Energinet
Tonne Kjærsvej 65
DK-7000 Fredericia

+45 70 10 22 44
info@energinet.dk
VAT no. 39 31 49 59

Date:
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Author:
MPI/MTY

MEMO

ENERGINET CONSULTATION ANSWER TO PC_2021_E_01 ACER CONSULTATION ON NEW AMENDMENTS TO DETERMINATION OF CAPACITY CALCULATION REGIONS

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1. Introduction

The ACER proposal has been discussed between the four Nordic TSOs and the effects the proposal will have on the Nordic cooperation has raised substantial concerns. The consultation answer has been drafted by Energinet as Energinet is the most directly affected TSO, but the concerns raised in the consultation answer is shared by the four Nordic TSOs and the consultation answer is supported by Svenska Kraftnät, Fingrid and Statnett.

The Nordic TSOs are grateful for the opportunity to submit its comments on ACER's consultation on a proposed CCR Decision, and in particular on ACER's proposal to move DK1-NL and DK1-DE/LU bidding zone borders from CCR Hansa to CCR Core, and to move the DK1-SE3 and DK1-DK2 bidding zone borders from CCR Nordic to CCR Hansa.

As ACER is aware, the configuration of CCRs is one of the fundamental elements of the internal electricity market. CCRs are the building blocks on which two of the most important processes in market and system operation are based, namely capacity calculation and operational security coordination (Articles 20 and 21 of CACM and Article 76 of SO GL). In view of the importance of these issues, it is essential that the CCRs are defined correctly. The relevant guidelines accordingly set out rules for the definition of CCRs that must be observed by all participants in the process.

ACER's proposal disregards these rules in a number of important respects. As will be explained in more detail in this response, ACER's proposal to move the bidding zone borders:

- lacks competence, by imposing on the TSOs a change of capacity calculation methodology (cNTC to flow-based) that ACER has no power to impose;
- reverses the burden of proof by requiring the TSOs to demonstrate that retention of the existing CCR Hansa region is more efficient than ACER's proposal. In fact, the correct test is the opposite: the proposed arrangement may be accepted only if it is demonstrated to be more efficient than the existing arrangement;
- in any event, ACER's proposal is less efficient. It is not required for effective capacity calculation as ACER claims;

- is not required for reasons of operational security in respect of the Cobra Cable or otherwise;
- has significant adverse consequences for operational security within DK2, and between DK1 and DK2,
- will result in unnecessary (and therefore inefficient) complexity, requiring Energinet to participate in 3 CCR regions and received services from 2 RSCs;
- is disproportionate, discriminatory and contrary to key objectives of CACM and SO GL.

These points summarise Energinet's response to the questions posed in ACER's consultation document. Energinet expands on these points in more detail below, and finally summarises its comments as brief formal responses to ACER's questions.

ACER is reminded that before approving terms, conditions and methodologies (TCMs) under the network codes and guidelines, it is required to ensure that they are "in line with the purpose of the network code or guideline and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market" (Regulation 2019/942, Article 5(6)). This requirement applies equally to ACER's proposed changes to TCMs. In this case, however, ACER's proposals do not meet the requirements of Article 5(6), or alternatively meet them less well than ENTSO-E's proposals.

Lack of competence

CACM sets out a clear series of procedures and responsibilities. Article 20 sets out a process for the development of capacity calculation methodologies. It provides for the introduction of flow-based capacity calculation in certain CCRs (including CCR Core). In others, it permits TSOs to request the retention of the cNTC approach, subject to certain conditions. The decision on the retention of the cNTC is a decision for the relevant NRAs. In the case of CCR Hansa, this decision was taken in December 2018.
The ACER website at https://www.acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/IMPLEMENTATION/Pages/2020CAPACITY-CALCULATION.aspx sets out the lengthy and comprehensive process by which the relevant NRAs approved the TSOs' request, resulting in approval of the CNTC methodology for Hansa: https://www.acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/16%20CCM/Action%205%20-%20CCM%20Hansa%20approval.pdf. It is not now for ACER to attempt to go behind the NRAs' decision by forcing a move to flow-based capacity calculation. There is no provision in CACM or elsewhere for it to do so, and it has no competence.

Reversal of the burden of proof

The determination of capacity calculation regions is governed by Article 15 of CACM. Article 15(3) provides for the merger of CCRs applying a flow-based approach where the following conditions are satisfied:

(a) their transmission systems are directly linked to each other;
(b) they participate in the same single day-ahead or intraday coupling area; and
(c) merging them is more efficient than keeping them separate.

What ACER proposes is in effect the partial merger of two CCRs (CCR Core and CCR Hansa), resulting also in the extension of the flow-based approach to what is currently part of CCR Hansa, as well as the DK1 bidding zone. This partial merger may therefore take place only if it is more efficient than keeping the two CCRs separate. The burden of proof is therefore on those parties proposing the merger, to demonstrate that the merger is more efficient than keeping the CCRs separate.

