

GDF Suez answer to ACER consultation on the influence of existing bidding zones on electricity markets

In responding to the public consultation, please specify whether the answer is general or whether it is related to a specific bidding zones (please specify which one). Wherever possible, please justify your opinion with qualitative or quantitative arguments or some references.

GDF SUEZ answer is not related to specific bidding zones, but is referring to general principles and requirements to assess bidding zones configuration.

In conducting the review of bidding zones both ENTSOE and ACER must, above all, take account of the overriding objectives of the Third Package which the realisation of a competitive market for electricity in the European Union. Transmission System Operators (TSOs) have special responsibilities in this respect and they are obliged to cooperate, via ENTSOE *“to promote the completion and functioning of the internal market in electricity and cross-border trade”*.

In fulfilling this objective, account needs to be taken of the historical development of the electricity sector in the EU and the starting position of the market as it is today. In particular, because electricity systems have typically been developed on a national level, the sector is characterised by the existence of rather large companies. Furthermore, there is, little tradition for cooperation between system operators and limited development of a regional system operators as seen in the United States.

The overriding factor to mention is that the current practice for consumers, is that supply contracts are based on a fixed electricity price over a particular period. This means that effective competition requires liquid wholesale markets for forward products to enable supply businesses to respond to an increase or decrease in the portfolio of customers. So although day-ahead markets are important in providing a reference price and supporting efficient use of transmission capacity, they are only one element of the wholesale market liquidity.

Our overriding view is that bidding zones need to be relatively large and include a range of buyers and sellers. These should all interact on the basis of a unique electricity price in the zone. The same zone must be used for all timeframes: forward, day-ahead, intraday and balancing markets.

The importance of a liquid market justifies a high level of redispatch by system operators which, in any case, is not a pure social welfare cost. Indeed redispatch is one of the functions TSOs should be encouraged to perform in order to maintain a framework where all market players can all compete on equal terms. This is a more effective way to deal with incidences of localised market power rather than entrenching market power into the entire structure, which would be the case with smaller zones.

European electricity market functioning could be improved through a judicious merging of some of the smaller zones (e.g.: merging the Belgian and Dutch zones in the CWE region, merging some zones in the CEE region and/or in the Nordic/Baltic region). Addressing this should be the priority rather than considering the splitting of existing zones which have well-functioning wholesale markets (forward, day-ahead, intraday). It would also result in price differences for end customers in a same

“market” as defined today, distorting also the competition between end customers. This would in general be against the aim of the objective to create one internal market in Europe.

1) How appropriate do you consider the measure of redefining zones compared to other measures, such as, continued or possibly increased application of redispatching actions or increased investment in transmission infrastructure to deal with congestion management and/or loop flows related issues? What is the trade-off between these choices and how should the costs attached to each (e.g. redispatching costs) be distributed and recovered?

1. Expanding transmission capacity is normally the most efficient way to solve/manage structural congestions and the only consistent way with the overall objective of an integrated European electricity market. Increased transmission capacity will allow for a better use and development of different generation technologies and could structurally reduce market power issues. However, in some cases, increasing transmission capacities is not possible or too costly. Structural bottlenecks may therefore be considered as the natural borders between bidding zones.

2. Redispatch, including cross-border redispatching and/or countertrading can be a very efficient congestion management method. ACER's analysis (section 2.1) only seems to consider redispatch to be a solution when performed “inside” a bidding zone, while actually, this method is possible between bidding zones. In most cases is redispatch not market based (section 2.6) but., if it is realised on a large geographical scope, overlapping more than one bidding zone, more competition in this market segment will appear, and the argument of “market power” in this activity is then strongly reduced. Likewise ACER argues that competition between small zones is possible via the market coupling approach (section 2.3), it would be also possible to achieve more competition in the redispatching phase by having a large set of bids from all generators available. This requires a kind of common bid platform where all generators are invited to make their (local) bids available, and requires a common methodology and approach from all TSOs. The drafted CACM code is very weakly provided in this domain, but we believe that any review of bidding zones should only be considered if indeed all (cross-zonal) redispatching opportunities have been implemented and have been exhausted, signalling then indeed that we arrive at the “edge” of redispatch possibilities. The electricity Balancing network code could also reinforce this approach by efficiently use cross-zonal redispatching opportunities. The fact that TSOs are calculating cross-border capacities based on D-2 assumptions implies that some capacities would be available in real time for coordinated redispatching measures. ACER should first analyse the gap between the capacities calculated in D-2 and the capacities available in real time to ensure an optimal use of the existing bidding zones before considering an alternative situation.

