FIRST EDITION OF THE BIDDING ZONE REVIEW

DRAFT VERSION FOR PUBLIC CONSULTATION UNTIL 9 MARCH 2018

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European Network of
Transmission System Operators
for Electricity

entsoe

DISCLAIMER

The proposal for maintaining or amending the bidding zone configuration resulting from the First Edition of the Bidding Zone Review is reserved to, and delivered by, the TSOs participating in the Bidding Zone Review in accordance with the process outlined in CACM Article 32(4). ENTSO-E's role has been to facilitate the process supporting the participating TSOs in the project, and ENTSO-E played an important role as a platform for the original pilot Bidding Zone Review project, anticipating the CACM requirements.

CONTENT

1 EXECUTIVE SUMMARY

Bidding zones are a core element of today's European market design. Cross-zonal electricity trades and exchanges are organised between these zones based on available transfer capacities calculated by TSOs, while internal trades inside bidding zones are considered as unrestricted. The definition of bidding zone boundaries is therefore a question of major relevance for the market and requires profound analysis. To accommodate and foster the transition towards fully integrated and sustainable power markets triggered by European Union (EU) policies, transmission infrastructure development is to be paired with regular assessment of the bidding zone configuration as specified in EU Regulation 1222/2015.

In its letter dated 21 December 2016 ACER has initiated the first edition of the bidding zone review process, specifying Central Europe[1)] as the relevant region. In a process lasting 15 months and ending on 21 March 2018, the participating TSOs are tasked with the following:

- specify the configurations subject to the review
- consult with the national regulatory authorities (NRAs) regarding the assessment methodology, assumptions and configurations, and with stakeholders regarding the alternative configuration proposals; and
- draw a final conclusion on whether to maintain or amend the bidding zone configuration for submission to the Member States.

On this basis, within six months upon receiving the proposal from the participating TSOs, Member States are obliged to reach an agreement on whether to maintain or amend the bidding zone configuration.

1) Austria, Belgium, the Czech Republic, Denmark, France, Germany, Hungary, Italy (North), Luxembourg, the Netherlands, Poland, Slovakia and Slovenia

BIDDING ZONE CONFIGURATIONS CONSIDERED IN THE REVIEW

This Bidding Zone Review consists of two different approaches to define alternative bidding zone configurations. The first approach is based on a selection of ex ante defined configurations encompassing splitting or merging of the existing bidding zones. Since these configurations are defined by the concerned TSOs based on their expert assessment, these are referred to as expert-based configurations.

In total, five expert-based configurations have been identified as particularly relevant for the First Edition of the Bidding Zone Review. Not all potentially relevant configurations could be considered in the First Edition of the Bidding Zone Review since time and scope of the review have been limited. The experience with the First Edition of the Bidding Zone Review showed that a careful selection of the analysed scenarios is of particular importance for the outcome and credibility of the analysis. Scenarios that split the current bidding zones consist of a separation of Austria from Germany/Luxembourg, a split of the 'big countries' France, Germany/Luxembourg and Poland and a further split of France and Germany/Luxembourg into three zones. The latter subdivision of France and Germany/Luxembourg is the result of an explicit request from the NRAs in the relevant region. In order to also consider the implication of merging zones, the combinations of Belgium with the Netherlands and the Czech Republic with Slovakia have been added to the set of configurations for the analysis. Finally, the current bidding zone configuration (also refered to as the 'Status Quo' in this First Edition of the Bidding Zone Review) has also been investigated to provide the reference to which the alternatives are compared.

An alternative approach for defining bidding zones employs academic models to determine bidding zones under a 'greenfield' approach. Based on a European nodal pricing calculation, nodes with the most similar prices have been clustered into zones. However in the course of the analysis, the nodal prices determined in this review were found to have been significantly impacted by local congestions in the 220 kV grids of particular countries. Since these prices served as an input for determining bidding zone definitions in model-based configurations, the resulting clustering has led to a fragmentation of bidding zones along those congestions. The countries most affected by 220 kV congestions have therefore been subdivided into several zones, while other areas remained unaffected. In order to obtain a more realistic overall configuration, the clustering results have been post-processed. Despite this post-processing exercise, the obtained nodal prices and model-based configurations are not considered sufficiently realistic or robust for use in the current Bidding Zone Review. The approach will be investigated further for potential use in future Bidding Zone Reviews.

EVALUATION OF BIDDING ZONE CONFIGURATIONS

The four expert-based configurations constituting alternatives to the fifth 'Status Quo' configuration have been evaluated according to the criteria of EU Regulation 1222/2015. Article 33(2) CACM requires an analysis based on scenarios taking into account a range of likely infrastructure developments, starting from the year following the year in which the decision to launch the review was taken up to ten years. This range is covered by the two chosen scenarios 2020 and 2025 and have been consulted formally with the relevant NRAs. The experience with this First Edition of the Bidding Zone Review has shown that the choice of the time-frame of the scenarios and the underlying assumptions (e.g. finalisation of infrastructure) has a significant impact on the results of the study (amongst others), due to increasing uncertainties in longer time scenarios.

The ratings can be understood as follows:

(+)	Better than the current bidding zone configuration (Status Quo)
(0)	No significant difference compared to the current bidding zone configuration (Status Quo) or a reasonable assessment of the impacts is not possible
(-)	Worse than the current bidding zone configuration (Status Quo)

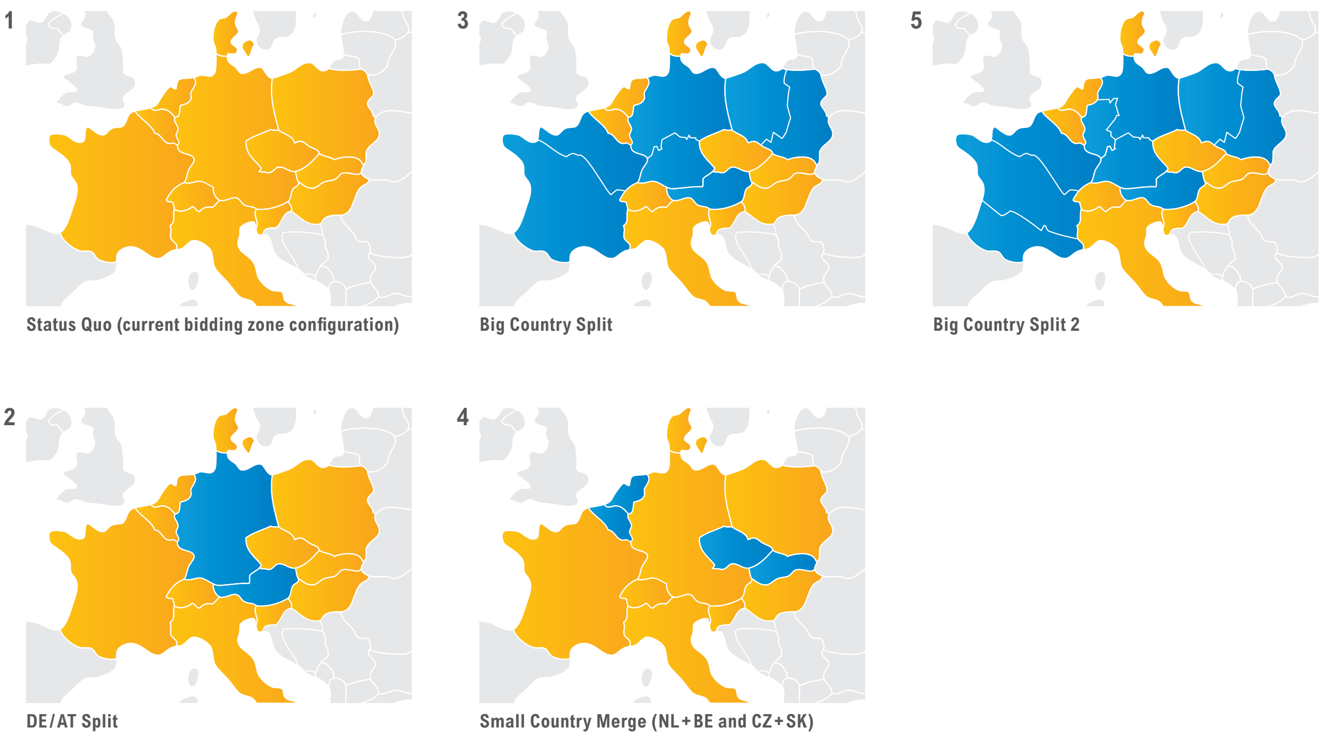

Figure 1.1: Bidding zone configurations under investigation in the Bidding Zone Review

This evaluation has been conducted in comparative terms, and all indicators are expressed in relative terms to the current bidding zone configuration. The underlying analyses in Chapter 5 are mainly qualitative and, hence, for the reasons explained in later sections, are not supported by comprehensive quantitative simulations. Furthermore, any assessment is dependent on the underlying assumptions, in particular with regard to relevant externalities such as the grid infrastructure development. All results, figures and tables shown in this report are no firm basis for drawing conclusions and have to be interpreted against the assumptions explained in this report. Therefore, the summing up of the evaluation displayed in Table 1.1 is inappropriate.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Network security				
Operational security	(+)	(+)	(+)	(-)
Security of Supply (for the entire system, short-term)	(0)	(0)	(0)	(0)
Degree of uncertainty in cross–zonal capacity calculation	(0)	(0)	(0)	(0)
Market efficiency				
Economic efficiency	(0)	(0)	(0)	(0)
Firmness costs	(-)	(-)	(-)	(+)
Market liquidity	(-)	(-)	(-)	(+)
Market concentration and market power	(-)	(-)	(-)	(+)
Effective competition	(0)	(0)	(0)	(0)
Price signals for building infrastructure	(0/+)[a]	(0/+)[a]	(0/+)[a]	(0/-)[a]
Accuracy and robustness of price signals	(0)	(0)	(0)	(0)
Long-term hedging	(-)[b]	(-)[b]	(-)[b]	(+)[b]
Transition and transaction costs	(-)	(-)	(-)	(-)
Infrastructure costs	Reference to investment costs as published in the TYNDP 2016			
Market outcome in comparison to corrective measures	(+)[c]	(+)[c]	(+)[c]	(-)[c]
Adverse effects of internal transactions on other bidding zones	(+)[d]	(+)[d]	(+)[d]	(-)[d]
Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes	(0/-)	(-)	(-)	(0/-)
Stability and robustness of bidding zones				
Stability and robustness of bidding zones over time	(0)	(-)[e]	(-)[e]	(0)
Consistency across capacity calculation time frames	(0)	(0)	(0)	(0)
Assignment of generation and load units to bidding zones	(0)	(-)	(-)	(0)
Location and frequency of congestion (market and grid)	(+)	(+)	(+)	(-)

[a] The importance differs between borders/countries and the effectiveness of the signal is low, given the incompatible lead times between market prices and grid investment decisions which are characterised by long construction periods and approval processes.
[b] Alternative long-term hedging instruments (such as system price or trading hubs) that might mitigate the negative impact are to be investigated.
[c] There can be no further distinction between the splits without further quantitative analyses.
[d] This assessment considers loop flows, but does not consider any adverse market effects linked to loop flows.
[e] For Germany, grid investment planning foresees the building of high voltage direct current (HVDC) links moving towards a copper plate. The intention of these grid investments is to resolve any relevant congestion that might justify a split of the German bidding zone. This makes the Big Country Split less stable but does not consider any adverse market effects linked to loop flows.

Table 1.1: Summarised assessment of the bidding zone configurations

The analysis of the overall results suggests, that, in comparison to the Status Quo, the split configurations are superior and the merge configurations are inferior with regard to the criteria related to operational security. This conclusion is justified by a decreasing need for corrective measures and frequency of congestion. Reducing the size of zones increases market participants' exposure to grid constraints, since trading with neighbouring zones requires them to compete with each other for access to scarce grid resources. With smaller zones, market participants are no longer permitted to dispatch generation or demand units if these are beyond grid limits, decreasing the need for corrective TSO measures and hence exerting a positive influence on operational security.

In contrast, the merge configurations appear to be superior, and the split scenarios to be inferior to the Status Quo with regard to market liquidity-related aspects and market concentration/power. Since the unconstrained trade is possible across a larger geographical area, the capability of market parties to find counterparts increases. This has a positive influence on competition and decreases market concentration/power.

With regard to several other criteria included in EU Regulation 1222/2015, a less clear distinction can be drawn between the positive and negative effects of the configurations.

Finally, it must be underlined that any change of bidding zones and, hence, implementation of both merge and split scenarios will introduce additional costs associated with changing the market structure and all supporting systems. These transition costs also need to be considered when elaborating the decision regarding maintaining or changing the bidding zone configuration.

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RECOMMENDATIONS

This First Edition of the Bidding Zone Review is the first exercise of its kind in Europe. It brings together detailed grid and market models to simulate market and system operations for the different analysed bidding zone configurations. In order to conduct the necessary simulations, TSOs have made assumptions on the future grid, generation and demand developments as well as on the future generation cost structures. Moreover, realistic simulations of power system responses to the market forces required realistic representation of all necessary processes, starting from cross-zonal capacity calculation and spanning through market coupling, security analysis and redispatching measures. The main challenge in simulating the above is that no operational reference process exists for the employed models (i.e. the Core capacity calculation region [CCR] has not yet fully produced all the required methodologies). Many of the processes and market arrangements modelled under the First Edition of the Bidding Zone Review are currently under development, so it is not possible to apply the agreed and proven methodologies for the purpose of the study. Moreover, since the calculations conducted in the scope of this First Edition of the Bidding Zone Review concern future time horizons spanning up to 2025, there are important modelling assumptions that need to be taken, including the exact localisation of new generation and loads, as well as on the generation and redispatch costs. Finally, it is to be underlined that replication of day-to-day operational TSO processes faces important challenges, since any modelling environment is limited in the extent to which it can represent real-time TSO actions (e.g. use of topological measures). In particular, tools allowing for simultaneous optimisation of market operations and topology measures do not yet exist. All these elements underscore the significant technical complexity of the First Edition of the Bidding Zone Review.

The numerical results obtained in the course of the study therefore need to be interpreted against the evolution of the simulation environment. Results of the calculation of locational marginal prices (LMPs) and model-based clustering require further improvement in terms of data quality and replication of the operational topological TSO measures related to management of constraints in some countries. The remaining calculations related to expert-based scenarios would have to be aligned further to the flow-based market coupling and redispatching methodologies applied in the Core CCR.

In terms of the evaluation, the different configurations have been evaluated against the criteria included in European Commission (EC) Regulation 1222/2015. Partially because of the inconclusive results of the quantitative analyses, this evaluation shows a heterogeneous picture where no configuration is clearly classified as superior to any other.

In light of the above considerations and needs for adapting and developing the simulation environment further, the evaluation presented in this First Edition of the Bidding Zone Review does not provide sufficient evidence for a modification of or for maintaining of the current bidding zone configuration. Hence, the participating TSOs recommend that, given the lack of clear evidence, the current bidding zone delimitation be maintained.

This recommendation should in no way be interpreted as an endorsement of or an objection against the pending split of the German/Luxembourgian and Austrian bidding zones, where TSOs respect all relevant regulatory decisions, e.g. the decision of the Agency for the Cooperation of Energy Regulators no 06/2016 of 17 November 2016 on the electricity transmission system operators' proposal for the determination of capacity calculation regions and the requests of the regulatory authorities of Germany and Austria.

This recommendation is compliant with the relevant legal provision of EU Regulation 1222/2015, which, in Article 32 (4) b), states that

[…] the TSOs participating in a review of bidding zone configuration shall:

(iii) submit a joint proposal to maintain or amend the bidding zone configuration to the participating Member States and the participating regulatory authorities within 15 months of the decision to launch a review.

It is to be reiterated that this First Edition of the Bidding Zone Review is the first attempt at analysing bidding zone configurations in Europe. The experience gained by TSOs in this process will allow for a further improved Bidding Zone Review in the future. Hence, even though no strong recommendation to maintain or change bidding zones can be expressed based on the First Edition of the Bidding Zone Review, TSOs will adapt the simulation environment to the emerging market regions such that more concrete recommendations, or at least the technical assessment required for such recommendations based on enhanced models, methodologies and assumptions, will be available in the future.

TSOs are committed to continuing this improvement process, delivering robust technical analysis for future Bidding Zone Reviews. The multitude of different evaluation criteria prescribed by CACM pose a challenge to interpretation of the Bidding Zone Review results. Some of these challenges and choices are associated with political issues raised by the different stakeholders during the Bidding Zone Review, which sometimes exceed the core TSO competences. While the technical robustness and quality of the report has been, and will be, significantly improved over time, the political concerns raised by some stakeholders may need to be addressed by harmonising the policy objectives within and across borders.

DISCLAIMER

Interested stakeholders are being formally consulted regarding the preliminary findings included in this report. This formal consultation follows the regular exchange between major associations on the subject in the stakeholder advisory group established by ENTSO-E.

Inputs received in the public consultation of this draft report will support the TSOs participating in the review to finalise their assessment.

2 INTRODUCTION

Bidding zones are a core element of the European market design. Electricity trades and exchanges are organised between these zones. The definition of a bidding zone boundary is therefore a question of major relevance for the market and requires profound analysis. In its Articles 32 to 34, the EU Regulation 1222/2015 sets the accordant framework for this assessment.

The analysis was initiated by drafting a technical report by ENTSO-E and a market report by ACER. Both reports for this Bidding Zone Review have been completed and are publicly available.[2)] On the basis of these reports, several institutions[3)] may initiate the actual review of bidding zones. ACER has taken this initiative and initiated the current review in a letter dated 21 December, 2016. Together with the initiation, ACER has specified the area for which the review is conducted.[4)] All regulatory authorities and TSOs located within this area have been declared participants of the review.

Upon this request from ACER, participating TSOs have initiated the review based on a previous ENTSO-E early implementation project of the Bidding Zone Review. The general framework applicable for this review encompasses several steps:

- In order to analyse different configurations, a scenario framework has to be defined. This framework specifies environmental conditions such as market characteristics, electricity generation and grid infrastructure. This framework is described in Chapter 3.
- The bidding zone configurations subject to the analysis have to be defined. The accordant process and proposals are described in Chapter 4.
- Further to the scenario framework and the configurations, evaluation criteria have to be determined and applied. Chapter 5 contains a description of, and the application of, these individual criteria. A dedicated section (5.24) summarises the individual evaluations and draws a comprehensive conclusion.
- Chapter 6 identifies the challenges in all-encompassing modelling of markets and grids, and provides an overview of key insights and lessons learned.

The quantitative analysis based on a flow-based market coupling model has, for several reasons, not been used for drawing firm conclusions. Those reasons, which include the yet to be specified market design in the relevant market region, as well as modelling complexities associated with the flow-based market coupling are described in Chapter 6.

In accordance with EU Regulation 1222/2015, participating regulatory authorities must consult with this general framework. This consultation has already been completed under the previous ENTSO-E early implementation project and is currently repeated in the formal Bidding Zone Teview.

Further to the consultation of regulatory authorities, the involvement of stakeholders ensures a comprehensive assessment encompassing all relevant aspects. The accordant stakeholder involvement approach is described in Chapter 7.

According to EU regulation 1222/2015, the results of the review must be available within 15 months of its initiation. The time target for completing the review is therefore 21 March 2018. By this date, the First Edition of the Bidding Zone Review will be submitted to the relevant NRAs with the recommendation to Member States on whether to maintain or amend the current bidding zone configuration will have to be made.

2) Under www.entsoe.eu and www.acer.europa.eu

3) In accordance with Article 32 of Regulation 1222/2015, these institutions are: ACER, several regulatory authorities, TSOs of a capacity calculation region or Member States.

4) Austria, Belgium, the Czech Republic, Denmark, France, Germany, Hungary, Italy (North), Luxembourg, the Netherlands, Poland, Slovakia and Slovenia

3 FUTURE SCENARIO ASSUMPTIONS

PICTURE COURTESY OF NATIONAL GRID

In the following sections, market and grid assumptions applied in this First Edition of the Bidding Zone Review are described in more detail. In general, two scenarios are differentiated; both are based on ENTSO-E's System Outlook and Adequacy Forecast (SOAF) 2015 scenario B, differentiating between the years 2020 and 2025 and two grid statuses: planned and worst case. Considering an appropriate implementation period of three to five years and a certain period for which the new configuration should be valid to unfold its effects, the years 2020 and 2025 have been chosen.

Article 33(2) CACM requires an analysis based on scenarios taking into account a range of likely infrastructure developments, starting from the year following the year in which the decision to launch the review was taken up to ten years. This range is covered by the two chosen scenarios 2020 and 2025 and has been consulted formally with the relevant NRAs.

The experience with this First Edition of the Bidding Zone Review has shown that the choice of the time-frame of the scenarios and the underlying assumptions (e.g. finalisation of infrastructure) has a significant impact on the results of the study (amongst others), due to increasing uncertainties in longer time scenarios.

3.1 MARKET DATA

For the intended time horizons of the study (2020 and 2025), market data from the ENTSO-E SOAF 2015 and the Ten-Year Network Development Plan (TYNDP) 2016 report are used. For the 2020 time horizon, the SOAF B 2020 (Best Estimate) has been chosen from the two future scenarios developed in the SOAF report. For the 2025 time horizon of the study, the TYNDP 2016 data for 2030 has been used, applying a linear interpolation of all relevant data between 2016 and 2036.

This has resulted in data for:

- Commodity prices such as coal, gas and uranium; and CO_2 price.
- Installed power plant capacities in all categories (e.g. hydro, thermal, wind, photovoltaic).
- Load profiles for 8760 hours.
- Capacities for other renewable energy sources (RES) and other non-RES
  (e.g. biomass, geothermal, wave),

Individual information on power plants (capacity, location, type, etc.) has been obtained from an external power plant data base corrected with individual TSO information where available.

Further details on market data determination are provided in Annex 1 to this report.

3.2 GRID DATA

A clear definition of grid scenarios is necessary in order to guarantee a harmonised set-up of those scenarios and to enable the involved TSOs to properly select their projects for each scenario.

Typically, a network development project's status is classified into four categories in the ENTSO-E TYNDP. These categories are applied in the Bidding Zone Review and can be defined as (and mapped, cf. Figure 3.1):

1) UNDER CONSIDERATION

2) PLANNING

3) DESIGNING & PERMITTING

4) UNDER CONSTRUCTION

This classification of grid projects is compliant with the relevant ACER definitions contained in Annex.[5)]

This leads to the following scenarios for this Bidding Zone Review where the 2020 scenario encompasses all grid investments under construction and the 2025 scenario in addition all grid investments which are at least in a planning stage:

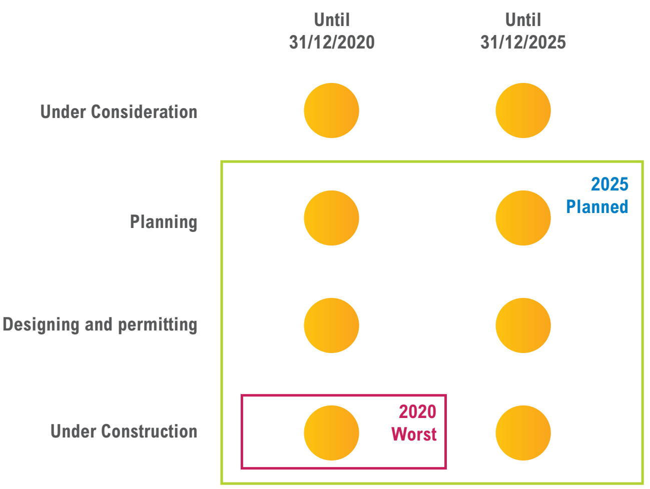


Figure 3.1: Overview of grid scenarios considered in the First Edition of the Bidding Zone Review

2025 PLANNED SCENARIO

This network represents the main case for 2025 and includes all network development projects expected to be put into service until 31 December 2025. As a general rule, projects that are by this point in time classified as 'under consideration' are not considered in the 2025 Planned Scenario. However, if their status is expected to be changed in the next TYNDP or domestic development plan, an exception from the general rule was possible.

2020 WORST SCENARIO

This network includes only those network development projects which are currently under construction or where construction cannot be delayed or cancelled (due to contractual or very binding legal clauses). In the latter case, sound evidence for the inclusion should be provided by the concerned TSO, in order to justify that their construction is virtually inevitable. Only the projects expected to be completed by 31 December 2020 are included in this scenario. For example, big internal HVDC projects are not included in this scenario.

PROJECT SELECTION FOR THE GRID SCENARIOS

The project selection itself was then based on the investments considered in the TYNDP 2016. Due to its broader focus, the TYNDP refers mainly to cross-zonal projects and considers the current bidding zone configuration (Status Quo) as an exogenous assumption. Since the Bidding Zone Review has a more detailed focus and aims for the assessment of alternative bidding zone configurations, national grid investment projects (located within the current bidding zones) were added to the list of TYNDP grid investments by the concerned TSO for the purpose of this Bidding Zone Review. In general terms, the longer the forecast reaches into the future, the less predictable the forecast tends to be.

5) With regard to the ACER definitions: step 1 (under consideration) corresponds to step i, step 2 (planning) corresponds to the conclusion of step i. up to the end of step ii., step 3 (Designing & Permitting) corresponds to step iii. to the end of step x., and step 4 (under construction) represents step x. up to the end of step xii.

4 ANALYSED BIDDING ZONE CONFIGURATIONS

Several aspects have to be considered when new bidding zone configurations are determined for further evaluation of a possible reconfiguration.

As a starting point, the current situation of the existing bidding zones (e.g. market prices and price differences between bidding zones, internal and cross-zonal network congestions, load flows, redispatch costs, firmness costs for guaranteeing cross-zonal capacity) may give some indications for the selection. Their explanatory power and reliability is, however, limited as any reconfiguration and its consequences have to be evaluated for the future. Considering an appropriate review time for the evaluation of a suitable reconfiguration – an implementation time of three to five years and a certain period for which the new configuration should be valid to unfold its effects – the evaluation has to look five to 10 years into an (uncertain) future.

In addition, any selection of configurations needs to be assessed for all relevant criteria as required by the Network Code on Capacity Allocation and Congestion Management (NC CACM). However, it is not clear which evaluation criterion should be the most important. It might, for example, be the maximisation of (monetised) welfare, minimisation of loop flows, maximisation of market liquidity or a mix of criteria. The catalogue of evaluation criteria prescribed in the NC CACM indicates the multi-dimensionality of the analysis, meaning all criteria are equally important.

Finally, the topic is politically contested. Stakeholders and market participants advocate different configurations and development directions. A principal disagreement, for example, concerns increasing or decreasing the number of bidding zones compared to the Status Quo and, respectively, the splitting or merging of zones (leading to the extreme cases of a nodal-pricing or single-zone market).

Another aspect is the number of configurations that shall be analysed. This had to be limited due to the following reasons: For each configuration, the analytical framework of this Bidding Zone Review has to be applied. This comprises inter alia a market coupling simulation, a grid calculation and the evaluation of several other criteria, for several time horizons. In this study, two time horizons, 2020 and 2025, are considered. Moreover, the configurations have to be tested for different future scenarios (political regulation, fuel prices, power plant portfolio, load, geographical distribution of supply and demand, meteorological year, etc.).

In conclusion, the selection of configurations is a complex, multidimensional decision-making exercise. Considering all the points above, the participating TSOs have developed configurations using expert-based assessments and others determined by academic models. Both approaches are described in sections 4.1 (expert-based bidding zone configurations) and 4.2 (model-based bidding zone configurations). In light of the following considerations, the participating TSOs propose an exclusive investigation of the expert-based configurations described in section 4.1.

Article 32 (4) of the CACM Regulation (EU) 1222/2015 provides participating national regulatory authorities (NRAs) the opportunity to require coordinated amendments regarding the bidding zone configurations subject to review. The proposals outlined in the following chapters have already been subject to an informal consultation with NRAs during the informal initialisation of the Bidding Zone Review and have also been officially submitted to NRAs under the formal process. The main requirement of NRAs with regard to the expert-based configurations has been the request to add one additional split scenario to the analytical scope. With regard to the model-based configurations, NRAs have requested an analysis of two such configurations and the analysis of nodal pricing.

4.1 SELECTION OF EXPERT-BASED BIDDING ZONE CONFIGURATIONS

The Bidding Zone Review considers five expert-based bidding zone configurations, as shown in Figure 4 1. In this context, expert-based means that these configurations have been determined by the TSOs based on their expert knowledge and coordinated with the relevant NRAs during the pilot project as required by the EU regulation 1222/2015, and the Big Country 2 Split configuration has been added as a result of this coordination. Not all potentially relevant configurations could be considered in this First Edition of the Bidding Zone Review since time and scope of the review have been limited. The experience with the First Edition of the Bidding Zone Review showed that a careful selection of the analysed scenarios is of particular importance for the outcome and credibility of the analysis. As Figure 4.1 demonstrates, the configurations proposed for the review encompass the current bidding zone delimitation, three split delimitations and one merger delimitation. A detailed explanation of the splits and merges and their justification is given in the following sections.

4.1.1 STATUS QUO: THE CURRENT BIDDING ZONE CONFIGURATION

Answering the question of whether the current bidding zone configuration should be modified requires a comparison of the current arrangement to alternative ones. Therefore, the current bidding zone configuration needs to be included in such an assessment, as required by the Network Code on CACM. Currently, the majority of the bidding zones are defined by national borders. However, some are larger than national borders (e.g. Germany, Austria and Luxembourg) and some are smaller and exist within individual countries (e.g. Italy).

4.1.2 DE/AT SPLIT

The DE/AT configuration considers a separation of the Austrian (AT) zone from the German–Luxembourgian (DE, LU) zone. The configuration has been explicitly requested by several stakeholders, arguing that commercial exchanges between AT and DE affect the physical flow conditions in neighbouring countries significantly. In the meantime (after the start of this First Edition of the Bidding Zone Review) the German and Austrian NRAs (Bundesnetzagentur and E-Control) asked the German TSOs TenneT, TransnetBW and Amprion, as well as the Austrian TSO Austrian Power Grid AG, to implement a new bidding zone border between Germany and Austria by 1 October 2018.

For the purpose of the Bidding Zone Review, the split of the currently common bidding zone of Germany–Luxembourg and Austria is in general done along the state borders. There

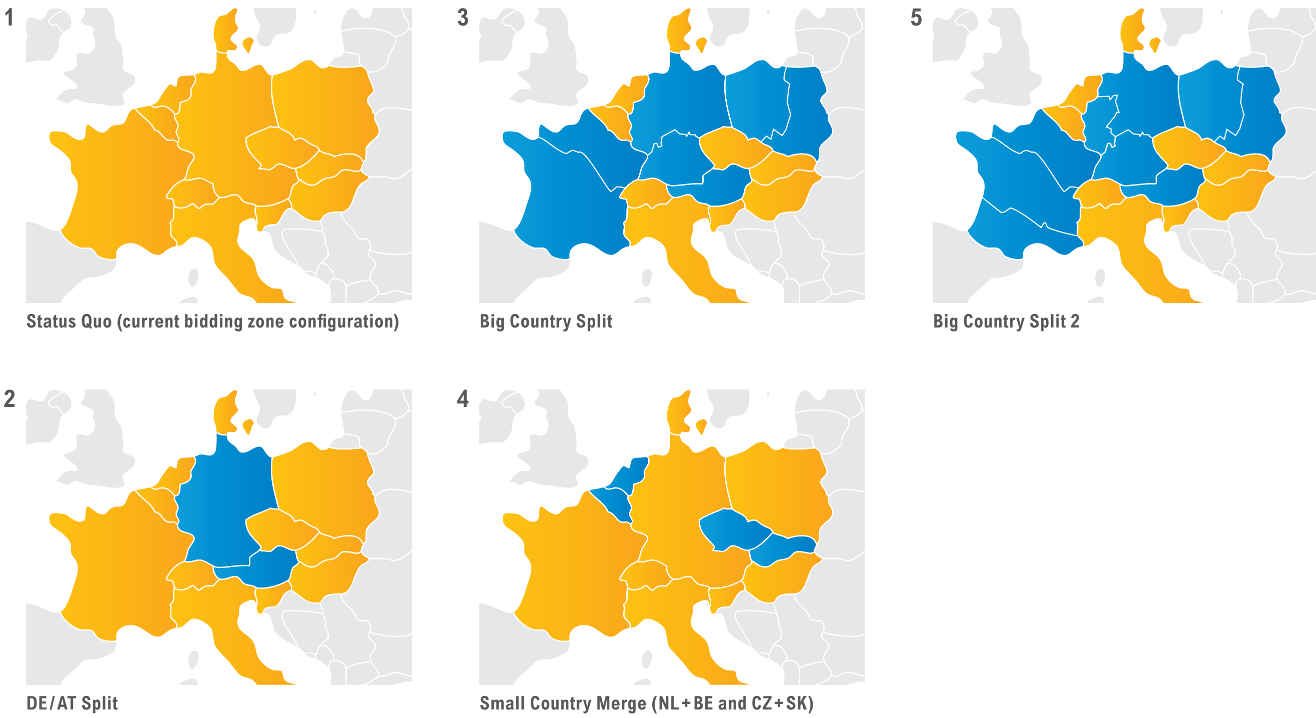


Figure 4.1: Expert-based bidding zone configurations under investigation in the Bidding Zone Review

are three exceptions to this rule. The first one relates to power plants located at the border along the Inn and Danube rivers. For the purpose of this study, approximately half of the installed capacity was allocated to Austria (324 MW) and half to Germany (352 MW).

Plant name	Country
Braunau-Simbach	AT
Jochenstein	AT
Schärding-Neuhaus	AT
Egglfing-Obernberg	DE
Passau-Ingling	DE
Ering-Frauenstein	DE
Oberndorf-Ebbs	DE
Nussdorf	DE

Table 4.1: Assignment of power plants to the Austrian and German bidding zone as considered in the First Edition of the Bidding Zone Review

The second exception considers the mutually used pump storage plants in Tyrol. They are modelled as half of their capacity belonging to the German and half belonging to the Austrian bidding zone. The plants in question are the power plants located in Kaunertal, Silz and Kühtai.

The third exception relates to the historically grown German grid substations and connections in the Austrian federal state of Vorarlberg. This mainly concerns the power plants along the Ill river which are considered part of the German–Luxembourgian bidding zone.

However, since the current Bidding Zone Review runs in parallel to the preparation process of the potential implementation of a bidding zone border between Germany–Luxembourg and Austria, the aforementioned assignment of power plants close to the political German–Austrian border (cf. Table 4.1) can only be considered as relevant for the First Edition of the Bidding Zone Review and might differ from the final assignment that will be applied for the implementation of this bidding zone border in reality.

4.1.3 BIG COUNTRY SPLIT AND BIG COUNTRY SPLIT 2

The alternative configurations Big Country Split and Big Country Split 2 extend the aforementioned configuration DE/AT Split by the additional splits of France (FR), Germany (DE) and Poland (PL).

In the Big Country Split the bidding zones of FR and PL are split once, whereas the AT/DE/LU zone is split twice. In the Big Country Split 2, the bidding zones of FR and DE/LU are further split, while PL remains in two zones. The general idea of these configurations is to split geographically large bidding zones following the philosophy of smaller bidding zones. The arguments for the approach are a better reflection of internal congestions, the minimisation of loop flows and re-dispatch requirements. The historic re-dispatch costs are, for example, relatively high in the three bidding zones. The issue of loop flows caused by larger bidding zones was also explicitly addressed by the European Commission. The configuration therefore addresses related stakeholder concerns. More equally sized zones are also considered by some stakeholders as advantageous for a flow-based market coupling.

4.1.3.1. German bidding zone delimitations applied in the alternative configurations Big Country Split and Big Country Split 2

German bidding zone delimitation applied in the alternative configuration Big Country Split

The delimitation shown in Figure 4.2 has been defined for the configuration Big Country Split of the Bidding Zone Review. It splits the German bidding zone along the borders of the federal states Bavaria and Baden-Württemberg into a northern and a southern bidding zones.

Figure 4.2: German bidding zone delimitation applied in the configuration Big Country Split

The configuration was selected among several alternatives that were investigated by grid and market experts of the German TSOs. The presented split has been evaluated with the highest ranking according to several criteria. The summary below gives a brief overview of this evaluation without being exhaustive.

First, the following fact is important. Both the German government and TSOs are heading for substantial investments in the German transmission grid in the course of the energy transition in Germany ('Energiewende'). These development projects are based on extensive planning processes involving many stakeholders and their realisation is legally anchored and follows a dedicated time plan. The grid expansion is planned in such a way that no important congestions remain within the German transmission grid. Consequently, the German transmission is assumed to facilitate all transmission requirements by 2025, which is an alternative approach to splitting the German–Austrian bidding zone within Germany. The split in Figure 4.2 is proposed to fulfil the requirements of the Big Country Split configuration that it was agreed would be investigated in the First Edition of the Bidding Zone Review.

The consideration of the described delimitation to be applied in the First Edition of the Bidding Zone Review is confirmed by all German TSOs. This is an alternative approach to restricting future trading through the introduction of an intra-German bidding zone border.

Summarised assessment of the split applied in the configuration Big Country Split

The efficient management of (future) long-term, structural congestion is one of the major targets of a reconfiguration of bidding zones. Therefore, any bidding zone should be designed in such a way that main congestions are observed between the zones (interzonal) and only some bottlenecks remain within the zones (intrazonal). The remaining non-structural (intrazonal) congestions would have to be managed by remedial actions.

However, a bidding zone configuration should also be as stable/robust as possible. Yet, faced with such large uncertainties as to the further development of conventional and RES generation capacities and related fluctuating shares of RES infeed, a precise definition of a robust (for several years) and efficient (for several grid situations) zone delimitation is challenging.

The German grid development plan encompasses an analysis of the maximum line utilisation under N-1 security and for a pessimistic grid development (ignoring major parts of the planned grid investments). Figure 4.3 shows the maximum line utilisations for the so-called 'Startnetz' for the entire year 2024 under N-1 security. A potential intra-German bidding zone border as described in Figure 4.2 (indicated by the red dotted line in Figure 4.3) would cross some of the highest utilised lines (with utilisations up to 200 %).

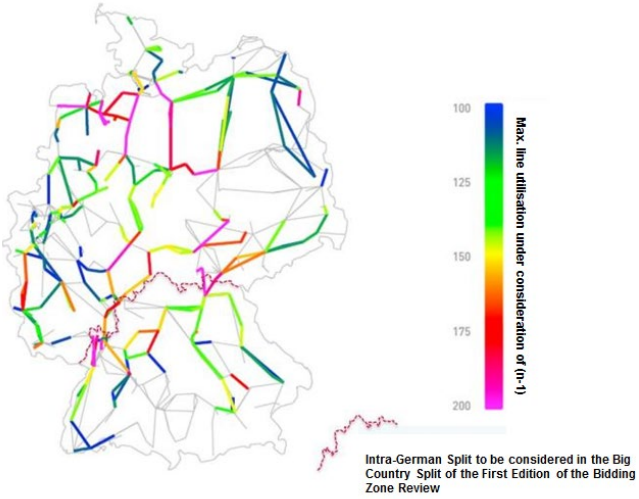


Figure 4.3: Maximum line utilisation under consideration of (N-1) for 2024 (scenario 'Startnetz'); Source: German grid development plan 2014

In addition, the indicated north-south split considers that congestions in the current German transmission grid generally occur along the north-south direction due to deviations between the locations of (wind) production (in the north) and large consumption centres (in the south).

German bidding zone delimitation applied in the alternative configuration Big Country Split 2

Figure 4.4 shows the delimitation for the alternative configuration Big Country Split 2 of the First Edition of the Bidding Zone Review. It keeps the intra-German split of the previous Big Country Split configuration and adds another split along the northern borders of a main parts of the control zone of Amprion.

The configuration was selected among several alternatives investigated by grid and market experts of the German TSOs. The presented split has been evaluated with the highest ranking according to several criteria. The summary below gives a brief overview of this evaluation without being exhaustive. For reasons of clarity, the following explanation focuses on the additional splitting and therefore does not repeat the assessment of the split of Germany into northern and southern zones.

As already highlighted in the section describing the split of Germany into northern and southern zones, the following fact remains important: The German government and

Figure 4.4: German bidding zone delimitation applied in the configuration Big Country Split 2

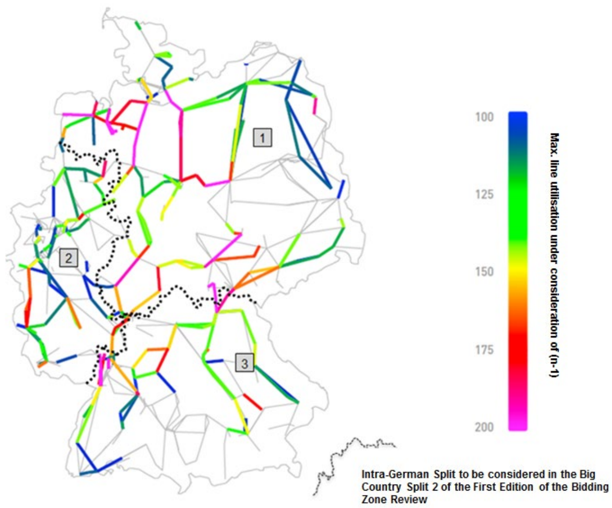


Figure 4.5: Maximum line utilisation under consideration of (N-1) for 2024 (scenario 'Startnetz'); Source: German grid development plan 2014

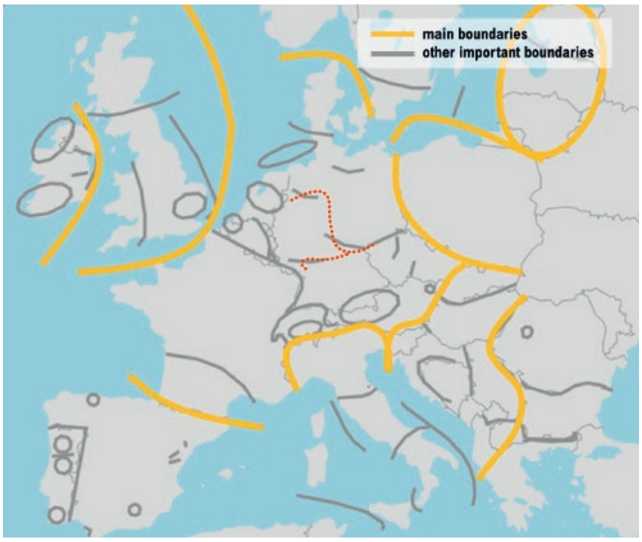


Figure 4.6: Map of the boundaries in Europe including the indicative German bidding zone delimitation applied in the configuration Big Country Split 2 (red dotted line not from TYNDP); Source: Ten-Year Network Development Plan 2016[6)]

TSOs are heading for substantial investments in the German transmission grid in the course of the 'Energiewende'. These development projects are based on extensive planning processes involving many stakeholders, and their realisation is legally anchored and follows a dedicated time plan. The grid expansion is planned in such a way that no important congestions remain in the German transmission grid. This will facilitate all transmission requirements by 2025 as an alternative approach to splitting the German–Luxembourgian–Austrian bidding zone within Germany. The split in Figure 4.4 is proposed to fulfil the requirements of the Big Country Split 2 configuration, that was agreed would be investigated in the First Edition of the Bidding Zone Review.

Summarised assessment of the split applied in the configuration Big Country Split 2

As already mentioned above (see Big Country Split), the German grid development plan encompasses an analysis of the maximum line utilisation under N-1 security and for a pessimistic grid development (ignoring major parts of the planned grid investments). The Figure 4.5 again shows the maximum line utilisations for the so-called 'Startnetz' for the entire year 2024 under N-1 security. The second intra-German border closely follows highly utilised lines. While respecting the borders of the control areas (at least to a large extent), this would be sufficient to influence the market in such a way that the main parts of the hypothetical and temporary congestion are considered by the market.

In addition, the inner German splits defined for the First Edition of the Bidding Zone Review are linked to the analysis performed in the TYNDP 2016, which highlights the necessity of inner German reinforcements especially in these areas (between the north and the south of Germany and in the north of Germany). Indeed, the boundaries shown in Figure 4.6 follow quite closely the proposed hypothetical

6) http://tyndp.entsoe.eu/projects/2016-12-20-1600-exec-report.pdf

split between Bavaria/Baden-Württemberg, the control area of Amprion, and the rest of Germany (these splits related to the First Edition of the Bidding Zone Review are indicated by the red dotted line).

The analysis of the TYNDP 2016 also indicates that the reinforcement of the internal German boundaries does have large European benefits. The TYNDP 2016 therefore underlines the need for realising the already planned internal German projects, which will resolve future internal bottlenecks (as also projected by the German grid development plans). For the status of the related TYNDP projects, see the TYNDP assessment sheets.

4.1.3.2 French bidding zone delimitations applied in the alternative configurations Big Country Split and Big Country Split 2

The two scenarios described as follows were requested in coordinated feedback from ACER and the involved NRAs in the First Edition of the Bidding Zone Review. They are compliant with the request, although RTE underlines that France experiences a very low level of internal congestion and that this structural situation will remain unchanged in the medium and long-term time frames according to the planning studies.

Method applied to evaluate the constraints on the French network

The following results are taken from an RTE internal study which is based on the 2030 data (load, renewable energy sources, central units, grid development). France is divided into 25 areas that are coherent from the impedance point of view (see Figure 4.7).

Based on the above delineation, the year 2030 has been simulated 50 times in order to consider the variability of the inputs (with different chronicles of renewable, consumption, flow infeed, etc.).

The hourly physical flows from the simulations are compared to the grid transfer capacity (GTC) equivalent to the capacities that the lines can physically handle. Usage of remedial action (topological and phase shifter transformer [PST]) is included in the definition of the GTC values. This reflects the operation rules that RTE is using to manage the congestions.

One of the main outputs of the study is the following map (cf. Figure 4.8) that presents the value of the average physical flow on each area border. The colour inside the arrow provides an indication of the distribution of the hourly physical flow compared to the GTC. The average value included in the arrow does not represent the severity of the constraint.

Scenario with two bidding zones in France (Big Country Split)

In order to split France into two bidding zones, the border has to represent a line of congestion. The following map (cf. Figure 4.9) represents the proposal.

The northern area regroups the consumption of the Paris area, the generation on the Manche and the wind of the northern part of France. The southern area includes Brittany and all the nuclear power plants along the Loire and Rhône rivers.

Scenario with three bidding zones in France (Big Country Split 2)

With the applied method, the creation of an additional relevant area within France does not appear natural due to the limited number of internal congestions. To do so, RTE used the long-term additional data from the European planning studies ENTSO-E TYNDP.

Based on the above, the initial delineation is kept and an additional border is introduced in order to consider the 'other important border' in the south of France. As the internal RTE study identified a constraining area in the north of the Rhône Valley, the border has been slightly adjusted eastwards to integrate PACA into the southern zone as well as eight nuclear plants in the south of the Rhône Valley.

4.1.3.3 Polish bidding zone delimitations applied in the alternative configurations Big Country Split and Big Country Split 2

The split of the Polish bidding zone has been determined with a model-based approach by an external consultant[7], considering the same input data as used for the clustering of the whole area considered in the Bidding Zone Review. This input data includes LMPs (locational marginal prices), shadow prices and nodal PTDFs (power transfer distribution factors). Although PSE is aware of the limited quality of LMPs used in the clustering exercise (see explanation provided in section 4.2), the issues were observed mainly in areas distant from Poland (see section 4.2) while no such issues were found in Poland and its direct vicinity. PSE has been provided with clustering results for Poland for ten scenarios[8] and two clustering methods i. e. PTDF-based and LMP-based, which are described in detail in the Annex.

The clustering results confirm PSE's understanding that there is no structural congestion in Poland, and hence no typical split of PL has been identified. The Polish bidding

7) The same consultant which is also responsible for the clustering of the whole area considered in the Bidding Zone Review.

8) SOAF and TYNDP visions and two cases of network infrastructure

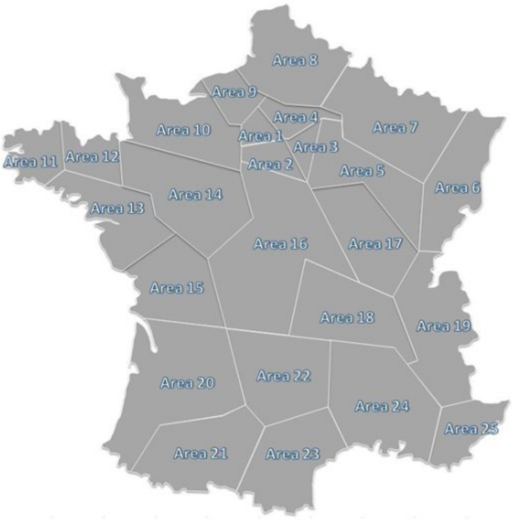


Figure 4.7: Map of France from the impedance point of view

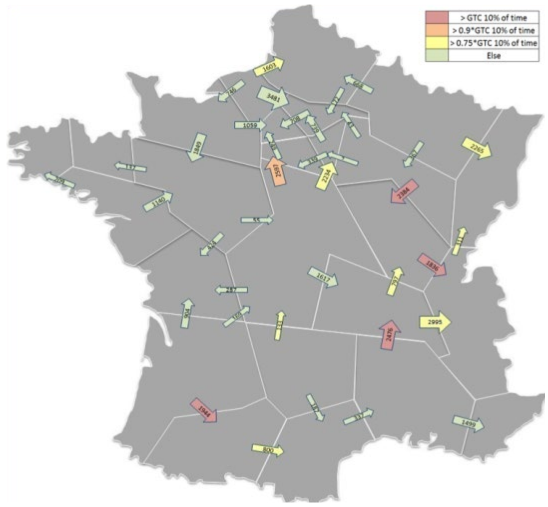


Figure 4.8: Projected physical flows in France in 2030 (MWh/h)

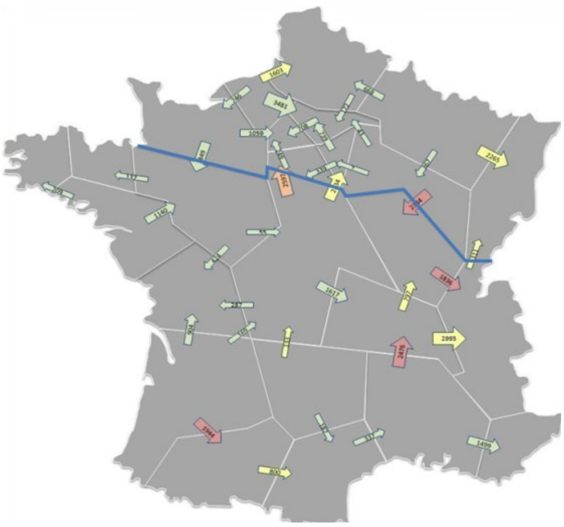


Figure 4.9: Projection with two bidding zones in France

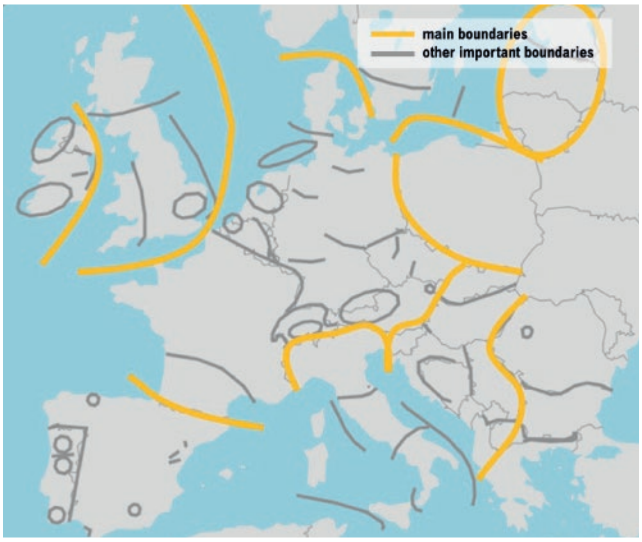


Figure 4.10: Map of the boundaries in Europe. Source: Ten-Year Network Development Plan 2016[9]

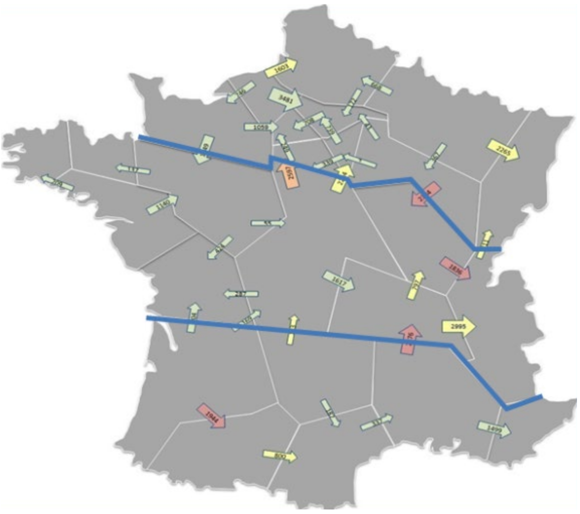


Figure 4.11: Projection with three bidding zones in France

9) http://tyndp.entsoe.eu/projects/2016-12-20-1600-exec-report.pdf

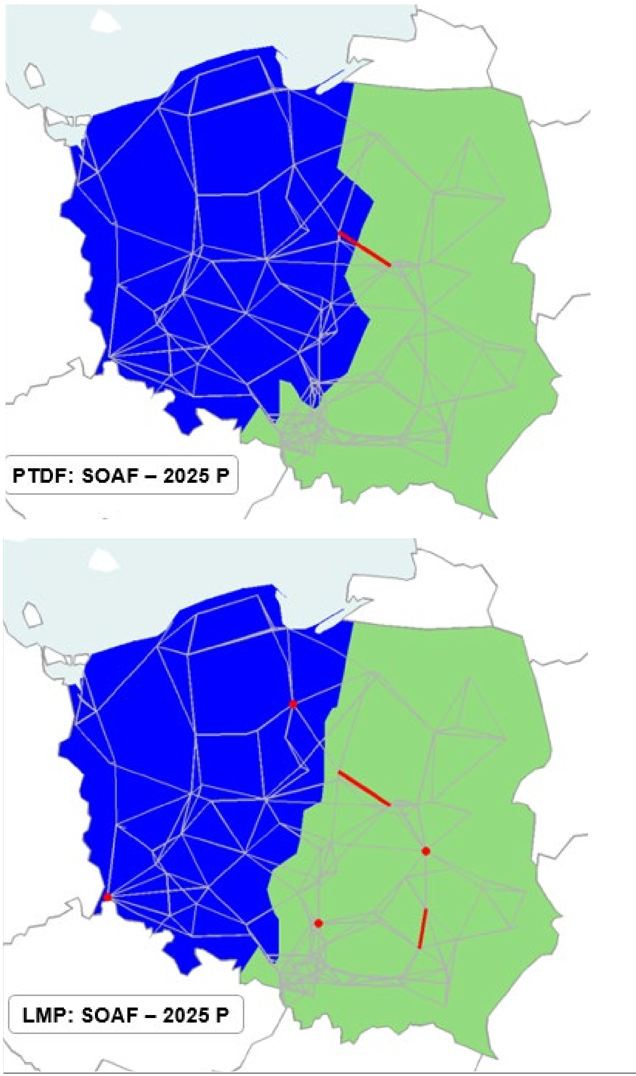


Figure 4.12: PL clustering results by PTDF and LMP methodology for the 'SOAF 2025 grid planned' scenario

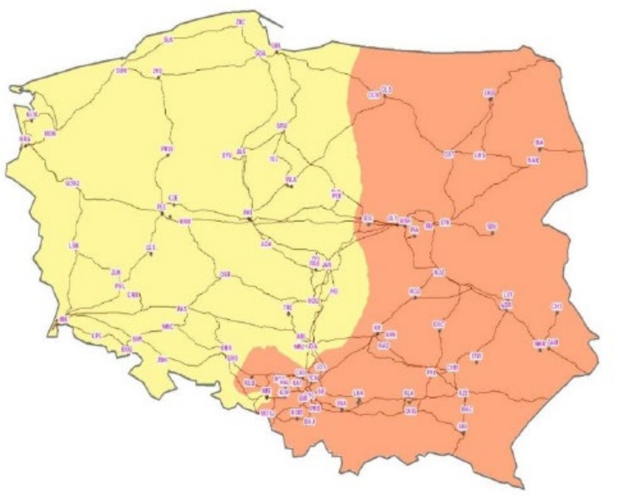


Figure 4.13: PL bidding zone delimitation to be applied in the bidding zone configurations Big Country Split 1 and Big Country Split 2 with the current transmission lines and substations in the background.

zone appears to be a fairly coherent one, without major dominant east–west or north–south power flows, nor any others. The power flow pattern changes with seasons and with demand, thus making it practically impossible to determine one suitable and congestion-based geographical PL split. However, due to the request of NRAs concerning the Big Country Split and Big Country Split 2 expert-based scenarios that included a split of the PL bidding zone, such a proposal had to be prepared nonetheless.

