RWE

European Regulators' Group for Electricity and Gas
Rue le Titien 28
1000 Brussels
Belgium

Market Design and Regulatory Affairs

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Your letter	
Our ref.	
Contact	William Webster
Phone	+44 1793 892612
Fax	+44 1793 892118
Email	william.webster@rwe.com

Swindon, 10/11/2010

Dear Fay,

RWE response to ERGEG's draft Framework Guidelines on Capacity Allocation and Congestion Management for electricity

RWE Group has various generation and supply businesses across the European Union as well as RWE Supply and Trading and RWE Innogy. This response is on behalf of all these companies.

The CACM guidelines represent the first part of a package that will result in harmonised electricity market arrangements across the European Union. We expect that the network codes resulting from these guidelines will be binding and apply comprehensively throughout the EU.

European policy makers must therefore develop a clear and coherent view on the overall framework to be delivered by the package of guidelines. As the CACM guidelines are the first opportunity to discuss many of these key market design issues, consultation is of utmost importance. There is no single "off the shelf" set of policies, relevant for the current EU situation, that can be imported from academic work or from other jurisdictions globally.

RWE believes that all Members States should have the same overall market arrangements. Many of the existing barriers between EU markets arise from unnecessary differences between market rules. The guidelines, as they stand, still leave too much scope for different national or regional solutions that will continue to impede competition. ACER's role in supervising the implementation of guidelines therefore needs to be strengthened to remove these differences and to ensure non-discriminatory and transparent arrangements.

RWE Supply & Trading GmbH
Swindon Branch

Windmill Hill Business Park
Whitehill Way
Swindon SN5 6PB
United Kingdom

T +44(0)1793/87 77 77
F +44(0)1793/89 25 25
I www.rwe.com

In the view of RWE, electricity market arrangements need to be aimed at the following objectives;

- promotion of competition through:
    - liquid wholesale markets
    - liquid & substitutable product definitions (e.g. reserve vs. energy markets),
    - enhanced trading of capacity between countries/market hubs with the opportunity to transfer mid/long term delivery options with intraday execution
    - possibility for merchant investment in new transmission lines as provided for in the Regulation
- efficient short-term generation dispatch;
- cost-reflective arrangements to give market participants suitable short and long-term incentives;
- regulatory stability to stakeholders including TSOs, power exchanges and market participants over the coming years to promote investment and the delivery of the EU's climate change objectives.

There are inevitably trade-offs between these objectives and an important task of ERGEG, ACER and eventually the Commission will be to balance these. However, our assessment of the draft guidelines is that they, in general, go in the right direction to meeting many of these objectives.

The attached Annex sets out our response to the individual questions. RWE has also contributed to the responses of EFET and Eurelectric with which we largely agree, particularly on the subjects of firmness and force-majeure. There are a number of key points we wish to emphasise below.

i. EU markets will function better the more that TSOs increase:

- **the amount and appropriateness of the transportation capacity offered;**
- **the amount of capacity that is allocated for longer dated products consistent with requirements of (power plant) investors and end users;**
- **firmness of capacity.**

And this requires appropriate incentives to be provided to TSOs to jointly increase physical capacities between markets.

Increasing capacity and firmness does not necessarily mean construction of new infrastructure. A significant amount of additional cross border capacity could be released through; greater co-ordination between TSOs, removing discrimination, and the provision and sharing of more real time information. Likewise the introduction of flow-based allocation at the day ahead stage would be welcome if it leads to a significant increase in the overall envelope of cross border capacity.

However, although all these things will help, increased investment is also needed, especially in view of the rapidly increasing wind and solar power generation, where generation is predominately located far from consumption (e.g. off-shore generation). For that reason RWE strongly recommends provision of incentives to enhance all existing lines where they are responsible for congestion in the transportation or distribution network. To make quick-wins possible these incentives have to be addressed without any national restrictions. For example, the situation at the FR-DE or CH-IT borders show that relatively minor enhancements to existing lines or transformer stations would increase capacity between markets significantly. A joint incentivation seems to be key to solve national (between TSO's) or local (between DSO and TSO) barriers.

