POSITION

Subject: Position BGA on categorization of Significant Grid Users – February 2016
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Position of the Belgian Generators Associations (BGA) about the categorization of significant grid users – February 2016

During a first iteration, exchanges of positions and arguments between all stakeholders on the topic of categorization of SGU took place at the meetings of the Experts Group Implementation Network Codes from the Elia Users' Group on 26.11.2015 and 25.01.2016. In this paper, the BGA would like to provide its current position on the categorization of significant grid users summarizing the view of Belgian generators after this first iteration.

Executive summary

Network Codes are a powerful tool to finalize the single European energy market. When categorizing significant grid users the BGA is of the opinion that **harmonization** within (regions of) Europe should be a primary goal and that competition distortions disadvantaging Belgian generation facilities should be avoided at all times. For all parties, overall **cost-effectiveness** is crucial. The BGA believes that a country such as Belgium, with a strongly meshed, highly developed and efficiently operated grid shouldn't deviate from the upper limits foreseen in the NC's for the different types of grid users. If Belgium would do so, a cost-benefit analysis for this choice needs to be performed. Furthermore, for the BGA the negative impact on markets should be limited when implementing the Network Codes. Grid services should be procured via **market based mechanisms** and the 'insurance' for grid operators provided by the Network Codes – by imposing on production facilities to be, technically, able to deliver certain services -shouldn't be exaggerated. Also, all requirements for delivering grid services should be in the service contract and should not be a categorization criterion.

The current position of BGA with respect to the specific limits is the following:

Types	ENTSO-e Latitude	Draft proposal Elia	Proposal BGA
Type A	Maximum capacity >= 800W & PoC<110 kV	800W<=Pinst <250kVA	800W<=Pinst <1MW
Type B	Maximum capacity >= XX but max 1MW & PoC<110 kV	250kVA<=Pinst<25MW Equipment certificate for DSO grids & LVRT	1MW<=Pinst <50MW
Type C	Maximum capacity >= XX but max 50MW & PoC<110 kV	25MW<=Pinst<75MW Or FCR, FRR, RR services	50MW<=Pinst <75MW

Type D	Maximum capacity >= XX but max 75MW or PoC>=110 kV	Pinst>=75MW Or Blackstart Or Pinst>=25MW & PoC>110 kV	Pinst>=75MW

Upper limit category A: 1MW

- Limits should be expressed in kW/MW, not in kVA/MVA. Otherwise there will be an incoherence with other MS and more installations will be in type B
- 250 kVA is arbitrary – why follow the Walloon grid code and e.g. not the Flemish grid code or Synergrid C10/11?
- The requirements of type B impose a significant impact on (small) installations:
    - Significant cost increase (vs type A: +15 up to +20%)
    - Additional costs from requirements of other NC's (e.g. the E&R code may require redundant communication installations for type B,C,D to be blackout proof)
- There will be an impact on the power equipment supply market if diverging limits exist between countries

Upper limit category B: 50 MW

- Industrial cogeneration units should be kept in type B as it is not useful to put them in type C for delivery of frequency control because these installations are exempted for this by the RfG. Industrial cogeneration are also embedded in industrial sites, so they are not directly interacting with the grid and might not deliver the desired behavior.
- In case of a substantial modification existing cogeneration units need to comply with RfG if they would be in type C, risking loss of capacity if the investment is too steep.
- What is the relevance to set a limit based on the individual production permit?
- Wind farms should be kept in B as long as there is no clear view on the implementation of requirements of type C for power park modules – a maximal implementation would be too demanding.

Criteria for category C

- Delivering FCR, FRR & RR should not be a criterion. Requirements for the capability of delivering these services should be in the contract for delivery of these ancillary services.

Criteria for category D

- An additional limit of "25 MW if PoC is >110 kV" creates an unequal treatment between installations that are or are not embedded in industrial sites
- Delivery of black start service should not be a criterion. Requirements for the capability of delivering this service should be in the black start contract.

