Variations in the Implementation of Flow-Based Market Coupling and their Implications for Efficiency

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Report summary

This report looks at similarities and differences in Member States' current and or planned implementation of flow-based market coupling (FBMC) and the assessment of compliance against the 70% rule. It summarises current and planned practice in a selection of Nordic and CORE markets and considers the theoretical implications of these differences for the efficiency of the internal power market. We conclude that for some of the areas examined, the observed differences in national practice are unlikely to significantly influence efficiency. They may even support greater efficiency where they allow TSOs to better reflect the system management constraints faced in their networks. In other areas, notably where cross-zonal trade capacity is expanded or restricted in a way that is unlikely to result in a more accurate representation of the transmission network's limitations, the impacts on efficiency are potentially more significant and likely to be negative.

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Summary and conclusions

EU electricity market regulation, specifically its Network Codes, allows for differences in implementation among Member States. This flexibility is made possible by separate regional Terms, Conditions and Methodologies (TCMs). This report looks to identify concrete examples of how practice differs between Member States in selected areas of implementation. In particular, we examine how cross-border transmission network constraints are represented in the European electricity market through so-called Flow-Based Market Coupling (FBMC). The overarching approach for representing such constraints is set out in the Guideline on Capacity Allocation and Congestion Management (CACM).

Elements of the FBMC process vary significantly among TSOs. Some of these differences are unproblematic and may even support efficiency.

Looking at a small sample of countries, we observe that there is considerable national variation in how certain key parameters within the FBMC process are set. This includes the initial approach to identifying network constraints (CNECs) and how TSOs make assumptions on the distribution of a trade among a zone's generation (and load) units (GSKs). Although the format of this information is standardised in European regulation and the supporting capacity calculation methodologies, determining these parameters takes place at a level of operational detail at which procedures are not specified. Thus, though the nature and the aim of these parameters are set out in European regulation, TSOs are effectively free to develop these assumptions however they see fit.

Our impression is that, for the TSOs examined, there is a sufficiently clear and common purpose such that the observed difference in their operational practices does not harm efficiency. In some cases, we instead observe a sort of convergent evolution among TSOs to similar operational practices.

In other cases, regulatory flexibility may support more efficient operation, for example by allowing TSOs to better reflect system constraints peculiar to their system.

Some attempts to expand the scope for cross-border trade may harm efficiency.

The FBMC process attempts to ensure that the limits placed on cross-border trade accurately reflect the physical constraints of the transmission system. The capacity calculation methodologies we examined include various ways in which the constraints are relaxed. The most notable of these are found within the FBMC methodology for the CORE capacity calculation region. Here, available capacity is expanded to ensure compliance with the so-called 70% rule, which imposes a lower limit on the amount of cross-zonal capacity that should be offered to the market. The capacity offered in the day-ahead market is also expanded to ensure that the capacity available is at least as large as the capacity sold in advance as transmission rights.

Both of these practices can result in the creation of so-called virtual capacity, namely transmission capacity that is accessible by the market to support cross-zonal flows but not supported by the physical transmission system. There may be other reasons to favour these expansions, such as to incentivise effective bidding zone design or minimise TSO financial losses. However, it must be recognised that, by providing a less accurate view of the physical capability of the transmission system, the creation of virtual capacity is liable to result in market prices and market results that are inefficient.

National assessments of compliance against the 70% rule differ, even though no variation is explicitly envisioned by European legislation.

The examples above cover differences in practice permitted by the formal development of differentiated regional methodologies. However, there also exist differences in practice among Members States within elements of the regulatory framework which are, in theory at least, standardised. A clear example of this is the assessment of compliance against the 70% rule by National Regulatory Authorities. Different authorities opt to assess compliance differently. Consistent application of the 70% rule would not necessarily imply greater efficiency but can influence whether or not a TSO is deemed to have complied with the relevant European legislation.

HVDC interconnectors have enjoyed privileged access to capacity on the AC network. However, changes to the way FBMC is implemented should support equal access in the future.

The FBMC process is primarily designed to represent flows in an AC network. However, the DC cables used to connect many bidding zones operate very differently. In particular, flows across these DC cables can be controlled independently of generation and consumption elsewhere in the AC network.

In the past, the market processes used to allocate scarce network capacity in the AC network effectively gave flows on DC cables priority access. This could lead to inefficiency. First, the forecast flows on the DC cables could be wrong, resulting in AC capacity being reserved, but not used. Second, giving DC flows priority access could prevent capacity within the AC grid from being allocated in alternative and potentially more efficient ways. Thankfully, the introduction of Advanced Hybrid Coupling will address these deficiencies in the current implementation, supporting the more efficient integration of DC cables into the FBMC process.

In conclusion, for the specific examples examined in this report, the scope for regional variation in the implementation of European regulation does not always result in substantive differences. Where differences do arise, some may enhance efficiency by recognising differences between regional systems. In other cases, these differences appear to reflect differences in local regulatory preferences.

1 Scope and Objective

This report forms part of the output of the ‘Implementing Network Codes’ project funded by the Research Council of Norway. The project is designed, among other things, to examine whether the flexibility provided by EU legislation to develop regional Terms, Conditions and Methodologies (TCMs) under the European electricity market Guidelines has contributed to the efficient integration of the power market.

This report looks to identify concrete examples of how practice differs between Member States and regions in:

- the current and or planned implementation of flow-based market coupling (FBMC)[1], and
- the assessment of compliance against the 70% rule.

Both these elements of the regulatory framework concern how trade in electricity from one area to another, including international trade, ought to be limited to reflect the physical limitations of the electricity network.

This report seeks to summarise some examples of similarities and differences in the approaches used and to consider what implications, if any, these have for the efficiency of the internal power market.

In scoping the work, we have intentionally selected a discrete set of activities where we expected to find differences and expected these differences to have potentially significant implications for market efficiency. As such, these areas should not be interpreted as representative of the implications of differentiated national or regional practice in general.

The selection of issues selected for review is listed below. Each of the issues is explained in further detail in section 2.2

List 1 Issues examined as part of the work

- Defining Critical Network Elements with Contingencies (CNECs)
- Defining Generation Shift Keys (GSKs)
- The treatment of DC cables in flow-based market coupling
- The extraction of the intraday security domain
- Incorporating virtual capacity into the flow-based security domain
- Assessing compliance with 70% rule

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[1] An obligation to develop a flow-based capacity calculation methodology was placed on Transmission System Operators by Article 20(2) of the Guideline on Capacity Allocation and Congestion Management (Regulation (EU) 2015/1222).

2 Primer on Flow-Based Market coupling and the issues examined

2.1 Highly simplified description of flow-based market coupling

The European power market is divided into areas, known as bidding zones, and the market design allows for power to be bought and sold across the borders of these bidding zones. The extent of such cross-zonal trade needs to be limited to reflect the physical limitations of the transmission system, thereby preventing market outcomes that cannot be implemented.

There are various ways in which the physical limitations of the transmission system could be represented in the market design. To facilitate potential exchanges in power, European regulation establishes a common high-level approach for defining these physical limits. It also requires TSOs to work together in defined regional groups, so-called Capacity Calculation Regions, to agree on detailed methodologies for defining the physical limits of the transmission system, consistent with the common high-level approach.

The preferred approach for defining the physical limits of the transmission system in the European market design is so-called flow-based market coupling (FBMC).[2] Like all such approaches, FBMC entails a simplification of the real-world limitations of the power system. This section provides a highly simplified account of how transmission network constraints are defined under FBMC and how these constraints are used to determine which cross-zonal trades are allowed.

The constraints are identified by Transmission System Operators (TSOs) and defined with reference to so-called Critical Network Elements (CNEs). These are the elements of the network, typically transmission lines, that the TSOs believe need to be monitored as part of the market-clearing process to ensure system security. In practice, the TSOs consider a variety of ‘contingencies’, i.e. potential outages or faults that might occur, and the CNEs that are potentially relevant will differ depending on the contingency being considered. The TSOs effectively report the list of CNEs relevant to consider under normal operation as well as a list of the CNEs relevant to consider under a variety of contingencies that should be monitored. Combining the information on the CNE and an associated contingency definition yields a ‘critical network element with contingency’ or CNEC. A numerical MW limit is assigned to each CNEC. This limiting amount of power that can be securely handled is the so-called Remaining Available Margin or RAM.

FBMC works by assessing the flows implied on each of these CNECs by a potential cross-zonal trade. If the trade implies a flow in excess of the RAM, then it is deemed to exceed the secure operational limits of the transmission system. In practice, the energy market will not match bids and offers for power in different bidding zones if doing so would imply flows that violate a RAM constraint.

The flows implied on individual CNECs by different potential patterns of trade are estimated based on a linear model of flows, as illustrated in Figure 1 below.

