Congestion management in the day-ahead timeframe: lessons from The Netherlands

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***Abstract*— The decarbonisation of electricity supply through variable renewable energy (VRE) is causing increasing congestion in electricity transmission and distribution grids. Redispatching after the closure of the day ahead market has been the most common congestion management instrument. A key challenge for congestion management via redispatching is the growing scarcity of upward reserves for counter activation, as synchronously connected assets are often out of merit order during periods of high VRE output. To proactively manage congestion before the day-ahead market closes, the Netherlands introduced the dispatch limitation product (DLP) in 2022. Since its introduction, the DLP has been widely contracted and used. Furthermore, starting in 2025, Flexible Connection Agreements (FCA) will be introduced, providing additional mechanisms for congestion management. This paper presents key lessons from the Dutch experience with congestion management in the day-ahead timeframe, analysing the effectiveness of these new instruments and their impact on grid flexibility and market efficiency.**

***Index Terms*-- Congestion management, market-based flexibility procurement, dispatch limitation product, flexible connection agreement, strategic behaviour**

I. Introduction

Decarbonisation of the energy system at large will necessitate the decarbonisation of electricity supply and the rapid electrification of many end-uses. Many positive developments of both fronts can be observed in the rising shares of emission-free electricity production and the uptake of heat pumps, electric vehicles by residential customers [1].

The continuation of these trends is put at risk, however, by the increased occurrence of grid bottlenecks, i.e. physical congestion in the electricity system. The occurrence of grid bottlenecks can become a reason for grid operators not to approve new connection requests until the grid is sufficiently reinforced. In The Netherlands, structural congestion is causing increasing delays in grid connection both on the supply as well as the demand side, and for connection to transmission and distribution networks. This hampers the ability to achieve climate ambitions.

Congestion management is a process in which the system operator (SO) assesses for each market time unit (MTU) the chance of physical congestion occurring within its grid area and uses the tools at its disposal to mitigate such foreseen congestion. In the operational time frame, those tools include (i) network-only actions such as topology optimization [2] and controlled thermal overloading [3]; (ii) direct control of generation and demand [4] and (iii) market-based congestion management options [5] that activate congestion services from its grid users that are placed behind the identified bottleneck. This paper focuses specifically on the tools (ii) and (iii) since these congestion management tools require a change in the foreseen dispatch of specific grid-connected production or consumption assets and serve to emphasize the possibilities when adopting new strategies for congestion management.

Congestion management ensures that grid operators can deploy flexible resource present within the grid area to solve foreseen congestions, and in doing so are able to facilitate additional grid connections in the period before the (time-consuming) grid reinforcement is complete. Congestion management thus enables ongoing decarbonisation and progress towards climate objectives in a context of lagging grid reinforcement. The 2019 EU Clean Energy Package contains rules for market-based procurement of congestion services in the context of delayed grid reinforcement or as a substitute for grid reinforcement[1].

The most common instrument for congestion management is the redispatch product, which the system operator can use to request a grid user to deviate from their foreseen production or consumption at a specific time and for a specific duration. The effective use of this product requires, among other things, that grid user submits accurate schedules for their (larger) production and consumption assets, and that the system operator has sufficient visibility over the expected probability of physical congestion at a specific time and place. These two

[1] See for instance Article 32 of [18]

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elements come together in the load flow analysis that the system operator performs on the afternoon of D-1.

This paper discusses challenges of relying solely on redispatching for congestion management. It presents two new instruments that have been introduced in The Netherlands to address these challenges: the dispatch limitation product (DLP) and the Flexible Connection Agreement (FCA) are both activated prior to the closure of the day-ahead market. This paper describes the similarities and differences between these instruments, first experiences with their use and their anticipated effect on DSO operations. Section II discusses conventional congestion management tools and their challenges. From this starting point, Section III presents the new congestion management tools introduced in The Netherlands and their benefits. Section IV describes the impact on the daily process of congestion management and Section V concludes with a discussion and suggestions for future research.

II. Conventional congestion management

Currently, most congestion management takes place after the day-ahead market gate closure time (DA GCT) through the activation of redispatching services. SOs typically wait until congestion is confirmed before taking action, as solving congestion involves incurring costs for flexibility procurement. In practice this means that system operators will typically not act until they have received the schedules for larger assets which are used to perform the load flow analysis[2]. Once a bottleneck has been identified in the load flow analysis, redispatching involves two key steps First, the SO requests market participants to modify their scheduled production or consumption from a specific asset during a specific market time unit. Second, the SO activates an equivalent volume of energy in the opposite direction outside of the congested grid area to maintain the system balance. This sequential approach ensures grid balancing but inherently delays congestion management until after DA GCT, since the schedules required for the load flow analysis are only submitted to the SO in the early afternoon of D-1 (the day before trading day D).