In order to comply with such a request, the results of the clustering performed by the contracted consultant have served as an input. When analysing the clustering results for all scenarios – as a first step – PSE made a preliminary directional decision to select the east–west split as the most often repeated, albeit on a basis of marginal differences, if any. In the figure below, the PTDF and LMP clustering results are depicted for the 'SOAF 2025 grid planned' scenario in which both clustering methods provided 'similar' results.

Given the fact that the zonal clusterings were not identical, the selection of which to use as the PL split was not self-evident; hence, in the second step, following the principle that the border of bidding zones should run through the most overloaded elements of the system,[10] it has been decided to define the bidding zone border by PTDF-based clustering (while maintaining the east–west split direction), as depicted in Figure 4.13 below.

PSE would like to emphasise, however, that the split of Poland in the Big Country Split and Big Country Split 2 configurations proposed above is only one of the possible splits resulting from the clustering exercise, without significant advantages over other possible split scenarios. The price differences between the Polish bidding zones in the different split scenarios are quite marginal (in the order of tens of euro cents per MWh), which, from a PSE point of view, confirms that there is no strong indication for any robust split of the Polish bidding zone. Moreover, it should be underlined that most of the (very limited) LMP price differential in Polish bidding zones comes from constraints located outside of Poland. This is extremely visible when comparing shadow prices of European critical branches – shadow prices of the Polish branches are of a magnitude lower than those in other European countries.

The split of the Polish bidding zone as foreseen in the Big Country Split and Big Country Split 2 expert-based configurations has not been requested by PSE. Without prejudice of the Bidding Zone Review process, based on

[10] There is only one overloaded line in the simulation results (Płock–Ołtarzew) which PSE does not consider as a structural congestion.

available information and current expert knowledge, PSE sees no sound justification for a particular Polish split. Internal transactions within the Polish bidding zone have no significant influence on power flows in neighbouring systems, and in particular, they do not constitute a structural cause for the worsening of conditions for the secure operation of these systems. Instead, given the dynamic development of intermittent sources of energy and the resulting frequent and significant trading pattern changes, PSE favours a more significant redesign of the European market by moving from a zonal model towards a more locational one, thereby avoiding the need for ex ante defining of bidding zones and all the implications these entail.

4.1.4 SMALL COUNTRY MERGE

This alternative configuration differs from the current one by a merge of the Belgian (BE) and Dutch (NL) bidding zones and a merge of the Czech (CZ) and Slovak (SK) bidding zones. The total number of bidding zones is therefore reduced by two. This configuration follows the philosophy of having larger bidding zones. In addition, the configuration was explicitly requested by stakeholders.

The main setback of this configuration is that, in the absence of network investment, merging borders where congestion is observed today (like BE–NL) into one single bidding zone copperplate will increase the number of remedial actions necessary in order to maintain network security and reduce the capacity allocation efficiency by distancing the commercial allocation further from physical flows. When further investment takes place, this merging possibility will need to be reassessed.

4.2 MODEL-BASED BIDDING ZONE CONFIGURATIONS

Besides the definition of bidding zone configurations by experts and stakeholders, alternative configurations could also be determined by the application of model-based approaches based on, e.g., an analysis of modelled nodal market prices (LMPs). This could lead to optimal but completely new designs of bidding zones. The following sections describe the applied methodologies (section 4.2.1) and the obtained results (section 4.2.2). Section 4.2.3 summarises the key findings of the analysis and concludes with a recommendation.

4.2.1 METHODOLOGIES TO DETERMINE BIDDING ZONES

In order to determine bidding zone configurations based on a model-based (greenfield) approach, two methodologies are applicable. The methodologies are based on simulations of a nodal (LMP) market design which is briefly described in section 4.2.1.1. The nodal prices (LMPs) are then clustered such that the most similar ones constitute a bidding zone. This clustering methodology is described in section 4.2.1.2.

4.2.1.1 (Underlying) LMP calculation

As input data to these methods, the results of a nodal market simulation of the future grid configurations and economic scenarios (as described in Chapter 3) are used. Most prominently, the matrices of PTDFs representing the power flow sensitivities to injections and withdrawals in particular nodes of the grid, and the LMPs for the hourly results of the optimal power flow (OPF) computations, are the inputs of the two delimitation methods applied. For the purpose of this study and in order to obtain an executable model, several simplifications had to be introduced. In order to keep the simulation time reasonable, rather than representing a N-1 secure grid, only N state simulations could be conducted. Furthermore, topological remedial actions and security policies are not an integral feature of LMP computations and have therefore been discarded.

In order to ensure full transparency, TSOs provided all LMP and clustering results to NRAs and stakeholders in June 2017.

4.2.1.2 Clustering

Based on the results of the LMP market simulation, two clustering methodologies have been applied, which will be explained in the following. A more detailed description of the full methodology can be found in the Annex.

Network- and market-based indicators (LMPs, PTDFs)

Similar LMPs as an indicator of copper-plate regions

The LMPs represent the value of electrical energy in each place (node) in an electrical system – that is, a cost of supplying an extra 1 MW of energy to this node. It consists of the cost of energy used at this node and the cost of delivering it there. The latter, in turn, depends on losses and congestions arising in the system. The LMPs can be obtained by running an optimal power flow algorithm on a model of the electricity network. Because the LMPs carry the information on congestions, the dissimilarity of LMPs can be used as a heuristic to gather the nodes into the bidding zones. The principle of this method is that congested lines are to be spanned between zones, and the biggest differences between LMPs are to be found on each side of congested lines, while between the nodes with similar LMPs the trade can take place almost as on copper plate. A stylised diagram of the influence of congestion on the nodal prices is depicted in Figure 4.14.

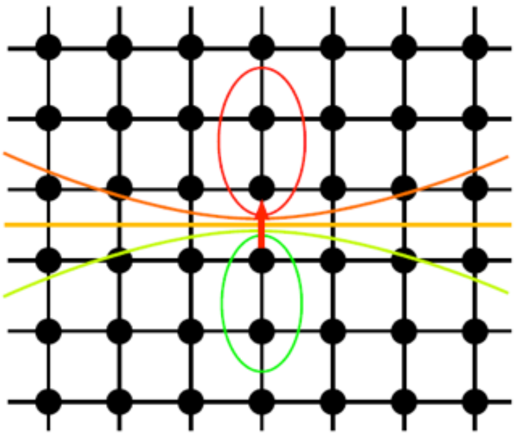


Figure 4.14: An exemplary grid showing a stylised influence of congestion (red arrow) on LMPs in neighbouring nodes (iso-price regions marked by coloured curves). Source: NCBJ inspired by Stoft (1997)

This approach to zonal delimitation is quite widely known in the literature on the subject (see, for example, Burstedde, 2012[11]; Bialek and Imran, 2008[12]; Wawrzyniak et al., 2013[13]).

[11] Burstedde (2012): *From nodal to zonal pricing: A bottom-up approach to the second-best*, in European Energy Market 2012

[12] Bialek and Imran (2008): *Effectiveness of zonal congestion management in the European electricity market*, in IEEE 2nd International Power and Energy Conference 2008

[13] Wawrzyniak, Orynczak, Klos, Goska and Jakubek (2013): *Division of the Energy Market into Zones in Variable Weather Conditions using Locational Marginal Prices*, in Proceedings of IECON 2013 – 39th Annual Conference of the IEEE, 2027–2032

Still, two characteristics of the electricity market make it hard to apply the standard clustering methods to the LMPs in order to obtain the zonal delimitations.

First, each resulting zone must constitute an electrically connected subset of the grid, so that the assumption about a zone being a copper plate is plausible. This calls for inclusion of a topological constraint into the clustering method: namely, a rule that prevents forming a zone that would consist of, for example, two regions separated in the network topology from each other. This requirement was addressed in the study by the adoption of a modification to the standard agglomerative hierarchical clustering proposed by Burstedde (2012).

Second, the load and generation conditions in the grid change essentially from hour to hour, resulting in varying LMP data for each hourly snapshot in a given year. In essence, a zonal delimitation resulting from clustering each hourly snapshot of LMPs separately can be different for each hour. A question thus arises, regarding how to obtain a delimitation that would be consistent across all the hourly snapshots in a given year. In order to deal with this issue, a method of consensus clustering was applied to the results of single-hour snapshot clusterings, which is based on the procedure delineated in Wawrzyniak et al. (2013).

Therefore, the LMP methodology of zonal delimitation is a two-stage approach, in which first a separate topology-constrained agglomerative hierarchical clustering for each of the 2 920 hourly snapshots of LMPs is used to obtain a division into m = 2, 3, … , 35 zones on the basis of the similarity of nodal prices. Next, the snapshots' individual results for each k (snapshot-transversal number of zones) are aggregated to obtain a frequency at which a pair of nodes were together in a zone across all the 2 920 hourly snapshot clusterings into k zones. This frequency is then treated as a similarity measure, and is coded in a similarity matrix.

Finally, the second-stage topology-constrained agglomerative hierarchical clustering on the basis of a similarity matrix for each m is performed. This operation is performed independently for each sensitivity scenario of grid investment and economic framework (see Chapter 3).

Similar PTDFs as a condition of an effective zonal market

Beside clustering nodes to bidding zones according to LMPs, so-called nodal PTDFs can also be used as a basis for the clustering. However, it turned out that this PTDF clustering method is highly sensitive to some assumptions taken for the calculation of the underlying LMPs (see section 4.2.1.1 for a description of the LMP results and the taken assumptions). As a consequence, it has been decided not to use these results for the First Edition of the Bidding Zone Review. In order to improve the readability of the report, the detailed description of the methodology can be found in the Annex.

Clustering procedures

Clustering of nodes according to locational marginal prices

As was noted already in the previous section, the LMP method of zonal delimitation is a two-stage approach, in which the following data is used for each of the six scenarios:

- LMP vectors calculated according to representing the T = 2 920 hourly snapshots[14] for N nodes of the grid.
- Grid topology (description of connections existing between the nodes).

First, for each hourly snapshot of LMPs, a separate topology-constrained agglomerative hierarchical clustering process was employed. The details of this process are described in the Appendix, but in essence it works as follows. At the beginning, each of the K nodes in the system constitutes a separate zone.[15] A matrix of LMPs differences for all the connected nodes/zones is then calculated.

A pair of connected nodes/zones with the highest price similarity (smallest price difference) is then grouped into a new zone. This new zone inherits both the connection properties and the average LMP of the two aggregated original zones it comprises of. The matrix of price differences for all the connected zones is then re-calculated to account for the new zone. The algorithm repeats these steps: pairs of most similar zones are continually merged into new zones on the basis of LMP differences until we end up with one big zone encompassing all the nodes in the system. The history of the subsequent merges and the dissimilarity distance at which these are effected is tracked in a so-called dendrogram merge tree (the latter displays the nodes being merged and the distances at which they do so). This tree can then be used to obtain a delimitation into any number (2, … , K) of zones.

During the calculations, the first-stage clustering has been used to obtain divisions into (2, … , 35) zones, with the highest number being chosen on the basis of preliminary analyses of the preliminary data sets (later replaced with the complete ones). In the second step, the results of hourly snapshot clusterings are aggregated across all hours – namely, for a given number of zones $m \in (2, \dots, 35)$. This is done based on a calculation of the frequency that a particular pair of nodes have been together in a zone across all the 2 920 hourly snapshots. This frequency is then treated as a similarity measure, just as the similarity of LMPs was used in the first step, and is coded in a similarity matrix. For each number of zones m, a similarity matrix is obtained. This matrix has been used to execute a topology-constrained agglomerative hierarchical clustering process and to produce a zonal delimitation into the final candidate number (8, … , 22) number of zones.

A set of divisions into (8, … , 22) zones[16] has been constructed for each of the 34 similarity matrices coded by $m \in (2, \dots, 35)$. The upper boundary (22 zones) of this set has been used for the further discussion of model-based configurations.

[14] Since LMPs have been calculated with a 3 h resolution, 8 760 h / 3 = 2 920 h have been the basis for further analysis

[15] The exact value of K varies between the scenarios, but after applying the processing of the data described in subsection 1.2.3, K was approximately 6½ thousands.

[16] The original range of 2, …, 35 zones has been reduced to 8, …, 22 zones in order to obtain a more realistic and implementable set of candidate zones.

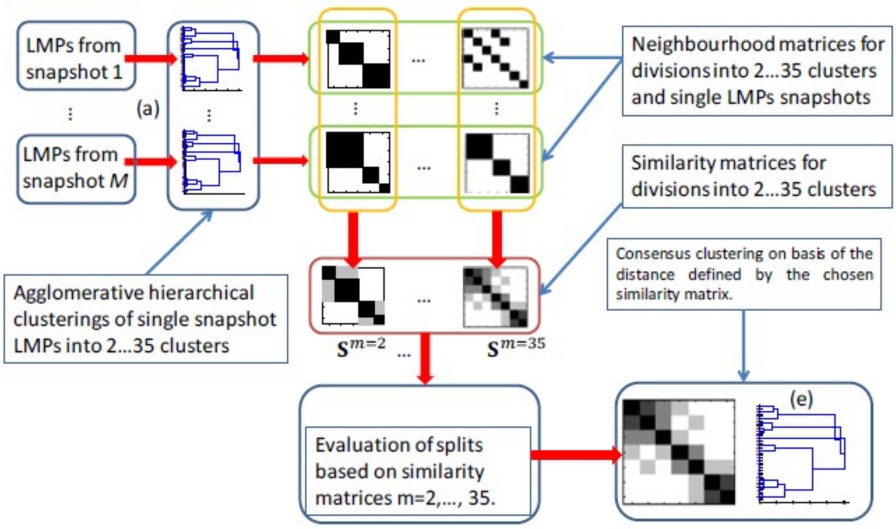


Figure 4.15: Flowchart of LMP consensus clustering

4.2.2 RESULTS OF THE MODEL-BASED BIDDING ZONE CONFIGURATIONS

The following results present a subset of the full LMP results calculated. Those shown are exclusively for the year 2025, considering both a worst and planned grid scenario. It is important to note that the LMPs used for the clustering have been calculated on an N-0 base due to computational complexity and time limitations and therefore their interpretation requires particular care as they do not correspond to real system operation. An important aspect of the N-0 simplification is the general underestimation of congestions.

4.2.2.1 Original clustering results and post-processing

The following section describes the original and the post processed clustering results based on the methodology described in the previous section. In addition, a more detailed analysis of the underlying LMPs/congestions is provided in section 4.2.2.2. Further to the scenario framework described in Chapter 3, the LMPs described in this report encompass scenarios based on the SOAF for the year 2025, including both the planned and worst case grid infrastructures.[17)]

Model-based bidding zone configurations (SOAF 2025 planned/worst case grid) prior to post-processing

Figures 4.16 and 4.17 show the model-based bidding zone configurations as original output of the clustering approach for the scenarios SOAF 2025, for the planned and the worst case grid, considering 22 zones. The results show a major fragmentation of the French bidding zone. The planned grid scenario encompasses a large Central European zone which is split up in the worst case grid scenario. The reasons for these results are further discussed in section 4.2.2.2. These bidding zone configurations have been used as the starting point for an ex post adjustment (post-processing) in order to obtain more robust results adapted to current market circumstances.

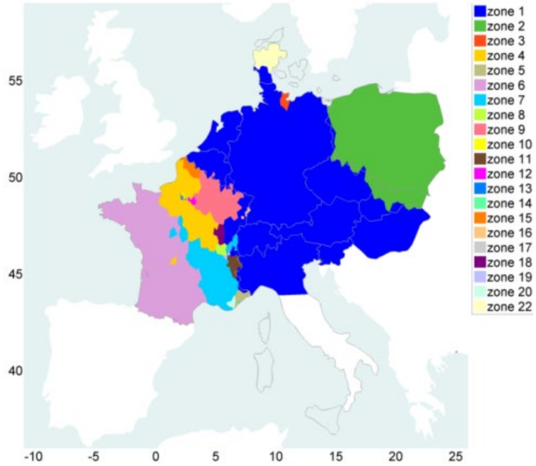


Figure 4.16: Clustering outcome, prior to adjustments, demonstrating the limitations of the modelling, 2025 SOAF planned grid (without post-processing, 22 bidding zones)

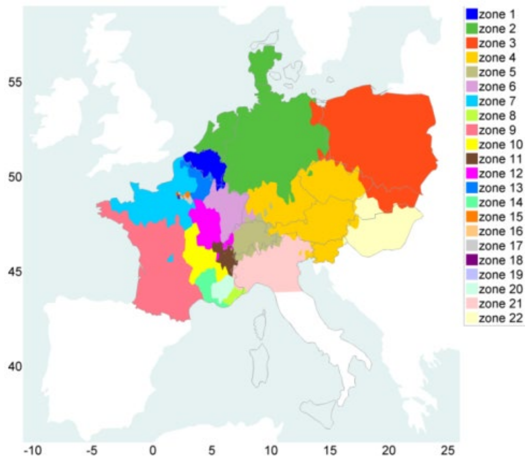


Figure 4.17: Clustering outcome, prior to adjustments, demonstrating the limitations of the modelling, 2025 SOAF worst case grid (without post-processing, 22 bidding zones)

Post-processing approach

The post-processing approach has been developed in order to adjust the pure model-based results. This approach consists of the following four consecutive processing steps, considering the scenarios of SOAF 2025 planned and worst case grids for 22 zones as the starting point:

Step 1: if more than 90 % of one country's substations are assigned to a given bidding zone, the remaining substations also form part of this bidding zone

Step 2: any shift of fewer than 10 substations of one country to a new bidding zone is discarded

Step 3: small bidding zones below 30 substations are merged

Step 4: individual, further alignments by TSOs (explanation is provided below)

17) The subsequent analyses of this report will exclusively focus on the SOAF 2025 planned grid and the SOAF 2020 worst case grid scenarios.

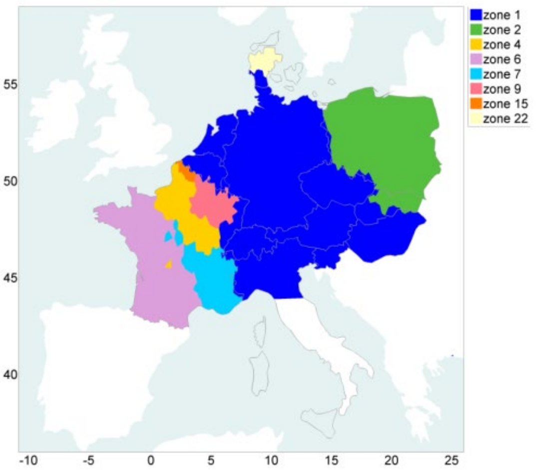


Figure 4.18: Clustering outcome, post adjustment steps 1–3, demonstrating the limitations of the modelling, 2025 SOAF planned grid (after post-processing steps 1–3)

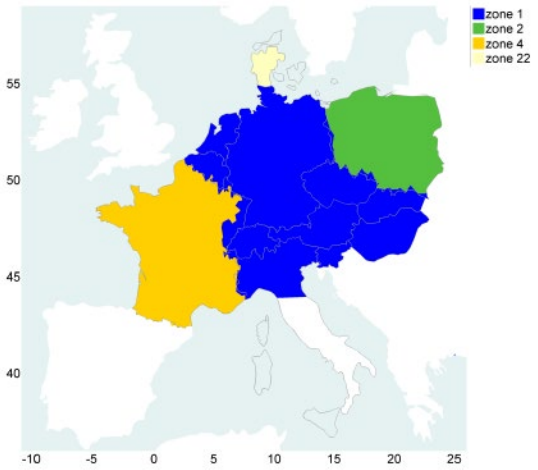


Figure 4.20: Clustering outcome, post adjustment steps 1–4, demonstrating the limitations of the modelling, 2025 SOAF planned grid (after post-processing steps 1–4)

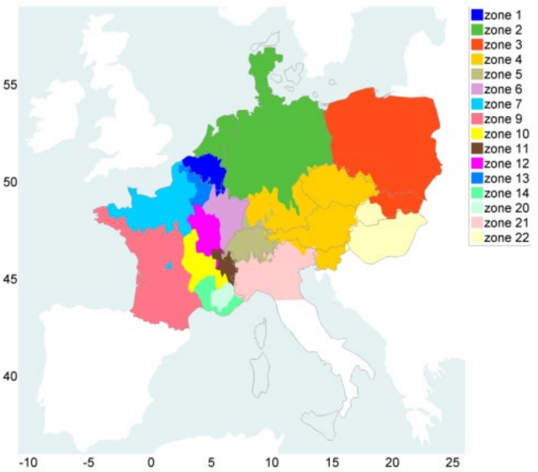


Figure 4.19: Clustering outcome, post adjustment steps 1–3, demonstrating the limitations of the modelling, 2025 SOAF worst case grid (after post-processing steps 1–3)

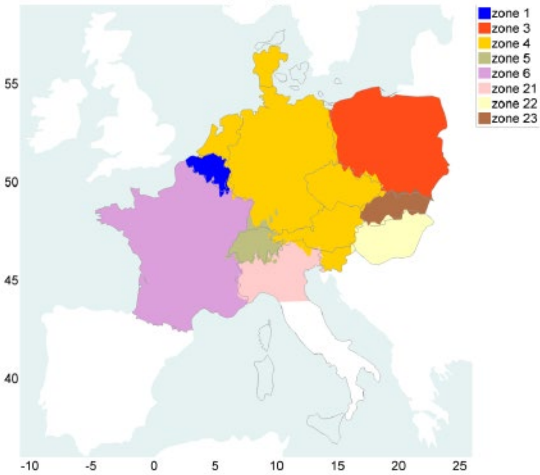


Figure 4.21: Clustering outcome, post adjustment steps 1–4, demonstrating the limitations of the modelling, 2025 SOAF worst case grid (after post-processing steps 1–4)

Post-processing results

Figures 4.18 and 4.19 show the resulting bidding zone configurations after the post-processing steps 1, 2 and 3, while Figures 4.20 and 4.21 show the results after post-processing step 4. As step 4 allows for individual, further alignments by TSOs, their individual explanations are also provided in the Annex.

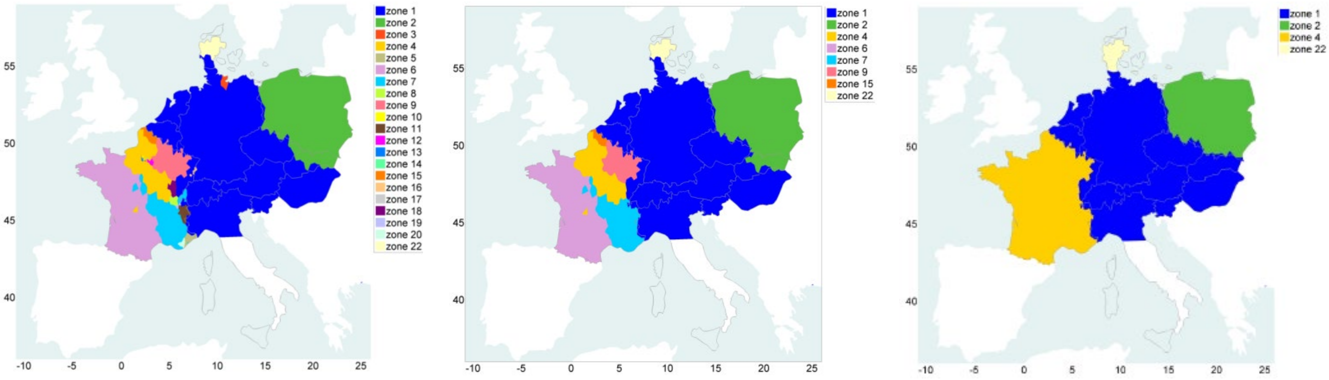
As mentioned previously, step 4 allows for individual alignments by TSOs. The justifications provided by TSOs who applied such adjustments in step 4 are provided in the Annex.

Figures 4.20 and 4.21 display the results after consideration of the aforementioned adjustments in post-processing step 4.

Model-based bidding zone configurations (SOAF 2025 planned/worst case grids) after post-processing

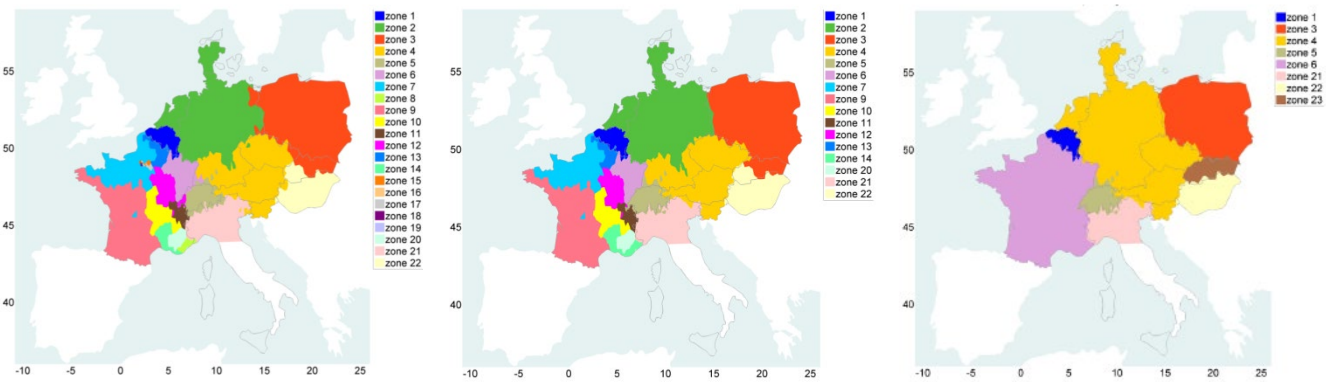
Figures 4.22 and 4.23 on the following page provide a summary of the previous steps and an overview of the model-based bidding zone configurations during the post-processing, starting from the original clustering results for 22 zones.

In order to explain the delimitations derived by the model, the results need to be analysed further. In this context, the underlying LMPs are of particular relevance.



without post-processing, 22 bidding zones | after post-processing steps 1–3 | after post-processing steps 1–4

Figure 4.22: Clustering outcome demonstrating the limitations of the modelling, overview of model-based bidding zone configurations; 2025 SOAF planned grid



without post-processing, 22 bidding zones | after post-processing steps 1–3 | after post-processing steps 1–4

Figure 4.23: Clustering outcome demonstrating the limitations of the modelling, overview of model-based bidding zone configurations; 2025 SOAF worst case grid

4.2.2.2 Analysis of the LMPs for 2025 SOAF planned and worst case grid scenarios

Due to the necessary model simplifications, the first outputs of the clustering have to be reviewed and interpreted carefully. In order to illustrate the limited robustness of the model-based results further, the following section provides further information of the LMP results that have been used as input for the clustering explained in section 4.2.2.1.

Total cost of the congestions and distribution per voltage level and country

The LMP simulations evaluate the constraints on the grid at the nodal level and the associated costs of these constraints. The computation of the LMPs has been performed with a three-hour time interval, which has a smoothing effect. The absolute values cannot be precisely calculated by multiplying by three because it is not possible to evaluate the behaviour of the system in the one-hour time intervals. In order to obtain a non-robust, indicative estimation, the computed costs may be multiplied by three. The following analysis of the LMP results focuses on 2025 and distinguishes between the planned and the worst case grid scenarios. As the clustering considers the LMP results as direct input, it is obvious that unintuitive behaviours observed in the LMP results also drove the clustering results. In the following, specific focus is put on the voltage level and the geographical location of the congestions.

	2025 planned	2025 worst
Total congestion cost[18]	€ 108 m	€ 114 m

Table 4.2: Total congestions costs in in the SOAF 2025 planned and worst case scenarios

[18] The total congestion costs are calculated as follows: For all critical branches, the number of hours with shadow prices > 0 is multiplied by the corresponding shadow prices of the critical branches. This is then summed up over the modelled period.

Country	2025 planned			2025 worst		
	400 kV	225 kV	Total	400 kV	225 kV	Total
Austria	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Belgium	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Czech Republic	0.0%	0.1%	0.1%	0.0%	0.1%	0.1%
Denmark	0.2%	0.0%	0.2%	0.2%	0.0%	0.2%
France	0.1%	71.1%	71.2%	0.2%	71.8%	72.0%
Germany	0.6%	4.1%	4.7%	0.1%	4.0%	4.1%
Hungary	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Italy	0.0%	22.9%	22.9%	0.0%	22.6%	22.6%
Netherlands	0.2%	0.0%	0.2%	0.2%	0.0%	0.2%
Poland	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
Slovakia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Slovenia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Switzerland	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-core model area	–	–	0.6%	–	–	0.5%
Total	1.3%	98.2%	100.0%	0.9%	98.6%	100.0%

Table 4.3: Share of congestion costs in the SOAF 2025 planned and worst case scenarios per voltage level and country

The congestion cost does not change significantly between the planned and the worst case scenario according to the simplified model. This can be explained by the fact that the n-state constraints provide an overestimation of the grid transmission capabilities and hence the impact of grid investments does not materialise. The n-state simulations are also one main reason why the figures should be seen as indicators rather than concrete costs.

Another question of relevance is where and at what voltage level congestions occur. Table 4.3 highlights the localisation of the constraints revealed in the LMPs per voltage level and country. The specific costs of constraints within a country are provided as percentages of the total cost of constraints of the entire system.

More than 98 % of the cost of constraints are on the 225 kV while the weight on the 400 kV is less than 2 %. The main idea of LMPs is to reflect the full grid situation in the (nodal) market prices. LMPs consist of marginal production costs, transportation costs and congestion costs. Neglecting transportation costs, all LMPs would be identical if there was no congestion in the system. If there is congestion in the system, then LMPs vary as the congestion costs are reflected directly in the nodal prices that can affect the prices of the nodes close to the congestions. The clustering results are mainly driven by the 225 kV grid, as LMPs consider the costs of constraints (shown in Table 4.3 above), and these costs of constraints are mainly located in the 225 kV grid. Geographically, this also becomes visible in the example given in Figure 4.28.

Localisation of the grid constraints focusing on their weight

In the remainder of this section, the congestions provided in Table 4.3 are displayed on maps for both scenarios. The first map (cf. Figures 4.2.4 and 4.2.6) displays the grid elements that create 99.5 % of the congestion costs. These are the most important congestions and should be the main driver of the clustering results. The colour of the element represents the weight of the constraint in the congestion cost. The second map (cf. Figures 4.2.5 and 4.2.7) displays all grid elements congested in at least one hour in the LMP calculation (100 % of the congestions costs/all elements). Or, in other words, the difference between both maps highlights the 'less' important constraints as these represent only 0.5 % of the congestion costs.

Analysis of the planned grid situation

Figure 4.24 shows, for example, two red and two orange elements in the area of Paris. The weight of these four transformers is 57.9 % of the total congestion cost. Comparing this map to the original clustering results (before post-processing, see Figure 4.18) shows that these congestions reported in the LMP calculation lead to a splitting of the area of Paris into four bidding zones in the clustering. Despite the original aim of applying a full greenfield approach based on scientific approaches, it could be argued that a congested transformer (reasonable or not) should in practice not lead to a splitting of Europe (or Paris in this case).

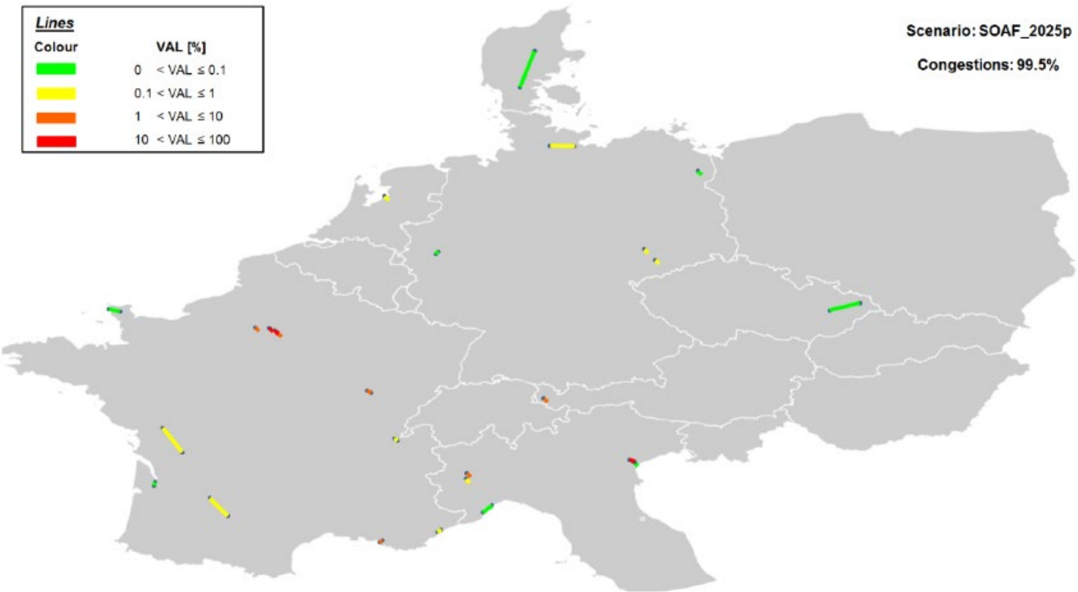


Figure 4.24:
N-0 grid constraints that create 99.5 % of the congestion cost in the SOAF 2025 planned scenario, coloured by weight of the constraint in the congestion costs – based on the assumption of a full implementation of the planned network extensions

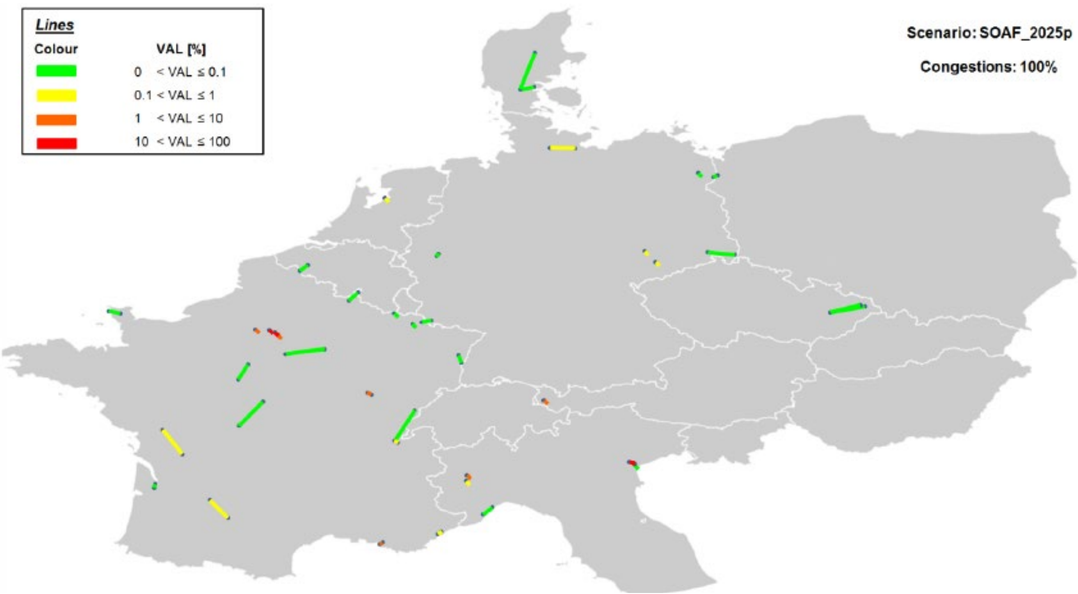


Figure 4.25:
All N-0 grid constraints that have a non-zero shadow price for at least one hour in the SOAF 2025 planned scenario, coloured by weight of the constraint in the congestion costs – based on the assumption of a full implementation of the planned network extensions

Analysis of the worst case grid situation

Figures 4.26 and 4.27 provide a geographical representation of the congestions for the worst case scenario. In addition, the worst case shows that a considerable part of the congestion (weighted by costs) is located in France. This becomes evident when comparing Figures 4.24 and 4.26, and also from the percentages given in Table 4.3.

As already shown in Table 4.2, the congestion costs do not differ significantly between the planned and the worst case scenarios. Comparing the constraints visualised in the maps for the planned and the worst case scenarios, shows that the additional constraints are not significant. The red- and orange-coloured constrained elements are more or less the same. Comparing the figures with all congested elements for the planned case (Figure 4.25) and the worst case (Figure 4.27), reveals that the additional constraints in the worst case grid have only a very low share of the total congestion costs (as these are coloured green).

Yet, although these additional congestions are 'less important' according to their congestion value (coloured green), these congestions have a significant impact on the clustering results. This becomes visible from the comparison to the non-processed clustering results for 22 zones (cf. Figures 4.18 and 4.19).

Figure 4.26:
N-0 grid constraints that create 99.5 % of the congestion cost in the SOAF 2025 worst case scenario, coloured by weight of the constraint in the congestion costs – based on the assumption of an only partial implementation of the planned network extensions

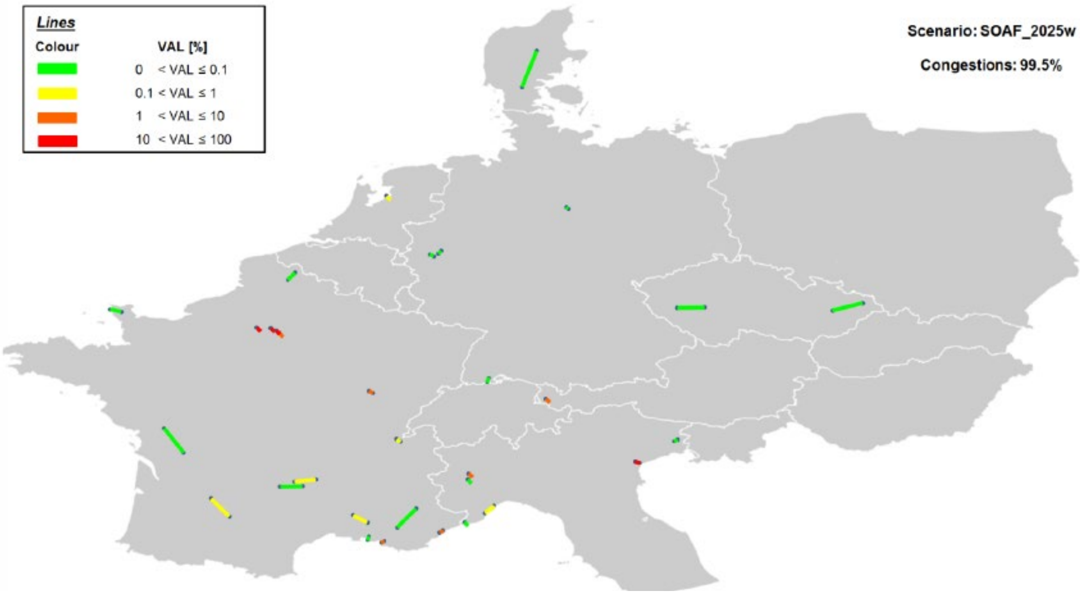
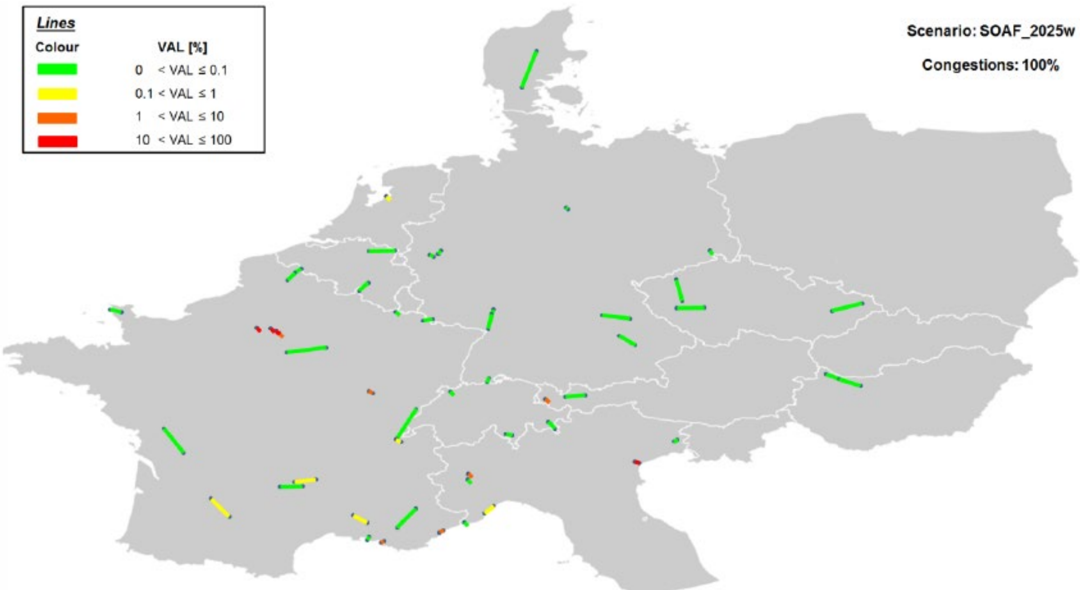


Figure 4.27:
All N-0 grid constraints that have a non-zero shadow price for at least one hour in the SOAF 2025 worst case scenario, coloured by weight of the constraint in the congestion costs– based on the assumption of an only partial implementation of the planned network extensions



Localisation of the grid constraints focusing on the voltage level

In the following, the congestions resulting from the LMP calculations are again displayed for both the planned and worst case scenarios of SOAF 2025. Comparable to the previous Figures 4.25 and 4.27, both maps show again all grid elements (100 %) which have been considered in the clustering. Yet, in Figures 4.28 and 4.29, the congestions are distinguished between the voltage levels. Red-coloured elements show congestions in the 380 kV grid, while green-coloured elements show congestions in the 220 kV grid. Congested transformers are marked yellow.

As an example of the significant impact of less frequent congestions in the clustering, the red area (zone 3) of France in Figure 4.30 is created by a 225 kV constraint marked in a blue circle in Figure 4.28. It is not foreseen that this line is to be congested in the national development plan.

As already shown by the quantitative analysis at the beginning (cf. Table 4.3), the visualisation via maps also shows that a considerable part of the congestion is in the 220 kV grid and therefore drives the clustering results. This holds for both grid scenarios.

Figure 4.28:
All N-0 grid constraints per voltage level in the SOAF 2025 planned scenario – based on the assumption of a full implementation of the planned network extensions

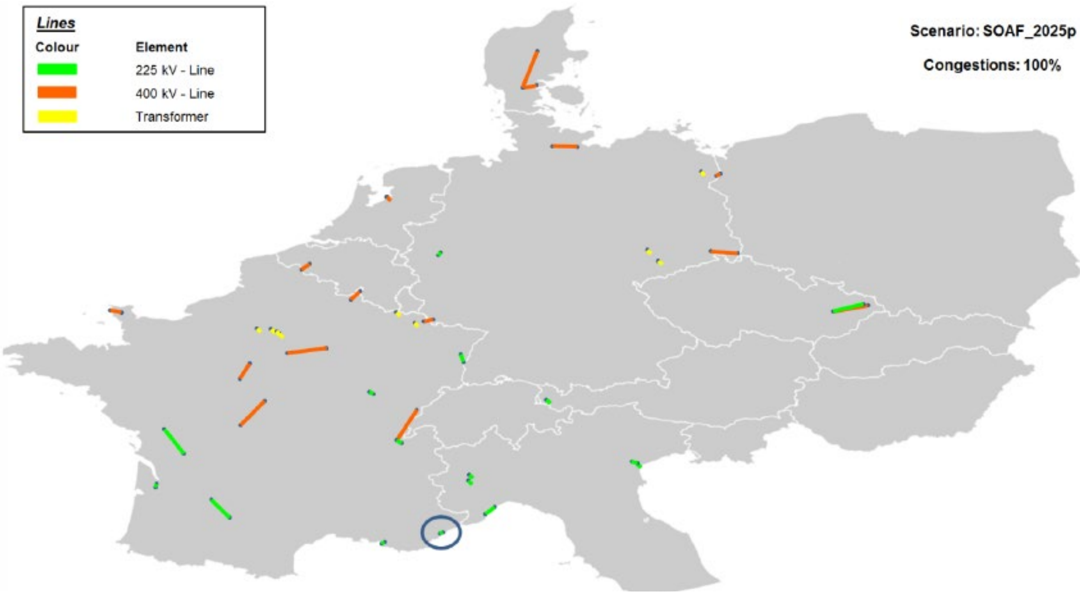
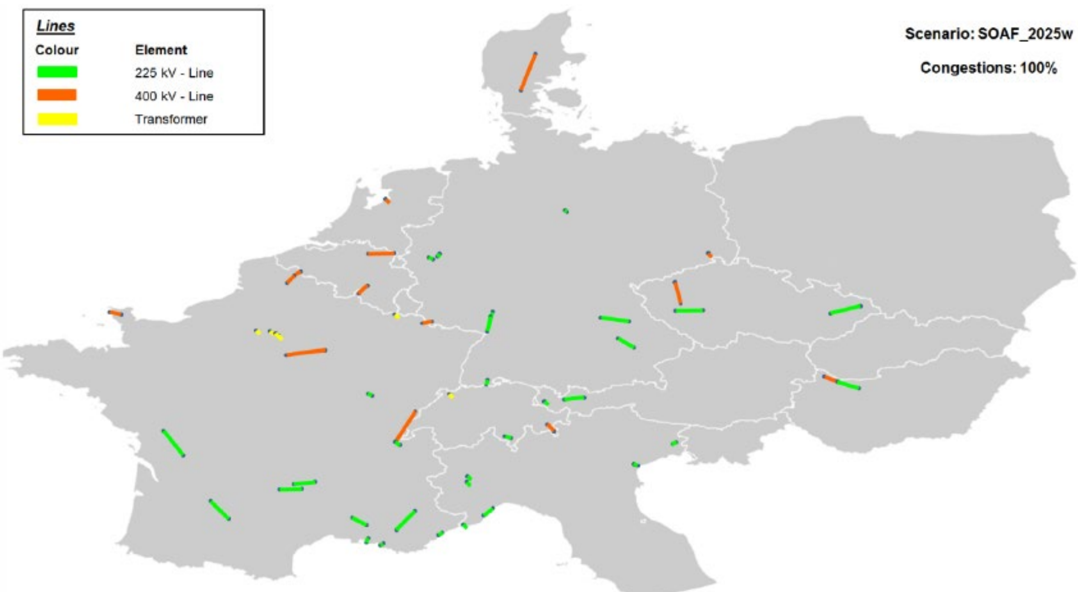


Figure 4.29:
All N-0 grid constraints per voltage level in the SOAF 2025 worst case scenario – based on the assumption of an only partial implementation of the planned network extensions



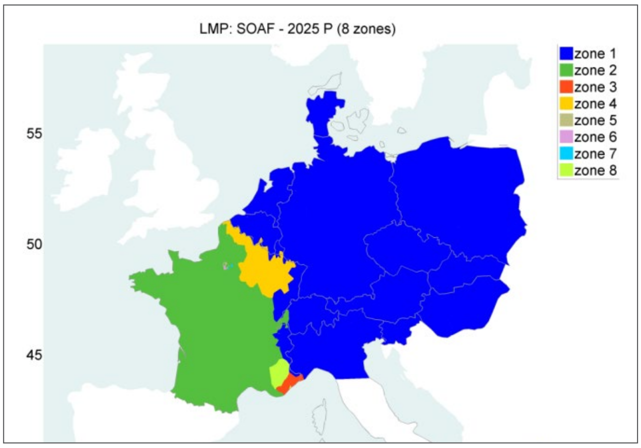


Figure 4.30: Illustration of clustering results in the SOAF 2025 planned scenario prior to the post-processing for eight zones

4.2.3 CONCLUSIONS

The obtained LMP computation and subsequent clustering results provide the following evidence:

- LMP results are mainly determined by constraints in the 220 kV network.
- This leads to a split of bidding zones mainly along these 220 kV constraints, but also if such constraints do not frequently occur.
- The LMP computations are based on simplifications (e.g. consideration of n state only; neglecting topological remedial actions and security policies).

Given these considerations, the participating TSOs propose not to use the model-based configurations or the nodal pricing for the current Bidding Zone Review but to investigate this approach further for potential use in future Bidding Zone Reviews.