However, ACER ignores this in the consultation. For example, it states: "if TSOs disagree with the default solution [ie. the reallocation of the BZBs to CCR Core], they may prove that the default solution is not the most efficient one in which case they would need to demonstrate such efficiency and make a proposal which cancels such reallocation." It is not open to ACER to reverse a legal test set out in the legislation. The default position should therefore be that the BZBs remain allocated to CCR Hansa, moving only if it can be established that a merger is more efficient.

In any event, even if (which Energinet does not accept, for the reasons set out above) it were required to prove that retention of the existing arrangements was more efficient than ACER's proposal, it would be able to do so, for the reasons set out below. Put simply, ACER's proposal is overall significantly less efficient than the existing arrangements.

2. Capacity calculation and allocation

On the subject of capacity calculation, it is useful to consider capacity calculation, flow distribution and the location of congestion. In each of these areas, Energinet demonstrates that the flow-based methodology brings no advantages over the cNTC methodology, in the specific circumstances of the DK1-DE/LU border, and in fact introduces significant inefficiencies.

2.1 Capacity calculation

ACER argues that moving the AC BZB DK1-DE/LU into CCR Core, thereby moving it into the CCR Core flow-based methodology, would address more efficiently the characteristics of the AC border. It argues that the flow-based methodology models more accurately the flows at the border. In particular, ACER builds its argumentation on the future new build of the so-called west coast line, which will be a two circuit new transmission corridor across the DK1-DE/LU bidding zone border, stating that this will mean that the border no longer will be radial.

Energinet accepts that the flow-based methodology may – as a general rule - be more appropriate for meshed AC borders. However, the specific characteristics of the DK1-DE/LU border are an exception to the general rule, such that retention of the cNTC approach is equally efficient. This does not undermine the position in relation to other AC borders.

From an electrical perspective, the DK1-DE/LU border is a radial border. Not only do the [3 lines] cross the border in very close proximity to each other, 2 of them pass through the same substations Kassø in Denmark and Audorf in Germany while the west coast line is located roughly 30 kilometres to the west of these. As the grid connecting the endpoints is very strong, the electrical distance is insignificant in cases of large power flows across the bidding zone border. There will, also when the west-coast line is built, only be one AC-path between the DK1 and DE/LU grids, and that is across the DK1-DE/LU bidding zone border.

ACER argues that the use of C-NTC methodology is not suitable for the DK1-DE/LU border as in reality the location and size of the congestion depends on the market outcome in Core and Nordic CCR, which can only properly be modelled with flow-based approach.
Energinet's analysis shows that flow-based capacity calculation does not yield any additional benefit compared to the cNTC approach on the DK1-DE/LU bidding zone border due to its radial nature. This is demonstrated in Figure 1.

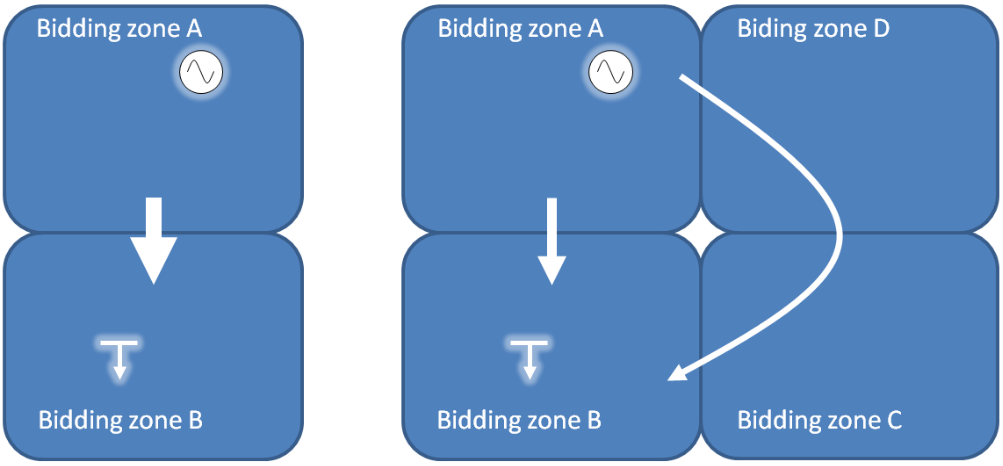

Figure 1 Figure 2

In figure 1, the bidding zones A and B are interconnected in a radial way. Just like the Danish-German AC border, there is a one-to-one translation from the scheduled power exchange between those bidding zones into a physical cross-border flow on the lines. Translated into the flow-based parameters, this means the interconnection has a PTDF = 1. With the general flow-based equation being:

$$PTDF_{A\to B} \cdot NP_{A\to B} \leq RAM$$

The full change in net position (NP) between the bidding zones A and B fully manifests onto the capacity of the interconnection. In case there are several lines connecting the two radially connected substations, the individual PTDFs of these lines sum up to 1 in total. I. e. the same amount of power that enters the line also must leave it again. In a setup as in Figure 1, there are no synchronous connections to other bidding zones. Therefore, any exchanges between other bidding zones (not shown in the example of Figure 1) have a PTDF = 0 onto this interconnection. Bidding-zone borders connected by HVDC lines also have no effect on the interconnection between A and B.