The BGA suggests to continue the discussion on categorization of grid users in a second phase, when the discussions on the implementation of the different requirements have taken place.

<u>General remarks</u>

Network Codes are a powerful tool **to finalize the single European energy market**. They are an opportunity to harmonize current regulation within (regions of) Europe and between best practices. Therefore, it is to us irrelevant to make choices about NC implementation based on current regulation (grid codes, laws and decrees). Furthermore, coordination between similar member states and control areas is needed as much as possible. It makes logic sense to us that similar systems demand similar requirements of their grid users and that the **level playing field** for grid users isn't distorted.

The BGA do not understand why a country such as Belgium, with a strongly meshed, highly developed and efficiently operated grid, would choose to **deviate from the upper limits** foreseen in the NC's for the different types of grid users. According to us, ENTSO-E (and ACER and the member states) aimed by the determination of a range for the category limits at a possible diversification between countries and regions based on the quality of the grids. It was never the intention that a country such as Belgium would pursue for the maximum of installations to be covered by the most ambitious categories possible. Especially the split between category A and category B (position of small renewable installations) and between category B and C (impact of a substantial modification of existing power generation modules) is of importance. To our opinion deviating from the upper limits is like taking a too high insurance by grid operators compared to the possible risks. On top of that, this insurance is paid by grid users and can have an impact on their competitiveness compared to neighboring countries that choose not to apply the same high level of requirements. The BGA are of the opinion that Elia should clearly state why it deviates from the upper limits and that Elia should analyze, through a **cost-benefit analysis**, the overall costs and benefits of the impact of this deviation on the Belgian electricity system as a whole (thus taking also into account costs for grid users). The additional costs for generators are – if not totally clear – certain and extensive. Up to this date, we have not seen any cost justification for lowering the limits.
An example with respect to FRT compatible units: according to Synergrid there are around 500 MW of generation installations in the range between 250 kW & 1 MW. This is less than 4% of the installed capacity in Belgium as monitored by Elia and even less than 3% if the total installed capacity is considered. When one reverts to marginal shares of the production park, and impose significant additional costs upon them, it should be clearly demonstrated that there is (1) a true need to have this additional reserve (2), there is proof that this is the most cost efficient solution for the whole of the system and (3) there is proof that a system contracting those same reserves through the liberalized market does not yield the same results.

Grid services should be procured via market based mechanisms. Grid users should have the option, not the obligation to participate in these markets and grid users not participating should not be obliged to invest in unnecessary equipment. Market prices for these services will trigger the interest of market parties to participate and make related investments. We notice that the RfG introduces on top of this principle an extra insurance for grid operators so that production facilities will, technically, always be able to deliver the required services (although there is never a guarantee about the actual delivery). But this extra insurance should remain proportional. Furthermore, as we expect new generation units mainly to be decentralized smaller units that are installed more stepwise in time (compared to a single important capacity increase by central units), we believe that the RfG and the Technical Grid Codes can be adapted quickly enough if this would be necessary. The uncertainty about the future can thus only be claimed partially as a reason to choose already today for a very ambitious implementation of the code.

Also the BGA would like to stress once more that the choices that will be made about the exact implementation of each requirement can interact with our position on categorization. Without a clear view and certainty on the **implementation of these requirements**, we need to consider a worst-case scenario. In this respect the BGA also regrets that there is no preliminary consensus on how the **system as a whole** will be operated based on an agreed level of security and quality. These operational principles should have been defined first in the network codes for system operation before deriving requirements for connections of generating or demand facilities.

We therefore believe that this round of exchange of positions and arguments on the topic of categorization of significant grid users cannot be the final round. The iterative process that Elia is

proposing, will be very important for this topic. Furthermore, the non-binding guidance documents can also increase the need for a review of the proposals.