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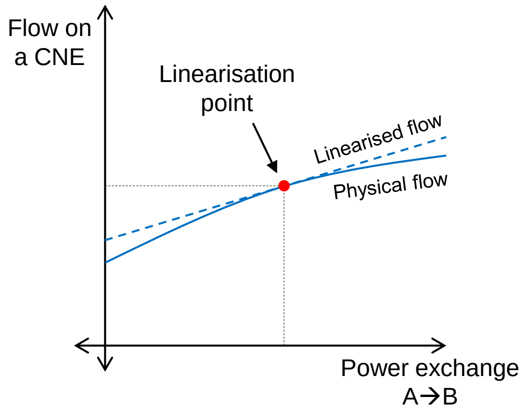
[2] See Article 20 of the Guideline on Capacity Allocation and Congestion Management (Commission Regulation (EU) 2015/1222). FBMC is often contrasted with the use of Net Transmission Capacities (NTC). Under the NTC approach, the limits on cross-border power exchanges are simply defined as a maximum exchange of power (MW) for each border and in each direction. The NTC approach fails to account for the fact that the flows on one border may influence the feasibility of flows on other borders.

Figure 1 Linear estimation of flows



Put simply, a base case projection of flows is developed that reflects an assumed pattern of trade between bidding zones. This defines the linearisation point shown in Figure 1. However, to assess how flows might deviate from this point due to a different pattern of trade, we also need to define the rate at which flows will change on the relevant CNEC if more or less trade occurs.

Specifically, FBMC defines Power Transfer Distribution Factors (PTDFs) for this purpose. The PTDF matrixes define the impact of a marginal increase in generation and consumption in two separate zones on the implied flows on all affected CNECs. In effect, they define how any cross-zonal trade will affect flows on all affected CNECs and define the slope of the straight line in Figure 1.

In summary, the list of CNECs and their associated RAMs define the network elements that need to be considered when assessing system security, as well as the maximum permissible flows on these network elements. The energy market uses these parameters to determine how much electricity can be securely exchanged between bidding zones.

The base case and PTDF matrices allow us to estimate the flows on any CNEC for any given pattern of trade by figuring out the implied deviation from the base case and using the PTDFs to come up with an adjusted estimate of the implied flows.

Put very simply, FBMC coupling uses this approach to ensure that market outcomes respect the physical limitations of the transmission system.

2.2 Relevance of the specific issues considered in the work

2.2.1 Defining CNECs

FBMC establishes a standard structure by which to define transmission system limits in the form of CNECs and RAMs. However, the TSOs face a variety of operational challenges and therefore considerable discretion in terms of which elements are defined as CNEs and how. As the constraints recognised as part of the FBMC are defined with reference to individual CNECs we therefore wanted to understand how CNECs are identified in practice and whether there were significant differences in the national or regional practice.

2.2.2 Defining Generation (and Load) Shift Keys (GSKs)

The European electricity market does not distinguish the location of bids and offers for power beyond the level of bidding zones. The lack of more granular spatial resolution creates a challenge when we want to estimate the implications for transmission system flows of clearing a trade between two different bidding zones. To see why, consider the implications of scheduling additional trade from France to Germany. If this trade implies changes in generation and consumption close to the border between the French and German bidding zones, then the implication on flows is concentrated on those network elements spanning the border. However, the same trade could alternatively imply an increase in generation and consumption at points far removed from the border and effectively require flowing power over long distances within the French and German transmission systems.

Because of this mismatch in the granularity of spatial information, with the network modelling using a more granular nodal model and the power market using less granular bidding-zone-level bids, we are forced to make some assumptions about how zonal-level changes should be simulated at a nodal level. These assumptions are defined by so-called Generation (and Load) Shift Keys (GSKs) and defined by each TSO.

The GSKs define how differences in trade flows relative to the base case are assumed to be distributed across the different generation and load units in the grid model. So, if a power market trade increases net generation in a bidding zone, the GSK for that zone tells us what share of the overall increase in generation is assumed to be injected at each node within that bidding zone.

This assumption about the spatial distribution of the change determines how flows are affected across each of the CNECs. Consequently, the assumptions made when determining GSKs are potentially important in determining the sensitivity of different CNECs to changes in trade patterns and the extent to which changes in power flows are deemed to be feasible.

2.2.3 Treatment of DC cables

FBMC is an attempt to account for the flow of power in the Alternating Current (AC) transmission network. A key feature of these flows is that they are largely beyond the control of the system operator. Instead, they are largely the result of injections and withdrawals of power at different points in the network, hence the need to carefully schedule these injections and withdrawals to account for their impact on network flows.

However, many network elements, notably Direct Current (DC) interconnectors, are controllable, with the system operator effectively able to specify the rate of power transfer.

In practice, AC and DC network elements are integrated, with, for example, DC interconnectors feeding into a meshed AC network. Power that leaves the DC interconnectors then fans out through the AC network just as if that power had been generated at the end of the cable.

When FBMC considers which of many different potential trade outcomes is preferable, it needs to consider how best to account for the controllable flows via DC cables. As this approach is defined in the flow-based methodologies defined by each capacity calculation region, there is scope for differences in regional practice. These, in turn, may affect which trade flows are scheduled by the FBMC process.

2.2.4 Extraction of intraday domain

FBMC coupling will initially be implemented only in the day-ahead market, with the intraday market using an alternative system to define feasible cross-zonal trade volumes. Discrepancies in the way that the transmission system's capabilities are represented in different markets could potentially influence both the scheduling of trade and market actors' incentives to trade in different markets.

2.2.5 Incorporating virtual capacity

The simplified description of FBMC in section 2.1 noted that the maximum cross-zonal flows that could be supported by each CNEC were defined in terms of a Remaining Available Margin or RAM.

The European legislative and regulatory framework effectively requires that this RAM value be no less than 70% of the maximum technical capacity of the relevant network element.[3]

As described further in section 3.6, the FBMC process in Continental Europe's CORE region involves a process by which RAM values may effectively be increased to help support compliance with this 70% rule.

This practice is sometimes referred to as the provision of virtual capacity since the additional capacity provided to the market is

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[3] See, in particular, Article 16(8) of Regulation (EU) 2019/943 and ACER's Recommendation 01/2019.

not matched by the physical capacity of the transmission system.

By increasing the capacity made available to the market for cross-sonal flows, this practice likely increases scheduled trade flows and alters the dispatch solution identified by the market.

2.2.6 Assessing compliance with 70% rule

Responsibility for enforcing compliance with the 70% rule is the responsibility of National Regulatory Authorities (NRAs). Although the relevant legislation does not explicitly anticipate the development of regionally or nationally differentiated interpretations of the rule, differences in national approaches to assessing compliance have emerged. By altering the effective level of capacity required for compliance, these differences may indirectly influence the amount of cross-zonal transmission capacity made available to the market.

3 Comparison of international practice

3.1 Scope and sources

Section 3 summarises our understanding of the issues examined with reference to the day-ahead market in the Nordic and CORE capacity calculation regions. FBMC is currently in use in the CORE region. It is expected to be implemented in the Nordics in October 2024. Unless stated otherwise, the information reflects the current implementation in CORE and the expected implementation in the Nordics.

The information has been gathered based on a review of publicly available documentation, notably the capacity calculation methodologies developed by the TSOs in each region. We have supplemented this information with interviews with Statnett, Svenska kraftnät and the Dutch part of Tennet, as well as emails with the Nordic Regional Coordination Centre (RCC).

3.2 Defining CNECs

The process used to develop an initial list of CNECs is not generally defined at a regional level irrespective of region. Instead, each individual TSO is responsible for the process used to identify the CNECs that are relevant within its control area. In practice, the selection of CNECs reflects the judgement of the staff responsible for security analysis in the relevant TSO. Given the differences in practice between TSOs, it is perhaps unsurprising that the process used for the initial identification of CNECs is not publicly documented. The interviews conducted provide some anecdotal insight into operational practice, as described further below.

It is worth noting that both the Nordic and CORE regions filter the initial CNEC lists submitted by TSOs to remove CNECs that are not significantly affected by cross-zonal trade.[4] This is done based on a review of the values in the PTDF matrices defined for each CNEC. These values effectively determine what share of a trade between two zones flows via each specific CNEC. If this value is less than 5%, then the impact is deemed to be insignificant and the relevant CNEC is removed from further consideration.

This filtering is conducted in part to help reduce the size of the optimisation problem that must be solved when clearing the day-ahead market. Removing unimportant constraints helps to keep the computation time within acceptable limits.

However, this filtering process also indirectly imposes some degree of uniformity among the list of CNECs submitted by different TSOs, despite differences in the processes used to identify these constraints. The differences among TSOs' processes are illustrated below.

In the Netherlands, we understand that TenneT's approach is to submit a relatively large number of CNECs and then allow the abovementioned filtering process to remove those that are not significant. Given the small size of the Dutch grid relative to other CORE bidding zones, all 380 kV lines are submitted as individual CNEs by default. Additional CNEs are added where TenneT is aware of specific operational risks not directly related to these lines. TenneT also maintains a standardised list of contingency scenarios that forms the basis for contingencies submitted as part of the process. TenneT encourages other TSOs to reference these contingencies when they wish to consider contingencies related to outages within TenneT's control area.