Therefore a crucial issue, and not just for the CACM guidelines, is to ensure that national regulators give TSOs the resources and incentives to maximise capacity and optimise the delivery of an efficient electricity transport service to better promote pan-European competition. There must be commitment among regulators to improving the functioning of cross border electricity markets in this way.

These objectives also need to be reflected in the CACM guidelines, particularly the capacity calculation section. In many ways the discussions around the size of price zones is secondary to the overarching need for Regulators to provide system operators with the incentives to do the "right thing" from the perspective of a competitive European market.

ii. Delimitation of price zones must promote liquidity and competition

In general, RWE is of the view that the regulatory framework should aim in the direction of expanding the size of existing price zones and thereby building on the liquidity that already exists. The value of a liquid uniform price zone to (e.g. power plant) investors and end-users should not be undervalued since it allows more market participants to compete, and reduces the market power of generators.

iii. Separating national from cross border aspects of CACM is not sensible

RWE believes that the degree of interdependence in connected systems makes it impossible to separate national and cross border aspects of capacity allocation and congestion management with any consistency or confidence. There is no good reason why congestion should be managed differently depending on whether it is purely national or cross border. So although the Regulation only refers to cross border exchanges, RWE considers that national rules must therefore be adapted to the cross-border framework that emerges.

iv. The guidelines should avoid prejudicing the outcomes of competitive processes.

A key issue in this respect is the maintenance of a clear division between the monopoly associated with system operation and the competitive provision of of trading platforms and venues. Regulators will therefore need to

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ensure an arm's length relationship between TSOs and power exchanges and clear governance rules on the ownership and responsibility for any shared algorithms for day ahead and intraday capacity allocation. It is important that established principles of EU energy markets are maintained in particular self-dispatch and the freedom for market participants to transact across a range of time frames and market platforms. The guidelines should not, for example, reintroduce the possibility of a Single Buyer type, centralised dispatch model by requiring market participants all to transact via a single platform.

In this context it is important that the TSOs are the ultimate owners of responsibility for shared algorithms as part of their (monopoly) capacity allocation duties. This will promote an open architecture which will allow for new trading platforms and exchanges to be developed, or for existing exchanges to extend their areas of operation.

v. CACM rules should not seek to deal with perceived market power issues.

The introduction of implicit allocation at the day ahead and intraday stages will mean that "capacity-hoarding" will no longer be possible. Companies which still own capacity rights by the day-ahead stage will no longer be able to retain the physical rights to that capacity. This removes the need for quantitative restrictions on the amount of rights any company can be allocated.

More generally RWE considers that established competition law processes, combined with strong transparency and record keeping obligations, are sufficient to deal with potential abuses of dominant positions, or market abuses. Ex-ante restrictions of any type on companies' behaviour are inappropriate and counter-productive in that they distort the normal price formation process.

Yours sincerely,

WILLIAM WEBSTER
HEAD OF EUROPEAN POWER MARKET DESIGN

RWE SUPPLY & TRADING GMBH

STEPHEN ROSE
HEAD OF GAS MARKET DESIGN

RWE SUPPLY & TRADING GMBH

ANNEX: REPLIES TO SPECIFIC QUESTIONS

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?

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?

The CACM guidelines are interdependent with the others yet to be drafted on balancing, network operation and transmission access. There will need to be consistency between these guidelines and this requires regulators to have an overall view of market design principles. This European market design needs to be coherent with existing practices and be robust to future energy market and policy developments. Consultation is vital as there is not a well established model to follow, either from other countries or from academic literature.

RWE notes that the following principles are either already embodied in European legislation, or are generally accepted and successful features demonstrated (either by their existence or absence) in the more developed national electricity markets:

- self dispatch;
- voluntary participation in markets, other than in balancing and reserve markets;
- that renewable producers should market their own power (either independently or via an intermediary) as far as their facilities are principally able to respond to price signals and that there should be incentives for renewable producers to contribute to stable grid operation;
- liquid forward markets supporting retail competition;
- market-driven generation investment;
- competition between trading venues;
- scope for real time pricing of final consumers (smart meters);
- removal of end user price regulation.

