CEER Response to the European Commission ASSET Study on Regulatory Priorities for Enabling Demand Side Flexibility

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1 Context

CEER welcomes the possibility to react to the European Commission (EC) ASSET Study on Regulatory Priorities for Enabling Demand Side Flexibility (DSF)[1]. The study has been carried out by a consultancy consortium (TRACTEBEL and NAVIGANT) for the EC (Directorate General for Energy) and was published in November 2020.

The study focuses on regulatory challenges related to DSF, with the aim to provide the EC with advice on defining the needs and scope of a regulatory priority list for DSF by specifying policy options in view of implementing new or updating existing Network Codes (NCs) in line with Article 59 (3) of the Electricity Regulation (EU/2019/943).

A first CEER-reaction[2] on this topic area was already submitted to the EC and published on 14 May 2020 as part of the EC's public consultation on the priority list of NCs[3].

DSF is an innovative and challenging topic which is expected to be relevant mostly at local level. Therefore, in this first reaction, CEER already was of the view that all can benefit from testing different approaches and collect lessons learned rather than setting common rules for the sake of harmonisation which, at this stage, might hamper ongoing developments.

As a general comment, CEER also already wondered if current efforts should be limited to DSF and should not be extended to all sources of flexibility.

2 CEER´s view

Generally, CEER states that it would be more efficient to await the effects of the national implementation of Article 32 of the Electricity Directive (EU/2019/944) by all Member States (MS) before considering an additional NC. This is similar to what CEER already noted in the response to the consultation on the priority list of Network Codes.

With respect to the aforementioned ASSET study, CEER highlights the following aspects:

- It is necessary to take experience of NC implementation into account before amending existing NCs or establishing new NCs. In many MS, provisions for DSF are still in a developing stage or not existing at all.
- The study does not address the relation of Article 13 of the Electricity Regulation (2019/943) and Article 32 of the Electricity Directive. However, this is a pivotal preparatory step for the delineation of the regulatory framework for congestion management at distribution level, including DSF.
- A congestion needs to be of cross-border relevance in order to benefit from a coordinated congestion management as stipulated in Article 76 of the System Operation Guideline (SOGL). A congestion as defined in Article 2(17) and 2(18) Capacity Allocation and Congestion

[1] ASSET Study on Regulatory priorities for enabling Demand Side Flexibility, November 2020.
[2] CEER response to the Commission's public consultation on the priority list of Network Codes, 14 May 2020.
[3] European Commission 2020 public consultation on the priority list of Network Codes.

Management (CACM) Regulation can be considered as physical (exceeding operational security limits of a network element) as well as market-based (limiting cross-border trade).