<u>Technical-economic remarks per category</u>

A. With respect to the upper limit of **category A**, we maintain our proposal to set the upper limit at 1 MW instead of 250kVA as proposed by the grid operators.

- We note that according to the NC's, **limits shouldn't be expressed in kVA/MVA but in kW/MW**. A kVA-rating of the upper limit for type A will only lead to the fact that a lower amount of installations will be considered as type A and consequently more small installations will be type B (as the power factor is always below 1, resulting in a lower kW rating as opposed to the kVA rating of a given piece of equipment)
  Furthermore, the use of a parameter deviating from the RfG (kVA vs. kW) will result in incoherence between the different Member States in the EU. The risk may very well be that neighboring countries use kW as the determining parameter. This will result in a range of products on the market that will not be able to comply in Belgium, as they are produced for type A requirements, but should apply type B requirements in Belgium. The common example would be the following: A 1200 kVA gas engine with a power factor of 0,8 resulting in 960 kW would be type A in a Member State using 1 MW, whilst it would be type B when using a kVA limit.
  This point is actually true for all the categories.

- The choice of **250 kVA by Elia is arbitrary** and based on the limit for remote control of active power in the Walloon grid code (cf. Elia slides with the reasoning on the boundaries). This is opposed to the limit in the Flemish grid code, stating 1 MVA (actually 1 MVA or lower). The difference between the two grid codes demonstrates the arbitrary nature of this decision. According to the current Synergrid C10/11 the limit for the Low Voltage Ride Through is currently set at 1 MVA, again indicating that 1 MW (as opposed to 1 MVA to be coherent with the other limits) is a suitable limit to make the distinction between type A and B. The reactive power capability is defined by the Synergrid C10/11 and is currently set at 1 MVA.

- Elia showed some calculations with respect to the impact of low voltage on distributed generation, caused by a short-circuit on a 380 kV busbar. We doubt that this calculation or even this reasoning can be used to justify the 250 kVA limit. Because, what is the chance that such an incident occurs and why can the consequences not be (partially) mitigated by ancillary services like R1? Demanding all generating facilities a FRT @0,5 seems a too excessive cost. Especially because the impact in case of a limit at 1 MW is not analyzed – can we be sure that the limit at 250 kVA compared to 1 MW has a significant different impact? With respect to the calculation itself, its underlying hypotheses and input data only limited details were available. Does for example the calculation take into account that increasing levels of decentralised production will have a positive effect on the voltage levels in those lower voltage grids, and hence lower the amount of impacted production installations? How does one come to the conclusion that 1800 MW will drop out, as it was earlier stated that the category 250-1000 kW only covers about 500 MW currently and is only estimated 2 x higher in 2025 (→ 1000 MW)?

- The **impact for (small) installations of the requirements of type B is not negligible**.

  The investment cost will increase as result of the demand of a remote control box, derating of the generator, the enhanced control and protection schemes and metering and possible additional certification requirements. For a CHP of a few 100 kW, these additional investment costs are high in comparison to the total investment cost (see attachment: document of AMPS). Besides investment cost, remote control can interfere with the business model through an impact on running hours, efficiency etc. Furthermore, since the generator is only able to withstand a very limited number of voltage incidents (LVRT) on the grid, the O&M cost will increase as the probability that the generator needs to be revised or replaced increases significantly.

We list some of the main costs to be expected for a small CHP:

- Remote control by the DSO: additional investment in a remote control box approved by the DSO (€4.000 to €18.000 depending on the distribution cabin) and a loss of revenue (electricity, CHP/GC certificates, possibly increased maintenance) as result of modulation of the generator by the DSO.
- Low Voltage Ride Through capability: at the time when the fault occurs, its effect on the alternator terminals is an abrupt voltage drop. If the voltage drops to 0 (i.e. voltage drop = 100%) this is similar to a short-circuit. If the short-circuit fault does not occur on the machine terminals, but at a remote point on the grid, the result is residual voltage at the alternator terminals (between 5% and 30%) due to the impedance between the fault location and the alternator terminals. Moreover, the fault which occurs does not necessarily cause a short-circuit on all three phases, only on one of them. It should therefore be noted that in these fault situations, the voltage at the alternator terminals falls suddenly, and it is likely that a certain voltage percentage will still be visible at the alternator terminals. The higher the residual voltage, the better this will be for fault withstand, the worst situation being voltage that is almost zero at the alternator terminals.