The definition for 'redispatching' from Regulation (EU) 2019/943 supports this view: 'redispatching' *means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security*. In June 2023, a Dutch court upheld the explanation given by the national regulatory agency that foreseen production or consumption can only be 'altered' after the schedules for the relevant asset(s) have been submitted to the SO [6].

To prevent congestion from reoccuring after redispatching, the SO may impose temporary limits to all parties in the congested grid area during the MTUs for which redispatching has taken place. These temporary limits, known as 'market restrictions' in The Netherlands, prevent grid users in congested areas from increasing their production or consumption beyond their scheduled levels during the MTUs for which the SO activated congestion services. The market restriction in itself does not constitute a form of redispatch. Unlike redispatching, which targets specific assets, a market restriction applies broadly to all relevant grid users in a congested area and obliges these grid users *not* to alter their production and consumption . Rules for temporary limits are currently being developed at EU level under the Network Code for Demand Side Response [7].

While redispatching remains a vital congestion management tool for SOs, its limitations highlight the need to introduce complementary instruments. The shortcomings of the redispatching product are described below.

A. *Limitations of redispatching product for the DSO*

There are several drawbacks to relying predominantly on redispatching as the only instrument for congestion management. First, the process for redispatch aligns well with the needs, the level of insight and tools of the transmission system operator (TSO) but is often not useful to distribution system operators (DSOs). For DSOs, there often are not enough grid users that are located behind the specific bottleneck and also able to deliver redispatching services to allow for effective competition for the provision of market-based redispatching. More competition for offering flexibility in local grids could come about via aggregation of smaller assets to minimum bid sizes (typically 100 kW for local congestion services in The Netherlands) but progress has been slow on this front, probably due to the interplay of technical hurdles and lack of clear benefits for participants. Second, grid visibility is often too limited for DSOs to effectively predict congestions in their own grids due to the 'meshed' nature of their grid topology, diminishing the effective use of available redispatching bids.

B. *Challenges with non-market-based redispatching*

In grid areas where the effective use of market-based redispatching is not possible, SOs can apply non-market based redispatching pursuant to Article 13(3) of the Regulation (EU) 2019/944 (Electricity Regulation). However, this too comes with specific challenges. First, there are technical prerequisites. When the grid user has not submitted a bid for the required redispatching volumes, the effective application of redispatching necessitates additional technical measures to ensure that the SO can curtail the foreseen production and/or consumption by the grid user. This typically involves placing hardware in the grid user's installation. It is also possible to take technical measures on the side of the SO, but this often implies that the affected grid users can only be completely curtailed and that a more modular, partial curtailment is not possible.

Second, in practice the SO and the grid user regularly disagree about both the affected volume (MWh) of non-market based redispatching as well as the corresponding compensation for these volumes pursuant to Article 13(7) of the Electricity Regulation. The missed volumes can be determined by agreeing on the relevant wind speed or solar irradiation and by comparing different assumptions and weather data. More challenging is the discussion about how to incorporate, if at all, the opportunity costs of curtailed production. As a

[2] In The Netherlands, the deadline for submission of schedules is 2:30 PM for DSO-connected assets and 3:30 PM for TSO-connected assets)\

consequence, agreeing on the appropriate compensation for curtailed renewable production can be a time-consuming process for system operators and grid users.

C. *Limitations of redispatch for small and large consumers*

Larger grid users, especially large consumers, could in theory provide significant demand response. This is increasingly relevant as more grid areas face demand congestion in winter. However, established business processes are often unable to adapt to short-term changes in scheduled electricity consumption, complicating the offering of flexibility for redispatching. In addition, system operators can express their doubts about the techno-economic fundamentals behind the offered prices for flexibility, and the SO is often unwilling to contract demand response at the offered prices. This in turn may reduce the grid user's willingness to invest in updated processes and equipment. A product with less operational complexity can serve to unlock much of the demand response potential from larger assets.