- Regarding the study's proposed Alternative A[4], taking into account the current state of play, a regionally coordinated operational security analysis including the distribution grid seems too complex and may not be feasible within the required time limitations. Such a time-critical optimisation requires such an analysis to be conducted several times, in the day-ahead timeframe as well as in intraday and to include time for calculation and coordination. Therefore, CEER strongly recommends considering to not extend the operational security analysis to the distribution level.
- Alternative A, and a combination of pathways based on this alternative, seems to ignore that the favoured EU congestion management method is based on a market coupling, i.e. implicit auctions (Article 16.1 and 16.5 of Regulation 2019/943) based on adequately defined bidding zones (Article 14.1 of the same Regulation). These bidding zones should in principle not contain structural congestions. This method for the management of congestions is market-based and can provide an efficient price signal. Re-dispatching (Article 13 of Regulation 2019/943) is used when the 70% targets for cross-zonal capacity cannot be met and, more generally, to relieve a physical congestion or otherwise ensure system security. This existing method seems to be more in line with Alternative B or the Top Down approach. However, its impacts and possible application towards distribution networks should be further analysed in terms of governance, of possible coordination between transmission and distribution system operators, of the objectives pursued (e.g. congestion management, balancing, other ancillary services), of efficiency, of the quality of the price signal provided, of liquidity (where the creation of hubs gathering liquidity seems non avoidable) and of transaction costs. If the study considers the creation of very small bidding zones (Distribution-based Locational MarginalPricing - DLMP) adapted to the distribution level, no approach is yet provided about the move from the existing bidding zones to nodal pricing at distribution level.
- Alternative B is very complex (i.e. a high number of small bidding zones and market fragmentation; major amendments of the existing European framework which has not been completely implemented yet) and would need a change in the European target model, which is currently a zonal model. Such a change should be discussed with the different parties involved and provide answers to issues that naturally arise such as liquidity and market distortion and amendments to monitoring activities.
- CEER considers market-based procurement of flexibility as one very important option which could allow for a substantial benefit in the distribution grid, contributing to its further development to support as renewable, reliant and efficient an energy supply as possible. This is especially salient when considering the integration of fluctuating renewables, electrification of industry and the further growth of appliances that increase demand like e-mobility, heat pumps and home storage. A careful design and assessment of efficiency is critical, where all necessary prerequisites for a market-based approach must be respected, imposing regulatory measures if/when necessary.[5]
- The congestions at distribution or transmission levels should be managed with the most economically efficient solution. DSF or other flexibility sources and options other than market-based procurement to assess flexibility should be favoured to network reinforcement when relevant and economically preferable.
- The study does not provide evidence on the economic efficiency of the considered policy options/scenarios. Without this evidence, CEER struggles to understand why to merge local congestion management and existing wholesale markets or even why to split up control areas and to establish local markets at the distribution level.
- Subsidiarity: The policy options addressed in the study do not leave room for coherent approaches according to the situation in MS, which may involve e.g. hybrid approaches, namely a coexistence of wholesale markets and congestion management markets, where two

[4] A summary of the ASSET study and the proposed alternative solutions and policy options can be found in Annex 1.
[5] This is taken from the CEER Paper on DSO Procedures of Procurement of Flexibility, Ref:C19-DS-55-05, 16 July 2020.

market signals exist (one for the scarcity in the wholesale market and one for scarcity in the network infrastructure). The two market signals shall not risk to overrule one another. Market delineation for these markets must respect the provisions of Article 13 of the Electricity Regulation and Article 32 of the Electricity Directive, exclude market distortion and abusive behaviour and must respect unbundling rules. On the other hand, co-optimisation is applied only in a few cases (e.g. centrally dispatched systems with integrated scheduling processes in place) and it is usually limited to the transmission network (business as usual) while gradually testing solutions to enlarge the perimeter of providers to the distribution level (but not necessarily implementing more detailed network models).

- Bidding zone size: A bidding zone is the largest geographical area in which market parties are able to exchange energy without capacity allocation. This is necessarily defined by the transmission grid. Consequently, Transmission System Operators (TSOs) (via ENTSO-E) have the responsibility to regularly conduct a bidding zone review based on structural congestions within the transmission grid on network elements >= 220 kV. Congestions in the distribution grid do not necessarily influence allocated capacities.

  Bidding zones need to ensure market liquidity, efficient congestion management and market efficiency. There is a clear obligation to redefine the bidding zone in case the minimum level of capacity cannot be provided (including internal and cross-border redispatch). There is already a complex process for this bidding zone review, as any change of bidding zone might have effects on e.g. new investments, liquidity and operational processes. Therefore, a reconfiguration must be carefully considered without rapid changes on short notice. Instead, all the criteria as stated in Article 33 of CACM, which aim to guarantee network security, market efficiency and robustness of the bidding zone, need to be thoroughly analysed. In addition, if DSF is seen as a solution to move toward a carbon neutral economy, as expressed in the ASSET study, it would be relevant to tackle climate neutrality in its definition as some segments of DSF could be based on fossil fuels (e.g. industrial emergency power generators with fossil fuels).