5 EVALUATION ACCORDING TO THE CACM NETWORK CODE CRITERIA

5.1 INTRODUCTION TO EVALUATION CRITERIA

In compliance with the NC CACM, the following three categories of criteria shall be applied:

- Network Security
- Market Efficiency
- Stability and Robustness of Bidding Zones

These three general categories of criteria consist of several individual criteria (as shown in Table 6.1), on which the bidding zone evaluation shall be based. For the evaluation, it is important to make sure that these criteria are clearly defined and do not allow for different interpretations, because only then can one or more suitable and undisputable indicator(s) for its assessment be defined. These indicators can then be analysed for different bidding zone configurations, time frames, grid and economic scenarios. However, some criteria are quantifiable – e.g. by comparable market or grid model runs – whereas other criteria are of a rather qualitative nature and do not allow for a mathematical description.

As such, it is not possible to make a straight-forward cost-benefit analysis of a bidding zone reconfiguration over all the criteria. Instead, the challenge is to make a comparable and objective assessment of the different bidding zone configurations over the different scenarios in order to come up with a recommendation on whether a bidding zone reconfiguration is recommended or not. As such, the strengths and weaknesses of qualitative criteria need to be elaborated next to a calculation of quantifiable criteria.

The NC CACM indicates the multi-dimensionality of the analysis, meaning all criteria are equally important. Therefore, it is not possible to apply a weighting to the criteria/indicators or to give some of them a higher priority, and this is despite the criteria possibly of differing in their relevance or their impact for certain time frames or scenarios.

As the Bidding Zone Review's aim is to compare different bidding zone configurations, the criteria assessment does not focus on national levels, absolute values or distributional effects (e.g. from one country to another or from producers to consumers), but on the relative change of the criteria under evaluation compared to the current bidding zone configuration on an aggregated level of the whole (European) system. Nevertheless, some results might be more conclusive on a country/bidding zone level. In addition, an aggregation over longer and different time frames, scenarios, bidding zones and countries is quite challenging when it comes to highly diverse and detailed information. Relative changes are sometimes also hard to interpret, as a 10% change for one criterion might not be as bad as a 10% change for another criterion. This means that the significance of this relative change is unclear.

Moreover, the Bidding Zone Review only provides a spotlight on the impacts of a reconfiguration under certain assumptions for input parameters. It does not elaborate on the long-term effects of a reconfiguration, e.g. that some benefits may only materialise after several years (e.g. incentive for new plants might not materialise within one year).

5.2 OVERVIEW OF EVALUATION CRITERIA

Article 33 of the Network Code on CACM lists several evaluation criteria for the assessment of the bidding zone configurations. The table below provides an overview of the 19 criteria sorted into three main categories. Following the feedback received from stakeholders during the Bidding Zone Review process (cf. Chapter 6), the CACM criteria are complemented by the market efficiency criterion of long-term hedging.

In the following sections, each evaluation criterion and the applied evaluation approach is described in detail. While the individual assessment of the alternative bidding zone configurations according to the specific evaluation criteria can also be found in these sections, the final overall assessment of the alternative bidding zone configurations that considers all criteria is provided in section 5.24.

Network security	Market efficiency	Stability and robustness of bidding zones
– Operational security (5.4) – Security of supply (5.5) – Degree of uncertainty in cross–zonal capacity calculation (5.6)	– Economic efficiency (5.7) – Firmness costs (5.8) – Market liquidity (5.9) – Market concentration and market power (5.10) – Effective competition (5.11) – Price signals for building infrastructure (5.12) – Accuracy and robustness of price signals (5.13) – Long-term hedging (5.14) – Transition and transaction costs (5.15) – Infrastructure costs (5.16) – Market outcomes in comparison to corrective measures (5.17) – Adverse effects of internal transactions on other bidding zones (5.18) – Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes (5.19)	– Stability and robustness of bidding zones (5.20) – Consistency across capacity calculation time frames (5.21) – Assignment of generation and load units to bidding zones (5.22) – Location and frequency of congestion (market and grid) (5.23)

Table 5.1: Overview of evaluation criteria

5.3 OVERVIEW OF EVALUATION APPROACHES FOR THE INDIVIDUAL ASSESSMENT OF BIDDING ZONE CONFIGURATIONS ACCORDING TO THE SPECIFIC EVALUATION CRITERIA

In the following sections, all expert-based configurations will be assessed individually for each CACM criterion. The individual assessments are built on quantitative indicators, statistical analysis, stakeholder surveys, expert interviews and qualitative assessments. For each CACM criterion, each alternative bidding zone configuration will be assessed in comparison to the current bidding zone configuration (Status Quo). The ratings can be understood as follows:

(+)	Better than the current bidding zone configuration (Status Quo)
(0)	No significant difference compared to the current bidding zone configuration (Status Quo) or a reasonable assessment of the impacts is not possible
(-)	Worse than the current bidding zone configuration (Status Quo)

The summarised assessment for all expert-based configurations considering all CACM criteria is provided in section 5.24.

It is important to highlight that all evaluation criteria are strongly interlinked and that an appropriate review of alternative bidding zone configurations can only be based on a comprehensive assessment that considers all relevant criteria and aspects.

5.4 CACM CRITERION 'OPERATIONAL SECURITY'

CACM regulations, in Article 33 (1a) i), prescribe that *'**the ability of bidding zone configurations to ensure operational security** and security of supply'* shall be considered in the context of a Bidding Zone Review process.

Article 3(2) of the guidelines on electricity transmission system operation (Commission regulation (EU) 2017/1485) defines 'operational security' as *'the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterised by operational security limits'*. Hereby, 'normal state' means '*a situation in which the system is within operational security limits in the N-situation*[19] *and after the occurrence of any contingency*[20] *from the contingency list, taking into account the effect of the available remedial actions'*.[21]

Article 18 (1) of the same guidelines, clarifies that *'a transmission system shall be in the normal state when all of the following conditions are fulfilled:*

a) *voltage an*d power flows are within the operational security limits defined in accordance with Article 25;

b) *frequency meets the following criteria:*

i) *the steady state system frequency deviation is within the standard frequency range; or*

ii) *the absolute value of the steady state system frequency deviation is not larger than the maximum steady state frequency deviation and the system frequency limits established for the alert state are not fulfilled;*

c) *active and reactive power reserves are sufficient to withstand contingencies from the contingency list defined in accordance with Article 33 without violating operational security limits;*

d) *operation of the concerned TSO's control area is and will remain within operational security limits after the activation of remedial actions following the occurrence of a contingency from the contingency list defined in accordance with Article 33.'*

19) 'N-situation' means the situation where no transmission system element is unavailable due to the occurrence of a contingency.

20) 'contingency' means the loss of one or more grid elements, power generating modules and/or demand facilities due to unplanned events.

21) 'remedial action' means a measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security, as well as to relieve physical congestion on their networks.

5.4.1 EVALUATION APPROACH FOR 'OPERATIONAL SECURITY'

The assessment of the impact of alternative bidding zone configurations on operational security will be based on the identification and discussion of fundamental principles/interrelations.

5.4.2 ASSESSMENT OF 'OPERATIONAL SECURITY'

5.4.2.1 Qualitative assessment of impacts on operational security

Operational security is the combined result of grid issues and related procedures in place

In all transmission systems, there are defined procedures to deal with grid issues (such as overloads, voltage stability or frequency control) and overloaded elements. Whether these grid issues will then lead to security issues depends on these procedures and their underlying factors (e.g. reserve capacities).

Consideration of structural congestion in the bidding zone configuration decreases redispatch

A considerable number of redispatch measures endangers operational security (tendency statement). Yet, it is important to understand that splitting a bidding zone along grid constraints would not delete the structural constraint observed in the grid. Rather, it would make a structural constraint visible in the market since redispatch costs (to resolve this congestion) are then considered in the market/prices. Or, in other words, the market dispatch will take the structural constraint into account as a bidding zone border, thus the dispatch in the day-ahead market will ensure that this constraint is not compromised. Thus, consideration of potential congestions/grid constraints in the day-ahead dispatch is beneficial for operational security.

Real-time operation is only partly affected by a change of the bidding zone configuration

However, problems in the grid detected in real-time operation cannot be fully addressed by a reconfiguration of bidding zones and by considering a potential constraint in the day-ahead dispatch only. For instance, deviations between expected flows and real-time flows resulting from forecast errors of RES infeed, load and unplanned outages in generation and grid cannot be influenced by a change of bidding zone borders – these aspects need to be dealt with in the new bidding zones as well. Regardless, a well-designed bidding zone configuration can solve structural operational security issues, limiting operational security risks to non-structural issues, unplanned events and/or local issues.

Neglection of internal critical network elements and contingencies (CNECs) endangers operational security

Furthermore, the design of the market coupling mechanisms is of major importance for operational security. In particular, consideration of internal constraints in the CNEC list of the flow-based market coupling approach ensures that the resulting day-ahead market dispatch takes the relevant parts of the grid into account. If the CNEC list allows only for cross-zonal elements (even if very close to the relevant border), grid security might be endangered by the day-ahead market outcome. Excluding internal elements would decrease the stability of the bidding zone configuration. In different scenarios, the congestions can appear on different elements, not always exactly at the bidding zone border. The methods to set CNECs in a more coordinated manner will be a key point of the methodologies on capacity calculation that are expected to be adopted in 2018 under the CACM regulation.

Grid investments can enhance operational security in the long-term

Internal grid investments/enhancements within a bidding zone can increase the level of operational security in the network and allow for a more flexible real-time operation, while cross-zonal grid investments/enhancements generally allow TSOs to increase cross-zonal capacities made available to the markets without significantly altering the level of operational security in the system. For this reason, we can generally expect that operational security will be more at risk in the worst case grid scenarios than in the planned grid scenarios (where both cross-zonal and internal investments are implemented). Besides, operational security is more challenging with a more fluctuating RES production in the system. This holds especially true in the case of the combination of high RES and worst case grid scenario. With considerably higher grid investments in 2025, operational security might be less at risk than in 2020, but the difference in the RES capacities also needs to be considered.

Congestion management is only a part of the tasks fulfilled by TSOs to ensure operational security

Although efficient management of congestions in the grid is one important task of TSOs, this alone cannot ensure operational security. Ensuring operational security includes aspects such as sufficient active and reactive power reserves, voltage control, inertia, fast-current injections, black-start capacities and balancing reserves. Please refer to the guidelines for system operation (GL SO) for a more comprehensive overview.

5.4.2.2 Summarised assessment of 'operational security'

Table 5.2 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'operational security'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Operational security	(+)	(+)	(+)	(-)

Table 5.2: Specific assessment of operational security

5.5 CACM CRITERION 'SECURITY OF SUPPLY'

5.5.1 DESCRIPTION AND UNDERSTANDING OF 'SECURITY OF SUPPLY' (GENERATION ADEQUACY)

CACM Article 33 (1a) i): ***the ability of bidding zone configurations to ensure*** *operational security and* ***security of supply***

The measurement and evaluation of security of supply (SoS) is a broadly discussed topic in both the academic literature and in practice.

In the understanding of this study, security of supply focuses on generation adequacy. Bidding zones are considered as copper plates, and potential constraints in the grid within a bidding zone are not considered in the security of supply assessment.

This understanding corresponds to the underlying concept of security of supply in the ENTSO-E Mid-term Adequacy Forecast 2016[22] and the Pentalateral Energy Forum (PLEF) report,[23] in which TSOs assess the security of supply at country, regional and national levels. It corresponds also to the applied understanding of security of supply in academic literature.

According to Keane et al. 2011,[24] generation adequacy refers to sufficient conventional and renewable installed generation capacity to supply the electrical load. To induce sufficient investments, the intended reliability level should consider the value of lost load (VoLL), which can be defined as the willingness of consumers to pay to avoid supply disruption (e.g. Cramton et al., 2013).

While TSOs are responsible for grid security, ensuring security of supply is not a TSO task. Yet, both are interlinked, i.e. grid security cannot be ensured in cases where generation adequacy is at risk. For instance, a merge of bidding zones might increase the security of supply of the new bidding zone, but simultaneously decrease operational security. However, operational security is considered as a separate criterion (see section 5.4.1), in addition to several other grid-related criteria.

22) https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2016_FINAL_REPORT.pdf

23) http://www.benelux.int/files/4914/2554/1545/Penta_generation_adequacy_assessment_REPORT.pdff

24) Keane et al. (2011), *Capacity Value of Wind Power*, in EEE Transactions on Power Systems, vol. 26, no. 2, pp. 564–572, May 2011

5.5.2 EVALUATION APPROACH FOR 'SECURITY OF SUPPLY' (GENERATION ADEQUACY)

Well-known indicators for the measurement of generation adequacy which are based on probabilistic modelling are loss of load expectation (LOLE) and expected energy not served (EENS),[25] but more static indicators such as remaining capacity margins (i.e. peak load minus available generation) can also provide useful information.

In this study, the focus is on the second methodology. Based on the input assumptions for the different scenarios and bidding zone configurations, simplified remaining capacity margins for an isolated case (meaning without consideration of cross-zonal contributions) will be calculated. These capacity margins will consider the contributions of RES and demand side management (DSM). The analysis of the indicators will be accompanied by the identification and discussion of fundamental principles/interrelations.

5.5.2.1 Remaining capacity margin for isolated bidding zones (local margin)

Without consideration of cross-zonal contributions (imports/exports), the remaining capacity margin of a bidding zone can be calculated by subtracting the maximum available generation capacity from the maximum hourly load per bidding zone. The neglection of cross-zonal capacities is a strong simplification, but, on the other hand, it may reflect the actual real-time behaviour in cases of simultaneous scarcity situations (i.e. the remaining capacities are activated for local/zonal purposes first).

Hereby, the maximum available generation capacity considers contributions from conventional generation[26] units as well as contributions from fluctuating RES. The contributions from conventional generation units are calculated by considering standard technology-specific availability factors. While fluctuating RES cannot be considered as secure, its full neglection would, however, underestimate its relevance for security of supply. Therefore, the maximum available generation is calculated by considering a minimum RES infeed for wind of 5%[27] and photovoltaic (PV) of 0%.

25) For details on the calculation of the security of supply indicators please refer to the ENTSO-E Mid-term Adequacy Forecast 2016.

26) Contributions from hydro and reserve power plants are considered in the analysis. Balancing requirements are not considered.

27) An analysis of the hourly wind speed data from Deutscher Wetterdienst (DWD) and hourly load profiles for Germany show a high concurrence between hours with high wind infeeds and high loads. Against this, a wind load factor of 5% can be considered as a conservative assumption.

Demand-side management is already considered in the maximum hourly load per bidding zone.

If such a remaining margin is negative, this indicates that a bidding zone is not able to cover its maximum load without any cross border contributions (i. e. in the isolated case). Hence, security of supply would be at risk in cases of neighbouring bidding zones being unable to support the bidding zone, for instance in simultaneous scarcity events.

5.5.3 ASSESSMENT OF 'SECURITY OF SUPPLY' (GENERATION ADEQUACY)

5.5.3.1 Calculation of remaining capacity margin indicators

In accordance with the formula and assumptions described in section 5.5.2 table 5.3 summarises the calculated remaining capacity margin indicator for both scenarios. The consideration of isolated bidding zones (i. e. no consideration of potential cross-zonal contributions in times of scarcity) can be interpreted as a form of worst case analysis.

While, in the SOAF worst case scenario, the remaining capacity margin for Germany in the isolated case is positive for every bidding zone configuration, this changes in the SOAF 2025 planned scenario. The RCM for the isolated case for the whole of Germany is almost equal to zero, which fits the recent results of the Midterm Adequacy Forecast (MAF) and PLEF study.[28)] Yet, in the Big Country Split and Big Country Split 2 configurations, the RCM for isolated DE_S turns out to be negative. This result is not surprising since the main generation capacities are currently already located in the north of Germany and the nuclear phaseout will strengthen the spatial difference between production and load centres in Germany until 2025. However, this RCM is calculated for an isolated case in which it is considered that DE-S would not be able to import electricity, e. g., from DE_N. Yet, the cross-zonal capacity between the north and south of Germany will increase significantly compared to today, due to the foreseen grid investments, especially in the direct current (DC) lines. However, at the same time, it has to be mentioned that in times of simultaneous scarcity, a new bidding zone DE_S would be treated as every other bidding zone (e. g. Belgium).

28) The recent PLEF study shows for 2023/24 a LOLE of 0.5, which means a negative capacity margin in less than one hour of a year. However, it can be argued that this is at the level of model inaccuracies. The PLEF study can be downloaded e. g. here: https://www.amprion.net/Dokumente/Dialog/Downloads/Studien/PLEF/2018-01-31-2nd-PLEF-GAA-report.pdf

SOAF 2020 worst	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Remaining capacity margin for isolated bidding zones (local margin)	DE: Positive RCM AT: Positive RCM	DE_N: Positive RCM DE_S: Positive RCM F_N: see 5.5.3.1 F_S: see 5.5.3.1 PL_N: see 5.5.3.3 PL_S: see 5.5.3.3	DE_N: Positive RCM DE_West: Positive RCM DE_S: Positive RCM F_N: see 5.5.3.1 F_C: see 5.5.3.1 F_S: see 5.5.3.1 PL_N: see 5.5.3.3 PL_S: see 5.5.3.3	BE & NL: see 5.5.3.1 CZ & SK: Positive RCM
SOAF 2025 planned	**DE/AT Split**	**Big Country Split**	**Big Country Split 2**	**Small Country Merge**
Remaining capacity margin for isolated bidding zones (local margin)	DE: RCM ≈ 0 AT: Positive RCM	DE_N: Positive RCM DE_S: Negative RCM F_N: see 5.5.3.1 F_S: see 5.5.3.1 PL_N: see 5.5.3.3 PL_S: see 5.5.3.3	DE_N: Positive RCM DE_West: Positive RCM DE_S: Negative RCM F_N: see 5.5.3.1 F_C: see 5.5.3.1 F_S: see 5.5.3.1 PL_N: see 5.5.3.3 PL_S: see 5.5.3.3	BE & NL: see 5.5.3.1 CZ & SK: Negative RCM

Table 5.3: Calculated remaining capacity margin indicators

France is the most thermo-sensitive country in Europe (in winter, power demand increases by 2.4 GW when the temperature decreases by 1 °C). Therefore, the maximum hourly load corresponds to a winter-time load peak that cannot be handled with conventional generation units only. In this particular case, the remaining margin can only be calculated with a probabilistic model which allows for fine adjustments of generation, and which is out of scope of this review. Please refer to the recent MAF report which applies a probabilistic model to analyse adequacy.

As for the configuration of the 'Small Country Merge', specifically of CZ & SK, the remaining capacity margin remains positive in the 2020 worst case scenario, so merging both markets will ensure sufficient capacity for the maximum hourly load. The situation changes when discussing the 2025 planned scenario, where RCM turns negative. The reason for this change is the significant decrease of usage of coal and lignite power plants in the Czech republic, which is accompanied by the rise in the maximum hourly load.

5.5.3.2 Qualitative assessment of impacts on 'security of supply' (generation adequacy)

An adequate share of conventional generation is crucial for security of supply

Security of supply is often referred to as generation adequacy, although this term does not fully reflect the relevance of cross-zonal capacities and DSM (see following aspects). However, it is worthwhile noting that conventional power plants contribute significantly to the security of supply level of a bidding zone since their generation is dispatchable, and, as such, it is important to ensure that there is an adequate share of conventional generation in the new bidding zones as well. The meaning of price signals in different bidding zone configurations for investments in generation capacities is discussed in a separate section (see 5.12).

High cross-zonal transmission capacities are beneficial for security of supply

Beside conventional generation capacities (and demand-side management) the increase (and efficient use) of cross-zonal transmission capacities contributes significantly to maintaining security of supply. It is well known that the sole national ensurance of security of supply, i.e. without any consideration of potential contributions from neighbouring countries, leads to overcapacities and, therefore, inefficiencies. The extension of transmission capacities between bidding zones strengthens the European market by increasing trading possibilities and ensures the implementation of the European target model of building a single European market with a high share of renewables.

Increase of flexibilities is beneficial for security of supply

Flexibilities on both the supply and demand sides are beneficial for security of supply, particularly in systems characterised by a high variable RES share. In order to balance the fluctuating infeed from RES, both the supply and demand sides need to be sufficiently flexible. Discrepancies in the geographical repartition of (industry and household) end-use customers eligible for demand response management and of flexible generators have to be considered when splitting one bidding zone in order to avoid an imbalance between flexible means and the variable RES share.

Limited consideration of grid constraints in security of supply assessment

As explained in the description (see section 5.5.1), security of supply focuses, in the following, on generation adequacy at the level of bidding zones and does not consider potential grid constraints. Yet, operational security is considered as a separate criterion in section 5.4.

5.5.3.3 Specific qualitative assessment of impacts on 'security of supply' (generation adequacy) in the bidding zone configurations

DE/AT Split:
For the DE/AT Split, it is expected that the generation adequacy will likely decrease in Austria because Austria's import in times of scarcity will be limited by the available cross-zonal capacities. Yet, a split of DE/AT will likely increase the available cross-zonal capacity between DE and PL and would therefore increase the level of security of supply (SoS) and security of system operation in Poland

Results of the recent Midterm Adequacy Forecast (MAF) and PLEF study show an RCM for Austria in the range of 3 GW including the power plants connected to the German grid stations in the Austrian federal state of Vorarlberg. Taking into account the loss of this generation capacity and the loss of the three pump storage plants in the Austrian federal state of Tyrol in the case of the DE/AT Split, the RCM goes down to about zero.

An important aspect for a hydro-dominated system like Austria is also the consideration of the hydro year (i.e. dry or wet). Taking such a dry case into consideration would lead to a negative RCM in Austria.

Security of supply in Germany would not be significantly impacted, although Germany would most likely lose storage capacities located in Austria, which would – depending on the available cross-zonal capacity – no longer be available in peak hours.

Big Country Split:
In the Big Country Split configuration, generation adequacy will likely decrease in DE_S since most of the generation capacities are located in the north and west of Germany. This impact is strengthened by the expected decrease of thermal generation capacities due to the nuclear phase out in Germany. Although it is expected that the cross-zonal capacities of DE_S, especially from the north of Germany, should be sufficient in order to ensure security of supply in DE_S, it has to be mentioned that in cases of simultaneous scarcity events, DE_S will be treated as every other bidding zone and can therefore not 'automatically' count on imports from DE_N.

A splitting of Poland will most likely not impact generation adequacy in Poland.

Big Country Split 2:
No significant difference compared to Big Country Split.

Small Country Merge:
Generation adequacy would increase as a result of the merges, but grid constraints are not considered, and therefore the level of operational security decreases. Congestions do not disappear but are no longer visible in the market (no price signals – e.g. for investors).

5.5.3.4 Summarised assessment of 'security of supply' (generation adequacy)

Table 5.4 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'security of supply' (generation adequacy). The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

In the short term, the overall level of security of supply in Europe will not be affected by an adaptation of bidding zones. In the long term, impacts might occur due to the changed price signals. Yet, individual impacts on the security of supply level of bidding zones are particularly expected in cases of simultaneous scarcity situations. Such impacts are described below. Yet, as for the other evaluation criteria considered in this report, distributional effects are not considered in the assessment.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Security of supply (for the entire system, short-term)	(0)	(0)	(0)	(0)

Table 5.4: Specific assessment of security of supply

5.6 CACM CRITERION 'DEGREE OF UNCERTAINTY IN CROSS-ZONAL CAPACITY CALCULATION'

5.6.1 DESCRIPTION AND UNDERSTANDING OF 'DEGREE OF UNCERTAINTY IN CROSS-ZONAL CAPACITY CALCULATION'

CACM Article 33 (1a) (ii): *the degree of uncertainty in cross-zonal capacity calculation.*

The flow-based (FB) capacity calculation process, as foreseen to be implemented in the Core Capacity Calculation Region (CCR) and as already in operation in the Central West Europe (CWE) region, uses flow reliability margins (FRMs) to estimate the uncertainties in the computed load flows used for the capacity calculation. Deviations between day-ahead (as used for FB market coupling [MC]) and real-time flows are inevitable due to several sources of uncertainty such as inaccuracy of zonal PTDFs, generator outages compensated by frequency containment reserve/frequency restoration reserve (FCR/FRR) and intraday changes in RES and load.

With regard to the degree of uncertainty in cross-zonal capacity calculation, the reconfiguration of bidding zones can have two different reverse impacts. On the one hand, uncertainty arises from the accuracy of zonal PTDFs. Assuming that the geographical distribution of generation and load in a smaller bidding zone is more equal than in a bigger bidding zone, the uncertainty arising from the zonal PTDF error is lower in such a smaller bidding zone. Or, in other words: the dispatch does more to 'follow' the grid here. On the other hand, uncertainty also arises from RES and load forecast errors, in particular in RES-impacted bidding zones. Due to the law of large numbers and portfolio effects, it is more difficult (i. e. higher uncertainty) to forecast the infeed of one wind park than to forecast the infeed of several ones located in a geographically bigger area. Considering this, the uncertainty in cross-zonal capacity calculation is linked to the intraday changes in RES (and load) increases in smaller bidding zones (compared to bigger bidding zones). It is unclear which of these reverse impacts will be higher and if, e. g., the splitting of a bidding zone will lead to a higher or lower degree of uncertainty in cross-zonal capacity calculation.

5.6.2 EVALUATION APPROACH FOR 'DEGREE OF UNCERTAINTY IN CROSS-ZONAL CAPACITY CALCULATION'

There is a fundamental difference between a methodology to determine FRMs in a long-term planning study and what is used for the daily operation. This difference is caused by the modelling time frame. TSOs can use historical data to estimate real-time flows in daily operation because the conditions such as network topology, generation and load pattern do not change fundamentally on a daily basis. FRM computation for daily operation is therefore based on a statistical analysis of the possible forecast error by comparing the modelled and measured flows for the same period.

In contrast, the time horizon of, e. g., the Bidding Zone Review is several years and this makes it impossible to rely on historical load flow values because significant changes in the assumed future grid topology, the generation and the load pattern will mainly impact the future load flows. Furthermore, historical data is not available for bidding zone configurations other than the current ones.

The methodology applied for a long-term planning study should therefore focus on both the root causes of forecasting errors in daily operation such as generator outages compensated by FCR/FRR, RES forecast errors, load forecast errors and model implementation errors caused by the inaccuracy of zonal PTDFs. This dual approach makes it possible to reflect the uncertainties of load flow computation used for capacity calculation in different bidding zone configurations to the largest possible extent.

The evaluation of the degree of uncertainty in the cross-zonal capacity calculation for different bidding zone configurations is based on a statistical analysis of the error sources RES and load (forecast errors). Yet, it has to be highlighted that unplanned outages and, in particular, the error caused by the application of zonal PTDFs can be considered as an important part of the FRMs applied in the operational practice.

The impact of alternative bidding zone configurations on the 'degree of uncertainty in cross-zonal capacity calculation' will be based on the discussion of fundamental principles/inter-relations.

5.6.3 ASSESSMENT OF 'DEGREE OF UNCERTAINTY IN CROSS-ZONAL CAPACITY CALCULATION'

5.6.3.1 Qualitative assessment of impacts on 'degree of uncertainty in cross-zonal capacity calculation'

Deviations between (day-ahead) market flows and real-time flows are inevitable

Deviations between day-ahead (as used for FB MC) and real time flows are inevitable due to several sources of uncertainty such as inaccuracy of zonal PTDFs, generator outages compensated by FCR/FRR, RES forecast errors and load forecast errors. Even 'perfectly' designed bidding zones would not avoid the consideration of uncertainties by FRMs. Yet, an adequate design of bidding zones that considers structural congestion might lower the uncertainty linked to the inaccuracy of zonal PTDFs and therefore lower the FRM to some extent.

FRM determination for daily operation and long-term planning studies are different

This aspect is described in section 5.6.1.

Uncertainty in cross-zonal capacity calculation arises from different error sources

The inevitable deviations between market and real-time flows are caused by several sources of uncertainty – mainly the inaccuracy of zonal PTDFs, generator outages compensated by FCR/FRR, RES forecast errors and load forecast errors. While some (mainly the inaccuracy of zonal PTDFs) of these can be impacted by a potential adaptation of bidding zones, others can only be affected to a limited extent (e.g. generator outages). Therefore, it is difficult to determine in advance which effect will be higher. Yet, one could argue that an adequate bidding zone configuration will not harm or increase the corresponding FRMs, and at the same time, it cannot be said that FRMs will be reduced significantly by the change of a bidding zone configuration.

5.6.3.2 Summarised assessment of 'degree of uncertainty in cross-zonal capacity calculation'

Table 5.5 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'degree of uncertainty in cross-zonal capacity calculation'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

As already explained in the introduction, the adaptation of bidding zones has reverse impacts on the degree of uncertainty in cross-zonal capacity calculation. While the uncertainty arising from the zonal PTDF error is likely to decrease in smaller bidding zones, the uncertainty arising from RES forecast errors in smaller bidding zones increases. Therefore, it is unclear which of these reverse impacts will be higher and if, e.g., the splitting of a bidding zone will lead to a higher or lower overall degree of uncertainty in cross-zonal capacity calculation.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Degree of uncertainty in cross-zonal capacity calculation	(0)	(0)	(0)	(0)

Table 5.5: Specific assessment of the degree of uncertainty in cross-zonal capacity calculation

5.7 CACM CRITERION 'ECONOMIC EFFICIENCY'

5.7.1 DESCRIPTION AND UNDERSTANDING OF 'ECONOMIC EFFICIENCY'

CACM Article 1(b) (i): *any increase or decrease in economic efficiency arising from the change*

Economic efficiency is a well-known economic concept, also known as the welfare concept. In energy economics, market efficiency (as an indicator of economic efficiency) is usually calculated based on market models. Hereby, market efficiency is defined as the change in the total system costs (i.e. variable production costs in the day-ahead market model) plus the corresponding redispatch costs. While in a nodal market design, redispatch costs are considered as already implicit in the total system costs, this is only partly the case for a zonal market design. For this reason, redispatch costs need to be considered when it comes to the assessment of any increase or decrease in the economic efficiency arising from a change in the bidding zone configuration. CACM Article 1(b) refers not only to the results of the day-ahead market, but also to the related impacts on the economic efficiency in general. This includes redispatch costs and focuses on the day-ahead market as well as the forward, intraday and balancing markets. Based on a market and redispatch simulation, it is also possible to analyse the distributional effects between countries and producer, consumer and congestion rents. Yet, considering the concept of FB MC, the interpretation of these distributional impacts is less meaningful than in a net transfer capacity (NTC)-based market design. In addition, the Bidding Zone Review does not focus on any distribution effects, but its main interest is the overall efficiency (expressed by the changes in the total system costs).

The system costs should never be misinterpreted as an indicator of welfare in general. First, they are derived by models that do not exactly represent reality. In addition, there are several other limitations. A main drawback of the determination of welfare solely by calculation of the change in the total system costs as indicated by a market model (adjusted by redispatch costs) is that the value of security of supply and operational security is not considered. In order to consider the impact of different levels of security of supply or grid stability for welfare, their economic value would have to be determined. Yet, its monetarisation is complex. Other relevant aspects are, for example, market liquidity and market power (and the long-term markets, which are typically not modelled). Their impact is not even reflected by any calculation of system costs. Nevertheless, they can have a crucial influence on the overall efficiency as they are main drivers for well-functioning electricity markets. The same holds for the balancing effects, the robustness of the price signals and others. Several of these aspects are considered as individual evaluation criteria in the CACM (see sections 5.4 and 5.5).

It is therefore important to highlight that economic efficiency is by no means an aggregating indicator. There is no ranking between the CACM evaluation criteria. An appropriate review of alternative bidding zone configurations can only be based on a comprehensive assessment that considers all relevant criteria and aspects.

5.7.2 EVALUATION APPROACH FOR 'ECONOMIC EFFICIENCY'

The impact of alternative bidding zone configurations on the economic efficiency will be done based on the identification and discussion of fundamental principles/interrelations.

5.7.3 ASSESSMENT OF 'ECONOMIC EFFICIENCY'

5.7.3.1 Qualitative assessment of impacts on 'economic efficiency'

Splitting an existing bidding zone will increase total system costs (day-ahead market), but decrease redispatch costs

The splitting of an existing bidding zone will have two major impacts on economic efficiency. If the structural congestion is not considered in the bidding zone configuration, redispatch costs will be higher than in cases where the bidding zone configuration would be adapted in order to better reflect the structural congestion. Yet, it is obvious that the costs at the day-ahead market will be higher in the scenario with an adapted bidding zone configuration, since potential congestions/redispatch costs are internalised into the day-ahead market (or, in other words: grid constraints are considered in the day-ahead market). Theoretically, the overall efficiency does not change, but this will never be achieved in practice. In reality, the additional costs for the redispatch, depending on the market framework or compensation mechanism might exceed the costs in the theoretical optimum (e.g. due to start-up costs).

In a theoretical model world, minor changes in the bidding zone configuration have no significant impact on the system costs calculated by a market coupling and redispatch simulation. The system costs are defined by the final power plant dispatch and are mainly driven by the related fuel and CO_2 costs and, to a lesser extent, by additional startup and shutdown costs. Depending on the modelling assumptions, the final dispatch is, however, not principally affected by the bidding zone configuration. In cases of smaller zones, the network restrictions are directly considered in the market simulation. The resulting dispatch takes them into account. In cases of larger zones, the network restrictions are considered in the redispatch simulation, leading to a similar dispatch. In theory, the two outcomes should be the same as those given in a central planning approach. However, as mentioned previously, this theoretical optimum cannot be achieved in practice.

Apart from modelling and practical limitations, there is one deviation from this relationship: The redispatch simulation should never improve the market outcome as such. It should only change the market outcome to deal with congestions. An upper efficiency limit is therefore set by the market. However, if the market is too strongly restricted (by an overly conservative capacity calculation), the given upper limit is low. Yet, in practice, this may not be true for the following reasons. While theory considers perfect markets, their level of efficiency is different in reality from theory. Market outcomes and redispatch are never as efficient in practice as they are in theoretical models – for instance, because models assume perfect foresight. This is especially true for the redispatch processes, where perfect optimisation is assumed. In real redispatch, there is currently no EU-wide optimisation, not all generation takes part (usually units bigger than 50–100 MW) and costs of increased generation under redispatch action differ from only variable costs of a given generation unit. Furthermore, the adequate determination of generation shift keys (GSKs) and CNECs has a very high impact on the efficiency of the market. The question of which impact is higher (decrease of redispatch costs vs increase of total system costs after market coupling) in practice mainly depends on the efficiency of the market and of the redispatch measures and associated costs.

System costs derived by market and redispatch simulations are therefore often driven by the detailed modelling assumptions (e.g. which restrictions are simulated in the market coupling and the redispatch). The extent to which they reflect real system costs is therefore questionable. However, simulational analyses may indeed indicate that costs of countermeasures in a zonal system (both within a zone and between zones) lead to higher effective prices of electricity than in a nodal solution. However, such simulations are often assumption driven.

Redispatch costs are very much related to the congestion that occurs after the market coupling. An assessment of this is provided in section 5.23. This assessment also provides a qualitative assessment of the redispatch costs that may occur in each bidding zone configuration.

In the First Edition of the Bidding Zone Review, the term 'economic efficiency' refers to the total system costs after all remedial actions have been considered. It is worth noting that in the event that two different bidding zone configurations lead to exactly the same final dispatch solution, the related costs to serve the load, and therefore the impact on the (total) economic efficiency (as understood in this report), should be identical. In consequence, all observed effects would be related to other characteristics that are not measured by this dimension (transaction costs, liquidity, or others). When discussing the final total level of global efficiency here, redistributional effects among timeframeworks or spatial effects among bidding zones are not considered either.

As mentioned previously, keeping a big copper plate bidding zone would likely lead to more redispatch, and splitting would transfer a part of this redispatch to the day-ahead market. Regarding inter-temporal effects (non-redistributive), the question remains as to whether market dispatch (within the day-ahead market coupling model) is more efficient than a well-functioning redispatch market. Firstly, redispatch can also be a market, though one could argue that due to its more local character it could tend to be more limited in choices and outcomes. The size of the day-ahead market and its time advance would provide further opportunities for optimisation via choice. On the other hand, the local character of redispatch and the availability of more information as we come closer to real time would also provide opportunities to eliminate uncertainties (as with the many ones related to a big copper plate, operated one day in advance). However, with redispatch we would have less remaining flexibility.

When it comes to the performance of day-ahead market coupling in terms of efficiency (ignoring the prior inter-temporal framework redispatch link), it can be said that market coupling efficiency has the potential to improve with smaller zones, since more geographical information and constraints can be considered in the system (by performing the splits). These would bring the calculated commercial flows closer to the actual realised physical flows feasible in the grid. By forcing the same price to all its underlying nodes, a big merged bidding zone copper plate would ignore part of this information, leaving it for redispatch to deal with.

Within implicit flow-based day-ahead systems, the calculation of GSKs could have the potential to become more precise in smaller areas, improving the PTDFs' definition and price accuracy. Model effects are improved by having similar-sized zones, via the same mechanism. The un-even geo-distribution of uncertainty plays, however, an important role in defining what similar sized-zones are, and the previous principle should be considered with caution.

5.7.3.2 Summarised assessment of 'economic efficiency'

Table 5.6 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'economic efficiency'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Economic efficiency	(0)	(0)	(0)	(0)

Table 5.6: Specific assessment of economic efficiency

5.8 CACM CRITERION 'FIRMNESS COSTS'

5.8.1 DESCRIPTION AND UNDERSTANDING OF 'FIRMNESS COSTS'

Article 1(b) (ii) of the CACM regulation requires an assessment of: *'market efficiency, including, at least* ***the cost of guaranteeing firmness of capacity****, market liquidity, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals'.*

CACM Article 2 (44) defines 'firmness' as 'a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed'. In the following, firmness costs will be understood as the related costs to ensure the cross-zonal capacity rights.

In addition, Article 61 of the Forward Capacity Allocation (FCA) Guidelines clarifies that the cost of ensuring firmness shall include costs incurred from compensation mechanisms associated with ensuring firmness of cross-zonal capacities as well as the cost of re-dispatching, countertrading and imbalance associated with compensating market participants, and must be borne by TSOs, to the extent possible in accordance with Article 16(6)(a) of Regulation (EC) No 714/2009.

This criterion is strongly interlinked with the of criterion operational security (cf. section 5.4). Higher congestions identified under this criterion increase the likelihood that capacity cannot be guaranteed. This leads to a higher firmness cost exposure.

5.8.2 EVALUATION APPROACH FOR 'FIRMNESS COSTS'

The assessment of the impact of alternative bidding zone configurations on the firmness costs will be based on the identification and discussion of fundamental principles/inter-relations.

5.8.3 ASSESSMENT OF 'FIRMNESS COSTS'

5.8.3.1 General assessment of qualitative aspects

Splitting bidding zones increases the number of borders where cross-zonal capacity rights are provided

Within a bidding zone there are no cross-zonal capacity rights and, hence, firmness costs cannot be incurred. By increasing the number of borders (e.g. splitting bidding zones), the number of cross-zonal capacity rights naturally increases.[29)]

Firmness costs tend to increase in the event that cross-zonal capacity rights increase

By definition, firmness costs can be incurred only in the case where cross-zonal capacity rights have been provided to market participants. For this reason, firmness costs tend to increase with the number of borders a bidding zone configuration has.

Splitting a bidding zone into two 'smaller' bidding zones implies:

- additional cross-zonal capacity rights provided to market participants and, consequently, a potential increase in firmness costs;
- market outcomes that, generally, do not cause congestions on the border between the split bidding zones, and hence, a reduction in redispatching costs.

5.8.3.2 Specific qualitative assessment of the alternative bidding zone configurations

Potential changes of the firmness costs in the DE/AT Split:

Since an additional border is introduced, a small increase in firmness costs can be expected. Hence, a slightly negative impact is expected.

Potential changes of the firmness costs in the Big Country Split

Since four additional borders are introduced, an increase in firmness costs can be expected. Hence, a negative impact is expected.

Potential changes of the firmness costs in the Big Country Split 2

Since six additional borders are introduced, an increase in firmness costs can be expected. Hence, a negative impact is expected.

29) Assuming that the new border does not reduce capacities on other borders to a significant extent.

Potential changes of the firmness costs in the Small Country Merge

Since two existing borders are deleted, a decrease in firmness costs can be expected. Hence, a slightly positive impact is expected.

5.8.3.3 Summarised assessment of 'firmness costs'

Table 5.7 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'firmness costs'. As explained above, introducing new borders increases the likelihood of incurring firmness costs. The split scenarios therefore lead to a comparatively higher firmness cost exposure, whereas the merge scenario tends to decrease firmness costs. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Firmness costs	(-)	(-)	(-)	(+)

Table 5.7: Specific assessment of firmness costs

5.9 CACM CRITERION 'MARKET LIQUIDITY'

5.9.1 DESCRIPTION AND UNDERSTANDING OF 'MARKET LIQUIDITY'

CACM Article 1(b) (ii): *market efficiency, including, at least the cost of guaranteeing firmness of capacity, **market liquidity**, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals*

By market liquidity, we understand the degree to which any market party can quickly (within the time frame the market participant needs) source/sell any volume of energy (implicit) or capacity (explicit) without greatly affecting the involved market price. Market liquidity is generally viewed as a multi-dimensional, not directly observable construct. Nevertheless, it is a crucial aspect for the electricity market to function well (as also highlighted in all stakeholder answers; see below). It is closely, and in a supporting way, linked to other criteria such as the accuracy of price signals, effective competition, market efficiency etc. High liquidity reflects an efficient distribution of relevant supply and demand information, leading to an efficient market dispatch. There is also a close connection to risk exposure. In liquid markets, open trading positions are closed more quickly, facilitating the trading and hedging process. In illiquid markets, traders face uncertainties regarding when they will be able to trade their assets. This risk exposure leads to increased costs. Liquid markets minimise risks and increase total market efficiency.

Possible indicators for market liquidity would normally be:

- Bid–offer spreads – The bid–offer spread is defined as the amount by which the ask price exceeds the bid. This is essentially the difference in price between the highest price that a buyer is willing to pay for a product and the lowest price for which a seller is willing to sell it.
- Market depth – Size of an order needed to move the market price by a certain level.
- Trading volume and number of trades per day – Indicators to measure trading activity rather than market liquidity, but commonly also used as liquidity indicators.
- Churn rate – A variant of the trading volume measure is the churn rate. It describes the trading volume in comparison to the physical consumption in the underlying market.
- Lot sizes – Size of the minimum trading volume usually provided by the local dominant trading platform.
- Number of players – Number of available counterparts within one bidding zone on one or more trading platforms

However, none of these indicators fully reflect the phenomenon of market liquidity.

5.9.2 EVALUATION APPROACH FOR 'MARKET LIQUIDITY'

The above-mentioned indicators rely on detailed empirical data of existing markets. However, such data is not available for the future and for alternative bidding zone configurations (and may even be unavailable for the present). All empirical data is linked to specific, unique historical evolutions, and each bidding zone is unique due to its own characteristics of generation, demand, market structure, etc. Such data can also hardly be simulated by any model. Trading activities depend on numerous factors, including, not least, human behaviour. Agent-based models are an attempt to simulate the actions of traders, but there are no suitable models available that could be used in a real case study, as is required here. In most cases, the impact of future bidding zone reconfigurations on market liquidity can therefore hardly be predicted. Consequently, the evaluation of market liquidity is mainly a qualitative one, using different sources of information.

The analysis is split into two parts (5.9.3.1 and 5.9.3.2): a more general assessment and a dedicated stakeholder survey (second survey). The final liquidity assessment is presented in 5.9.3.3.

5.9.3 ASSESSMENT OF 'MARKET LIQUIDITY'

5.9.3.1 General assessment of market liquidity

Input from different sources was sought in order to grasp the relevant aspects of liquidity with regard to bidding zones. This included a workshop of the TSOs with two representatives of two consultancies (Energy Brainpool and Ecco International) on the 14th and 15th of September 2016. At the workshop, potential links between bidding zones and liquidity were discussed in a controversial manner, and the findings were documented. In addition, a first stakeholder survey on liquidity (and other market indicators) was held (executed in 2016) addressing the same topic. A summary of the main conclusions derived can be found in the following. After that, the theoretical links between bidding zone configuration and market liquidity are discussed. At the end of the section, these different parts are merged into a first qualitative assessment of liquidity for all configurations.

Outcome of the expert workshop and the first stakeholder survey on market liquidity

The expert workshop and the first stakeholder survey led to the following theses which were drafted based on the received stakeholder answers and the discussion during the workshop. Some statements are taken literally from the received stakeholder answers. Market liquidity and its relation to small and large bidding zones is addressed in general terms, but no specific configurations are considered here.

- Market liquidity is a key indicator for a well-functioning electricity market. A low level of liquidity leads to: measurably higher transaction costs, higher risks and risk costs (lower ability of market participants to hedge risks), higher market entry barriers, less clear price signals, less efficient dispatch.

- There is an important effect of self-reinforcing liquidity. High liquidity is attractive for traders, leading to an increase in liquidity ('liquidity attracts liquidity'). In the same logic, there is a risk that a small decrease in liquidity triggers a 'downwards spiralling effect'.

- Price signals based on liquid markets are essential for (plant) investors (or for robust closure decisions). Even if liquid trading only applies to delivery periods of one or a few years in advance, this liquidity is also helpful for investors in long-term assets such as power plants. The existence of liquid forward markets reduces risks for new investments, and therefore reduces risk premiums and overall costs. According to another answer received from a stakeholder, market liquidity – being in fact a short-term factor – should not impact investment decisions. From an investment point of view, future prices are not sufficient to make decisions and determine the profitability of an investment. Key determinants of investments are predictability and stability of legal conditions/regulatory framework, as well as a transparent energy policy of a given country/region.

- Larger zones are beneficial for liquidity as there are fewer products available for the same number of market participants. For example, if a bidding zone is split, the number of forward/future products will likely double, whereas the number of market participants remains equal. This results in lower liquidity. This effect is mitigated by the exchanges between the bidding zones, but these will be structurally smaller than the exchanges within bidding zones.

- Contracts for difference (CfDs) are not a replacement for the liquidity of large bidding zones. If the market for forward contracts is illiquid, then the market for instruments such as CfDs is all the more likely to be illiquid. CfDs may imply high transaction costs. ACER has analysed the risk premiums of electricity price area differentials (EPADs) in the Nordic market and identified positive risk premiums. They may act as a barrier to market participants who are generally not able to bear the price risk of congestion. In the absence of liquid forward markets, CfDs do not appear to be a likely substitute.

- The liquidity of the Nordic market (forward/future) has decreased. The volumes of future contracts traded on Nasdaq-OMX have decreased by over 20% from 2011 to 2015. A similar trend can be observed in the liquidity of EPADs. This concern is also confirmed by Nordic power market participants. It is also recognised by Nasdaq Commodities. Another view expressed by stakeholders was that Nordpool is a very liquid and constantly growing market.

- Cross-zonal exchanges are a relevant element for market liquidity. Proper and efficient congestion management is important. For example, the DE/AT bidding zone is not well designed, reducing liquidity in other zones.

These points give a first input for the assessment of the relationship between bidding zone configurations and market liquidity. The theoretical underlying principles of the different statements are investigated in the following.

Establishment of links between market structure and liquidity

The phenomenon of liquidity is linked to several characteristics of the underlying market structure. These links are discussed in the following based on the statements above and other sources. Each relation is considered as an isolated one in order to accentuate the specific influence.

The investigation of liquidity in general refers to all market segments, including spot markets and long-term markets if not stated otherwise. In general, the different market segments are naturally interlinked and the liquidity of each of them influences the others.

Aspect: size of bidding zones

A large bidding zone size is beneficial for liquidity and generally translates into greater generation capacities and higher demand. In most cases, this triggers greater participation in the electricity markets. More market participants are equivalent to more trading activities and increase liquidity. A high diversity of market participants is also beneficial for liquidity. This applies to all market segments.

The relationship is supported by Figure 5.1, showing the churn factors of major European forward markets as published by ACER. The churn factors are estimates of total volumes traded from 2014 to 2016 as a multiple of consumption.

In the large zone of DE/AT/LU, the churn factor is nearly twice as high as in the other zones.

Aspect: interconnectivity of bidding zones

High connectivity (or improved congestion management) between bidding zones is beneficial for liquidity as it assures more trading possibilities. More electricity can be shifted from one zone to another, allowing for more interactions between the market participants. This applies to all market segments where the determination of trading capacities is directly linked to the interconnector capacities. However, it has less impact on the over-the-counter (OTC) trading that has no access to the interconnector capacity being traded as standardised products at the power exchanges. Figure 5.2 shows the market trading volumes per type (in TWh) in the largest European forward markets for 2016, as published by ACER.

OTC trading constitutes an important part of the traded volumes. The liquidity represented by these volumes is not supported by interconnection between bidding zones.

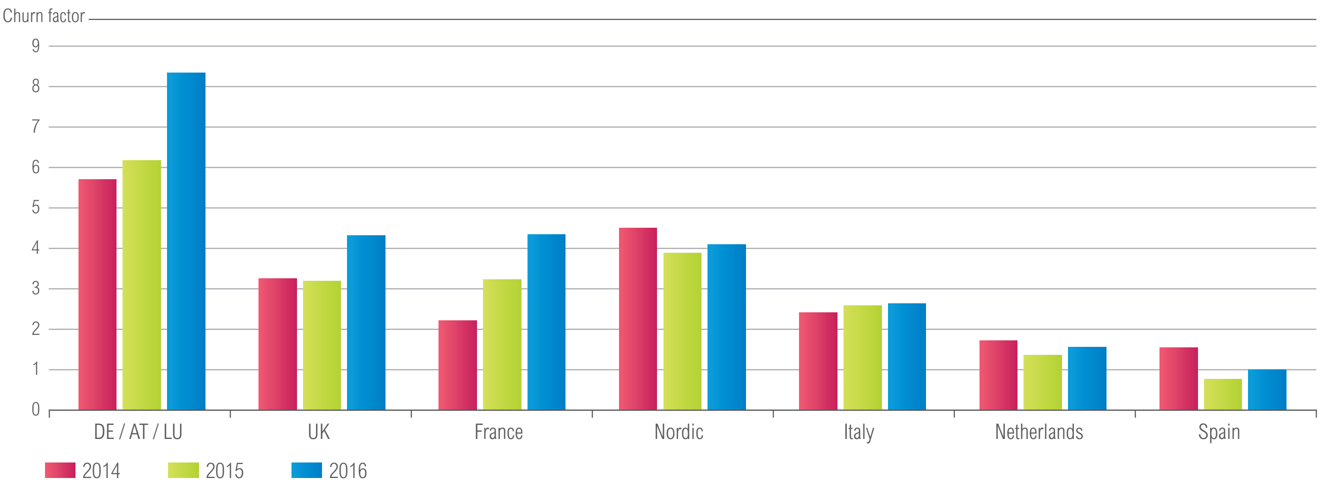


Figure 5.1: Churn factors in major European forward markets 2014–2016; Source: ACER Market Monitoring Report 2016[a)]

a) www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf

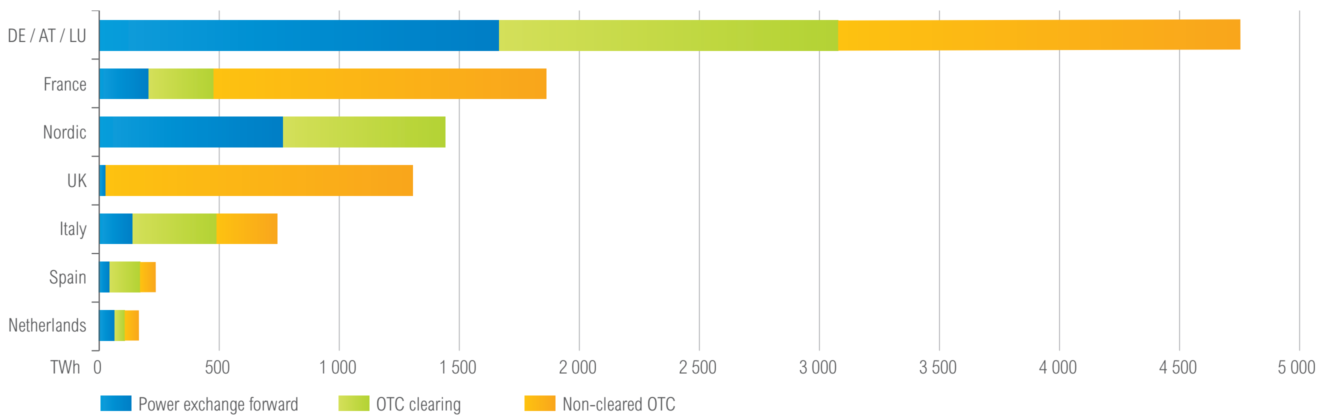


Figure 5.2: Forward market trading volumes per type in the largest European forward markets 2016 (TWh); Source: ACER Market Monitoring Report 2016[b]

b) www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf

Aspect: products for long-term cross-zonal trading

In order to allow for long-term cross-zonal trading, long-term transmission rights are introduced. Contracts for differences (i.e. electricity price area differentials) may also be available. Such CfDs rely on the difference between the singles zonal prices and a representative system price (which is calculated based on the prices of all single zones). These products are important for trading, but they do not replace the trading possibilities defined by the physical underlying, the interconnectors or the unlimited trading within a zone. As an example: for a given level of interconnection capacity, the increase of CfD products will not have a positive impact on liquidity. The insufficient liquidity of EPADs was also pointed out by EFET in the stakeholder survey and supported by data from Nasdaq and ResearchGate.