In case of an NTC calculation, the NTC value between the bidding zones A and B is equivalent to the full change in net position since the whole flow must pass through the interconnection between A and B. Therefore, both methods will lead to the same results. Application of the cNTC methodology therefore captures all information needed in order to model accurately the capacity at the bidding zone border. The explanation shows that the cNTC method is an efficient means to allocate the commercial exchanges in grids with radial connections, and therefore also on the DK1-DE/LU bidding zone border.

In Figure 2 the situation in meshed grids – like the Continental European and Nordic power systems – is depicted. A commercial exchange between the two bidding zones A and B results in a physical flow fanning out through the meshed system. It is exactly this behaviour that is captured by the flow-based methodology, which makes it the preferred solution in meshed grids.
Given the physical layout of the DK1-DE/LU bidding zone border and the DK1 bidding zone in general, the situation of Figure 2 cannot happen. In fact, in radially connected systems, the flow-

based methodology does not provide different results and therefore has not any added value compared to cNTC, as there are no alternative routes from bidding zone A to bidding zone B.

2.2 Flow Distribution

ACER also argues that the cNTC methodology is unable to model accurately the flows and constraints away from the borders. In reality, the highly radial nature of the border makes it unnecessary to do so. This is illustrated in Table 1 below. This table focuses on flow distribution and in both the N-0 case and in the three different N-1 scenarios there is generally only up to 1 percentage-point of difference in the flow across the three corridors, as between two very different market scenarios (high wind, low demand, export on all interconnectors (Scenario A), as opposed to medium wind, high demand, low exchange on most interconnectors (Scenario B). This means, that when capacity is calculated on the bidding zone border, the distribution of load and generation in DK1 does not significantly influence the power flow distribution on the border, and therefore will not significantly influence which CNEs are limiting and thereby what the capacity on the bidding zone border will be.

Table 1

Scenario A **High wind, low demand, export on all IC**	**West coast systems**	**Central systems**	**East coast systems**	**Total**
N-0 flow	33%	31%	36%	100%
Contingency 1	28%	33%	39%	100%
Contingency 2	34%	23%	43%	100%
Contingency 3	38%	45%	17%	100%
Scenario B Medium wind, high demand, Low exchange on most IC.	West coast systems	Central systems	East coast systems	Total
N-0 flow	34%	30%	35%	100%
Contingency 1	29%	33%	38%	100%
Contingency 2	35%	23%	42%	100%
Contingency 3	40%	45%	15%	100%

Table 1: In two significantly scenarios the flow distribution in percentages on the three different double systems across the DK1-DE/LU bidding zone border is shown for both N-0 and the three contingencies on the bidding zone border. The table shows there is not a large difference between the scenarios. Contingency 1 is losing one of the West coast circuits, Contingency 2 is losing one of the central system circuits, while Contingency 3 is losing one of the East coast circuits.

The deviations in Table 1 should be held up against capacity calculation in flow-based market coupling. In flow-based, the electrical parameters are linearised in order for them to be transformed into Power Transfer Distribution Parameters (PTDFs) which can be used directly by the power exchanges in the allocation phase of the market. This linearisation will for flows above

22MW on average have a flow-error of 1,5%[1]. When this 1,5% flow-error is compared to a difference of 1 percentage-point in flow difference between the two scenarios shown in Table 1, then they are very similar, thus the error in one of the main ex-ante assumptions made in flow based corresponds in size with the inaccuracy of flows in an NTC methodology as shown here. Therefore, it is clear, that it brings no advantages to represent the radial grid on the DK1-DE/LU bidding zone border with flow-based compared to cNTC.

2.3 Where are congestions likely to occur

Even when the DK1-DE/LU bidding zone border is congested, it is not the cross-border CNEs which will be congested under normal operating conditions. In reality, the bidding zone border connections will be a much stronger part of the network than the national grids in DK and, we believe DE, which are connected by the border. Thus, it is highly likely that it will not actually be the cross-border CNE's which will be congested, but internal grid elements, also when accounting for the CEP70% requirement. Here it is very important to note, that the CCR Hansa CCM, specifically only includes the cross border CNEs as relevant CNEs. Internal CNEs within DK1 and DE/LU respectively are already taken into account and allocated efficiently under the flow-based methodologies applied in DK1 (as part of CCR Nordic) and DE/LU (as part of CCR Core), albeit the flow-based methodologies in DK1 and DE will be slightly different. In Table 2 it is shown, for two significantly different situations, how the capacity on the bidding zone border CNEs will be subject to contingencies on each of the 3 double circuits, represented in the three contingencies. Based on this the thermal capability of the bidding zone border CNEs will be in the region of 5900 to 6100MW. Based on full system studies, including dynamic constraints, from Energinet and TenneT the expectation is that about 3500MW is a possible transfer capacity when *all* operational security limits are taken into account. This very clearly shows that the cross border CNEs are not going to be the limiting factor for exchanges across the bidding zone border.