These already have some implications for the CACM guidelines. Not all of these issues formed part of the PCG discussions and we would encourage regulators, in consultation with stakeholders, to develop a coherent picture of overall EU market design which covers not only issues related to capacity allocation, but also on the other aspects of market design referred to above.

Another crucial issue, is to ensure that regulatory rules and the institutional framework requires regulators to give TSOs appropriate incentives to maximise both cross border capacity and the proportion of this that is allocated as firm transmission rights over longer dated maturities. This will maximise the scope for effective cross-border competition and liquidity in national and regional forward markets. ERGEG has already consulted on this subject which is of utmost importance to the development of competitive cross border markets.

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

More consideration of the differences between timeframes is required. A distinction may need to be drawn between the way capacity is allocated in real time and the way longer term rights are bought and sold.

A particular example of this relates to the use of flow based versus ATC allocation. We would not recommend longer maturity products to be sold based on anything other than ATCs between price areas. However we could envisage a role for flow based market coupling at the day-ahead stage provided that it implies a significant expansion in the overall capacity envelope.

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

It is not clear what is meant by this question. RWE expects that the guidelines will be developed into binding network codes that will be generally applicable from a certain date, and with which all companies will have to comply. We do not see the need for any interim stages and would expect all Member States to implement the guidelines\codes by 2015, if not well before. However, over time, network codes may well evolve as regulatory thinking or technology develops. The transition from ATC to flow based allocation might be an example of this.

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

Force majeure (FM) needs to be very clearly defined. The current guidelines leave it to TSOs jointly to define the terms of FM for approval by relevant regulators. RWE believes this is insufficient. The legal definition of force majeure is relatively standard and any particular "tailoring" of the definition is certain to take it away from genuine cases of force majeure towards the shifting of more operational risk to network uses. We therefore recommend that the definition is incorporated into the network codes and approved at the same time as an Annex or protocol. We do not see any reason for a difference in treatment between 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?

The framework guidelines need to be very explicit in terms of the definition of firmness and the compensations to be paid in the event of curtailment. Risks should ultimately lie with the party best placed to manage that risk. In this case the party best placed to manage the risk of transmission capacity availability is the system operator. Although transmission capacity over time may depend on the pattern of inputs and outputs to the network, system operators are in a unique position to optimise the construction, maintenance and operation of the transmission network to assure the availability of capacity against the likely pattern of deliveries. Regulators need to recognise this aspect of the TSOs role in the incentive framework and prevent outcomes where increased firmness leads to a reduction in the amount of capacity made available.

On the other side of the equation, firm transmission capacity is essential for market participants to be able hedge their portfolios efficiently. It is no use being able to agree a prices with a customer, if you subsequently have an open ended risk on the price and availability of the transport capacity to deliver power. Without firm capacity, the value of the transmission right will decrease.

RWE agrees that physical firmness is preferred for nominated capacity – meaning that the TSOs must provide energy in the curtailed area for capacity holders in the event of a curtailment. For rights which are the subject of explicit auctions, TSOs may organise an auction process to buy back capacity. Otherwise, if curtailment occurs before nomination, capacity holders should be compensated at market spreads.

A harmonised approach to firmness is linked to a harmonised definition of force majeure. The definition of force majeure decides on (when) the TSOs' obligation to bear the risk and to pay compensation to the capacity owner. However, in FM cases, TSOs must assure physical firmness if the event occurs after the nomination stage.

In the presence of financially firm long-term transmission products, secondary markets will become more attractive. The establishment of a liquid secondary market is of vital interest to market participants as it provides the capacity owner with an additional option of making unneeded capacity available for the market. It also gives an additional way for market participants to acquire the needed transmission capacity they need. TSOs should be responsible for establishing and managing organised secondary markets.

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.

RWE shares EFET's approach to this issue which is reproduced below:

"There are a range of potential benefits that will come from improvements to capacity allocation and congestion management. In the short term, there will simply be more efficient use of the networks in a static sense – often termed "social welfare" gains from more efficient pricing in real time. In this respect, the largest benefit is expected to be achieved in making more capacity available for the market. Current approaches are partially based on arbitrary rules and are probably based on too pessimistic scenarios. Also the practice of shifting internal congestions to the border is likely to be very often not optimal. At the same time it must be noted that this benefit should also be possible to be materialized if regulators would more rigidly ensure compliance of TSOs with existing regulations.