In Norway, CNEs are identified as part of the operational planning process. The staff responsible for operational

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[4] A similar filtering process is also used in the Channel capacity calculation region.

planning model network flows under various scenarios. These scenarios are not pre-defined but are selected by the responsible staff member based on his or her knowledge of the relevant potential risks. The analysis helps to identify those network limits that are at risk of being violated and this information, as well as the scenarios considered as part of the analysis, allows the relevant member of staff to pull together the list of CNECs for submission. Which network elements are limiting depends on the topology of the network and therefore will change when this topology changes, notably as a result of maintenance or predicted outages. The list of CNECs submitted therefore changes over time, primarily in response to changes in the expected network topology. The contingencies considered in this process include potential outages in the Norwegian and Swedish control areas.

Statnett noted that, in addition to the use of CNECs, it also imposes allocation constraints in the form of so-called combined dynamic constraints. Although the FBMC methodology centres around constraints defined in terms of maximum flows on individual CNECs, it allows for additional constraint types where necessary. Statnett faces operational limits that are not related to the thermal overloading of specific lines but instead to the need to preserve the dynamic stability of the power system in the event of a disturbance.[5] These dynamic stability limits are instead captured in the form of 'combined dynamic constraints'. Such constraints take the form of a combined upper limit on power flows across a set of multiple network elements.

In Sweden, the selection of CNECs reflects the judgement of Svenska kraftnät's operational planning staff and is based on those network elements that most frequently result in violations as part of Svenska kraftnät's real-time network analysis. At present, Svenska kraftnät does not consider contingencies based on outages outside their control area, in part because their wider observability area is still being defined. In the future, it is expected that contingencies outside of Svenska kraftnät's control area will also be included.

3.3 Defining GSKs

Similar to the identification of CNECs, the process used to define GSKs is ultimately the responsibility of individual TSOs. As such, there appears to be considerable diversity in the approach used. That said, the three TSOs interviewed all sought to ensure that the linearised flow estimates produced as part of the FBMC process were as accurate as possible. Indeed, both the Nordic and CORE capacity calculation methodologies state that GSKs should be set so as to minimise forecast errors. As such, despite the differences in approach, all TSOs were working towards a common goal.

The accuracy of the flow estimates is maximised when the GSK correctly identifies how changes in the net generations/consumption balance in the zone are distributed among the different nodes of the network. This involves correctly estimating what sources of generation or load will increase or decrease as the market moves from the projected baseline case.

In the Netherlands, the GSKs are distributed proportionally among all generation units based on the range between their minimum and maximum output under modelled dispatch scenarios. Specifically, TenneT has modelled generators' output under extreme import and export scenarios, thereby identifying a plausible range for each generator's output. This range is then divided by the sum of all such ranges to determine the proportional response of each generation unit. (CWE TSOs, 2021, ss. 6-7) The modelling exercise captures the fact that

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[5] Put simply, dynamic stability refers to the ability of the synchronous power system to return to back to its original state following a short-lived disturbance. If, instead, this disturbance persists or becomes amplified due to interactions among the system's components, the system is dynamically unstable.

baseload units are less likely to alter their output than marginal/peaking plants. Although the GSKs submitted by TSOs vary across different timeframes to reflect differences in typical dispatch behaviour, we understand that TenneT's GSKs have unusually high temporal variation because they are based on the detailed modelling exercise described above, rather than more stable system characteristics, such as plant type. The GSKs are also adjusted to reflect plant outages and new build.

The Nordic capacity calculation methodology foresees that the Nordic TSOs will review their GSKs annually and so the methods currently being used may be subject to change. The Nordic Capacity Calculation Methodology defines a menu of standardised keys that can be used to define a bidding zone's GSK. These options are reproduced below in Table 1. In general, these involve allocating changes proportionally across all generators, all loads or both. Typically (for strategies 5, 6 and 7), these proportions are determined by the size of current generation or load in MW.

Table 1 Nordic GSK strategies

Strategy number	Generation	Load	Description/comment
0	k_g	k_l	Custom GSK strategy with individual set of GSK factors for each generator unit and load for each market time unit for a TSO
1	$\max\{P_g - P_{min}, 0\}$	0	Generators participate relative to their margin to the generation minimum (MW) for the unit
2	$\max\{P_{max} - P_g, 0\}$	0	Generators participate relative to their margin to the installed capacity (MW) for the unit
3	P_{max}	0	Generators participate relative to their maximum (installed) capacity (MW)
4	1.0	0	Equal GSK factors for all generators, independent of the size of the generator unit
5	P_g	0	Generators participate relative to their current power generation (MW)
6	P_g	P_l	Generators and loads participate relative to their current expected power generation or loading power (MW)
7	0	P_l	Loads participate relative to their expected loading power (MW)
8	0	1.0	Equal GSK factors for all loads, independently of their expected size of loading power

where
k_g : GSK factor for generator g
k_l : GSK factor for load l
P_g : Active power generation [MW] for generator g contained in the Common Grid Model
P_{min} : Minimum active generator output [MW] for generator g
P_{max} : Maximum active generator output [MW] for generator g
P_l :Active power load [MW] for load l contained in the Common Grid Model

Source: (Nordic TSOs, 2020)

In practice, it seems that Statnett and Svenska kraftnät use the methods described by options 1–8 as a starting point but then adjust the values to account for the fact that some sources of generation or load are not sensitive to market outcomes.

Thus, in the interview with Statnett, they noted that they variously start with strategies 5, 6 or 7, with different strategies applied to different bidding zones depending on whether generation or load was more likely to be responsible for deviations from the baseline flow projection. However, these starting profiles would then be adjusted (creating a custom profile as allowed for under strategy 0). Specifically, price-insensitive sources of generation or load would be removed from consideration. These amendments were typically made to remove non-flexible run-or-river hydropower or energyintensive industries from being included as potential sources of change.

Finland and Sweden both apply a very similar approach. Specifically, the GSKs are initially set following strategy 6, under which changes are applied to all generators and loads in proportion to the size of their projected generation or consumption in the Common Grid Model. However, generation for nuclear and wind farms is then assumed to be fixed at the projected level, since generation from these sources is unlikely to respond to market outcomes. (Joint Allocation Office, 2023)

According to the information provided to the Joint Allocation Office, Energinet in Denmark applies a different approach, assigning "equal participation factors assigned to thermal powerplants and offshore windfarms".

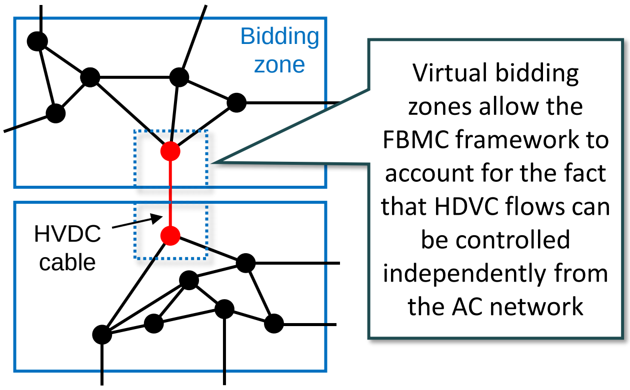
3.4 Treatment of DC cables

In an AC grid, induced flows through the meshed network cannot be controlled directly but, instead, reflect the physical properties of the multiple routes by which power can flow from generation to load. Flow-based market coupling aims to model the propagation of such flows in an AC grid. Unlike flows within AC grids, flows along DC lines *are* fully controllable. This allows commercial flows to be directly converted into physical flows. The way that DC cables are incorporated into FBMC can differ according to the FBMC procedures in use.

DC cables will terminate at converter stations. These stations are the interface between AC and DC infrastructure. When these DC assets inject or withdraw power from the AC network, they will induce flows on the CNECs in this AC network similar to other injections and withdrawals of power.

To capture the effect of these induced flows, the FBMC process can add two virtual bidding zones per DC cable, one for each of the converter stations. Like all bidding zones, flows into or out of these converter station (bidding) zones are recognised as inducing flows on CNECs, as described by a set of PTDFs. By allowing flows to and from these virtual zones and the real bidding zones within which they are physically located, we can capture explicitly how flows on the DC cable, via the converter stations, induce flows on CNECs. We can also specify how flows can be scheduled from one bidding zone to another via a DC cable and its converter stations. This setup is illustrated visually in Figure 2.

Figure 2 Incorporating DC lines using virtual bidding zones



Virtual bidding zones allow the FBMC framework to account for the fact that HDVC flows can be controlled independently from the AC network

Unlike normal bidding zones, no bids or offers can be placed by market participants in these virtual zones and the price established in the virtual bidding zone has no impact on the revenues or settlement of any market party.