Table 2

	High wind, low demand	Medium wind, high demand
N-0 flow	8400	8500
Contingency 1	6100	5900
Contingency 2	6500	6600
Contingency 3	6600	6700

Table 2: The calculated max flows in MW in export direction from Denmark,, seen from an Energinet perspective, in N-0 situation and when contingencies on the bidding zone border CNEs are taken into account. This is purely a consideration of the thermal limitations on the cross border CNEs.

With the bidding zone border DK1-DE/LU being the only AC connection from Denmark to continental Europe and the east coast and west coast lines being located quite close to each other they are radial in an electric sense. All net-position deviations will materialise exactly and only on the DK1-DE/LU border, on these exact lines, and will have insignificant impact on all other bidding zone borders due to the distance. Thus, the application of flow-based will also have insignificant impact on the market efficiency on this border. This impact should also be compared

[1] Paper: Usefulness of DC Power Flow for Active Power Flow Analysis, Konrad Purchala, Student Member, IEEE, Leonardo Meeus, Daniel Van Dommelen, Senior Member, IEEE and Ronnie Belmans, Fellow, IEEE

to all the other assumptions and simplifications which are made to enable the flow-based methodology, the GSK strategy, linearisation of electrical parameters etc.

Energinet recognises that flow-based has significant efficiency advantages in cases where there are several paths from A to B. In this case, from DK1 to DE/LU, there is only one bidding zone border on which the power can flow, that is the DK1-DE/LU border, thus all power flows will be exactly here. Energinet's position in respect of the DK1-DE/LU border therefore does not mean that the same principle should apply to other AC borders. The situation of CCR Hansa does not undermine the approach adopted for other CCRs/AC borders.

Energinet demonstrates above that moving the DK1-DE/LU border into CCR Core, and consequently applying the flow-based methodology, would have no material benefits in terms of improving the accuracy of the capacity calculation exercise. However, the move would have significant adverse effects. These are outlined below.

For the sake of completeness, Energinet should point out that moving the DK1-NL bidding zone border into CCR Core will similarly have no advantages in terms of efficiency. As a DC interconnector it can easily be modelled within a cNTC context and does not need to be modelled on a flow-based basis. In any event, as this change in CCR configuration is only to be carried out after AHC is implemented in CCR Core, the handling of the DK1-NL interconnector will be the same, as specified in the CCR Hansa CCM, where AHC representation in the two flow-based methodologies of CCR Nordic and CCR Core is preconditioned.

A final point regarding capacity calculation that should be noted. With the proposed change from ACER, two different flow-based methodologies will have to be implemented in DenmarkFor Energinet this will in addition mean that two different flow-based IT systems as well as procedures need to be implemented and maintained going forward, which leads to additional cost, and will also lead to more complex system operation in general in Energinet, thus an increased likelihood of errors being made.

3. Operational Security

ACER also argues that moving the DK1-NL border in particular, as well as the DK1-DE/LU border, to CCR Core will permit greater efficiency in regional operational security coordination. In particular, ACER expresses concern about an outage of the DK1-NL (Cobra) interconnector. Here also, however, ACER's proposal in fact adds no material benefit, because any fault on Cobra is already handled efficiently under current arrangements. In fact, the partial merger of CCRs proposed by ACER would have significant adverse effects for operational security in other parts of the system.

When considering if operational security is impacted by moving the DK1-DE/LU and DK1-NL bidding zone borders to CCR Core it is important to separate the timelines based on where the RSCs will be able to play a role and where they, due to not having any information, will not be able to play a role.

To begin with, Energinet already now makes Individual Grid Models (IGM) available to continental Europe TSOs and RSCs in the timeframes Intraday, day-ahead and seasonal in accordance with the requirements in Regional Group Central Europe (RGCE) in the UCTE-def format, and have done so for years. This is important as DK1 is part of the continental synchronous area and therefore is a part of the observability area of the continental RSCs and some TSOs. Furthermore it should be noted that CCR Hansa TSOs have contracted both Nordic RSC and TSCNET to provide all services to CCR Hansa due to which they are obliged to corporate on the delivery of capacity calculation, operational security analysis, outage planning, short and medium term adequacy assessment and merging of IGMs to CGM to CCR Hansa. Lastly the CCR Hansa NRAs have on 4. January 2021 approved the CCR Hansa ROSC proposal in accordance with SOGL art. 76 aiming at ensuring secure system operation in the region and efficient use of remedial actions.