Aspect: temporal development

A stable set-up of a bidding zone (i.e. long-lasting existence) is also beneficial for liquidity. In the churn rate figure above, it can be seen that liquidity has increased in most markets, supporting the assumption that markets require time to develop. A main driver for liquidity is trust in the market and its attractiveness. This relates to the effect of self-reinforcing liquidity that was also highlighted by the stakeholders.

Summary of the general assessment of market liquidity

The identified relations and interconnections are translated into an assessment of liquidity, looking at the bidding zone configurations investigated in the study. Due to the qualitative character of the analysis, no differentiation between the framework scenarios is introduced. The First Edition of the Bidding Zone Review puts a specific emphasis on stakeholder views on liquidity effects.

The reduced size of the bidding zones in the split configurations makes a decrease of liquidity very probable, due to the reduced number and diversity of market participants and the reduced trading possibilities. Especially in the cases of the Big Country Split and Big Country Split 2, a self-enforcing drop of liquidity is possible. The effects may be attenuated by cross-zonal capacities and related trading products, but they are not likely to be overcome. This only holds if the splitting leads to a relevant reduction of the cross-zonal trading capacities. If cross-zonal trading is not limited by the split, there will be no impact. In addition, the impact of cross-zonal capacities has to be differentiated between the single market segments. On the day-ahead market, being highly coupled, the liquidity is less impacted than it is for the intraday or the long-term markets. Moreover, in a coupled market, the liquidity will develop differently in the zones and the level to which the liquidity changes might be different for the individual zones. For example, a split bidding zone may lose liquidity, but neighbouring bidding zones may see an increase of liquidity due to more available cross-zonal trading capacities.

5.9.3.2 Outcome of the second stakeholder survey on market liquidity

A second stakeholder survey was executed in 2017. In this survey, the stakeholder representatives were asked to give their assessment of liquidity for the specific bidding zone configurations under investigation in reference to the Status Quo configuration. As an additional assumption, a bidding zone change before 2020 is assumed and the change of liquidity is evaluated considering the period from 2020 to 2025 (being in line with the target years of the study). For example, the assessment 'liquidity increase' for a bidding zone configuration states that if the configuration is introduced before 2020, the liquidity within 2020 and 2025 will be higher compared to a case without any reconfiguration. In all cases, liquidity as it impacts the European market in total is considered. This aggregating approach is in line with the evolutionary nature of liquidity.

The questions differentiate, however, between the liquidity for day-ahead trading, intraday trading and forward and future trading. Possible answers were: 'increase', 'strong increase', 'decrease', 'strong decrease', 'no material change' and 'not known'. 'Strong increase' is thereby intended to represent an increase of the traded volume by 50 % or more and/or a reduction of the bid/ask spreads by 25 % or more. 'Increase' represents an increase of the traded volume by a magnitude of 10 % to 50 % and/or a reduction of the bid/ask spreads by 10 % to 25 %. 'Strong decrease' represents a reduc-

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Spot market (especially intraday)	-	-	-	+
Forward/future market	-	-	-	+
Liquidity in general	-	-	-	+

Table 5.8: General assessment of relations and interconnections between bidding zone configurations and liquidity

tion of the traded volume by 25 % or more and/or an increase of the bid/ask spreads by 50 % or more. 'Decrease' represents a reduction of the traded volume by 10 % to 25 % and/or an increase of the bid/ask spreads by 10 % to 50 %. Finally, 'no material change' is between 'decrease' and 'increase'. The classifications could be commented on by further explanations. An overview of the questionnaire can be found in the Appendix.

5.9.3.3 Stakeholder answers in table form

Several stakeholders have answered the questionnaire in table form. The general tendency of the answers is given by Table 5.9. The complete answers are shown in the Appendix. Not all stakeholders have delivered answers for all configurations/time frames.

All answers state decreased liquidity in cases of split configurations and increased liquidity in cases of merge configurations. However, the answers often differentiate with regard to the specific zones within a configuration. For example, in the DE/AT Split, the decrease for the Austrian zone is seen as stronger than for the German zone. In the same manner, the given answers vary in other cases. The overall assessment is, however, well reflected by the table.

5.9.3.4 Additional explanations provided by stakeholders

In the following, some main statements of the stakeholders as given in the answers are summarised. They mostly support the assessments gathered up to now. The complete answers are given in the Appendix.

Europex (Association of European Energy Exchanges):

» Stable bidding zones are beneficial for liquidity in all respects (number and heterogeneity, of participants, standardisation of products, etc.). In derivatives markets, market participants with open derivatives contracts would be exposed to a changed underlying risk. Therefore, it is of the utmost importance that bidding zones remain stable over time.

» The limited amount of cross-zonal capacity made available by TSOs is one of the most significant barriers to the further integration of wholesale markets. While this is the case for coupled short-term markets, it is true that long-term markets remain more fragmented due to the fact that energy delivery is restricted to a single bidding zone.

EEX (European Energy Exchange):

» Large and liquid bidding zones are critical to renewable energy integration and should be the preferred solution for an efficient European electricity market. The German–Austrian electricity market is the most liquid market in Europe and serves as a reference for the whole region.

» Forward and future markets represent over two-thirds of traded volume in the European Union.

» Splitting bidding zones put market functioning and European electricity system integration at risk, e.g. due to the fragmentation and reduction of the existing liquidity on spot and derivatives markets.

» Experiences from former and ongoing bidding zone splits should be taken seriously. A look at the Scandinavian power market, where a split into several price zones was carried out in Sweden in 2011, helps to assess the effects of any split: since 2011, liquidity has declined significantly. The example of Sweden shows that the achievements of liberalisation – first and foremost a liquid market and a strong price signal – are jeopardised by price zones which are too small.

» The splitting of zones also has the potential to undermine the current extension of the grid and, therefore, further joint development of the European Internal Energy Market.

Type of market	Answer type	Impact by DE/AT-Split	Impact by Big Country Split	Impact by Big Country Split 2	Impact by Samll Country Merge
Intraday trading	Change of liquidity	decrease	strong decrease	strong decrease	increase
Day-ahead trading	Change of liquidity	decrease	strong decrease	strong decrease	increase
Forward/future markets – shorter period	Change of liquidity	decrease	strong decrease	strong decrease	increase
Forward/future markets – longer period	Change of liquidity	decrease	strong decrease	strong decrease	increase

Table 5.9: Summary of stakeholders' answers to the second survey on market liquidity

PKEE (Polish Electricity Association):

- We believe that bidding zone configuration may have a limited impact on the liquidity of the day-ahead market and also for the Intraday market. However, the impact on the forward or hedging market may have strong consequences. There are some ways to mitigate the impact of bidding zone reconfiguration on liquidity, such as contracts for differences in the Nordic market.

EDFT (EDF Trading):

- Strongly opposed to splitting France, no benefits. Market won't be stable with this split.

- Strongly opposed to merging Belgium and Holland. No benefits.

EFET (European Federation of Energy Traders):

- We note once again that with only one – quite limited – bidding zones merger scenario, the review misses the opportunity to analyse the effect on both network management and market efficiency of merging bidding zones in the same way it does for splitting them.

- Liquid wholesale markets are key to managing and reducing risks for market participants, and thus key to allowing for timely investments in generation, storage and demand response. By lowering risks and thereby risk premiums, liquid wholesale markets bring down financing costs for investments. This results in a general increase in socio-economic welfare.

- Stability and certainty in the delineation of bidding zones is particularly important in the current period of uncertainty for the market.

- Market efficiency, however, does not stop at liquidity. Competition, both at the wholesale and retail levels, is also a vital element of it. We expect ENTSO-E to conduct proper scrutiny on the competition effects of the different scenarios as part of its market efficiency analysis before submitting its final review proposal.

IFIEC (International Federation of Industrial Energy Consumers):

- In connection with the bidding zone proposal in the winter package, IFIEC promoted the idea that bigger market zones lead to higher liquidity and more options to provide flexibility to a broader geographical scope. In the current consultation, three out of four configurations focus on the splitting of bidding zones; only one on merging.

- Bidding zones are also addressed in the winter package proposal. In order to find a balanced solution, IFIEC proposed the following change: Whenever long-term structural congestions in the transmission network occur, Member States shall take all necessary measures to solve those congestions in a reasonable time frame.

5.9.3.5 Summary of stakeholder assessment of liquidity

In total, the stakeholder answers indicate the following evaluation of liquidity:

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Spot market	-	-	-	+
Forward/future market	-	-	-	+
Liquidity in general	-	-	-	+

Table 5.10: Summary of stakeholders' assessment of liquidity based on the outcome of the second stakeholder survey on market liquidity

5.9.4 SUMMARISED ASSESSMENT OF 'MARKET LIQUIDITY'

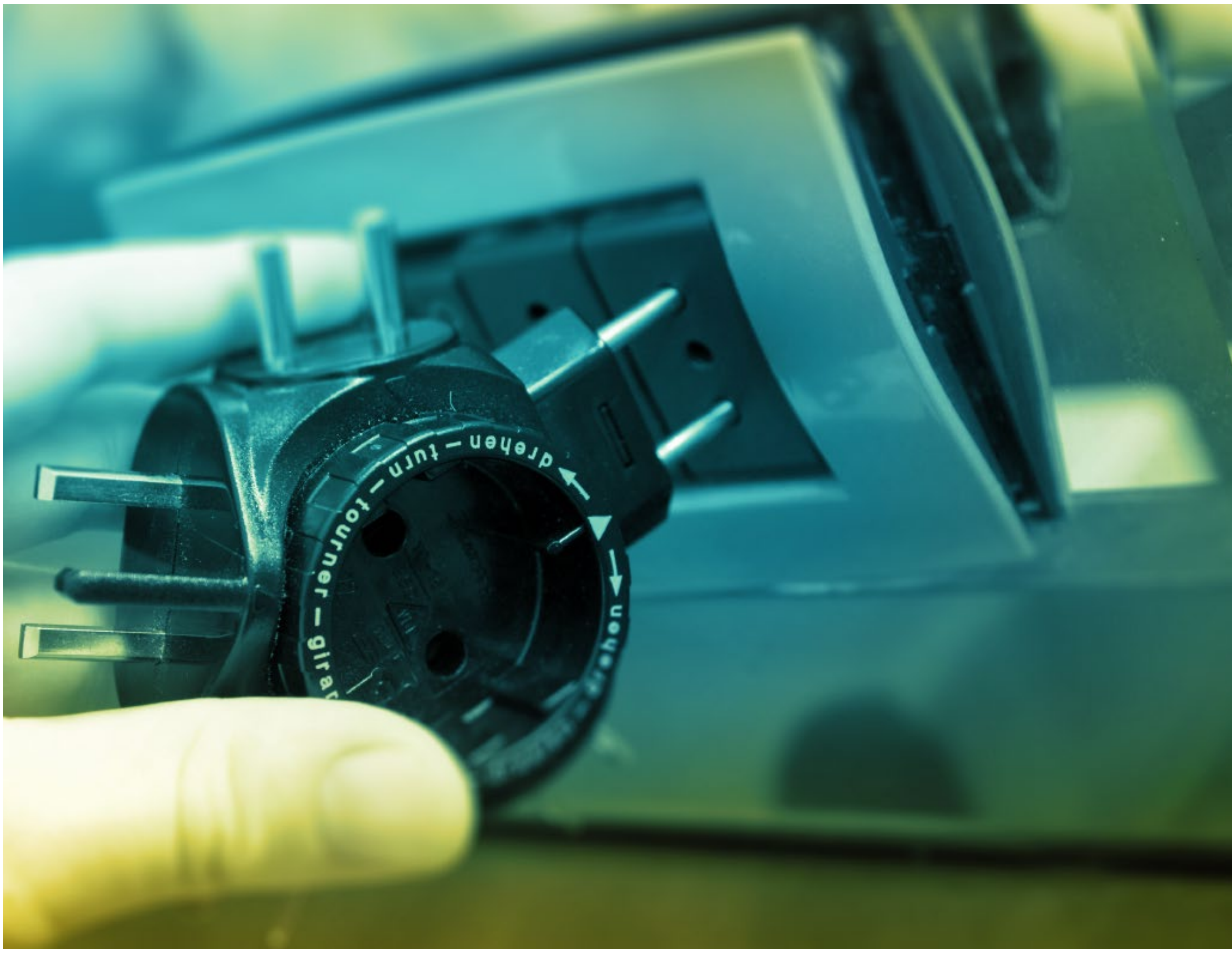
Table 5.11 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'market liquidity'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

The given assessment only holds if the newly introduced bidding zones borders are effective, i.e. they have a limiting impact on the trading at that border (or, respectively, they release cross-zonal trading capacities in cases of being cancelled). However, the above-mentioned psychological reactions and effects of any introduction of new borders, even if not effective, still have to be considered. The assessment especially refers to the long-term markets and the intraday market (at least as long as no cross-zonal intraday market coupling is established). For long-term trading, alternative products like CfDs may be introduced, but it is uncertain to what extent they can replace the trading fundament of single bidding zones.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Market liquidity	(-)	(-)	(-)	(+)

Table 5.11: Specific assessment of market liquidity



5.10 CACM CRITERION 'MARKET CONCENTRATION AND MARKET POWER'

5.10.1 DESCRIPTION AND UNDERSTANDING OF 'MARKET CONCENTRATION AND MARKET POWER'

CACM Article 1(b) (ii): *market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity,* ***market concentration and market power****, the facilitation of effective competition, price signals for building infrastructure, the accuracy and robustness of price signals*

Market concentration describes the number of players with a relevant market share at the demand and supply sides. Since the supply-side concentration is considered to be more relevant in most adaptations of bidding zones, the Bidding Zone Review will concentrate on the supply side.

Market power is a different concept and is related to the capability of certain parties to profitably manipulate market prices by:

- Either reducing their offer, or just by increasing their offering prices directly in an individual way (monopoly) or through implicit coordination (collusion);

- Lack or reduced offer from resources that are critical for the reliable operation of the system (dependence on the location of resources).

It is worthwhile mentioning that, compared to other markets, some of the economic characteristics of electricity markets are potentially 'beneficial' for market power: mainly the existence of transmission constraints, inelastic demand, peak demand conditions and instantaneous balancing needs. Some of the most relevant determinants of market power in the electricity market are (non-exhaustive):

- Physical: supply curve (cost, capacities), ownership structure of generation assets, price elastic of demand, load profiles, network constraints, etc.

- Administrative and regulatory environment: mandatory or voluntary market, existence of bilateral trading/forward market, horizontal/vertical integration, market monitoring, market entry barriers, etc.

5.10.2 EVALUATION APPROACH FOR 'MARKET CONCENTRATION AND MARKET POWER'

The evaluation of the market concentration and market power of alternative bidding zone configurations will be based on the input assumptions for the different scenarios and bidding zone configurations. Two market power indicators will be calculated. The analysis will be accompanied by the identification and discussion of fundamental principles/inter-relations.

5.10.2.1 Assumptions taken for the calculation of market power indicators

The availability and accuracy of data on the future ownership of generating units is an important part of the analysis of market power effects. Several indicators to assess market power (such as the Herfindal–Hirschmann–Index [HHI] or Residual Supply Index [RSI]) are well-known in economic theory and applied in practice. Yet, market power is usually assessed based on existing market data. To derive statements about the change of market power in future scenarios, adequate information about the future ownership of power plants is crucial. As this is not available, reasonable assumptions have to be taken. These include assumptions on the decommissioning and commissioning of plants in general as well as on the ownership of existing and future plants and their location. Although an increasing part of the future energy system will be decentralised, decentralised power plants (including variable RES such as wind and PV) will be neglected in the quantitative analysis as it is in the nature of a decentralised system that assumptions on the ownership of decentralised and mainly small units cannot be considered in an adequate manner (at least not for small units).

In order to build up an adequate database for the quantitative assessment of future market power for alternative bidding zone configurations, the power plant database from Platts (which includes information about the ownership of existing plants but also for some future projects) will serve as a base. In order to improve this list, TSOs updated the Platts ownership assumptions based on their knowledge and available information, e.g. press releases from generating companies (to the extent possible). Hereby, consistency with the market model assumptions regarding the commissioning and decommissioning of power plants for the different scenarios has to be ensured (see Chapter 3). As it is difficult to take reasonable assumptions for generic power plants, i.e. future power plants which are not linked to a specific project announced, these will not be considered in the following analysis of market power. Furthermore, it will be assumed that the ownership of a specific power plant will not change over the different scenarios and will not be impacted by an alternative bidding zone configuration (static analysis). While cross-zonal contributions can in general be considered in indicators such as the RSI, it is difficult to make reasonable assumptions for the ensured import or export capacities in case of scarcity events in the future. In the context of the assessment of bidding zone reconfiguration, it is even more challenging to define reasonable assumptions since no historic import/export time series are available for the newly created borders. Therefore, net imports will not be considered in the following indicators.

It has to be noted that any indicator and derived conclusions will be sensitive to the assumptions made in the aforementioned database.

There are different approaches to assessing the existence of market power. Besides structural/static analysis (such as concentration ratios, HHI and RSI), it is possible to use behavioural/dynamic analysis (Price–Cost Margin Index, Lerner Index) or simulation models (competitive benchmark using oligopoly models) to analyse market power and competition .

However, in the following, the focus relies on indicators based on a structural (static) analysis (considering the assumptions described before).

5.10.2.2 Herfindal–Hirschmann-Index

The HHI is the 'traditional' indicator of economic theory to measure market concentration and is defined as the sum of the squared market shares:

$$HHI = \sum_{i=1}^{N} s_i^2$$

where s_*i* is the market share of company *i* in the market and *N* is the total number of companies in the market. The HHI ranges from 1/N to 1.

A small HHI indicates a highly competitive (unconcentrated) market, while a high HHI indicates a high market concentration.

5.10.2.3 Residual Supply Index or Pivotal Supplier Indicator

Another well-known indicator to measure market concentration is the RSI, also known as the Pivotal Supplier Indicator, which also considers potential imports. The RSI measures how much capacity remains in the market, when one provider retains its capacity:

$$RSI = \frac{Total\ Supply - Largest\ Seller's\ Supply}{Total\ Demand}$$

where s_*i* is the market share of company I in the market and *N* is the total number of companies in the market. The HHI ranges from 1/N to 1. Cross-zonal contributions can in general be considered as follows:

$$Total\ supply = Total\ domestic\ supply\ capacity + Total\ net\ import$$

An RSI above 100 % indicates that sufficient capacity remains in the market to meet the demand. An RSI below 100 % indicates that the remaining capacity does not meet the demand.

The total demand will be considered as the maximum residual load (i. e. substracting wind and PV infeed from the total demand) of a bidding zone. Since it is not possible to derive meaningful assumptions regarding the net import or export that could be considered for new bidding zone borders for which no historical import and export values are available, the quantitative analysis will neglect these. Yet, consideration of net imports would lead to decreased domestic market concentration, while consideration of net exports would lead to increased domestic market concentration.

5.10.3 ASSESSMENT OF 'MARKET CONCENTRATION AND MARKET POWER'

5.10.3.1 Calculation of market power indicators

In accordance with the formula and assumptions described in section 5.10.2, Table 5.12 summarises the changes of indicators for each scenario independently. The impacts for the alternative bidding zone configuration are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo). Although these are 'well-known' indicators that are often applied in practice and literature, the interpretation of the exact values of the indicators is not clearly defined. For instance, there are different understandings in the academic literature of the thresholds for the definition of a concentrated or highly concentrated market.

As already discussed in section 5.10.2, these indicators will be labelled as market power indicators, although it is worthwhile mentioning that these indicators focus on market concentration and will be used as a proxy for market power. However, it should be noted that even in the event of both indicators showing increased market concentration, it is not clear to what extent this would materialise in reality.

	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
SOAF 2025 planned				
Change of HHI per concerned bidding zone	DE: +25% AT: +370%	DE_N: +76% DE_S: +119% F_N: -0.6% F_S: +0.7% PL_N: see explanation below PL_S: see explanation below	DE_N: +206% DE_West: +261% DE_S: +119% F_N: -0.6% F_C: +5.2% F_S: -4.9% PL_N: see explanation below PL_S: see explanation below	BE & NL: see explanation below CZ & SK: - 29% (compared to SK) - 73% (compared to CZ)
Change of RSI* per concerned bidding zone	DE: -12% AT: +3%	DE_N: -7% DE_S: -31% F_N: -13.3% F_S: +11.3% PL_N: see explanation below PL_S: see explanation below	DE_N: -19% DE_West: -25% DE_S: -31% F_N: -13.3% F_C: -4.4% F_S: +31.2% PL_N: see explanation below PL_S: see explanation below	BE & NL: see explanation below CZ & SK: +35% (compared to SK) +59% (compared to CZ)
SOAF 2020 worst				
Change of HHI per concerned bidding zone	DE: +24% AT: +377%	DE_N: +80% DE_S: +102% F_N: -1.4% F_S: +1.2% PL_N: see explanation below PL_S: see explanation below	DE_N: +157% DE_West: +329 % DE_S: +102% F_N: -1.4% F_C: +6.1% F_S: -4.6% PL_N: see explanation below PL_S: see explanation below	BE & NL: see explanation below CZ & SK: -21% (compared to SK) -40% (compared to CZ)
Change of RSI* per concerned bidding zone	DE: -10% AT: -6%	DE_N: -10% DE_S: -25% F_N: -8.3% F_S: +7.5% PL_N: see explanation below PL_S: see explanation below	DE_N: -17% DE_West: -30% DE_S: -25% F_N: -8.3% F_C: -13.2% F_S: +34.3% PL_N: see explanation below PL_S: see explanation below	BE & NL: see explanation below CZ & SK: +63% (compared to SK) +60% (compared to CZ)

*Since it is not possible to take reasonable assumptions for net imports/exports at new bidding zone borders, the RSI is calculated without considering potential cross-zonal contributions.

Table 5.12: Calculated market power indicators

An increase of the HHI indicates increased market concentration, and a decrease of the RSI also indicates increased market concentration. For Germany and Austria, both indicators indicate increased market concentration and, therefore, increased market power. The French market is already concentrated in the Status Quo configuration, thus the variations of HHI are not significant and do not show a clear pattern. For the Big Country Split configuration, HHI and RSI give contradictory tendencies. For the Big Country Split 2 configuration, the FR_Centre zone would be more concentrated and the FR_South less concentrated, but markets still remain concentrated overall.

A splitting of Poland will most likely not impact market power in Polish bidding zones significantly – especially when considering cross-zonal contributions.

For the merge configuration, the evolution of market power would vary depending on the respective consolidation of market shares on both sides of the border and the resultant commercial reaction. Nothing can be said for certain, since global indexes per country/BZ area do not capture aspects such as generation technology-based strategies, nor portfolio strategy impacts in a cross-zonal environment. General economic theory asserts that larger markets mean lower market power problems. In practice, and considering that this market power could be exercised in different time frames (larger markets may need more redispatch, and this one is, by definition, local) the effects are unclear.

For the configuration 'Small Country Merge'– in this case, specifically of CZ & SK – it is clear that merging two smaller bidding zones into one will result in reduced market concentration. The results of the calculation of both indicators show that the situation in the market would be better, and even much better, comparing the merged market to the single Czech market.

Qualitative assessment of the impacts on 'market concentration and market power'

As already discussed in the previous section, the measurement of market power is more difficult since it requires competition modules to be incorporated in the modelling. Thus, in addition to the market concentration indicators (as a proxy for market power), market power, in alternative bidding zone configurations, will be assessed qualitatively.

In general, one could argue that the incentives to manipulate market prices due to location effects, i. e. lack or reduced offer from resources that are critical for the reliable operation of the system, depend on the size of the market. Smaller market areas with fewer market participants are likely to increase the possibilities for the abuse of market power.

Yet, the 'size' of a bidding zone cannot be measured in one value, as it has several dimensions and is characterised by several factors, mainly by the structure of the plant park (inc. RES), the level of cross-zonal capacities, the level of demand flexibility and the location of the participants. All of this has to be considered when it comes to the assessment of a change in the 'size' of a bidding zone and its meaning for a change in market concentration and power.

Relevance of the structure of a plant park

The energy mix has high relevance for the possibility of abuse of market power. The more decentralised / distributed the generation, the lower the market concentration and, thus, the lower the possibilities for an abuse of market power.

Relevance of the level of cross-zonal interconnection

A low level of cross-zonal interconnection of a bidding zone with its neighbouring bidding zones might increase the risk market power for domestic plant owners, as the level of competition 'from abroad' is lower.

Conversely, if a bidding zone split allows to significantly increase cross-zonal capacities, it has the potential to reduce the market power of domestic companies.

Relevance of the level of demand flexibility (demand side management)

Although electricity demand is usually considered inflexible, this will most likely change in future. An increased level of demand-side management and an increased share of storage might be beneficial with regard to market power.

Relevance of the location of market participants

Market concentration – and, respectively, market power – is not only linked to day-ahead markets but also to other market segments. While the intraday and balancing time segments are typically organised as markets, some countries in Europe also organise redispatch procurement in the form of markets. Yet, for some countries, redispatch cannot be procured via markets, as the redispatch is dominated by a few generators that are located at the 'right' locations in the country in order to resolve congestion. For instance, this is the case for Germany. A splitting of the bidding zone at the day-ahead (and timely following) markets would make this market concentration more visible. Yet, it has to be noted that the market concentration is not created by the splitting itself.

High market concentration indicates potential market power, but the abuse of market power is controlled by the relevant regulating authorities

Whether market concentration exists in European markets or whether existing market power is abused is controlled by several European and national authorities. These authorities control, for instance, whether the merge of two companies could create or strengthen a market-dominating position or whether existing market power is abused in order to impact market prices. Therefore, market concentration, market power and the abuse of market power are interlinked, but to have a high concentration in a market does not mean, per se, that market power is abused. In the event of an adaptation, the relevant European and national monitoring bodies should carefully review the potential impacts with regard to market concentration and power.

5.10.3.2 Summarised assessment of 'market concentration and market power'

Table 5.13 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'market concentration and market power'. The impacts for the alternative bidding zone configurations are not assessed on a standalone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Here, a minus indicates a higher market concentration compared to the current bidding zone configuration. For the DE/AT Split, the market concentration in the Austrian market would especially increase since the number of market participants/generators would decrease significantly. For the Big Country Split and Big Country Split 2, a significant increase of the market concentration is expected for DE_S. While the main generation centres are currently already located in the north and west of Germany, the nuclear phaseout will lead to a further decrease of generating units and, therefore, market participants in the south of Germany. In the event of the Small Country Merge, it is expected that the number of market participants would increase, therefore lowering the market concentration.

As already mentioned, before the adaptation of bidding zones, their impacts on market concentration and power should be checked by the competent authorities.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Market concentration and market power	(-)	(-)	(-)	(+)

Table 5.13: Specific assessment of market concentration and market power

5.11 CACM CRITERION 'EFFECTIVE COMPETITION'

5.11.1 DESCRIPTION AND UNDERSTANDING OF 'EFFECTIVE COMPETITION'

CACM Article 1(b) (ii): *market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power,* ***the facilitation of effective competition****, price signals for building infrastructure, the accuracy and robustness of price signals*

The classical economic definition of a workable competitive market considers that enough companies compete to produce the same product such that no single company is able to raise prices significantly above the system marginal cost for a sustained time period.

While the four aspects of market liquidity, market concentration, market power and price signals are strongly interrelated, the facilitation of effective competition seems to combine these aspects. High market liquidity, low market concentration and low market power combined with robust price signals are preconditions for effective market competition. Hence, the facilitation of effective competition in markets should be assessed in a qualitative, rather than quantitative, way.

Besides competition between suppliers and between consumers, there is also competition for access to grid infrastructure between all market participants, especially the capability of market participants to compete for scarce grid elements on a level playing field..

5.11.2 EVALUATION APPROACH FOR 'EFFECTIVE COMPETITION'

The impact of alternative bidding zone configurations on effective competition will be based on the identification and discussion of fundamental principles/inter-relations.

5.11.3 ASSESSMENT OF 'EFFECTIVE COMPETITION'

5.11.3.1 Qualitative assessment of impacts on 'effective competition'

A change in the existing bidding zone configuration may have a significant impact on the wholesale market prices, which may have a significant impact on the retail and end-consumer prices as an inevitable consequence. Retailers may have to change their business processes or even their business strategies, which will consequently result in new (hedging) products and in procurement that is more complex. Furthermore, traders with less experience in cross-zonal trade (such as small companies without their own generation assets) and who are currently focused on trades within a bidding zone, will especially suffer if a market area is split. Finally, the entry barriers for traders would be increased by a split.

Trades through OTC contracts will have to be complemented by the necessary number of capacity rights on the relevant borders, thus increasing the effort required by companies.

On the other hand, effective competition may increase in the case of smaller bidding zones with the consequent increase of bidding zone borders. Cross-zonal competition would be enhanced, which in larger zones is limited on borders where cross-zonal capacities are loaded by flows resulting from internal transactions (which have priority over cross-zonal transactions). Considering that in the target model – which is single price coupling for the EU – all short-term cross-zonal trade is to be managed via power exchanges, more bidding zone borders may result in more competitive trade instead of OTC trade. This could be especially valid for vertically integrated companies. When a new border is implemented and this results in the splitting of a vertically integrated company, this company needs to trade via power exchanges (before splitting, this company would trade OTC inside the company without any competitors).

It is possible to shift certain elements like liquidity, market power and concentration from the forward and day-ahead markets to the redispatch (market) and vice versa. For example, one might have a regulated redispatching (without any market liquidity) in favour of a more liquid spot and long-term market.

The priorities of market segments, i.e. potential shifts of visible market concentration between the different market segments, are not linked to technical arguments, but are more a question of the market design and the acceptable/desirable distributional impacts. For example, if there was a high market power concentration in redispatch, the liquidity in forward and day-ahead markets is of great importance, and thus a split could be counterproductive by reducing the liquidity here. On the other hand, the introduction of an additional border could also lead to less redispatch and, therefore, to lower total system costs (incl. redispatch costs). For a split market area, the market concentration would be moved from redispatch to the day-ahead market, which would, through this, have a different prioritisation.

To compensate for effects arising from market power, monitoring and regulation are key. This leads to the question of whether a regulated spot or a regulated redispatch market is the lesser evil. Today, the incentives for future grid investments are spot (forward) market driven.

Retailers currently compete on markets at a national level, with the exception of the Nordic markets. If countries are to be split into several smaller bidding zones, then these countries will have geographically differentiated prices in cases of congestion/limited cross-zonal capacities. This will lead to new balancing of responsible entities, new contracts and new risks due to different imbalance settlements. Because the situation might change every three years (due to the technical and market reports that need to be prepared every three years), the retailers will additionally lose their ability to plan and monitor. This risk will be passed on to the end consumer, resulting in lower transparency, higher complexity and increased market entry barriers, and ultimately harming effective competition and leading to higher end-consumer prices.

5.11.3.2 Summarised assessment of 'effective competition'

Table 5.14 provides the summarised assessment of the potential impacts of a changed bidding zone configurations with regard to the CACM criterion 'effective competition'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Effective competition	(0)	(0)	(0)	(0)

Table 5.14: Specific assessment of effective competition

5.12 CACM CRITERION ‘PRICE SIGNALS FOR BUILDING INFRASTRUCTURE’

5.12.1 DESCRIPTION AND UNDERSTANDING OF ‘PRICE SIGNALS FOR BUILDING INFRASTRUCTURE’

CACM Article 1(b) (ii) requires an assessment of: *market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power, the facilitation of effective competition,* ***price signals for building infrastructure****, the accuracy and robustness of price signals*

In Art. 33 CACM, price signals are referred to twice, namely as ‘price signals for building infrastructure’ (this section) and ‘accuracy and robustness of price signals’ (cf. the next section, 5.13). Art 33. CACM does not clarify whether ‘infrastructure’ refers to investments in generation/demand only or investments in network infrastructure. For the purpose of this report, infrastructure is interpreted as transmission grid infrastructure. Price signals for generation/demand will be discussed in the next section, 5.13.

With respect to price signals for building network infrastructure, a distinction between internal and cross-zonal lines needs to be drawn.

For internal lines, it is worth discussing whether actual ‘real world’ price signals (i.e. signals based on actual market results) are necessary to deliver information on the efficiency of potential grid expansion projects. Internal grid infrastructure investments are widely regulated and hence usually do not depend on market price signals, as a copper plate is assumed internally. There are different national regulation schemes related to grid investments across Europe where investments are normally regulated/approved by the NRAs. It is the nature of such regulated investments that they do not depend on revenue streams that stem from markets/market prices.

Price signals for building cross-zonal lines are understood as price differences between neighbouring zones. The higher the price difference, the better the price signals for building a new interconnector. Although price signals play a key role for a decision on such grid investment, other aspects such as increased/decreased system security need to be considered as well. Furthermore, the robustness of such price signals should be verified, as a new interconnector is perceived as a long-term investment.

Hence, price signals are perceived as more relevant for cross-zonal investments. However, to some extent, internal lines also may influence cross-zonal capacity in both NTC and flow-based environments. In NTC calculations, the first overloaded element when an increase of the net position of a given bidding zone is simulated may not necessarily be a cross-zonal one. In the flow-based approach, prices, and consequently price differences, result from an active constraint of an element which is on a list of CNEC. By definition, the CNEC list consists of grid elements which are relevant for cross-zonal exchanges (not necessarily only cross-zonal elements). Thus, price signals may also work for internal lines in cases where they are relevant for cross-zonal exchanges.

5.12.2 EVALUATION APPROACH FOR ‘PRICE SIGNALS FOR BUILDING INFRASTRUCTURE’

The assessment of a changed bidding zone configuration on the ability of prices to serve as a signal for building infrastructure is based on the identification and discussion of fundamental principles/inter-relations.

5.12.3 ASSESSMENT OF ‘PRICE SIGNALS FOR BUILDING INFRASTRUCTURE’

5.12.3.1 Qualitative assessment of impacts on ‘price signals for building infrastructure’

Accurate price signals guide efficient short-term utilisation and long-term development of the power system

An optimal bidding zone configuration should promote accurate price signals for the efficient short-term utilisation and long-term development of the power system. Accurate short-term price signals reflecting demand, supply and power system conditions (including technical as well as financial constraints) and, consequently, price differences between bidding zones encourage the efficient use of cross-zonal capacity. On the other hand, accurate and robust long-term price signals may show a required cross-zonal network development.

The more accurate prices reflect market conditions and the restrictions of the underlying grid, and the better prices will be able to guide market participants in efficiently utilising the power system in the short-term (e.g. dispatch reflects important grid constraints) and to develop the power system in the long-term (e.g. grid enhancement to increase transmission capacities). On the other hand, real day-ahead market prices reflect the current market situations. This does not coincide with lead times for onshore grid enhancements which are typically around a decade.[30] Even future products offered at power exchanges do not reach this maturity and such long term products tend to be less liquid and hence less representative.[31] Therefore, even though real market prices provide locational information of current market needs for grid infrastructure, verifying the long-term robustness of such information before a decision to start such a long-term investment is difficult if not impossible. The lack of robustness of information on current (real) market prices could even be counterproductive. A short-term price signal for 'no investment' which changes into a price signal for 'investment' in the long term could prevent a short-term decision to build grid infrastructure even though it is necessary in the long term.

5.12.3.2 Summarised assessment of impacts on 'price signals for building infrastructure'

Table 5.15 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'price signals for building infrastructure'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Assuming that the splitting is effective, i.e. placed where major congestions occur and cross-zonal constraints are active resulting in price differences, such splitting provides more short term price signals for building long-term network infrastructure which is relevant for cross-zonal exchange.

However, the long lead time (long construction period and approval processes) which is relevant for the grid investment decision-making does not coincide with the time period for which market time signals are provided. Therefore, even though price signals exist, they provide only partial information in this context (high differences in day-ahead prices can serve as a first indication for a new grid investment).

Furthermore, there are different approaches to grid development over Europe. TSOs build infrastructure not only because of price signals/differences, but also in order to solve congestions, increase operational security or enhance the single European market. It must be noted that TSOs are regulated, and decision on investments – although they may be supported by price signals – need to be approved by NRAs.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Price signals for building infrastructure	(0/+)*	(0/+)*	(0/+)*	(0/-)*

* importance differs between borders/countries and the effectiveness of the signal is low, given the incompatible lead times between market prices and grid investment decisions which are characterised by long construction periods and approval processes.

Table 5.15: Specific assessment of impacts on price signals for building infrastructure

30) This is different for offshore DC cables which can be realised faster.

31) Further details can be found on websites of relevant power exchanges where time horizons (max. five years lead time) and traded volumes are published.

5.13 CACM CRITERION 'ACCURACY AND ROBUSTNESS OF PRICE SIGNALS'

5.13.1 DESCRIPTION AND UNDERSTANDING OF 'ACCURACY AND ROBUSTNESS OF PRICE SIGNALS'

CACM Article 1(b) (ii) requires an assessment of: *market efficiency, including, at least the cost of guaranteeing firmness of capacity, market liquidity, market concentration and market power, the facilitation of effective competition, price signals for building infrastructure, the* ***accuracy and robustness of price signals***

As already indicated in the previous section, accuracy and robustness of price signals are for the purpose of this analysis, interpreted as relevant for generation/demand. Price signals with regard to transmission infrastructure are discussed in the previous section 5.12.

An optimal bidding zone configuration should promote accurate and robust price signals for efficient short-term utilisation and long-term development of the power system. Accurate short-term price signals reflecting demand, supply and power system condition (including technical as well as financial constraints) and, consequently, price differences between bidding zones encourage efficient use, generation dispatch, generation flexibility and activation of demand-side response. On the other hand, accurate and robust long-term price signals may affect generation and load investment decisions.

In the following, the accuracy of price signals is understood as the ability of prices to reflect all relevant market and grid conditions. The more accurately prices reflect market conditions and the restrictions of the underlying grid, the better prices will be able to guide market participants in efficiently utilising the power system in the short term (e.g. dispatch reflects important grid constraints) and developing the power system in the long term (e.g. generation investments at locations that consider market conditions and existing grid constraints).

In contrast, the robustness of price signals refers in the following to the ability of prices to be stable. Especially in the context of the evaluation of alternative bidding zone configurations, the robustness/stability of price signals over time and over different scenarios is of high importance. In order to assess if an alternative bidding zone configuration is advantageous or not, price signals need to be as robust/stable as possible over time and over different scenarios. If not, e.g. if prices and especially price differences between bidding zones change significantly between different scenarios, this will impact the evaluation of the bidding zone configuration under assessment. In the worst case, the assessment of an alternative bidding zone configuration (compared to the Status Quo) will be different for every future scenario considered. Clearly, the robustness/stability of prices has a major impact on the predictability of future prices and also their variability, and is therefore a main factor considered by investors in their future investment decisions.

5.13.2 EVALUATION APPROACH FOR 'ACCURACY AND ROBUSTNESS OF PRICE SIGNALS'

The assessment of a changed bidding zone configuration on the accuracy and robustness of price signals will be based on the identification and discussion of fundamental principles/interrelations.

5.13.3 ASSESSMENT OF 'ACCURACY AND ROBUSTNESS OF PRICE SIGNALS'

5.13.3.1 Qualitative assessment of impacts on 'accuracy and robustness of price signals'

Robustness of price signals is especially important for the long-term development of the power system

Price signals have to be robust/stable over time in order to provide appropriate incentives for investments, e.g. for generation. If not, e.g. if prices, and especially price differences between bidding zones, change significantly between different scenarios, this will impact the evaluation of the bidding zone configuration under assessment. In the worst case, the assessment of an alternative bidding zone configuration (compared to the Status Quo) will be different for every future scenario considered. Robustness of price signals is strongly interlinked to the sensitivity of prices (see next aspect).

High sensitivity of prices decreases the robustness of price signals

In order to assess the robustness of prices, the sensitivity of prices has to be verified and, more importantly, sensitivity has to be distinguished from the volatility of prices. Prices can be described as being sensitive in cases of minor changes in the framework parameters or variants heavily influencing the corresponding market prices. In addition, if a significant change in the price cannot be reasoned properly with any fundamental fact, the price signals of the respective bidding zone configuration are not robust. In small bidding zones, prices tend to be more sensitive to changes in the underlying system, such as a new power plant installation, more demand-side response or additional transmission capacities. Assuming limited cross-zonal transmission capacities, the robustness of the price is then affected.

In contrast, the volatility of prices refers specifically to price fluctuations, which is neither good nor bad as it could, e.g. just reflect seasonal or time patterns (e.g. during the day). Compared to other commodity prices, electricity prices are particularly volatile due to the fact that electricity is not storable (on a large-scale) and therefore needs continuous balancing. In addition, electricity is also grid-bound, and its transportation is subject to different physical laws.

Prices reflecting structural congestions might increase economic incentives for investments in generation and demand side response

Pricing scarce transmission capacity (according to structural congestion) in the markets might incentivise investments in generation and demand-side response in the high-price market zones (i.e. zones with scarce generation and import capacity) in the long term. Yet, although prices are an important factor for an investment decision, there are several more aspects which are of very high relevance (as described in the following). With respect to price signals for generation infrastructure – in the energy only market – it is understood that price signals should reflect system scarcity i.e. price signals at high-price peaks in general provide incentives to investors to build new generation capacities (or to not mothball existing generation capacities). Furthermore, in cases of scarce transmission capacities, price signals (especially price differences between zones) should indicate which bidding zone requires additional generation. If the price peaks are high enough, there may also be an incentive to develop a demand-side response in a given location.

Predictability of prices is an important decision factor for investors

Besides the expected price level, its predictability is also of high relevance for an investment decision. For instance, if an investment has a positive expected net present value because one expects very high market prices but only for a few hours a year, an investor will want to ensure that the forecast of such price spikes is sufficiently stable to base an investment decision on it. However, it has to be noted that the volatility of prices is not good or bad in itself, since high price volatility can also mean greater opportunities (and risks) for investors. Yet, it is likely that investors will ask for a sufficiently reliable forecast of prices – and, respectively, of price differences – which is, especially in highly interconnected markets with high variable RES share, more challenging than in the past.

Political risk is an important decision factor for investors which cannot be influenced by adapted bidding zones

The CACM foresees the regular review of the efficiency of bidding zones. Every three years, ACER has to prepare a market report while requiring ENTSO-E to prepare a technical report that considers a geographical area defined by ACER. If one of the reports indicates inefficiencies, a full Bidding Zone Review is likely to be initiated. The final decision (considering the recommendation from TSOs) will be taken by Member States. Hence, the bidding zone configuration can be adapted every three years. Yet, the bidding zone configuration has a high impact on the corresponding market prices, which are an important decision factor for investors. The potential regular adaptation of bidding zones represents a very high risk for investors, which is difficult to estimate. The risk of stranded investments or plants which are in a new bidding zone configuration no longer 'in money' is high. In order to mitigate this risk, investors will require very high return rates for potential investments in new generation capacities, if they are willing to take the risk of a misinvestment at all.

Pricing scarce transmission capacity in the day-ahead market might incentivise demand side response in the long-term

Pricing scarce transmission capacity in the day-ahead market (according to structural congestion) might incentivise consumers to increase their demand in bidding zones with excess supply, as well as lowering electricity prices and decreasing their demand in market zones with scarce generation and import capacity. However, for the efficiency of DSR investments, it is crucial that prices are not capped but can increase to the value of lost load (in times of scarcity). Another important aspect in this context is the idea of the aggregation of prices for demand, as actually implemented in Italy. An important driver for such an aggregation is to avoid politically undesirable distributional impacts of more regional prices for consumers. However, load-weighted average prices could counteract the development of demand response.

5.13.3.2 Summarised assessment of impacts on 'accuracy and robustness of price signals'

Table 5.16 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'accuracy and robustness of price signals'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

There is a trade-off between spatial precision of prices (i.e. high enough price peaks reflecting system scarcity) on the one hand and their stability and predictability on the other hand. By definition, smaller zones may sharpen price peaks; however, bigger zones may increase the long-term predictability of the average level of prices. In the discussion on the definition of an appropriate bidding zone structure, there is no unanimously shared answer from the involved stakeholders regarding the question as to which of these properties deserves preference when it comes to assessing the effectiveness and efficiency of investment incentives.

Moreover, there are other factors that influence decisions on generation/or Demand-Side response (DSR) investments. For instance, while for the demand-side response the adequate price signals may be a key factor, for investments in conventional power plants, the grid connection and the fuel delivery also play an important role.

It must be noted that, in the context of the First Edition of the Bidding Zone Review, prices refer mainly to day-ahead market prices. OTC trading is not considered explicitly. The impact of prices on forward, intraday and balancing markets are considered to the extent possible.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Accuracy and robustness of price signals	(0)	(0)	(0)	(0)

Table 5.16: Specific assessment of impacts on accuracy and robustness of price signals

5.14 STAKEHOLDER CRITERION 'LONG-TERM HEDGING'

5.14.1 DESCRIPTION AND UNDERSTANDING OF 'LONG-TERM HEDGING'

The aspect of long-term hedging is not part of Article 33 of the CACM Network Code, where the evaluation criteria for the assessment of the bidding zone configurations are listed. However, stakeholders are strongly recommended to consider this aspect.

Generally speaking, there are well-functioning day-ahead markets and financial markets in the countries considered in this Bidding Zone Review. The financial markets seem to be liquid and to provide ample hedging opportunities for consumption as well as for production. Participants in these markets can hedge their price risks by selling or buying local financial contracts, or may create their own cross-zonal hedges using the existing local financial markets.

If local financial markets are immature or do not exist, long-term transmission rights (LTRs) add hedging possibilities by providing a bridge to liquidity in adjacent markets. If one side of a border represents an inefficient market or a market heavily dominated by one large utility, LTRs can be used to establish a hedge for new entrants.

Against this background, Article 30 of the FCA Network Code states:

Article 30
Decision on cross-zonal risk hedging opportunities

1. *TSOs on a bidding zone border shall issue long-term transmission rights unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border. […]*

2. *Where long-term transmission rights do not exist on a bidding zone border at the entry into force of this Regulation, the competent regulatory authorities of the bidding zone border shall adopt coordinated decisions on the introduction of long-term transmission rights no later than six months after the entry into force of this Regulation.*

3. *The decisions pursuant to paragraphs 1 and 2 shall be based on an assessment, which shall identify whether the electricity forward market provides sufficient hedging opportunities in the concerned bidding zones. The assessment shall be carried out in a coordinated manner by the competent regulatory authorities of the bidding zone border and shall include at least:*

   (a) a consultation with market participants about their needs for cross-zonal risk hedging opportunities on the concerned bidding zone borders;

   (b) an evaluation.

4. *The evaluation referred to in paragraph 3(b) shall investigate the functioning of wholesale electricity markets and shall be based on transparent criteria which include at least:*

   (a) an analysis of whether the products or combination of products offered on forward markets represent a hedge against the volatility of the day-ahead price of the concerned bidding zone. Such product or combination of products shall be considered as an appropriate hedge against the risk of change of the day-ahead price of the concerned bidding zone where there is a sufficient correlation between the day-ahead price of the concerned bidding zone and the underlying price against which the product or combination of products are settled;

   (b) an analysis of whether the products or combination of products offered on forward markets are efficient. For this purpose, at least the following indicators shall be assessed: (i) trading horizon; (ii) bid-ask spread; (iii) traded volumes in relation to physical consumption; (iv) open interest in relation to physical consumption.

5. *In case the assessment referred to in paragraph 3 shows that there are insufficient hedging opportunities in one or more bidding zones, the competent regulatory authorities shall request the relevant TSOs: (a) to issue long-term transmission rights; or (b) to make sure that other long-term cross-zonal hedging products are made available to support the functioning of wholesale electricity markets.*

This article requires that for each new bidding zone border, TSOs will have to offer long-term transmission rights, unless otherwise decided by NRAs, in cases where the electricity forward market already provides sufficient hedging opportunities in the concerned bidding zones. As such, it is ensured that even with a reconfiguration of bidding zones, market parties will have proper hedging possibilities.

The aspect of hedging is actually a question of market design to be implemented within the new bidding zone and on bidding zone borders. Given the precondition that e.g. an intra-German split will not lead to bidding zones with different market designs (as this is, regardless, determined in a harmonised way within the capacity calculation regions), a bidding zone reconfiguration will not have an impact on this.

5.14.2 EVALUATION APPROACH FOR 'LONG-TERM HEDGING'

For each new bidding zone border, TSOs will have to offer long-term transmission rights unless otherwise decided by NRAs, in cases where the electricity forward market already provides sufficient hedging opportunities in the concerned bidding zones. An analysis on whether there are already sufficient hedging opportunities shall, as such, be made by the NRAs and is not part of this bidding zone review. This analysis requires an in-depth assessment of the concerned markets and would as such be a study on its own.

5.14.3 ASSESSMENT OF 'LONG-TERM HEDGING'

5.14.3.1 Qualitative assessment of impacts on 'long-term hedging'

The introduction of a new bidding zone border does not per se reduce or improve the possibilities for long-term hedging. This is because if there is a need for hedging which cannot be solved within the markets of the new bidding zones, the TSOs will have to offer cross-zonal long-term rights.

The assessment of whether a reconfiguration of bidding zones leads to a situation in which the electricity forward market does not provide sufficient hedging opportunities in the concerned bidding zones will be made by the NRAs of the concerned bidding zones (according to Article 30 of the FCA Network Code). As such, the default option would be that TSOs offer long-term rights on new bidding zone borders unless otherwise decided by NRAs.

However, clearly, any bidding zone split means an additional border for which hedging products need to be traded. A new bidding zone border with constrained cross-zonal capacity will yield a higher risk for market participants and will therefore increase the costs for hedging.

New hedging instruments that might mitigate this negative impact have to be investigated. Yet, this goes beyond the scope of this study.

5.14.3.2 Summarised assessment of impacts on 'long-term hedging'

Table 5.17 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'long-term hedging[32]'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

32) This is not required by CACM but was a stakeholder requirement.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Long-term hedging	(-)*	(-)*	(-)*	(+)

* Alternative long-term hedging instruments (such as system price or trading hubs) that might mitigate the negative impact are to be investigated.

Table 5.17: Specific assessment of impacts on long-term hedging

5.15 CACM CRITERION 'TRANSITION AND TRANSACTION COSTS'

5.15.1 DESCRIPTION AND UNDERSTANDING OF 'TRANSITION AND TRANSACTION COSTS'

CACM Article 1(b) (iii): *transaction and transition costs, including the cost of amending existing contractual obligations incurred by market participants, NEMOs and TSOs*

Transition and transaction costs follow an adjustment of a bidding zone configuration. In the following, transition costs are understood as the 'one-time' costs directly related to a configuration change (e.g. required IT investments due to market changes or maybe also stranded investments or assets due to price changes or costs for rearranging established trade deals between market participants which are no longer executable due to a change in the bidding zone delimitation). Since the level of transition costs can depend on the time span since the new configuration comes into effect (lead time), for this study, it has been decided that all the transition cost estimates will be reported for an estimated lead time of four years.

In contrast, transaction costs generally refer to the costs of participating in the market. They are permanent costs for search and information, bargaining, policing and enforcement. Transaction costs are, to some extent, specific to a given bidding zone configuration. For the purposes of the bidding zone review, only the difference of transactions costs between bidding zone configurations is relevant. The report takes the current bidding zone configuration as a reference point and refers only to the (permanent) increase or decrease of transaction costs that are expected due to the new configuration.