3. Redispatch costs are not necessary a welfare loss. Indeed, it could be better considered as the value embodied in the location and flexibility of a particular plant. The two types of congestion management, namely (i) zonal model with limited capacities for the market between the zones, and (ii) copper plate model with corrective measures, can in fact result in exactly the same dispatch of resources. In the model (ii), the redispatch costs need to be socialised through transmission tariffs. In the model (i), the same costs (actually the congestion costs) are incurred but are implicitly part of the market prices. It is therefore not appropriate to depict redispatch as a “cost” in the model (ii) and not in the model (i). Those costs are in theory the same, it is more a matter of distribution.

4. One should not only focus on “redispatch costs”, but also on the “market benefits”. Top priority for ACER should be to improve the current redispatch methods, in order to use at all moments the most

appropriate plants (or demand) to achieve the cheapest redispatch if needed. Indeed, many current problems associated with redispatch are the result of a lack of cooperation between TSOs meaning that the least costly actions are not always taken. Priority should be given to improve current redispatch methods, especially cross-border redispatch procedures which are still completely missing.

5. If redefining the zones resulting in smaller zones, then the associated costs / welfare loss because of reduced liquidity and competition in both the wholesale and retail markets should not be underestimated and neglected. Section 2.3 of the ACER consultation document does not reflect these negative impacts and, in particular, seem to ignore the negative impacts on the forward markets (e.g.: increase risk premium) and retail markets (e.g.: increase implementation costs and contractual risks). ACER should draw in best practice among regulators in this respect and examine the market monitoring and liquidity assessments that individual national regulators have produced. These underline the need for deep and liquid forward markets over a range of baseload and peakload products. This increases scope for competition and reduced transaction costs for market participants and ultimately for consumers. Indeed, the argument that price formation in small areas is influenced by neighbouring zones via the day ahead market coupling, seems to forget that any additional shipment of energy via power exchanges increases transaction costs (PXs member fees, fees for energy exchanged, etc.), and this is not only the case in the Day-Ahead, but also in the intraday, where unfortunately at this moment a well functioning intraday trading platform is not yet in place, increasing the transaction costs and also not allowing market players to achieve the lowest possible market price.

6. ACER seems also to underestimate the impact of support schemes for RES (including CHPs) that have been socialised over currently large bidding zones. When splitting bidding zones, some customers will benefit from lower price areas, and other will suffer from higher price areas, while the support schemes have been globally socialised. At the same time, there will be a higher need for backup capacity (reserves) and balancing in those areas with a lot of variable RES (marginal cost at zero), while it is not for sure that these flexible resources will be economically available in these areas. In any case, ACER remains silent whether a review of bidding zones also leads to a review of control areas, which would then also create additional costs for TSOs, and whether globalised RES support schemes would be allocated differently over the new (smaller) bidding zones.

7. ACER also considers (section 2.2) that loop flows are more created due to large price areas. We believe that this is not the case, when the correct capacity calculation methodology is used. Even in the flow based approach, there are many strong simplifications and differences in the approach to determine the D2C-File (the base case) and the Generation Shift Keys (GSKs). TSO have different methodologies, and simplify GSK on "pro rata basis", while it is evident that any additional exchange between 2 areas will only increase the dispatch of the cheapest plant in the exporting area and decrease the dispatch of the most expensive plant in the importing area. A more realistic model is much more appropriate, because it is closer to physical reality, and limits the loop flows. Loop flows are often defined as difference between physical flows and commercial (cross-border) nominations: a flow-based calculation with appropriate GSK/PTDF would actually reduce strongly such differences. Also, consistency between cross-border capacity calculation on the forward, day-ahead and intraday timeframes could reduce current loop flows. The fact that TSOs are calculating differently the internal flows on D-2 assumptions implies that cross-border capacities are not optimally used in real time and that more coordination between TSOs would already significantly reduce the existing flaws in the flow based calculation.

