E.ON proposals for a regionally compatible electricity interconnector policy in the framework of Ofgem's consultation (Ref. 12/10)

The E.ON Group welcomes Ofgem's consultation. We see this consultation as a fundamental chance to put forward arrangements which effectively increase the level of interconnection of the GB market and which make certain crucial capacity allocation features more compatible with those in mainland Europe.

Our amendments therefore reflect the wish to promote an efficient internal market for electricity by applying market-acknowledged best practice. We also strongly support the need to create a positive framework for investments in new interconnections, in particular to be proactive towards European targets for 2020.

Question 1.1: Have we accurately captured the benefits of or the demand for new interconnections? Are the projects under consideration all viable? Would they be sufficient? Are there other projects being developed?

We agree that the major benefits of new interconnections are covered by the introductory chapter of the consultation paper. However, we feel that too little emphasis has been given to the opportunity to significantly increase liquidity and efficiency across all relevant timeframes and market places.

In 1.8 Ofgem assumes that price differentials are likely to be structural either due to different fuel mixes, a different timing of demand variations or an increasing volume of intermittent wind generation. As long as these kinds of market fundamentals remain to some extent different, physical interconnection capacities and cross-border electricity trading are needed to achieve price convergence. Arbitrage seekers therefore automatically support through their trading activities the level of liquidity which helps to strengthen competition, in order to establish a robust market price on both sides of an interconnector and thus maximise overall social welfare.

Greater liquidity and a robust market price will attract more new market participants and drive more portfolio optimisation business models which strongly rely on sufficient liquidity in the markets in which they trade. The value of market integration should be seen as a social welfare maximisation issue. Benefits should be evaluated at least at regional level and considering the conditions that maximise efficiency in *each hour*.

We are not in a position to judge whether all of the projects under consideration are viable from a total cost-benefit perspective. Of course cost estimation – and the *minimum cost option* – is part of potential investors' role in drafting a business case. The availability of information concerning the *system* is thus a key concept to make decision making on investments as efficient as possible.

However, we would like to see clear advantages for the market should they be realised such as:

- Increasing efficiency: social welfare maximisation
- Improved system security: additional interconnection will help accommodate fluctuations in wind output and also create alternative sources of energy flows in case of disturbances, maintenance or exceptional occurrences.

Question 1.2: Are there other key aspects of the legal or regulatory framework that we should consider, or should some features be given a different emphasis?

We would like to address three further issues:

Interconnector licence

We are aware of the Energy Act provision that the same legal person may not hold an interconnector licence and any generation, transmission, distribution or supply licence, as stated in 1.17. On further reflection, we have some doubts as to whether such a limitation is still justified under all circumstances.

Whereas a legal separation from other activities subject to competition is reasonable, we see a disadvantage in separating interconnector activities from any other regulated network business. In the case of a regulated interconnector a separation is usually inefficient from an operational point of view and may raise difficulties in respect of allowing customers to benefit from the revenues received through auction processes (3.14). It might also be incompliant with the relevant provisions in Regulation 714/2009, article 16 para 6, which requires an interconnector operator to use the auction revenues to guarantee the actual availability of the assets, to maintain or increase capacities through investments or, as a third option, to incorporate those revenues into tariffs. Whereas the first two options are possible under an approach with separate businesses and licenses – e.g. to provide financially firm interconnector capacities – we see limits in the implementation of the third option. Clearly an interconnector which forms part of a local regulated transmission business can use congestion revenue for reducing charges for local transmission users, whereas a separate business clearly will not do so. Separate businesses may also result in difficulties for cross-border trading with respect to currently applied transmission charges as described further below.

Notwithstanding this view, we remain sceptical whether a regulated TSO should be allowed to operate merchant lines. The regulated TSO has an interest to invest in interconnection if the expected rate of return, subject to regulatory approval, is sufficient to set an incentive to invest. As part of this assessment, we would expect the regulated TSO and the regulator to investigate whether a new interconnector is from a collective welfare point of view reasonable. This should be the only guideline which is part of TSOs' institutional role to invest in new interconnections. So we wonder why an investment in interconnections is not part of National Grid's regulated core business as it is the case for many, if not all, other TSOs across Europe.