Smaller assets, especially those located behind-the-meter in low-voltage grids, can be aggregated to provide demand response services. However, it can often prove challenging for aggregators to reach the required minimum bid size of 100 kW, especially if all pooled assets need to be located behind the same grid bottleneck. Aggregators trying to unlock this pooled demand response have encountered difficulties in determining whether the assets in their portfolio are located behind the same bottleneck, as the tooling for flexibility allocation is not set up to efficiently collect and check whether spatially aggregate bids can resolve congestion. Moreover, it is currently required for the measurement and validation of group bids that that all assets belonging to a group bid are not only located behind the same bottleneck, but also all belong to the same balancing responsible party (BRP). This has further complicated the ability to reach sufficient scale to participate with pooled smaller assets.

D. *Increasing scarcity of upward reserves*

In addition, although curtailment of variable renewable energy sources (VRE) is becoming more regular feature of grid management, there is an increasing scarcity of upward reserves (including load reduction) to perform the counter activation required to ensure that VRE curtailment does not cause a system imbalance. VRE curtailment is more likely at moments of high VRE output and low spot prices, when few thermal assets are dispatched and therefore few assets are able to ramp up production. SOs observe increasing difficulty procuring sufficient volumes of upward reserves to maintain system balance. In cases where the SO applies curtailment as a form of non-market based redispatching, i.e. in the final 45 minutes before real time, when the deadline for activation of redispatching bids has passed, it is no longer possible to activate upward reserves for redispatching. This form of curtailment can affect the TSO balancing actions, especially if such curtailment is done at a larger scale and/or simultaneously by several SOs.

E. *Potential for strategic behavior that worsens physical congestion*

Finally, it is increasingly evident that relying on redispatching to mitigate congestion can create incentives for so-called *increase-decrease gaming in zonal electricity systems* [8]. Market actors that anticipate congestion may adjust their strategy on the DA market to extract additional revenue from the SO [9]. Specifically, there are three different ways this can be achieved: through market power (setting prices), misrepresentation of transmission schedules, and through adjustment of expected revenues [10]. The latter is especially challenging, as it is a problem that is inherent in the market design when congestion is predictable at the DA GCT [11].

III. NEW INSTRUMENTS FOR CONGESTION MANAGEMENT IN DAY-AHEAD

In May 2022, the Dutch regulator (Autoriteit Consument en Markt (ACM)) published new rules for congestion management [12]. Notably, the dispatch limitation product (DLP) was introduced. The DLP is a voluntary agreement that makes it possible for the SO to request, before the closure of the day-ahead market, that a specific grid user does not use the entire firm transport capacity which has been granted for that grid user, during specific market time unit(s) the next day. The compensation for the activation of the DLP is set in €/MW and complemented, in some cases, by fixed payments. One application of DLPs is the use for an extended period of several days or weeks to maintain N-1 operational security during grid maintenance. For the purposes of this paper, we focus on a second application of DLPs, whereby the SO activates the DLP for specific MTUs the next day during which, based on its weather forecast and historic data, there is a sufficiently high probability of congestion. As Fig. 1 below illustrates, the deadline for activating FCA or DLP lies on the morning of D-1. To date, dozens of DLP contracts have been concluded. During the summer months, some SOs may activate DLP services from renewable producers almost every day[3]. DLPs are also used for demand congestion, for example by having greenhouses shift part of their power demand to on-site generation.

A. *Benefits of the dispatch limitation product*

This application of the DLP has some crucial advantages. First, since activation occurs prior to DA GCT, there is no need to perform a counter activation and the abovementioned scarcity of upward reserves is no longer relevant. Second, all relevant market roles (congestion service provider, balancing service provider, and balancing responsible party) are notified of the limitations placed on specific assets and can adapt their bidding and trading strategy in the remaining hours of the day-ahead market. Depending on the deadline for DLP activations, market parties could also apply this information in the balancing capacity auction which also occurs on the morning of D-1. In The Netherlands, the deadline for DLP activation is 8:30 AM, which comes too late for participation in the FCR

[3] The Dutch energy regulator receives information from SOs about the use of various congestion products. At the moment there is no public data about DLP activations. In the near future, however, the GOPACS platform will expand data transparency to include the activation of DLP in The Netherlands.