8. Redefining the delimitation of zones is an intrusive measure with a large impact on the market (implementation costs, risk premium, contractual risks,...). Such redefinitions should therefore be performed only rarely, and only if the global benefits are large and certain and with a sufficient long lead time (e.g.: 5 to 10 years). Moreover, we need to keep in mind that this appropriate lead time might be so long that we could hope in the meantime for significant reform of non-market based financial support schemes and of absolute priority access for RES-E plants. Such reform might change the incidence of loop flows and change expected patterns of investment, so that some structural congestion would be alleviated.

9. ACER realises in its section 2.5 that reviewing bidding zones is a rather dynamic process, as changing bidding zones might impact generation investments and/or consumption pattern at some locations if prices become (too) high or (too) volatile. This is creating a risk or an opportunity for both generators and consumers, but instability in the bidding zones structure will only deteriorate even further the investment climate in Europe and/or reduce attractiveness for new entrants.

2) Do you perceive the existing bidding zone configuration to be efficient with respect to overall market efficiency (efficient dispatch of generation and load, liquidity, market power, redispatching costs, etc.) or do you consider that the bidding zone configuration can be improved? Which advantages or disadvantages do you see in having bidding zones of similar size or different size?

In general, it can be noted that the economic welfare losses of redispatch are small compared with the welfare gains by creating larger zones, due to increased liquidity and competition. It is also our firm believe that network expansion to remove congestion should be the primary option.

Also, ACER should be more precise in the question on what is exactly meant by “size”: is it “geographical size”, is it “electrical size” (like installed MW capacity, MWh produced/consumed, grid length), or is it competition size (like number of market players, market concentration, sufficient differences in generation mix). It would be fair to investigate whether another delimitation of bidding zones would possibly lead to a better outcome for the European social welfare. Inside a bidding zone, market players can exchange energy (both commercially and physically) without having to consider the “grid access and usage”. Any deal they make is firm, not subject to grid constraints (although congestions even can occur inside the bidding zone, in that case the TSO will take measures to let execute the contract), and the deal conditions (the price) are the same for everyone who is connected to that bidding zone.

If Europe would be one bidding zone, all market participants from Norway to Italy would have the same market price, and would not need to consider grid constraints when acting in that virtual bidding zone. But, once all deals would be known and the consequent dispatching notified to the TSOs, the latter would rapidly see that this would not be achievable without correcting the dispatching, and they would need to change both the dispatch of Norway and Italy. They would incur a cost for this granted huge amount of “firm” deals, and it is obvious they would have a problem to charge this cost to the (exact) causer of the problem, in particular if the redispatching would be needed on a line somewhere in the middle of Europe but far away from Italy and Norway. In this virtual EU wide market, TSOs would not have any congestion income, and recovering the costs would have to be made via harmonized national transmission tariffs or via Inter-TSO compensation mechanism. Therefore, it is crucial that TSOs are coordinating much more their actions and activities to ensure system security; but also NRAs should discuss and agree on common principles for the transmission tariffs structure.

Current CWE borders of the zones mostly follow the borders of the Member States. Save the historical development of the electricity arrangements dating before the liberalisation, there is no apparent justification for that choice (with the exception that for a well-functioning retail market in one Member State it is beneficial to have one bidding zone for that Member State). In this current configuration, TSOs observe in the day to day business “structural” bottlenecks, which are also partly due to the existing zone delimitation. A French power plant can trade freely with a French customer located at the French/German state border, while, if this (state or electrical) border would be changed, he would not longer be allowed to have a “firm” grid independent deal with his customer. Hence, if this border would be displaced, also the electrical flows would change, because the deal between the producer and the customer would not longer be concluded directly (at least not on the French Hub), because in the new situation, the border would be placed at the structural bottleneck location, while before this location was inside France. Structural bottlenecks are thus also a consequence of the current “imposed” bidding zone design. Changing bidding zone delimitation has a direct impact on the wholesale but also retail market outcome, as it also affects the demand/supply equilibrium in the bidding zone, and thus it will be extremely difficult to anticipate if any such change would be more efficient for the European social welfare or not. This illustrates also that the efficiency is not necessarily the question, but how the costs caused by lacking grid infrastructure will be shared between the stakeholders.

It is not obvious to assume that all bidding zones should be of similar size, even though in a flow based market coupling it could be beneficial. The existence of structural bottlenecks, the differences in generation mixes and market structure may result in different bidding zone sizes. Therefore, first a set of requirements should be settled to launch the discussion on reviewing existing bidding zones; then a quantitative analysis could be performed based on those requirements. The implementation costs should be well taken into account, and will probably have the most significant impact in the final decision.