In contrast a merchant line requires congestion revenue in order to make a return. The incentive on merchant interconnectors is therefore to limit the amount of capacity so as not to undermine congestion revenue, even if additional investment would allow full price equalisation and an optimal allocation of resources. A regulated approach would evaluate this marginal investment still as beneficial, whereas a merchant approach would not. So, under all circumstances the marginal investment needs to be a regulated one.

Therefore, it remains to be considered whether a regulated TSO should be allowed to keep the congestion revenues of the first merchant interconnector for itself to the disadvantage of British customers whereas the last marginal investment without congestion revenues is socialised. The merchant approach should be seen as a complement of TSOs' role in interconnection investment and it should not produce any unintended consequence of underinvestment.

Transmission network use of system charge (TNUoS), balancing service use of system charge (BSUoS) and treatment of losses

We perceive the current national transmission charging regime for TNUoS and BSUoS as reasonable in the context of the GB market. However, given the different transmission charging methodologies in continental Europe, we are concerned that TNUoS and BSUoS are incompatible and, prove an obstacle to trade in their current form of application. For instance, they may prevent a full convergence of prices and make any kind of implicit auction difficult to implement. We note that further arguments have been raised by EFET in its letter to Ofgem, dated 28 November 2009. Additionally, we have some concerns whether the application of TNUoS could be considered as a specific charge for entering the power market of GB and therefore being incompliant with European energy law and regulatory practice. Against this backdrop, we believe that a review of both types of charges would be helpful to ascertain whether they could be structured in such a way as to better facilitate cross-border trade whilst avoiding any distortion within the internal GB market.

Two alternative solutions to achieve this could be:

i) Regulated approach

- Merge system operator and interconnector operator licence, recover interconnector costs from national transmission charges and let national customers benefit from any excess congestion revenues
- Excess congestion revenues not spent for either investments in interconnections or to guarantee capacities once allocated to customers, are eligible to be incorporated into national tariffs (as under article 16 (6) of Regulation 714/2009)
- Alternatively, TNUoS charges could be applied virtually to the interconnector owner(s) and offset by excess congestion revenues

⇒ *National grid charges will be reduced, cross-border trading will not be affected and the TNUoS will remain in place in its fundamental form.*

ii) Merchant approach

- Require merchant interconnector operator not to explicitly pass-through its TNUoS charge to interconnector users
- Merchant interconnector operators should instead be allowed to incorporate TNUoS into a reserve price for long-term explicit auctions; reserve prices should not be allowed for any implicit auction.

⇒ *A reserve price makes sure that energy flows in and out of GB just if it is economic, merchant interconnector operators cover their costs, cross-border trading is not affected and TNUoS will remain in place in its fundamental form.*

We are willing to contribute to further discussions and look into alternative ways of transmission charging complying with national and wider European objectives.

The costs for losses should be also incorporated into a reserve price for merchant lines and recovered through either the Inter TSO-mechanism or congestion revenues in the case of a regulated approach.

Regional regime and expected future offshore bottlenecks

An additional approach might be to consider a joint regulatory regime for all types of interconnecting lines which are under consideration either for offshore wind purposes such as the North Sea Offshore Grid/Seatec or the more conventional links developed for trading purposes only such as IFA, BritNed etc. This could be done with a single approach, inter alia, of how to allocate available capacities to interested parties, being aware that offshore wind parks may enjoy a priority in-feed and transport right for the time being.

In this light it might be also sensible to anticipate future needs and to agree with other European regulators how to allocate grid capacities among offshore wind parks. With the number of offshore wind parks connected to the planned North Sea offshore grid and a potential imbalance of support schemes' attractiveness, the competition among offshore wind parks will increase such that bottlenecks to transport the energy to a certain country become likely.

