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E.ON's Position on

ERGEG's Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity

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1 General Remarks

E.ON welcomes the consultation on the draft Framework Guidelines on Capacity Allocation and Congestion Management. This is a very important step for the harmonization of procedures and plays a crucial role in achieving the objective of a single European electricity market.

The codes on capacity allocation and congestion management (CACM) for electricity will be drafted by ENTSO. The fact that the codes will regulate some parts of the TSOs' business means that the framework guidelines need to be very concrete and clear to ensure that the codes are developed to meet the requirements of the market and the regulators.

The framework guidelines should be clear on the legal basis for implementing the regulation. The fact is that the existing congestion management guidelines have not been consistently implemented nor enforced inside national jurisdictions. Thus it will be of crucial importance that Regulators will not only draft the new guidelines correctly, but also insist on full implementation of them by TSOs from the time when they enter into force and in the mean time focus on enforcing implementation of the existing Congestion Management Guidelines.

E.ON believes that solutions need to be consistent around Europe and should not allow local markets to continue with models that are not in line with the target model, such as for example that Nordic TSOs are not allocating forward transmission rights within the Nordic market, and the frequency of implicit auctions in the Iberian intra-day market. E.ON believes that it will be difficult to separate national from cross- border aspects of capacity allocation and congestion management, given the interdependence, which means that the CACM network code should be made binding through comitology and national network codes have to be aligned with them.

E.ON is of the opinion that transparency requirements should be included in the Transparency Comitology Guidelines to ensure a clear structure of the different guidelines.

2 Specific Remarks

General Issues

1. Are there any additional issues and / or objectives that should be addressed in the Capacity Allocation and Congestion Management IIA and FG?

Yes, some issues are not properly addressed in the new draft, including:

- Duty of TSOs to maximize the volume of capacity allocated for cross-border, and of regulators to ensure adequate optimization and to actively monitor non-discrimination.
- Rule that transmission capacity rights issued by TSOs must be as firm as possible; and that to the degree they are firm, a TSO is not allowed to curtail allocated capacity, except in the case of force majeure or emergency situations.

We would also like to point out that we see a cross border redispatching systems as mentioned in provisions 5.1 to 5.4 as a valuable tool to manage congestions and therefore this method should have a broader role in the framework guideline. A more detailed elaboration of such system for discussion with involvement of stakeholders is necessary.

2. Is the vision of the enduring EU-wide target model transparently established in the IIA and FG and well suited to address all the issues and objectives of the CACM?

E.ON believes that the EU wide target model has to be described in much more detail to ensure that there will be a common understanding and that consistent network codes will be developed and implemented in all parts of the EU.

We would appreciate a deeper analysis (costs & benefits) of the potential critical elements related to the process.

3. Should any of the timeframes (forward, day-ahead, intraday) be addressed in more detail?

Yes, E.ON believes that all timeframes have to be described in much more detail to ensure that there will be a common understanding and a consistent implementation in all parts of the EU.

4. In general, is the definition of interim steps in the framework guideline appropriate?

No, the framework guidelines should give a clear and detailed description of how and when the target model for capacity allocation and congestion management should be implemented in all parts of the EU with full implementation no later than 2015. Given the very different starting points, the interim steps should not be laid down in the framework guidelines. Rather, there should be a clear statement that interim solutions need to take the target model into account and appropriate mechanisms for supervision should be implemented.

5. Is the characterisation of force majeure sufficient? Should there be separate definitions for DC and AC interconnectors?

E.ON would like to see a much clearer definition of force majeure to avoid diverging definitions. E.ON sees no reasons for separate definitions for DC and AC interconnectors.

6. Do you agree with the definition of firmness for explicit and implicitly allocated capacity as set out in the framework guideline? How prescriptive should the framework guideline be with regard to the firmness of capacity?