3) Do you deem that the current bidding zones configuration allows for an optimal use of existing transmission infrastructure or do you think that existing transmission infrastructure could be used more efficiently and how? Additionally, do you think that the configuration of bidding zones influences the effectiveness of flow-based capacity calculation and allocation?

The question of zone size is largely irrelevant to the question of whether transmission infrastructure is being used optimally or not. The main reason for non-optimal use of infrastructure is largely down to insufficient cooperation between TSOs. This is clearly demonstrated by the recent discussions on “unplanned flows” through some CEE countries that were apparently caused by large in-feed of renewables in Germany. Clearly, in the case of good cooperation between TSOs, these “unplanned flows” should not appear, they would have been “planned flows”. German TSOs already have accurate forecasts of in-feed from renewables and should be able to share this information with all neighbouring TSOs, so that the impact is known. Likewise, the absence of cross-border redispatch measures is another cause of no-optimal use of infrastructure that must be corrected before starting any discussion about size of bidding zones. Although there are some regional cooperation initiatives on security coordination among TSOs our view is that such initiatives still have lot of room for further improvement and expansion.

In this context, Section 2.2 of the consultation document states that “in particular, large bidding zones induce higher uncertainty in capacity calculation, which may result in higher reliability margins and reduction of cross-zonal capacity given to the market”. However, TSOs have have a lot of “nodal

information” irrespective the size of the bidding zones. TSOs know (or can forecast) quite precisely the expected generation from renewables (based on weather forecasts) and also from conventional generation (as they know the availability and have estimations of the variable costs of each plant; even if they would not have the “ *variable costs*”, TSO see everyday how the market dispatches the plants; which plant starts earlier, which one later, etc . TSOs also have quite accurate load forecasts on a nodal basis. Therefore, TSOs are in a good position to forecast actual flows in the network, irrespective of the size of the bidding zones.

Unfortunately, the current base case capacity calculation method, as proposed in the Flow Based, has many flaws, and seems not at all in line with an harmonized calculation process. There are all kind of steps that might be questioned, amongst others:

- 1) Does it make sense to use the last know generation dispatch as the basis for the dispatch of the next day ?;
- 2) Does it make sense, like German TSOs do in their D2CF process, to adapt the load, in case more wind is forecasted for the next day? In such a case, the load might not change at all, but it will be the plant dispatch that will be adapted;
- 3) Would it not be more appropriate to make a best guess of the generation dispatch for the day of operation based on a more nodal calculation whereby TSOs use all generation information (like availability, wind forecast, assumed marginal costs, etc.) and all load information they have, in order to find the D2CF (the base case)? Indeed, one should assume that the market will try to find (via the market coupling process) an outcome that leads to minimize generation cost;
- 4) The current pro rata GSK factors seem to change the generation dispatch quite arbitrary. Does it make sense to use “pro rata” GSK factors? Would it not be more appropriate to change dispatch of power plants based on their (estimated) marginal cost to find the PTDF factors around the base case? Uncertainties in wind forecast (and PV) might be studied in the D-2 phase. Based on the estimated marginal costs of conventional plants, another optimal dispatch output could be anticipated.

For all these situations, flows in electrical lines could be modelized and anticipated much better than in the proposed D2CF/GSK methodology. It would also give insight in the needed TRM/FRM (when simulating for some cases the forced outage of power plants, or a strongly different generation pattern in particular for wind generation). In all cases, it would need much more cooperation and coordination between TSOs, and also require a more harmonised approach. It would allow to find a better definition of the flow based domain, whereby both internal trades and external trades would be fully put under competition. As long as the potential for improved calculation is not exhausted, there is little reason to consider a review of bidding zones.

4) How are you impacted by the current structure of bidding zones, especially in terms of potential discrimination (e.g. between internal and cross-zonal exchanges, among different categories of market participants, among market participants in different member states, etc.)? In particular, does the bidding zones configuration limit cross-border capacity to be offered for allocation? Does this have an impact on you?

Due to limited transparency on the actual usage of the grid, congestions and ATC-calculations, it is difficult to assess whether there is any discrimination between internal and cross-zonal exchanges. However, the ideal situation with respect to non-discrimination would be a copperplate situation whereby a market participant could access all potential customers throughout the EU on the same basis. This, however, would be rather inefficient and some delimitation is necessary.