Question 1.3: How can the Regional Initiative best contribute to development or implementation of policy? Do you agree with the priorities and approach outlined?

We see the major benefit of the Regional Initiative as bringing together all of the regional stakeholders and to discuss practical steps to accelerate European market integration. However, there is still room for improvement in the effectiveness of discussions and the early involvement of market participants when it comes to considering enduring solutions and their practical implementation.

We fully agree with the priorities as set out in 1.24 and would like to add the priority to agree on a single set of explicit auction rules including an alignment with the neighbouring Central Western Europe region. Particularly we would wish to see an implementation of financially firm capacities, compensation at full market spread in case of curtailment and a common definition of force majeure. Furthermore, we would welcome an incorporation of the explicit capacity allocation management into the auction office CASC-CWE which may serve as a very practical step and a strong signal for a closer cooperation between the FUI and CWE region. In this light, we also fully welcome the draft FUI Strategy 2010 which intends to, inter alia, deal with a number of trading obstacles such as BSUoS and TNUoS charges and considers an increased cooperation with regional CWE stakeholders.

Question 2.1: Are the target models explained in this chapter appropriate for GB? What are the issues that need to be considered? Are there alternative approaches that would be better? Will the target models effectively accommodate increased intermittency?

We confirm in principle our commitment to the target model as defined in the Florence Forum process. However, there are a few things regarding the intra-day trading approach where we have a different view.

We strongly favour a **simple set of financially firm products with annual, monthly, daily and intra-day allocation**. We believe that **annual and monthly allocations should be explicit** and it should be investigated whether bi- or tri-annual explicit products could be additionally offered. Existing seasonal, quarterly or weekly products should be suspended. These changes with reference to IFA practice and BritNed proposals would allow the concentration of available capacities to just a few products. Seasonal, quarterly and weekly products could be sliced from the annual and monthly products and unused parts either sold on the secondary market or given back to IFA/BritNed as part of subsequent explicit or implicit auctions (UIOGPFI). **Daily capacities could be allocated implicitly** as soon as possible along with an **implicit continuous intra-day trading**. We do not support the highly complex two layer approach for intra-day (2.22) because it would prevent a one step trading process and limit the benefits of continuous trading to the disadvantage of intermittent wind power market integration.

We would support a **secondary market to facilitate capacity resale among traders**. In case long-term capacity is not resold (TSO should be notified of the resale) or nominated in the morning of D-1, the remaining capacity should be automatically given to the day-ahead market coupling mechanism once available. The original holder will be compensated with the price of the subsequent day-ahead allocation. We see this **use-it-or-get-paid-for-it (UIOGPFI) as an initial step towards financial transmission rights**.

Capacities should always be maximised according to Regulation 714/2009, article 16 para 3, leading to an implicit distribution of capacities offered to the market. In order to take into account a larger contribution of wind energy resource to market liquidity and its intermittent characteristics, in contrast to 2.23, we propose a distribution of capacities with **one third made available for each timeframe (yearly, monthly, daily)**. Netting of capacities according to Regulation 714/2009, article 16 para 5 clearly seems sensible.

There should be **no reservation of capacities for intra-day and balancing purposes.** Not nominated capacities subject to use-it-or-lose-it (UIOLI) or those made newly available should be used for a continuous intra-day trading on an ELBAS-like platform or used for exchanging balancing services among TSOs. We therefore suggest moving to this ELBAS-like solution where intraday power bids are matched considering remaining cross border capacity. Due to the continuous nature of trading we prefer to trade in a single currency as it is the case with Nord Pool's ELBAS.

Although the balancing mechanism in place on IFA is amongst the most advanced in Europe, the enduring solution should mean that further changes towards a different but compromise solution from a regional perspective should still be possible.