The above approach, therefore, provides a common method by which to represent the impact of DC flows on AC network assets as part of FBMC. Where capacity calculation regions differ is the extent to which these DC flows are assumed, and therefore outside the FBMC optimisation, or optimised as part of the FBMC process itself.

Here it is useful to distinguish between so-called Standard Hybrid Coupling (SHC) and Advanced Hybrid Coupling (AHC), both of which relate formally to the treatment of such cables when they connect two different capacity calculation regions.

In Standard Hybrid Coupling, the DC flows are assumed and are inputs into the FBMC process. The AC flows that will be induced on each CNEC by the assumed DC flows can be calculated using the relevant PTDFs and these induced flows are effectively reserved. In practice, the RAM made available on each of the affected CNECs for the FBMC process is adjusted to account for the induced flows. This is sometimes described as giving priority access to these DC flows, as this capacity allocation occurs in advance of the FBMC optimisation.

In contrast, under Advanced Hybrid Coupling, the DC flows are one of the parameters that the flow-based optimisation must determine as part of the optimisation process. This means that FBMC is free to vary the size and direction of flows on the DC cable subject to the technical limits of the cable itself and the knock-on implications for the feasibility of flows within the AC network. Consequently, the DC flows do not receive priority access and FBMC is free to select among alternative uses for limited CNEC capacity.

Currently, the treatment of DC cables in the CORE region differs depending on whether or not the cable connects two CORE bidding zones or is a link to an area outside the CORE region. Within the region, such cables are modelled using the so-called evolved flow-based (EFB) methodology. Similar to the process described for Advanced Hybrid Coupling above, DC flows within the CORE region are modelled and optimised explicitly.

DC lines that connect the CORE region to bidding zones in other capacity calculation regions, including the Nordics, are currently incorporated using Standard Hybrid Coupling (SHC) (CORE NRAs, 2021). However, the CORE TSOs have submitted proposed amendments to the capacity calculation methodology that would allow for the use of Advanced Hybrid Coupling and these are expected to be approved shortly (ACER, 2023). Following these changes, flows on the DC lines between the CORE region and other capacity calculation regions will cease to be prioritised in terms of their access to network capacity. They will instead compete for this capacity alongside internal cross-zonal exchanges of power.

When FBMC is implemented in the Nordics, Advanced Hybrid Coupling is expected to be used on DC interconnectors that link a bidding zone included in the Nordic Capacity Calculation Region with a bidding zone located in the CORE capacity calculation region, for example the NordLink cable.

It should be noted that flows on the relevant DC lines can only be optimised as part of the FBMC process where the bidding zones at each end of the cable are part of the market coupling process. Thus, cables with Great Britain, for example, cannot be optimised using Advanced Hybrid Coupling, since Great Britain is not a part of the Single Day-Ahead Coupling.

We explore the efficiency implications of this in section 4.4.

3.5 Extraction of intraday domain

Eventually, it is expected that the intraday market will also make use of FBMC to assess the feasibility of cross-zonal trade. However, the intraday market is currently coupled using a far simpler approach, which uses so-called Net Transfer Capacities (NTCs). As such, a set of NTC constraints also needs to be defined for use in the intraday market and there could well be an extended period in which the day-ahead and intraday markets use different definitions to determine what the transmission system is capable of.

To get an intuitive understanding of the difference in the nature of the constraints used, it is helpful to chart the set of cross-zonal flows that are deemed feasible. This set is known as the security domain.

Figure 3 Visualising the security domain under FBMC and NTC

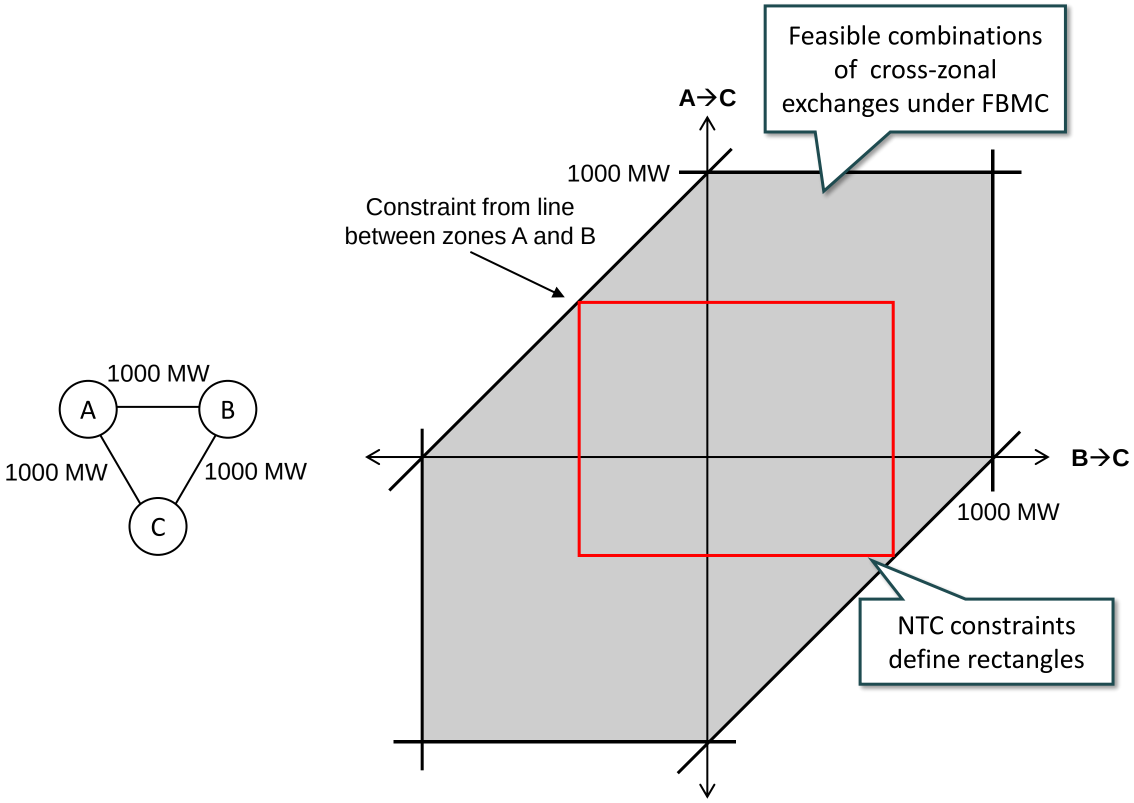


Figure 3 above considers a simple example in which there are three bidding zones connected as shown. The chart on the right shows the combinations of flows that zone C could potentially have with its neighbouring zones without violating the defined network limits. Under FBMC, each of the AC lines connecting these three zones would be a CNE. Each of these CNEs defines two boundary lines that constrain the size of the security domain, one boundary for each direction in which power could potentially flow across the relevant CNE. Remember that flowing power from A to C also entails flowing power along the line connecting B and C due to the physical behaviour of meshed AC transmission networks Consequently, all three lines impose constraints on the power that can be flowed between any two bidding zones. The result is a six-sided flow-based security domain, as shown.

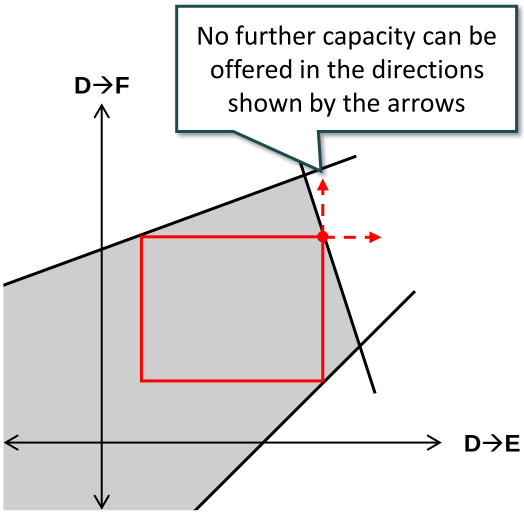
Net Transmission Capacities, however, take the form of a maximum volume of power that can be scheduled to flow from one zone to another zone. Geometrically, such constraints take the form of vertical and horizontal lines on the chart shown. One line for each direction and each border. This gives us four boundary constraints in total.

The task facing TSOs is geometrically equivalent to translating the six-sided security domain defined by FBMC into a simplified rectangular domain at right angles to the chart's axes. In all practically relevant examples, it will not be possible to define NTC constraints in such a way that they perfectly align with the flow-based security domain and TSOs are therefore forced to make compromises when translating flow-based constraints into NTC constraints.

These decisions are important because, in doing so, TSOs are making a trade-off between preserving system security and facilitating cross-border trade. In theory, TSOs could define the NTC values such that the security domain defined by these values (i.e. the rectangle mentioned above) falls entirely within the flow-based security domain. This should ensure that any intraday market results using the NTC domain are feasible. However, this will also end up foreclosing some trading outcomes that are secure (i.e. within the flow-based security domain). Alternatively, TSOs could opt to set more relaxed NTC constraints, effectively expanding the size of the rectangular NTC security domain. However, doing so implies allowing some trading outcomes that the flow-based approach would have considered to be beyond the transmission system's technical limits.