E.ON believes that the framework guideline should define firmness of capacity in detail and that curtailment of cross-border transactions may only be applied in case of force majeure or in emergency situations. Holders of capacity in the form of PTRs or FTRs should be compensated by the relevant market spread in emergency situation and by the initial payment (to the TSO, not in the secondary market) in case of force majeure. Allocated day-ahead capacity should be financially firm, even in case of force majeure, to ensure that market coupling outcomes will not be changed. E.ON does not see any reason why financial firmness may be accepted in case of explicit auctions, but not in the case of implicit auctions. Physical firmness is preferred in both cases as market participants do not have to change nominations, which would simplify it for market participants. Physical firmness can be achieved by the TSOs countertrading to ensure that nominated schedules do not have to be changed.

7. Which costs and benefits do you see from introducing the proposed framework for Capacity Allocation and Congestion Management? Please provide qualitative and if applicable also quantitative evidence.

Costs and benefits are in general difficult to quantify. On the cost side there are figures from CWE market coupling project but when evaluating them it has to be taken into consideration that this was a pilot project under special circumstances. Any further enlargement will probably be much cheaper. As for benefits, it is clear that efficient congestion management will increase competition across Europe and facilitate that consumer prices will have advantages by better cross-border competition. E.ON's impression is that the consultation document takes a short term perspective and does not consider the long term effects on investments. Efficient short term use of transmission capacity is only one aspect and shouldn't be considered as the only main criteria when evaluating the size of bidding areas. The development should be towards larger, not smaller bidding areas as small zones will decrease liquidity and increase uncertainty for investments made by energy intensive consumers and generators. Furthermore, small price zones will hinder effective competition in retail markets and will add complexity for customers.

Section 1.1: Capacity calculation

Short term and long term capacity calculation should be defined or linked to another FG /NC where capacity calculation is defined.

8. Is flow based allocation, as set out in the framework guideline, the appropriate target model? How should less meshed systems be accommodated?

Flow based methodology has been promoted to offer higher capacities for trading and better usage of the grid, especially in cases of highly meshed grids. As far as it is known, calculation and allocation is more complex for market participants compared to the ATC approach, and clear and substantial benefits and operability for traders have to be demonstrated urgently before flow based allocation is introduced. As stated in the initial impact assessment (IIA), there is so far no experience from flow based allocation. We therefore want to point out that without any further proof, it might be premature to include a conclusive provision (1.1.2) in the framework guidelines with regard to types of situations for which ATC or Flow Based methods are most appropriate. Less meshed systems should be treated in the same way, but it might be difficult to demonstrate substantial benefits in these cases.

We fully support the provision (1.1.2) that the practical usage of the Flow Based method should start only after the market participants have been given sufficient time for their preparation (learning the new methodology and adaptation of the systems) and for a smooth transition to the new arrangement. TSOs should be obliged to publish all necessary data on the methodology and for follow-up of calculation in a transparent manner.

9. Is it appropriate to use an ATC approach for DC connected systems, islands and less meshed areas?

Less meshed systems should be treated in the same way, but it might be difficult to demonstrate substantial benefits in these cases.

10. Is it necessary to describe in more details how to deal with flow-based and ATC approach within one control area (e.g. if TSO has flow-based capacity calculation towards some neighboring TSOs and ATC based to the others)?

Yes, it is necessary to describe this in more detail and to fix that no discrepancies of calculation and allocation of capacities can result out of such situation.

11. Is it important to re-calculate available capacity intraday? If so, on what basis should intraday capacity be recalculated?

Yes, it is important to recalculate available capacity intraday to ensure that the market has access to maximum capacity and that the system is safe. The capacity should be recalculated based on changed status of the transmission system itself, generation and consumption. E.ON believes that the increasing amounts of intermittent generation will make recalculation of intraday capacity more important. The framework guidelines should be precise and not merely state "sufficiently often" or "as often as required" as there are very different practices today. E.ON thinks that even hourly re-calculation could be appropriate under special circumstances. An appropriate methodology and a common structure/ institution for calculation of capacities are preconditions.