Concerning the comparison between continuous trading and auctions for the intraday market (2.10), we support the former because we believe that the priority to make capacity available as quickly as possible is most important when the capacity available is relatively small. In fact, if a large amount of capacity is still free after market coupling at the day-ahead stage, it's most likely that in that timeframe it is not a scarce resource. A continuous trading would also much better facilitate intermittent wind generation and even allow an immediate trading in the previously not appreciated direction.

In contrast to our basic approach above and taking the increasing level of intermittency into account, we would find it reasonable **in liquid markets** to shift long-term capacities to shorter time frames such as day-ahead. Continuous intra-day trading may then facilitate a cross-border exchange of volumes (due to deviations from the initial day-ahead wind power forecast and other changes) as well as efficient flows at real-time (2.31). Merchant lines should be obliged to optimise their power flow intraday, as well as regulated infrastructure providers.

Question 2.2: What should be our approach to firmness of interconnector capacity? Should this vary between new and existing interconnectors, or between regulated and exempt? What are the categories of costs and benefits from changing approach, where should they fall and can hey be quantified?

Full financial firmness for all capacity products would facilitate cross-border trading the most. European traders association EFET has already issued a paper in 2008 that clearly outlines how firmness could be practically implemented.[1] The major benefits of financial firmness are that traders can accurately hedge forward positions, do not need to contract individual reserve volumes as an alternative risk measure and will therefore value interconnection capacities even more as also stated in 2.18. This would provide a more correct economic signal against which grid enhancement can be evaluated. Additionally, it would provide a non-discriminatory level playing field for parties importing into GB compared to incumbent domestic production. Therefore, the level of competition of companies from abroad with those in the market is likely to increase.

On the other side, those who are inherently able to manage the risk of an interconnection failure, namely the TSOs, will have the correct incentive to avoid any compensation by making sure their assets does not fail. This is in the interest of all. Therefore, we see the operation of an interconnector as a fundamental business risk which a TSO or interconnector operator has to cope with. This is in principle not different to any other business for which warranty or compensation is common practice (e.g. flights cancelled due to any shortcomings except force majeure). Therefore, we do not agree with the current practice of allocating non-firm capacities.

The arguments of NGIL as expressed in 2.34 are to some extent one-sided. If the level of compensation was indeed £10 million, NGIL would have a very strong incentive to invest in better and more reliable equipment.

We do not support physical firmness, as it would put a burden on the interconnector operator and take it closer to being a (trading) business which is not its basic role. As physical firmness and financial firmness bring the same advantages, we favour a pure financial approach which is much easier to implement. Compensation at full day-ahead market spread should then be paid to customers in the event of a curtailment, if force majeure does not apply.

However, it is correct to say that physical firmness is required in a market coupling process. Therefore, we would like to make clear that if the current GB practice does not change at least to this extent there will not be an opportunity to apply the European target model for day-ahead: market coupling. Given the number of DC lines in the Nordic region and the good experience with market coupling, physical firmness does not seem to be problem in this sense.

We would also like to stress that we do not support any interruptible capacity products (2.18) without financial firmness as this would strongly increase the cost for alternative risk measures with an impact on market prices.

[1] http://www.efet.org/GetFile.aspx?File=2730

Since we support a regime applicable to all interconnectors in principle, we recommend using the financial firmness approach for all interconnections. For merchant interconnectors, it needs to be ascertained whether a retrospective change is allowed according to the conditions of the relevant exemptions.

Question 2.3: Should we seek regional solutions rather than individual project solutions for access rules, such as through a broader North West European solution for market coupling? What are the priority areas for greater regional co-ordination?

We would clearly prefer a standard approach applicable to all GB interconnections. This should be aligned with arrangements with neighbouring countries such as The Republic of Ireland, France, Belgium, The Netherland and Norway to end up with a regional capacity allocation mechanism. A single point of contact for all explicit auctions in the FUI and CWE region such as the CASC-CWE auction office may also help to improve the efficient use of interconnectors, to facilitate trade, and to act in a co-ordinated manner.