  When the fault appears, the alternator which was delivering a certain amount of power from the grid, can no longer deliver this power once the voltage drops (P = U*I) . At the same time, when the fault appears, the alternator will react by generating a current, and the higher the value of the voltage drop, the higher the current will be.

  In conclusion, when the voltage drop appears:

  - The greater the voltage drop, the greater the instantaneous current. In short-circuit mode, the instantaneous current can reach 10*In.
  - The greater the voltage drop, the greater the risk of desynchronization.
  - The greater the voltage drop, the more speed/frequency the genset will pick up.

  The above mentioned effects imply that these capabilities need a reinforced alternator due to the high currents that are possible:
- Derating of the alternator: for the same apparent power, an alternator that should be able to withstand a LVRT must be 1,5 to 3 times bigger than without this LVRT-requirement (depending on LV levels).
- Advanced control and protection schemes: a basic SHUNT excitation system cannot handle the LVRT, instead a more expensive AREP or PMG excitation is required.

  During the fault the alternator (AVR) should switch from power factor regulation to voltage regulation mode to try and supply the maximum power to the grid. Additional cost: €1.200 - €1.500. Probably a more advanced mains breaker relay (netontkoppelingsrelais) is required. Additional cost: unknown at the moment.

  It is recommended to be able to register events noticed during transient fault periods (e.g. LVRT), using a data logger type measuring instrument. Cost: at least several 1.000's of euro's.
- Engine-alternator resistant to large torques: during a grid fault (mostly at the beginning and the end of the grid fault) the engine-alternator is subject to large torques on the shaft. The engine, the alternator and the coupling between both must be designed to withstand those large torques. Additional cost: unknown at the moment
- Certification of the genset by the DSO: if certification of the engine-alternator for LVRT is required based on numeric models, those numeric models must be purchased by the engine and alternator manufacturer. Additional cost for each type engine/alternator: €10.000 - €15.000 (spread out over units sold).

- If certification based on testing is required, each test will cost up to €40.000-€50.000.
- Risk of breakdown of the generator: alternators can maintain the power supply to the grid for a limited number (10-20) of dips or voltage incidents on the grid (LVRT), with the maximum current of 10*In for a period to be defined according to the destructive limit curves specific to each alternator. However, a detailed inspection of stator windings, shaft and coupling is necessary after every serious incident. This will increase the cost of the O&M contract. The cost of revising or replacing an alternator will be higher if the CHP installation is difficult to access, which is often the case for CHP installations in hospitals and nursing homes. Additional cost: unknown.
- Supply of reactive power: the efficiency of the alternator decreases with 1 to 2 percent point when the power factor decreases from 1 to 0,8. Furthermore, due to physical stability limits, the reactive power that a generator can absorb (under excitation) is limited. This limitation changes from generator to generator (0,2 to 0,3 * Pnom).

The AMPS document shows the **incremental cost increases** due the different constraints from one category to another:

- Baseline (as is now) → Category A: +15%
- Category A → B: +15-20% on top of category A cost
- Category B → C: +20-30% on top of category B cost

As many of these smaller installations are used in CHP, the additional requirements will lead to higher costs and thus a higher need for support (green certificates / CHP certificates). Furthermore, when the uncertainties and additional costs are not fully covered by a higher support, the number of installations will decrease. This has a negative impact on primary energy saving, CO_2 emissions and security of supply.