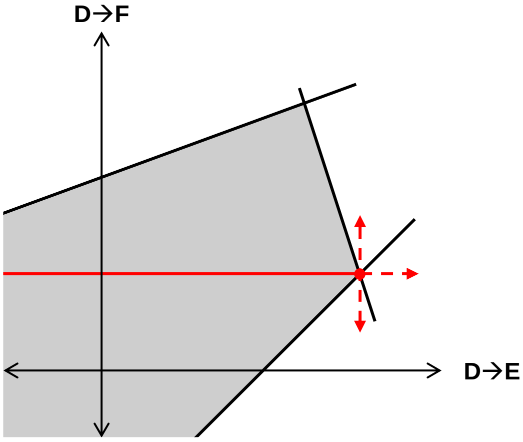
This problem of inconsistent security domains is at least partly responsible for what is sometimes referred to as 'blocked borders' in the intraday market. Blocked borders are a natural consequence of the day-ahead market's desire to fully utilise CNEC capacity and FBMC's detailed recognition that this (fully utilised) capacity is required to support trade across multiple cross-zonal borders. As such, we should expect the day-ahead market solution to leave us at the boundary of the security domain, as shown in Figure 4 below. If we then try to define NTC constraints that fit within the flow-based domain from this point, we will discover that capacity can only be given in one direction on the constrained CNEC. Since this CNEC may be needed to support trade on many borders, all of these borders may find themselves with capacity available in just one direction.

Figure 4 Example of a binding flow-based constraint



If the day-ahead solution results in trade flows that are close to where multiple constraints meet, as exemplified by the case shown in Figure 5, the NTC domain that can be fully enclosed within the flow-based domain may be extremely limited. This implies very restricted intraday trade.

Figure 5 Example of multiple binding flow-based constraints



3.5.1 Approach in CORE

The process of defining NTC constraints for use by the intraday market is referred to as Available Transmission Capacity (ATC) Extraction.[6]

In the CORE region, the process of defining the NTC security domain relies on a process of iteratively expanding the allowed security domain. The starting point for this process is a situation in which the ATC is set to zero for all borders, i.e. no trade is allowed in any direction across any border.

The process then looks sequentially at each CNEC and takes the residual RAM not yet utilised. In the first instance, this residual will be the RAM not already allocated by the day-ahead solution. The process then calculates how much this RAM could, when considered in isolation, be used to support higher scheduled flows on each of the borders reliant on the relevant CNEC.

Specifically, the total amount of residual RAM is divided evenly between all the affected borders and then these RAM (MW) values are converted into MW flows for the relevant borders using the PTDF values specific to the CNEC. Thus, if 12 MW of residual RAM could potentially support trade on four borders (in a specific direction in each case), this would be split into four lots of 3 MW, one for each border. If, for a specific border, the PTDF defined that only half of scheduled flows at the border flowed via the relevant CNEC, this 3 MW on the CNE would be translated into 6 MW in terms of maximum permissible border trade.

After computing the maximum additional bilateral exchanges allowed by each CNEC, the smallest of these potential additions is then accepted. The residual RAMs are then recomputed, accounting for the implied increased use of the RAMs available, and the process is repeated until the size of the increase in all the ATC values is smaller than 1 kW.

In practice, this process involves defining an NTC security domain that is fully contained within the flow-based domain by trying to expand a rectangle outwards from the scheduled flows implied by the day-ahead market. This implies a strong focus on ensuring security.

However, it should be noted that the CORE TSOs are currently examining the scope of relaxing the constraints on some CNECs to help prevent the NTC domain from becoming overly constrained. Specifically, this would involve amending the PTDF parameters to make some marginal CNEC constraints strictly vertical or horizontal (as illustrated in Figure 6 below) (CORE TSOs, 2022). At present, this remains an area of research.

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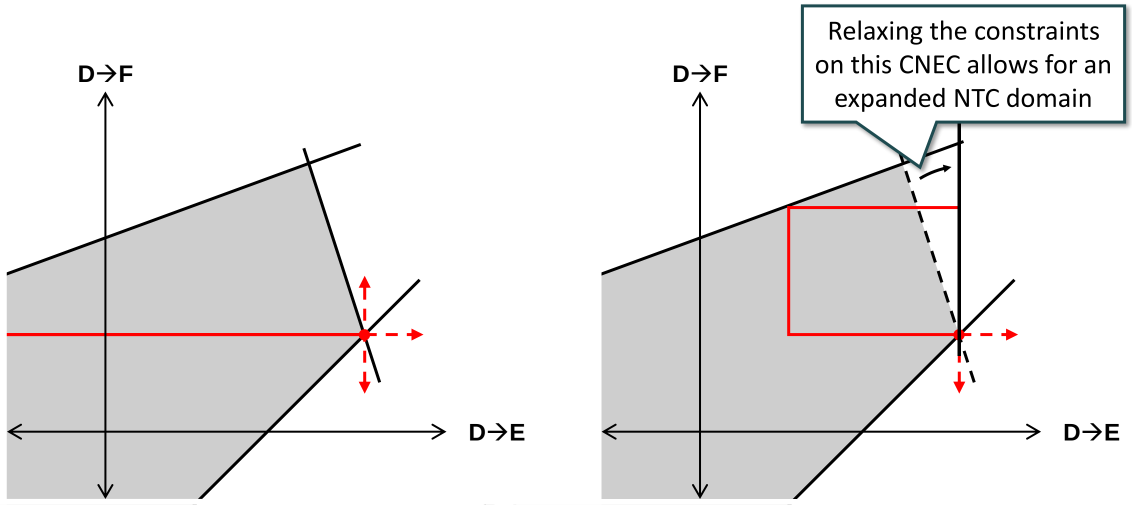
[6] Available Transfer Capacity (Intraday) = Net Transfer Capacity (Day-ahead) – Already Allocated Capacity (Day-ahead)
In other words, the intraday ATC represents the residual capacity for scheduled cross-zonal exchanges after account for those exchanges already scheduled in the day-ahead market.

Figure 6 Impact of proposed relaxation of constraints on marginal CNECs



3.5.2 Approach in the Nordic region

FBMC market coupling has yet to be implemented in the Nordics. However, it will be implemented in the day-ahead market before it is implemented in the intraday market. This results in the same need for distinct domains in the day-ahead and intraday markets. A proposed approach for ATC Extraction has been developed in the Nordics that differs from the approach in the CORE region.

The proposed Nordic approach begins by estimating those flows implied by the day-ahead market solution on the CNECs that physically link two bidding zones. By summing the flows on all such links, we get an estimate of the cross-border flows already allocated by the day-ahead market. The NTC values estimated below are constrained such that they must, at a minimum, allow for this level of already allocated flows. In other words, the residual capacity made available to the intraday market, i.e. the ATC, cannot be negative in any direction.

An optimisation process is then calculated to define the set of NTC limits that maximises the product of the total capacities made available on each border. Specifically, the objective function can be written as follows.

$$\prod_{\forall i}[\overleftarrow{NTC_i} + \overrightarrow{NTC_i}]$$

Where i are the borders between zones

In words, for each border, the transfer capacity made available in each direction is summed to provide a total capacity for the relevant border and then these total capacities are multiplied together. The set of NTCs that maximise this product is chosen.

In general, the optimisation is carried out subject to the constraint that the NTCs selected do not violate the flow-based constraints. In other words, the NTC domain is generally limited to being within the flow-based domain, similar to the approach used in CORE, albeit with one important exception.

The Nordic approach already plans to incorporate some explicit relaxation of the flow-based constraints to help expand the permissible NTC domain. They have considered both amending the PTDF parameters, as illustrated in Figure 6, as well as adding capacity to the RAM values. When relaxing both the RAM and PTDF values, the TSOs observed large potential overloads when conducting parallel flow-based market simulations. They are therefore proposing to only increase the RAM values, adding 10 MW to the RAM values associated with CNECs.

In summary, the objective function above is maximised subject to being within an expanded flow-based domain. This domain has been expanded to ensure that the day-ahead RAM values are increased by 10 MW and, where this requires a further increase in the RAM values, such that the reported NTC values are no smaller than the imputed day-ahead flows on cross-border CNECs.

3.6 Incorporating virtual capacity

One of the most fundamental differences between the capacity calculation methodology used in the CORE region and that proposed for the Nordic region is the CORE methodology's inclusion of so-called virtual capacity in the day-ahead flow-based security domain. Put simply, the capacity made available for cross-zonal trade is intentionally expanded beyond the expected technical limitations of the transmission system. The Nordic capacity calculation methodology does not include a similar expansion.