In addition, liquidity should also increase to the extent that wholesale market functioning is improved. This will reduce transaction costs and permit more competitive markets by allowing a higher level of entry into generation and retail markets. In this context it is worth noting that small price zones may well reduce liquidity and therefore increase uncertainty for investments made by energy intensive consumers and generators. Also well-functioning retail markets could be hindered by smaller price zones.

More liquidity and competition will also provide dynamic benefits by giving better investment incentives and encourage cost reduction and innovation. Implementing the Guidelines will increase competition across Europe and facilitate robust cross-border competition which will reduce consumer prices.

There are some potential trade-offs between short term efficiency of network operation and long term incentives. In this respect, EFET's impression is that the consultation document takes a short-term perspective and does not consider the long term effects on investments.

Costs and benefits are difficult to quantify at this stage. However it is clear that the benefits of implementing the CACM Guidelines will be significant. These benefits do not just come from simple improvements in dispatch efficiency, but also through

- Higher liquidity leading to lower transaction costs,
- More effective competition driving cost reductions and innovation,
- The avoidance of unnecessary investments in, for example, peaking plant.

Implementing the Guidelines will also give greater scope to accommodate wind and therefore provide CO2 savings. We believe that benefits will be higher in the case of large liquid trading zones which will increase competition and encourage entry.

Although it is difficult to make quantitative assessments, the EU27 electricity consumption of around 3500TWh corresponds to expenditure of over Euro300bn per annum. So, even a small percentage reduction in costs arising from these improvements would amount to gains measured in billions of Euros per year. It is difficult to imagine that the costs associated with implementing the CACM Guidelines will exceed such amounts."

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

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

Flow based allocation is more complex for market participants compared to the ATC approach and although the potential benefits are acknowledged, these need to be demonstrated before proceeding along these lines. It needs to be demonstrated that flow based allocation would lead to a significant expansion in the overall envelope of cross border capacity.

Another issue that needs exploring is the possibility to use different allocation processes in different time frames (see question 3). Flow based allocation may be useful to derive prices at the day ahead stage and to determine if any new capacity is available at the intraday stage. However, we do not consider FB to be an appropriate way to define longer duration rights (i.e. anything longer than day ahead).

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 neighbouring TSOs and ATC based to the others)?

Such a situation should be avoided. The binding network codes rules should specify where and how different allocation processes should be used and avoid such anomalies.

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

Capacity must be recalculated on a regular basis during the intraday period to reflect network availability and changes to generation nominations and evolutions in demand. This is increasingly important as the amount of intermittent generation expands. With regular exchange of information it would be possible for an updated calculation to be made every hour. It is expected that the TSO will update the information on available capacity immediately as capacity is allocated to market participants during the intraday phase.

Section 1.2: Zone delineation

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

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

RWE believes that bidding zones should be as large as possible and not necessarily limited by national borders as is presently the case. Network topology is one criterion. There are, however, limits to the size of zones and a EU copper plate model is not feasible.

Where existing zones deliver liquid and competitive markets with a large range of market participants, further segmentation should be avoided and significant expense on redispatch is justified to retain the benefits of a well-functioning market with sufficient liquidity for end-consumers. This is particularly true where a segmentation of zones would increase the market concentration of generators and suppliers.

We do not share ERGEG's conclusion that the implementation of smaller bidding zones will not affect liquidity and competition. Every border between bidding zones is an obstacle to suppliers resulting in short- and long term risks and operational burdens. This is particularly relevant if regulators have not provided TSOs with the correct incentives to provide an efficient, firm and long-term transmission service between those zones.

It is hard to see how price differences between zones will be prevented from being passed through to end-customers. The market will always be able to supply end-consumers in a low-priced bidding area for a lower price than in a high-priced bidding zone. In the long run even large suppliers will not be able to smear price differences between their customers in different bidding areas. Differing prices can only be avoided if there is a regulated tariff system for end-customer prices - which is clearly not a market based solution.