Section 1.2: Zone delineation

E.ON believes that a transparent methodology for calculation and evaluation of the relevant issues for price zones has to be developed. E.ON agrees with ERGEG that if more bidding zones are introduced, a constant revision of zones will be necessary. However, TSOs should not solely be responsible for the analysis of the market situation and the restructuring of zones. This has to be undertaken in close collaboration with all relevant stakeholders and under the monitoring of ERGEG/ACER, given the importance for cross-border trading and the possibility for bidding zones crossing national borders, to ensure that all socio-economic factors are considered adequately. In order to ensure stability of market rules for cross-border trade, possible changes in the delimitation of zones should be allowed only after giving early notice to ensure legal clarity of existing contracts. For example, if electricity can be traded three years ahead, changes should not be allowed without three years notice. ERGEG/ACER has to define the details of the revision process and a list of criteria (e.g. market integration, price impact, investment certainty, competition in wholesale and retail markets) that need to be included in every revision by all TSOs.

In any case, price/bidding zones can only be an interim measure and as such, zones have to be re-merged as soon as they are no longer needed

12. Is the target model of defining bidding zones on the basis of network topology appropriate to meet the objectives?

First of all, E.ON does not agree with the approach to the objective that seems to center on the optimization of the currently existing network. Severe grid congestions or structural congestions are an issue because of a lack of investments into new grid extensions by the TSOs. Any discussion on managing congestions in the current system has to include a discussion on how these congestions can be avoided in the first place. Thus, E.ON believes that grid extensions should be the most important and first step to avoid structural congestions.

E.ON believes that any mechanism introduced should be effective, efficient and appropriate. The widely used redispatching qualifies as a mechanism that meets all of these criteria. Through ramping up and down of specific plants in front of and behind the congestion, the affected lines are relieved and the congestion is dissolved. The mechanism is also easily implemented, as a fundamental interference with established market designs is not necessary. Additionally, the liquidity of the market is not affected and all customers are facing the same wholesale prices. Redispatching costs are socialized through grid tariffs over all customers, which constitutes the most sensible way as it is impossible to identify certain groups of customers who can be claimed responsible for the TSOs' lack of investments into grid extensions. The congestion costs reflect the costs of building the new line. They are by nature nothing else than opportunity costs for an infrastructure investment not yet completed and commissioned. Overall costs of redispatch can be monitored by the regulator for the sake of transparency and can also be evaluated against the estimated cost for new grid investments. Furthermore, a redispatching system can involve an incentive scheme for TSOs in order to redispatch in the most cost-efficient way.

As far as bidding zones are concerned, E.ON acknowledges there are some arguments that splitting a market into several zones could be an alternative way to manage congestions. However, it is highly questionable if a system of price zones/bidding zones represents a mechanism superior to redispatch, as it bears a number of severe side effects which make this system rather unsuitable:

- Splitting an established market into several price/bidding zones will negatively impact the liquidity and diminish competition. E.ON cannot support a congestion management system that seems to contradict many positive characteristics of the Integrated Electricity Market (IEM). The splitting of existing large zones will be a step backwards from achieving an integrated market and destroy the work done by the Regional Initiatives that have put a lot of effort into integrating markets.

- The IIA fails to consider that the designing, implementing and applying of price zones/bidding zones are rather complex tasks that may take several years to complete and require, in most cases, a fundamental redesign of existing markets. Implementation might be postponed even further if national legislation–especially concerning Renewable Energy Sources, their remuneration and special feed-in rights–is not compatible with a zonal design.
- By splitting markets, the underlying problem of inefficient grid capacity is not solved. Quite the contrary, the urgency to engage in grid extensions is mitigated. This bears the risk, as it can be observed in some markets, that the current state of grid capacity is established and investments will be postponed indefinitely. This may lead to a situation in which the amount of accumulated outstanding investment is reaching a level that makes it virtually impossible to make up for the missed investments. This situation will further hinder the integration of European energy markets.
- It will be difficult for consumers and retail companies to deal with more zones. With the splitting up of Sweden's one price area into four zones due to commence shortly, there is evidence of a reduction in retail competition, as at least some retailers have now restricted the areas where they sell power to those price areas in which they have their main customer base.