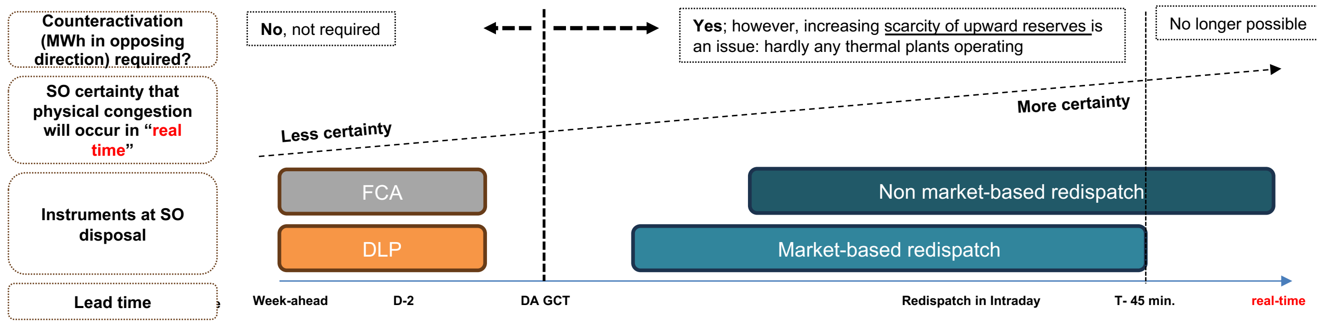

Figure 1: Different instruments for congestion management

auction (frequency containment reserves) but in time for the FRR auction (frequency restoration reserves). Third, the DLP can be more easily adopted by larger consumers who, for a variety of reasons, are unable to offer redispatching services. In The Netherlands, greenhouses represent a category of grid users for whom the DLP has proven particularly useful [13]. Fourth, early indications suggest that the DLP could significantly reduce cost for congestion management, in particular supply congestion: in recent months, prices for downward reserves from VRE sources on the basis of DLP contracts have come down from over 300 €/MWh to 200-250 €/MWh and this downward trend is expected to continue as operational experience grows. Many newly connected grid users accept a standard price formula based primarily on spot market prices, with a 10 €/MWh margin to account for opportunity costs [14]. Since DLP activations are likely to coincide with moment of high VRE output and low (or even negative) spot market prices, DLP activations from these newly connected assets will come at a much lower cost to the grid operator[4]. This is especially true since, as indicated above, contrary to the redispatch instrument, for DLP activation no counteractivation is required. The DLP price gap between older and more recently connected VRE assets is expected to decrease as grid operators gain experience with applying non-market based redispatch on VRE assets pursuant to Article 13 of the Electricity Regulation: the level of compensation for such non-market based 'curtailment' is likely to resemble the pricing structure of the standard price formula mentioned above[5]. Finally, the DLP may be better suited than redispatching to the statistical behaviour of some demand processes, such as electric vehicle charging stations [15]. The introduction of DLP can thus serve to unlock demand side response resources.

B. Link with flexible connection agreements

From October 1, 2025 onward, the DLP will be complemented by a flexible connection agreement for grid users connected to the TSO grid. The FCA functions similarly to a DLP, in the sense that the TSO determines on a daily basis, and prior to 8:30 AM, whether the transport capacity is firm or not based on the probability of congestion. The FCA is, from an operational point of view, the cheapest congestion management instrument available to the TSO since there is no compensation for designating the affected transportation capacity as non-firm; the grid user instead benefits from reduced tariffs.

To prevent distortion of wholesale market functioning, it is important that the deadline for activation of the FCA, i.e. the moment at which the system operator communicates whether the capacity is firm or not, occurs before the closure of day-ahead market and ideally even a few hours earlier, similar to the deadline for DLP activation. Any deadline for FCA activation after DA GCT would mean that market parties in a portfolio-based electricity market cannot reliably trade with all their assets up until day-ahead. This would lead to inefficient market outcomes and a suboptimal allocation of flexible resources, since affected BRPs would reserve flexible assets within their own portfolio of assets to cover for the risk of FCA activation closer to real time. An initial investigation of the effect of activation time on day-ahead trading strategies was done by Hennig et al. [16] comparing activation before DA GCT with near real time activation in a model setting.

A knock-on effect of delayed activation by the SO is that BRPs will take into account the risk of close-to-real-time activation by keeping some flexible resources available within their own portfolio. Therefore, these flexible resources would be offered less often in intraday markets or for balancing services – either in the form of balancing capacity on the morning of D-1 or as non-contracted 'free' balancing energy bids. This would likely increase the cost of balancing capacity (reserve) procurement and dampen liquidity in intraday markets, and such effects should be duly assessed when designing FCAs[6].