5.15.2 EVALUATION APPROACH FOR 'TRANSITION AND TRANSACTION COSTS'

The type of such costs as well as their level varies largely among different actors affected by a reconfiguration. This variety makes the quantification of the aggregated costs particularly challenging. To overcome this challenge, stakeholders have been given the opportunity to report their cost range estimates for different scenarios. Their cost estimates and replies will be used to evaluate the associated impact of different bidding zone configurations in the following. The stakeholder survey will be accompanied by the identification and discussion of fundamental principles/interrelations.

Stakeholder survey on transition and transaction costs

The stakeholder survey, as well as the received feedback from stakeholders, can be found in the Annex. Table 5.18 on pages 77 and 78 gives an overview of the relevant actors and respective cost categories and lists some examples for different cost positions that have been provided to the stakeholders and TSOs. The outcome of the survey and the respective assessment can be found in section 5.15.3.1. While table 5.18 already lists some cost categories and was included in this form in the survey, section 5.15.3.1. includes a second table which complements this (in a non-exhaustive manner) and gives an overview of the necessary adjustments linked to a bidding zone adaptation.

5.15.3 ASSESSMENT OF 'TRANSITION AND TRANSACTION COSTS'

5.15.3.1 Outcome of the stakeholder survey on transition and transaction costs

Cost ranges for transition and transaction costs

No stakeholder provided specific estimations for the transition and transaction costs arising from a change of the current bidding zone configuration for the entire relevant sector. One stakeholder specifically stated that he is not capable of delivering such estimates due to the high uncertainties and the complexity of the changes caused by an adaptation of the bidding zone configuration and the high uncertainties. However, all stakeholders delivered qualitative arguments which are summarised in the next section. For the same reasons (high complexity of adaptation and uncertainty), TSOs were not able to provide a reliable estimation of such costs in euros. Therefore, in the following section, an overview of the necessary changes on the TSOs' side is provided. Yet, in the Nordic countries, TSOs are obliged to be able to change the bidding zone configuration and therefore need to estimate costs. Energienetdk estimates the total costs related to a change on their individual side as rather low. However, it has to be noted that the system and the market design in Scandinavia is much more flexible than that of continental Europe. While a change of the configuration in the Nordic market would mean changing some settings in the operational planning system, the number of necessary changes in continental Europe would be far higher (see the following section). Further reasons for lower costs are the less complex market coupling mechanism in the Nordics (i.e. no flow-based market coupling) and the fact that the Nordic markets are designed as a pool market, which means that the clearing of any trades has to be done at the power exchanges (mandatory).

Adjustments in	With regard to adaptation of	Explanation/Examples (not exhaustive)
Governmental institutions (including regulating authorities)	Legal design	– Adjustments of RES support scheme might be necessary if the scheme is related to a bidding zone configuration or to a reference price, that is/are no longer valid – The argument above also holds for other support schemes based on a market price as reference price – Risk of legal and court costs
	General remarks	...
Producing companies (including RES)	Organisational	– Resizing of teams
	Operational and IT	– Adaptation to new markets creates learning costs (e. g. trading and valuation) – Temporary loss of efficiency – Adjusting IT processes and implementation of new ones – Additional costs of market observation (working hours, travel expenses)
	Contracts and financial procurements	– Adaptation of bilateral agreements – Increasing cost of hedging with decreasing market liquidity – Costs related to market participation (e. g. exchange fees/charges and registration costs for participating in organised markets in each bidding zone) – New valuation of existing contracts/positions
	General remarks	– Stranded costs or windfall profits (resulting from the increase or decrease of energy market revenues). Stranded costs might be even higher for countries without government guarantees or CRMs for conventional power plants and third party merchant transmission lines in place. – Further opportunity costs (costs related to postponing projects, e. g. due to the tie-up of working resources) – Regulatory risks faced by investors(e.g. when bidding zone configuration is likely to be revised periodically)
Trading companies and institutions (including banks)	Organisational	...
	Operational and IT	– Restructuring of activities – Costs related to market participation (e. g. exchange fees/charges and registration costs for participating in organised markets in each bidding zone) – Learning costs (new trading and valuation tools) – Temporary loss of efficiency – Increasing cost of hedging with decreasing market liquidity
	Contracts and financial procurements	– New valuation of existing contracts/positions (not restricted to market participants in the affected bidding zone, if market participants outside the bidding zone used the market price as their respective reference price) – Negotiation/adaptation of new contracts
	General remarks	– Opportunity costs (costs related to postponing projects, e. g. due to the tie-up of working resources)

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Adjustments in	With regard to adaptation of	Explanation/Examples (not exhaustive)
TSOs	Organisational	– Resizing of teams
	Operational and IT	– Learning costs (new evaluation tools)
	Contracts and financial procurements	– Costs for adaptation of existing contracts
	General remarks	– Costs associated with re-calculation of tariffs and RES levies
DSOs	Organisational	– Resizing of teams
	Operational and IT	– Learning costs (new evaluation tools)
	Contracts and financial procurements	...
	General remarks	– Costs associated with re-calculation of tariffs and RES-levies
Electricity exchanges incl. clearing houses and OTC platforms (all together)	Organisational	...
	Operational and IT	– Adaptation of IT systems
	Contracts and financial procurements	– Costs for the adaptation of existing contracts referring to market price of adjusted bidding zone – Costs for new contract negotiation with market participants
	General remarks	...

Table 5.18: Categories and explanations (not exhaustive) as considered in the stakeholder survey on transition and transaction costs

More generally, stakeholders highlighted that experiences from market reconfigurations made in the past should be considered and that currently occurring costs during the pre-implementation phase of a potential splitting of Germany and Austria can provide further insights. Yet, given the fact that all split scenarios of the considered expert-based configurations cover the German market, the complexity and the related costs of such a reconfiguration are considered to be higher than in any previous case due to the fact that Germany is the most mature and liquid market in Europe; although one stakeholder stated that past experiences show significant costs. Another stakeholder, as a producer, estimated his individual costs for the Big Country Split and Big Country Split 2 in the range of billions of euros.

List of necessary adaptations in cases of bidding zone reconfigurations – completions by stakeholders and TSOs

Yet, as indicated by several stakeholders and TSOs in their replies, the estimation of transition and transaction costs is very difficult due to the high complexity of the changes related to a bidding zone reconfiguration. Concrete costs are unknown, since organisational details of the configurations are unknown. Producing concrete and more reliable estimate figures in euros would require a preliminary functional study (which is beyond the scope of the Bidding Zone Review). Hence, several stakeholders and TSOs provided an overview on the necessary adaptations which they consider as being relevant for transition and transaction costs. A summary of these (without a distinction between transition and transaction costs) is provided in Table 5.19. The following list complements (but not in an exhaustive manner) the list of necessary adaptations that has been provided to stakeholders in the survey and that is included as Table 5.18 in the previous section.

TSOs – Completion of list of necessary adaptations in cases of bidding zone reconfigurations	
Although most of the points in the following apply to all kinds of bidding zone reconfigurations, some of them are related to specific splits or specific countries. If so, this is made explicit. The list may not be exhaustive.	
Update of grid contracts	An adaptation of bidding zone areas in a manner meaning they no longer correspond to control zones would make an adaptation of all related grid contracts necessary. For instance, in Germany, there are currently more than 1000 contracts; splitting Germany would mean adapting/concluding a significantly high number of (new) contracts.
Grid tariffs	In the case of adapted bidding zones no longer corresponding to control zones, adaptations of the grid tariffs might be required. This also depends on whether harmonised tariffs are foreseen.
Scheduling systems	Since bidding areas correspond to scheduling areas, TSOs acting in several, e.g. two, bidding zones would need to oversee two different scheduling areas and thus all relevant processes linked to the calculation of scheduled exchanges resulting from intraday, day-ahead and year-ahead market coupling. Due to the fact that both market areas need to be treated separately, a second schedule management IT-system has to be implemented. This results in high IT- and human resource costs.
Settlement of balancing areas	The splitting of a national bidding zone as e.g. Germany into two bidding zones implicates changes with regard to the settlement process of balancing areas. Contracts need to be redrafted and adjusted to reflect new bidding zones. Balancing responsible parties (BRPs) acting in both market zones would need corresponding contracts in each bidding zone – including negotiations with suppliers on existing power supply contracts. Traders would now need to hedge their position between the new set of market zones, resulting in more trade transactions and, thus, costs. For the settlement process of balancing areas, IT systems and interfaces between market participants and TSOs in the market areas need to be adjusted (principles for implementation of market rules for balancing group settlement, also MABIS). If a bidding zone reconfiguration results in a change of control areas, this could lead to different prices for balancing service providers (BSPs) in both regions, thus impacting overall settlement process. Imbalance values cannot be settled as before and cause a high degree of complexity.
Update of the balancing management mechanisms/ processes	– Dimensioning and procurement need to be reorganised to fit the new size of the bidding zones. - Potentially higher costs of balancing from more costly/less efficient providers, e.g. for APG – The technical setup of the controllers need to be adapted in order to allow the balancing in the new bidding zone scheme, e.g. more than one bidding zone per load frequency control (LFC) area might need more than one controller per LFC area – Merging: • The political concept that is now also stated in the Clean Energy Package (CEP) is that within a bidding zone, the imbalance settlement price shall be the same. So, the imbalance settlement process needs to be adapted to allow for a common imbalance settlement in the new bidding zone region. From a TSO point of view, there is limited added value in extending existing LFC blocks/areas. It would require major changes in controller setup and additional monitoring. • Need to harmonise the regulatory regimes, so it may be the case that regulators from two or more countries need to agree on details of an imbalance settlement scheme. • If LFC areas/blocks are kept (i.e. do not correspond to bidding zones) this would require solutions in case of congestion between the new bidding zones. This might result in the procurement of core shares. – Splitting (of Germany): • Two balancing markets and processes would need to be organised. In addition to that, one might face some issues with available balancing reserves as, e.g. a north region with significant wind infeed and low prices in strong wind situations impacts the running of conventional power plants that might be needed in case of forecast errors. In such situations, prices for balancing capacities could be strongly increased to keep conventional plants running. • Even worse, operational security might result in must-run constraints for conventional power plants as dispatchable generation is required to ensure stable operation in an RES-dominated bidding zone. • Until the CEP comes into force, there might be the political requirement to keep a common imbalance price in Germany, which would make an additional process necessary to achieve this. • Balancing capacity costs will most likely increase as the cheapest of all German bids will no longer be accepted instead being the cheapest in each region. Therefore, there will be an efficiency loss. Balancing energy costs might also increase due to the split market liquidity. In the event of available cross-zonal capacity between the split zones, the balancing energy costs might not change in these situations.

Capacity calculation processes and cross-zonal trade/ Update of the allocation mechanism	Not only as a legal consequence, but also from a technical point of view, bidding zones need to be defined and transmission capacities between these bidding areas need to be allocated. With regard to the existing methods of the European market coupling, a new bidding zone would need to be translated in applied methods and processes. For the cross border capacity allocation for all time frames (intraday, day-ahead and long-term), the new bidding zone configuration needs to be included in the capacity calculation method and the market coupling algorithm. In addition, adaptations of system restoration and curtailment rules may be required. Furthermore, additional costs for auctioning are expected as the calculation of congestion rents will change and make adaptations in the allocation office (e. g. JAO) necessary. Another aspect is that more bidding zones will significantly increase the complexity of the calculations and of the coordination of remedial actions and computation times.
Renewable energy	Renewable infeed tariff – political decision required as to whether this shall still depend on market prices. (different tariff or harmonised tariff?) Calculation of renewable levy might have to be adjusted. Integration of RES might also be impacted by new imbalance prices.
Additional metering	There may also be a need for technical adaptations 'in the field' – e.g. measurements along the new border (new meters need to be put in place) in case the new border does not follow control areas.
Other processes	– TSO procurement of grid losses might also depend on market prices. For instance, German TSOs calculate and procure energy for one market area. With a split of Germany into north and south, the calculation and the procurement needs to be done separately for both market areas. This leads of course to a higher degree of costs for the overall process. – Training for employees whose activities are impacted by a new bidding zone configuration (operators, lawyers, economists, sales and marketing people, research & development [R&D]) – Increase of network studies (more sensitive elements) for planning and real-time operations, more (market) data in general to handle and more studies to analyse impacts due to the (partly temporary) increase of complexity – Increased costs for planned outages (more sensitive elements to consider in the planning) – Renewal of models and software for prospective studies and update of the grid management software – For TSOs, possible cost reimbursement for other market parties (power exchanges [PXs], ..)
Singular Responsibility	In the event that the split is not along existing control zones, the assignment of the responsible TSOs will be highly sensitive.
DSOs	Assignment of distribution system operators (DSOs) to bidding zones: In Germany, there are nearly 1 000 DSOs that have established working relations with the TSOs. Apart from the costs arising at the DSOs, the established TSO/DSO procedures may be affected by several bidding zones within Germany.

Stakeholders – Completion of list of necessary adaptations in cases of bidding zone reconfigurations	
Qualitative transaction costs	In the event that the split is not along existing control zones, the assignment of the responsible TSOs will be highly sensitive.
Distributional effects	Different market conditions and prices after a bidding zone split could result in market participants/consumers becoming winners while others will be losers (windfall profits/losses).

Table 5.19: Completion of the list for necessary adaptations in case of bidding zone reconfigurations as provided in the stakeholder survey – completion by stakeholders and TSOs

Qualitative feedback provided by stakeholders:

Changes in the configuration should be published to the market in due time prior to the change

Only in this way can players conduct the adjustments and preparations in an efficient way to the lowest possible costs. Stakeholders also highlighted the necessity to take the transition and transaction costs of all stakeholders and market players into account when it comes to the assessment of an adaptation of bidding zones.

Safeguarding the regulatory framework is important and the long term must also be considered

Stakeholders highlighted the importance of a stable regulatory framework, also with regard to the infrastructure investments. A balanced approach needs to consider the impacts in the short and long terms.

From an exchange point of view, large and liquid bidding zones create less costs than bidding zone spitting

This statement was provided by one stakeholder, who also highlighted the importance of liquidity in the context of transition and transaction costs. Yet, TSOs would like to add here that in the event of a merge of bidding zones, transition and transaction costs occur, for instance, due to the necessary adjustments and harmonisation of balancing mechanisms

5.15.3.2 Qualitative assessment of 'transition and transaction costs'

Changes to the current bidding zone configuration will require adaptations of the current market regulations to the new structure. Following the definition given in the previous section, it is distinguished between transition ('one time' costs directly related to a configuration change) and transaction costs (increase of permanent costs due to a configuration change) that follow an adjustment of a bidding zone configuration.

Market parties, power exchanges (including other market platforms) and TSOs will be mainly affected by adaptations to the current bidding zones. In addition, regulatory costs could be considered. Therefore, stakeholder consultation seems crucial in order to realistically estimate the volume and nature of transition costs for concrete bidding zone configurations. In addition to the outcome of the stakeholder survey (see previous section), the following general statements can be made.

A regular adaptation of bidding zones will increase transition and transaction costs

Market participants, TSOs and regulatory authorities need to adapt their processes, tools and existing contracts to the new bidding zone structure. Beside the costs of renegotiating contracts, the costs of IT developments to adapt tools for market price forecasting, cross-zonal capacity calculation and market coupling, as well as learning costs (as temporary loss of efficiency) for trading and valuation tools, especially on the side of market participants, have to be considered. Due to the high complexity of the European electricity markets, the adaptation of bidding zones will always require adaptations on a very detailed and complex level. For efficiency reasons, the adaptation of bidding zones should be restricted only to cases in which an adaptation clearly leads to an increase of overall efficiency, considering all related gains and losses, including transition and transaction costs.

The transition period is relevant for transition and transaction costs

The lead time for the reconfiguration of bidding zones should be aligned with the term structure of forward markets. Hence, the configuration should not be changed before three years after the announcement. However, the speed at which the adaptation to the new bidding zone structure has to be done will also impact the level of transition and transaction costs.

Transition and transaction costs depend on whether a reconfiguration of bidding zones considers LFC areas

In cases where the adapted bidding zones are not the same as LFC areas, the technical setup of the controllers needs to be adapted in order to allow balancing in the new bidding zone scheme, e.g. more than one bidding zone per LFC area might need more than one controller per LFC area. The related transition costs are difficult to assess beforehand, but they are considered to be significant. Thus, a reconfiguration of bidding zones along LFC areas would lead to lower transition and transaction costs (compared to a reconfiguration that does not consider LFC areas). Furthermore, a bidding zone reconfiguration will have an impact on the dimensioning and procurement of balancing reserves, which can be considered as transaction costs.

5.15.3.3 Summarised assessment of 'transition and transaction costs'

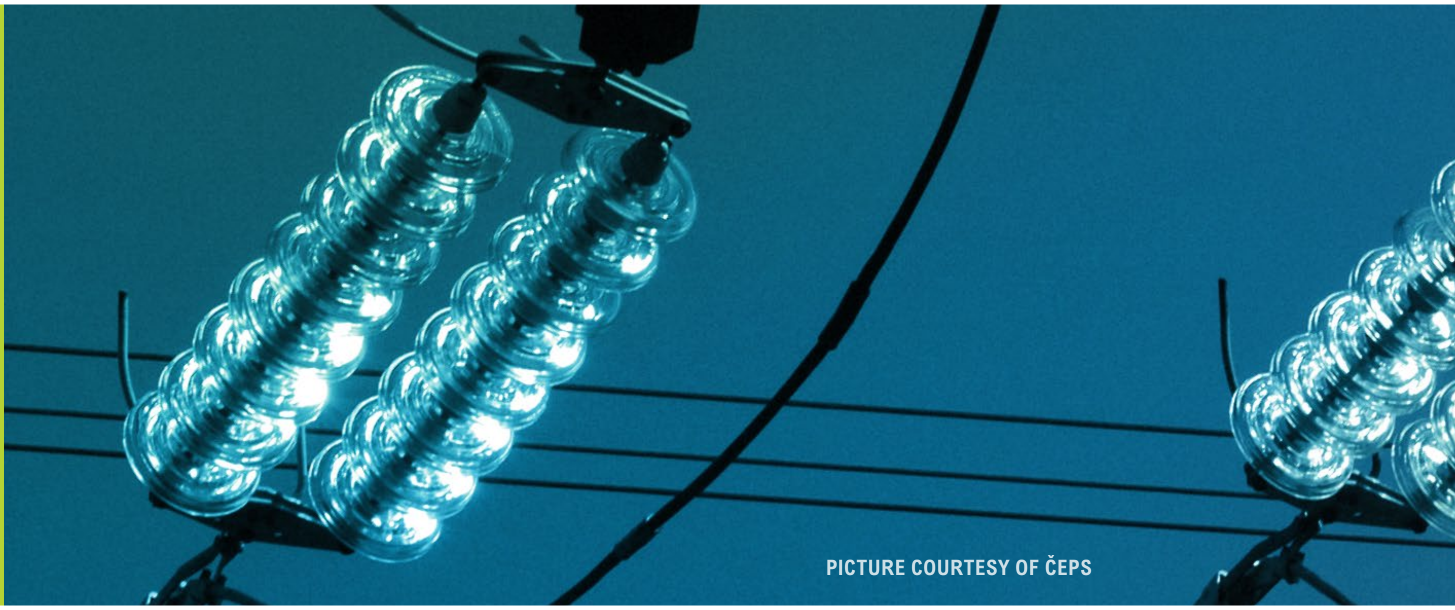
Table 5.20 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'transition and transaction costs'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

It is quite obvious that any adaptation of bidding zones, either through a merge or a split, would yield transition and transaction costs which would not occur in the event of maintaining the Status Quo. Therefore, the impact for all assessed bidding zone configurations is assessed to be negative. For Big Country Split and Big Country Split 2, the related transition and transaction costs are estimated as being higher compared to the DE/AT Split and the Small Country Merge. The reason for this is that the former consider the splitting of countries and control zones. Hence, a greater amount of adaptation is necessary compared to splitting along a control zone border.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Transition and transaction costs	(-)	(-)	(-)	(-)

Table 5.20: Specific assessment of transition and transaction costs



5.16 CACM CRITERION 'INFRASTRUCTURE COSTS'

5.16.1 DESCRIPTION AND UNDERSTANDING OF 'INFRASTRUCTURE COSTS'

CACM Article 1(b) (iv): *the cost of building new infrastructure which may relieve existing congestion*

The ENTSO-E Guidelines for Cost Benefit Analysis of Grid Development Projects[33] provides a definition for project costs and states that 'total project expenditures are based on prices used within each TSO and rough estimates on project consistency (e.g. km of lines). Environmental costs can vary significantly between TSOs. More details on the Cost Benefit Analysis, which is e.g. applied in the TYNDP, can be found in the Guidelines themselves (e.g. project costs are pre-tax).

5.16.2 EVALUATION APPROACH FOR 'INFRASTRUCTURE COSTS'

As described in section 3.2, the grid scenarios considered in this First Edition of the Bidding Zone Review are based on the investments considered in the TYNDP. Due to its broader focus, the TYNDP refers mainly to cross-zonal projects and considers the current bidding zone configuration as an exogeneous assumption. Since the Bidding Zone Review has a more detailed focus and aims for the assessment of alternative bidding zone configurations, national grid investment projects (located within the current bidding zones) were added to the list of TYNDP grid investments for the purpose of this Bidding Zone Review. Grid investments included in the TYNDP address the major system bottlenecks and structural congestions. Addressing those structural congestions by an adaptation of bidding zones would not remove them but rather disclose those congestions transparently to the market and restrict trading accordingly. This would not, per se, change the need for grid investments. Since, in comparative terms, grid investments would not change in the different configurations, a detailed assessment of the costs of building new grid infrastructure to the full extent is not relevant for the Bidding Zone Review. The absolute level would correspond to the costs of investments reported in the TYNDP. The TYNDP 2016 indicates up to 150 billion euros of investments in grid infrastructure supporting 200 projects in transmission and storage, leading to a reduction in congestion hours by 40%.[34]

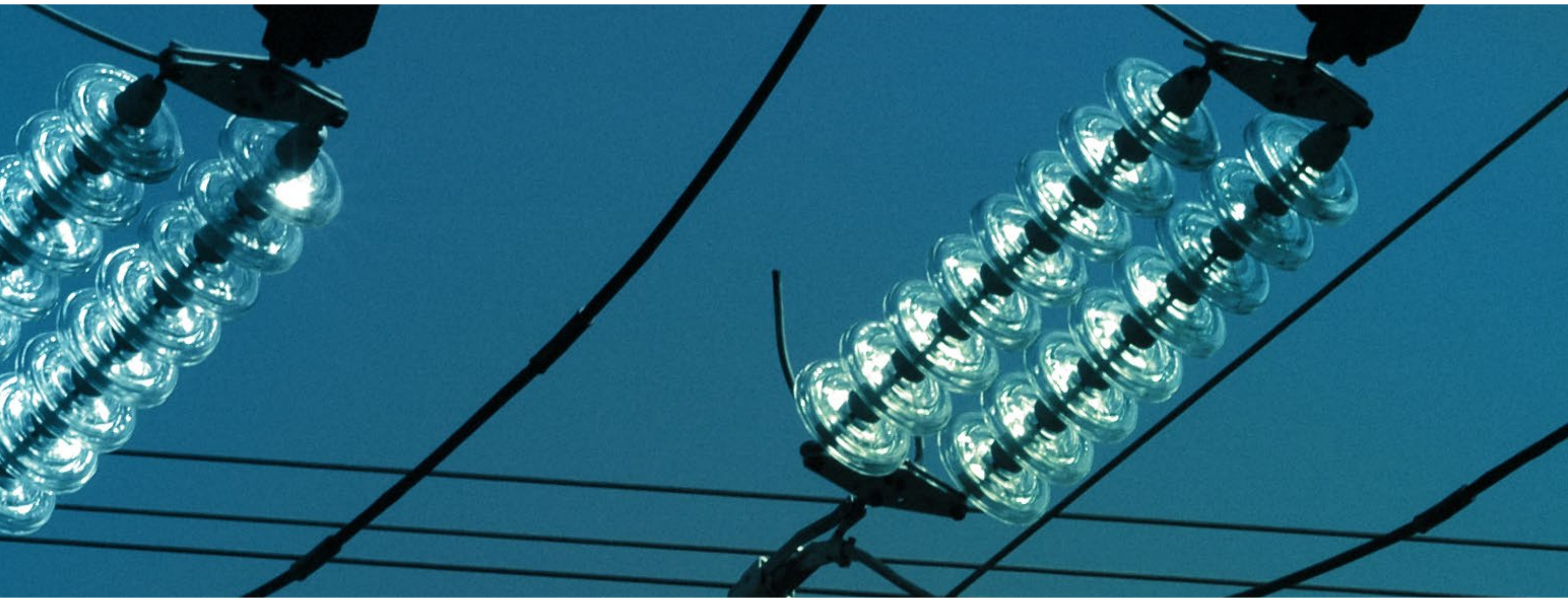
Therefore, the impact of alternative bidding zone configurations on the infrastructure costs will not be considered explicitly in this Bidding Zone Review. Instead, we refer here to the TYNDP 2016. In addition, costs for national investment projects can be found in the national grid development plans.

5.16.3 ASSESSMENT OF 'INFRASTRUCTURE COSTS'

Please refer to the explanation given in section 5.16.2.

33) https://www.entsoe.eu/Documents/SDC%20documents/TYNDP/ENTSO-E%20cost%20benefit%20analysis%20approved%20by%20the%20European%20Commission%20on%204%20February%202015.pdf

34) TYNDP 2016



5.17 CACM CRITERION 'MARKET OUTCOMES IN COMPARISON TO CORRECTIVE MEASURES (FEASIBLE MARKET OUTCOME)'

5.17.1 DESCRIPTION AND UNDERSTANDING OF 'MARKET OUTCOMES IN COMPARISON TO CORRECTIVE MEASURES (FEASIBLE MARKET OUTCOME)'

CACM Article 1(b) (v): *the need to ensure that the market outcome is feasible without the need for extensive application of economically inefficient remedial actions.*

Under a strict interpretation of the criterion, a market outcome would be feasible in all instances where the overall system operates. Under a looser interpretation, a market outcome is only feasible if no corrective measures (e.g. remedial actions) have to be taken. In accordance with the requirement of CACM NC, the measures potentially considered for correcting the market outcome should not imply an extensive application of economically inefficient remedial actions.

5.17.2 EVALUATION APPROACH FOR 'MARKET OUTCOMES IN COMPARISON TO CORRECTIVE MEASURES (FEASIBLE MARKET OUTCOME)'

Following the less strict interpretation mentioned in the previous paragraph, a market outcome is completely feasible when the corresponding dispatchment and unit commitment does not require any remedial actions to cope with system security constraints. Correspondingly, a bidding zone configuration provides more feasible market outcomes when it implies a lower number of congestions to be solved.

In line with this interpretation, the evaluation approach applied for assessing this CACM criterion is the same considered for the operational security criterion in section 5.4.1.

5.17.3 ASSESSMENT OF 'MARKET OUTCOME IN COMPARISON TO CORRECTIVE MEASURES (FEASIBLE MARKET OUTCOME)'

Table 5.21 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'market outcomes in comparison to corrective measures (feasible market outcome)'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Market outcome in comparison to corrective measures	(+)*	(+)*	(+)*	(-)

* There can be no further distinction between the splits without further quantitative analyses.

Table 5.21: Specific assessment of market outcome in comparison to corrective measures (feasible market outcome)

5.18 CACM CRITERION 'ADVERSE EFFECTS OF INTERNAL TRANSACTIONS ON OTHER BIDDING ZONES (LOOP FLOWS)'

5.18.1 DESCRIPTION AND UNDERSTANDING OF 'ADVERSE EFFECTS OF INTERNAL TRANSACTIONS ON OTHER BIDDING ZONES (LOOP FLOWS)'

CACM Article 1(b) (vi): *any adverse effects of internal transactions on other bidding zones to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009*

According to the flow definitions of the ENTSO-E Joint Task Force on Cross Border Redispatch,[35] a loop flow is defined as 'the physical flow on a line where the source and sink are located in the same zone and the line or even part of the tie-line is located in a different zone'. Irrespective of the market design, physical flows never match the planned commercial exchanges 100 %, which is due to the underlying assumption that bidding zones are copper plates and due to uncertainties in grid models and forecast errors.

Although there is a shared definition of loop flows, there are different ways of calculating loop flows. Two concepts followed by TSOs are the natural flow concept and the power flow decomposition. Despite the general approach of how to calculate loop flows in a model, even in the real world there are different ways to determine the number of loop flows. For this reason, TSOs applied three different indicators in their Technical Report published in 2014.[36]

5.18.2 EVALUATION APPROACH FOR 'ADVERSE EFFECTS OF INTERNAL TRANSACTIONS ON OTHER BIDDING ZONES (LOOP FLOWS)'

The assessment of a changed bidding zone configuration with regard to the adverse effects of internal transactions on other bidding zones (i.e. loop flows) will be based on the identification and discussion of fundamental principles/inter-relations.

35) For a more detailed explanation of the definition of flows please refer to https://www.entsoe.eu/Documents/MC%20documents/150929_Joint%20Task%20Force%20Cross%20Border%20Redispatch%20Flow%20Definitions.pdf#search=flow%20definitions

36) https://www.entsoe.eu/Documents/MC%20documents/140123_Technical_Report_-_Bidding_Zones_Review__Process.pdf

5.18.3 ASSESSMENT OF 'ADVERSE EFFECTS OF INTERNAL TRANSACTIONS ON OTHER BIDDING ZONES (LOOP FLOWS)'

5.18.3.1 Qualitative assessment of impacts on 'adverse effects of internal transactions on other bidding zones (loop flows)'

Relevance of bidding zone configuration for loop flows

By changing bidding zones, loop flows can be translated into transit flows and through this, explicitly considered in the capacity calculation and market coupling.

Relevance of the 'impedance shape' of a bidding zone

The number of loop flows can be reduced, ensuring that the bidding zone configuration reflects congestions (i.e. commercial flows better reflect physical flows) and the 'impedence shape' of the bidding zone. Every grid investment changes the network impedance (except for DC lines) and therefore load flows will change (i.e. resulting in a changed PTDF value which rebalances the network flows). This changes the loop flows. Consequently, careful grid investment can reduce loop flows. In addition, loop flows can be reduced by DC lines or PSTs. DC lines do not create loop flows. PSTs can reduce loop flows in a very effective way by changing the impedance of a single line.

Please see section 5.9.3 for a more detailed discussion of the relevance of the 'size' of a bidding zone that needs to be defined in more dimensions which cover the generation mix/load, its regional distribution and the level of cross-zonal capacities.

Neglection of internal CNECs in the FB MC increases loop flows

As already discussed in the context of operation security, the design of the market coupling mechanism is of major importance. This also holds true in the context of loop flows. The idea behind the flow-based market coupling approach is to keep the approach of a zonal market design (market aspects) but to consider the operational constraints of the underlying grid (security aspects). Or, in other words: the trading shall be as high as possible while not endangering the grid security. In order to keep the trading 'as high as possible', bidding zone borders shall consider permanent structural congestions. Yet, congestions which arise only a few times a year or which will be removed by grid investments in the future can be dealt with by remedial actions and shall not restrict the trading in every hour of the year. For this reason, the concept of CNECs is a very important aspect of the flow-based market coupling approach. If internal congestions (which are of a temporary and not a structural/permanent nature) are no longer allowed to be considered as CNECs, the market dispatch and the corresponding load flows will not reflect these constraints, leading to higher loop flows.

A modification of loop flows is not equal to a change of load flows

The term 'loop flows' is a concept related to zonal market designs. It must not be confused with load flows and congestions. The load flows are determined by the power plant and load dispatch, the grid infrastructure and the laws of Kirchhoff, and they determine the efficiency of the system. The most important factors for an efficient dispatch are the generators and a sufficient grid infrastructure. For a given grid infrastructure and for a given power plant and load dispatch, load flows and congestions stay the same, independently of the market design.

Loop flows cannot be avoided fully

Irrespective of the market design, physical flows never match 100 % with the planned commercial exchanges, due to uncertainties in grid models and forecast errors.

Relevance of loop flows for competition

Moreover, smaller bidding zones may translate loop flows to transit flows after splitting, which further increases competitiveness between internal and cross-zonal trade.

5.18.3.2 Summarised assessment of impacts on 'adverse effects of internal transactions on other bidding zones (loop flows)'

Table 5.22 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'adverse effects of internal transaction on other bidding zones'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

In general, one could argue that in bigger bidding zones (in which generation and load centres are geographically distributed further away from each other) more loop flows occur than in smaller bidding zones (in which the geographical distance between generation and load units tends to be smaller). Yet, loop flows do not per se increase the loading of grid elements, as they can also have a relieving impact. Therefore, a general assessment of the impact of alternative bidding zone configurations without a detailed quantitative analysis is not possible.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Adverse effects of internal transaction on other bidding zones	(+)*	(+)*	(+)*	(-)*

* This assessment considers loop flows, but does not consider any adverse market effects linked to loop flows

Table 5.22: Specific assessment of impacts on adverse effects of internal transactions on other bidding zones (loop flows)

5.19 CACM CRITERION 'IMPACT ON THE OPERATION AND EFFICIENCY OF THE BALANCING MECHANISMS AND IMBALANCE SETTLEMENT PROCESSES'

5.19.1 DESCRIPTION AND UNDERSTANDING OF 'IMPACT ON THE OPERATION AND EFFICIENCY OF THE BALANCING MECHANISMS AND IMBALANCE SETTLEMENT PROCESSES'

CACM Article 1(b) (vi): *the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes*

The adjustment of a bidding zone configuration, especially if the new bidding zones do not consider national borders anymore, will most likely impact the operation and the efficiency of the balancing mechanisms of the concerned TSOs and the imbalance settlement process.

5.19.2 EVALUATION APPROACH FOR 'IMPACT ON THE OPERATION AND EFFICIENCY OF THE BALANCING MECHANISMS AND IMBALANCE SETTLEMENT PROCESSES'

The type of impacts as well as their level might vary largely among the different TSOs involved in the specific bidding zone reconfiguration. For the evaluation of impacts on balancing mechanisms and imbalance settlement processes, it is specifically important whether the new bidding zones merge or split different LFC blocks. Furthermore, in-depth knowledge of the balancing markets and procedures in Europe is crucial.

Expert interviews and survey for balancing experts

Detailed knowledge of the national and cross-zonal balancing mechanisms and imbalance settlement processes is of major importance for a sound assessment of the impacts of a changed bidding zone configuration. For this purpose, TSO balancing experts have been asked for their expert view on potential impacts for all relevant aspects. Important aspects/questions discussed and validated by TSO experts include the following:

- The kind of impacts that a bidding zone reconfiguration might have regarding
  - the dimensioning and procurement of the balancing reserves/capacities
  - the activation and pricing of balancing energy (for BSPs)
  - the imbalance prices (for BSPs)
- In cases of bidding zone reconfigurations, what are the advantages and disadvantages when it comes to the question of whether the balancing shall be organised within the new bidding zone borders or whether the balancing should be kept organised and separated according to the LFC areas or blocks?
- In cases of bidding zone reconfigurations, what are the relevant aspects for the organisation of the imbalance settlement?
- In cases of bidding zone reconfigurations, what are relevant cost aspects with regard to a corresponding reorganisation of the imbalance settlement?
- In cases of specific bidding zone reconfigurations, can statements about the change in the prequalified capacity (which is available for balancing) be drawn beforehand?

5.19.3 ASSESSMENT OF 'IMPACT ON THE OPERATION AND EFFICIENCY OF THE BALANCING MECHANISMS AND IMBALANCE SETTLEMENT PROCESSES'

For the assessment of impacts on the operation and efficiency of the balancing mechanisms and imbalance settlement processes that might occur if bidding zones are adapted, several aspects are relevant. A reconfiguration of bidding zones will lead to changes in the dimensioning and procurement of balancing power (depending on the definition of LFC blocks and areas and the following treatment of exchanges).

Firstly, if LFC blocks are kept as they are but bidding zones are changed, solutions have to be found in case of congestion between the new bidding zones. Nonetheless, changing, dividing or merging of existing bidding zones might produce indirect effects for single parts in the balancing and the imbalance settlement processes or for the processes as a whole. Imbalance settlement price (ISP) areas are to be given particular consideration, as the current version of the CEP states that the ISP should be calculated on the bidding zone level.

Secondly, the level of dimensioning and procurement might experience changes due to a different technical basis (e.g. renewable energy sources, load) and a different power plant portfolio that can be prequalified to deliver balancing power or different market incentives for providers.

A third aspect concerns the possibility of shortness of balancing power compared to an increased balancing need in areas with higher RES share.

Existing European regulation, especially the Guidelines for Energy Balancing (GL EB), are the basis for organising the pricing of balancing energy. The aimed harmonisation of activation to be achieved by a common European MOL and ongoing projects for the development of common European balancing markets (PICASSO, MARI, TERRE) are expected to reduce the effects on the pricing of balancing energy in the future (irrespective of potential bidding zone configurations). Nevertheless, until these common markets are in place, balancing prices might be affected due to changed market liquidity (e.g. lower liquidity in smaller bidding zones), partly because of a less diversified balancing providers portfolio leading to higher economic risks for providers, the outcome of which is that higher prices for balancing capacity and energy occur.

In the following, the extent to which a reconfiguration of bidding zones might cause changes in the operational processes, and have possible impacts on the efficiency, will be discussed. While the summary of the expert interviews given in section 5.19.3.1. discusses these impacts in a more general way, section 5.19.3.2. focuses on the potential impacts regarding the specific expert-based bidding zone configurations.

5.19.3.1 Summary of expert interviews and survey for balancing experts

In the following, the outcome of the balancing expert interviews and the TSO survey is summarised. The expert statements are divided into three subsections, answering the questions raised in section 5.19.2. In order to increase the readability, all expert statements made with regard to a specific bidding zone configuration are considered in section 5.19.3, which deals with the assessments of the specific expert-based configurations.

Potential impacts of a bidding zone reconfiguration regarding the dimensioning and procurement of the balancing reserves/capacities

Based on the current regulation, balancing processes, i.e. load-frequency controllers, are set up at the LFC area level, irrespective of bidding zones inside/ outside the LFC block. According to the GL SO, the LFC block can equal the LFC area or have more LFC areas inside However, the GL EB states clearly that cross-zonal capacities shall be used first for scheduled exchanges. Allocating cross-zonal capacity for the exchange or sharing of balancing capacities is only allowed in cases employing the methodologies stipulated in the GL EB.

In the case of an adaptation of bidding zones, TSOs will have to decide whether they see a need to adapt LFC blocks to bidding zones. If so, a bidding zone reconfiguration would have an impact on the dimension and the procurement of balancing capacities. In the event that two or more LFC blocks exist in one bidding zone (see Figure 5.3), the impacts on the dimensioning and procurement of balancing reserves might be very limited.[37)]

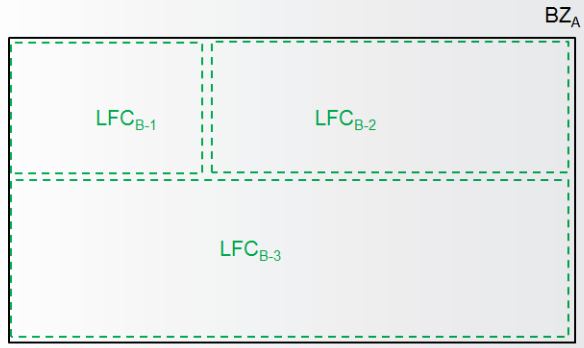


Figure 5.3: Several LFC blocks in one bidding zone

Yet, in the event that the bidding zones are not the same as the LFC blocks, several changes might be necessary since the technical setup of the controllers might need to be adapted in order to allow the balancing in the new bidding zone scheme, e.g. more than one bidding zone per LFC block might lead to an adaptation of process and responsibility structures within the given LFC block(s). In this case, (i.e. if one LFC block performing a common dimensioning includes several bidding zones), congestions between the bidding zones will need to be considered, potentially leading to dedicated shares that need to be procured in each bidding zone and a decrease of economic efficiency due to restricted locational procurement, as well as higher costs for the procurement of balancing capacity.

37) Two or several LFC blocks may decide to commonly procure balancing reserves/capacities respecting operational limits for the exchange of balancing reserves and to increase the economic efficiency of procurement. However, even if there are two LFC blocks in one bidding zone, the GL SO limits procurement outside of LFC blocks. For frequency containment reserve (FCR), a TSO is not allowed to procure more than 30% of its FCR obligation or a maximum of 100 MW outside its LFC block. For frequency restoration reserve (FRR) (total), a TSO is obliged to procure at least 50% of the FRR obligation from within its LFC block.

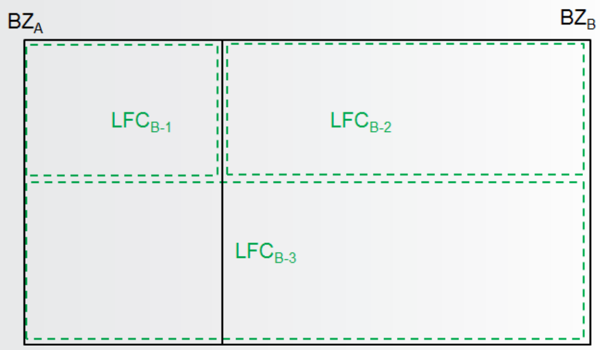


Figure 5.4: One LFC block in several bidding zones (here: in two bidding zones)

In cases where a merge of bidding zones also requires a merge of LFC blocks, it is likely that less balancing capacity has to be procured. The reasoning is that each LFC block has to cover its own dimensioning incident. For the same reason, it is likely that smaller bidding zones (in case LFC blocks are also smaller) will, in sum, dimension more balancing capacity. Yet, it has to be noted that a part of the gain of a common dimensioning might already be achieved with reserve sharing agreements. However, even under the consideration of a constant volume, the procurement in a larger market might have a positive impact on the costs of the procured reserves due to the expected higher competition. Only TSOs in their synchronous area operational agreement (GL SO article 139[1]) can define the LFC block and the related process structure. The TSOs might deem it a requirement to change the LFC blocks/areas due to a bidding zone reconfiguration (e.g. split of zone). Potential impacts of a bidding zone reconfiguration include the activation and pricing of balancing energy (for BSPs)

The GL EB foresees the implementation of dedicated European platforms for the exchange of balancing energy. which will result in the creation of a unique price per ISP per process per bidding zone. Hence, the impacts of an adaptation of bidding zones on the pricing of balancing energy are rather limited (considering the go-live of the European balancing platform).

In the event of no congestions between bidding zones, this price will be the same in these two zones (as with the day-ahead market); only in the event of congestions between two bidding zones will each zone have its own unique price. Hence, if an LFC-block is split into more bidding zones, it can have different balancing energy prices, just like the day-a-head market.

However, the market volume may increase (merging of zones) or decrease (splitting of zones) and this will have an impact on the prices, especially in the event of congestions. With the splitting of existing bidding zones and the introduction of additional borders, the economically optimal exchange of balancing energy might be jeopardised, depending on the available cross-zonal capacities after energy trading (usually intraday) or potential allocated capacities for the exchange. The issue becomes severe in the event that the bidding zone configuration limits competition in the balancing energy markets, possibly leading to higher costs for balancing energy of the respective LFC block.

Potential impacts of a bidding zone reconfiguration regarding the imbalance prices (for BRPs)

As the GL EB requires some kind of harmonisation of pricing of imbalances, the impacts may also be limited. The prices may change in the new bidding zones, depending on size and congestions between the zones, e.g. smaller zones may lead to higher imbalance prices and larger zones to lower imbalance prices, mainly due to competition on the BSP side and ability of BRPs to optimise their own portfolios/schedules.

From the regulatory/political perspective, introducing several imbalance prices in one country seems questionable.

While the GL EB allows for different geographical scopes of imbalance areas (for imbalance pricing), LFC blocks (for procurement of balancing capacity/energy) and bidding zones, the CEP foresees the requirement that the imbalance price area should be equal to a bidding zone, which will impact the portfolios of BRPs.

However, imbalance pricing rules and mechanisms should be coordinated with the bidding zone configuration in place in order to avoid strategic behaviours from market participants and to ensure that the prices in the different markets provide consistent signals to market participants. For instance, it seems to be reasonable to consider that the imbalance price areas are harmonised if the LFC blocks are merged (e.g. after a merge of bidding zones) since the imbalance price should give the signal to the BRPs to be in balance in the area in which the TSOs are managing their balance. This consistency is particularly important for TSOs with a reactive balancing philosophy. However, as already mentioned, the current regulation (GL SO) does not foresee an adaptation of LFC blocks which reflects a potential adaptation of bidding zones.

5.19.3.2 Specific qualitative assessment of impacts on 'operation and efficiency of the balancing mechanisms and imbalance settlement processes' for the alternative bidding zone configurations

Potential impacts on the operation and efficiency of the balancing mechanisms and imbalance settlement processes in the DE/AT Split:

In order to fulfil the TSO task of balancing the system efficiently, it is considered that the balancing processes would be adapted to the new bidding zones. As the balancing markets are currently organised locally, a splitting of the DE/AT/Lux Bidding Zone into national bidding zones should not have an impact on the balancing mechanism. Thus, competition on aFRR balancing energy might decrease as the currently commonly organised CMOL (for this balancing process) between DE and AT is more restricted. The key question is whether cross-zonal capacity between DE and AT can be used for the exchange of aFRR balancing energy. Indirect effects, though, might occur due to different incentives for dispatching and investing in plants and the behaviour of market participants regarding internal price calculation because of changed pricing regimes on the markets for scheduled energy.

As the imbalance settlement is already separated, no changes are needed here.

Potential impacts on the operation and efficiency of the balancing mechanisms and imbalance settlement processes in the Big Country Split

Germany

Impact on balancing mechanism: a split of Germany into north and south would make the organisation of two balancing markets and processes necessary. This may lead to different prices for BSPs and BRPs in both regions, which could be a political issue. In addition, the integration of RES might be impacted, as imbalance prices might have an impact on investments. Furthermore, the TSOs might face issues with available balancing reserves as, e.g., a north region with lots of wind infeed and low prices in strong wind situations impacts the running of conventional power plants that might be needed in case of forecast errors. In such situations, prices for balancing capacities could strongly increase to keep conventional plants running. Even worse, operational security might result in must-run constraints for conventional power plants as dispatchable generation is required to ensure stable operation in an RES-dominated bidding zone.

Impact on the imbalance settlement: a split of Germany into north and south may lead to different imbalance prices within Germany, depending on congestions. Until the CEP comes into force there might be a political requirement to keep a common imbalance price in Germany, which would require an additional process.

Impact on balance costs: Balancing capacity costs will most likely increase as the cheapest of all German bids will no longer be accepted, instead being the cheapest in each region. Therefore, there will be an efficiency loss. The balancing energy cost might also increase due to the split market liquidity. In cases of available cross-zonal capacity between the split zones, the balancing energy costs might not change.

France

A split of France may also lead to the creation of two balancing markets, with potentially different prices. Furthermore, balancing margins will have to be guaranteed in both zones, which will have a negative impact on the cost of the balancing mechanism.

Potential impacts on the operation and efficiency of the balancing mechanisms and imbalance settlement processes in the Big Country Split 2

For Germany, the remarks for the Big Country Split are also valid for the Big Country Split 2. Even the must-run issue increases. In bidding zones with few thermal units (see Belgium), dispatch constraints become even more important to ensure secure system operation. Furthermore, the Big Country Split 2 would create three borders in Germany, likely resulting in three imbalance prices within Germany (depending on congestions) and in an increase of the balancing energy costs.

France

The assessment of the previous configuration remains valid for this configuration with regards to France.

Potential impacts on the operation and efficiency of the balancing mechanisms and imbalance settlement processes in the Small Country Merge

Regarding balancing markets, the merging of bidding zones might lead to increased market liquidity and an increased level of competition, as well as potentially resulting in lower prices, and therefore, lower costs for balancing capacity and energy. This thinking, which is of course true for spot markets, is also true for balancing markets to a certain extent.

Furthermore, when merging bidding zones, care must be taken to reorganisie the processes of the imbalance settlement and its pricing. As a result, an agreement on the general approach and the details of a common imbalance settlement scheme has to be reached between the two regulatory authorities concerned. It is crucial to reach congruency of imbalance settlement areas and bidding zones.

5.19.3.3 Summarised assessment of the impact on the 'operation and efficiency of the balancing mechanisms and imbalance settlement processes'

Table 5.23 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the CACM criterion 'operation and efficiency of the balancing mechanisms and imbalance settlement processes'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

DE/AT Split:

As the imbalance settlement and the balancing markets are already separated, the impacts are considered to be limited. Yet, competition on aFRR balancing energy might decrease as the currently commonly organised CMOL (for this balancing process) between DE and AT is more restricted. The key question is whether cross-zonal capacity between DE and AT can be used for the exchange of aFRR balancing energy.

Big Country Split and Big Country Split 2:

For Germany, internal splits would make the organisation of two or three balancing markets and processes necessary, leading to different imbalance prices within Germany. From a technical point of view, the TSOs might face issues with available balancing reserves, as a north region with lots of wind infeed and low prices in strong wind situations impacts the running of conventional power plants that might be needed in case of forecast errors. This might result in must-run constraints for conventional power plants, as dispatchable generation is required to ensure stable operation in an RES-dominated bidding zone. Balancing capacity costs will most likely increase, while balancing energy costs might also increase due to the split market liquidity (depending on the available cross-zonal capacity). In case the bidding zones are not the same as LFC areas, several changes are necessary since the technical set-up of the controllers also needs to be adapted in order to enable the balancing in the new bidding zone scheme.

Small Country Merge:

Considering the implementation of the GL EB, the merge might have limited impacts.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Impact on operation and efficiency of the balancing mechanisms and imbalance settlement processes	(0/-)	(-)	(-)	(0/-)

Table 5.23: Specific assessment of the impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes

5.20 CACM CRITERION 'STABILITY AND ROBUSTNESS OF BIDDING ZONES OVER TIME'

5.20.1 DESCRIPTION AND UNDERSTANDING OF 'STABILITY AND ROBUSTNESS OF BIDDING ZONES OVER TIME'

CACM Article 33(c) (i): *the need for bidding zones to be sufficiently stable and robust over time*

The requirement for bidding zones to be 'sufficiently stable and robust over time' is strongly linked to the CACM criterion 'location and frequency of congestion', which requires TSOs to assess whether structural congestion influences the delimitation of bidding zones (considering any future investment which may relieve existing congestion). Hereby, and in accordance with Article 2 (19) CACM, structural congestion means 'congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions'.

5.20.2 EVALUATION APPROACH FOR 'STABILITY AND ROBUSTNESS OF BIDDING ZONES OVER TIME'

The assessment of a changed bidding zone configuration with regard to the stability and robustness of bidding zones over time will be based on the identification and discussion of fundamental principles/inter-relations.

5.20.3 ASSESSMENT OF 'STABILITY AND ROBUSTNESS OF BIDDING ZONES OVER TIME'

5.20.3.1 Qualitative assessment of impacts on 'stability and robustness of bidding zones over time'

Consideration of structural congestion in the bidding zone configuration is beneficial for its stability and robustness over time

A bidding zone configuration can be seen as stable and robust over time if the congestions that the bidding zone borders reflect are sufficiently stable and robust over time. This is, in general, the case for structural congestion as defined in Article 2 CACM. Yet, to be robust over time requires that the structural congestions 'always' occur in the same grid area. To ensure such a 'robust' map of congestions in continental Europe is quite difficult due to the high degree of intermeshing of the alternating current (AC)-dominated transmission grid.

Consideration of temporary congestion decreases the stability and robustness of bidding zones

While structural congestion frequently reoccurs under normal power system conditions, temporary congestions might occur only in a few hours of a year and/or only under exceptional power system conditions. CACM explicitly foresees that bidding zones shall reflect permanent structural congestions only. The idea behind this is that trading/commercial exchanges within Europe shall reflect the operational constraints of the underlying system. Yet, trading shall not be limited for every hour of a year if the congestion (which shall be considered by this trading limitation) occurs only in a very few hours of a year. This concept of efficiency might be comparable to the grid development planning done by TSOs. For reasons of efficiency, the grid development does not aim for a grid that can deliver the 'last kWh of wind or solar energy produced', but to considers a shedding of such peaks (which will occur only in very few hours of a year).

Sufficient predictability of (structural) congestion is important

In order to identify permanent structural congestion and to potentially adjust bidding zone borders to them, such structural congestions need to be sufficiently predictable. First, the definition of structural congestion already foresees that it has to be predictable. Second, congestions need to be geographically stable over time. If congestions are not sufficiently predictable (e.g. because they vary significantly under the assumption of different but likely developments of the energy system), a robust definition of bidding zone borders becomes challenging.