Apriority for greater regional coordination, and even a quick win, should be the creation of a single set of auction rules (including financially firm capacities, compensation at full market spread in case of curtailment and a unique definition of force majeure).

When it comes to market coupling we would propose a global solution including BritNed, IFA as well as APX UK and N2EX. Under all circumstance we recommend the promotion of cooperation between both day-ahead power exchanges in order to concentrate liquidity in the day-ahead process. In the case the cooperation will not being developed as required, a global solution would still be possible with a single price coupling. Just in the case a single price coupling would not be available we would recommend to work on an embedded solution with one exchange integrating its volumes via BritNed to The Netherlands and the other exchange via IFA to France. Explicit auctions on IFA and market coupling on BritNed should only serve as contingency but might be more efficient than sticking with daily explicit auctions only.

Question 3.1: Does this chapter capture the key issues in regulation of new electricity interconnectors? Should we assume that all new interconnectors will seek exemption?

In principle, we find the chapter complete.

Given the relatively low levels of interconnection with the GB market we would assume that in the short-run merchant lines might be highly attractive whereas over time the regulated approach will become more dominant.

Taking the financial attractiveness of still high congestion revenues into account, we think National Grid should be required to provide interconnections within a regulated approach. Regulation 714/2009 requires regulated TSOs to collect congestion revenues for the purpose of re-investing them into increased capacities. Whereas the first regulated investment needs to trust on reasonable regulatory conditions with an adequate return for investment, subsequent projects can enjoy being already financed upfront from available congestion revenues. Once commissioned this project would collect further congestion rents. This kind of revolving mechanism will relieve national customers from financing a high level of interconnection with mainland Europe but forward them with better integrated market, increased competition and more price convergence. This kind of revolving financing mechanism could run until the marginal investment is made. Merchant investors relying to some extent on long-term capacity contracts could then compete on the basis of who can set up a line before this marginal investment is made.

Question 3.2: Of the options set out, which are preferable and why? What are the key considerations in taking forward any of the options?

We favour a mixture of option 1 and 4 as it would allow revenues to be determined according to the willingness of the market to pay. In option 4 the regulated TSO or regulated interconnector operator would be compensated at a specific rate of return. Taking the current level of interconnection capacities, we do not really see a downward potential and would on the contrary assume an upside potential. That means that the foundation for any market spread compensation or a revolving financing mechanism for further enhancements, including the marginal investment, is laid. This is likely to mean that further investments do not need to be recovered from national transmission customers again. Therefore we think that the risk of any downside to the disadvantage of National Grid’s customers is low.

This option 4 could in principle also work for merchant lines. The merchant line operator is allowed to transparently set a reserve price according to its operational costs for its long-term allocations (no reserve price for market coupling and intra-day). Furthermore it is permitted to market a specific amount of capacities through long-term contracts. All the other capacities are allocated through explicit or implicit auctions. Any excess revenues may cover initial business risk which is in fact the idea of option 1. Any cap would tend to result in a lower incentive to invest in interconnection.

However, TSOs and regulated non merchant interconnector operators should be required to maximise available capacity according to all time frames to counterbalance any incorrect incentive to limit of capacity.

Question 3.3: Is it feasible to have a mixture of different approaches for different interconnectors – such as some exempt and others regulated? If not, why and how should this be resolved?

In principle the products, auction rules and the methods for allocating capacities should be the same (see 2.1).

For merchant lines it is sensible to allow a larger amount of long-term capacity contracts, even beyond the common annual capacity products, in order to allow a sufficient rate of return and to already cover a certain amount of the initial business risk. Therefore, no price cap should apply as well. However, we recommend the reservation under all circumstances of some capacity for shorter time frames, such as day-ahead, and to apply an automatic use-it-or-get-paid-for-it rule for long-term capacities. This would support day-ahead market coupling with a sensible amount of capacity.