The concern raised by ACER is that if Cobra Cable (DK1-NL) has a forced outage, then it will lead to an overload requiring remedial actions. It is concerned that under the current determination of CCRs, DE/LU-NL, DK1-DE/LU and DK1-NL bidding zones are not applying a common methodology for i) regional operational security coordination in accordance with Article 76(1) of the SO Regulation, ii) coordinated redispatching and countertrading in accordance with Article 35 of the CACM Regulation and iii) redispatching and countertrading cost sharing in accordance with Article 74 of the CACM Regulation. However, as Energinet demonstrates below, these concerns are unfounded.

The outage of DK1-NL is fully covered in the System Operation Agreement (SOA) made by TenneT NL and Energinet before the Cobra Cable was commissioned. The SOA has also been discussed with TenneT Germany, in whose control area the overload is most likely to take place, and they have agreed to the principles in the SOA, otherwise the cable could not have been commissioned. This means, that if Cobra Cable for some reason has an unexpected outage, it is up to the three TSOs to fix any operational security issues that follow from this, by applying remedial actions, as they would be the only ones who can see in real time what happens to the system in the control centres. The RSCs will not know anything at this stage, as it is the TSOs who will have the overview and responsibility to solve any operational security issues in the interconnected grid.

In case the cable is out for a longer time period, the RSC will obtain knowledge of the cable outage through the TSOs update of the IGMs which will be merged by the merging entity. At this point in time, the RSCs will be able to run a Remedial Actions Optimisation (RAO) in order to try to find more cost effective remedial actions to be applied than the ones which the TSOs have activated when handling the operational security violations that occurred immediately after the cable fault.

In case that DK1-DE/LU and DK1-NL would be in CCR Hansa, as at present, it would be up to TSCNET or Coreso to call the Nordic RSC to get knowledge of which remedial actions would be available in DK1 and at which price in order to take this into account in a Core RAO update. In case that DK1-DE/LU and DK1-NL would be in CCR Core, then TSCNET or Coreso would already have the remedial action list for DK1 to use in the RAO update. Again, it should be stressed that this is only in circumstances where the outage lasts for longer than 1-2 hours. In the case of any shorter outage, the TSOs would already have activated relevant remedial actions in accordance with their SOA. The only difference here between the DK1-NL border being placed within CCR Hansa and being placed in CCR Core is therefore whether TSCNET or Coreso would have to call the Nordic RSC to get knowledge of which remedial actions are available for the rest of the day. With cable trips happening only a few times a year, this cannot be considered a significant cost to society, thus the benefit of making the change is very limited if it exists at all. In fact, as Energinet explains below, any negligible and largely theoretical benefit resulting from moving the BZB into CCR Core would be very heavily outweighed by the disadvantages from the perspective of other operational security issues.

By reallocating the bidding zone borders DK1-SE3 and DK1-DK2 ACER would be creating the same problem that ACER believe is challenging the triangle of interconnectors DE/LU, DK1-DE/LU and DK1-NL in another place of the grid, namely the Hasle cut between SE3 and NO1. When problems occur in this place it is often alleviated by utilising DC-loopflows, which is a non-costly remedial action that the RSC can plan, from SE3 to DK1 to NO2 which is AC connected to NO1. With the ACER proposed change to CCRs, this would be influencing 2 CCRs where the methodologies are not the same. Not only will the ACER proposal shift the problem. Due to the fact that overloading's on the SE3-NO1 bidding zone border are more common than trips of the DK1-NL interconnector ACERs proposal will increase the problem. Today the DK1-SE3 border support the Swedish West coast corridor (placed in SE3) to fulfil the 70% minimum requirement on the Swedish connections to DE, PL, LT, DK1 and DK2, (NO1) Also, it should be kept in mind that DK1 provides costly remedial actions to Sweden as well as to Germany to alleviate internal congestions and maintain the 70% minimum requirement, something which could to some degree be hindered if the DK1 remedial actions are to be prioritised to CCR Core as described below.

Generally it seems that ACER is missing the fact, that as long as there are more than one CCR then, on the borders between CCRs, there will be operational tasks and actions which will not be covered by the same methodology or carried out by just one RSC. This is particularly true as market coupling has been rolled out across Europe, increasing the cooperation between TSOs. All TSOs are cooperating across all their borders, and with this proposal of reallocating some borders, ACER seems to ignore this, and seems to assume that cooperation happens only within a synchronous area which is off course not true.