5.20.3.2 Summarised assessment of impacts on 'stability and robustness of bidding zones over time'

Table 5.24 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'stability and robustness of bidding zones'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

In order to ensure stability and robustness of bidding zones over time, bidding zone borders shall reflect structural congestion as well as ensuring that it occurs within the same grid area. To provide such a robust 'map' of structural congestion that does not change significantly over time is highly challenging in Europe, since the AC-dominated European transmission system is highly intermeshed (within national borders and also highly interconnected between countries). Furthermore, the grid investments outlined in the European TYNDP process for the next 10 years are planned to relieve structural congestions. Hence, the 'map' of structural congestion will, regardless, change significantly with the implementation of grid investment projects. Additionally, congestions that are mainly driven by variable RES infeeds are difficult to predict anyway (and are therefore less stable), as is the case for Germany.

To summarise, compared to the current bidding zone configuration, an adaptation of bidding zones may not, per se, lead to an increase of stability and robustness of bidding zones over time.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Stability and robustness of bidding zones over time	(0)	(-)*	(-)*	(0)

* For Germany, grid investment planning foresees the building of HVDC links moving towards a copper plate. The intention of these grid investments is to resolve any relevant congestion that might justify a split of the German bidding zone. This makes the Big Country Split less stable but does not consider any adverse market effects linked to loop flows.

Table 5.24: Specific assessment of impacts on stability and robustness of bidding zones over time

5.21 CACM CRITERION 'CONSISTENCY ACROSS CAPACITY CALCULATION TIME FRAMES'

5.21.1 DESCRIPTION AND UNDERSTANDING OF 'CONSISTENCY ACROSS CAPACITY CALCULATION TIME FRAMES'

CACM Article 33(c) (i): *the need for bidding zones to be consistent for all capacity calculation time frames'*

CACM requires that 'bidding zones should be identical for all market time-frames'. Although the CACM regulation focuses on guidelines for the day-ahead and intraday markets, the term 'all market time frames' is not specified further in the regulation. However, in order to ensure overall market efficiency, it is understood in the following that the term 'all market time frames' also considers forward and balancing markets.

5.21.2 EVALUATION APPROACH FOR 'CONSISTENCY ACROSS CAPACITY CALCULATION TIME FRAMES'

The assessment of a changed bidding zone configuration with regard to its consistency across all capacity calculation time frames will be based on the identification and discussion of fundamental principles/inter relations.

5.21.3 ASSESSMENT OF 'CONSISTENCY ACROSS CAPACITY CALCULATION TIME FRAMES'

5.21.3.1 Qualitative assessment of impacts on 'consistency across capacity calculation time frames'

Consistency of bidding zones in all markets is important to avoid arbitrage possibilities and inconsistencies

To avoid inconsistencies and undesirable arbitrage possibilities, bidding zones shall not be considered only in the day-ahead market, but across all capacity calculation time frames. Beside the day-ahead market, this includes forward, intraday and balancing markets. Only a consistent consideration of price zones across all markets will ensure an overall efficient market design. In the case of forward markets, financial transmission rights are one way of assisting market participants in hedging their risks. As the balancing markets are normally monopsonistic[38], (i.e. the system operator is the only demander) offers with locational information about the provider of balancing power would help to prevent a sub-optimal congestion intensifying activation of balancing power.

Consistency of bidding zones is strongly interlinked with potentially incentivising investments in generation and DSM

As already discussed in sections 5.12 and 5.13, the appropriate pricing of scarce transmission capacity (according to structural congestion) in the markets might incentivise investments. Yet, only a consistent bidding zone configuration can ensure a consistent set of price signals along all time frames.

5.21.3.2 Summarised assessment of impacts on 'consistency across capacity calculation time frames'

Table 5.25 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'consistency across capacity calculation time frames'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

The question as to whether an alternative bidding zone configuration leads to a higher or lower level of consistency across capacity calculation time frames is not a technical one but related to the market design. From a technical/economical point of view, the same bidding zones shall be considered across all time-frames. If not, a different structure of bidding zones (e.g. bidding zones in day-ahead markets look different than in the intraday or balancing market segments) might lead to inconsistent price signals and might create undesirable arbitrage possibilities (between the different markets). Hence, whether the consistency across all capacity calculation time frames shall be ensured or not is a question of the desired market design. It is, therefore, more a decision than an evaluation criterion.

[38] Only one demanding entity

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Consistency across capacity calculation time frames	(0)	(0)	(0)	(0)

Table 5.25: Specific assessment of impacts on consistency across capacity calculation time frames

5.22 CACM CRITERION 'ASSIGNMENT OF GENERATION AND LOAD UNITS TO BIDDING ZONES'

5.22.1 DESCRIPTION AND UNDERSTANDING OF 'ASSIGNMENT OF GENERATION AND LOAD UNITS TO BIDDING ZONES'

CACM Article 33(c) (i): *the need for each generation and load unit to belong to only one bidding zone for each market time unit*

The clear assignment of generation and load units to bidding zones can be interpreted as a requirement for the definition of alternative bidding zone configurations. In the event that, e.g., a generation unit, was assigned to two bidding zones, this could yield very distortive effects since the allocation would be arbitrary. The same holds for loads.

5.22.2 EVALUATION APPROACH FOR 'ASSIGNMENT OF GENERATION AND LOAD UNITS TO BIDDING ZONES'

The assessment of a changed bidding zone configuration with regard to the necessary assignment of generation and load units to bidding zones will be based on the identification and discussion of fundamental principles/inter-relations.

5.22.3 ASSESSMENT OF 'ASSIGNMENT OF GENERATION AND LOAD UNITS TO BIDDING ZONES'

5.22.3.1 Qualitative assessment of 'assignment of generation and load units to bidding zones'

5.22.3.1.1 General assessment of qualitative aspects

The clear assignment of generation and load units to bidding zones is a requirement for an efficient bidding zone configuration

The assignment of generation and load units to more than one bidding zone would yield very distortive effects since the allocation would be arbitrary.

Units located close to bidding zone borders impede the clear assignment of generation and load units to one bidding zone and can endanger the efficiency of market coupling

In general, the geographical location of a generation or load unit should clearly indicate to which bidding zone the unit would be assigned in case of an adaptation of bidding zones. Yet, specific contractual requirements can lead to an assignment which does not correspond to its geographical location.

While for the merging of existing bidding zones, the assignment should be less problematic, it can still be so in the case of a split. This holds especially true if a national bidding zone is split. It is not unusual that huge thermal generation units are connected to more than one substation. If such a generation unit is close to the new bidding zone border, one has to decide to which bidding zone both substations shall be assigned.

The assignment of units located close to a bidding zone border is of high relevance for the efficiency of the market coupling in general. The reason is that electricity does not follow defined bidding zone borders per definition but will flow according to Ohm's law, e.g. if generation units are directly located at a bidding zone border, its production (according to the price signal of the bidding zone to which it is assigned) might lead to differences between the scheduled (market) and unscheduled (physical) flows, although the bidding zone border follows the structural congestions.

5.22.3.1.2 Specific qualitative assessment of the alternative bidding zone configurations

Potential impacts on the assignment of generation and load units to bidding zones in the DE/AT Split:

As indicated in the general assessment, contractual requirements or specifics of the grid topology can lead to an assignment of generation and load units which does not correspond to their geographical locations. This holds true for the German–Austrian border, where some units are geographically located in Austria but are considered as generators in Germany due to specific contracts. The clear assignment of every substation to the German or the Austrian bidding zone shall be possible, but requires adequate contractual alignments. Considering that the DE/AT border is already included in the CCR decision and an agreement[39] between the Austrian regulatory authority E-Control and the Bundesnetzagentur on the introduction of a congestion management scheme for the exchange of electricity at the border between Austria and Germany as from 1 October 2018, the split is assessed as neutral against this CACM criterion.

Potential impacts on the assignment of generation and load units to bidding zones in the Big Country Split

As highlighted already in the general assessment, the assignment of units and loads is expected to be more problematic in the event that a national bidding zone is split than in the

[39] https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2017/15052017_DE_AU.html?nn=404422

event that two countries are split along the national border. Especially in Germany, the distribution grid is strongly intermeshed with the transmission grid. Yet, in particular due to the increasing distributed generation, generators are no longer connected only to the transmission grid. Therefore, a clear assignment of units and loads has to consider generation (and load) that feeds into the lower voltage levels too, in particular to avoid arbitrage possibilities and/or counterintuitive incentives for market participants. To summarise, an arbitrage-free assignment of units to new bidding zones will be more challenging than in the Status Quo.

Potential impacts on the assignment of generation and load units to bidding zones in the Big Country Split 2

For Germany, the additional split foresees a split along the control zone Amprion, which includes the highly meshed area of North Rhine Westfalia. Yet, even a splitting along the control zone borders can be seen as problematic with regard to the relevant CACM criterion, since several units are located close to the newly introduced bidding zone border.

Potential impacts on the assignment of generation and load units to bidding zones in the Small Country Merge

As two existing bidding zones are merged into a new bidding zone, negative impacts or challenges regarding the new assignment of load and generations arising from merges are not expected.

5.22.3.2 Summarised assessment of impacts on the 'assignment of generation and load units to bidding zones'

Table 5.26 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion the 'assignment of generation and load units to bidding zones'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

It is in the nature of things that the assignment of units and loads in a new bidding zone configuration cannot become easier or 'better' compared to the current one, because the current bidding zone configuration already considers a clear assignment of every generation and load unit.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Assignment of generation and load units to bidding zones	(0)	(-)	(-)	(0)

Table 5.26: Specific assessment of impacts on the assignment of generation and load units to bidding zones

5.23 CACM CRITERION 'LOCATION AND FREQUENCY OF CONGESTION (MARKET AND GRID)'

5.23.1 DESCRIPTION AND UNDERSTANDING OF 'LOCATION AND FREQUENCY OF CONGESTION (MARKET AND GRID)'

CACM Article 33(c) (i): *the location and frequency of congestion, if structural congestion influences the delimitation of bidding zones, taking into account any future investment which may relieve existing congestion*

According to Article 2 (19) CACM, structural congestion means '*congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently recurring under normal power system conditions*'. As already highlighted in section 5.19.3, this criterion is strongly linked to the CACM requirement for bidding zones to be 'sufficiently stable and robust over time'. Hereby, the assessment of the location and frequency of congestion forms the basis for the evaluation of whether reconfigured bidding zones can be considered as sufficiently stable and robust over time (see section 5.19.3).

5.23.2 EVALUATION APPROACH FOR 'LOCATION AND FREQUENCY OF CONGESTION (MARKET AND GRID)'

The assessment of a changed bidding zone configuration with regard to the location and frequency of congestions will be based on the identification and discussion of fundamental principles/interrelations.

5.23.3 ASSESSMENT OF 'LOCATION AND FREQUENCY OF CONGESTION (MARKET AND GRID)'

5.23.3.1 Qualitative assessment of impacts on 'location and frequency of congestion'

Distinction between structural and temporary congestion is important

Considering the requirement of stability and robustness, temporary congestions are not reliable for determining a bidding zone configuration. Only structural congestions, as defined above, should be considered.

Distinction between congestions in the market and in the grid is important

Bidding zone borders impose limitations on commercial exchanges. Those limits should be linked to structural grid congestions in order to provide an accurate price signal to the market and for future investments. However, if structural congestions could be internalised by creating a new border at the same location, other market limitations could also be introduced where no structural congestion occurs. For example, loop flows induced by commercial exchanges could create physical constraints in other parts of the grid. This situation could thus be handled by introducing a new border at the location of the commercial exchange and not where the physical congestions occur.

Introducing new bidding zone delimitations will change the price pattern of the whole area and will have a significant impact on market behaviour and physical flows (e.g. flow inversion at a border). Those changes may lead to the emergence of new structural congestions that may challenge the new envisaged configuration.

Moreover, the robustness of a configuration can be challenged regarding the relevance of drawing a continuous border in function to a few disjointed structural congestions. Therefore, the configuration and the number of zones should ensure the best balance between market congestions and physical congestions.

5.23.3.2 Summarised assessment of impacts on 'location and frequency of congestion'

Table 5.27 provides the summarised assessment of the potential impacts of a changed bidding zone configuration with regard to the criterion 'location and frequency of congestion'. The impacts for the alternative bidding zone configurations are not assessed on a stand-alone basis, but always in comparison to the current bidding zone configuration (Status Quo).

Please note that the overall assessment of all alternative bidding zone configurations considering all CACM criteria can be found in section 5.24.1.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merge
Location and frequency of congestion (market and grid)	(+)	(+)	(+)	(-)

Table 5.27: Specific assessment of impacts on location and frequency of congestion

5.24 SUMMARISED EVALUATION OF THE BIDDING ZONE CONFIGURATIONS

5.24.1 SUMMARISED ASSESSMENT OF THE EXPERT-BASED BIDDING ZONE CONFIGURATIONS

Table 5.28 summarises the individual assessment of the expert-based configurations as described in detail in the previous sections. For each CACM criterion, each alternative bidding zone configuration is assessed compared to the current bidding zone configuration (Status Quo). The ratings can be understood as follows:

(+)	Better than the current bidding zone configuration (Status Quo)
(0)	No significant difference compared to the current bidding zone configuration (Status Quo) or a reasonable assessment of the impacts is not possible
(-)	Worse than the current bidding zone configuration (Status Quo)

This evaluation has been conducted in comparative terms and all indicators are expressed in relative terms to the current bidding zone configuration. The underlying analyses are mainly qualitative and, hence, for the reasons explained, are not supported by comprehensive quantitative simulations. Furthermore, any assessment is dependent on the underlying assumptions, in particular with regard to relevant externalities such as the grid infrastructure development. All results, figures and tables shown in this report are no firm basis for drawing conclusions and have to be interpreted against the assumptions explained in this report. Therefore, the summing up of the evaluation displayed in the Table 5.28 is inappropriate.

5.24.2 TIMESCALE FOR IMPLEMENTATION OF ALTERNATIVE BIDDING ZONE CONFIGURATIONS

Article 32 (4) b) ii) requires TSOs to include timescales for the implementation of the assessed alternative bidding zone configurations. Given the uncertainties and complexities linked to the ongoing implementation processes resulting from the implementation of the network codes (e.g. implementation of flow-based day-ahead market coupling in Core CCR, intraday market coupling and adaptation of balancing markets), TSOs can only provide a first indication for the timescale. TSOs consider that the implementation of an alternative bidding zone configuration within a flow-based region in all capacity calculation time segments (i.e. forward, day-ahead, intraday and balancing markets) will take **at least 3–5 years**. Hereby, the merging of existing bidding zones might be of reduced complexity. However, even for the merging of existing bidding zones, several aspects have to be considered. In particular, all market segments have to be adapted in order to form one joint market zone in all time segments.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	DE/AT Split	Big Country Split	Big Country Split 2	Small Country Merges
Network security				
Operational security	(+)	(+)	(+)	(-)
Security of Supply (for the entire system, short-term)	(0)	(0)	(0)	(0)
Degree of uncertainty in cross-zonal capacity calculation	(0)	(0)	(0)	(0)
Market efficiency				
Economic efficiency	(0)	(0)	(0)	(0)
Firmness costs	(-)	(-)	(-)	(+)
Market liquidity	(-)	(-)	(-)	(+)
Market concentration and market power	(-)	(-)	(-)	(+)
Effective competition	(0)	(0)	(0)	(0)
Price signals for building infrastructure	(0/+)[a]	(0/+)[a]	(0/+)[a]	(0/-)[a]
Accuracy and robustness of price signals	(0)	(0)	(0)	(0)
Long-term hedging	(-)[b]	(-)[b]	(-)[b]	(+)[b]
Transition and transaction costs	(-)	(-)	(-)	(-)
Infrastructure costs	Reference to investment costs as published in the TYNDP 2016			
Market outcome in comparison to corrective measures	(+)[c]	(+)[c]	(+)[c]	(-)[c]
Adverse effects of internal transactions on other bidding zones	(+)[d]	(+)[d]	(+)[d]	(-)[d]
Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes	(0/-)	(-)	(-)	(0/-)
Stability and robustness of bidding zones				
Stability and robustness of bidding zones over time	(0)	(-)[e]	(-)[e]	(0)
Consistency across capacity calculation time frames	(0)	(0)	(0)	(0)
Assignment of generation and load units to bidding zones	(0)	(-)	(-)	(0)
Location and frequency of congestion (market and grid)	(+)	(+)	(+)	(-)
Note: the summing up of the evaluation displayed in this table is inappropriate				

a The importance differs between borders/countries and the effectiveness of the signal is low, given the incompatible lead times between market prices and grid investment decisions which are characterised by long construction periods and approval processes.
b Alternative long-term hedging instruments (such as system price or trading hubs) that might mitigate the negative impact are to be investigated.
c There can be no further distinction between the splits without further quantitative analyses.
d This assessment considers loop flows, but does not consider any adverse market effects linked to loop flows.
e For Germany, grid investment planning foresees the building of high voltage direct current (HVDC) links moving towards a copper plate. The intention of these grid investments is to resolve any relevant congestion that might justify a split of the German bidding zone. This makes the Big Country Split less stable but does not consider any adverse market effects linked to loop flows.

Table 5.28: Summarised assessment of the bidding zone configurations

6 IDENTIFICATION OF CHALLENGES IN ALL-ENCOMPASSING MODELLING OF MARKETS AND GRID

PICTURE COURTESY OF TRANSNET BW

In order to assess alternative bidding zone configurations according to the criteria defined in CACM to a full and comprehensive extent, a detailed all-encompassing modelling of the future system[40] is necessary. A core requirement of several stakeholders, regulatory authorities and TSOs has been the inclusion of flow-based market coupling in this modelling, as well as the simulation of real operational capacity calculation practices to the largest possible extent. As the following section will show, representing such real operational practices in a future model environment creates particular complexities, which will be described in this section.

In this context, the procedural differences and diverging data used in real operational systems compared to the applied model environment deserve particular attention.

The flow-based capacity calculation as applied in real systems has been designed for the operational planning time frame with a short prediction time horizon[41]. With such short lead times, close-to-real-time information on the electricity system can be used for the flow based capacity calculation. In more concrete terms, essential (flow-based) market parameters can be set such that they represent close to real time system conditions. Both the actual grid situation and fundamental market parameters[42] available at this point in time can be used to calibrate those parameters.

In a model environment which looks several years into the future and analyses new bidding zone configurations, such information on the real system is not available. Hence, in order to accommodate the above mentioned requirement of simulating a flow-based system in a long-term study, it has been necessary to design and implement various assumptions and simplifications replacing the operational information.

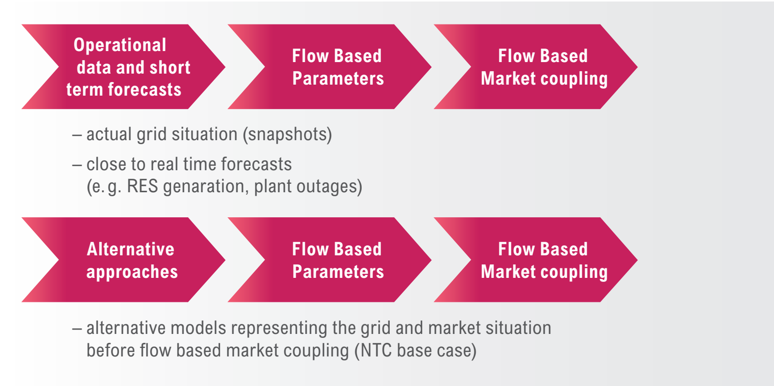


Figure 6.1: Different preconditions in operational flow-based systems and a future flow-based market model

Figure 6.1 above illustrates these fundamentally different preconditions in real operational flow-based systems in comparison to a future flow-based market model.

The fact that several of the important detailed methodologies and market design specifications do not yet exist but are being developed in parallel to the First Edition of the Bidding Zone Review (e.g. flow-based methodology to be established in the Core CCR[43]) or amendments foreseen by the Clean Energy Package) increases the uncertainty associated with modelling a future flow-based system further.

Uncertain assumptions replacing close-to-real-time information in regard to future market design are particularly sensitive, since small changes to the input data and modelling assumptions can have a significant impact on the results obtained in a flow-based market coupling simulation.

40) Market and grid on a nodal basis

41) Typically few days ahead of the delivery period

42) E.g., RES injections

43) The enlarged geographical scope of the flow-based area (from the CWE area to the Bidding Zones Review's area) constitutes an additional element of complexity.

In order to assess this overall sensitivity in further detail, the relevant impact is discussed for each computation step linked to the flow-based market coupling. The full applied model framework,[44] which consists of five major steps, is displayed in the Figure 6.2:

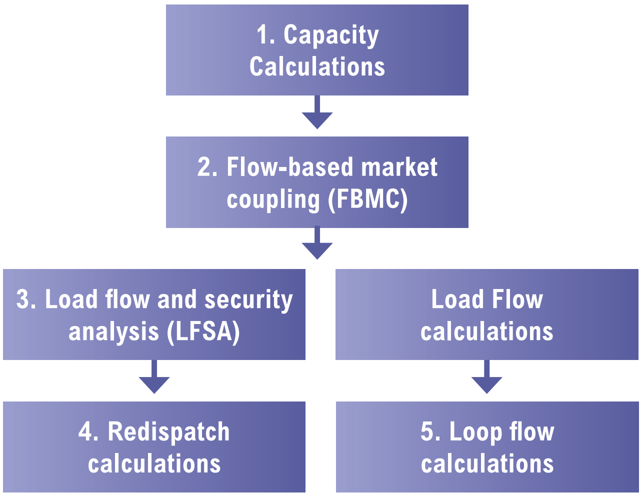


Figure 6.2: Initial model set-up in the First Edition of the Bidding Zone Review

44) As in real systems, the model starts with a capacity calculation module which determines the relevant parameters for the market coupling. Based on the results of this market coupling simulation, Load Flow and Security Analyses (LFSA) and Load Flow computations can be executed. These computations serve as a basis for redispatch and loop flow analyses.

The following sections refer to the model structure illustrated in Figure 6.2 in order to describe the model and its complexities associated with each represented step. Section 6.1 discusses complexities and challenges for the capacity calculation module of the model chain by comparing it to real operational systems. This discussion is expanded to the flow-based market coupling simulation in section 6.2. Section 6.3 provides an example of how these current characteristics of the model translate into uncertainties with regard to the assessment of the bidding zone evaluation criteria. As a final conclusion, section 6.4 recommends not using the flow-based market coupling results as a quantitative element in the current Bidding Zone Review but to dedicate further work on enhancing flow-based simulations in a future environment before firm conclusions can be drawn. The insights gained during this First Edition of the Bidding Zone Review provide valuable contributions for such an exercise.

6.1 IMPLICATIONS OF THE CAPACITY CALCULATION

In real operational systems, capacity calculations are principally based on four distinct steps which are represented in Table 6.1.

Translating those operational steps in a future model environment requires particular assumptions. In the following, all capacity calculation steps in the future model and the identified main challenges are described in more detail.

6.1.1 CAPACITY CALCULATION STEP 1: DETERMINATION OF THE BASE CASE

In operational 'day-to-day' systems in CWE the base case is determined based on a representation (snapshot) of the actual grid situation two days before real time (D–2). In order to create a forecast for the real time situation, this snapshot is adapted by first removing actual cross-zonal exchanges and subsequently considering long-term allocated capacities and other factors (e.g. expected wind generation).

This information on the actual grid situation close to real time (D–2 snapshots) is not available when modelling a future market environment[45], especially if the future scenarios under assessment are characterised by significant variations in demand and generation patterns as well as in the grid structure. For the purpose of the required simulation, this snapshot has been replaced by grid situations determined by a full-year market simulation based on simplified cross-zonal NTC values.[46] This simplified base case approach leads to several challenges, which are illustrated in the following.

45) Please note: while the model applied in the First Edition of the Bidding Zone Review does not consider uncertainty (e.g. no RES forecast error), the underlying detailed nodal assumptions for a future system are subject to high uncertainties.

46) Please note: applying flow-based market coupling for the simulation of the base case would have resulted in a typical 'chicken and egg problem' since the determination of the base case is the first step of the capacity calculation for a flow-based market simulation.

Step	Purpose
1. Selection of relevant market and grid situations (base case)	Identification of relevant market and grid situations (so-called base case) to be considered for each of the steps below
2. Identification of CBCOs	Identification of critical-branch-critical-outage combinations (CBCO) to be considered in the FBMC
3. Calculation of GSKs/PTDFs	– Translation of a net position change of a given bidding zone into estimated specific injection increases or decreases in the grid model; (generation shift key, GSK) – Determination of power transfer distribution factors (PTDF) that represent the influence of exchanges on critical branches
4. Calculation of FRMs	Calculation of flow reliability margins (FRMs) that represent the uncertainties within capacity calculation

Table 6.1: Capacity calculation steps

One of the most important points to consider when determining the (cross-zonal) NTC values for the base case is that this base case is used to select the CBCOs which in turn determine the constraints for the flow-based market coupling. In order to avoid a flow-based domain that is too restricted or too large, these NTC values have to be determined carefully. NTC values that are too high would result in an extensively long CBCO list and, therefore, a highly restricted flow-based domain. As a consequence, computations may become infeasible. In contrast, NTC values that are too low enlarge the risk of neglecting important CBCOs, leading to a flow-based domain that is too large.

It has to be noted that such 'base case NTC values' do not relate to real operational NTC calculations but are rather a method to determine a suitable base case that can be considered in a future flow-based computation.

Due to the complexity of the calculations, these base case NTC values have been determined per season (summer/winter) and per year. Furthermore, the CBCO list considered per scenario has been fixed for the entire year of the computation. Both aspects introduce a high level of approximation.

Figure 6.3 below illustrates this effect using an example from one of the simulated base cases. As shown by the left figure, more than 50 % of all CBCOs are overloaded in the original base case with NTC values above zero (blue graph, CBCOs are sorted by maximum loading). When correcting for the influence of cross-zonal exchanges (orange graph), i. e. when setting all NTC values and hence cross-zonal exchanges to zero, the maximum loadings of most CBCOs decrease substantially, which confirms that most CBCOs are indeed substantially influenced by cross-zonal exchanges. However, as indicated by the orange line in Figure 6.3, about 10 % of all CBCOs remain congested, representing a pre-congested base case. The consequence of considering these pre-congested CBCOs in the capacity calculation (i. e. to keep them on the CBCO list) is that the flow-based market coupling has to resolve these pre-congestions, which may result in counter-intuitive exchanges.

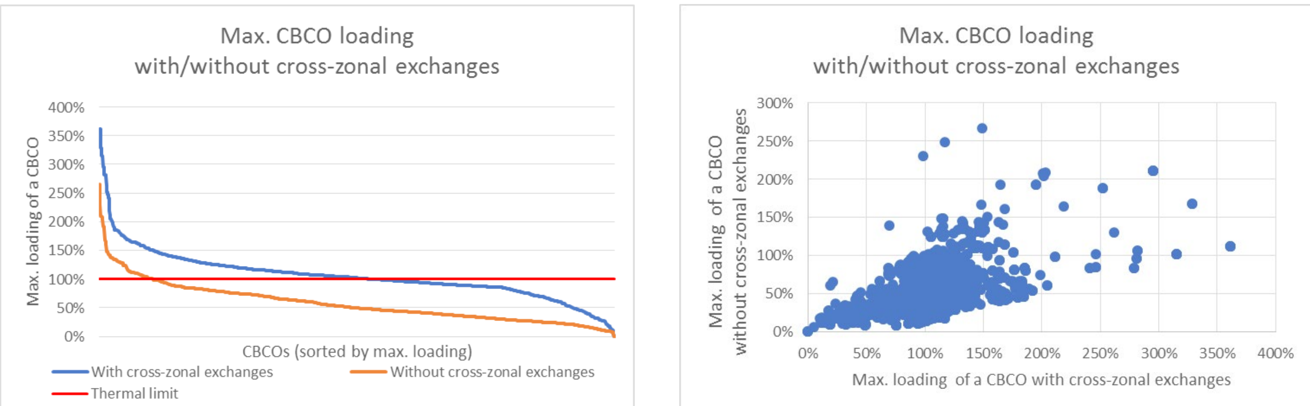


Figure 6.3: Analysis of a pre-congested base case for an illustrative scenario

At first sight, it seems reasonable to assume that cross-zonal exchanges always contribute to the loading of CBCOs, i.e. that the loading of the corresponding CBCO will be higher in a situation with cross-zonal exchanges. As the right graph in Figure 6.3 shows this is not always the case. Indeed, the graph on the right shows that for several CBCOs the loading decreases without cross-zonal exchanges. But there are also several cases where the maximum loading without cross zonal exchanges is higher than the maximum loading with them. In these cases, crosszonal exchanges alleviate the CBCO. In the displayed sample about 3% of all CBCOs that were overloaded in the original base case show a higher loading without cross-zonal exchanges. In these cases, cross-zonal exchanges would have a relieving impact on the congestion observed in the base case.

Finally, it should also be mentioned that the enlarged geographical scope of the flow-based area (from the CWE area to the Bidding Zones Review's area) constitutes an additional element of complexity, further increasing the degree of uncertainty in the base case creation. Fundamental detailed market design choices, e.g. PST settings or use of (internal) DC cables, have currently not been taken in this area.

6.1.2 CAPACITY CALCULATION STEP 2: IDENTIFICATION OF CBCOS

In operational systems, the selection of CBCOs is based on defined criteria applicable to real grid situations, e.g. the '5% sensitivity rule' in CWE[47]. Such criteria are applied in an environment with observed market behaviour, based on a large number of calculated snapshots and complemented with operational experience. The proper selection of appropriate CBCOs is of key importance for the efficiency of flow-based market coupling. Neglecting relevant CBCOs would overestimate the scope for cross-zonal exchanges, while the inclusion of non-relevant CBCOs (e.g. local congestions) would not only underestimate the potential for cross-zonal trading but may even make it impossible to find a feasible solution. A fixed set of criteria, even if they are designed carefully, will always risk identifying congestions as being cross-zonal relevant even though they would be identified as local congestions in operational practice. Such local congestions are for instance cases which could be easily solved by certain local remedial actions (such as non-costly topological measures or redispatching of a selected power plant). Also the opposite case might occur. A defined set of criteria might neglect CBCOs that may actually be relevant for cross-zonal trading in operational practice. Therefore, operational knowledge and its potential translation into generally applicable rules is key for a transparent adaptation of the CBCO list. Designing such rules for a future, not yet implemented market area is not straightforward.

47) CBCOs with power flow sensitivities (PTDFs) to cross border trade above 5%

The challenge was therefore a definition of criteria that can, on the one hand, be applied automatically and consistently to the full geographical scope of the study and would therefore avoid/minimise the scope for manual discretion, and on the other hand, reflect operational behaviours to the largest possible extent as requested by stakeholders. As one important consequence of this approach, topological measures have been neglected which is also compliant with requirements from regulatory authorities. The consideration of topological measures would have required considerable operational knowledge about uncertain, future systems. As well as such measures and their impact on future load flows having to be described in detail, the relevance of such measures for cross-zonal trading would have to be assessed and implemented in the model since a flow-based algorithm would have to consider these measures as additional decision variables, increasing the complexity of the model significantly with every considered topological measure.[48] The drawback of neglecting topological remedial actions is a smaller flow-based domain. Also, as the redispatching module is executed after the capacity calculation, the flow-based domain is computed without any remedial actions, which reduces its representativeness.

In order to better understand how local issues can impact the capacity calculation process, it is important to mention 'local issues at bidding zone borders'. First, it should be mentioned that all the cross-zonal elements are automatically selected for the capacity calculation. In fact, a situation can arise in which flows on some cross-zonal lines are mainly affected by local generation and load conditions rather than cross-zonal exchanges, making it inefficient (in terms of overall system costs) to consider these elements (even if cross-zonal) as CBCOs in the capacity calculation process. This phenomenon typically appears for cross-zonal lines which have a thermal capacity significantly lower than the overall capacity at the bidding zone border and are located in an area with high loads and or production (for example, some 220kV lines in the Alps during the high hydro production season). In these cases, TSOs typically solve the potential overloads by applying local remedial actions (mainly non-costly remedial actions). Hence, neglecting remedial actions in the capacity calculation process could induce unrealistic limitations of the flow-based domain.]

48) Please note: even in operational nodal pricing markets topological measures can only be considered to a very limited extent.The potential increase of the model complexity mentioned above is particularly relevant since the modelling performed for this study has been based on a comprehensive load flow and security analysis for a full grid model of more than 10,000 nodes and elements considered N-0, N-1 and selected double-circuit contingencies. This results in more than 100 million combinations whose relevance for the cross-zonal trading in a future scenario had to be assessed. Increasing this number by considering a significant number of topological measures would raisethe model complexity beyond its computational limits.

In summary, the core issue of the identification of relevant CBCOs (step 2) is the differentiation between 'local' CBCOs and those relevant for cross-zonal exchanges. Several of these issues have been identified and are summarised (non-exhaustively) in Table 6.2.

Identified challenges in the CBCO selection applied in a long-term future study	
A. Cross-zonal relevance of voltage levels differs between TSOs	Whilst TSOs in some bidding zones use also the 220 kV grid for long-distance transportation of electricity, this part of the grid is not used for long distance exchanges in others. Potential congestions of 220 kV elements located in such zones are in reality usually resolved by topological measures. In order to avoid extensive/long expert assessments this aspect (which is not only relevant for the CBCO selection but for the entire study) has been addressed by applying TSOs' individual voltage thresholds. However, an important observation is that such an approach may be too pragmatic as it risks the inclusion of CBCOs that are not cross-zonal relevant (or vice versa the neglection of CBCOs that are cross-zonal relevant).
B. Identification of sensitivity of CBCOs to cross-zonal exchanges	In order to identify CBCOs that are cross-zonal relevant, the so-called 5 % rule, as already applied in CWE, has also been applied in the First Edition of the Bidding Zone Review. While in operational day-to-day system, the CBCO list is assessed based on operational experience, in a long-term study such information is not available. An important learning of the First Edition of the Bidding Zone Review is that such operational experience cannot be fully replaced. It is worth mentioning that the validation of the CBCO list would have required a manual intervention after the automatic selection procedure. Such a step would have induced a certain degree of discretion, potentially distorting the comparison between different configurations. Additional CBCO selection criteria had to be developed instead, as the flow-based domain was excessively constrained by elements that were not significantly influenced by foreign bidding zones or that an expert would identify as local issues. Therefore, an additional CBCO selection criterion considered the better identification of local grids in a long-term study. For this reason, the 5 % rule has been extended to the consideration of zone-to-hub PTDFs* in order to avoid artificial 'min/max generation' constraints on local bidding zones. These additional criteria have only partially resolved the issue of local congestions overly restricting the pan European electricity exchange in the simulation model. To provide a better understanding of this issue, an illustrative example is provided below this table.
C. Sensitivity of CBCOs to the nodal distribution of generation and load	While in an operational day-to-day system the forecast of the generation and load on a nodal level is quite good, assumptions for the future distribution have to be made for a long-term study. It is evident that the approach for deriving such nodal assumptions impacts the expected loading of elements and therefore, the CBCO selection. Also, the decision on the weather year/temperature influences the loading of the lines and, therefore, the CBCO selection.
D. Impact of pre-congested CBCOs	As already explained in the previous section regarding the determination of the base case (step 1), pre-congestions in the base case are likely caused by future assumptions in nodal allocation of (distributed) future generation/load and simplified NTC values. Pre-congestions in the base case yield in numerous pre-congested CBCOs as they are not excluded from the CBCO list.
E. Sensitivity of CBCOs to internal DC exchanges only	At present, the operation of DC links is not optimised as part of the market coupling process, but forms part of the assumptions underlying the base case. In the future scenarios considered by the First Edition of the Bidding Zone Review, however, some DC links operate within and between bidding zones in the flow-based area. It was, therefore, decided to explicitly include DC links in the setup for flow-based market coupling. This is achieved by considering the flows across DC links as separate decision variables and with separate PTDF columns. The explicit consideration of DC links led to issues with regards to the 5% rule for the sensitivity of CBCOs to cross-zonal exchanges. This rule implicitly assumes that any congestion may be resolved by an (unlimited) change of cross-zonal exchanges. In the case of DC links, however, such changes are limited to the thermal capacity of each DC link. This may lead to a situation where the 5 % rule is assumed to be satisfied, whilst the absolute impact of a given DC link remains very small relative to the size of potential flows on the CBCO and is thus too small to effectively resolve congestion. As this leads to infeasible outcomes, it was decided to exclude DC links from the sensitivity check and apply the 5% rule for 'general' cross-zonal exchanges only, i. e. to exchanges via the AC grid.
* The hub node is a reference node that compensates the variations of the net position of a zone. The zone-to-hub PTDF represents the variation of the flow on a CBCO in function of the variation of the net position of a zone.	

Table 6.2: Overview of the identified challenges in the CBCO selection applied in a long-term future study

In order to make the relevance of the identified challenges in the CBCO selection for a long-term future study more understandable, specific examples partly extracted from the modelling results are provided in the following. Each challenge is labled with the letter already included in the overview illustrated in Table 6.2.

Challenge A: cross-zonal relevance of voltage levels differs between TSOs

The existing transmission network structure in each country is the result of decades of grid development activities performed by TSOs (and by the previous grid operators) and is mainly the result of policies defined at national level.

For this reason, the relevance of each voltage level in terms of long-distance energy transmission (e.g. with cross-zonal relevance) can significantly vary between countries (or even between areas).

Consequently, as explained in Table 6.2, while the 380 kV network is universally recognized as the main infrastructure for long-distance energy transmission, the role of the 220 kV grid for the transmission grid differs between the European TSOs. Whilst 220 kV elements clearly serve in some zones as long distance transmission grid, 220 kV elements in other zones are not used for long-distance exchanges. This is typically dependent on the degree of development of the 380 kV network: in areas where 'strong' 380 kV infrastructures exist, the 220 kV grid is typically operated in order to accommodate 'local' flows (mainly driven by local generation and loads). In these cases, topological remedial actions can be applied with a higher degree of flexibility (e.g. in order to change the flow pattern, a 220 kV line can be opened with lower impact on the system security where a 'strong' 380 kV network is present) and/or local redispatching actions can be the most efficient way to avoid overloads when they materialise.

For the above mentioned reasons, a harmonised approach over all areas considering voltage levels as relevant for the capacity calculation can distort the results of the capacity calculation(and, consequently, the flow-based market coupling results. In particular, if only the 380 kV network is considered, cross-zonal capacities can be overestimated where the 220 kV network is important for accommodating cross-zonal flows. In contrast, including 220 kV elements in the whole area under assessment can lead to a significant reduction of the flow-based domain.

A typical example of the latter case appears when industrial/big urban areas are located close to bidding zone borders. In this case, in some countries, the network is typically designed in order to accommodate cross-zonal flows mainly with 380 kV elements, while the local loads are fed by 220 kV grid connected to the 380 kV network in some relevant substations. In this case, due to their location, even the 220 kV elements show a significant sensitivity to cross-zonal exchanges, but in the real operation, they are not considered as binding for the cross-zonal capacities since they show a higher sensitivity to local generation and load patterns and their possible overloads can be solved, without additional costs, by applying topological remedial actions.

This issue can be solved by either representing in a detailed way, remedial actions applied by TSOs or defining a voltage-level relevance differentiated per area of the network.

The first approach allows to obtain a 'perfect' reproduction of the expected real operation, but it significantly increases the complexity of the simulation chain.

The second approach applied in the study seemed to be the most promising one for a complex and long-term analysis like the Bidding Zone Review. It allows to avoid excessive limitations to the flow-based domain without impacting, in any significant way the complexity and computation time requirements of the simulation chain. However, this approach exposes the analyses to a certain degree of discretion.

Challenge B, example 1: CBCOs that are sensitive to one bidding zone only

In order to identify CBCOs that are relevant for cross-zonal trading, the so-called 5 % rule applied in CWE has been considered in the First Edition of the Bidding Zone Review. A CBCO is considered to be significantly impacted by cross-zonal trade, if its maximum zone-to-zone PTDF is larger than 5 %.

Although this criterion ensures that CBCOs are sensitive to cross-zonal trading in general, some CBCOs are extensively sensitive to one bidding zone only. As shown in the example in Figure 6.4[49], one particular CBCO is impacted by a change of the generation in bidding zone 11 only.

[49] taken from the modelling results performed in this study, for illustration purposes only

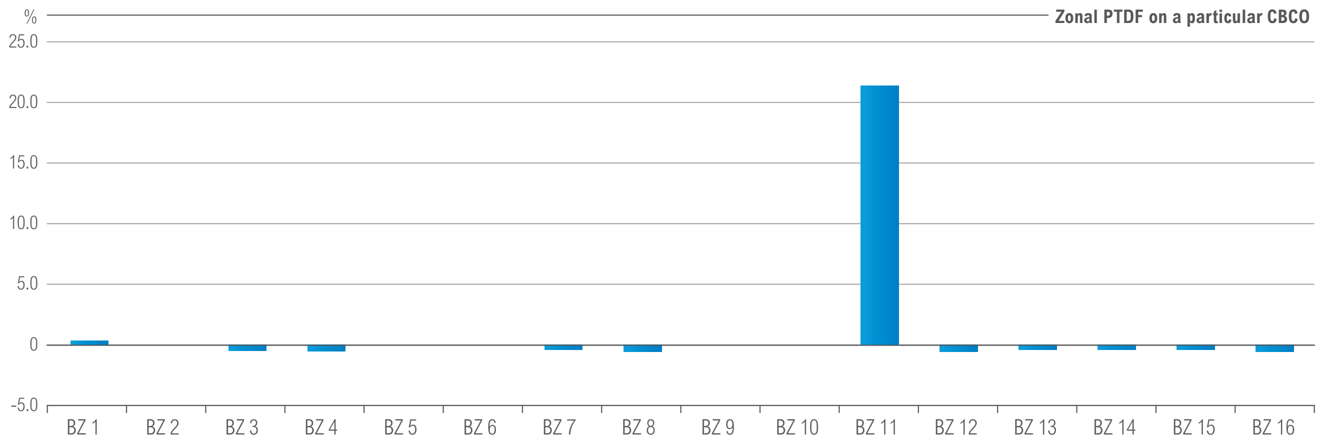


Figure 6.4: Illustrative example for CBCOs that are sensitive to one bidding zone only

To put it in more general terms, even if CBCOs pass the 5 % threshold for cross-zonal trade sensitivity, such values can exclusively occur for generation in one single zone, while all other zone-to-hub PTDFs are extremely small (or even zero). CBCOs serve as artificial constraints on generation in that particular bidding zone that cannot be released by any other means.

While, in operational systems, operational experience provides insights and can identify such congestions as non-relevant for cross-zonal exchanges, in a long-term future model, mathematical methodologies replacing this expert assessment would not automatically capture the local characteristic of the congestion.

In order to address this phenomenon, the 5 % rule has been complemented by an additional requirement of at least two zone-to-hub PTDFs exceeding a certain threshold. While this additional criterion may help identify some CBCOs as local, it may likewise fail to identify CBCOs as relevant for European trade in a case where this trade is predominantly influenced by only one particular zone.

Challenge B, example 2: CBCOs that are sensitive to the generation of power plants

Another challenge, which has also been encountered in real operational systems, are CBCOs that are strongly impacted by a local power plant. Unless such cases are separately treated, e. g. by removing one or more CBCOs or by ignoring the influence of the corresponding power plant(s), this may result in congestion that is hard or even impossible to resolve by adjustment of cross-zonal exchanges. As Figure 6.5 shows, this effect is also present in the final data set used for the Bidding Zone Review.

Each dot represents a unique combination of a major power plant and a CBCO, but each plant or CBCO may be shown several times (i. e. in different combinations). The PTDFs on the horizontal axis indicate the share of generation that will flow across the CB(CO), whereas the vertical axis expresses the max. induced flow (i. e. at max. generation), in per cent of the CB's thermal limit. For instance a dot at 0.5/100 % indicates that the induced flow on the CB(CO) will be equivalent to 50 % of the generation and may reach up to 100 % of the CB's thermal limit. In other words, the generator represented by this dot has a large impact on this specific CB(CO). Considering this generator in the base case as producing (or not), has a fundamental impact on the loading of this CB(CO) and also on its selection as a CBCO for the flow-based market coupling.

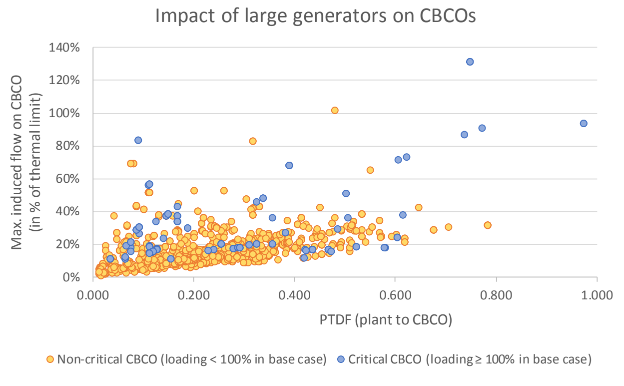


Figure 6.5: Analysis of large plants (≥ 400 MW) having a significant influence on CBCOs

More specifically, nearly 8 % of all CBCOS, or nearly 80 % of all pre-congested CBCOs, are substantially impacted by about two dozen large generators. A detailed analysis of some examples has revealed several cases where pre-congestion is indeed caused by the dominant impact of a nearby power plant only, but has also shown that this effect is not the only driver for pre-congestion in other cases. In other words, whilst a special treatment would appear necessary for the first group of plants or CBCOs, this may not be the case for others. This highlights the complexity of identifying a practical rule and criterion for identifying and treating corresponding cases.

Challenge C: Sensitivity of CBCOs to the nodal distribution of (distributed) generation and load

In a given network structure, a grid element's loading level is dependent on the nodal generation and load pattern. In order to perform detailed future market and network simulations, reasonable nodal assumptions for the future generation and load pattern had to be taken. For an analysis which encompasses a larger, European region such assumptions need to be harmonised in order to accommodate a fair and unbiased comparison. The drawback of such a harmonised approach is a potentially insufficient representation of local specificities. The extent to which such local specificities are relevant is, however, a rather complex question. Whereas local characteristics are highly relevant for detailed grid planning, this may not be the case for market analyses related to long-distance bulk European electricity transmission.

For the First Edition of the Bidding Zone Review, a rather harmonised European approach has been used for the nodal allocation of generation and loads. The model results provide some evidence that this approach has been too general to be applied in a flow-based environment, and may serve as an explanation of some significantly constrained flow-based domains.

6.1.3 CAPACITY CALCULATION STEP 3: CALCULATION OF GSKS AND PTDFS

Besides CBCOs, GSKs and PTDFs are important capacity calculation parameters that form a necessary input for a flow-based market coupling.

In operational day-to-day systems, each bidding zone applies a customised approach for the determination of GSKs, which may be adjusted on a daily basis (e. g. due to generator outages). PTDFs are then determined in a separate step. Operational knowledge of the actual market behaviour is key for this determination.

In a future model environment, detailed knowledge about the specific market behaviour is not available. GSKs and PTDFs therefore need to be determined by a unique and consistent approach that is applied to all bidding zones. In the Bidding Zone Review, GSKs are implicitly considered by using the set of hourly market simulations for the base case. More specifically, a separate set of load flow calculations is used to determine the relation between generation by 'dispatchable' plants (i. e. plants assumed to be driven by market prices) in each bidding zone and the flows across each CBCO. By means of a functional approximation of the corresponding flows, this information is then used, to determine so-called 'merit order' PTDFs, i. e. a set of PTDFs that are a function of the current operating level of dispatchable plants in each bidding zone.[50)]

In comparison to operational systems based on a known market and grid situation, the choice of the 'right' GSKs and hence PTDFs for a long-term study is less trivial. The marginal generators will change in line with market prices, daily/seasonal load impacts, the changes in the fluctuating generation of RES etc. Also generator outages impact GSKs and, hence, PTDFs.

Table 6.3 provides an overview of the key differences between the determination of GSKs and PTDFs as performed in an operational day-to-day system and as applied in a long-term future study like the Bidding Zone Review.

50) However, while such merit order PTDFs in the First Edition of the Bidding Zone Review have been used to identify relevant CBCOs (see step 2), in the flow-based market coupling simulation, ultimately only average PTDFs were used. Such average PTDFs were calculated based on the merit-order PTDFs.

Differences between the approach to determine GSKs/PTDFs in an operational day-to-day system and a long-term future study like the Bidding Zone Review	
In operational systems, PTDFs are derived from the incremental variation of the generation dispatch for selected snapshots. PTDF values may or may not be varied for different times/dispatch situations.	In the BZR, two different approaches have been combined: As a starting point, zonal PTDFs have been derived from the 'merit-order PTDF' of each bidding zone (see text above). For active elements and/or connections to third countries, the nodal PTDF of the corresponding connections to the AC grid have been used, either in addition or as an alternative.
In operational systems, maintenance/outages may be explicitly considered where relevant (i. e. for major units).	By using the set of NTC-based market simulations for determination of the merit-order PTDF, generator maintenance and outages are effectively 'smeared' into the zonal PTDF function. This may lead to inaccuracies, especially in case of power plants having a substantial impact on the zonal PTDF of the local BZ.
In operational systems, PTDF matrices may vary for each timestamp.	Due to the high complexity of the model set-up of the First Edition of the Bidding Zone Review, a single PTDF matrix for an entire year has been applied, i.e. the PTDF values were not differentiated by season/day/time of day. This means that for instance, seasonal changes in the operation of some forms of dispatchable plants (e. g. CHPs or hydropower storage) are not considered in the zonal PTDF.
In the current CWE arrangement, no DC links operate within the relevant market area. For adjacent bidding zones, flows for DC links are assumed (so-called reference flow).	In the future, DC links are considered to operate within bidding zones and therefore need to be considered in the capacity calculation. For the First Edition of the Bidding Zone Review, an endogenous consideration of DC links was considered (by means of separate PTDF columns). It is evident, that different approaches for the consideration of internal DC links will result in different flow-based market coupling results. Yet, as such operational schemes for internal DC links and their consideration in a flow-based domain are under development in parallel to the First Edition of the Bidding Zone Review, these could not be considered in the model and reasonable assumptions had to be taken.
Exchanges with third countries	Compared to future studies, the consideration of third countries in operational day-to-day systems is 'easier', since the underlying market and grid structure, as well as the behaviour of third-country markets, is known. Yet, in a future study this knowledge is not available. Therefore, in the First Edition of the Bidding Zone Review constant PTDFs have been assumed for exchanges with third countries (via AC grid).

Table 6.3: Overview of the differences between the approach to determine PTDFs in an operational day-to-day system and a long-term future study like the Bidding Zone Review

In order to make the relevance of the identified challenges in the CBCO selection for a long-term future study more understandable, specific examples are extracted from the modelling results performed for the First Edition of the Bidding Zone Review in the following.

Example A: calculation of PTDFs considering GSKs implicitly ('merit-order PTDFs')

In the First Edition of the Bidding Zone Review, zonal PTDFs are determined by regression analysis applied to separate load flow analysis for variation of (dispatchable) generation in each relevant bidding zone. These zonal PTDFs are limited to dispatchable generation, i. e. fluctuating RES, run-of-river, etc. are treated separately.

Regression analysis is used to convert the observed flows[51] (blue dots in Figure 6.6) into a polynomial function. This approximate function is then used to estimate the hourly flow across a CBCO as a function of generation by dispatchable plants (orange dots). In a second step, the approximated flows (orange) are then used to calculate the (merit-order) PTDFs, which implicitly consider the impact of different generators (so-called GSKs). It is clear that any inaccuracies in these PTDFs (as capacity calculation parameters) may impact flow-based market coupling results..

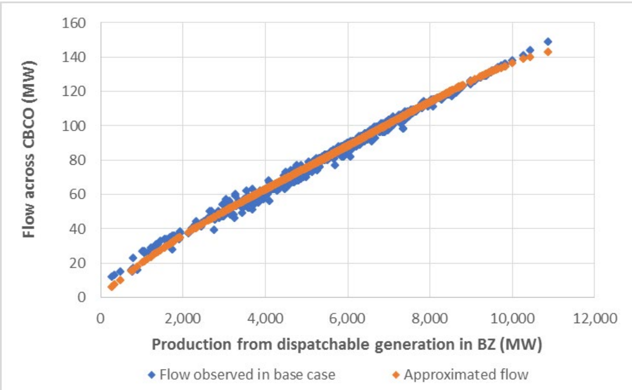


Figure 6.6: Approximation of load flows in the merit-order PTDF approach (for an illustrative line); Note: 'Generation' refers to dispatchable generation only, i. e. excluding variable RES

51) Each dot represents the combination of aggregated generation by dispatchable plants (horizontal axis) and induced flow on the CBCO (vertical axis) in a single period, as observed for the base case. For each scenario and each bidding zone configuration, the base case includes every two-hour-time interval of the third week of an entire year.