There are two mechanisms by which the day-ahead flow-based security domain is expanded in the CORE region: the adjustment for minimum RAM (abbreviated to AMR) and the Long-Term Allocation (LTA) Inclusion.

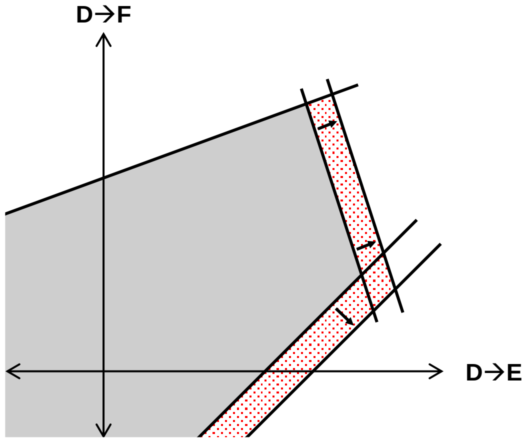
The adjustment for minimum RAM imposes a lower limit to the RAM values as a way of ensuring compliance with the 70% rule.[7] Put simply, European legislation requires TSOs not to restrict cross-zonal trade capacities as a means of relieving congestion within their bidding zones. The 70% rule effectively states that the above obligation will be deemed to have been fulfilled if the TSOs provide RAM values that are at least 70% of a CNECs theoretical maximum capacity.

The ARM adjustment mechanism in the CORE capacity calculation methodology increases RAM values to ensure that this minimum threshold is met. In fact, it actually ensures that the RAM value is sufficient to ensure that two conditions are met. The RAM value for all CNECs must be:

1. At least 70%[8] of the CNEC's theoretical maximum capacity when this share includes flows over non-CORE-region borders
2. At least 20% of the CNEC's theoretical maximum capacity when this share considers only the capacity made available to flows between CORE bidding zones.

Where an AMR adjustment is made, the flow-based security domain is pushed outward for the affected CNECs as illustrated in Figure 7 below.

Figure 7 Expansion of the flow-based security domain due to the AMR process



The day-ahead flow-based domain in the CORE region may also be expanded by the Long-Term Allocation (LTA) Inclusion process. Put simply, TSOs effectively sell transmission capacity across borders in advance of the day-ahead market in the form of so-called Long Term Transmission Rights (LTTRs). For a given day, therefore, TSOs may already have sold transmission rights equivalent to a flow of X MW in a given direction across a specific border. Typically, these transmission rights will take the form of financial contracts obligating the TSO to pay the

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[7] Established in Article 16(8) of Regulation (EU) 2019/943

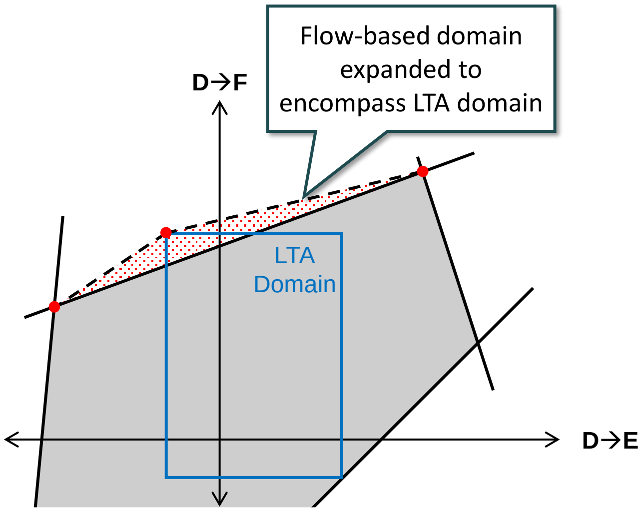
[8] In the event that a derogation has been granted such that a lower percentage value is applicable, then the relevant lower value is used here instead.

congestion income earned on the corresponding volume of flows. The LTA Inclusion process is designed to expand the flow-based domain so that the day-ahead market can potentially schedule flows across the relevant borders that are large enough to accommodate the potential size of any payment obligations arising from the sale of LTTRs. This helps to ensure that the congestion income earned by a TSO on an individual border is at least sufficient to cover any payment arising from the prior sale of LTTRs.

Since the LTTR volumes are defined per border, as opposed to per CNEC, these LTTR volumes are represented by vertical or horizontal lines in our simplified two-dimensional representation of the security domain. Similar to the NTC domain described in section 3.5, the LTA domain, i.e. the minimum set of potential cross-border exchanges implied by the sale of LTTRs, is represented by a rectangle in this two-dimensional illustration.

Put simply, the LTA Inclusion process effectively pushes out the flow-based domain by joining the vertices formed by the corners of the LTA domain and the intersections of the constraints defined by multiple CNECs. The boundaries of the flow-based domain are pushed out as needed to meet these joins as illustrated in Figure 8 below.

Figure 8 Expansion of the flow-based security domain due to Long-Term Allocation (LTA) Inclusion



Both the adjustment for minimum RAM and the Long-Term Allocation Inclusion process expand the flow-based domain beyond the limits of the transmission capacity as defined by FBMC. For this reason, they are sometimes referred to as providing virtual capacity to the market, namely transmission capacity that is not backed by physical transmission infrastructure.

3.7 Assessing compliance with 70% rule

As noted in the previous section, the CORE and Nordic capacity calculation methodologies differ in terms of the extent to which they attempt to integrate enforcement of the 70% rule into the capacity calculation process. Such variations are arguably envisaged by the fact that the process for developing the capacity calculation methodologies, as established in European legislation, is explicitly delegated to those TSOs within each capacity calculation region. What may not have been envisioned are differences between Member States in the approach to assessing compliance with the 70% rule. These differences are the (potentially unintended) result of the lack of technical detail in the legislation combined with the lack of an obvious process to develop binding technical guidance. Since the 70% rule is an obligation on TSOs and enforcement of these obligations falls to National Regulatory Authorities, NRAs have had scope to assess compliance in different ways.

This is not to say that there have not been efforts to develop a harmonised approach. In 2019, ACER published a Recommendation detailing the methodology for monitoring the so-called Margin Available for Cross Zonal Trade (MACZT), i.e. the value that is intended to equal or exceed the 70% threshold. The Recommendation was complemented by a follow-up methodological paper (v1 in Oct 2019, v2 in Dec 2020) that further describes the steps used by ACER in its own monitoring to estimate the MACZT, including a description of the simplifications and caveats needed to generate results in the face of limited data or model availability. Finally, in April 2022, ACER published a note on a common approach to monitoring the MACZT. This ‘practical note’ presents a common approach to monitoring and reporting on MACZT results and is intended to support consistency in the monitoring and reporting conducted by ACER, the NRAs and TSOs.

However, there remain potentially important differences in national approaches. Below we outline three notable examples of national differences from the abovementioned approach published by ACER.

3.7.1 Germany

The German approach to monitoring compliance accounts differently for flows due to cross-border exchanges with zones outside of the CORE region. Arguably, this tends to result in greater assessed compliance than had ACER's approach been used.

The Margin Available for Cross-Zonal Trade consists of two components:

1. The margin from the coordinated capacity calculation (MCCC)—which accounts for the margin made available for flows within the coordinated capacity calculation region—and
2. The margin from the non-coordinated capacity calculation (MNCC)—which accounts for the margin made available for flows across borders outside the relevant coordinated capacity calculation.

The ACER and German approaches differ in terms of how they estimate the second of these two quantities.

Under the ACER approach, the MNCC per CNEC is calculated using forecast exchanges across those borders not included in the coordinated capacity calculation.

In contrast, Germany's national monitoring framework estimates the MNCC values from the Net Transfer Capacities made available in both directions on the relevant borders. Specifically, these NTC values are converted into imputed flows using strictly positive PTDF values.

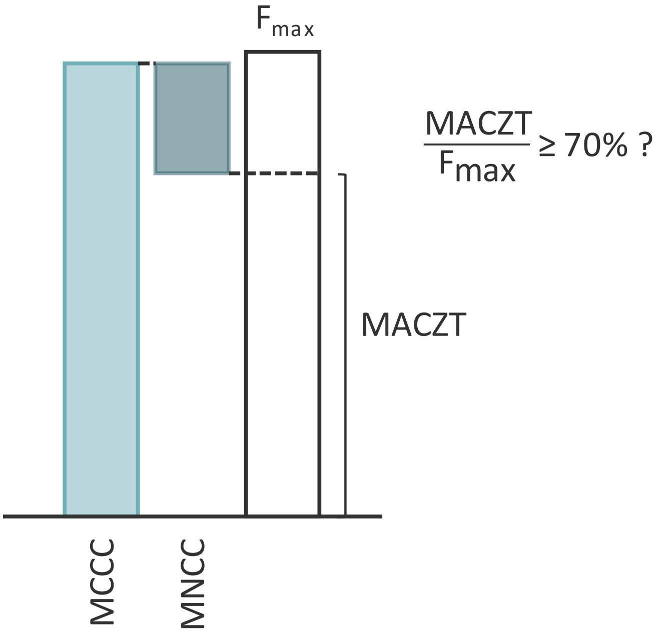
This difference in the approach used has at least two implications for the assessment of compliance against the 70% rule.