Finally, it should not be overlooked that often the main reason for structural congestion is the growing capacity of on- and off-shore wind farms with discriminatory dispatch arrangements which do not respond to the signals from price zones. This problem should be dealt with first before there is any assessment of appropriate bidding zones.

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?

Capacity products should be offered on a forward basis by TSOs, not any other party. As TSOs are the only parties that are "long" transmission capacity, cross-border price risks can only be managed efficiently if the TSOs sell forward transmission contracts to market participants. TSOs should allocate as much capacity as possible to the forward markets to facilitate retail competition across borders. It is significantly easier and more efficient for long-term capacity to be broken down into short time periods in the secondary markets as positions evolve, than it is for market participants to attempt to synthesise term products from daily "sales" of capacity via implicit auctions. The type of forward transmission products offered should therefore seek to replicate the requirements of end users in terms of the contract periods.

RWE believes transmission products should normally be sold as rights rather than obligations since this will allow value to be maximised for the benefit of consumers. Once day-ahead markets are liquid enough, we believe that transmission rights should largely be financial rather than physical. In any case TSOs should collectively ensure that a single product type is sold at the individual border between any price zone.

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. Transmission rights should be allocated in a co-ordinated way, preferably by a single auctioning office. This requires consistency of processes and definitions. It is therefore suitable for the guidelines and then the network codes to specify this in detail.

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?

It is important for the day ahead allocation phase to reflect the competitive nature of the provision of exchange and clearing services. Although most Member States only have a single day-ahead exchange, this need not be the case in future (or indeed today in the case of the UK). It is therefore important that any shared order book functions, either at the day-ahead or intraday stage are open architecture and do not bar the entry of new competing trade platforms, or the expansion of existing service providers. The matching algorithm should therefore be owned by the system operator and accessible to any exchange platform that wishes to use it.

We also consider the principle of self dispatch, embodied in the Directives, as being pre-eminent. Other than real time balancing and reserve markets operated by the TSO, producers and other market participants should not have obligations to participate in any particular market. So the day-ahead market should be voluntary. In addition RWE expects day-ahead markets to only relate to the purchase and sale of energy (MWh) and market participants should submit bids and offers on that basis. Parameters relating to fixed costs, start costs, ramp rates etc. should not form any part of bidding in day ahead markets and it should be up to market participants how these are taken into account in their bidding behaviour.

Section 4: Intraday allocation

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

The target model was not sufficiently well developed in the PCG process which has led to a number of misunderstandings and unnecessary discussion. However RWE regards it as indispensible that market participants should not be obliged to transact in a particular pre-defined manner or on a certain platform at the intraday stage (whereas this has been accepted at the day-ahead stage). OTC trading is currently important for the provision of liquidity at the intraday stage and is indispensable in situations of a plant failure. It is important not to remove this possibility before market participants' needs are provided by alternative routes.

With respect to the pricing of capacity, it is unlikely that networks will be congested at the day ahead stage (i.e. different prices between zones) but that significant capacity subsequently becomes available for intraday transactions. Likewise, if there is no price difference at the day ahead stage it seems unlikely that significant congestion rents will arise during the intraday period. In any case, these will be quickly captured before the congestion rent reaches a significant value provided that intraday markets and capacity allocation start directly after the conclusion of the day-ahead stage.

Therefore it is a reasonable approximation that any capacity available at the intraday stage will not usually have a significant market value. Thus it is not necessary to have a means for collecting congestion rents through the implicit allocation methodology. Furthermore continuous allocation does imply a cost to the users since linking of transmission allocation to a particular transaction requires the seller to give up the opportunity cost of selling later in the day, or in the balancing market.

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

The possibility to renominate across borders is suitable for dealing with wind intermittency. To the extent that capacity is available, market participants will be able to refine their positions as their forecasts increase in accuracy during the day. We envisage that optimisation of these smaller volumes would be done through exchanges; whereas larger transactions (e.g. relating to a plant failure) will need to be done via OTC transactions. An open one-many congestion management module should therefore be a requirement of the guidelines, especially at the current stage. An exclusive arrangement between TSOs and particular market platforms runs the risk of being considered as a foreclosure of a downstream market by monopoly transmission companies.