E.ON believes that facilitating the establishment of the IEM should be the ultimate objective and this is impossible if already established large zones are split. Thus, a mechanism that prevents establishing the IEM should not be introduced.

13. What further criteria are important in determining the delineation of zones, beyond those elaborated in the IIA and FG?

E.ON believes that the draft framework guidelines have a too narrow perspective when discussing the delimitation of price-/bidding zones. Splitting large zones down to small zones will add to investment uncertainties for generators and energy intensive consumers. The ultimate goal is the IEM and a possible split of existing bidding zones will be difficult to understand for many consumers and will add further complexity. In contrary, there should be incentives to enlarge zones through merger of smaller zones.

E.ON does not agree with the statements in the IIA: "Very often, a reduction in the size of the zone is interpreted as a reduction in the liquidity of the day-ahead market. This is, however, too simplistic a view, as the important parameter here is the overall liquidity of all zones covering a given territory: with the obligation to trade day-ahead between zones through implicit auctions, the volume (liquidity) of cross-zonal trade will benefit from "internal" trade that should otherwise not have been offered to the market coupling/splitting." and "If the zones resulting from the division of the network based on its topology are considered too small to ensure liquidity, nothing prevents the creation of liquid hub made up of several zones."

E.ON is of the opinion that it is important that market participants (generators and suppliers) have the possibility to hedge their fundamental positions over all time horizons and that the liquidity in the relevant area is of importance in this perspective.

E.ON would like to comment the statement in the IIA, "It is also possible to aggregate bidding areas into one price zone, as is done in Italy, which is divided into six bidding areas, but with uniform pricing on the demand side (i.e. the demand price is the average of the zonal prices weighed on the zonal consumptions)." It is true that this solution exists, but it cannot be in line with the basic principle that consumers and producers are faced with the price in their zone. One perceived advantage of price zones are price signals. It is not clear, however, why-if price zones are introduced-the "advantage" of price signals should only apply to generators and not to customers. Customer prices not reflecting the market price in each zone will not give proper incentives e.g. to behavior of customers or acceptance of new lines, right price signals for customers will be even more important when developing smart grids and other demand side management solutions.

E.ON would like to comment the statement in the IIA, "Indeed, the relevance of a price signal in day-ahead may be questioned if large amounts of redispatching costs are necessary to ensure system security and if these redispatching costs are socialized on all network users and not charged to those who are responsible for it." It is highly questionable if a single group of network users can be claimed responsible for causing redispatching and can therefore be held accountable for the costs. The basic principle is that the TSO is the one responsible for keeping a bidding zone together and building new lines when necessary. Therefore, TSOs should make necessary and timely investments in network capacity to avoid structural congestions which might cause large amounts of redispatch which has not been the case until now. The costs for new grid capacity should be passed on through grid tariffs. Because customer still benefits from an integrated merit order in the price finding process. In case TSOs have failed to make the necessary investments, redispatch will be needed for an interim period and should consequently be socialized as well.

The conclusions in the IIA, I item 2.C.3 saying that "For instance, choosing zones according to the limits of the system operators gives 38 % higher generation costs compared to optimal dispatch" is not true. The 38 % relates to a smaller difference between different cases, which means that the difference in generation costs is much less.

E.ON believes that bidding zones, if they are unavoidable, should be as large as possible and not limited by national borders but based on the structural mid-and long-term situation in the grid. Furthermore, it is important that bidding zones are stable to ensure that counterparties are not subject to the risk that bidding zones change during the lifetime of a contract. E.ON does not believe that bidding zones should be different in different time frames. There has to be the same definition of zones for forward, day ahead, intraday and balancing. Ancillary services can have a locational element within a price zone. The size of bidding zones is limited by the possibility for TSOs to ensure in an efficient way that capacity between zones is not curtailed except in emergency situations or during a limited period when grid investments are ongoing.