IV. IMPACT ON DAILY PROCESS OF CONGESTION MANAGEMENT

Fig. 1 summarizes the available congestion management tools, underlining the sequential nature of congestion management. The introduction of DLPs and FCAs has the potential to significantly reshape how SOs manage congestion

[4] Assessing the cost reduction potential for DLP in the context of demand congestion will require further real-world experience.
[5] Court rulings will play a role in providing guidance on the appropriate compensation for non-market based redispatch and specifically the treatment of opportunity costs. See for instance case C-36/25 at the Irish Supreme Court
[6] This paper does not analyse the use of FCAs within the scope of balancing by the TSO, however the same effects on liquidity and flexibility bidding can be expected

and how they interact with their grid users. By design, the SO activates the DLP and the FCA at a moment when there is less certainty about the likelihood of physical congestion, compared to any moment after the load flow analysis that the system operator performs after receiving the schedules for larger assets. While this may lead to an overprocurement of flexibility, experience suggests that earlier interventions by the SO can ultimately reduce congestion management costs, particularly by mitigating the scarcity of upward reserves required for balancing actions.

From a regulatory perspective, which adopts a more holistic view of costs and benefits than the narrower costs and benefits that SOs would perceive, it is beneficial for society at large if the SO initially activates more than enough DLP and FCA, and subsequently learns to use these resources more efficiently on the basis of data-driven refinements in forecasting and activation strategies. Simply put, SOs can activate more than enough DLP and FCA resources to be sure that the congestion is solved and analyse ex post, based on actual metered data on grid flows, whether and to what extent such activations were indeed necessary. In this way SOs can gradually render the activation of these resources more efficient and less costly for society as a whole, whilst ensuring that there is enough flexibility available for all moments of foreseen congestion.

From the perspective of market participants, earlier congestion management by activation of DLP and FCA gives them more freedom to optimise the various assets in their portfolio across different markets, taking into consideration the limitations placed on specific assets in the form of activated FCA and DLP. Importantly, by reducing the predictability of redispatch requests, using FCA and DLP is likely to reduce opportunities for the abovementioned increase-decrease bidding behaviour.

Accurate congestion forecasting by the SO is crucial. Leveraging updated weather forecast (typically received around 7 AM on D-1), historical grid data, and advanced analytics can improve predicitions and enable more precise activation of congestion services. Where forecasting remains challenging, as is often the case in more meshed grids with suboptimal metering of grid flows, a cautious approach whereby the SO activates more flexibility than strictly necessary may be preferable, as it allows continued grid access for new connections whist the SO refines the activation strategy.

Activating more flexibility while allowing new parties to connect to the grid represents a win-win situation for the wider electricity system. First, the activation of DLP and FCA gives a monetary value to the relevant flexible resources and thus supports unlocking additional flexibility resources. Second, the parties wishing to connect to the grid, be it supply- or demand-driven projects, are what drive the decarbonisation of both supply and demand for energy. Both of these advantages carry lasting positive effects for society at large.

The success of DLP and FCA also depends on the efficiency of contracting processes. In previous years, coming to an agreement on the terms of contracts for DLP and FCA proved to be a time-consuming process since these contracts can involve many customised terms (e.g. activation limits, pricing structures). Standardising such contractual terms can play an important role in accelerating the contracting process. Standardised contract templates have been published to reduce the lead time for contracting flexibility [17]. In addition, the broad acceptance of standard prices for DLP for newly connected VRE grid users has also helped to reduce the delays in contracting, whilst also supporting the SO in estimating the projected cost of congestion management using DLP on all additional greenfield VRE projects [14].

Under the abovementioned conditions, SOs will have clear incentives to improve visibility of their grid, and the costs incurred for activating flexible resources will steer investment decisions in that the installation of improved metering equipment will be prioritised in grid areas where this stands to have the highest financial impact for the SO.

V. Discussion

Ultimately, the shift towards more proactive congestion management requires a cultural and operational adjustment for SOs. Not only do SOs need to shift away from their reliance on post-market interventions, they also need to engage with their grid users in novel ways and incur costs for solving congestions based on assumptions earlier in time.

The level of transparency regarding the activation of FCA and DLP, as well as the timing of such activation, needs to take into account the risk that market parties may decide to inflate the schedules of certain assets within their portfolio. Such behavior, which shows similarities to the inc-dec gaming described in [8], could undo some of the benefits of earlier congestion management. Monitoring the accuracy of schedules, also through the use of financial incentives, is an important process that must take place in parallel. As suboptimal outcomes may occur also in the absence of explicit misrepresentation or market power [8], [11], the introduction of additional products may be of value. For example, options for congestion services procured ahead of time that can be activated closer to real time, when congestion is more certain to occur.

Different SOs will have varying preferences regarding the proportion of either DLP or FCA as part of their complete congestion management toolkit. As the adoption of DLP and FCA expands, further research is needed to evaluate their long-term impact on system cost, market efficiency and their ability to help unlock additional sources of flexibility.

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