A regulatory framework is then required that minimises the impact of the existence of different zones by making sure that sufficient capacity between zones is made available and the nature of transmission rights between zones is as close as possible to that within the bidding zone. Therefore, TSOs should be incentivised to make available the maximum amount of firm capacity between zones (since internal capacity rights within zones are also firm) and for any costs to TSOs from offering firm rights can be recovered from the regulatory formulas. The Swedish case could be considered as an example, as SvK was accused of “*shifting internal bottlenecks to the border*” and thus of discriminating cross-zonal exchanges. In effect, the rights offered between Sweden and Denmark were less firm than those within Sweden. Although four bidding zones were implemented in November 2011 as a remedy, this is not necessarily an ideal long term solution. Creating smaller bidding zones is not a necessary sanction to avoid possible discriminatory behaviour.

Moreover, the whole setup of bidding zones and the capacity calculation process gives by definition priority (and firmness) to deals inside the bidding zone. The flow based capacity calculation process (although probably with limited accuracy due to the “*prorata*” set GSK factors), is only verifying whether an additional export (or import) is possible. It does not verify whether internal deals in the bidding zone are possible, and even if not possible because of already existing congestions in the base case, they will not really be addressed in the calculation process, but afterwards, redispatch actions will take place to solve them. We believe it also leads to a need for higher TRM/FRM assumptions than those really necessary during the operation of the network itself. Improving the capacity calculation process as suggested earlier would to a large extent address this issue.

Indeed any wrong assumption in the capacity calculation process may lead to a wrong market outcome, because based on the grid constraints, the market coupling algorithm will maximise the total economic surplus. However, the reasoning that the capacity calculation would be better when one has smaller bidding zones is also not yet proven. It is true that if the zone would be very small that by definition the GSK would be exact: only the plants at the node would be able to set the PTDF. However, still then it would depend on the marginal price of the plant in order to decide whether one should dispatch plant at node A or at node B. It is therefore not understandable that the size of the zone has to be reduced upfront in order to have the optimal capacity calculation. Indeed, one needs anyway also to look at the marginal costs of the plants, one needs anyway to take some forecast data of the wind, the load, the generation like wind and hydro, etc. Even with small bidding areas, TSOs do not coordinate and don't take common assumptions on all these factors (marginal costs, wind/hydro production, load forecasts, etc.). We are thus convinced that the debate is not about the size of the zones, but about the methodology followed by TSOs in the capacity calculation process. The alternative remedy of merging one TSO's control area with those of others to form a larger bidding zone should be analysed, preferably by testing it in pilot projects.

5) Would a reconfiguration of bidding zones in the presence of EU-wide market coupling significantly influence the liquidity within the day-ahead and intraday market and in which way? What would be the impact on forward market liquidity and what are the available options to ensure or achieve liquidity in the forward market?

Liquidity is defined as a level of trading allowing buying and selling with minimum price disturbance at any time (forward, day-ahead, intraday, balancing timeframes). It is a market ability to ensure market participants the “*fair price*” in any situation and not only when there is no congestion. We do not agree that the use of mechanisms for implicit allocation of capacity between bidding zones will make good for this loss. Even if interconnectors are fully efficiently utilised through implicit mecha-

nisms, a market split will occur if the interconnection capacity is fully used. In these situations, generation and demand can only participate in their local market and not the regional market. As a consequence, market participants' ability to rely on the market is impaired because they have expect a limited liquidity at certain times. When all capacity is used, market participants with assets in a bidding zone (generation and consumption units) face a market with a reduced number of counterparties and offers.

Liquidity of forward markets is a necessary condition for competition in both the wholesale and the retail markets. Without liquid wholesale markets there can be no independent entry and the prospect of real competition could be severely constrained. Most consumers and generators are unable or unwilling to have total exposure to day-ahead prices, so competition requires a high degree of liquidity of forward markets as a price discovery and hedging tool. This also allows companies to gain and lose market share and trade out of these positions. An effective market requires a sufficient number of active market participants on both buying and selling side as well as some financial players providing additional liquidity.