As Figure 6.6 shows, the approximation is quite good in several cases, i.e. the approximated values (orange dots) are very close to the original observations (blue dots) made in the base cases. However, as displayed in Figure 6.7, there are also cases where actual load flows vary widely (i.e. high differences between red and blue dots), such that the functional fit is much weaker. For example, the figure below shows an example for the same CBCO as above, but for the impact of a different bidding zone. In this particular case, the flow across the CBCO is largely determined by a local generator with two large units. As a result, the CBCO flows are no longer correlated with the aggregate level of dispatchable generation in the bidding zone, resulting in an error of up to 1600 MW.

Such issues are also encountered by TSOs in practice, and there may be several reasons for this, including seasonal impacts or the strong influence of local plants.

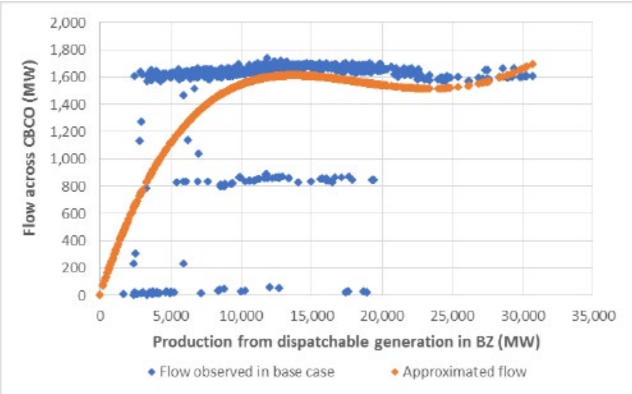


Figure 6.7: Deviations between actual and approximatised load flows (for an illustrative line)

6.1.4 CAPACITY CALCULATION STEP 4: CALCULATION OF FRMS

In operational day-to-day systems, FRMs are determined based on a statistical analysis of the difference between the expected and the real load flow on a critical grid element. Such data is not available for future scenarios.

In the future model environment of the First Edition of the Bidding Zone Review, the assessment was based on a simplified stochastic analysis of selected aspects:

- Operation of FCR, FRR
- Forecast inaccuracy for RES and load
- Major generator outages
- Inaccuracy of zonal PTDF (GSK, 'internal trade', generation patterns)

A more detailed description of the FRM methodology developed for the consideration in a future study can be found in the Annex.

In order to mitigate the risk of unreasonably high or low (negative) FRM values, these were limited to a range of [0 %, 30 %] of each CB's thermal capacity.

Based on the model results performed for the First Edition of the Bidding Zone Review, Table 6.4 shows the extent to which modelled FRMs were higher than 30 % (in absolute terms) of the thermal capacity of the relevant CB. For example, a value of 4 % provided for the Big Country Split 2 in the 2025 planned grid scenario (2Z2020w) means that 4 % of all CBCOs considered in this scenario had FRM values that were originally higher than 30 %.

The highest FRM value observed in this scenario is 44 %. Or in other words: 44 % of the thermal capacity of the related CB would not be available for the market due to the above mentioned uncertainties. Yet, as described before such high FRM values are considered to be unreasonable and the result of the challenges described in the sections before and have therefore been reduced to a maximum of 30 %.

Scenario	Share of CBCOs with FRM values higher than 30%	Maximum FRM value observed over all CBCOs
SQuo2020w	6 %	49 %
DAT2020w	0 %	10 %
2Z2020w	4 %	44 %
3Z2020w	4 %	44 %
Merge2020w	7 %	54 %
SQuo2025p	10 %	54 %
DAT2025p	0 %	11 %
2Z2025p	1 %	39 %
3Z2025p	1 %	40 %
Merge2025p	2 %	44 %

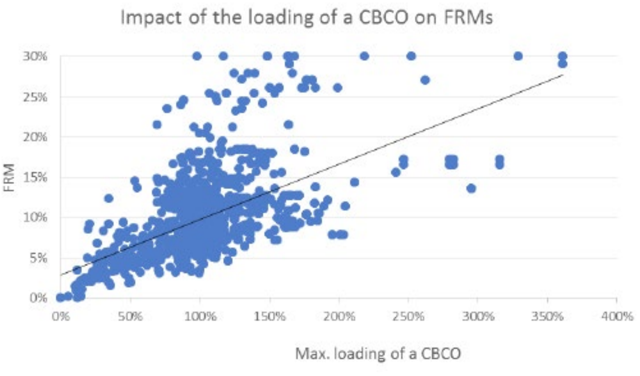
Table 6.4: CBCOs with unreasonably high FRM values

In this context, Figure 6.8 below displays the correlation of FRMs and the loading of CBCOs. It is obvious that there is a strong positive correlation between the loading of CBCOs and the corresponding FRM values (see left-hand box within figure). Or, in other words: a higher loading correlates positively with a higher FRM value (as shown by the black line that indicates a linear approximation), which means in particular that pre-congested CBCOs are more likely to be (further) constrained by high FRM values than other CBCOs.

Yet, as many instances of (very) high FRM values for CBCOs with limited loading show[52], the loading of a CBCO is not the only factor for the FRM. And whilst one might expect that this positive correlation is even stronger when looking at CBCOs with high FRMs only, this assumption does not hold as illustrated by the right graph below (which focuses only on those FRMs higher than 15 %.) Although the correlation between the loading of CBCOs and the FRM values is still positive, it is much weaker than for the sample of all CBCOs (see left graph). This becomes visible by the lower slope of the black line (compared to the left graph).

This analysis indicates that the calculated FRM values are impacted by various factors, including the challenges already described in the previous sections. For instance, high FRM values may be caused by pre-congestions in the modelled base case. Similarly, large plants with a major influence on nearby CBCOs may lead to high FRM values and any inaccuracies in the nodal distribution of (distributed) generation and load may impact FRM values.

52) And the fact that the linear approximation does not cross the vertical axis at zero.



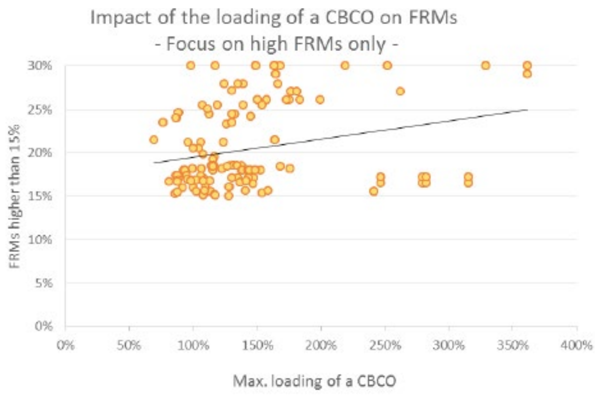


Figure 6.8: Correlation between loading of a CBCO and its FRM

6.2 IMPLICATIONS OF THE FLOW-BASED MARKET COUPLING

All implications related to the determination of the capacity calculation parameters (base case, PTDFs/GSKs, FRMs) materialise in the flow-based market coupling simulation. While several challenges have already been discussed in section 6.1, in the following some main challenges focusing on the outcome of the flow-based simulation are discussed.

In order to make the relevance of the identified challenges in the flow-based market coupling for a future study more understandable, specific examples are extracted from the modelling results performed for the First Edition of the Bidding Zone Review and explained in the following.

Identified challenges in the flow-based market coupling as implemented in a long-term future study	
A. Challenges related to the determination of the capacity calculation parameters materialise in the flow-based market coupling simulation	See section 7.1 Amongst others: – Considerable share of pre-congested CBCOs (i.e. negative margins in one direction) – Extreme sensitivity to 'wrong' CBCOs/margins can lead to extreme/infeasible market outcomes
B. Counterintuitive flows are accepted in the model environment	Counter-intuitive flows mean that the direction of the cross-zonal flows (as an outcome of the flow-based market coupling algorithm) does not correspond to the direction of price differences. Such flows can be, overall, welfare-maximising, especially in cases where the modelled flow-based domain is already strongly restricted and high congestions (that already occurred in the base case) need to be solved in the flow-based market coupling. The modelling performed in the First Edition of the Bidding Zone Review showed that the assumption on whether counter-intuitive flows (if welfare-maximising) shall be considered in the algorithm or not is a highly important design feature. It becomes even more relevant if pre-congestions are observed in the base case and the flow-based domain is highly restricted.
C. Restriction of the flow-based domain by NTCs with non-core model regions	For flow-based capacity calculations, reasonable assumptions have to be taken not only on exchanges within the CCR but also for exchanges with the surrounding regions ('third countries'). In operational day-to-day systems, the market and grid situation in these areas can be predicted more easily, and available capacities (NTC) are well known. In contrast, a long-term study cannot rely on robust NTC values for a future situation. Therefore, simplified NTCs have been considered in the First Edition of the Bidding Zone Review. Especially in case of DC connections, these NTC values were sometimes lower than those applied today. This decrease clearly restricted the scope for cross-zonal exchanges with third countries. Indirectly, it may also restrict the flow-based domain, which – as experiences in the First Edition of the Bidding Zone Review have shown – is particularly critical in an already strongly restricted flow-based domain (e. g. due to pre-congestion). In the model environment, exchanges with and between third countries were furthermore partially used to relieve congestion in the flow-based domain, even if this implied counter-intuitive exchanges. This highlights that it is not sufficient to represent only the core model region as 'good' as possible, but that non-core model regions have to be considered carefully as well.
D. Restriction of exchanges by CBCOs with very low sensitivity to those exchanges.	Small PTDFs can even constrain exchanges far away, leading to extreme outcomes. One reason for this phenomenon is the considerable geographical scope of the Bidding Zone Review and the large number of bidding zones, which multiply the number of PTDFs per CBCO, with some of them being very small. A threshold below which PTDFs are not considered was introduced in order to resolve this issue. However, there is some degree of discretion which might potentially distort the comparison between different configurations.

Table 6.5: Overview of the identified challenges in the CBCO selection applied in a long-term future study

6.3 IMPLICATIONS OF THE IDENTIFIED CHALLENGES FOR THE ASSESSMENT OF ALTERNATIVE BIDDING ZONE CONFIGURATIONS ACCORDING TO CACM CRITERIA: EXAMPLE OF THE OPERATIONAL SECURITY INDICATOR

The currently non-resolvable complexities associated with simulating flow-based market coupling arrangement that does not currently exist have been illustrated in sections 6.1. and 6.2. This section provides an example of the associated impact on the computation results and, ultimately, the evaluation of bidding zone configurations. For illustration purposes, the indicator 'operational security' is used as an example.

6.3.1 FIRST QUANTITATIVE EVALUATION APPROACH FOR 'OPERATIONAL SECURITY'

In the context of this Bidding Zone Review, a quantitative approach for assessing the impact of different bidding zone configurations on the operational security of the interconnected system has been developed. Based on the outcomes of N-1 security assessment computations,[53] the operational security evaluation has been focused on the identification of power flows that breach thermal capacities of grid elements (e.g. so-called 'overloads'): in order to reduce model complexity to an acceptable extent, dynamic and voltage assessments are neglected in these calculations and, hence, operational security issues analysed are only a subset of the potential issues that TSOs have to tackle in reality. It must, however, be made clear that overloads (in this study detected after the market) are a simplified indicator for operational security.

Whether, and to what extent, the overloads will materialise and ultimately impact operational security depends on further measures (redispatch, provision and activation of reserves, topological measures). Nevertheless, operational security is, in this review, measured in terms of expected congestions in the system.[54]

For this reason, load flow computations have been performed based on the outcomes of the flow-based market coupling simulations for 4116 timestamps in a year (bi-hourly resolution), for each bidding zone configuration and each relevant scenario.

In order to compare operational security performances of different bidding zone configurations, a simplified 'operational security' indicator has been derived from the results of the above mentioned load flow assessments, according to the approach described in the following.

Load flow computations provide the loading level of each critical branch in each timestamp. Hence, in each scenario sc and for each bidding zones configuration *bz*, for each critical branch *i*, an '*N condition CB congestion leve*l' is computed as follows:

$$CL^{N}_{i,sc,bz} = \sum_{h} max\left[0;\left(\frac{\left|Flow\ N^{\ h}_{i,sc,bz}\right|}{PATL^{h}_{i,sc}} - 1\right)\right]$$

where:

» *bz* is the bidding zone configuration under assessment;

» *sc* is the scenario under assessment;

» $Flow\ N^{\ h}_{i,sc,bz}$ is the N-state flow (in MW) on the element *i* in the timestamp *h* in N-state system conditions;

» $PATL^{h}_{i,sc}$ is the 'permanently admissible transmission loading', also known as 'thermal capacity' (in MW), of the element *i* in the timestamp *h*.

53) 'Security assessement' means a numerical analysis performed in order to identify potential violations of the TSO's operational security limit, taking into account the N-1 security criterion.
'N-1 security criterion' means the rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits.
Security assessments are typically based on 'load flow' computations and form a numerical analysis of the flow of electric power in an interconnected system. Given the topology of the network and the nodal generations and loads, a 'load flow' computation enables the computation of the expected flow on each branch and the expected voltage at each node of the network.
In the context of this Bidding Zone Review, the following simplifications have been applied in the load flow calculation performed after FB MC:
– DC load flow computation (voltages are not taken into account);
– Phase shifters are partially optimised only (i.e. only a limited share of the full regulating range/tab positions can be used), while operation of DC links is endogenously optimised according to market outcomes.

54) However, it has to be noted that operational security means more than congestion management, including aspects such as sufficient active and reactive power reserves, voltage control, inertia, fast-current injections, black-start capacities and balancing reserves. Please refer to the System Operation Guidelines for a more comprehensive overview.

Then, for each bidding zone configuration *bz*, a Scenario N-State Congestion Level (SCL^N) has been computed for each assessed scenario sc as follows:

$$SCL^{LFSA}_{sc,bz} = \sum_{i=1}^{M} (VL_i \cdot CL_i^N)$$

where:

- » VL_i is a weighting factor based on the (minimum) voltage level of the CB *i*. It assumes the following values:
  - › 2 if the (minimum voltage level) is equal to or higher than 380 kV
  - › 1 if the (minimum voltage level) is equal to or higher than 220 kV, but lower than 380 kV
- » M is the total number of monitored critical branches *i*.

It has to be noted that this indicator focuses on N-state congestions only and does not reflect the TSO security policies in terms of security assessment.

6.3.2 STATISTICAL ANALYSIS FOCUSING ON CONGESTIONS – HIGHLIGHTING THE REASONING FOR COUNTER-INTUITIVE FLOWS

In accordance with the formula and assumptions described in the previous section, the market and load flow model results performed for the First Edition of the Bidding Zone Review have been used to calculate an operation security indicator for each bidding zone and each scenario. Yet, it turned out that the results of this indicator are counter-intuitive. Their counter-intuitiveness is mainly driven by highly precongested base cases, that cause several counter-intuitive flows[55] and lead to non-intuitive market coupling results. These observations are explained in the following in more detail.

The values presented in Figure 6.9 are the sum of the load flow indicators per concerned bidding zone configuration for each scenario over all bidding zones (higher values correspond to a lower degree of security). The indicator shown in the following has been computed excluding busbar couplers and radial lines.

Bidding Zone Configuration	2020W SOAF	2025P SOAF
Status Quo	35,237	143,995
Small Country Merge	113,653	130,086
DE/AT Split	125,439	104,537
Big Country Split	35,993	29,191
Big Country Split 2	112,061	138,464

Figure 6.9: Non-intuitive results of a statistical indicator for operational security related to congestions – Scenario N-State Congestion Level

These results show a non-intuitive behaviour:

- » A decrease in the number of bidding zones (as in the case of a merge of bidding zones) should increase (or, at least, should not decrease) the number of congestions expected in the system, since generation is restricted in more zones by the market. Yet, this is not the case for the obtained results, where the 'Small Country Merge' configurations show lower congestions/better performances than the 'Status Quo'.
- » In contrast, an increase in the number of bidding zones (as in the case of splitting bidding zones) should decrease (or, at least, should not increase) the number of congestions expected in the system, since fewer potential grid constraints are made visible to the market. However, this is not the case for the obtained results, where the split configurations 'DE/AT Split' and 'Big Country Split 2' show higher congestions/worst performances than the 'Status Quo' in the 2020 worst case scenario.

The example demonstrates the impact of the modelling restrictions illustrated in sections 6.1 and 6.2 on the results. For example, one CBCO automatically selected by the accordant algorithm only in the split configurations could overly restrict the accordant flow-based domain. This configuration would then be constrained to a higher extent. As a consequence, the less constrained merge configuration without the restrictive CBCO would experience higher load flows.

55) Counter-intuitive flows mean that the direction of the cross-zonal flows (as an outcome of the flow-based market coupling alghorithm) does not correspond to the direction of price differences. As explained in section 6.2, such flows can be, overall, welfare-maximising, especially in cases where the flow-based domain is already strongly restricted and high congestions (already occurring in the base case) need to be solved in the flow-based market coupling. In operational day-to-day systems like CWE, the flow-based market coupling algorithm does not allow for counter-intuitive flows.

6.4 KEY INSIGHTS AND OUTLOOK

Flow-based market coupling is a concept designed for close-to-real-time operation. Information on the electricity system which is available with relatively short lead times of less than two days is translated into market properties and constraints[56]. This leads to an efficient use of the grid infrastructure since the market obtains the most recent and precise information on where and to which extent the grid can be used and operates within these boundaries, the so called 'flow-based domains'.

In a future simulation environment, such close-to-real-time information is not available. As outlined in the previous sections of this chapter, substituting this information with suitable alternative assumptions and modelling approaches is rather complex and hence constitutes a major source of uncertaintiy with regard to the reliability of the results. This complexity is further exacerbated by the fact that market design choices are still to be taken in the region most relevant for the study (capacity calculation region Core). Since these choices are still pending, their outcomes had to be assumed for the simulation.

Section 6.3 has provided an example of how the necessary assumptions impact the results to a significant degree and may lead to counter-intuitive results.

Against this background, the obtained results need to be interpreted carefully and can currently not be used as a basis for a solid and comprehensive assessment of bidding zone configurations. Further conceptual work is required in order to improve the model calibration. Following the key insights gained in this First Edition of the Bidding Zone Review such improvements need to focus in particular on the following aspects:

- essential market design features (especially regarding the design of the capacity calculation approach, e. g. base case approach, CBCO selection, GSK strategy)
- representation of local characteristics (e. g. nodal allocation of relevant parameters[57], inclusion of the 220 kV infrastructure) to an extent which allows for a sufficient representation of individual aspects while at the same time not distorting a fair and unbiased European comparison
- comprehensive sensitivity analyses are essential in this context in order to take informed decisions on relevant design choices and parameters

The 15 months allowed for the review process, as specified in EU Regulation 1222/2015, does not provide sufficient time to accommodate such comprehensive analyses. A promising idea to overcome this time constraint would be to initiate the formal regulatory process only after a solid model is available where critical aspects mentioned above are fully resolved. The same approach could apply to relevant market design choices which ideally need to be made for the relevant capacity calculation region before a bidding zone review is formally initiated.

Against this background, drawing firm conclusions on the basis of the currently available simulation results is therefore premature at this point in time.

56) E. g. critical branches and critical outages (CBCOs), generation shift keys (GSKs), power flow distribution factors (PTDFs)

57) E. g. load, renewables

7 STAKEHOLDER CONSULTATION AND INVOLVEMENT

Involved external parties belonging to different parts of the electricity market value chain support a profound impact assessment of bidding zone delimitations on the overall electricity market. In order to facilitate such stakeholder involvement, a stakeholder advisory group consisting of major EU stakeholder associations[55] and regulatory institutions[56] has been established. An overview of the stakeholder meetings is provided in the Annex.

As a first step, the group has sought to identify key areas of relevance for the study. The accordant discussions have led to the prioritisation of topics, represented in Figure 7.1.

A majority of stakeholders have attributed a very high priority to wholesale market liquidity and to direct involvement in the study. In order to meet these stakeholder expectations, a survey within the stakeholder advisory group on market liquidity has been conducted. This survey has been directly used for the impact analysis of bidding zones on market liquidity (cf. section 5.9.3.2). Three stakeholder responses requested analysis of increased redispatch efficiency and the influence of bidding zones on retail market. These subjects are addressed in sections 5.7 and 5.13, respectively. Since the assessment of bidding zones is conducted on a European level, overall indicators are mainly used for the analysis. Distributional aspects in the form of discussing the impact of certain evaluation criteria for individual bidding zones are complemented where appropriate. As requested by two stakeholders, two different grid scenarios are used in the study. One of these scenarios represents the planned grid in 2025 and the other the grid infrastructure without major reinforcements in 2020 (cf. Chapter 3). The impact of bidding zone delimitations on other externalities (e.g. RES support schemes or capacity mechanisms), which one stakeholder suggested, would require a profound analysis of the individual circumstances in every country. Despite its relevance, this suggestion has therefore only been considered to a limited extent. One stakeholder suggested discussing and analysing the impact of bidding zones on trade between countries, which is a core element of the evaluation in several instances.

Further to identifying and prioritising key areas of stakeholder relevance, the stakeholder advisory group has been used as a communication platform. The participating TSOs and ENTSO-E have regularly informed the group about the project status including time plans, content-related questions and regulatory requirements. Stakeholders illustrated their views on these subjects, which have been considered in the evaluation.

In order to extend the stakeholder spectrum to the entire market, a more comprehensive consultation is to be in February 2018. This stakeholder consultation will facilitate the contribution of any party interested in the subject, supporting a comprehensive and broad impact assessment of the effect of bidding zones on the entire market. As required by Regulation 1222/2015, the public consultation will be complemented by a dedicated workshop related to the subject, which is planned for 15/02/2018.

58) EFET, eurelectric, EuroPex, GEODE, IFIEC, ÖsterreichsEnergie, PKEE

59) ACER and the representatives from individual regulatory authorities

Stakeholder Priorities

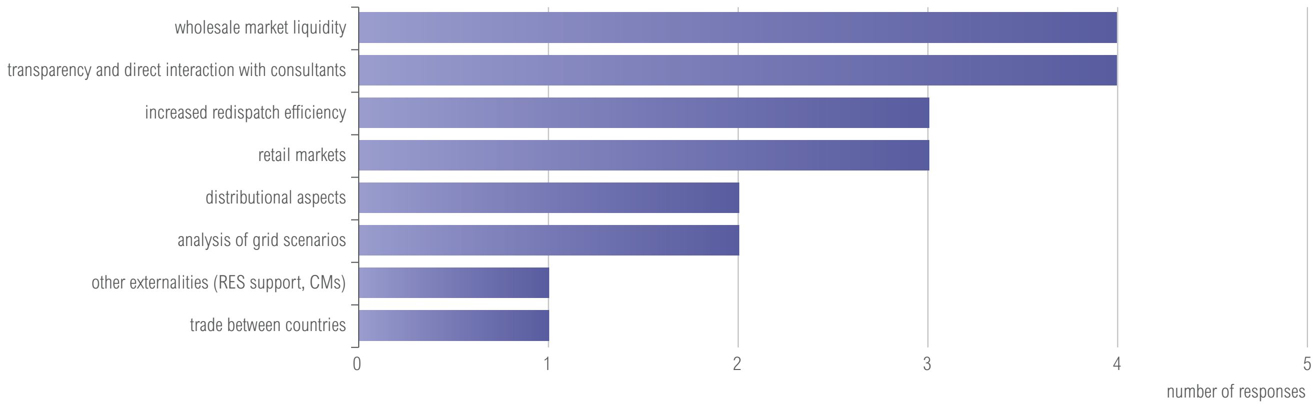


Figure 7.1: Stakeholder priorities

APPENDICES

1 MARKET AND GRID DATA: FURTHER DETAILS

Modelling of power demand

Demand is a combination of industrial and residential load. Total annual peak demand (GW) is provided explicitly by the SOAF for both the 2020 and 2025 scenarios. Peak demand for the scenarios based on TYNDP data was determined by interpolating between the 2016 SOAF peak and the 2030 TYNDP peak (assuming the peak occurs at the same time in both scenarios: [2030 value from TYNDP + 2020 value from SOAF]/2).

Annual demand (in TWh) was assumed to vary based on the TYNDP 2020 annual demand in conjunction with the 2020 peak demand. For instance, if the TYNDP 2020 profile showed a peak demand of 80 GW and an annual generation of 500 TWh, then the annual demand for another scenario with a 85 GW peak would be 500 TWh × 85 GW/80 GW.

Secondly, certain demands have been attributed to industry. The amount of industrial demand has been determined by the TSOs, as well as the structure that this demand would take, e.g. this industrial demand would occur as constant demand, i.e. a band throughout the year, or it would occur during working hours, assuming a constant band of eight hours every weekday. The amount of industrial annual load was deducted from the total load to determine residential annual power demand per country.

For residential annual power demand, the profiles of load in the TYNDP were considered. The TYNDP supplies 8 760 hourly load values for each of its scenarios for 2020 and 2030. The profile from the TYNDP Expected Progress scenario is taken for all three scenarios for 2020 and 2025 for the First Edition of the Bidding Zone Review.

Modelling of generation

The different generation units are, in all scenarios, modelled individually, with set parameters not changing between models. It is only the allocation of the individual units which differs for each grid representation: individual units are allocated at a substation level in the nodal representation and allocated to a greater zonal region in the zonal representation. Large units are modelled individually; smaller units (< 50 MW) of the same type that are attached/assigned to a certain area/node are aggregated in a larger unit.

Demand side management

The demand-side management (DSM) capacity is modelled as country-specific generators. The capacity of this is also derived from the TYNDP.

DSM capacities have no operational constraints apart from variable costs. These are set to € 1 750/MWh based on research performed by the contracted consultant. For unannounced, sudden supply interruptions (e.g. in case of inadequate generation capacity) a price of € 9 999/MWh is applied.

NTC values

NTC values for the base case calculation were either assumed to be 25 % of the thermal capacity on the borders or were provided by the respective TSOs through expert knowledge.

Renewable generation units

Renewable generation units are typically defined as units that generate power intermittently due to their reliance on intermittently available renewable fuel sources, such as wind, sun and water.

RES are generally assumed to have no operating costs due to their reliance on 'freely available' fuel. Renewable energy generation units will therefore operate as long as the resource they run on (wind, water, sun etc.) is available, except at times when their generated energy can no longer be consumed. The latter situation would, for instance, arise at times with an excess of power, e.g. during excess of conventional must-run and high RES generation. In such a situation, RES would be curtailed, with the most expensive first.

As such, generation of wind onshore and offshore, run-of-river (RoR), photovoltaics (PV) and small/decentralised biomass can – and usually will – deliver a fixed amount of power every hour, determined by the maximum predicted availability of the renewable resource in the respective hour. Estimates of the hourly and regionally different structure of this fuel-dependent maximum hourly generation were derived from the profiles from the TYNDP and historical weather data. For RoR, furthermore, an absolute energy amount is specified (e.g. per plant per year) that each plant has to generate. This amount is based on 2012 data.

Wind offshore capacity is allocated to individual wind parks. Any remaining capacity not accounted for by these parks is additionally distributed pro rata to the nodes already linked to wind offshore as decentralised offshore wind power. Each offshore wind park is assigned a generation profile based on the predicted maximum availability of wind in each hour at its location in the simulated years.

PV generation, wind onshore, small biomass and any other RES generation that should be considered, but is not captured by explicit 'large' plants, are modelled as aggregated units and provide their infeed proportionately to population per node.

Hydro generation units

The market model considers several types of hydro plants to achieve a realistic representation of hydro flexibility in the individual European power markets. Hydro plants are modelled consistently per type. The different types of hydro plants considered are RoR pondage, daily, weekly or annual storage or pumped-storage (with and without natural inflow). Plants in each zone are modelled individually per type. The latter implies that the capacity of units, i.e. of the individual generators or machines, is combined per hydro plant type per zone, but the information on the number of units is retained. For example, Nant de Drance has six units and a total plant capacity of 900 MW.

Combined heat and power generation units

Combined heat and power (CHP) plants have the ability to generate heat in addition to power. As such, they provide an additional product to a separate market. This separate heat market puts additional operational constraints on the plant. CHP plants may therefore have:

- must-run restrictions, forcing a plant to operate when the heat is needed even if no incentive on its operation is provided by the power market alone;
- cheaper operating costs, as they can receive additional revenues from providing the additional product on a separate heat market.

Grid development status according to ACER

ACER, in its 'RECOMMENDATION OF THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS No 07/2013', envisages the following steps in the general process of developing electricity transmission and gas infrastructure projects of EU-wide importance:

i. 'under consideration' status: planning studies (pre-feasibility and feasibility, including the techno-economic analysis of the project) and consideration for inclusion in the national plan(s) (and ENTSOs' Regional I EU-wide TYNDPs);

ii. 'planned' status: approved inclusion in the national plan(s);

iii. preliminary design studies (basic engineering design, environmental impact assessment, etc.);

iv. market test (when relevant for gas projects creating bookable capacity);

v. preliminary investment decision (when relevant);

vi. permit granting process (including a pre-application procedure and a statutory permit granting procedure);

vii. definition of the financing scheme and cross-zonal cost allocation (if applicable);

viii. final investment decision;

ix. detailed engineering design and technical specifications as a basis for construction;

x. tendering (if applicable), from call for tenders to contract award(s);

xi. construction;

xii. commissioning.

2 CLUSTERING ALGORITHMS

[will be part of the final report]

3 GLOSSARY

AC	Alternating current
AT	Austria
BE	Belgium
BRPs	Balancing responsible parties
BSP	Balancing service provider
BZ	Bidding zone
BZ TF	Bidding zone taskforce
CA	Control area
CACM	Capacity allocation and congestion management
CB	Critical branch
CCR	Capacity calculation region
CEP	Clean energy package
Cf.	Confer, compare
CfDs	Contracts for difference
CHP	Combined heat and power
CNEC	Critical network elements and contingencies
CWE	Central West Europe
CZ	Czech Republic
DC	Direct current
DE	Germany
DSM	Demand-side management
DSO	Distribution system operator
DSR	Demand-side response
DWD	Deutscher Wetterdienst (German Meteorological Office)
EC	European Commission
EENS	Expected energy not served
EPADs	Electricity price area differentials
EU	European Union
FB	Flow-based
FCA	Forward capacity allocation
FCR	Frequency containment reserves
FR	France
FRM	Flow reliability margin
FRR	Frequency restoration reserve
GL EB	Guideline on Electricity Balancing or Electricity Balancng Guideline
GL SO	Guideline on Electricity Transmission System Operation
GSK	Generation shift key
GTC	Grid transfer capacity
GW	Gigawatt
HHI	Herfindal–Hirschmann Index
HU	Hungary
HVDC	High-voltage direct current
ISP	Imbalance settlement price
kV	Kilovolt
kWh	Kilowatthour
LFC	Load frequency control
LMP	Locational marginal price
LOLE	Loss of load expectation
LU	Luxembourg
MABIS	Principles for implementation of market rules for balance group settlement
MAF	Midterm adequacy forecast
MC	Market coupling
MW	Megawatt
MWh	Megawatt hour
n/a	not applicable
NC	Network Code
NC CACM	Network Code on Capacity Allocation and Congestion Management
NEMOS	Nominated electricity market operator
NL	Netherlands
NRA	Network regulatory authority
NTC	Net transfer capacity
OPF	Optimal power flow
OTC	Over-the-counter
PACA	Provence-Alpes-Côte d'Azur
PL	Poland
PLEF	Pentalateral Energy Forum
PST	Phase-Shifting transformer
PTDF	Power Transfer Distribution Factors
PV	Photovoltaics
PX	Power exchanges
R&D	Research and developement
RES	Renewable energy sources
ROR	Run-of-River
RSI	Residual Supply Index
SK	Slovakia
SOAF	System Outlook and Adequacy Forecast
SoS	Security of supply
TSO	Transmission system operator
TWh	Terawatt per hour
TYNDP	Ten-Year Network Development Plan
VoLL	Value of lost load

4 QUESTIONNAIRE ON TRANSITION AND TRANSACTION COSTS

4.1 QUESTIONNAIRE ON TRANSITION AND TRANSACTION COSTS SENT TO STAKEHOLDERS

Introduction

Transition and transaction costs follow an adjustment of a bidding zone configuration. The type of such costs as well as their level vary largely among different actors affected by the bidding zone reconfiguration. This variety makes the quantification of the aggregated transition and transaction costs on a system level particularly challenging[60]. In order to overcome this challenge we decided to give stakeholders the opportunity to report their cost range estimates for different cost positions. Based on the cost estimates received from stakeholders, the BZ TF should be able to evaluate transition and transaction costs for different bidding zone configurations in the final report.

As the robustness of the cost assessment increases with participation, we shall appreciate any response and partial answers are also welcome.

Definition/Explanation of transition of transaction costs

In this survey transistion costs are understood as the "one-time" costs directly related to a configuration change (e.g. required IT investments due to market changes or maybe also stranded investments or assets due to price changes). As the level of transition costs can crucially depend on the time span since the new configuration comes into effect (lead time), we suggest that in this survey transition cost estimates are reported for a lead time of about four years.

In contrast, transaction costs are generally referring to the costs of participating in the market. They are permanent costs for search & information, bargaining, policing and enforcement. Transaction costs are to some extent specific to a given bidding zone configuration. For our purposes, only the difference of transactions costs between bidding zone configurations is relevant. So, please take the current bidding zone configuration as a reference point and report the (permament) increase or decrease of transaction costs that you expect with the new configuration.

Overview on cost categories and description with examples

Table 1 (next page) gives an overview of the relevant actors and respective cost categories and lists some examples for different cost positions. The table is not exhaustive and comprehends transition and transaction cost positions. If you want to add futher points or any comments, feel free to use the empty space below the table.

Cost estimations

Please provide your estimated costs (preferably as range) for a change of the current bidding zone configuration to the assessed bidding zone reconfigurations in table 2 and table 3. Please take into account that the respective reconfiguration might **impact the balancing zones** as well. For your estimate of the (one-time) transition costs in table 2, please assume a **lead time of four years**[61]. In contrast, **transaction costs** should be **reported as yearly costs relative to the current bidding zone configuration**. All **cost estimates** should be given **for the affected companies or institutions in total** (e.g. operational transition costs caused by the respective configuration change for all trading companies). Generally, a change from the current bidding zone configuration to the new one is assumed. With regard to the model-based configuration please assume, that the new configuration includes a partially merge of two countries (one part of country A is merged with one part of country B) and that at least one TSO, one trading company and one DSO are affected by the reconfiguration (e.g. this means, that at least one DSO is split by the reconfiguration). Furthermore, it is important that your estimates comprehend only costs that are clearly and exclusively induced by the change of the bidding zone configuration.

60) According to the GL CACM, the bidding zone review should encompass criteria related to transition and transactions costs.

61) In case you consider that a short/long transition period will impact your estimated cost range, please explain.

Adjustments in	With regard to adaption of	Explanation/Examples (not exhaustive)
Governmental institutions (including regulating authorities)	Legal design	– Adjustments of RES support scheme might be necessary if the scheme is related to a bidding zone configuration or to a reference price, that is/are no more valid – The argument above also holds for other support schemes that are based on a market price as reference price – Risk of legal and court costs
	General remarks:	...
Producing companies (including RES)	Organisational	– Resizing of teams
	Operational and IT	– Adaptation to new markets creates learning costs (e. g. trading and valuation) – Temporary loss of efficiency – Adjusting IT processes and implementation of new ones – Additional costs of market observation (working hours, travel expenses)
	Contracts and financial procurements	– Adaptation of bilateral agreements – Increasing cost of hedging with decreasing market liquidity – Costs related to market participation (e.g. exchange fees/charges and registration costs for participating in organised markets in each bidding zone) – New valuation of existing contracts/positions
	General remarks	– Stranded costs or windfall profits (resulting from the increase or decrease of energy market revenues). Stranded costs might be even higher for countries without government guarantees or CRMs for conventional power plants and third party merchant transmission lines in place. – Further opportunity costs (costs related to postponing projects, e. g. due to the tie-up of working resources) – Regulatory risks faced by investors (e. g. when bidding zone configuration is likely to be revised periodically)
Trading companies and institutions (including banks)	Organisational	...
	Operational and IT	– Restructuring of activities – Costs related to market participation (e.g. exchange fees/charges and registration costs for participating in organised markets in each bidding zone) – Learning costs (new trading and valuation tools) – Temporary loss of efficiency – Increasing cost of hedging with decreasing market liquidity
	Contracts and financial procurements	– New valuation of existing contracts/positions (not restricted to market participants in the affected bidding zone, if market participants outside the bidding zone used the market price as their respective reference price) – Negotiation/adaption of new contracts
	General remarks	– Opportunity costs (costs related to postponing projects, e. g. due to the tie-up of working resources)

Adjustments in	With regard to adaption of	Explanation/Examples (not exhaustive)
TSOs	Organisational	– Resizing of teams
	Operational and IT	– Learning costs (new evaluation tools)
	Contracts and financial procurements	– Costs for adaptation of existing contracts
	General remarks	– Costs associated with re-calculation of tariffs and RES-levies
DSOs	Organisational	– Resizing of teams
	Operational and IT	– Learning costs (new evaluation tools)
	Contracts and financial procurements	...
	General remarks	– Costs associated with re-calculation of tariffs and RES-levies
Electricity exchanges incl. clearing houses and OTC Platforms (all together)	Organisational	...
	Operational and IT	– Adaptation of IT systems
	Contracts and financial procurements	– Costs for the adaptation of existing contracts referring to market price of adjusted bidding zone – Costs for new contract negotiation with market participants
	General remarks	– Adaptation of contracts referring to market price of adjusted bidding zone/Contract negotiation with market participants – Adaptation/introduction of products (e.g. LTRs) – Adaptation of IT
End consumers, retailers and suppliers	Organisational	– Resizing of teams
	Operational and IT	– Adaptation of IT systems – Costs through the modification of customer portfolios (e.g. changes of intermixing effects of load profiles)
	Contracts and financial procurements	– Costs for the adaptation of existing contracts referring to market price of adjusted bidding zone
	General remarks	– Stranded costs or windfall profits (resulting from the increase or decrease of electricity prices) – Increasing cost of hedging with decreasing market liquidity – Adaptation of bilateral agreements – Potential losses for suppliers if cost increases in case higher electrity procurement cannot not be directly passed on to end consumers

Table 1: Categories and explanations (not exhaustive) (The costs of TSOs are assessed within the ENTSO-E Bidding Zone Taskforce)

Adjustments in	With regard to adaption of	Estimated cost range for "DE/AT"-Split in M €	Estimated cost range for "Big Country Split 1" in M €	Estimated cost range for "Big Country Split 2" in M €	Estimated cost range for "Merge" in M €	Remarks
Government institutions	Legal design					
	Other Costs					
Producing companies	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
Trading companies and institutions (incl. banks)	Organisational					
	IT					
	Contracts and financial procurements					
	Other Costs					
DSOs	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
Electricity exchanges incl. clearing houses and OTC Platforms	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
End Consumers, retailers and suppliers	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					

Table 2: Estimates of transition costs (Transistion costs are understood as the "one-time" costs directly related to a bidding zone configuration change. Please assume a lead period of four years.)

Adjustments in	With regard to adaption of	Estimated cost range for “DE/AT”-Split in M €	Estimated cost range for “Big Country Split 1” in M €	Estimated cost range for “Big Country Split 2” in M €	Estimated cost range for “Merge” in M €	Remarks
Government institutions	Legal design					
	Other Costs					
Producing companies	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
Trading companies and institutions (incl. banks)	Organisational					
	IT					
	Contracts and financial procurements					
	Other Costs					
DSOs	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
Electricity exchanges incl. clearing houses and OTC Platforms	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					
End Consumers, retailers and suppliers	Organisational					
	Operational & IT					
	Contracts and financial procurements					
	Other Costs					

Table 3: Estimates of transaction costs (Your estimates should be on a yearly basis.)

Appendix to the questionnaire: Considered expert-based configurations

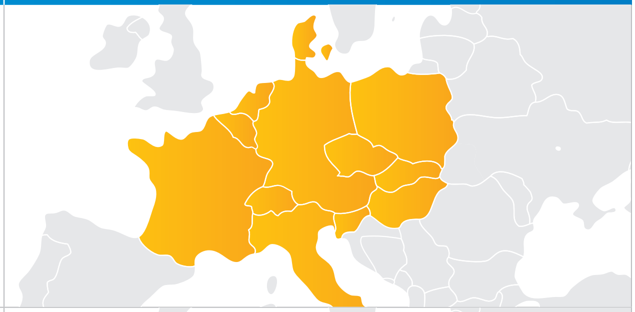
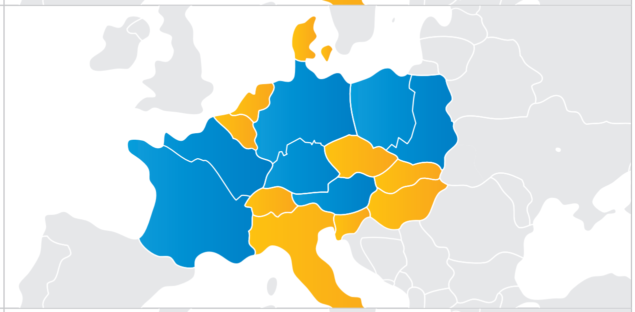
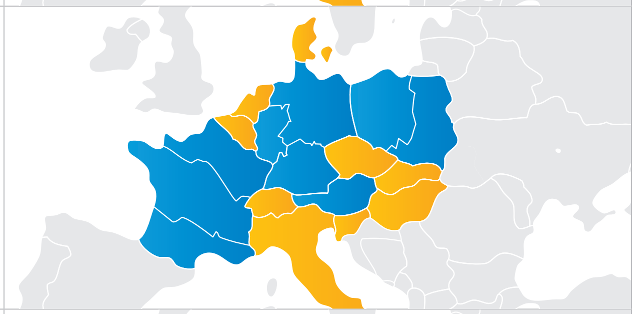
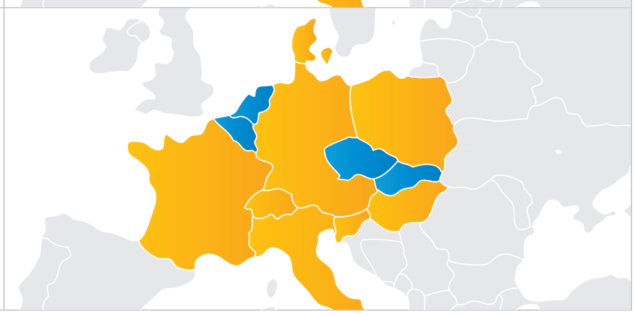
Name	Description	Indicative map
“DE/AT”-Split	Germany and Austria are separated bidding zones.	
“Big Country Split 1”	France, Germany, Poland are split into two zones (Austria as a separate zone).	
“Big Country Split 2”	France and Germany are split into three zones and Poland into two zones (Austria as a separate zone).	
“Merge”	Belgium and Netherlands are merged to one zone and Czech Republic and Slovakia are merged to one zone.	

Table 4: Appendix to the questionnaire: Considered expert-based configurations – The model-based configurations are not considered in this survey.

4.2. STAKEHOLDER FEEDBACK TO THE QUESTIONNAIRE ON TRANSITION AND TRANSACTION COSTS

4.2.1 RESPONSE BY EEX

Response by European Energy Exchange AG (EEX) **20 November 2017**

Survey on transition and transaction costs with regards to bidding zone configuration

Introduction

EEX is welcoming the opportunity to take part in the ENTSO-E survey on transition and transaction costs and providing expectations on cost development.

Actual costs would in particular depend on the exact geographic definition of the bidding zones and consequently also on the actual necessary transition requirements. Therefore, were a not able to provide estimations in form of concrete figures.

However, some experiences exist from market re-configurations which have already been implemented. These experiences should be taken into consideration. Additionally, we suggest to observe and analyse the costs of the DE-A split which has already been decided and is still in the phase of implementation. This case could serve as a benchmark, due to the fact, that the most liquid European market is affected.

General remarks on transition and transaction costs with regards to bidding zone configuration

a) Costs of a reconfiguration of bidding zones should not be underestimated

In general, any of the reconfigurations considered in the bidding zone review would lead to additional costs and it is not justified that the estimated benefits would outweigh these costs.

In order to evaluate alternative bidding zone configurations, one has to estimate the future costs of electricity generation and grid operation for a different configuration of bidding zones. For example, an analysis of the economic effects of splitting the German-Austrian price zone by independent consultancy Consentec shows that considerable inefficiencies would arise. The study compares the economic costs and benefits of splitting the German-Austrian power market into two bidding zones. A trade-off between costs becomes apparent: if the bidding zone is split, costs for redispatch can be reduced in some cases while continuous inefficiencies arise from uncertainties when determining total transmission capacities between the smaller zones. Comparing these two cost factors, the studyshows that a split of the German-Austrian bidding zone would increase total cost of power supply by up to EUR 100 million per year. Additional factors such as loss of liquidity and substantial transaction costs would add to those inefficiencies.[1]

Consequently, from an exchange point of view EEX believes that large and liquid bidding zones would create less costs than bidding zone splitting. In fact, market participants would only have to comply with few requirements. Bidding zone splitting, on the contrary, creates higher costs, as market participants have to adjust to many more requirements. That also means a potentially higher risk of misjudging the mutating situation, affecting e.g. the decision as to which of the newly created market area to be active in.

b) The described transition and transaction costs are not exhaustive cost categories

Besides the described cost categories transaction and transition costs there are other factors which could lead to addidional costs:

- Qualitative transaction costs like loss of reputation or decrease of market's reference effect
- Distributional effects: different market conditions and prices after a bidding zone split could result in market participants / consumers that will be winners while others will be losers (windfall profits / windfall losses).

[1] Consentec, Economic efficiency analysis of introducing smaller bidding zones, 2015, https://www.eex.com/blob/7412/97dfe4307af0ded860ba2c0e3ffb1e99/20150213-consentec-eex-bidding-zones-data.pdf

Response by European Energy Exchange AG (EEX) **20 November 2017**

c) Experiences based on past re-configuration projects show significant costs

Experiences based on past re-configuration projects show significant costs up to a mid triple-digit million Euro range.[2] Given the fact that all split-scenarious of the considered "expert-based configurations" are covering the German market - as the most mature and liquid market in Europe - it is likely that the complexity of such a re-configurations would be higher than in any previous case. Consequently, we would expect that a higher complexity would also lead to higher cost compared to previous experiences.

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4.2.2 RESPONSE BY EDFT

Answer to: "Overview on cost categories and description with examples – If you have any comments or further points regarding table 1, you are invited to use the empty space below"

- For a group like EDF, the costs would be estimated in Billions euros for scenario 2 and 3, and would have a dramatic financial impact.
- Massive impact on the end users consumers who will see their bills massively increased

Answer to: "Cost estimations"

No response to cost estimations provided by EDFT

4.2.3 RESPONSE BY IFIEC EUROPE

ifiec europe
international federation of industrial energy consumers

securing competitive energy for industry

Position on the Bidding Zone Review questionnaires on liquidity and transaction costs

November 2017

On the 4th October ENTSOE provided the members of the Bidding Zone Stakeholder Advisory Group with two questionnaires as a part of a two-phase consultation. One questionnaire addresses market liquidity with regards to bidding zone configuration and the other one transaction costs. The results of the questionnaires should feed into the official one-month public consultation early 2018.

Since IFIEC is not capable of delivering estimates on the increase or decrease of liquidity in specific bidding zone configurations or neither can provide detailed information on transaction costs either for a single industrial player or the power intensive industry as a whole, we would at least like to give some general comments.

IFIEC would like to emphasis that when changes in the bidding zone configurations are considered, the transition cost of the market players should be taken duly into account in the cost/benefit analysis. Further, any changes in the configuration should be published to the market and market players in due time before the changes, so the market players can conduct the adjustments and preparations in an efficient way to a lowest possible cost.

In connection to the bidding zone proposal in the Winter package, IFIEC promoted the idea that bigger market zones lead to higher liquidity and more options to provide flexibility to a broader geographical scope. The current statement of Commissioner Arias Canete on the final report by Commission Expert Group on 2030 electricity interconnection targets let us believe, that the EC works into the same direction. Mr. Canete stated that the EC will present a clean energy infrastructure package, which will include the third list of Projects of Common Interest and ideas for making operational the 15% interconnection target for 2030. In the current consultation 3 out of 4 configurations focus on the splitting of bidding zones, only one on merging. Bidding zones are also addressed in the winter package proposal. In order to find a balanced solution IFIEC proposed the following change:

page 1 of 2

IFIEC Europe
International Federation of Industrial Energy Consumers
Av. Louise 250, box 80 | 1050 Brussels
www.ifieceurope.org | ifieceurope@ifieceurope.org | Phone: +32 888 52 69 | Mobile: +49 172 26 99 063
a.i.s.b.l. NI 436 343 513 | VAT: BE 0436.343.513 | EU Transparency Register: 1978775156-31

Art. 13. 1. Bidding zone borders shall be based on long-term, structural congestions in the transmission network and bidding zones shall not contain such congestions. The configuration of bidding zones in the Union shall be designed in such a way as to maximise economic efficiency and cross-border trading opportunities while maintaining security of supply.	Art. 13.1. ***Whenever long-term structural congestions in the transmission network occur, member states shall take all necessary measures in order to solve those congestions in a reasonable time frame.*** The configuration of bidding zones in the Union shall be designed in such a way as to maximise economic efficiency and cross-border trading opportunities while maintaining security of supply.
Justification Members states should take all necessary steps to solve structural congestions as soon as possible.	

The experience from many member states show that performing infrastructure investments often experience delays due to many reasons. Our proposal should safeguard the regulatory framework from hasty reactions on the splitting of bidding zones. Even if the results from the questionnaires indicate „quick wins“ on the short term, it might not be the most economic solution for the long term. Therefore, we are asking for a balanced approach taking into account the efforts of member states, who are planning and implementing to reduce and remove structural congestions within reasonable time frames.

IFIEC Europe represents energy intensive industrial consumers where energy is a major component of operating costs and directly affects competitiveness.

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5 SECOND QUESTIONNAIRE ON MARKET LIQUIDITY

5.1 SECOND QUESTIONNAIRE ON MARKET LIQUIDITY SENT TO STAKEHOLDERS

Introduction

Market liquidity may depend on the configuration of bidding zones. By Market Liquidity we understand the degree to which any Market Party can quickly (within the time frame the market participant needs) source/sell any volume of energy without greatly affecting the involved market price. Market Liquidity is generally viewed as a multi-dimensional, not directly observable construct. There are several indicators for market liquidity, as bid/offer spreads, market depth, trading volume and number of trades, churn rates etc.

These indicators rely on detailed empirical data of existing markets. However, in the framework of the Bidding Zone Review, all quantitative market analyses will rely on a fundamental market model-based on merit-order curves (optimisation of the unit commitment and dispatch). Trading activities are not simulated by such a model. In general, trading activities are not known for future bidding zone configurations as they depend on numerous factors, including not least human behaviour. The impact of future bidding zone reconfigurations on market liquidity can therefore be hardly predicted in quantitative terms. Even though, a limited analysis of "market depth" based on merit-order curves is envisaged in the Bidding Zone Review, potentially accompanied by an assessment of historical data.

In any case, the evaluation of market liquidity in the Bidding Zone Review will consequently be mainly a qualitative one. An important part of this assessment could be the liquidity trend evoked by a bidding zone reconfiguration. The expert-knowledge of the stakeholders is of valuable input here and the stakeholders are invited to share their estimation by this questionnaire.

Information to the questionnaire

The following table questions are to be understood as follows. Basic assumption is a bidding zone change before 2020. The change of liquidity is evaluated considering the period from 2020 to 2025 (being in line with the otherwise modelled years). The liquidity change is compared to the case of keeping the status-quo configuration. For example, the answer "increase" for a bidding zone configuration states that, if the configuration is introduced before 2020, the liquidity within 2020 and 2025 will be higher compared to a case without any reconfiguration.