Moreover the use of the limit at 250 kW instead of 1 MW will imply significant additional requirements and thus costs, not only because of the RfG but equally due to **other network codes imposing demands** as from type B units. E.g. the E&R code may require redundant communication installations for type B,C,D to be blackout proof.

- The use of a specific level, **diverging from neighboring countries**, will result in incoherence between the different Member States in the EU and may result in an unfair market distortion between neighboring countries. But it is not only a matter of unfair market distortion, but also a matter of smaller scale markets: if every MS demands different abilities, for each MS a different genset (a main group of installations that would be impacted by this classification) will have to be designed, tested, put on the market ..., This will result in a range of products on the market that will not be able to comply in Belgium, as they are produced for type A requirements, but should apply type B requirements in Belgium. The common example would be the following: A 500 kW gas engine would be type A in a Member state using 1 MW as limit, whilst it would be type B in Belgium. This results in a serious amount of small installations that would not be able to comply in Belgium resulting in a loss of opportunities for small cogeneration units which in turn will result in less reductions of primary energy savings.

B. With respect to the upper limit of category B, we maintain our proposal to set the upper limit at 50 MW instead of 25 MW as proposed by the grid operators.

- **Requirements for <u>industrial cogeneration units</u> should be kept reasonable** (i.e. not be type C), both for technical and economic reasons. Industrial cogeneration units typically have a capacity around 40 MW, which supports a category limit of 50 MW.

  If the reasoning to apply 25 MW instead of 50 MW would be the additional requirements for frequency control, it can be noted that the RfG has foreseen that CHP's of type A, B & C are

excluded from any obligation to deliver frequency control (see art. 6 §4 of the RfG). The targeted installations will thus be excluded from the frequency control activities rendering them of no use as type C. Indeed, requirements to industrial cogeneration units relating to frequency stability are not economically feasible because of their normal operation in function of heat production instead of electricity production.

Also industrial cogeneration units are often **embedded in industrial sites**. These units are typically gas turbines in the range between 25 to 50 MW and are not directly interacting with the grid. The monitoring takes place at the connection point of the industrial site and not of the generation unit itself. If frequency control is not required, only voltage control remains possible on such installations. However, due to the fact that they are mostly embedded in industrial sites, this will not result in the desired behavior at the connection point. The following sequence may further explain this. Assume a gas turbine coupled to a 36 kV internal grid of an industrial site which in turn connects to the 150 kV grid through a transformer:

- TSO/DSO asks for delivery of more MVAR and relays this message to the gas turbine
- The gas turbine increases the voltage at 36 kV
- The voltage level on the 150 kV will increase as well (as demanded by the TSO)
- The regulating unit of the transformer will then automatically lower the voltage level of the 36 kV output
- It is then unclear how the GT will react and what would be the ultimate result at the level of the 150 kV. It may very well be that no change will effectively be realized. And even if it is technically possible to deliver the requested behavior, this will require additional investments in which case it becomes part of a cost benefit analysis.

Therefore industrial cogeneration units are of no use to the system operator with regards to system regulation.

Furthermore, integration of cogeneration facilities into category C also means that a **substantial modification of existing power generation modules** implies the application of the RfG code. This means additional costs for existing installations up to 65% (source: AMPS-document) to fulfill the requirements of the RfG, which would not be the case if the installation would be in category B. We foresee that many replacement investments will not occur, with a negative impact on primary energy savings and security of supply.

- The argument to set the limit in accordance to the **individual production permit** is pointless. The limit in the permit is administrative, and by no means a technical limit.

- Wind farms should be kept as much as possible in type B as the additional requirements of type C are unclear for the moment and might be too demanding.
  E.g. synthetic inertia: this is possible for wind turbines but developments are necessary – it is currently a very expensive service with likely a strong negative impact on the lifetime of a wind turbine.
  E.g. power oscillations: a broad interpretation of the definition of power oscillations will raise technical problems for wind turbine producers to comply with the requirement.