3 Summary and further aspects to consider

Regulators, in general, welcome the ASSET study but CEER does still recommend to carefully follow, monitor and evaluate the ongoing processes regarding the utilisation of DSF. Regulators offer, of course, full support to the relevant monitoring and design processes. Since the potential starting date for the work on a DSF NC is 2022, we do suggest taking a final decision on the need and the timing for such a NC closer to this date. As currently assessed, regulators do not see the need to produce a specific NC on this topic now, as the scope is currently unclear.

Another important reason for having careful considerations on the timing is that in case a DSF NC would be elaborated, it is likely that the established EU DSO entity would play a role in this elaboration process. Thus, this entity should be properly and fully operational when this work commences, otherwise a pivotal actor could not give its essential contribution.

It is worth mentioning that besides market-based procurement, there are also other options to assess flexibility needs at DSO level, for instance, a rules-based approach, connection agreements and network tariffs[6]. In all cases, flexibility is not an end in itself; it is a tool to operate grids more efficiently and can contribute to managing the ongoing challenges stemming from the integration of renewable generation. Therefore, freedom to test different solutions is necessary, considering existing local

[6] For more on this, see the CEER Paper on DSO Procedures of Procurement of Flexibility, Ref: C19-DS-55-05,16 July 2020.

contexts. The possibility for EU-wide sandboxes would be helpful to allow testing without complying with all European obligations or rules in place.

The current design of CACM GL and EB GL is already “technology neutral” oriented, meaning that all resources that satisfy the requirements shall be eligible to participate in the market. If some barriers are detected or there is need for further specification, an amendment process aiming to remove those barriers would be an efficient approach. On the other hand, if the barriers lie in the national terms and conditions, this is a compliance issue of local TSOs and DSOs. However, in both cases there is no clear need for a new NC.

The study includes some new and challenging aspects. Especially, it seems that there are risks existing which should be carefully considered before actions are taken. For instance, risks related to further combining wholesale energy markets with system operation or ancillary services and congestion management which would require a deep rethinking of the whole target model. Also, in some areas sufficient experience is still lacking (e.g. implementation of grid codes is not finished), and, in light of this lack of experience, a preferred next step would be to possibly amend existing NCs, where needed rather than jumping to creating new NCs. In other areas, national frameworks seem to be better suited, such as for potential frameworks for DSO flexibility procurement after NRA assessment compliant to Article 32 of the Electricity Directive of for proper implementation of national terms and conditions of existing NCs.

Annex 1 – CEER´s summary of the EC ASSET Study on Regulatory Priorities for Enabling Demand Side Flexibility

The outcome of the study provides specific policy recommendations, which build on different scenarios and design options for DSF:

1. The study's preferred way forward is the so-called "Balanced Scenario": This approach puts forward the idea of a congestion market at DSO level defined in a Bottom Up scenario and recommends the definition of a minimum set of harmonised products to additionally enable cross border trade.

   Two pathways can be envisioned within this scenario (Alternative A and B).

   Alternative A builds on the current framework in which TSOs agree on a common methodology for coordinated redispatching and countertrading at Capacity Calculations Region (CCR) level (Article 35 CACM). According to Article 35 paragraph 2 of Electricity Regulation (EU) 2019/943, redispatching has to be organised with market-based mechanisms (base case) if none of the exemptions in paragraph 3 of the same article are applicable.

   Alternative A also includes the DSOs since Article 57 of Electricity Regulation (EU) 2019/943 requires DSOs and TSOs to cooperate with each other to manage their networks. Therefore, Alternative A proposes to extend the market-based framework to manage redispatch at CCR level to also include congestion management at distribution level. The consultants suggest to jointly optimise congestion at distribution and transmission level. Therefore, a minimum set of standardised products shall be defined at CCR or even at EU27 level and distribution grid congestion shall be adequately considered in the wholesale electricity price formation and cross-border capacity allocation. No changes in the current pricing system at wholesale level would be required and it would remain based on bidding zones at transmission level. But the volumes would need to be adjusted depending on the flexibility activation in the congestion market. Therefore, concrete amendments of the CACM are suggested. Furthermore, the delineation of the local congestion markets would need to be defined to capture the main dynamics at low voltage level. More aspects should be considered in this approach, e.g. the timing of the redispatch market.