Section 2: Forward markets

14. Are the preferred long-term capacity products as defined in the framework guideline suitable and feasible for the forward market timeframe?

Long term capacity products at the border of price/bidding zones are essential for hedging of production and sales. Financial Transmission Rights (FTR) and Physical Transmission Rights (PTR) are important for cross-border competition in the forward markets. E.ON believes that FTRs or PTRs should be implemented in a consistent way between all bidding zones in all parts of the EU. The framework guidelines should clearly state that all TSOs should allocate FTRs or PTRs corresponding to the full available capacity. A system of Contracts for Differences (CfD), as used in the Nordic market, is not fulfilling the requirements to enable cross-border competition in the forward market between fundamental competitors. This needs to be reflected in the framework guidelines to ensure that exceptions are not allowed that will hinder competition.

CfDs are very different instruments that do in fact not bear any link to the underlying physical transmission of capacity because the physical path from one price area to another is not referred in the CfD as the CfD is the difference between a price area and a "virtual" system price. CfDs are inappropriate instruments for managing cross border market exposure, primarily because TSOs do not issue these products to start off with. Market participants themselves can generally not take on a price-spread risk between two markets because they do not have an ability to manage such a risk as long as there is no transmission right available that provides a valid hedge. Even trading companies that might in principle be willing to take such risks would likely only occasionally and to a limited extent be able to offer market spread hedges off the back of other transactions. The following example shows that cross-border competition will be improved in case transmission rights are used instead of CfDs. A generator would proceed in the following way to hedge a cross border sale to a customer in another bidding zone in case of CfD and in the case of transmission rights.

CfD

The generator would sell a CfD to a customer (as fundamental buyer of CfDs) in its own bidding zone and buy a CfD from a competing generator (as fundamental seller of CfDs) in the other bidding zone.

Transmission rights

The generator would buy a transmission right in an auction arranged by the TSOs or in the secondary market. This is undertaken to manage and hedge risks across zones, countries or price areas.

15. Is there a need to describe in more detail the elaborated options for the organisation of the long-term capacity allocation and congestion management?

Yes, this should be described in more detail to ensure that long-term capacity allocation and congestion management are implemented the same way around Europe.

Section 3: Day Ahead allocation

16. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the day-ahead allocation?

Yes, first of all, the target model should be described in more detail to ensure that it is implemented in the same way around Europe. E.ON would like to see a clear statement that TSOs are not allowed to include ramping restrictions. Ramping restrictions should be handled in the ancillary services market.

E.ON fully supports the target model for the Day-Ahead market based on capacity allocation through implicit auctions via a single price coupling algorithm. There should be a clear call for the necessary harmonization of market rules and products in the countries to allow for an appropriate implementation.

Section 4: Intraday allocation

E.ON does not agree with the statements ″Intraday allocation and trade foreseen in the CACM network code(s) should be coordinated by the TSOs with redispatching/countertrade and with (cross-border) balancing markets, while being guided by the principle of overall efficiency.″ and ″efficient arbitrage with the day ahead and balancing time-frames is possible″ because intraday markets are between market participants and there should be no reservation of cross-border capacity for ancillary services or balancing except the safety margin.

17. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the intraday allocation?

Yes, first of all, the target model should be described in more detail to ensure that it is implemented the same way around Europe. Intraday trading should be possible at least until one hour before delivery. E.ON believes that there are no relevant reasons for keeping the option to have implicit auctions in some markets. If a European intra-day market should be achieved, there is a need for the same allocation method around Europe. It would not be sufficient to ″have adequate gate closures″.

18. Does the intraday target model provide sufficient trading flexibility close to real time to accommodate intermittent generation?

Yes, in case continuous implicit allocation is implemented around Europe. E.ON believes that pricing of intraday capacity will add complexity to the process without adding substantial value. When design of intraday is discussed it should also be kept in mind that enough liquidity remains for day ahead as liquid and reliable day ahead prices are crucial.