Price zones need to be large enough to support a necessary critical mass of market participants. The liquidity of forward markets will especially be negatively affected if smaller zones would be introduced. If one zone is split in two zones, the number of forward products will simply double. This means that the liquidity of the forward market in that zone is now split over twice as many products (or half as many market participants). This obviously has a negative impact on the liquidity. Also the well-functioning of retail markets would be negatively affected. Retail completion will benefit if suppliers are able to offer competitive prices for a larger zone. The larger the zone, the better the retail and wholesale markets in that zone can function.

On the contrary, smaller bidding areas in general would lead to a higher volatility in the short term prices. As an extreme example, a bidding area with only one expensive and one cheap plant might become much more dependent on the availability of these plants (this compared to a large bidding area with many plants covering the whole marginal cost area). In the forward markets, smaller bidding areas might probably also lead to more variable long-term cross border rights, and thus to even a lower willingness for TSOs to issue long-term cross-border rights. Also, where with "larger" bidding areas, a certain bidding zone is only "one border" away from a "liquid" bidding zone, it might be that one of the split new bidding zones becomes several borders away from a more liquid area. This would reduce cross-border hedging opportunities, and affect liquidity in the forward markets. It means that higher risk premiums would appear in the forward contracts. This would also be emphasised due to the higher expected volatility in the spot markets.

6) Are there sufficient possibilities to hedge electricity prices in the long term in the bidding zones you are active in? If not, what changes would be needed to ensure sufficient hedging opportunities? Are the transaction costs related to hedging significant or too high and how could they be reduced?

Even with the current zone configuration, there are only limited areas in the EU market where there are sufficient possibilities for market participants to hedge electricity prices. Indeed, long term cross-border hedging opportunities depend in the first place on the long-term transmission rights issued by TSOs. From this perspective, market participants face 2 problems:

1. TSOs currently allocate only a rather “small” portion of the cross-border capacity to the longer term, and also the horizon (limited to one year) is limited, as a first step, the portion to be allocated on the long term and the horizon should be higher (e.g.: 3 years-ahead);
2. Capacity calculation process, likewise for the short term calculations, should be improved, in order to increase the cross-border hedging opportunities.

The less borders exist, the less cross-border hedging is needed, and the more nearby one bidding zone becomes from another (larger) bidding zone, thus also the less the hedging costs become. Competing in a neighbouring market (bidding zone) where a player has not an appropriate portfolio requires cross-border hedging, and thus additional contracts (auction office), rules (nomination, how to use the rights, how to participate in the auction, etc.), while working in a large (merged) bidding zone obviously reduces all these burdens. So, the answer is evident: large bidding areas create more liquidity and facilitate the forward contracting reducing risk premiums.

7) Do you think that the current bidding zones configuration provides adequate price signals for investment in transmission and generation/consumption? Can you provide any concrete example or experience where price signals were/are inappropriate/appropriate for investment?

Price signals as such are only one element in the investment decision process : indeed, market prices are too short signals for future investment decision (time horizon for investments is between 10 years and 20 years). Much more important are fundamentals of the system, amongst others driven by the amount of RES, RES support schemes, etc. However, the size of a bidding zone is also an essential element to take into account for an investment decision: the larger a bidding zone is, the more stable prices should become, the more easy it is to sell in the market. These are fundamental investment facilitators reducing financial and physical risks.

De facto, a process of reviewing bidding zones towards a downsizing is a possible investment inhibitor. Indeed, it creates uncertainty about the future price level in the new bidding zone. The opposite, moving towards merged bidding zones normally gives more confidence, although this process should not be repeated constantly as any reversibility might again make doubting the investment decisions. This process should give sufficient lead time to market participant and be effectively accepted and understood by market participants. Although structural congestions will always exist, and there is indeed (as explained in section 2.5 of ACER’s consultation document) some dynamic due to technological but also political (e.g. RES support) decisions, market players would always prefer one large European bidding area, allowing them all to compete on the same market under the same conditions.

Finally, TSOs have the statutory obligation to (i) use the existing the transmission infrastructure to the maximum extent, and (ii) expand the transmission grid whenever the socio economic cost benefit of such investment is positive. The choice of size of bidding zones should not be of any importance for stimulating or incentivizing TSOs to act properly. Instead, much more transparency is needed on how TSOs calculate ATC values, redispatch costs, etc. As far as investment signals for generation/consumption are concerned, we have the impression that the benefits of smaller zones (and therefore “more correct” prices on such investment signals are easily overestimated). Moreover, harmonisation by TSOs and NRAs of injection and load transmission charges and locational signal role could also impact the benefit of smaller zones. ACER and ENTSO-E future work on the network code of harmonization of transmission tariffs is therefore very important for future investment decisions.