3.1 Remedial Actions Planning

In case that the two bidding zone borders DK1-DK/LU and DK1-NL are moved to CCR Core it will not just be the bidding zone borders that move into the CCR Core. In fact, the whole DK1 bidding zone would effectively move into CCR Core, because the CCR Core CCM would be applied in the DK1 bidding zone to capture the interactions between flows and limitation on the Critical Network Elements (CNE). Energinet would therefore become a CCR Core TSO.

This would have important consequences for remedial actions.

In the ACER decision on SOGL art. 76 for CCR Core, the so-called ROSC methodology, the preparation and activation of remedial action for the whole CCR Core region is covered.

In article 9(2) of the methodology it is stated that: *"All potential RAs identified pursuant to paragraph 1 shall be considered as cross-border relevant (XRAs), unless all Core TSOs unanimously agree that a potential RA is not cross-border relevant."* [2]

This means that all remedial actions identified shall be considered cross-border relevant, thus they can be used to alleviate cross border issues. Certain remedial actions can only be left out if all TSOs in the region agrees to this.

In article 15(1) it is stated that: "*Each Core TSO shall make available all XRAs as identified in Article 9(2) to the Core RSC(s) for each day-ahead and intraday CROSAs as defined in CSAM unless an XRA is not available pursuant to this Article.*"[3]

[2] XRA is cross-border relevant remedial actions

[3] CROSA is Coordinated Regional Operational Security Assessment in accordance with SOGL art. 78.
CSAM is the all TSO methodology for coordinating operational security analysis, following SOGL art. 75.

This means, that all the remedial actions shall be made available for the RSCs to be used to solve operational issues within the CCR. Article 15(2)(b) does not provide an option for a TSO to hold back remedial actions for use inside its own control area or in other bidding zones under that TSOs control.

In Article 20(1) it is stated: "*Core TSOs and RSC(s) shall optimise XRAs in order to identify in a coordinated way the most effective and economically efficient XRAs, based on the following principles: (a) The remedial action optimisation (RAO) of XRAs shall be performed with consideration of all available XRAs in accordance with Article 15;*"
Article 20 makes it clear that the RSCs can utilise all available remedial actions sent to them in the RAO.

Article 27(2) and (3) states: "*In accordance with CSAM, Article 78(4) of the SO Regulation and Article 42(2) of the Electricity Regulation, during each CROSA, the recommended XRAs shall be considered as agreed, except where it is rejected by: (a) any XRA affected TSO (including XRA connecting TSOs) on the grounds that the implementation of a specific XRA would result in operational security violations; (b) XRA connecting TSO on the grounds that the recommended XRA is no longer available. 3. If a Core TSO rejects a recommended XRAs, it shall provide to Core RSC(s) and other Core TSOs clear reasons for rejection, including the evidence for the claimed grounds of rejection.*"

Article 27 shows that there are no national interests which can justify not utilising all XRAs proposed by the RSCs to alleviate operational security issues within the CCR. And the fact that a TSO who rejects a proposal for application of XRAs shall provide an explanation to Core RSCs and TSOs, including evidence, further shows this is a very firm process which does not leave any room for individual approaches to remedial actions within CCR Core.

In general it can be said that the Danish grid and procurement of reserves to a very large extent is focused on being able to provide as much capacity to the market as possible and while doing so, procuring as little reserves as possible. This to ensure as efficient a system as can be done in Danish conditions. This also includes seeing Denmark as one control area, sharing reserves across the bidding zones and it results in the two bidding zones being partially dependent of each other, in particular when the full grid is not available or during contingencies.

Most of the Danish reserves used for N-1 security is found in DK2 and are then partly shared with DK1. In case there is a 600MW flow on the western direction on the DK1-DK2 line, a fault on the 400kV lines across DK2 will result in a need to reduce flow on the DK1-DK2 link. This is done by utilising upward regulation in DK1 (DK1 RA) and down regulation in DK2 (DK2 RA). In the immediate operation, this will be done by Energinet, provided there are any upward regulation resources left.

However, if DK1 is allocated to CCR Core, and Energinet becomes a CCR Core TSO, it will be required to make its RAs available to the CCR Core RAO process. The RAs may therefore have been allocated prior to a fault happening in the DK2 area. If no or only few resources are left, then the reduced flow on the DK1-DK2 interconnector will be apparent as an imbalance on the DK1-DE/LU bidding zone border. The general intention of SOGL is to ensure that a TSO does not unnecessarily export problems from its control area to other areas. This virtually becomes impossible to comply with for Energinet, in this case, due to the resources in DK1 having been utilised by CCR Core's RAO process.

The same case can be described for an east going flow on the DK1-DK2 interconnector, where it will be possible downward regulation offers which would be missing if they have been allocated by the Core RAO process.