First, the estimated-flow and NTC values may be different, with the NTC values likely to be higher. For example, if the NTC value is high but this trade capacity is not expected to be used, then this will result in a correspondingly low MNCC when assessed under the ACER approach but a high MNCC when assessed using the German approach. Since expected flows will typically be lower than NTC values, the assessed MACZT will tend to be higher under the German approach, making compliance relative to the target threshold (e.g. 70 percent) easier to achieve.

Second, the ACER approach is designed to allow for the netting of flows—something that is not possible when using the German approach. Put simply, when a specific flow is anticipated on a given border, this induces flows in a specific direction on each CNEC. Trade flows on other borders can potentially offset these flows by inducing flows in the opposite direction. These opposing flows give rise to netting in the way RAM is allocated and potentially allow for the same RAM to support higher trade flows.

The ACER methodology, which is based on a specific set of forecast flows, accounts for potential offsetting. For a TSO to meet the 70 percent target under the ACER methodology, it must release capacity sufficient to account for any helpful offsetting flows expected on borders outside the coordinated capacity calculation. In terms of the actual calculations, the ACER methodology can therefore result in a negative MNCC, implying a need to make more capacity available via coordinated capacity calculation (the MCCC) to reach the target. This offsetting relationship is illustrated in Figure 9 below.

Figure 9 Example of how flows on borders with non-coordinated zones could actually make the 70% target harder to achieve



In contrast, the German approach cannot result in a negative MNCC. Effectively, when considering the impact of flows on non-coordinated borders, these flows are always expected to be in the direction that competes for capacity on the CNEC. Consequently, there are never any ‘helpful’ flows and the effective MNCC is always strictly non-negative. This tends to increase the assessed Margin Available for Cross-Zonal-Trade and, again, will tend to make assessed compliance with the 70 percent rule better.

This difference in the assessment methodology has historically led to marked differences in the assessed compliance of German TSOs with the 70% threshold depending on the approach. For example, Germany’s border with Poland and the Czech Republic was subject to a transitional target of 31% (rather than 70%) in 2022. According to the German TSOs assessment, “For the borders DE-PL&CZ, the minimum of 31.0% was complied with for every MTU [Market Time Unit] during the period from 01/01/2022 through 08/06/2022.” [The full period considered by the assessment] (German TSOs, 2023, p. 19). In contrast, ACER’s assessment concludes that this 31% target was met in just 30–49% of hours in 2022 depending on whether one examines import or export flows and on the treatment of third-country flows (ACER, 2023, p. 37). These differences in the conclusions reached follow from differences in the assessment methodologies used.

3.7.2 France

The French National Regulatory Authority monitors all time units but considers that the target must be met only in those market time units when there is no price convergence across the affected borders. In contrast, ACER considers that the target applies to every market time unit and assesses compliance accordingly.

The argument underlying France’s decision not to enforce the rule during periods of price convergence is that increasing trade capacity during such periods will not add to social welfare. To understand why, it is worth remembering that the benefits realised from increases in cross-zonal trade capacity result from an ability to substitute high-cost power in one zone with cheaper power from a bordering zone. The difference in price between the zones reflects the size of the associated welfare gain. By extension, when prices are the same between zones, substituting power from one zone with power from the other zone does not result in any direct reduction in costs and therefore produces no welfare gain. From the French NRA’s perspective, forcing TSOs to comply with the 70% rule when prices have already converged entails potentially forcing TSOs to incur costs, e.g. the costs of remedial action, for no welfare benefit. This cannot be efficient.

The main counterarguments are as follows. First, price convergence is only established after System Operators allocate capacity. If TSOs incorrectly anticipate price convergence and limit cross-zonal trade to avoid costs, they may still impose a welfare cost. However, it is worth noting that such cases would still be captured under France’s assessment framework, since prices did not converge. Second, even in periods in which prices converge, limits to cross-zonal trade capacity may still imply unwarranted discrimination between network users in different bidding zones. Specifically, the restriction of trade capacity between zones favours the matching of bids and offers within a zone even though, from a market-price perspective, out-of-zone bids and offers are equally attractive.

3.7.3 Poland

The Polish NRA chooses not to consider the implications of so-called 'allocation constraints' in fulfilment of the 70% target.

In addition to setting the RAM capacities made available for cross-zonal trade, TSOs also have the option to impose separate allocation constraints. These constraints take various forms and exist to ensure that potentially important security criteria that cannot be readily captured by the structure of constraints defined in FBMC are not excluded from consideration. Two common forms of constraint include so-called 'external constraints'—which limit the maximum import into and/or exports from a specific bidding zone—and 'technical profiles'—which limit the joint allocation of a set of NTC capacities on defined, oriented bidding-zone borders. The latter operate like a joint NTC limit across two or more borders. Poland imposes an allocation constraint (the Polish optimisation area) to limit the total sum of imports into Poland from SE4 and Lithuania.

ACER's methodology seeks to assess whether such allocation constraints end up forcing the security domain to be smaller than some minimally compliant size. If so, this implies that the allocation constraint is preventing the 70% target from being realised.

However, the Polish NRA has historically opposed considering the impact of allocation constraints when assessing compliance with the 70% rule. Instead, they consider that the assessment should be limited exclusively to the RAM levels made available to the market.

4 Implications for efficiency

In the previous section, we outlined some examples of how the implementation and monitoring of flow-based coupling differ by country after looking in detail at current and planned practice in the Nordic and CORE capacity calculation regions.

In this section, we consider the theoretical implications of these differences on the efficiency of the electricity market. We conclude that for some of the areas examined, for example the processes used to define CNECs or determine GSKs, differences between national approaches are unlikely to significantly influence efficiency. Indeed, flexibility in implementation may support greater efficiency where it allows TSOs to better reflect the system management constraints faced in their networks. In other areas, notably generic expansions or restrictions of the trading domain, the impacts on efficiency are potentially more significant. It is not always easy to determine whether these impacts are likely to be positive or negative. However, assuming that the flow-based domain is a reasonable if imperfect estimation of efficient trade capacity, some of the current amendments of this domain seem likely to harm spot market efficiency.

4.1 Defining CNECs and GSKs

We observe that there is considerable variation in national practice in terms of how CNEC constraints are initially identified and the approach to parameterising the GSKs. Although the format of this information is standardised by European regulation and the supporting capacity calculation methodologies, these activities take place at a level of operational detail at which specific procedures are not specified. Thus, though the nature and the aim of these assumptions are set out, TSOs are effectively free to develop these assumptions however they see fit.

Our impression is there is a sufficiently clear and common purpose among the TSOs examined that these differences in operational practice do not harm efficiency. In particular, the practices used to define GSKs in Norway, Sweden, Finland, the Netherlands and Germany, although somewhat different, all seem to approach the goal of minimising the deviation between projected and actual flows from slightly different angles. The presence of a common goal means that their different methods end up capturing the same fundamental real-world considerations.

In some areas, the flexibility built into the system may be beneficial for the efficient operation of the system. Statnett was keen to note that ACER's willingness to let them apply combined dynamic constraints—an allocation constraint imposed in addition to the basic constraints that define FBMC—was important to allow them to accurately account for the operational limits peculiar to their network topology.

4.2 Redefining the secure domain

As noted in section 3.5 on the extraction of the intraday domain and section 3.6 on the incorporation of virtual capacity, there are various ways in which the secure domain identified by FBMC changes before capacity is made available to the market. The amendments considered in these sections are not intended to provide a more accurate representation of the transmission systems' capability to support cross-zonal flows but instead intended to reflect other considerations, such as the practical limitations of the intraday market coupling mechanism, the 70% rule and the financial obligations of TSOs.

These explicit changes to the trading solutions allowed by the market are liable to have more direct and potentially more significant impacts on the overall efficiency of the power system. From an efficiency perspective, expanding the scope for cross-zonal trade can have positive and negative welfare impacts. In general, more cross-zonal trading capacity provides the market with greater scope to reduce costly generation (or enable high-value consumption) in one zone by increasing lower cost generation (or displacing low-value consumption) in another zone. This arbitrage between bidding zones supports higher overall welfare. However, welfare gain assumes that the cross-zonal trade scheduled by the market can be implemented in reality without triggering potentially costly redispatch action.

FMBC is a simplification of the real-world capabilities of the transmission network. It is an imperfect representation of reality. Consequently, scheduling trade beyond the secure domain could increase welfare where the arbitrage benefits of trade outweigh any additional costs in terms of system management. Similarly, restricting trades that would otherwise have been permissible within the flow-based domain could also conceivably support higher welfare. When considering the welfare implications of deviations from the flow-based domain, we need to acknowledge the limitations of this domain in determining what is and not efficient.

