.com/media/leuh5cod/balancing-reforms-final-summary.pdf.

[15] The converse is true for closure decisions too. Namely, generators in export-constrained areas of the system face an unduly strong incentive to remain on the system due to the availability of national prices and compensation payments when it might be preferable for the system that those generators exit the grid (which would free up capacity for newer, likely more efficient, capacity). Equally, generators in import-constrained parts of the country likely face an unduly weak incentive to remain open.

[16] Jason Mann, Joe Perkins, and Dan Roberts, 2024. "Transmission investment, flexibility and locational pricing" https://www.linkedin.com/posts/jason-mann-7722722_transmission-investment-flexibility-and-activity-7168592615280472064-qbrJ/?utm_source=share&utm_medium=member_desktop .

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