If Energinet were to handle the internal 400KV fault solely by utilising internal DK2 RA's, then Energinet would be forced to either reduce capacities between DK1 and DK2 and possibly DK2 and SE4 in some cases or procure more reserves, and these would have to be located at specific geographical locations in DK2, which would be very expensive as there would not be any flexibility in the tender. Otherwise Energinet would have to build another 400kV line across DK2 at a cost of several 100 million Euros.

In addition, if the fault persists, then no single RSC will have a full picture of the Danish grid, thus there is not one RSC which can optimise remedial actions for all of Denmark. This would have to be two different optimisation processes split by an internal Danish transmission line which seems very unfortunate seen from a Energinet perspective.

On a final note regarding remedial actions, Energinet do not disagree with sharing of remedial actions. Energinet finds however, that all Danish remedial actions should be shared with the same RSC, which then would be able to carry out a RAO process which includes all of Energinets control area.

4. The economic consequences for Energinet of the change

Energinet has described above the operational and efficiency consequences of ACER's proposal to move the DK1-NL and DK1-DE/LU bidding zone borders to CCR Core. These consequences will translate into adverse economic consequences for Energinet and ultimately the Danish electricity consumers would have to pay over the tariffs. If the borders are moved Energinet will be a part of 3 different CCRs with different methodologies, which Energinet for the respective bidding zone border would need to be compliant with. This creates major adverse economic consequences in terms of representation/resource costs, IT developments and implementation, service costs in terms of CCR Core methodologies and derived costs in terms of the consequences on the remedial actions in Denmark. This is imposed on Energinet without any socio-economic efficiency proved by moving the bidding zone borders.

Denmark spans two synchronous areas and in 2005 the Danish government made a conscious decision to create one National TSO and to build the interconnector from DK1 to DK2 to connect the two parts of the system together in 2010, in order for the National TSO to be able to operate the system as one, and obtain benefits of this for the good of the danish consumers. This merging of the Danish system is now being threatened by ACER with its decision to split the Danish system operation and thereby restrict the benefits of which the merging of the Danish system was based upon.

A reallocation of the borders DK1-DE/LU and DK1-NL will have a significant increase in terms of Energinets internal resources, as it will require participation in 3 different CCR Regions (Nordic, Core and Hansa). It is estimated that Energinet's costs for representation in CCR regions will increase annually with **EUR 1.1 million** by participating in CCR Core, in addition to representation costs in CCR Nordic and CCR Hansa.

A reallocation of the bidding zone borders will as described above have an impact on the allocation of remedial actions and consequences for the remedial actions across DK1 and DK2. If giving priority to internal Danish remedial actions to CCR Core, an annual increase in costs for the procurement of reserve capacity in DK1 is estimated to **EUR 27-40 million**.

A reallocation of the bidding zone borders, Energinet will have to pay a share of the common costs incurred as part of the CCR Core work. An increased cost of approx. **EUR 8 million** for participation in the CCR Core flow-based implementation, based on the experience of developing a Nordic Flow-based implementation.

A reallocation of the borders DK1-DE/LU and DK1-NL to CCR Core will have an impact on Energinet's IT investments and IT resources. As part of CCR Core, Energinet will have to make several IT implementations, in order for Energinet to be compliant with CCR Core's methodologies. Furthermore, Energinet will also have to implement IT implementations in line with the ongoing methodology developments in all three CCR regions. It is expected that the complexity of IT development and operations will increase, as different methods must be taken into account, and all changes to market and operational systems will be different between DK1 and DK2, leading to additional work and complexity, driven only by the reallocation of bidding zone borders to CCR Core. An increased annual cost for IT solutions of **EUR 6.3 million** is expected.

It is clear that ACERs proposal to moving the bidding zone borders will have significant economic consequences for Energinet, without adding any efficiency gains in the handling of those bidding zone borders but adding more complexity.

Infringement of EU law

As outlined above, when considering whether to approve TCMs, ACER is required to consider whether they are in line with the purpose of the relevant network code or guideline and contribute to market integration, non-discrimination, effective competition and the proper functioning of the market.

Article 3 of CACM sets out the purposes of the Regulation. They include:
"…
(b) ensuring optimal use of the transmission infrastructure;
(c) ensuring operational security;
(d) optimising the calculation and allocation of cross-zonal capacity;
(e) ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants;
…
(j) providing non-discriminatory access to cross-zonal capacity."

The objectives of SO GL are similar. In particular (Article 4(2) of SO GL), Member States, competent authorities and TSOs must:
"(a) Apply the principles of proportionality and non-discrimination;
…
(c) apply the principle of optimisation between the highest overall efficiency and lowest total costs for all parties involved;
…
(e) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation:

The proposed move of DK1-DE/LU and DK1-NL from CCR Hansa to CCR Core fails all of these requirements. It will result in less efficient use of the transmission infrastructure, specifically the DK1-DK2 line by prioritising remedial actions from DK1 to CCR Core rather than allowing them utilised at Energinet's discretion as TSO. It therefore fails to respect Energinet's responsibility for system security, imposed on it by national law. For the same reason, it will not ensure operational security. It will not improve operational security in respect of Cobra Cable, but in the light of the specific topology of Denmark, sitting across two separate synchronous areas, it will make operational security for Energinet's system less efficient. Similar, the move will make capacity calculation less efficient, by imposing on the DK1-DE/LU border a methodology which is not best suited to it, and will result in unnecessary complexity and therefore cost (as outlined below).