However, if we take the flow-based domain as a reasonable if imperfect estimation of the welfare maximising balance between allowing or restricting trade, then we should conclude that amendments of this domain are likely to harm efficiency unless there are specific grounds to believe that the modification corrects an imperfection in FBMC's simplified representation of the transmission networks real-world constraints.

The process of extracting an intraday NTC domain, as noted above, is motivated by the need to convert the flow-based domain into NTC constraints suitable for use in the intraday market. It is a necessary step given the limitations of the intraday coupling process. However, in performing the extraction, different regions may differ in terms of how they trade off the risk of an overly restrictive domain, which prevents potentially efficient arbitrage between zones, with an overly expansive one, which results in the need for costly remedial actions.

As described in section 3.5, the extraction approach used in the CORE region is more restrictive than that proposed for the Nordic region, since it limits the NTC domain to being fully within the flow-based domain. This requirement potentially harms efficiency by foreclosing efficient intraday trades. The fact that the CORE TSOs are examining options to relax these constraints potentially implies that they recognise that the solution is not fully efficient.

The Nordic approach does include some relaxation of the RAM parameters. If the additional RAM provided represents some reasonable estimate of what is likely to be feasible on the network, the Nordic approach may well give rise to more efficient outcomes overall.

It is important to note, however, that the more restrictive extraction procedure conducted in the CORE region may be a response to the fact that the flow-based domain on which this extraction is based has already been expanded. In other words, the fact that the intraday procedure appears conservative may be a reaction to the fact the day-ahead domain on which it is based is expansive.

As described in section 3.6, the CORE capacity calculation methodology incorporates two processes to expand the day-ahead flow-based domain. Neither of these appears likely to support efficiency, at least when considering the day-ahead market outcome in isolation. This is because these expansions are not motivated by the desire to create a more accurate representation of network limits.

One of these expansions of the security domain acts to impose a regulatory minimum RAM consistent with the 70% rule. This target is arbitrary when we consider the real-world capabilities of the transmission system in isolation and is liable to trigger costly remedial actions that are not efficient when the dispatch solution is viewed in isolation. Proponents of the approach may argue, however, that this efficiency cost is more than offset by the potential benefit that the approach can bring about indirectly by motivating network infrastructure investments and efficient bidding zone design. In short, like many arguments related to the 70% rule, while the target is unlikely to be a rational objective in its own right, it may nevertheless force activity that contributes to the broader efficiency of the power system and the market design.

The LTA expansion cannot be justified in terms of supporting more efficient market dispatch, as the expansion of the flow-based domain has no basis in increasing the accuracy of FBMC's representation of the transmission network. On the contrary, the LTA expansion may well involve knowingly making the representation of transmission capacity less accurate. This will be the case where, for example, forward capacity was overestimated when it was sold and it is known now that this capacity is not available. Instead, the motivation of the LTA expansion is financial, namely to avoid potentially significant financial liabilities from the sale of Long Term Transmission Rights that are not matched by congestion income revenues. Overall, therefore, it is hard to see LTA expansion as anything but harmful to the efficiency of the physical market. If an argument for the efficiency of the LTA expansion is to be made, presumably it must be by arguing that it helps to support the functioning of the forward market through the sale of Long Term Transmission Rights. However, such an argument would need to rely on a long chain of causal impacts being true to be valid.

4.3 Assessing compliance with 70% rule

Section 3.7 demonstrated differences in some national approaches to assessing compliance with the 70% rule. Such differences are only likely to have an impact on efficiency to the extent that they affect Member States' and TSOs' decisions on how much capacity to make available to the market, how much transmission capacity to invest in and whether or not to redefine bidding zone borders.

The difference in national practices may well imply effectively different target levels between countries. However, it is difficult to imagine that these differences are sufficient to motivate material differences in behaviour. As we've seen, the 70% rule is implemented relatively directly in the CORE region's RAM calculation process. As such, any differences in Germany's approach to assessing compliance are unlikely to affect the cross-zonal capacity made available by German TSOs. Conceivably, a less stringent assessment framework in Germany and Poland could reduce the political and regulatory appetite to invest in cross-zonal capacity or redefine bidding zones due to better perceived performance relative to the target. However, to judge the impact on efficiency, one needs to consider how significant compliance with the 70% rule is as a motivator of investment and bidding zone design decisions and whether the size of the difference in assessed outcomes would be decisive in motivating different decisions.

More generally, it must also be noted that consistent application of the 70% rule does not necessarily imply greater efficiency, since the numerical target itself has no clear basis in welfare maximisation. If, however, we believe that investment in more cross-zonal transmission capacity or bidding zone redesign is likely to add to welfare and we believe that differences in assessed compliance might lead to different decisions, due to the aforementioned impact on political and regulatory will, then we would conclude that the presence of less stringent notional compliance frameworks could harm market efficiency.

France's decision to limit compliance only to hours where there is no price convergence is far more explicitly linked to the aim of enhancing efficiency and maximising welfare. Indeed, it is explicitly intended to avoid incentivising costly remedial action that is very unlikely to enhance welfare. As such, there is a clear theoretical argument that France's approach to compliance supports improved efficiency.

4.4 Treatment of DC cables

As discussed in section 3.4, the introduction of Advanced Hybrid Coupling allows the FBMC process to optimise DC cable flows that had previously been simply projected. This should support more efficient outcomes because the FBMC process is now free to allocate limited CNEC capacity flexibly to support either DC or AC flows across a range of borders. Thus, DC flows that provide little net welfare, because they flow power between similarly priced zones, can be reduced if doing so frees up trade capacity on more beneficial borders, namely those with large price spreads. This extension of the optimisation process to include DC flows enables market solutions with greater overall welfare.

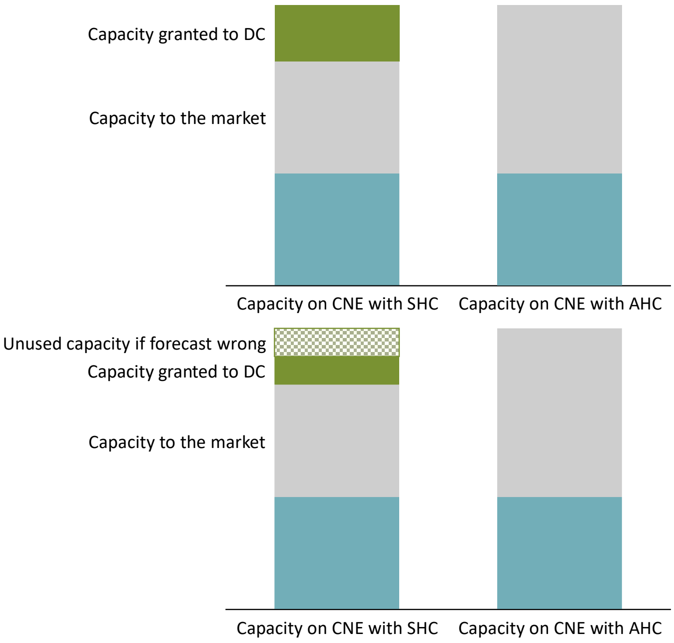
It should be noted, however, that Advanced Hybrid Coupling cannot be applied to all DC cables. DC cables that are linked to markets outside the Single Day-Ahead Coupling (SDAC) process cannot be incorporated into the relevant optimisation. This means, for example, that links to Great Britain cannot benefit from Advanced Hybrid Coupling.

For such cables, flows will continue to be projected ahead of the market and network capacity will reserved on CNECs to support these projected flows. This will create ongoing problems for efficiency.

First, the projected flows could frequently be wrong, especially where variable renewable generation implies that cable flows are volatile. Where the projected flows are wrong, the rest of the system is being optimised against inaccurate residual RAM values.

Figure 10 illustrates an example in which this approach results in the underutilisation of network capacity. Here, DC flows are overestimated, resulting in too much capacity on CNECs being reserved to support these flows. Since this reserved capacity is not included in the FBMC process, it is not automatically reallocated but will instead go unused, potentially to be released in the intraday market. This is inefficient and reduces total welfare. On the right-hand side of the figure, the DC flows are a part of the optimised market under Advanced Hybrid Coupling and, as such, under allocation due to forecast error is not possible.

Figure 10 Example of the efficiency benefits of Advanced Hybrid Coupling



Second, even where the projections are accurate, they may not reflect an optimal allocation of scarce network capacity. This is likely to be especially problematic where these DC flows rely on CNECs that also contribute significantly to enabling flows across other borders. In such cases, where Standard Hybrid Coupling is employed, the DC flows end up effectively jumping the queue and reserving capacity on CNECs that, if allocated to other borders, could have supported higher overall welfare. In contrast, allowing for such trade-offs to be made as part of the FBMC optimisation, as under Advanced Hybrid Coupling, ensures that potential trade-offs in the use of CNEC capacity are made efficiently such that the greatest overall welfare is achieved.

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