The questions differentiate between the liquidity for day-ahead trading, intraday trading) and for forward and future trading. In all cases, liquidity as it impacts the European market in total is considered. Possible answers are: "increase", "strong increase", "decrease", "strong decrease", "no material change", "not known". As a pure indication, "strong increase" represents something like an increase of the traded volume by 50 % or more and/or a reduction of the bid/ask spreads by 25 % or more. "Increase" represents an increase of the traded volume by an order of magnitude of 10 % to 50 % and/or a reduction of the bid/ask spreads by 10 % to 25 %. "Strong decrease" represents a reduction of the traded volume by 25 % or more and/or an increase of the bid/ask spreads by 50 % or more. "Decrease" represents a reduction of the traded volume by 10 % to 25 % and/or an increase of the bid/ask spreads by 10 % to 50 %. "No material change" is between "Decrease" and "Increase". If you deem other classifications more reasonable, please comment accordingly.

Explanations and comments supporting the answers are encouraged and welcome.

Type of market	Answer type	Impact by "DE/AT"-Split	Impact by "Big Country Split 1"	Impact by "Big Country Split 2"	Impact by "Merge"
Intraday trading	Change of liquidity				
Day-ahead trading	Change of liquidity				
Forward/future market – shorter period (e.g. one year-ahead base load product)	Change of liquidity				
Forward/future market – longer period (e.g. three year-ahead base load product)	Change of liquidity				

Table 5: Estimated liquidity impact

Answer possibilities for change: "increase", "strong increase", "decrease", "strong decrease", "no material change", "not known".

Please consider the current bidding zone configuration as the reference configuration for the comparison. The impact assessment ("Increase" etc.) is related to this reference.

Appendix to the questionnaire: Considered expert-based configurations

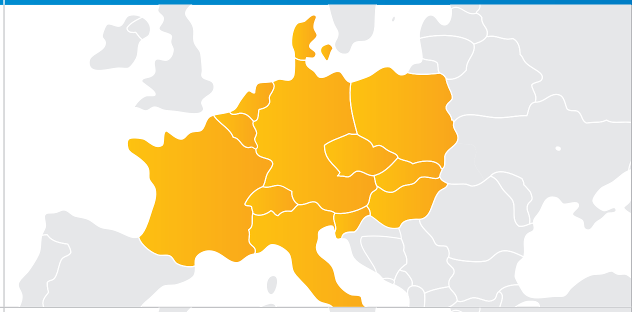
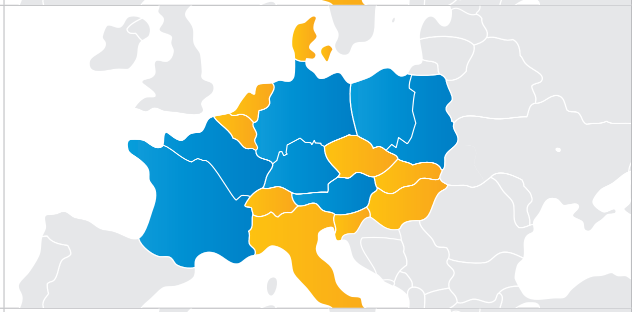
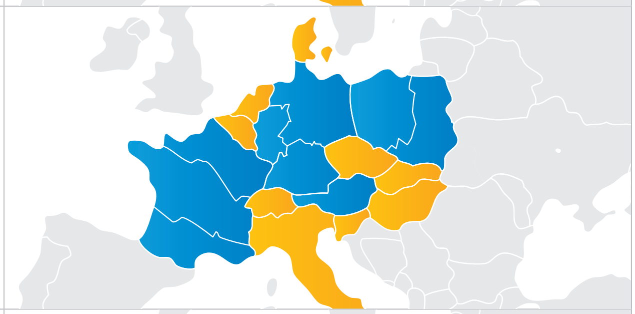
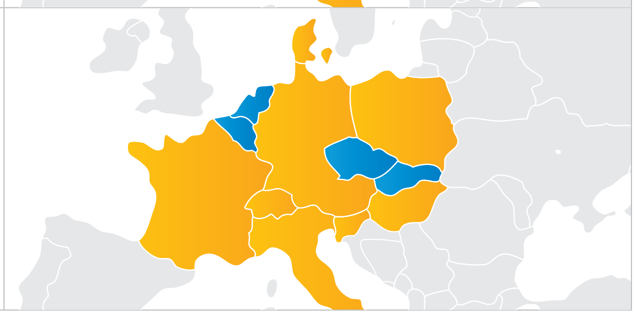
Name	Description	Indicative map
"DE/AT"-Split	Germany and Austria are separated bidding zones.	
"Big Country Split 1"	France, Germany, Poland are split into two zones (Austria as a separate zone).	
"Big Country Split 2"	France and Germany are split into three zones and Poland into two zones (Austria as a separate zone).	
"Merge"	Belgium and Netherlands are merged to one zone and Czech Republic and Slovakia are merged to one zone.	

Table 6: Appendix to the questionnaire: Considered expert-based configurations – The model-based configurations are not considered in this survey.

5.2 STAKEHOLDER FEEDBACK TO SECOND QUESTIONNAIRE ON MARKET LIQUIDITY

5.2.1 RESPONSE BY EUROPEX

(No answers in table form received)

Liquidity and efficiency in the long-term (derivatives) market

Forward and futures markets – exchange traded as well as OTC – represent the vast majority of traded volume in the European Union, although the figures vary significantly across regions. A significant part of long-term energy trading does not result in physical delivery; however, it is based on the underlying fundamentals of the energy market as it may serve the purpose of hedging against short-term energy prices formed via price coupling at multi-regional, regional and bidding zone level.

Experiences show that bidding zones which are stable over time and based on the underlying fundamentals of the energy market are beneficial for the development of trading liquidity, number and heterogeneity of market participants, and the standardisation of products and processes.

Any split or merger of existing bidding zones must be thoroughly justified in order to reduce the likely negative effects on market functioning (positive effects that might come from such changes should also be acknowledged). Particularly, in derivatives markets, market participants with open derivatives contracts would be exposed to a changed underlying risk if the underlying of their long-term derivatives contracts is lost before the product falls due, especially if the underlying reference is only a single bidding zone (spot) price for the given delivery period.

Energy companies and investors need stability to be able to invest in innovation and infrastructure. A reliable market is able to provide this stability, where it is supported by a solid regulatory framework and given enough room for entrepreneurship. Therefore, it is of utmost importance that bidding zones remain stable over time and are based on the underlying fundamentals of the energy market in order to guarantee legal certainty for long-term investment decisions.

Liquidity and efficiency in the short-term (spot) market

In a coupled EU day-ahead and intraday market, liquidity cannot be measured only on the basis of the market participants located within a bidding zone. Indeed, the liquidity in any bidding zone that participates in the single day-ahead and intraday market increases significantly thanks to the implicit allocation of cross-zonal capacities. In this context, the number of cross-zonal capacities made available to the market becomes the most relevant factor for short-term market integration, competition and efficient price formation, thus more significant than bidding zone configuration.

In this regard, ACER's market monitoring analysis shows that the limited amount of cross-zonal capacity made available by TSOs is one of the most significant barriers to the further integration of wholesale markets. Approximately one third of the gap[62] is due to insufficient TSO coordination, while the remaining part is due to flows within the bidding zone and production/consumption being prioritised to the detriment of cross-zonal exchanges.

While this is the case for coupled short-term markets, it is true that long-term markets remain more fragmented due to the fact that energy delivery is restricted to a single bidding zone.

In terms of balancing energy, balancing zones must be aligned with bidding zones. In this respect, imbalance price areas should follow the configuration of bidding zones, not the other way around.

Other important considerations

A bidding zone review should, to the extent provided for by the applicable regulatory frameworks (e.g. CACM and other Network Codes and Guidelines), explicitly include the full involvement of all key market stakeholders, including spot market operators and long-term forward and futures market operators. Given the complexity of the issue and its multiple consequences, it is important to develop a comprehensive understanding of possible positive and negative consequences for the underlying spot and derivative markets.

It is vital for such a survey to include a balanced range of scenarios or configurations. The four configurations considered in the current survey include three splitting scenarios and only one merger scenario. ENTSO-E should consider further scenarios foreseeing merging/extension of some bidding zones to ensure a balanced analysis. Furthermore, balance should be ensured in terms of the types of market considered. To ensure transparency, information should be provided on how these configurations were chosen, and what factors were considered in this process.

62) i.e. the gap between commercial cross-zonal capacity and benchmark capacity.

5.2.2 RESPONSE BY EEX

Response by European Energy Exchange AG (EEX) **20 November 2017**

Survey on market liquidity with regards to bidding zone configuration

Introduction

EEX is welcoming the opportunity to take part in the ENTSO-E liquidity survey and providing expectations on liquidity development.

EEX is operating power derivatives markets all across Europe and thus is directly affected by any re-configuration of bidding zones in existing European electricity markets. Particularly, the German-Austrian market is EEX' core market and the most liquid European market, providing the reference price for all other markets.

General remarks on market liquidity and the role of bidding zone configuration

a) *Large and liquid bidding zones are critical to renewable energy integration and should be the preferred solution for an efficient European electricity market*.

EEX believes in a market design based on large and liquid bidding zones. The reality of the positive development of the German-Austrian electricity market (both spot and derivatives) is under everybody's eyes and proves the benefit of large bidding zones. The German-Austrian electricity market is the most liquid market in Europe and it serves as a reference for the whole region.

Forward and future markets represent over two thirds of traded volume in the European Union. Our experience shows that a large bidding zone is beneficial for the correct development of trading liquidity, number and heterogeneity of market participants, and the standardisation of products and processes. All these have led to a significant level of market maturity and trading professionalism.

Also, the growing share of renewable energy sources can only be efficiently integrated into a market-based electricity system through the use of the largest possible bidding zone configuration with the highest possibly liquidity, to synchronise supply and demand at all time.

b) *Against this background, we strongly suggest that ENTSO-E adds to its analysis further scenarios foreseeing the merging / extension of already liquid and mature market areas, e.g. in the CWE region*

c) *Splitting bidding zones put market functioning and European electricity system integration at risk.*

Any split of an existing bidding zone into two or more bidding zones would constitute a case of serious market intervention and entails a number of negative consequences[1] both for the energy industry and for the consumers. This, e.g., include:

- Fragmentation and reduction of the existing liquidity on spot and derivatives markets. When a bidding zone is split, derivative products need to be remodelled on the new zone. This was the case in the recent past: EEX successfully replaced a German-Austrian product with two different products for the German and Austrian market. As in the derivative market liquidity has to move from existing products to new products, there is the risk that liquidity in old products dries out, whilst liquidity in new products needs to be built from scratches. During the transition in between two different bidding zones configurations, liquidity is very likely to be lost.
- Exposing market participants with open derivatives contracts to an underlying risk since the underlying of their long-term derivatives contracts is lost before the product falls due. Currently, there are approximately EUR 30 billion of open interest in the German-Austrian market.

[1] Cf. Consentec, Economic efficiency analysis of introducing smaller bidding zones, 2015, https://www.eex.com/blob/7412/97dfe4307af0ded860ba2c0e3ffb1e99/20150213-consentec-eex-bidding-zones-data.pdf

1

- Market concentration into smaller price zones and market power of individual market players.
- Less balanced generation structure than in a bigger price zone, which would result in price fluctuations that are hard to foresee.
- Occurrence of different market prices and consequently different fees, levies and taxes (as based on market prices)

d) Experiences from former and ongoing bidding zone splits should be taken seriously.

A look at the Scandinavian power market, where a split into several price zones was carried out in Sweden in 2011, helps in assessing the effects of any split: since 2011, liquidity has declined significantly. For example, the volume of futures contracts cleared via exchange has reduced by 20%. And in the case of the so-called EPADs (Electricity Price Area Differentials) permitting hedging between the prices in the individual small zones and the system price, the decline in Sweden was even higher than 40%.[2] The example of Sweden shows that the achievements of liberalisation – first and foremost a liquid market and a strong price signal – are jeopardised by price zones which are too small.

e) Splitting of zones also has the potential to undermine the current extension of the grid and therefore the further joint development of the European Internal Energy Market

Physical integration of energy infrastructure between the Member States is a precondition for the proper functioning of EU energy markets and the sharing of electricity across borders. EEX recognises that European electricity transmission systems, notably cross-border interconnections, are not sufficient to allow the internal energy market to work properly and address the problem of energy islands in some regions of Europe.

Therefore, in 2002, the European Council set a 10% electricity interconnection target, whose implementation was eventually postponed until 2020. In May 2014, the European Commission suggested as part of the European Energy Security Strategy that the 10% target should be extended to 15% by 2030. The October 2014 European Council called for interconnection of at least 10% of installed electricity production in the Member States by 2020, endorsed the 15% target by 2030 and underlined that both targets will be attained via implementation of Projects of Common Interest in energy infrastructure.

According to a study prepared for the European Commission, 'an adequately interconnected European energy grid (...) [could bring], (...) the benefits of the market closer to European citizens, as consumers could save EUR 12-40 billion annually by 2030'.[3]

Consequently, the Energy Union framework strategy published by the Commission on 25 February 2015 includes an interconnection communication, setting out the measures needed to reach the target of 10% minimum electricity interconnection by 2020. The Commission pushed forward to the fourth quarter of 2017 (from end 2016) the date of adopting a communication on progress towards completing the list of the most vital energy infrastructures and on the necessary measures to reach a 15% electricity interconnection target by 2030. The Commission previously announced in the 2016 work programme that this communication 'might point to additional activities to be deployed at the EU level' and '(...) give some first thoughts on new approaches to planning, cost sharing, regulatory incentives and the regulatory framework more in general'. The communication should be adopted in 2017 together with the third list of Projects of Common Interest.

2 Cf. EFET, A reality check on the market impact of splitting bidding zones, http://www.efet.org/Files/Documents/Electricity%20Market/General%20market%20design%20and%20governance/EFET-memo_Swedish-zones-reform.pdf

3 Cf. Booz & Co., Benefits of an integrated European energy market, https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf

The second report on the state of the Energy Union of 1 February 2017 alerts that '11 Member States have not yet reached the 2020 electricity interconnection target of 10 % (Bulgaria, Cyprus, Germany, Spain, France, Ireland, Italy, Poland, Portugal, Romania and the United Kingdom) and need to continue their efforts'.[4]

4 Cf. European Commission, http://www.europarl.europa.eu/legislative-train/theme-resilient-energy-union-with-a-climate-change-policy/file-15-electricity-interconnection-target

Response by European Energy Exchange AG (EEX) 20 November 2017

Table 1 ESTIMATED LIQUIDITY IMPACT

Type of market	Answer type	Impact by "DE/AT"-Split	Impact by "Big Country Split 1"	Impact by "Big Country Split 2"	Impact by "Merge"
Intraday trading	Change of liquidity				
	Explanation				
Day-ahead trading	Change of liquidity				
	Explanation				
Forward / future market – shorter period (e.g. one year-ahead base load product)	Change of liquidity	DE: decrease A: strong decrease	Strong decrease	Strong decrease	Increase
	Explanation	Experiences in the German-Austrian derivatives market after the announcement and decision by BNetzA to split up the common bidding zone by 1. Oct 2018 have shown a decrease of approximately 10% during the first half of 2017 compared to the same period 2016. Although volumes are slowly recovering due to the common effort of EEX, associations such as BDEW and EFET and market participants, the difficulties for the market to adapt to the new bidding zone set-up stand clear. Not only is the development of the overall trading volume relevant for the change of liquidity, but also the distribution of liquidity among the new products in the "split set-up". In the DE-A case EEX introduced new DE-Futures as well as A-Futures. While liquidity in DE-Futures is developing constantly, however, on a significant lower level than DE-A-Futures, the corresponding new A-Futures are lacking almost any trading activities and thus liquidity. Instead, Austrian market participants are using the new DE-Futures to mitigate future price and volume risks, even though this would mean imperfect hedges and higher costs for hedging.	The actual development would particularly depend on the exact geographic definition of the bidding zones. DE North and DE South: Splitting the most liquid market into two bidding zones would lead to a dramatic loss of the existing liquidity pool and consequently the loss of the reference for the whole region / adjacent markets. AT: Considering the relatively small size of the Austrian market, we do not expect the development of a liquid Austrian derivatives market. Instead, Austrian market participants are likely to use DE South to mitigate price and volume risks, even though this would mean imperfect hedges and higher costs for hedging.	The actual development would particularly depend on the exact geographic definition of the bidding zones. DE North / DE South / DE West: Splitting the most liquid market into three bidding zones would lead to a dramatic loss of the existing liquidity pool and consequently the loss of the reference for the whole region / adjacent markets. AT: Considering the relatively small size of the Austrian market, we do not expect the development of a liquid Austrian derivatives market. Instead, Austrian market participants are likely to use DE South to mitigate price and volume risks, even though this would mean imperfect hedges and higher costs for hedging.	A merge would increase the number of market participants and thus the opportunities to trade. Consequently, an increase of liquidity is expected.

Response by European Energy Exchange AG (EEX) **20 November 2017**

Forward / future market – longer period (e.g. three year-ahead base load product)	Change of liquidity	DE: decrease A: strong decrease	Strong decrease	Strong decrease	Increase
	Explanation	Experiences in the German-Austrian derivatives market after the announcement and decision by BNetzA to split up the common bidding zone by 1. Oct 2018 have shown a decrease of approximately 10% during the first half 2017 compared to the same period 2016. But not only is the development of the overall trading volume relevant for the change of liquidity but also the distribution of liquidity among the new products in the "split set-up". In the DE-A case EEX introduced new DE-Futures as well as A-Futures. While liquidity in DE-Futures is developing constantly, but on a significant lower level than DE-A-Futures, the corresponding new A-Futures are lacking trading activities and thus liquidity. participants are using the new DE-Futures to mitigate future price and volume risks, even though this would mean imperfect hedges and higher costs for hedging.	The actual development would particularly depend on the exact geographic definition of the bidding zones. DE North and DE South: Splitting the most liquid market into two bidding zones would lead to a dramatic loss of the existing liquidity pool and consequently the loss of the reference for the whole region / adjacent markets. AT: Considering the relatively small size of the Austrian market, we do not expect the development of a liquid Austrian derivatives market. Instead, Austrian market participants are likely to use DE South to mitigate price and volume this would mean imperfect hedges and higher costs for hedging.	The actual development would particularly depend on the exact geographic definition of the bidding zones. DE North / DE South / DE West: Splitting the most liquid market into three bidding zones would lead to a dramatic loss of the existing liquidity pool and consequently the loss of the reference for the whole region / adjacent markets. AT: Considering the relatively small size of the Austrian market, we do not expect the development of a liquid Austrian derivatives market. Instead, Austrian market participants are likely to use DE South to mitigate price and volume risks, even though this would mean imperfect hedges and	A merge would increase the number of market participants and thus the opportunities to trade. Consequently, an increase of liquidity is expected.

Answer possibilities for change: "increase", "strong increase", "decrease", "strong decrease", "no material change", "not known".

Please consider the current bidding zone configuration as the reference configuration for the comparison. The impact assessment ("Increase" etc.) is related to this reference.

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5.2.3. RESPONSE BY PKEE

Table 1 ESTIMATED LIQUIDITY IMPACT[1]

Type of market	Answer type	Impact by "DE/AT"-Split	Impact by "Big Country Split 1"	Impact by "Big Country Split 2"	Impact by "Merge"
Intraday trading	Change of liquidity	DE: no material change AT: slight decrease Neighbouring zones: Increase	DE: decrease FR: Strong Decrease PL: Strong Decrease	DE: decrease FR: Strong Decrease PL: Strong Decrease	No material change or slight increase
	Explanation				
Day-ahead trading	Change of liquidity	DE: no material change AT: slight decrease Neighbouring zones: Increase	DE: slight decrease FR: Strong Decrease PL: Strong Decrease	DE: slight decrease FR: Strong Decrease PL: Strong Decrease	No material change or slight increase
	Explanation				
Forward / future market – shorter period (e.g. one year-ahead base load product)	Change of liquidity	DE: no material change AT: decrease Neighbouring zones: Increase	Strong Decrease	Strong Decrease	Increase
	Explanation				
Forward / future market – longer period (e.g. three year-ahead base load product)	Change of liquidity	DE: no material chance AT: decrease Neighbouring zones: Increase	Strong Decrease	Strong Decrease	Increase
	Explanation				

[1] Explanation is on the next pages

General comments from Polish Electricity Association (PKEE):

- **We believe that bidding zone configuration may have a limited impact on the liquidity of the Day-Ahead market and also for Intraday market.**
- **However, the impact on the forward or hedging market may have strong consequence.**
- **Generally, we would like to say that liquidity does not only depend on bidding zone configuration or market participation but also on market structure, market design, market concentration, demand and available generation.**
- **There are some ways to mitigate the impact of bidding zone reconfiguration on liquidity, like contract for differences in the Nordic Market.**
- **Moreover, market liquidity is generally viewed as a multi-dimensional, not directly observable construct.**

Explanation:

1. "DE/AT"-Split
    a. Intraday trading
        i. Change of liquidity
            1. DE: no material change
            2. AT: slight decrease
            3. Neighbouring zones: Increase
        ii. Explanation
            1. Germany is a big zone with a lot of market participants, with high generation and consumption, so there is a chance that potential reconfiguration won't have negative impact on liquidity.
            2. Austria is a small zone and potential reconfiguration may have negative impact on liquidity (Intraday market in Netherlands is a good reference point)
            3. However, for the rest European Countries this reconfiguration may have positive impact on liquidity, especially in regard to loop flows and transit flows which actually have strong impact of cross-border exchange. Generally, we believe that if the problems with unscheduled flows are solved, you could improve level of cross- border exchanges and liquidity.
    b. Day-ahead trading
        i. Change of liquidity
            1. DE: no material change
            2. AT: slight decrease
            3. Neighbouring zones: Increase
        ii. Explanation
            1. In DA there are even more market participants than in ID, so situation may look better. So in this context, potential reconfiguration may have less impact on liquidity in Germany and also in Austria.
            2. Same comments as for the ID.
    c. Forward / future market – shorter period (e.g. one year-ahead base load product)
        i. Change of liquidity
            1. DE: no material change
            2. AT: decrease
            3. Neighbouring zones: Increase
        ii. Explanation
            1. Same comments as for the ID.
            2. However, reconfiguration can have negative impact on hedging so also on liquidity.
            3. The Impact on reliability in the stability of zones is likely to have another decreasing impact.
    d. Forward / future market – longer period (e.g. three year-ahead base load product)
        i. Change of liquidity
            1. DE: no material chance
            2. AT: decrease
            3. Neighbouring zones: Increase
        ii. Explanation
            1. Same comments as for the ID.
            2. However, reconfiguration can have negative impact on hedging so also on liquidity.
            3. The Impact on reliability in the stability of zones is likely to have another decreasing impact.

2. "Big Country Split 1"
    a. Intraday trading
        i. Change of liquidity
            1. DE: decrease
            2. FR: Strong Decrease
            3. PL: Strong Decrease
        ii. Explanation
            1. Smaller bidding zones with smaller number of market participants, with lower generation (and also variety of generation in every new zone) and consumption.
            2. A split of either the French or especially Polish single bidding zones would probably divide liquidity and have a negative impact on the markets concerned.
            3. Especially, because French or Polish zones are not so active competitive or liquid. According to that, in our opinion this reconfiguration probably has strong impact on liquidity.

b. Day-ahead trading
    i. Change of liquidity
        1. DE: slight decrease
        2. FR: Strong Decrease
        3. PL: Strong Decrease
    ii. Explanation
        1. Same comments as for the ID.
        2. However, DA market has more market participants than ID.
c. Forward / future market – shorter period (e.g. one year-ahead base load product)
    i. Change of liquidity
        1. Strong Decrease
    ii. Explanation
        1. A split of either the French or especially Polish single bidding zones would probably divide liquidity and have a negative impact on the markets concerned.
        2. Especially, because French or Polish zones are not so active competitive or liquid. According to that, in our opinion this reconfiguration probably has strong impact on liquidity.
        3. Germany is the most liquid market in EU so potential reconfiguration may have lower impact on liquidity than in France and Poland.
        4. The Impact of reliability on stability of zones is likely to have a strong decreasing impact.
        5. However, there are some ways to mitigate the impact of bidding zone reconfiguration on liquidity, like contracts for differences (CfDs) which have been used on NordPool since 2000 as a forwards market product used to hedge against the difference between the Area Price and the 'hub' price[2].
d. Forward / future market – longer period (e.g. three year-ahead base load product)
    i. Change of liquidity
        1. Strong Decrease
    ii. Explanation
        1. A split of either the French or especially Polish single bidding zones would probably divide liquidity and have a negative impact on the markets concerned.
        2. Especially, because French or Polish zones are not so active competitive or liquid. According to that, in our opinion this reconfiguration probably has strong impact on liquidity.
        3. Germany is the most liquid market in EU so potential reconfiguration may have lower impact on liquidity than in France and Poland.
        4. The Impact of reliability on stability of zones is likely to have a strong decreasing impact.
        5. However, there are some ways to mitigate the impact of bidding zone reconfiguration on liquidity, like contracts for differences (CfDs) which have been used on NordPool since 2000 as a forwards market product used to hedge against the difference between the Area Price and the 'hub' price[3].

[2] Ofgem, FTA Team, *Bidding Zones Literature Review*, July 2014

[3] Ofgem, FTA Team, *Bidding Zones Literature Review*, July 2014

3. "Big Country Split 2"

<u>Same comments like for the "Big Country Split 1" scenario.</u>

4. "Merge"
    a. Intraday trading
        i. Change of liquidity
            1. No material change or slight increase
        ii. Explanation
            1. Cross-border exchange between Czech and Slovakia is already very active, the same in BL/NL
            2. Larger variety of market players
    b. Day-ahead trading
        i. Change of liquidity
            1. No material change or slight increase
        ii. Explanation
            1. Cross-border exchange between Czech and Slovakia is already very active, the same in BL/NL
            2. Larger of variety of market players
            3. DA generally has more market participants and designated trading times
    c. Forward / future market – shorter period (e.g. one year-ahead base load product)
        i. Change of liquidity
            1. Increase
        ii. Explanation
            1. Larger variety of market players.
            2. Volumes and number of counter parties increases.
            3. Actually, it is hard to be sure about impact on this area.
    d. Forward / future market – longer period (e.g. three year-ahead base load product)
        i. Change of liquidity
            1. Increase
        ii. Explanation
            1. Larger variety of market players.
            2. Volumes and number of counter parties increases.
            3. Actually, it is hard to be sure about impact on this area.

5.2.4. RESPONSE BY EDFT

Type of market	Answer type	Impact by "DE/AT"-Split	Impact by "Big Country Split 1"	Impact by "Big Country Split 2"	Impact by "Merge"
Intraday trading	Change of liquidity	decrease	strong decrease	strong decrease	
	Explanation: Liquidity will differ across the different price zones which will have a negative impact on financial players' willingness to participate. They will prefer one big market rather than several small ones		Strongly opposed to split France, no benefits. Market won't be stable with this split. Market won't be stable with this split.	Strongly opposed to split France, no benefits. Market won't be stable with this split.	Strongly opposed to merge Belgium and Hollande. No benefits.
Day-ahead trading	Change of liquidity	decrease	strong decrease	strong decrease	
	Explanation: same as above		Strongly opposed to split France, no benefits. Market won't be stable with this split. Market won't be stable with this split.	Strongly opposed to split France, no benefits. Market won't be stable with this split.	Strongly opposed to merge Belgium and Hollande. No benefits.
Forward/future market – shorter period (e.g. one year-ahead base load product)	Change of liquidity	decrease	strong decrease	strong decrease	
	Explanation: same as above		Strongly opposed to split France, no benefits. Market won't be stable with this split. Market won't be stable with this split.	Strongly opposed to split France, no benefits. Market won't be stable with this split.	Strongly opposed to merge Belgium and Hollande. No benefits.
Forward/future market – longer period (e.g. three year-ahead base load product)	Change of liquidity	decrease	strong decrease	strong decrease	
	Explanation: same as above		Strongly opposed to split France, no benefits. Market won't be stable with this split. Market won't be stable with this split.	Strongly opposed to split France, no benefits. Market won't be stable with this split.	Strongly opposed to merge Belgium and Hollande. No benefits.

Response by EDFT

5.2.5. RESPONSE BY EFET

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ENTSO-E Bidding Zones review survey on market liquidity

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EFET response – 20 November 2017

EFET thanks ENTSO-E for giving us the opportunity to comment on this survey analysing the expected liquidity of the various markets in the context of potential new bidding zones configurations. We would like to stress that **our high-level qualitative assessment, and that of other stakeholders responding to this informal consultation within the ENTSO-E Bidding Zones Stakeholder Advisory Group (BZ SAG), should be an integral part of, but should not replace the analysis that ENTSO-E is mandated to perform on market efficiency** in the different bidding zones re-delineation scenarios.

We note once again that with only one – quite limited – bidding zones merger scenario, the review misses the opportunity to analyse the effect on both network management and market efficiency of merging bidding zones in the same way it does so for splitting them. We repeatedly made this request over the past five years, and we are disappointed to see it not go through even after the decision of ENTSO-E not to proceed with the model-based scenarios, which we expect will free up time for the team working on the bidding zones review.

As ENTSO-E is well aware, EFET favours stability in the configuration of bidding zones along the lines of long-standing structural congestions. This certainty and continuity are essential to underpin cross-border competition, liquidity in the forward, day-ahead and intraday wholesale power markets. Liquid wholesale markets are key to manage and reduce risks for market participants, and thus to allow for timely investments in generation, storage and demand response. By lowering risks and thereby risk premiums, liquid wholesale markets bring down financing costs for investments. This results in a general increase in socio-economic welfare.

A stable configuration of bidding zones should produce reliable price signals, and, especially in the case of larger zones where many generators and suppliers are active, underpin competition between market participants across all timeframes of the market. **Stability and certainty in the delineation of bidding zones is particularly important in current period of uncertainty for the market**, with many new features

The European Federation of Energy Traders (EFET) promotes and facilitates European energy trading in open, transparent, sustainable and liquid wholesale markets, unhindered by national borders or other undue obstacles. We currently represent more than 100 energy trading companies, active in over 28 European countries. For more information, visit our website at www.efet.org being implemented such as CORE day-ahead flow-based market coupling, the upcoming establishment of the XBID cross-border intraday continuous trading platform, and various challenges relating to the performance of coupling algorithms. Any review of the delineation of bidding zones, even a review implicating just two zones or nations, must be transparently organised and objectively implemented. It must take in a serious and thorough analysis of market efficiency, including effects on competition and liquidity, in different bidding zone configuration scenarios.

We welcome the consideration of forward market liquidity in the survey circulated by ENTSO-E to the members of the BZ SAG, after EFET and other market participant representatives long insisted on the importance of considering this timeframe in the liquidity analysis. **Market efficiency however does not stop at liquidity. Competition, both at the wholesale and retail levels, is also a vital element of it**. **We expect ENTSO-E to conduct proper scrutiny on the competition effects of the different scenarios as part of its market efficiency analysis before submitting its final review proposal**.

In the table below we have indicated the expected liquidity effects of the potential changes in bidding zones delineation according to the different expert-based scenarios of the review.

Type of market	Answer type	Impact by "DE/AT"-Split	Impact by "Big Country Split 1"	Impact by "Big Country Split 2"	Impact by "Merge"
Intraday trading	Expected Change of liquidity	**Decrease** (DE: no material change; AT: strong decrease)	**Strong decrease** (DE North: decrease; DE South: decrease; AT: strong decrease; FR North: decrease: FR South: decrease; PL West: n/a; PL East: n/a)	**Strong decrease** (DE North: decrease; DE South: decrease; DE West: decrease; AT: strong decrease; FR North: decrease: FR Central: decrease; FR South: decrease; PL West: n/a; PL East: n/a)	**Increase** (BE-NL: increase; CZ-SK: no material change or increase)
	Explanation	• **DE**: Liquidity is expected to remain stable or only slightly decrease on the German ID market. • **AT**: Liquidity is expected to decrease sharply on the Austrian ID market.	• **DE North**: Liquidity is expected to decrease on the German North ID market. Also, this market will be negatively affected by an imbalance between a large power generation fleet (incl. RES-E) and limited demand. • **DE South**: Liquidity is expected to decrease on the German South ID	• **DE North**: Liquidity is expected to decrease on the German North ID market. Also, this market will be negatively affected by an imbalance between a large power generation fleet (incl. RES-E) and limited demand. • **DE South**: Liquidity is expected to decrease on the German South ID	• **BE-NL**: Liquidity on the Belgian and the Dutch ID markets is rather hampered by the size of the bidding zones than by an inappropriate market design. Merging the two zones into one would increase liquidity on the joint ID market. However, the joint bidding zones would still be too small to experience

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			market. Also, this market will be negatively affected by an imbalance between a limited power generation fleet (incl. RES-E) and strong demand. • **AT**: Liquidity is expected to decrease sharply on the Austrian ID market. • **FR North**: Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease. • **FR South**: Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease. • **PL West**: Poland being a central dispatch model, there is no market for ID to speak of as far as our understanding of a market is concerned, where market participants freely exchange bids and offers. Volumes exchanged with the TSO in the ID timeframe are expected to remain stable. • **PL East**: Poland being a central dispatch model, there is no market for ID to speak of as far as our understanding of a market is	market. Also, this market will be negatively affected by an imbalance between a limited power generation fleet (incl. RES-E) and strong demand. • **DE West**: Liquidity is expected to decrease on the German West ID market. • **AT**: Liquidity is expected to decrease sharply on the Austrian ID market. • **FR North**: Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease. • **FR Central**: Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease. • **FR South**: Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease. • **PL West**: Poland being a central dispatch model, there is no market for ID to speak of as far as our understanding of a market is concerned, where market participants freely exchange bids and offers.	a significant increase in ID liquidity • **CZ-SK**: Liquidity on the Czech and the Slovak ID markets is hampered both by the size of the bidding zones and market design choices. Merging the two zones into one without market design reform would likely not result in any material change, or at best in a slight increase of liquidity on the joint ID market.

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			concerned, where market participants freely exchange bids and offers. Volumes exchanged with the TSO in the ID timeframe are expected to remain stable.	Volumes exchanged with the TSO in the ID timeframe are expected to remain stable. • **PL East**: Poland being a central dispatch model, there is no market for ID to speak of as far as our understanding of a market is concerned, where market participants freely exchange bids and offers. Volumes exchanged with the TSO in the ID timeframe are expected to remain stable.	
Day-ahead trading	Change of liquidity	**Decrease** (DE: no material change; AT: strong decrease)	**Strong decrease** (DE North: decrease; DE South: decrease; AT: strong decrease; FR North: decrease: FR South: decrease; PL East: no material change or increase; PL West: no material change)	**Strong decrease** (DE North: decrease; DE South: decrease; DE West: decrease; AT: strong decrease; FR North: decrease; FR Central: decrease; FR South: decrease; PL East: no material change or increase; PL West: no material change)	**Increase** (BE-NL: increase; CZ-SK: no material change or increase)
	Explanation	• **DE**: Liquidity is expected to remain stable or only slightly decrease on the German DA market. • **AT**: Liquidity is expected to decrease sharply on the Austrian DA market. Price sensitivity on the Austrian market will sharply	• **DE North**: Liquidity is expected to decrease on the German North DA market. Also, this market will be negatively affected by an imbalance between a large power generation fleet (incl. RES-E) and limited demand. • **DE South**: Liquidity is expected to decrease on the German South DA market. Also, this	• **DE North**: Liquidity is expected to decrease on the German North DA market. Also, this market will be negatively affected by an imbalance between a large power generation fleet (incl. RES-E) and limited demand. • **DE South**: Liquidity is expected to decrease on the German South DA market. Also, this	• **BE-NL**: Liquidity on the Belgian and the Dutch DA markets is rather hampered by the size of the bidding zones than by an inappropriate market design. Merging the two zones into one would slightly increase liquidity on the joint DA market, and reduce price sensitivity. However, the joint bidding zones would still be too

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		increase, which even with market coupling will affect the Austrian DA market (incl. OTC) directly.	market will be negatively affected by an imbalance between a limited power generation fleet (incl. RES-E) and strong demand. • **AT**: Liquidity is expected to decrease sharply on the Austrian DA market. Price sensitivity on the Austrian market will sharply increase, which even with market coupling will negatively affect the Austrian DA market (incl. OTC) directly. • **FR North**: Liquidity is expected to decrease sharply on the French North DA market. Price sensitivity on the French North market will sharply increase, which even with market coupling will negatively affect the French North DA market (incl. OTC) directly. • **FR South**: Liquidity is expected to decrease sharply on the French South DA market. Price sensitivity on the French South market will sharply increase, which even with market coupling will negatively affect the French South DA market (incl. OTC) directly. • **PL West**: Liquidity on the Polish West DA market is	market will be negatively affected by an imbalance between a limited power generation fleet (incl. RES-E) and strong demand. • **DE West**: Liquidity is expected to decrease on the German West DA market. • **AT**: Liquidity is expected to decrease sharply on the Austrian DA market. Price sensitivity on the Austrian market will sharply increase, which even with market coupling will negatively affect the Austrian DA market (incl. OTC) directly. • **FR North**: Liquidity is expected to decrease sharply on the French North DA market. Price sensitivity on the French North market will sharply increase, which even with market coupling will negatively affect the French North DA market (incl. OTC) directly. • **FR Central**: Liquidity is expected to decrease sharply on the French Central DA market. Price sensitivity on the French Central market will sharply increase, which even with market coupling will negatively affect the French Central	small to experience a significant increase in DA liquidity. • **CZ-SK**: Liquidity on the Czech and the Slovak DA markets is hampered both by the size of the bidding zones and market design choices. Merging the two zones into one without market design reform would likely not result in any material change, or at best in a slight increase of liquidity on the joint DA market.

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			expected to remain stable, though it could benefit from a slight increase due to the reduction of unscheduled flows at the PL-DE border. • **PL East**: Liquidity on the Polish East DA market is expected to remain stable.	DA market (incl. OTC) directly. • **FR South**: Liquidity is expected to decrease sharply on the French South DA market. Price sensitivity on the French South market will sharply increase, which even with market coupling will negatively affect the French South DA market (incl. OTC) directly. • **PL West**: Liquidity on the Polish West DA market is expected to remain stable, though it could benefit from a slight increase due to the reduction of unscheduled flows at the PL-DE border. • **PL East**: Liquidity on the Polish East DA market is expected to remain stable.	
Forward / future market – shorter period (e.g. one year-ahead base load product)	Expected Change of liquidity	**Decrease** (DE: no material change; AT: strong decrease)	**Strong decrease** (DE North: strong decrease; DE South: strong decrease; AT: decrease; FR North: no material change or decrease: FR South: decease; PL West: no material change or decrease; PL East: decease)	**Strong decrease** (DE North: strong decrease; DE South: strong decrease; DE West: strong decrease; AT: decrease; FR North: no material change or decrease: FR Central: decrease; FR South: decrease; PL West: no material change or decrease; PL East: decrease)	**No material change** (BE-NL: no material change or increase; CZ-SK: no material change)
	Explanation	• **DE**: Market participants in both Germany and Austria are likely to mainly rely	• **DE North**: Splitting Germany into two bidding zones means the German market is likely to no longer serve as a reference and	• **DE North**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and	• **BE-NL**: While the Belgian-Dutch merger may slightly boost liquidity in the forward market for the joint bidding

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		on the German market alone for forward trades. This means that the German forward market will remain stable, as the hub for forward trading (including hedging) for the region it is today. • **AT**: As a consequenc e of the above, we do not expect the Austrian market to develop a liquid local forward market. Market participants in Austria will rely on the liquid German market for forward trading (incl. hedging). As far as hedging is concerned, this means that Austrian market participants will use imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase	pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE North. • **DE South**: Splitting Germany into two bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE South. • **AT**: Considering the relatively small size of the Austrian market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Austrian market than the case when Germany is one single bidding zone (“DE-AT split scenario”). However, Austrian market participants are likely to remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in Austria, as well as the cost for the development of long-term projects. • **FR North**:	pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE North. • **DE South**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE South. • **DE West**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE West. • **AT**: Considering the relatively small size of the Austrian market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Austrian market than the case when Germany is one single bidding zone (“DE-AT split scenario”). However, Austrian market participants	zone, it would not result in the creation of a sufficiently large bidding zone to draw liquidity at a level that would allow reducing bid-ask spreads, limit price sensitivity, etc. Market participants in the joint bidding zone are likely to continue to rely on the German-Austrian market alone for forward trades (incl. hedging), as they do today. • **CZ-SK**: As the Czech-Slovak merger would not result in the creation of a significantly large bidding zone, market participants in the joint bidding zone are likely to continue to rely on the German-Austrian market alone for forward trades (incl. hedging), as they do today.

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		the cost of hedging in Austria, as well as the cost for the development of long-term projects.	Considering the relatively small size of the French North market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the French North market than if Germany had remained one single bidding zone. However, France North market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France North, as well as the cost for the development of long-term projects. • **FR South**: Considering the relatively small size of the French North market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France South market participants will remain in the	are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Austria, as well as the cost for the development of long-term projects. • **FR North**: Considering the relatively small size of the French North market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the French North market than if Germany had remained one single bidding zone. However, France North market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France North, as well as the cost for the development of long-term projects. • **FR Central:** Considering the relatively small size of the French Central market, we do not expect it market to develop a liquid local	

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			position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France South, as well as the cost for the development of long-term projects. • **PL West**: Considering the relatively small size of the Polish West market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Polish West market than if Germany had remained one single bidding zone. However, Poland West market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland West, as well as the cost for the development of long-term projects. • **PL East**: Considering the relatively small size of the polish East market, we do not expect it market to develop a liquid local forward market. This zone would also be too	forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France Central market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France Central, as well as the cost for the development of long-term projects. • **FR South**: Considering the relatively small size of the French South market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France South market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging	

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			far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. Poland East market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland East, as well as the cost for the development of long-term projects.	in France South, as well as the cost for the development of long-term projects. • **PL West**: Considering the relatively small size of the Polish West market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Polish West market than if Germany had remained one single bidding zone. However, Poland West market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland West, as well as the cost for the development of long-term projects. • **PL East**: Considering the relatively small size of the Polish East market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to	

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				grow its own forward market. Poland East market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland East, as well as the cost for the development of long-term projects.	
Forward / future market – longer period (e.g. three year-ahead base load product)	Expected Change of liquidity	**Decrease** (DE: no material change; AT: strong decrease)	**Strong decrease** (DE North: strong decrease; DE South: strong decrease; AT: decrease; FR North: no material change or decrease: FR South: decease; PL West: no material change or decrease; PL East: decease)	**Strong decrease** (DE North: strong decrease; DE South: strong decrease; DE West: strong decrease; AT: decrease; FR North: no material change or decrease: FR Central: decrease; FR South: decrease; PL West: no material change or decrease; PL East: decrease)	**No material change** (BE-NL: no material change or increase; CZ-SK: no material change)
	Explanation	• **DE**: Market participants in both Germany and Austria are likely to be mainly reliant on the German market alone for forward trades. This means that the German forward market will remain stable, as the hub for forward trading (including hedging) for the region it is today. • **AT**: As a	• **DE North**: Splitting Germany into two bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE North. • **DE South**: Splitting Germany into two bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward	• **DE North**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE North. • **DE South**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward	• **BE-NL**: While the Belgian-Dutch merger may slightly boost liquidity in the forward market for the joint bidding zone, it would not result in the creation of a sufficiently large bidding zone to draw liquidity at a level that would allow reducing bid-ask spreads, limit price sensitivity, etc. Market participants in the joint bidding zone are likely to continue to rely on the German-Austrian market alone for forward trades (incl.

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		consequence of the above, we do not expect the Austrian market to develop a liquid local forward market. Market participants in Austria will rely on the liquid German market for forward trading (incl. hedging). As far as hedging is concerned, this means that Austrian market participants will use imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in Austria, as well as the cost for the development of long-term projects.	trading for DE South. • **AT**: Considering the relatively small size of the Austrian market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Austrian market than the case when Germany is one single bidding zone (“DE-AT split scenario”). However, Austrian market participants are likely to remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in Austria, as well as the cost for the development of long-term projects. • **FR North**: Considering the relatively small size of the French North market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the French North market than if Germany had remained one single bidding	trading for DE South. • **DE West**: Splitting Germany into three bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE West. • **AT**: Considering the relatively small size of the Austrian market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Austrian market than the case when Germany is one single bidding zone (“DE-AT split scenario”). However, Austrian market participants are likely to remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in Austria, as well as the cost for the development of long-term projects. • **FR North**: Considering the relatively small size of the French North market, we do not expect it market to	hedging), as they do today. • **CZ-SK**: As the Czech-Slovak merger would not result in the creation of a significantly large bidding zone, market participants in the joint bidding zone are likely to continue to rely on the German-Austrian market alone for forward trades (incl. hedging), as they do today.

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			zone. However, France North market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France North, as well as the cost for the development of long-term projects. • **FR South**: Considering the relatively small size of the French South market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France South market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France South, as well as the cost for the development of long-term projects. • **PL West**: Considering the relatively small size of the Polish West market, we do not expect it market to	develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the French North market than if Germany had remained one single bidding zone. However, France North market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France North, as well as the cost for the development of long-term projects. • **FR Central:** Considering the relatively small size of the French Central market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France Central market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price	

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			develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the Polish West market than if Germany had remained one single bidding zone. However, Poland West market participants are likely to remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in Poland West, as well as the cost for the development of long-term projects. • **PL East**: Considering the relatively small size of the polish East market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. Poland East market participants will remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase	and volume risks. This will increase the cost of hedging in France Central, as well as the cost for the development of long-term projects. • **FR South**: Considering the relatively small size of the French South market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. France South market participants will remain in the position to rely on imperfect hedges (or “dirty hedges”) to mitigate price and volume risks. This will increase the cost of hedging in France South, as well as the cost for the development of long-term projects. • **PL West**: Considering the relatively small size of the Polish West market, we do not expect it market to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak	

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			the cost of hedging in Poland East, as well as the cost for the development of long-term projects.	picture for the Polish West market than if Germany had remained one single bidding zone. However, Poland West market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland West, as well as the cost for the development of long-term projects. • **PL East**: Considering the relatively small size of the polish East market, we do not expect it market to develop a liquid local forward market. This zone would also be too far removed and would have too few market participants to benefit from the loss of liquidity in the German forward market to grow its own forward market. Poland East market participants will remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in Poland East, as well as the cost for the development of long-term projects.	

5.2.6. RESPONSE BY IFIEC EUROPE

securing competitive energy for industry

Position on the Bidding Zone Review questionnaires on liquidity and transaction costs

November 2017

On the 4th October ENTSOE provided the members of the Bidding Zone Stakeholder Advisory Group with two questionnaires as a part of a two-phase consultation. One questionnaire addresses market liquidity with regards to bidding zone configuration and the other one transaction costs. The results of the questionnaires should feed into the official one-month public consultation early 2018.

Since IFIEC is not capable of delivering estimates on the increase or decrease of liquidity in specific bidding zone configurations or neither can provide detailed information on transaction costs either for a single industrial player or the power intensive industry as a whole, we would at least like to give some general comments.

IFIEC would like to emphasis that when changes in the bidding zone configurations are considered, the transition cost of the market players should be taken duly into account in the cost/benefit analysis. Further, any changes in the configuration should be published to the market and market players in due time before the changes, so the market players can conduct the adjustments and preparations in an efficient way to a lowest possible cost.

In connection to the bidding zone proposal in the Winter package, IFIEC promoted the idea that bigger market zones lead to higher liquidity and more options to provide flexibility to a broader geographical scope. The current statement of Commissioner Arias Canete on the final report by Commission Expert Group on 2030 electricity interconnection targets let us believe, that the EC works into the same direction. Mr. Canete stated that the EC will present a clean energy infrastructure package, which will include the third list of Projects of Common Interest and ideas for making operational the 15% interconnection target for 2030. In the current consultation 3 out of 4 configurations focus on the splitting of bidding zones, only one on merging. Bidding zones are also addressed in the winter package proposal. In order to find a balanced solution IFIEC proposed the following change:

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Art. 13. 1. Bidding zone borders shall be based on long-term, structural congestions in the transmission network and bidding zones shall not contain such congestions. The configuration of bidding zones in the Union shall be designed in such a way as to maximise economic efficiency and cross-border trading opportunities while maintaining security of supply.	Art. 13.1. ***Whenever long-term structural congestions in the transmission network occur, member states shall take all necessary measures in order to solve those congestions in a reasonable time frame.*** The configuration of bidding zones in the Union shall be designed in such a way as to maximise economic efficiency and cross-border trading opportunities while maintaining security of supply.
Justification Members states should take all necessary steps to solve structural congestions as soon as possible.	

The experience from many member states show that performing infrastructure investments often experience delays due to many reasons. Our proposal should safeguard the regulatory framework from hasty reactions on the splitting of bidding zones. Even if the results from the questionnaires indicate „quick wins“ on the short term, it might not be the most economic solution for the long term. Therefore, we are asking for a balanced approach taking into account the efforts of member states, who are planning and implementing to reduce and remove structural congestions within reasonable time frames.

IFIEC Europe represents energy intensive industrial consumers where energy is a major component of operating costs and directly affects competitiveness.

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6 OVERVIEW OF STAKEHOLDER MEETINGS

- First public workshop on 21 March, 2014
- Stakeholder Advisory Group meeting on 27 June, 2014
- Stakeholder Advisory Group conference call on 29 October, 2014
- Individual stakeholder calls between December 2014 and January 2015
- Stakeholder Advisory Group meeting on 30 January, 2015
- Stakeholder Advisory Group meeting on 19 June, 2015
- Stakeholder Advisory Group meeting on 16 December, 2015
- Stakeholder Advisory Group conference call on 15 March, 2016
- Stakeholder Advisory Group meeting on 22 June, 2016
- Stakeholder Advisory Group conference call on 24 November, 2016
- Stakeholder Advisory Group meeting on 13 June, 2017
- Stakeholder Advisory Group meeting on 10 January, 2018

7 POST-PROCESSING RESULTS: JUSTIFICATIONS PROVIDED BY TSOs

As explained in section 4.2, the post-processing of the model-based bidding zone configurations allows for individual, further alignments by TSOs. The justifications provided by TSOs who applied such adjustments in step 4 are provided in the following.

RTE

The constraints highlighted by the computation of the LMPs are mainly located in the 225kV grid or transformers to the distribution grid (e.g. 2020 SOAF 76 % of the European congestion cost, 99.8 % of the French congestion cost). For example, in the Paris area, the main reason seems to be the nodal allocation of consumption. The 400 kV constraints (0.2 % of the French congestion cost) are not relevant and not foreseen in planning studies (TYNDP and French TYNDP). Furthermore, the present computations lack the use of topological remedial actions that are the basis for congestion management of the French grid.

PSE/SEPS/MAVIR

The Single Control Area (CA) may contain more than one bidding zone and bidding zones may be built up from a few CAs but not parts of CAs; therefore, the proposal is not to divide SEPS' CA. Some constraints are not visible in the presented results due to the fact that only n-0 simulation is available. N-1 LMPs should show significant congestions on: (1) PL–SK border both in the SOAF 2025 planned and worst case and (2) SK–HU border in SOAF 2025 worst case. There will be no grid reinforcement in the event of these borders (except SK–HU 2025 planned), and the current operation clearly shows congestions in today's grid topology. This is further confirmed by the results of the most recent TYNDP, where boundaries are indicated on the border of the Polish bidding zone and SK–HU border as well.

Energinet

Some data implemented in the Plexos model creates distortions. There is, in the modelling, 2,500 MW of biomass must-run capacity, which generates more than 12 TWh of electricity. In the data submission, only 15 % of this capacity should be must run; the rest should react to the price signals in the dispatch decisions. Furthermore, the interconnector Cobra cable is implemented with a capacity of 490 MW, and the 1,700 MW interconnections to Norway are hardly ever used, which is very far from believable given the fact the connection is to a country with 96% hydro production from a country with a significant excess of windpower. Lastly, there was only half capacity on several internal DK1 AC 400 kV lines in the CNEC selection compared to reality.

Germany

After analysing all the arguments/issues in the post-processing, the intra-German split which is contained in the worst case grid scenario is considered to be irrelevant due to the following reasons: the congestions observed in the German grid leading to the split are located in the 220 kV network. These congestions represent a relatively low share of the overall congestion costs and are therefore negligible (0–0.1 % of the congestion costs where congestion costs are determined as the price difference between nodes multiplied by the flows over the congested elements connected to these nodes). Since all networks and congestions should be treated equally across Europe, the internal German split should be removed in order to ensure comparability with other splits.

8 MERIT-ORDER PTDF APPROACH

[will be part of the final report]

9 DETERMINATION OF FLOW RELIABILITY MARGINS (FRMS)

[will be part of the final report]

10 DETERMINATION OF LOCATIONAL MARGINAL PRICES (LMPS)

[will be part of the final report]

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