The issue of non-discrimination is particularly significant. While Energinet accepts that Regulation 2019/943 prohibits discrimination against cross-border flows, CACM equally prohibits discrimination against specific TSOs. Energinet's situation is unique among TSOs, in that it sits across two synchronous areas. It faces operational issues not faced by other TSOs. The current arrangements represent an efficient and effective way of operating, for which Energinet, at the direction of the Danish government and regulator has been optimised for many years. Moving a large part of its system into CCR Core will remove much of the efficiency that has been gained in this way and will expose Energinet and thereby Danish consumers to considerable unnecessary and unjustified cost. Article 4(2)(c) of SO GL provides for relevant parties to apply the principle of optimisation between efficiency and cost. ACER's proposal entirely fails this requirement because it reduces efficiency and adds significant annual cost (of the order of EUR 35-50m) and an initial cost as well. This cost will fall almost entirely on Danish consumers, and therefore infringes the principle of non-discrimination. Because there are other less disruptive options (in particular, maintaining the status quo), at least until it can be established whether the introduction of AHC in CCR Core will address the concerns identified in that region, the proposal also infringes the principle of proportionality.

Furthermore, this would seem a clear violation of the powers given ACER in Regulation 942/2019. According to recital 16 of the Regulation ACER can only adopt individual decisions in regard to situations concerning more than one-member state. By giving priority to internal Danish remedial actions to other member states ACER is adopting individual decisions regarding pure internal national matters in Denmark and thereby violation the prerogative of Energinet as national TSO to allocate remedial actions in both DK 1 and DK2 both being a part of the internal Danish electricity system and thus Energinets national area of rights and responsibilities. This also bearing in mind that the "Storebælt" DC-connector between DK1 and DK2 is not per definition an interconnector but a pure national transmission line and thus outside ACERs competences

The proposal from ACER states that "*An outage of the DK1-NL HVDC interconnector would, for example, require a large amount of remedial actions located in these bidding zones but, under the current determination of CCRs, these bidding zones are not applying a common methodology for i) regional operational security coordination in accordance with Article 76(1) of the SO Regulation, ii) coordinated redispatching and countertrading in accordance with Article 35 of the CACM Regulation and iii) redispatching and countertrading cost sharing in accordance with Article 74 of the CACM Regulation. A cross-regional coordination of remedial actions and the related sharing of costs cannot be considered as possible enduring solution to address the problems related to these three borders*", Moving the bidding zone borders as proposed by ACER seems to ignore that this exact same problem will then occur on the NO1-SE3 border, where the change of setpoint of the interconnectors SE3-DK1 and DK1-NO2 is used to alleviate operational challenges. Today that will be covered by CCR Nordic methodologies, while with ACERs proposal, this would have to be covered by both CCR Nordic and CCR Hansa methodologies, thus the problem persists where remedial actions are to be utilised across CCRs but being covered by different regional methodologies, it is just moved to a new place in the grid.

Summary: responses to questions:

Q1 - Please provide your comments concerning the ACER's reasoning for default reallocation of Hansa CCR bidding zone borders and the request to TSOs to make a proposal on a suitable time-line for such reallocation.

For the reasons set out in detail in the text above, Energinet considers that ACER's proposed move of the DK1-NL and DK1-DE/LU bidding zone borders from CCR Hansa to CCR Core does not comply with the requirements of CACM, SO GL or Regulation 943. The proposal is no more efficient than the current arrangements. On the contrary, it is considerably less efficient, and is likely to result in significant operational difficulties for Energinet, as well as costs in the region of EUR35-50m annually. ACER is unable to point to any corresponding cost benefits or real efficiencies that would outweigh even a fraction of this cost.

Q2 - Please provide your comments concerning the option to cancel such reallocation and the assessment criteria for making such a proposal.

Energinet understands that this question relates to the purported requirement that the TSOs should justify any retention of the existing arrangements by reference to greater efficiencies in the current arrangements. While it is clear from the points made in response to Question 1 that the current CCR Hansa/CCR Core configuration is in fact considerably more efficient than ACER's proposal, Energinet notes that ACER has reversed the burden of proof clearly set out in Article 15 of CACM, which requires any merger of CCRs (such as this proposed partial merger) to take place only if more efficient than retention of the current configuration.

Energinet is of the opinion that ACER is asking the wrong questions in this Q2 section.