   Alternative B involves the integration of the distribution grid with existing wholesale markets. It would not go as far as the Top Down scenario in terms of geographical granularity of the market delineation; however, it describes a bidding zone split. According to the study, the bidding zones could initially be based on "larger" distribution zones, defined at medium voltage level where needed. The consultants regard the coherent way of managing the grid and the market as an advantage. The fact that more grid constraints would be integrated in the market clearing algorithm would reduce the need to resort to out-of-market measures and/or to congestion markets separated from wholesale markets. Smaller bidding zones would be a consequence. Reference is made to the Ten-Year Network Development Plan (TYNDP) by ENTSO-E which uses a network of about 100 zones to identify systems needs by 2040.

   However, this alternative is expected to require a major revision of the European legislative framework, including strong adaptations along the market sequence towards the real-time. The study provides some adaption examples, such as a much more formalised cooperation between DSOs and TSOs compared to what is currently foreseen in NCs. A common grid model would need to include information on distribution grids and require consideration of many bidding zones where the balancing market would become more and more the reference market. In a common grid model institutional questions would have to be considered (is a separate operation of the TSO and DSO grid and of the market still manageable?); the model's smaller bidding zones would raise liquidity issues.

2. Policy Options:
   The study assessed whether there is sufficient justification for the EC to intervene. The consultants see the relevance of the congestion market as a main decision factor and state that when these developments are solely left to the MS, lock-in effects are likely to be created and could strongly impede cross-border market integration. Therefore, intervention by the EC is deemed necessary.

   In case intervention is taken, there are the following three options to proceed:
   The first policy option suggests to only amend existing network codes and guidelines. This option would be required if Alternative A of the Balanced Scenario is chosen and the amendments aim to ensure that distribution grid constraints are adequately considered in the wholesale market price formation and cross-border capacity allocation. Amendments could focus on some articles in the CACM and EG BL This option would provide a lower risk of failure since no major derivations from the target model would be requested. The EC would have to consult the EU Agency for Cooperation of Energy Regulators (ACER), ENTSO-E and the EU DSO entity. The consultants state that Alternative A is not perfect from an economic efficiency point of view, since inefficiencies can be expected in the relationship between congestion management markets and wholesale markets.

   However, the CACM acknowledges that the distribution grid might have an effect on contingencies and contestations, but the distribution grid and DSOs as such are not directly impacted by cross-border capacity calculation and therefore, not subject to this regulation. The inclusion of DSOs in this regulation constitutes an enormous change and impacts current processes to a barely-manageable and undesired extent.

   The **second policy option** stipulates the introduction of new NCs or guidelines and corresponds with implementing Alternative B, which highlights a consistent way of looking at TSO and DSO congestion also at EU level. Nodal pricing which extends to the DS level is not foreseen. This option will require important institutional changes and is expected to be time and resource consuming. The consultants assign to this option a relatively high risk of failure, due to the significant step change required.

   Since the methodologies and deliverables originate from the current NCs and guidelines concerning capacity calculation and redispatch optimisation are not yet implemented, it is not the right time to replace these regulations. Currently, marginal changes of CACM are being discussed in order to include new provision of Electricity Directive 2019/943. But the EC has strictly narrowed the scope of possible changes.

   The **third policy option** is to combine the amendment of existing NCs together with an introduction of new NCs. The EC would start working on Alternatives A and B of the balanced scenario together. The consultants see the advantage that it can help address local congestion within the time horizon of 2025, while allowing for a consistent way of managing congestion at transmission and distribution level. Also, the EC would be provided with time to prepare Alternative B while learning from Alternative A. The high-risk failure of only considering Alternative B would be reduced.

   This option manifests the disadvantages of both options that have already been addressed above.