8) Is market power an important issue in the bidding zones you are active in? If so, how is it reflected and what are the consequences? What would need to be done to mitigate the market power in these zones? Which indicator would you suggest to measure market power taking into account that markets are interconnected?

Mitigating market power is an issue of transparency and monitoring. Several legal instruments already exist for this purpose (e.g. REMIT, transparency guidelines, competition authorities, ect.).

Generally speaking, larger bidding areas should be preferred to smaller ones in most circumstances, because such development contributes to achieving the goals of the EU Internal Electricity Market. The above general statement can be applied to the case of a **potential merger of the Belgian and Dutch bidding areas**. Forming a larger bidding zone out of the two existing ones would yield positive effects in terms of technical and overall economic (welfare related-) aspects. As with all modifications of the market structure, sufficient lead time (e.g.: 3 to 5 years) should be granted. While the majority of the benefits would arise as a direct consequence of the bidding zone merger, some would be more or less dependent on further integration steps. This applies to the fields of balancing and retail markets. Theoretically, the overall positive effect of the bidding zone merger would be at risk if led to a significant increase of the severity of congestion and, consequently, to significantly increased redispatching effort. However, numerical simulations show that the increase of redispatching when merging the Belgian and Dutch bidding zones is small, such that this does not constitute a counter-argument¹.

9) As the reporting process (Activity 1 and Activity 2) will be followed by a review of bidding zones (Activity 4), stakeholders are also invited to provide some expectations about this process. Specifically, which parameters and assumptions should ENTSO-E consider in the review of bidding zones when defining scenarios (e.g. generation pattern, electricity prices) or alternative bidding zone configurations? Are there other aspects not explicitly considered in the draft CACM network code that should be taken into account and if so how to quantify their influence in terms of costs and benefits?

Reviewing bidding zones is a long-term process. It cannot be done without assumptions on the future system, whereby all elements are important (economic growth, RES development, generation investment climate, interconnections investments, market integration, etc.). It is important that the possible market effects as well as the costs for network measures (redispatching, phase shifters etc.) are concretely assessed and priced for the existing zone delimitation and alternative scenarios. Qualitative assumptions are definitely not sufficient. It is crucial that ENTSO-E stipulates the method before the pilot project proceeds with its work and discusses its approach with all stakeholders.

The whole process should also be evaluated from a “*economic dynamic*” perspective: if a split of bidding zones would lead to a very low price area, in this area, a very fast economic closure process might occur. If such a process would lead to a “*split*” of an existing bidding zone, a sufficient long-term notice is needed, to avoid stranded investments and to avoid disappointing customers that would suddenly be confronted with a high price area.

Moreover, we need for participation in all phases of the market of RES-E generators, as per our submission to the EC on post-2020 climate change and renewable energy policies.

¹ Reference to the Consentec study on merging the Belgian and Dutch bidding zones

10) In the process for redefining bidding zones configuration, what do you think are the most important factors that NRAs should consider? Do you have any other comments related to the questions raised or considerations provided in this consultation document?

GDF SUEZ believe it is utmost that NRA evaluate the benefits of liquidity (forward, day-ahead, intra-day, balancing timeframes) and understand the impact review of zones might have on the investment climate. GDF SUEZ would urge NRA and ACER to see how redispatch rules, in particular cross-border redispatch arrangements can be improved between TSOs and together with the market. This might need to be tackled before one really starts a bidding zone review: good arrangements for this market segment might overcome even the need for a bidding zone review.

The two most important factors that currently seem to be ignored or misunderstood are the following:

1. NRAs seem to have insufficient understanding of the benefits of larger zones on liquidity and well-functioning of both wholesale and retail markets;
2. It is important to note that redispatch costs are not a cost for society, as long as the result dispatch (after the redispatch actions) is optimal. Redispatch only results into costs for society of an ultimate optimal dispatch cannot be obtained. The current redispatch procedures, especially for cross-border redispatch, need to be improved. Only after implementing such improvements and only after implementing a truly common approach for cross-border capacity calculation, one can start to consider a new bidding zone delimitation.