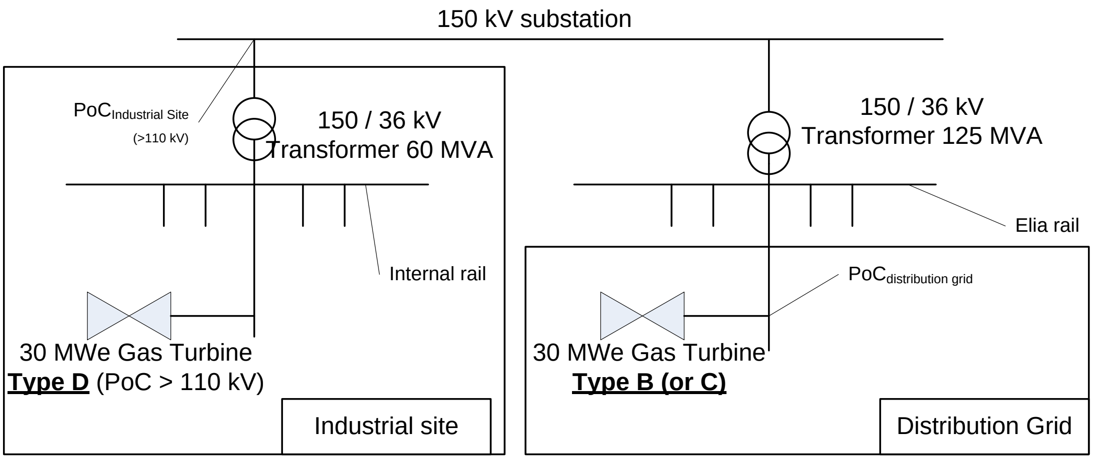
- Specific requirements as the **equipment certificate vs. the simulations** may be imposed through the grid connection contract if needed for the local situation, but should not be the reference scenario for all new units to be built or modernized. The same goes for the LVRT profile vs. the defined FRT.

C. With respect to **category C**, we maintain our proposal to not use the delivery of FCR, FRR & RR as a categorization criterion

- Delivering FCR, FRR & RR should not de facto lead to a categorization of the facility as type C which implies the application of type C requirements. This is not demanded by the RfG either. The requirements for units delivering FCR, FRR and/or RR must be part of the contract with regards to that service. Simply imposing the requirements of type C to all units delivering FCR, FRR & RR, may even exclude some installations from further offering these services. A typical example here could be a large wind farm in type B. For the moment, it can be capable of delivering FCR and be compliant with type B. Applying all the requirements of type C to this installation will then lead to a loss of regulation capacity. As a result, the windfarm will probably make the choice not to deliver FCR at all. In the end there might be a possible increase of the price for the service, as less installations will be able to deliver it.

D. With respect to **category D**, we maintain our proposal to not use the additional "limit of 25 MW if PoC > 110 kV", nor to use delivery of black start as a categorization criterion.

- Delivering black start should not de facto lead to a categorization of the facility as type D which implies the application of type D requirements. This is not demanded by the RfG either. The requirements for units delivering black start must be part of the contract with regards to this service. Simply imposing the requirements of type D to all units delivering black start may even exclude some installations from further offering these services, with a possible increase of the price for the service, as less installations will be able to deliver it according to type D requirements.
- The additional capacity limit of "25 MW if the PoC is higher than 110 kV", asides from the 75 MW limit, leads to the bizarre fact that a 30 MW installation connected on an industrial site would be type D, whilst the exact same unit connected to a lower voltage grid would be type C or even B. This situation is possible because of the Point of Connection, being the point where the industrial site connects to the grid, is in the first case the TSO grid. The following schematic clarifies this situation:



Attached to this document is also an overview made by the Association of Manufacturers and Suppliers of power systems and ancillary equipment (AMPS) of the cost impact of the RfG types on a Class H Prime Rated Industrial Generator (ISO 8528 pt1 performance capability).